INFORMATION SHEET

PRESIDING: Chair Mitchell and Commissioners Brown-Bland, Gray, and Clodfelter
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: July 17, 2019
TIME: 9:00 a.m. – 12:37 p.m.
DOCKET NO.: E-100, Sub 158
COMPANY: DEC, DEP and Dominion Energy
DESCRIPTION: Generic Electric – Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2018
VOLUME: 5

APPEARANCES
Please see attached.

WITNESSES
See attached.

EXHIBITS

TRANSCRIPT COPIES ORDERED: E-mail: Dodge, Cummings, Harrod, Fentress, Grigg, Dantonio, Smith, Bowen, Hutt, Kemerait, Levitas, Ross, Snowden, Wills, Quinn
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DATE: Wednesday, July 17, 2019

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DOCKET NO.: E-100, Sub 158

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

VOLUME: 5

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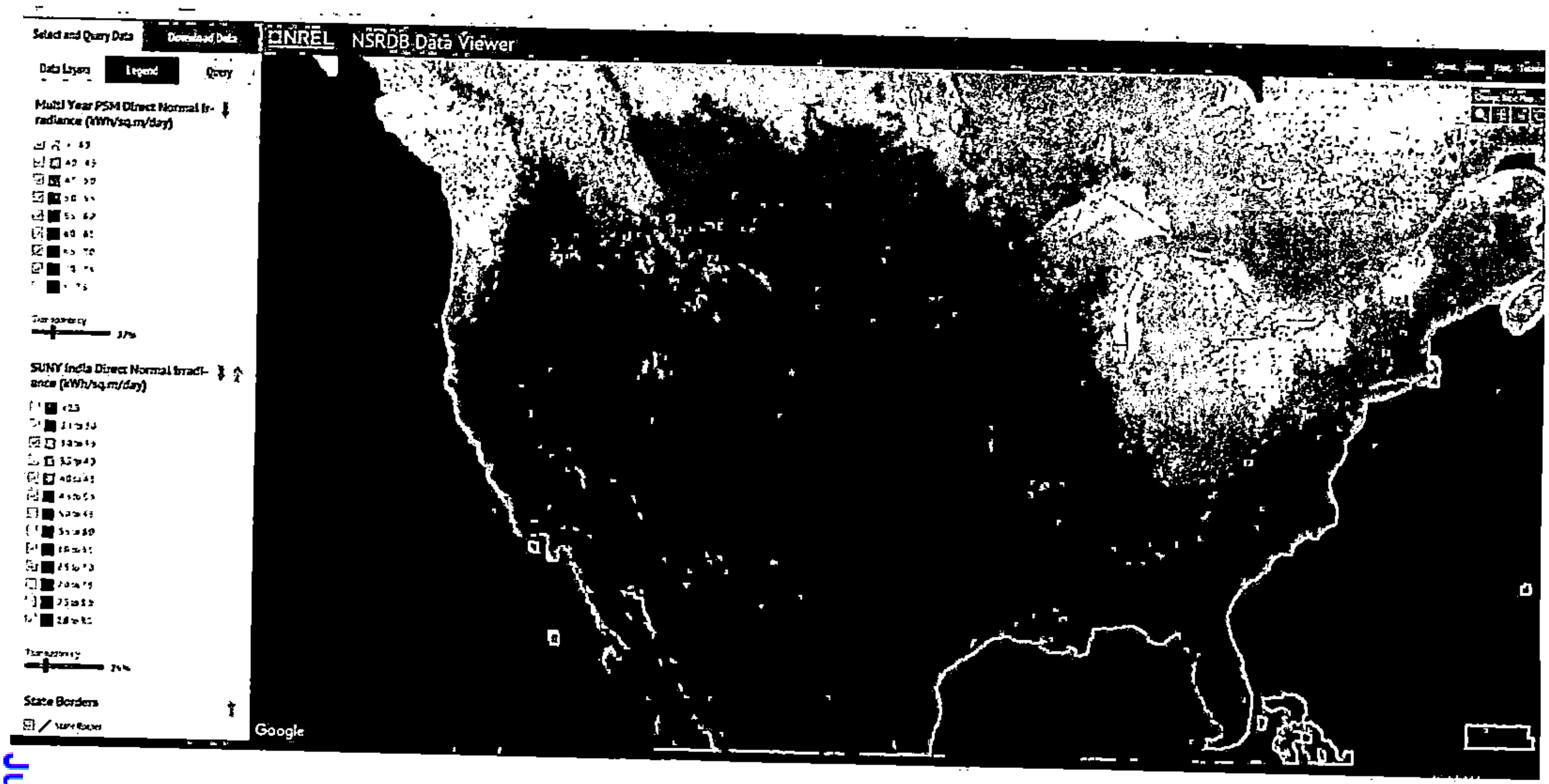

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	INITIAL STATEMENT AND
Rates for Electric Utility Purchases from	)	EXHIBITS OF DOMINION ENERGY
Qualifying Facilities – 2018	)	NORTH CAROLINA

NOW COMES Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company"), pursuant to the June 26, 2018 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Procedural Order") issued by the North Carolina Utilities Commission ("Commission") in the above-captioned docket, and submits its Initial Statement and Exhibits relating to the Company's proposed avoided cost rates and standard avoided cost contract terms and conditions. In support thereof, DENC shows the Commission the following:

I. Introduction

The Company's previously effective avoided cost rates and standard contract terms and conditions were filed on November 13, 2017, in compliance with the Commission's October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* ("2016 Order"), issued in Docket No. E-100, Sub 148 (the "2016 Avoided Cost Case"). In the 2016 Order, the Commission addressed the methods used to calculate avoided cost payments as well as proposals by DENC, Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP") (collectively, the "Utilities") to revise the applicability of standard avoided cost rates and contract terms and the content of those standard contract terms.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided Cost	)	**REPLY COMMENTS OF**
Rates for Electric Utility Purchases from	)	**DOMINION ENERGY NORTH**
Qualifying Facilities – 2018	)	**CAROLINA**

NOW COMES Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC" or the "Company") and, pursuant to the North Carolina Utilities Commission's ("Commission") February 8, 2019 *Order Granting Extensions of Time*, submits these Reply Comments in response to the Initial Statement of the Public Staff and the Initial Comments and affidavits[1] of the North Carolina Sustainable Energy Association ("NCSEA") and the Southern Alliance for Clean Energy ("SACE") filed in this proceeding on February 12, 2019.

I. INTRODUCTION

With its Initial Statement and Exhibits submitted on November 1, 2018 ("Initial Filing"), DENC proposed updates to its standard avoided cost schedules, Schedule 19-FP and Schedule 19-LMP. The Company also proposed to: (1) adjust its methodology for calculating avoided energy rates to account for re-dispatch costs associated with the addition of distributed intermittent generation to its system; (2) establish a cap on annual avoided capacity payments to reflect the intermittent nature of these resources; (3) offer more granular hours and seasons for avoided cost rates and adjust the seasonal allocation

[1] NCSEA attached the affidavits of Benjamin F. Johnson and R. Thomas Beach to its initial comments. SACE attached the affidavit of Brendan Kirby to its initial comments.

factors relevant to avoided capacity rates accordingly; and (4) adjust the performance adjustment factor ("PAF") applicable to avoided capacity payments to 1.07. As directed by the Commission in its final order in the 2016 avoided cost proceeding (Docket No. E-100, Sub 148) ("2016 Case"),[2] the Company also provided updates on the increased backflow occurring on its system from distributed renewable qualifying facilities ("QFs"), hourly operational marginal combustion turbine cost data, the adjustment to avoided energy rates to reflect the locational value of generation in its North Carolina service area as approved in the 2016 Case, and responded to other directives.

The 2016 Order and North Carolina House Bill 589[3] resolved a number of issues that DENC and other parties debated in previous avoided cost proceedings pertaining to the availability of standard rates and terms to North Carolina QFs and to the actual terms applicable to utilities' purchases of energy and capacity under the Public Utility Regulatory Policies Act of 1978 ("PURPA") standard offer in this State. The Company's Initial Filing was based on those conclusions and provided updates to the Commission on issues specific to DENC that were addressed in the 2016 Order. As demonstrated by these reply comments, the remaining issues in this case between the Company and the Public Staff in particular are few. In addition, and in the interest of resolving issues where possible and appropriate, the Company is willing to modify certain aspects of its original proposals based on discussions with the Public Staff conducted subsequent to the filing of initial comments. The Company believes that these modifications should

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[2] In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("2016 Order").
[3] North Carolina Session Law 2017-192 (July 27, 2017) ("HB 589").

address many of the concerns raised by NCSEA and SACE as well as the Public Staff with respect to DENC's Initial Filing, as discussed further herein.

II. REPLY COMMENTS

A. Energy Rates

The Public Staff's initial comments recognized that the Company's method for calculating avoided energy costs for Schedule 19-FP in this proceeding is consistent with DENC's approach in the 2016 Case. The Public Staff concluded based on its review of the PROMOD inputs that the inputs to the model and the output data from the model are reasonable for determining the Company's avoided energy costs.[4]

1. Fuel Forecast

As discussed in the Initial Filing, consistent with previous avoided cost filings, DENC used the PROMOD utility production cost model to calculate avoided energy costs as reflected in the rates offered in Schedule 19-FP. Also consistent with past practice, with regard to forward commodity prices (fuels, power, emission allowances), DENC developed avoided energy rates using 18 months of forward market prices, 18 months of blended ICF International, Inc. ("ICF") and market prices, and then ICF prices exclusively from then onward. In the 2016 Order, the Commission found the input assumptions the Company used to determine avoided energy cost rates to be reasonable.[5]

[4] Public Staff at 19. On page 19 of the Public Staff's initial comments, the Public Staff references DENC's "Schedule 19-DRR," which is now closed to new customers. On page 20 of the Public Staff's initial comments, Table 7 shows the incorrect 10-year levelized Schedule 19-FP energy rates. The on-peak rate DENC proposed in its Initial Filing is 3.211 c/kWh, and the off-peak rate is 2.523 c/kWh. The Company has discussed these items with the Public Staff.
[5] 2016 Order at 7.

As noted above, the Public Staff states in its initial comments that it believes that inputs that DENC used for its PROMOD model and the output data from the model are reasonable for determining the Company's avoided energy costs.

NCSEA proposes that DENC as well as Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Duke Utilities" and together with DENC, the "Utilities") use forward market prices for two years, transitioning in the next three years to an average of a set of recent fundamentals forecasts, including the ICF forecast and the 2019 Energy Information Administration ("EIA") Annual Energy Outlook forecast.[6] NCSEA also states, however, that it would not object in the alternative to the Company's forecast methodology.[7] NCSEA affiant Beach also did not object to the Company's fuel forecast or modeling assumption, but recommends that the Utilities use the same average advocated by NCSEA.[8] No other party objected to DENC's fuel forecast or modeling assumptions.

The Company's use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136),[9] and DENC continues to believe that the ICF forecast of commodity prices is, on its own, appropriate for estimating avoided energy cost rates. First, ICF forecasts are reputable and respected in the industry and NCSEA has not presented a convincing reason why the Company's continued use of the ICF

[6] NCSEA at 19.
[7] *Id.*
[8] Beach at 3-4.
[9] The Company has also used the ICF forecast since 2008 to develop its Integrated Resource Plans ("IRPs").

forecast is not reasonable, particularly given the Commission's recent history of accepting that approach.

Additionally, while the EIA forecast appears to be nationwide in scope, ICF provides the Company a full complement of commodity prices, and tailors its forward prices for the mid-Atlantic region of the U.S. in which the Company operates. Because the EIA study is nationwide, it is not clear whether it includes the regional (mid-Atlantic) commodity prices that DENC requires, including, for example, central Appalachian coal prices and PJM Interconnection, L.L.C. ("PJM") energy market prices. Based on all of these factors, DENC believes it has appropriately forecasted fuel prices for use in this proceeding.

2. Avoided Hedging Costs

Consistent with the 2016 Case, the Company has used the same Black-Scholes option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 avoided cost proceeding (Docket No. E-100, Sub 140). Based on that approach, the Company calculated a fuel price hedging value of $0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The Public Staff concludes that DENC's hedge value calculation is reasonable.[10]

NCSEA and Mr. Beach recommend that the value of hedging should be calculated based on the cost of executing hedges over the full 10 year PPA horizon.[11]

Mr. Beach refers to two studies in support of his recommendation. The first is a study conducted by Xcel Energy in 2013, which he states estimated "long-term (20-year) hedging benefits of distributed solar resources on its system to be $6.60 per MWh," and

[10] Public Staff at 28.
[11] NCSEA at 20-23; Beach at 4 and Exh. 1, at 14-17.

which he states "appears to have used the cost of call options in the over-the-counter gas futures market to calculate the hedging benefit."[12] Mr. Beach also cites a study conducted by Clean Power Research for the Maine Public Utilities Commission ("Maine Study") that suggests the hedge value of renewable energy could be as high as \$7.30/MWh of QF generation.[13] Mr. Beach recommends that the Commission adopt this method for calculating avoided hedging costs in this case.[14]

The hedge value of renewable energy was thoroughly reviewed in the 2014 avoided cost proceeding, in which the Commission decided that it was reasonable to use the Black Scholes option pricing method recommended by the Public Staff to estimate the hedge value of QF generation.[15] The Commission also concluded in that proceeding that hedging benefits should only be valued over the hedging terms actually used by the Utilities.[16] Consistent with this determination, since the Company's current natural gas hedge program extends approximately 18 to 24 months in the future, it is appropriate that it calculate avoided hedging costs using this time frame.

The Xcel study cited by Mr. Beach is not appropriate for use in this proceeding. First, the resulting \$6.60/MWh that results from that study is inflated, because the study looked 20 years into the future (with the related stale high gas prices) versus a PPA horizon of 10 years with only 18 to 24 months of actual hedging activity by the Company. Moreover, as it is dated 2013, the study itself is stale, and dates from a time

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[12] Beach Exh. 1 at 16.
[13] *Id.* at 16-17.
[14] Beach at 4.
[15] In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 30, Docket No. E-100, Sub 140 (Dec. 17, 2015) ("2014 Order").
[16] In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014, *Order Setting Avoided Cost Input Parameters* at 42, Docket No. E-100, Sub 140 (Dec. 31, 2014) ("Parameters Order").

when natural gas futures prices were much higher. While the prices used in the Xcel study may have been accurate at that time, current forward prices are significantly lower. For example, in 2013 the forecasted natural gas price for 2025 was approximately \$7.50/mmbtu, while the current forecasted gas price for 2025 is closer to \$4.00/mmbtu. It is not apparent how or if the Xcel study used the cost of call options to determine the hedge value. The method appears to be simply a cash flow discounting exercise and does not accurately represent the value of reduced natural gas price volatility in the future.

The Maine Study is also somewhat dated, as it was last updated in 2015, and the authors admit "there are practical difficulties with this method, requiring some simplifying assumptions."[17] Moreover, the study is flawed because it is a one-sided analysis that included the cost and risk of natural gas prices increasing in the future, without including the possibility of future downward movements in those prices. The result is that the alleged hedge value would drastically and unreasonably increase the energy rates paid to QFs.

Consider the following example. A solar generation facility with capacity of 100 MW, assuming a 24% capacity factor, would generate approximately 200,000 MWh of energy per year. The Maine Study suggests that the existence of this QF generation provides \$1.4 million per year in reduced natural gas purchased cost volatility. There is no reason to believe that the avoided hedge transaction costs or the reduction in natural gas price volatility would actually approach \$1.4 million each year, particularly over the course of a 10-year standard avoided cost PPA. Put another way, if the Maine approach advocated by Mr. Beach, which reflects a payment of up to \$7/MWh for hedging, were

[17] Maine Study, Vol. 1 at p. 40.

adopted, assuming a combined-cycle gas unit heat rate of 7.0 mmbtu/MWh, the implied fuel hedge value would be approximately $1/mmbtu, at current gas prices. This would mean that the Company would pay $4/mmbtu, which would represent a 33% premium above current natural gas prices of roughly $3/mmbtu. This is an unreasonably high price to pay QFs for hedging value. Given the flaws with both the Xcel study and the Maine Study and the significant cost impact these approaches would have on avoided energy rates, it would not be reasonable to adopt either of these methods for calculating avoided hedging costs for North Carolina.

3. Re-Dispatch Charge

In the 2016 Order, the Commission concluded that with their initial filings in this proceeding the Utilities should address, among other issues, "consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable."[18] In response to this directive, DENC has proposed to adjust the avoided energy payments that the Company makes to intermittent, non-dispatchable QFs to reflect the increase in system supply costs (re-dispatch costs) that results from the addition of these resources to the system. To calculate this re-dispatch charge, the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar photovoltaic ("PV") penetration using data from 26 solar sites to determine an overall cost impact attributable to the intermittency of the new resources. The Company calculated that overall cost impact to be approximately $1.78/MWh, which it proposed to use to adjust the avoided energy

[18] 2016 Order at 110-111; *see also* In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utilities Purchases from Qualifying Facilities – 2018, *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* at 1, Docket No. E-100, Sub 158 (June 26, 2018) ("2018 Order Establishing Proceeding").

payments. The Company explained that the application of this charge to QFs will help ensure that the Company's customers pay for accurate avoided costs, since without the charge customers would be overpaying for QF output.

a. Response To Public Staff Comments

In its initial statement, the Public Staff does not oppose the concept of a re-dispatch charge. The Public Staff states that the avoided energy per kWh rate should not be reduced by separately calculated charges, even if the total amount of avoided energy costs is reduced.[19] It states that a consolidated charge would present difficulties for tracking costs of compliance with the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"), and recommends that DENC collect and administer these costs separately from the avoided energy rate, similar to the Duke Utilities' approach.[20] The Public Staff comments further that while it was reasonable to calculate the re-dispatch charge using solar resources, due to solar being the dominant type of intermittent, non-dispatchable QF, it requests that in the future the Company separately calculate the charge specific to each type of intermittent, non-dispatchable QF that seeks to interconnect to its system.[21] The Public Staff also notes that based on a preliminary review it had identified concerns with regard to the Company's proposal and anticipated continuing discussions with DENC about those concerns.[22]

The Public Staff first recommends that DENC modify the application of its re-dispatch charge using an approach similar to the Duke Utilities, which have proposed to collect and administer solar integration cost charges separately from the avoided energy

[19] Public Staff at 30-31.
[20] *Id.* at 31-32.
[21] *Id.* at 46.
[22] *Id.* at 44-45.

rate. The Company proposed to apply the re-dispatch charge as a reduction to the avoided energy rate for purposes of administrative efficiency. However, if the Commission agrees with the Public Staff that it should be separated from the avoided cost payment, the Company can modify the administration of the charge to occur as a separate line item on a QF invoice.

With respect to the Public Staff's recommendation that in the future the Company calculate separate re-dispatch charges for solar, wind, biomass, etc., DENC is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases.

Since the filing of initial comments in this proceeding, the Company has discussed the re-dispatch proposal with the Public Staff in several conference calls. During those conversations, DENC and the Public Staff discussed how each of the 85 PLEXOS model runs were used to calculate the charge, how the generation portfolios were constructed and the utilization of historic data versus average generation portfolios, and addressed the questions that were raised in the Public Staff's initial comments.[23] The Company explained that the data input to PLEXOS model used to calculate the charge was actual historical data on the 26 selected sites from calendar year 2017.

Based on these conversations, the Company understands the Public Staff's remaining concerns with the re-dispatch proposal to include the weighting of cost categories and the selection and weighting of solar penetration rates. As discussed further below, the Company continues to believe that the approach it took in the simulation analysis with respect to cost category and solar penetration level selection and

[23] *Id.* at 45.

weighting was reasonable. However, in the interest of reaching compromise on this issue and narrowing down the areas of dispute in this proceeding, the Company is willing to re-calculate the re-dispatch charge for purposes of this proceeding with modified cost category and solar penetration scenario weightings, resulting in a re-dispatch charge of $0.78/MWh.

In the analysis that provided the basis for the proposed re-dispatch charge, the Company gave equal weight to each of the cost categories considered. These cost categories included all costs, PJM purchases/sales, pumping costs/reserves, and generator costs only. The Public Staff questioned in its initial comments and in subsequent discussions whether it was reasonable for DENC to equally weight cost and solar penetration scenarios.[24] Through subsequent discussions, the Public Staff has indicated that it recommends that DENC recalculate the re-dispatch charge giving 100% weight to the "all costs" category and none to the other categories.

With regard to the cost categories reflected in the re-dispatch analysis, the Company believes it was appropriate to weight each of these cost categories equally, since each category plays a major role in the total re-dispatch cost related to distributed solar generation.

First, even though DENC is a member of PJM, the Company's ability to make sales into the PJM market is not a given, and the inability to make market sales would increase the re-dispatch costs associated with solar distributed generation ("solar DG"). For example, if distributed solar generation exceeds the Company's load on sunny days, but DENC was unable to sell that excess power into PJM, it would be forced to reduce its

[24] *Id.*

own generators' output. DENC must run its own units at certain minimum levels; otherwise it must shut those units down. If the reduction in output was below minimum levels and the Company was forced to shut down its own units, the cost of solar dispatch would increase significantly due to the addition of start-up and dispatch costs.

With regard to the no-pumped storage cost category in the re-dispatch analysis, the Company used pumping as storage to simulate the solar DG being dispatchable. When there is an excess of energy (generation is greater than demand), the Company's Bath County Pumped Storage Station ("Bath County") will pump and store the energy for use at a later time. When there is a need for energy, either during non-daylight hours or during periods of cloud cover, Bath County will generate power. The weighting of the pumped storage category reflects the fact that Bath County has a limited capacity of approximately 1,800 MW. In the 2,000 MW and 4,000 MW scenarios, therefore, Bath County will not be able to meet the total need of these scenarios on its own.

In the Company's view, because it cannot curtail QF output except during emergencies,[25] these cost categories represent actual costs that the Company incurs due to intermittent, non-dispatchable QF generation. However, as indicated above and for purposes of this proceeding, the Company is willing to recalculate the re-dispatch charge with 100% weight assigned to the "all costs" category.

DENC chose penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the re-dispatch analysis. The Company scaled each solar site to have equal annual energy amounts at the chosen penetration levels while maintaining actual shape, and applied a common capacity factor of 22.42%. The Company used ramp rates of 200 MW/year and

[25] 18 C.F.R. § 292.307(b) (2018).

400 MW/year for the 2,000 and 4,000 MW scenarios, respectively. The following example explains the process the Company used to scale the data for the re-dispatch cost analysis. The example shows two unique 1,000 kW sites scaled to have equal energy while maintaining their actual shapes.

Hour of Day	Site 1 - Original	Site 2 - Original	<-- Scaling -->	Site 1 - Scaled	Site 2 - Scaled
Hour 1	0	0		0	0
Hour 2	0	0		0	0
Hour 3	0	0		0	0
Hour 4	0	0		0	0
Hour 5	0	0	Site 1	0	0
Hour 6	50	0	multiplied	45	0
Hour 7	100	0	by 90%	90	0
Hour 8	200	75		180	112.5
Hour 9	250	200		225	300
Hour 10	300	400		270	600
Hour 11	400	500		360	750
Hour 12	700	550	Scale to 22.5%	630	825
Hour 13	950	650	Capacity Factor	855	975
Hour 14	950	550	(5400 kWh)	855	825
Hour 15	750	400		675	600
Hour 16	700	200		630	300
Hour 17	450	75		405	112.5
Hour 18	150	0	Site 2	135	0
Hour 19	50	0	multiplied	45	0
Hour 20	0	0	by 150%	0	0
Hour 21	0	0		0	0
Hour 22	0	0		0	0
Hour 23	0	0		0	0
Hour 24	0	0		0	0
Total kWh	6,000	3,600	Total kWh	5,400	5,400
CF %	25%	15%	CF %	22.50%	22.50%

In discussions conducted after the filing of initial comments, the Public Staff has indicated to the Company that it recommends re-calculating the re-dispatch charge without considering an 80 MW solar penetration level and allocating 70% to the 2,000 MW scenario and 30% to the 4,000 MW scenario.

The re-dispatch analysis was designed to evaluate data from a range of solar penetration levels – low, medium, and high. The Company included the 4,000 MW solar scenario size in the analysis because that is the Company's DOM LSE portion of the 5,000 MW of solar found to be in the public interest by the Grid Transformation and

Security Act of 2018 ("GTSA")[26] to be built by 2028. The 2,000 MW solar scenario was included to represent a middle ground between the amount of solar currently operational on the Company's system (577 MW) and the 4,000 MW to be built by 2028. Since, however, all of these facilities will by definition be intermittent, they will not consistently produce 4,000 MW. During times when there is widespread cloud cover in the region, the output of these facilities could be significantly less than that amount, and the re-dispatch costs therefore higher. The 80 MW case was intended to represent a scenario of low levels of solar generation, due to widespread cloud cover or otherwise, given the current level of installed solar generation on the Company's system. In sum, the Company included the 80, 2,000, and 4,000 MW levels in the analysis, and weighted each penetration level equally, to capture output and cost scenarios associated with the intermittency of these facilities.

The Company continues to believe that this was a reasonable approach to calculating the re-dispatch charge. Again, however, for purposes of this proceeding, the Company is willing to re-calculate the proposed re-dispatch charge with no weight allocated to the 80 MW scenario, 70% weight allocated to the 2,000 MW scenario, and 30% weight allocated to the 4,000 MW scenario. Combined with the re-weighting of the cost categories discussed above, the re-calculated re-dispatch charge amounts to \$0.78/MWh, a full dollar decrease in the charge from the Company's original proposal.

[26] *See* Grid Transformation and Security Act of 2018, SB 966, 2018 Virginia Acts of Assembly Chapter 296 (enacted Mar. 9, 2018).

b. Response To NCSEA And Affiant Johnson Comments

NCSEA contends that DENC admitted in its Initial Filing that the re-dispatch proposal (which NCSEA terms a "penalty") fails to comply with the 2016 Order.[27] NCSEA argues that the proposal is inappropriately based on generation technology rather than QF characteristics, and that the Utilities should account for market impacts of added wind and solar generation.[28] Finally, it claims that the re-dispatch charge violates PURPA because it is not a "rate," and that it simultaneously violates the doctrine against retroactive ratemaking because it *is* a "rate."[29]

While NCSEA affiant Johnson asserts that the Commission should reject the re-dispatch proposal because it overstated costs and did not consider the benefits of distributed solar QF generation,[30] contrary to NCSEA's position he does not oppose the concept of a re-dispatch charge itself. He acknowledges that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy."[31] He asserts that such costs should be netted against benefits, and that DENC's analysis understates the value of geographic diversity, which he claims reduces transmission and distribution costs.[32] Dr. Johnson presents his own calculation of a re-dispatch charge of $0.69,[33] which appears to have excluded the lowest level of solar penetration.

[27] NCSEA at 34.
[28] *Id.*
[29] *Id.* at 47-48.
[30] Johnson at 17-28.
[31] *Id.* at 18.
[32] *Id.* at 18-20.
[33] *Id.* at 20.

NCSEA's characterization of the Company's proposal as an "admi[ssion] ... that its re-dispatch charge proposal fails to comply" with the 2016 Order is not accurate. The Company's Initial Filing statement, that it "[a]t this time ... is not proposing to adjust avoided cost rates to specifically account for the potential costs or benefits related to changes in ancillary service requirements,"[34] was intended to clarify that the proposal did not address ancillary services, but was instead focused on quantifying the added costs due to the re-dispatching of units caused by the intermittency of solar QF output.

NCSEA also asserts that the re-dispatch proposal does not comply with the 2016 Order because it does not take the form of a separate rate schedule, and because it is based on a particular generation technology rather than QF characteristics.[35] In preparing the Initial Filing and developing the re-dispatch proposal, the Company carefully evaluated the Commission's directives in the 2016 Order. The Company recognizes the Commission's conclusion in that order that "it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity."[36] In developing its proposal, DENC determined that it would be more efficient, and therefore benefit both the QF and the Company, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. The Company believes that QF developers are generally sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. Nevertheless, if the Commission determines

[34] Initial Filing at 12.
[35] *Id.* at 34-35.
[36] 2016 Order at 98.

that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, the Company will comply with that determination.

With regard to NCSEA's comments regarding the focus on generation technology, the Company disagrees that its proposal is not consistent with the 2016 Order and the Commission's conclusions therein. The re-dispatch charge is derived based on data associated with the intermittent, non-dispatchable QFs in the Company's service area, all of which at this point in time are in fact solar QFs. Additionally, while the proposed charge is actually "based upon a consideration of the characteristics of the power supplied by" these QFs[37] (those characteristics being intermittency and unreliability), for purposes of North Carolina, where almost all intermittent non-dispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." Practically, these terms present a distinction without a difference. As noted above, the Company is willing to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, non-dispatchable QFs in a future proceeding.

Finally, NCSEA argues that the re-dispatch charge "is single-issue ratemaking" that is not supported by Chapter 62 of the General Statutes or PURPA. NCSEA first contends that the re-dispatch charge is a "rate" as defined at N.C. Gen. Stat. § 62-3(24) and as such should be set during general rate cases pursuant to N.C. Gen. Stat. § 62-133.

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[37] *See* 18 C.F.R. § 292.304(e)-(f); *Windham Solar LLC*, 157 FERC ¶ 61,134 (2016) ("we remind the parties that the Commission's regulations allow state regulatory authorities to consider a number of factors in establishing an avoided cost rate. These factors which include, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity, allow state regulatory authorities to establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs") (citing 18 C.F.R. § 292.304(e)-(f)).

However, the definition of "rate" contained at Section 62-3(24) provides that the term means every compensation, charge, etc. "charged ... for any service product or commodity *offered by [the utility] to the public*" (emphasis added). While the re-dispatch charge is a "charge," it is not related to any service product or commodity offered by DENC to the public, but rather to the impact to the Company's system of the distributed, non-dispatchable QF from which the Company is required by law to purchase energy.[38]

Moreover, the remainder of the definition states that the term "rate" means in addition to "charges," etc., "any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental, or classification." Therefore, taken to its logical end, NCSEA's argument that the re-dispatch charge falls under N.C. Gen. Stat. § 62-3(24) means that the avoided cost rate schedules and contracts related to it also fall under this definition, and should therefore also be determined during general rate cases under Section 62-133. This is not a reasonable result and would nullify Section 62-156, the North Carolina PURPA statute, pursuant to which the Commission has the authority to approve the charge. In sum, the charge does not constitute single issue ratemaking, because it is not a "rate" as that term is contemplated by Section 62-3(24).

After asserting that the re-dispatch charge *is* a "rate" under N.C. Gen. Stat. § 62-3(24) that should be determined through a general rate case, NCSEA argues that the charge *is not* a "rate" under Federal Energy Regulatory Commission ("FERC") rules

[38] NCSEA's statement at page 47 of its initial comments that "[t]he solar integration and re-dispatch charges are a compensation or charge, to be demanded, charged, or collected, for a service product, in this case ancillary services..." is not accurate with respect to DENC, as again the Company's proposed re-dispatch charge does not and was not intended to account for ancillary services impacts of intermittent non-dispatchable QFs.

implementing PURPA, because it "do[es] not involve the sale or purchase of electric energy or capacity."[39] While it is not entirely clear why not qualifying as a "rate" under FERC's regulations would invalidate the re-dispatch charge, NCSEA goes on to state that even if the re-dispatch charge is a rate under 18 C.F.R. § 292.101(b)(5), it is still inappropriate under Section 292.304(e) of FERC's rules. While the remainder of this argument does not appear to be focused on the Company's proposal, to the extent it is intended to apply to DENC's proposed re-dispatch charge, the Company believes that its proposed charge is consistent with Section 292.304(e). The Company's original proposal was to adjust the avoided energy rate to account for re-dispatch costs, but even if the Commission directs this charge to be separately billed as recommended by the Public Staff, DENC believes that it would comply with this regulation. The rule enumerates "factors affecting rates for purchases," and states that "in determining avoided costs, the following factors shall … be taken into account." Those factors include "[t]he availability of capacity or energy from a [QF] during the system daily and seasonal peak periods, including: (i) [t]he ability of the utility to dispatch the [QF]; (ii) [t]he expected or demonstrated reliability of the [QF] … (v) [t]he usefulness of energy and capacity supplied from a [QF] during system emergencies…."[40] Whether or not the charge qualifies as a "rate" under FERC rules, the re-dispatch costs experienced by the Company may be considered in determining avoided costs under Section 292.304(e).

Contrary to NCSEA's assertions, the Company did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis. With regard to the macro benefits to new solar generation, including zero fuel cost for solar

[39] NCSEA at 48.
[40] 18 C.F.R. § 292.304(e) (2018).

generation, displacement of Company owned generation and PJM purchases during daytime hours, and the related fuel price hedge benefit, these items were reflected in the production cost modeling and in the separate hedge value adder to the energy rates. In addition, to reflect the fact that the solar generation included in the re-dispatch analysis earns renewable energy certificates ("REC"), the Company factored RECs into the re-dispatch analysis, which resulted in lower dispatch costs. However, while intermittent, non-dispatchable generation does produce measurable costs of adding intermittent generation, which the re-dispatch study was intended to quantify, the Company has not observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid from the addition of these types of intermittent resources to its system.

With regard to Dr. Johnson's contentions regarding geographic diversity, and associated claims of lower transmission and distribution ("T&D") costs,[41] the solar sites that the Companies evaluated for the analysis are in fact geographically dispersed throughout DENC's service area, including North Carolina. In the Company's experience, however, due to their intermittent nature, these non-dispatchable QFs do not allow the Company to avoid any T&D costs. In fact, due to the potential for additional line losses resulting from backfeeding, the opposite is more likely true. Finally, as noted in the Initial Filing there are 70 solar QFs operating in DENC's North Carolina service area representing approximately 491 MW of solar capacity. Once the QFs with whom the Company has executed power purchase agreements ("PPAs") come online, that total will rise to 621 MW, exceeding the Company's 2017 average on-peak load of

[41] Johnson at 17-19.

approximately 520 MW by over 100 MW. As a result there is little locational benefit to a QF locating in one area over another within the Company's service area in this State.

Dr. Johnson also contended that re-dispatch costs can "be reduced by engaging in power purchases and sales with other utilities..." and that the Company should net re-dispatch costs vs. PJM purchases and sales.[42] PJM market purchases and sales are accounted for in the Company's re-dispatch study. The PLEXOS model assumed that the Company would sell excess power into PJM during the peak hours with higher LMP costs and make market purchases at low prices. In calculating the re-dispatch cost, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost.[43]

As noted above, the Company is willing to re-calculate the re-dispatch charge by assigning no weight to the 80 MW penetration scenario as well as assigning 100% weight to the "all costs" cost scenario. This modification, and the resulting charge of $0.78/MWh, should address Dr. Johnson's concerns with the re-dispatch charge, which again he does not oppose in and of itself.

c. Response To SACE And Affiant Kirby Comments

SACE contends that the Company has not adequately supported its proposed re-dispatch charge and that the Commission should reject the proposal.[44] SACE affiant Kirby objects to the inclusion of the 80 MW solar penetration level in the re-dispatch analysis, as well as the Company's approach of averaging re-dispatch costs of the

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[42] *Id.* at 19-20.
[43] The netting of PJM market purchases and sales was not reflected in the "no PJM market" cost category. However, due to the Company's willingness to recalculate the re-dispatch charge by allocating 100% weight to the "all costs" category, the netting of PJM purchases and sales, and the resulting net benefit to the solar re-dispatch cost, would be reflected in the $0.78/MWh.
[44] SACE at 17-18.

multiple solar penetration levels and cost categories.[45] While neither SACE nor Mr. Kirby offered an alternative re-dispatch charge, but instead simply recommended rejection of the proposal, the Company's willingness to re-calculate the re-dispatch charge as discussed above should address SACE's and Mr. Kirby's concerns.

4. Energy Seasons And Hours Designations

In response to the Commission's directives in the 2016 Order and the Procedural Order to consider offering rate schedules that provide more granularity of peak seasons and hours, in the Initial Filing the Company proposed rate schedules that offer additional granularity for energy and capacity rates to provide improved price signals. In light of these proposals and to simplify the Schedule 19 rate offerings, the Company proposed to eliminate the Option A and B rates, and modified its avoided cost rate design to differentiate between Energy Peak Hours and Capacity Peak Hours. Specifically with respect to energy, the Company proposed to add a shoulder season to include the spring and fall months of March, April, October and November.

The Public Staff recognized that the Company's proposed changes to its on- and off-peak energy hours designations comply with the Commission's directive to propose more granular rates.[46] It supported the Company's proposal of a shoulder season.[47] It also recognized the need to balance rate granularity and the administrative burden associated with implementing more granular rate schedules.[48] The Public Staff also, however, asserted that mismatches between proposed rates and average LMPs from the last several years remain, posing the example that DENC's proposed summer rates will

[45] SACE Attachment C at 1.
[46] Public Staff at 48.
[47] *Id.* at 52-53.
[48] *Id.* at 53.

overpay QFs in the morning and significantly underpay them in the afternoon peak.[49] It therefore proposed additional refinements to the Utilities' on- and off-peak hours designations, through a three-step analysis that includes a shoulder season and a "premium peak" designation, resulting in nine pricing sub-periods for energy (6 peak and 3 off-peak).[50] The Public Staff asked the Utilities to comment on the proposal, including any billing system changes necessary or administrative challenges that could arise, in their reply comments.[51]

The Company continues to believe that its proposed energy seasons and peak hours designations are reasonable and appropriate, particularly for the standard rates and terms that are developed in these proceedings, where the goal is to try to achieve a balance between providing good price signals for QFs and maintaining administrative efficiency for the Utilities. The Company did add granularity to its energy rate design as directed by the Commission and recognized by the Public Staff. Implementing the Public Staff's proposed method will add complexity to the calculation and billing of the energy rates, as the Company will need to redesign its Schedule 19 billing system to accommodate it.

In subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in the Company's summer peak season. In addition, the Public Staff has proposed expanding the "premium peak" summer and winter hours such that there are four premium peak summer hours in the afternoon and four premium peak winter hours, two in the morning and two in the

[49] *Id.*
[50] *Id.* at 55-56.
[51] *Id.* at 57.

evening. Based on these discussions and upon additional consideration the Company would be willing to accept the Public Staff's proposal, modified as discussed above, in the interest of achieving consensus on this issue. While the Company's initial proposal included the afternoon hours on weekdays and weekends in the Energy Peak Hours, if the Public Staff's modified proposal is accepted DENC will revert to its normal practice of paying peak (and premium peak) avoided energy rates on weekdays only.

NCSEA asks the Commission to direct the Utilities to develop tariffs that incorporate geographic price signals that provide an economic incentive for QFs to locate in areas that are most advantageous to the grid.[52] NCSEA affiant Dr. Johnson argues for more geographically granular rates and rate designs that "better recognize how costs vary across different seasons and different times of the day."[53] He objects to DENC's use of the same energy rates across the summer, winter, and shoulder seasons, and to the Company's use of the same on-peak hours in the winter and shoulder seasons. He argues that this is unnecessary and excessive cost averaging that obscures underlying cost patterns and weakens price signals.[54] Dr. Johnson proposes that the Utilities calculate separate rates for each hour of each month, to be displayed in a tariff (his "12x24" proposal).[55] As an alternative, he suggests using summer, winter, and "other" seasons, with each season having three rate periods corresponding to the time of the day when

[52] NCSEA at 27.
[53] Johnson at 61-62.
[54] *Id.* at 63.
[55] *Id.* at 64-66.

energy is most needed.[56] He also suggests that real time pricing should be applied to QF under "extreme conditions" – when system costs are extremely high or extremely low.[57]

The majority of Dr. Johnson's concerns are addressed by the Public Staff's proposed energy rate design, which as noted the Company is willing to accept with the modifications discussed above. His proposal to modify standard offer tariffs to include some number of hours that would use real-time pricing during extreme conditions is unnecessary and overcomplicated for the standard offer, which is designed to be a fixed-price tariff. While the Company believes the additional administrative work required to implement the Public Staff's proposed energy rate design is not overly burdensome, incorporating real time pricing to the rate design would unreasonably increase the time and costs of administering standard offer PPAs due to the need for additional personnel and processes to monitor the likelihood and duration of these extreme events. Finally, this modification is not necessary when the QF can sign onto the Company's Schedule 19-LMP tariff, which is locational in nature, and has hourly granularity in its market-based prices. If a QF wants more specific geographic price signals, the LMP tariff provides that level of granularity, and pays a unique energy price for every hour for the next 10 years.

5. Renewable Energy Impact On Market Power Prices

NCSEA contends that the Utilities have failed to "accurately capture the effect that wind and solar resources have on market prices," stating that distributed solar has a price suppression effect on future power prices.[58] Mr. Beach makes the same argument,

[56] *Id.* at 66-68.
[57] *Id.* at 68-73.
[58] NCSEA at 43-45.

and claims that with a reduction in demand due to new renewable generation, there is a corresponding market energy price reduction, "which benefits the utility when it does buy power or natural gas in these markets."[59] He claims that "this benefit reduces the ratepayer cost of market purchases."[60]

Because DENC is a vertically integrated utility located within the PJM RTO, the Company buys energy from the PJM market to serve its load responsibility and sells into the PJM market energy provided by its owned and contracted generation. To the extent that energy market prices decrease, regardless of the cause, the Company's load cost decreases and the generator revenue decreases. Both the load cost and the generator revenue flow directly to customers, primarily via the annual fuel factor adjustment. A lower PJM energy price in absolute terms therefore does not necessarily correlate to lower customer bills, since it also decreases the amount of generator revenue customers receive. Because DENC customers are largely indifferent to the marginal cost of PJM power prices, NCSEA's and Dr. Johnson's reliance on this argument to support their recommendation that the Utilities reflect market price impacts in avoided energy cost rates does not have merit.

Moreover, ICF's fundamental modeling for the Company's 2018 IRP did not include the 5,000 MW of solar/wind development found to be in the public interest in Virginia's 2018 GTSA. If NCSEA's contention that new solar generation will lower net energy prices is true, then the Company's underlying energy price forecast may actually be overstated since it did not include this reduction. This means that the energy prices

[59] Beach at 6-7 and Exh. 1 at 26-28.
[60] Beach Exh. 1 at 26-28.

paid to new QFs will likely be higher than DENC's actual avoided energy costs because ICF's forecasted power prices were over-stated.

Finally, NCSEA and Mr. Beach refer in support of their contentions to studies conducted in Arizona, the western U.S., and New England. None of these are applicable or relevant to the PJM region where renewable penetration levels are more moderate and where this price suppression impact from behind the meter solar has not been acknowledged, observed or quantified.

For all of these reasons, NCSEA's arguments regarding the added value of solar on power prices should be rejected.

6. Virginia Compliance Filing To 2018 IRP

DENC develops its IRPs on a system basis to serve customers in both North Carolina and Virginia, and submitted the same 2018 IRP to the Commission and to the State Corporation Commission of Virginia ("VSCC") on May 1, 2018 in Docket No. E-100, Sub 157. On December 7, 2018, the VSCC issued an order in VSCC Case No. PUR-2018-00065 ("VSCC Order") that directed the Company to "re-run and re-file the corrected results of its 2018 IRP within 90 days from the date of this Order, subject to the requirements of this Order."[61] Pursuant to the VSCC Order, on March 7, 2019, the Company submitted the 2018 Virginia Compliance Filing with both the Commission and the VSCC.[62]

The Company has reviewed the $/MWh avoided energy costs based on the assumptions used in the refiled 2018 IRP, and the resulting avoided energy costs are

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[61] VSCC Order at 9.

[62] *See* 2018 Integrated Resource Plan – Virginia Corrections and Revisions Compliance Filing, Docket No. E-100, Sub 157 (Mar. 7, 2019) ("Revised 2018 IRP Filing").

lower in the updated case than the rates the Company proposed in this proceeding with its Initial Filing. This is primarily because the VSCC directed the Company to use the PJM load forecast, which is lower than the Company's load forecast, and hourly marginal costs are lower when system loads are lower. The Company does not, however, plan to file updated, reduced avoided cost rates in this docket to reflect the updated IRP.

B. Capacity Rates

1. CT Installed Cost

As discussed in the Initial Filing, DENC used the applicable costs of the Company's Greensville Power Station, a combined cycle power plant, as the basis for combustion turbine ("CT") equipment costs in this proceeding. For the remaining CT costs, the Company used the PJM cost of new entry estimates, based primarily on the "PJM Cost of New Entry for Combustion Turbine and Combined Cycle Plants With June 1, 2022 Online Date" report prepared by The Brattle Group and Sargent & Lundy, dated April 19, 2018 ("Brattle Study"). The Company made a number of adjustments as detailed in its Initial Filing to tailor the Brattle Study results to meet the requirements of the Parameters Order and account for the separate estimation of CT equipment costs. The Company also explained that the construction and owner cost estimate provided by the Brattle Study, which assumes a commercial operation date ("COD") of 2022, was de-escalated for a 2019 COD. After adjusting for carrying costs, the resulting total installed CT cost was $559.8/kW as shown in Figure 2 of the Initial Filing. The Company noted that, since this amount does not include financing costs, the value is converted to annual fixed costs inclusive of financing costs, allocated to seasons, divided by the applicable on-peak hours, and then levelized, to determine the avoided capacity cost rates.[63]

In its initial comments, the Public Staff states that based on its review of the capital cost inputs and other assumptions incorporated in DENC's proposed rates, it finds those inputs and assumptions reasonable for the determination of the Company's avoided capacity rates, with the exception of the PAF as discussed further below.[64] No other party opposes the Company's estimated CT costs.

The Public Staff also recommends that all of the Utilities "evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility."[65] Specifically with regard to brownfield site development, the Public Staff states that "[s]hould the Utilities determine that there are available brownfield sites on which to construct new capacity additions for the foreseeable future, a cost adjustment for a brownfield site may be appropriate."[66]

The Company has long advocated for the use of a brownfield CT to determine avoided capacity cost rates,[67] and agrees with the Public Staff's comments regarding the efficient use of brownfield sites for the construction of new CT facilities because of their land availability and existing gas and electrical infrastructure. If the Commission so

[63] Initial Filing at 16-18.
[64] Public Staff at 18.
[65] *Id.* at 17-18.
[66] *Id.* at 6.
[67] *See* Parameters Order at 45-46.

directs, the Company will evaluate the potential for such cost adjustments in the next avoided cost proceeding.

2. In-Service Date Of New QFs

NCSEA and Dr. Johnson argue that the Utilities' avoided capacity calculations "include unrealistic assumptions about when QFs will begin providing capacity," noting DENC's assumed January 1, 2019 start date. NCSEA and Dr. Johnson claim that due to delays in the interconnection queue, "it is reasonable to assume" that a QF entering into a PPA in this biennial period will not begin providing capacity until December 2021 or later, as a result providing capacity during more years in which the Utilities have shown needs for capacity, and argue for a December 31, 2021 start date.[68] NCSEA also claims that the Utilities should be directed to calculate avoided cost rates for negotiated PPAs "based on the presumed in-service date of the QF subject to the negotiated PPA."[69] Dr. Johnson makes similar arguments, and suggests that for negotiated PURPA PPAs, the Utilities could "specify[] a 'cost curve' (or matrix of rates) which varies based upon the actual in-service date."[70] He suggests calculating how the avoided costs change depending on the in-service date, and using this information during the rate negotiations, to specify what rates will apply if the project is delayed.[71]

The avoided cost biennial pricing exercise is straightforward – to determine capacity and energy rates for small power producers that sign a contract during the 2019-2020 timeframe, for power deliveries during the 10 year period 2019-2028. By its nature some assumptions must come into play in this process. Trying to account for every

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[68] NCSEA at 11-12; Johnson at 58-59.
[69] NCSEA at 12.
[70] Johnson at 59.
[71] *Id.*

potential outcome—including adjusting assumed start dates based on uncertainty regarding QFs' commercial operations dates—would nullify the purpose of establishing standard rates and terms. The Company has assumed a January 2019 start date for QFs entering into standard PPAs in this proceeding, as it has in every recent avoided cost proceeding, because that is an administratively efficient way to develop standard rates and terms for small QFs.

With regard to NCSEA's and Mr. Johnson's suggestions for negotiated PPAs, the Company already calculates avoided cost rates for large QFs based on data available at the time the QF establishes a legally enforceable obligation or "LEO," consistent with FERC and Commission directives.[72] To the extent NCSEA or Dr. Johnson are suggesting that rates for large QFs should be calculated based on the projected in-service date, that would be inconsistent with the Commission's previous determinations in this regard. In addition to that inconsistency, Dr. Johnson's proposal that the Utilities be required to calculate multiple rates based on different in-service dates so that large QFs can select an in-service timing that will result in the most income would unreasonably burden the Utilities, which are required under PURPA to purchase QF output but are not obligated to assist developers in determining which business plan will result in the most revenues.

[72] *See* 18 C.F.R. § 292.304(d)(2)(ii) (2018); Parameters Order at 21 ("establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 210 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources"); *In the Matter of Economic Power & Steam Generation, LLC v. Virginia Electric and Power Company*, Order on Arbitration at 7, Docket No. SP-467, Sub 1 (June 18, 2010) (once an LEO is established a QF is entitled to "avoided cost rates derived by a method that provides fixed payments over the term of the contract based upon forecasts using data as of the time the obligation is incurred").

3. CT Fuel Supply

NCSEA and Mr. Beach contend that the "Utilities" allocate a significant portion of avoided capacity costs to the winter season, and argue that CT facility costs should therefore include the cost of firm natural gas transportation service to operate during this time.[73] To the extent that these arguments are directed at DENC, the hypothetical CT proposed by the Company is a gas/oil dual-fueled facility whose construction cost already includes the cost of the oil-fueling equipment, and therefore does not require firm natural gas transportation ("FT") service. The cost of natural gas FT service would not be economically justifiable for a CT facility that has limited run-hours during the year, particularly for a dual-fueled plant that has #2 oil as a back-up fuel. NCSEA's proposed adjustment, to the extent intended to apply to the Company's capacity cost calculations, is therefore not necessary.

4. IRP Basis For Capacity Need

SACE contends that DENC has not complied with the 2016 Order directive to provide avoided capacity payments in years that the utility's IRP forecast period demonstrates a capacity need. SACE first argues that because the VSCC rejected the Company's IRP as originally filed in 2018, the 2018 IRP does not accurately represent the Company's future capacity plans and cannot be relied upon in this proceeding.[74] As SACE notes and as discussed above, the VSCC directed the Company to refile its 2018 IRP by March 7, 2019, which filing was timely made. As indicated in that filing, the Company's need for capacity has not changed in the refiled 2018 IRP; based on the input assumptions directed by the VSCC to be used in the refiled 2018 IRP, including the solar

[73] NCSEA at 23-24; Beach at 4.
[74] SACE at 21.

build-out per the Virginia GTSA in Plan F ("No CO2 Tax with GT Plan"), the resulting capacity expansion plan continues to show the first CT build in the No CO2 case to occur in 2022.[75]

SACE also contends that DENC has not identified a "preferred plan" in its 2018 IRP, and that absent a preferred plan, the capacity need should be demonstrated based on the Alternative Plan that anticipates the most immediate capacity need.[76] In the Initial Filing, the Company based its determination of capacity need for purposes of calculating avoided capacity rates on the "No CO2 case resource expansion plan" reflected in the originally filed 2018 IRP. As discussed above, based on the consistent projection of the next CT need in Plan F as reflected in the refiled 2018 IRP, the basis for the Company's determination of capacity need for purposes of calculating avoided capacity rates has not changed. This reliance on a "No CO2" plan is the same approach that DENC has taken in the last several North Carolina avoided cost proceedings, and it is an appropriate approach because it is consistent with the Commission's conclusions in previous proceedings that only known and quantifiable costs should be reflected in avoided cost calculations.[77] At the current time, CO2 costs are not yet known or quantifiable. For this reason, a preferred plan is not relevant to the determination of avoided cost, and the Company's reliance on the no-CO2 plan(s) in these proceedings is appropriate.

[75] *See* Revised 2018 IRP Filing at 19, Figure 1.4.1.
[76] SACE at 21.
[77] *See* Parameters Order at 44 ("If and when [CO2 regulation] costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable"); 2014 Order at 24 ("the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs").

Finally, SACE contends that certain capacity additions in 2019, 2020, and 2021 that are reflected in the 2018 IRP could be deferred, delayed, or reduced "as a result of QF capacity contributions," and therefore that DENC's calculation of avoided capacity costs as not including such costs through 2021 does not comply with FERC's conclusion in Order No. 69 that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, to build a smaller unit, or to purchase less firm power.[78] The practical reality is that new QFs signing PPAs during this biennial period will not avoid any capital costs related to these near term generation projects. As SACE notes, some of the projects projected for 2019-2021 in the IRP are already under construction.[79] Purchases from QFs that establish LEOs under this proceeding will not be able to avoid those costs, and these QFs therefore will not allow the Company to avoid capacity costs as contemplated by Order No. 69.

5. Annual Capacity Payment Limit & Seasonal Allocation Of CT Costs

As noted above, in its Initial Filing the Company proposed to modify its avoided cost rate design to eliminate Options A and B, and to differentiate between Energy Peak Hours and Capacity Peak Hours. Similar to the energy rate design, the Company proposed to add a shoulder season to the capacity rate design to include the spring and fall months of March, April, October and November.[80] The Company also proposed to adjust its seasonal allocation of fixed CT capacity costs to 50% to the summer, 40% to winter, and 10% to the newly proposed shoulder season.[81]

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[78] SACE at 22.
[79] *Id.*
[80] Initial Filing at 28-29.
[81] *Id.* at 31-32.

In addition, based on data demonstrating the lower capacity value offered by intermittent and non-dispatchable QFs as compared to a fully dispatchable CT facility, in its Initial Filing the Company proposed to apply annual caps on capacity payments. All QFs, regardless of technology, would receive the same capacity rates, but the payments would be capped on an annual basis for intermittent non-dispatchable QFs at levels that reflect the operating characteristics and capacity value of these resources. The Company calculated the levelized annual capacity value of a new CT to be approximately \$37.17/kW/year, and then calculated the annual caps based on the relevant capacity value relative to a CT multiplied by that amount.[82]

In its initial comments, the Public Staff notes the progress made with the 2016 Order and House Bill 589 to reduce the risk of overpayment to QFs for capacity.[83] The Public Staff also asserts that "capacity payments to an intermittent QF will inherently be lower than the capacity payments to a dispatchable QF if the seasonal allocation and Capacity Payment Hours are accurately chosen to reflect the utility's seasons and hours of greatest capacity need."[84] It states that because a QF cannot provide its nameplate capacity early in the winter morning, the QF "will only be paid a fraction of the available early winter morning capacity payment, relative to a dispatchable QF."[85] Based on its review of generation data from 61 solar facilities the Company provided in its 2018 fuel factor adjustment case (Docket No. E-22, Sub 558), the Public Staff concludes that the average capacity factor during the 12 months ending June 2018 was 18.2%, with a maximum of 25.1%. Based on the Company's responses to Public Staff discovery

[82] *Id.* at 18-26.
[83] Public Staff at 60-61.
[84] *Id.* at 61.
[85] *Id.*

requests in this case, the Public Staff also concludes that the capacity cap would affect tracking solar facilities with a capacity factor over 25.8%, which the Public Staff states suggests that few QFs would actually hit the threshold for the cap.[86] The Public Staff acknowledges that this information is based on existing facilities and that newer facilities eligible for rates established in this case may experience increased outputs.[87]

With regard to the capacity cost seasonal allocation and designation of Capacity Peak Hours, the Public Staff acknowledges that it may be appropriate for the Company to seasonally allocate capacity payments and determine Capacity Peak Hours consistent with PJM, which is summer planning, and of which DENC is a member. The Public Staff also states, however, that "the capacity needs of the PJM market as a whole are different from the capacity needs of a utility operating in North Carolina," and notes that overpayment does not appear to be an issue for the Duke Utilities, which seasonally allocated capacity payments based on their seasons of highest risk of load loss. The Public Staff acknowledges that the cap would reduce the risk of overpayment to QFs, but states that it appears to be "an attempt to reduce the impact of seasonal allocations and Capacity Payment Hours that may not perfectly align with the season and hours where QF capacity is most able to defer future capacity needs," and states that a slight shift away from the summer allocation can cause total payments to fall below the cap.[88] The Public Staff recommends that, instead of the cap based on the projected capacity value of an intermittent QF relative to a fully dispatchable CT resource, the Company evaluate

[86] *Id.* at 61-62.
[87] *Id.* at 62.
[88] *Id.* at 63, 83.

alternative seasonal allocation and Capacity Payment Hours that align more directly to DENC's system (as opposed to the PJM system as a whole).[89]

NCSEA did not comment on the Company's proposed seasonal allocation of capacity costs. With respect to DENC's proposed annual capacity cap, NCSEA affiant Dr. Johnson argued that a capacity cap is not needed if his "12 x 24" pricing proposal is adopted.[90] SACE did not comment on the Company's proposed seasonal allocation of capacity costs or proposed annual cap on capacity payments.

Due to its membership in PJM, the Company is situated differently than the Duke Utilities. While the Duke Utilities operate their own control areas and can do loss of load probability ("LOLP") studies for DEC and DEP, it would not be reasonable for DENC to run an LOLP study as if it were an island, because the practical reality is that the Company is not an island. It is a member of the multi-state PJM RTO, which is summer planning. Due to its participation in summer-planning PJM and to recently observed strong winter peak loads, the Company continues to believe that the 50/40/10 percentages are reasonable seasonal allocators. However, the Company would be willing to use a 45/40/15 seasonal allocation of CT costs. These weightings would continue to reflect the Company's participation in PJM and the recent strong winter peak loads, but also reflect shifting the month of May from being a summer month for capacity to being a shoulder month

The Company also believes that its proposed Capacity Peak Hours are appropriate, based on data from 2015-2018 as presented in Figure 6 of its Initial Filing showing the hours during each month when system peak loads have occurred and system

[89] *Id.* at 63-64.
[90] Johnson at 63-78.

emergencies are most likely to occur. The Company has designated peak hours in the shoulder season in addition to winter and summer to reflect the capacity value that the Company believes can be provided during these months.

With regard to the proposed annual cap on capacity payments, the cap is not intended to be a punitive measure against QFs. It is rather an administratively straightforward way to accomplish two goals. First, it links IRP principles to avoided cost payments. The Company's IRP values solar capacity at 23% of its nameplate capacity, consistent with its intermittency and non-dispatchability, and the resulting Capacity Performance risk in the PJM capacity market. The cap accounts for that solar capacity value. Second, the annual cap offers a useful and reasonable way of reducing the risk that customers overpay for capacity beyond the Company's actual avoided costs. The Company recognizes that the 2016 Order made significant progress toward lowering the risk of customer overpayments. This progress does not, however, eliminate the need for the cap, which is intended to act as a stopgap to prevent overpayments that could still result due to potential imperfections in the rate design, peak hours selection, and CT seasonal cost allocations. With the proposed shift to a 45/40/15 seasonal allocation as discussed above, the potential for the cap to be invoked is reduced, but the Company views the cap as still needed as a safety mechanism to prevent overpayment.

Moreover, consistent with the Public Staff's own recognition that its calculated historical average solar capacity factor of 18.2% was based on existing solar facilities, solar technology is advancing and these lower historical capacity factors (many existing units are fixed tilt) may not accurately represent future performance of solar resources (which could be tracking solar units). Given the uncertainty of capacity factor performance of new QFs in the future, and the likelihood that new units will utilize tracking solar technology with higher capacity factors, the Company believes that the capacity payment cap would provide a good safeguard to protect customers from over-paying for capacity.

C. <u>Performance Adjustment Factor</u>

As noted in the Initial Filing, in the 2016 Order the Commission required the Utilities to support their PAF recommendations based on evidence of peak season equivalent availabilities for their fleets in total in this proceeding. Consistent with this requirement, DENC proposes to use the metric Equivalent Availability ("EA") to determine the PAF. Based on that metric, the Company calculated a resulting PAF of 1.07, an increase of 0.02 above the currently effective PAF of 1.05, and used the 1.07 PAF to calculate proposed Schedule 19-FP capacity rates. The Company assumed the peak seasons to be June, July, August, January, and February, which are the months PJM considers to be critical, when system emergencies and performance assessment hours are expected, and when generator planned outages would typically not be scheduled.

In its initial comments, the Public Staff states that the Utilities' approaches to calculating the PAF meet the intent of the 2016 Order, but recommends that the Commission direct the Utilities to refile their fleet weighted average peak month Equivalent Forced Outage Rate ("EFORs") utilizing five years of historical data and a minimum of five years of prospective data, but in no event greater than the PPA term (10 years).[91] The Public Staff noted that DENC excluded December from its calculations, and recommended that the Commission direct the Utilities to perform a revised PAF

[91] Public Staff at 71, 83.

calculation, including June (which DENC already includes) and December EFOR data. The Public Staff stated that using a critical peak load analysis to determine the critical peak period(s) of the Utilities' systems is consistent with the Commission's guidance in the 2016 Order.[92]

Through discussions conducted with the Public Staff subsequent to the filing of initial comments, the Company understands the Public Staff's position to have evolved such that the Public Staff no longer recommends the use of projected EFOR, but instead favors relying on 3 to 5 years of historic data. The Public Staff has also suggested in these discussions that another method, the Weighted Equivalent Unplanned Outage Rate or "WEUOR" has some merit, and that it is open to potentially exploring this issue further between now and the next case with the Duke Utilities and DENC, as appropriate.

NCSEA and Dr. Johnson do not appear to object to DENC's proposed 1.07 PAF.[93] SACE does not comment on DENC's proposed PAF.

The Company believes that the PAF should be determined based on three years of EA history. Three years of historical data provides the most meaningful EA data because it is actual, observable, and recent. The use of five historical years of data would not be as meaningful or appropriate, as the older data is less relevant due to generation unit changes such as, for example, unit fuel conversions, and investments made to the generation fleet. The Company also believes that the use of a prospective EA component

[92] *Id.* at 72 n. 106 (citing 2016 Order at 56 and saying that "In its discussion about the PAF, the Commission said, 'This should include consideration of a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's cost during the critical peak demand periods.' (emphasis added)."), 83.
[93] NCSEA at 30-32; Johnson at 28-37.

add subjectivity and unnecessarily complicates the calculation of the PAF, and supports the Public Staff's shift away from using a prospective component.

The peak period months used by the Company to determine the PAF (June, July, August, January, and February) match the months that PJM considers to be the peak months from a system operations perspective, when system emergencies would likely occur, and when planned outages would not be scheduled. The Company continues to believe that these months are reasonable and appropriate. Including December or March in the calculation would mean that there would be 7 'peak' months, which does not make sense because there would then be more peak months than non-peak months. In an effort to spread out the spring and fall outages, there may be unit planned outages that extend into early December, or that may start in the month of March. Including December or March data would therefore increase the PAF and unfairly burden electric customers with increased QF capacity costs simply due to the Company's efforts to efficiently plan outages for it numerous generating units. Including the months of March and December would also run counter to the Commission's finding in the 2016 Case that it "agrees ... that Public Staff's witnesses use of availability factor is flawed because it includes planned outages that a utility intentionally schedules for off-peak shoulder periods when electricity demand is low."[94] Since generator planned outages scheduled in the spring can start in March, and fall outages can extend into December, those months should not be included in the PAF calculation.

Based on initial discussions with the Public Staff, the Company does not support adoption of the WEUOR to determine the PAF. The WEUOR is an obscure metric that

[94] 2016 Order at 55.

the Company does not currently calculate, and the EA metric that DENC used to calculate the PAF in this case is appropriate for the reasons discussed in the 2016 Order. For these reasons and the considerations discussed above, the Company continues to support the EA metric used to calculate the 1.07 PAF, which is higher than the currently effective PAF of 1.05.

D. Continued Elimination of the Previous Line Loss Adjustment is Supported by the Evidence

In the 2016 Case, the Commission addressed the issue of line loss avoidances on DENC's system and thoroughly considered all of the evidence presented by the parties involved. Given the evidence presented, in the 2016 Order the Commission determined that line loss avoidance benefits on DENC's system had been greatly reduced or eliminated and thus the line loss adder should be removed from DENC's avoided cost rates.[95] Further, the Commission instructed all of the utilities in this proceeding to address "the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations."[96]

In response to the Commission's directive, the Company presented with its Initial Filing an updated analysis showing that the Company substations with connected solar DG continue to experience backflows and to do so with more frequency as compared to the analysis presented in the 2016 Case.

Despite this analysis and the conclusions reached by the Commission in the 2016 Order, SACE continues to maintain in this proceeding that the line loss adder should be

[95] *Id.* at 92-93.
[96] 2018 Order Establishing Proceeding at 1.

restored in DENC's avoided cost rates.[97] SACE asks the Commission to require the Company to recalculate and include a line loss adder, although it does not offer any suggestions for a method by which to make such a calculation. Based on SACE's initial comments and responses provided through discovery, the Company disagrees with SACE's comments and analysis for several reasons.

First, SACE's analysis does not take into account irradiance levels to determine whether a solar QF *could* generate energy. If it is cloudy or rainy and a solar QF is not generating during any given hour, then the relevant substation will show more hours of positive flow. Including these hours with cloudy or rainy conditions skewed SACE's analysis to show more hours with positive flow. DENC's territory experienced an historical amount of rainfall during the time period of this analysis (September 2016 – August 2018). This is demonstrated by Attachment 1, which presents National Weather Service data of historical precipitation records for Elizabeth City, North Carolina and shows that 2018 was the wettest year on record for this area going back to at least 1934. Attachment 2 presents more detailed, monthly rainfall data for Elizabeth City from 2000 through 2018, and also shows 2018 as the wettest year on record during that time frame. Because SACE's analysis does not account for the abnormal level of rainfall during this time period, it shows more positive flow than would be the case under more normal weather conditions. Given as discussed below that the overall trend is *still* toward increased backflow on the Company's system in North Carolina, this consideration further supports the continued elimination of the line loss adder.

[97] SACE at 19-20.

Moreover, SACE's comments fail to acknowledge the general observable trend at several DENC substations that backflows are occurring with more frequency as more solar distributed generation is connected to the system. As noted in the Company's Initial Filing, as compared to the study conducted for the 2016 case, the number of transformers experiencing backflow has increased as more solar DG has become operational. Specifically, of the 38 transformers with solar DG connected (compared to 33 in the prior study), the updated study shows 16 transformers realizing consistent backflow, compared to 11 in the prior study. Only 2 transformers are shown to have consistent positive flow, compared to 4 in the 2016 study.[98] SACE's own analysis and categorization of the Company transformers with solar DG connected show a majority of the transformers (21 out of 38) classified as either "neutral" or "negative."

Finally, SACE's comments do not recognize the fact that even when DENC substations are experiencing positive flows, outside of a few outlier data points, the "room" remaining on the transformer before it starts experiencing backflows is less than 20 MW.[99] Given that the Company still has over 200 MW of solar DG (several that are 15 to 20 MW in size) with an executed avoided cost PPA but not yet operational, the Company expects that existing backflows will continue to increase and remaining positive flows will continue to be eroded as this solar becomes operational. Given all of these considerations, the Commission's previous determination that it is appropriate for

[98] Initial Filing at 35.

[99] SACE states that the data for the 38 DENC substations it reviewed for its analysis "includes the five QFs that were queued when the Commission issued [the 2016 Order] whose impacts the Commission was concerned would eliminate line loss avoidance." SACE at 19. It is not clear to the Company which five QFs SACE is referring to. At the time of the 2016 Order, the Company had 24 executed PPAs with QFs that had not yet achieved COD.

DENC to eliminate the line loss adder from avoided energy rates is still true and SACE's arguments to the contrary should be rejected.

III. CONCLUSION

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission accept these Reply Comments and issue an order accepting the Company's Initial Filing, as modified herein, and making such other determinations as are necessary and proper.

Respectfully submitted,

DOMINION ENERGY NORTH CAROLINA

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March 27, 2019

Attachment 1

** This Product will be Updated on a Monthly Basis
Last Update: Jan 2019

Top 5 LIST Elizabeth City, NC Precipitation
(Period of Record: 1934-Present) (some MM data in early 1900s) *AVG is for (1981-2010)

Rank	JAN Wettest		FEB Wettest		MAR Wettest		APR Wettest		MAY Wettest		JUN Wettest	
	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	1987	10.77	1938	7.40	2002	8.60	1934	7.28	1944	11.76	1945	10.57
2	1979	8.94	1948	6.75	1989	8.05	2003	7.21	1972	8.39	2006	9.27
3	1937	8.49	1944	6.71	1934	7.92	1936	6.35	2000	7.73	1991	8.70
4	1960	8.32	1945	6.22	1978	7.70	1991	6.34	*2012	*7.62	1988	6.56
5	1978	7.66	1982	6.16	1994	7.68	1970	6.12	1946	7.59	2016	6.52
AVG	3.57		2.97		3.68		2.99		3.72		4.66	

Rank	JUL Wettest		AUG Wettest		SEP Wettest		OCT Wettest		NOV Wettest		DEC Wettest	
	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	1998	13.99	2006	11.85	1979	14.56	2016	10.28	1948	10.50	2003	8.25
2	1946	12.66	1981	11.64	1938	13.39	1971	8.75	1947	7.84	1945	7.48
3	1950	12.26	1986	11.16	2016	12.03	1942	8.51	2009	7.56	1938	7.34
4	1949	11.80	1955	10.89	2010	11.86	1958	8.30	2006	7.00	1942	5.70
5	1966	11.69	1940	10.40	1958	11.65	1964	7.86	2018	6.53	1973	5.57
AVG	5.54		5.54		4.28		2.97		3.06		2.98	

Rank	JAN Driest		FEB Driest		MAR Driest		APR Driest		MAY Driest		JUN Driest	
	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	2008	0.51	2009	0.59	2007	0.75	1942	0.33	1986	0.65	2011	0.79
2	1981	1.16	1947	0.65	1945	0.97	1967	0.52	2011	0.58	1978	0.96
3	2004	1.17	2017	0.92	1967	1.05	1985	0.67	2013	1.19	*1934	*1.20
4	1940	1.34	1978	1.01	1946	1.11	2001	0.92	1991	1.20	1964	1.22
5	2018	1.40	2006	1.11	[illegible]	1.26	1995	1.00	2008	1.35	1944	1.29

Rank	JUL Driest		AUG Driest		SEP Driest		OCT Driest		NOV Driest		DEC Driest	
	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	1983	0.64	1970	1.21	1978	0.07	2000	0.05	2001	0.18	1968	0.35
2	1996	1.06	2005	1.47	1981	0.38	1935	0.35	2012	0.36	1985	0.49
3	1987	1.27	2008	1.94	2007	0.71	2001	0.36	1965	0.49	1983	0.76
4	2007	1.32	1976	2.22	2013	0.64	1940	0.39	2007	0.61	1955	0.89
5	1955	1.67	1992	2.31	1980	0.89	2009	0.40	1941	0.76	2011	0.94

Rank	WINTER (Dec-Feb) Wettest		SPRING (Mar-May) Wettest		SUMMER (Jun-Aug) Wettest		FALL (Sep-Nov) Wettest		ANNUAL Wettest	
	Seasn	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	1936-1937	20.62	1934	20.59	2006	28.46	2016	23.93	2018	63.95
2	1986-1987	18.04	2003	17.48	1945	27.30	1979	20.22	1979	62.13
3	1938-1939	16.66	1989	17.25	1996	26.23	1947	19.93	1936	61.88
4	1978-1979	16.10	1978	16.68	2018	24.71	1938	19.37	1996	61.36
5	1945-1946	16.04	1973	16.27	2004	23.32	1967	18.40	1945	60.98
AVG	9.53		10.39		15.74		10.31		45.97	

Rank	WINTER (Dec-Feb) Driest		SPRING (Mar-May) Driest		SUMMER (Jun-Aug) Driest		FALL (Sep-Nov) Driest		ANNUAL Driest	
	Seasn	Amt	Year	Amt	Year	Amt	Year	Amt	Year	Amt
1	2008-2009	4.34	1986	3.19	1980	6.93	2001	1.53	2007	25.58
2	1985-1986	4.38	1967	3.56	2008	7.26	1988	3.41	2001	27.99
3	2000-2001	5.08	2013	5.62	1976	7.45	1973	3.71	2008	29.31
4	1980-1981	5.28	1986	6.22	1987	8.35	1981	3.84	2011	34.39
5	2006-2007	5.33	2007	6.31	2007	8.44	2007	4.39	1980	36.48

* ALSO IN EARLIER YRS

Monthly Total Precipitation for ELIZABETH CITY COAST GUARD AIR STN, NC

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2000	3.89	1.36	1.83	4.37	7.73	7.50	2.69	7.27	4.16	0.05	2.31	1.22	**44.38**
2001	1.88	1.98	4.12	0.92	2.48	6.44	3.81	3.77	0.99	0.36	0.18	1.06	**27.99**
2002	5.32	1.90	8.60	3.20	1.48	5.06	5.89	7.53	2.73	6.81	5.77	3.74	**58.03**
2003	2.84	5.96	4.81	7.21	5.46	4.85	4.20	4.21	7.58	3.76	1.54	8.25	**60.67**
2004	1.17	1.78	3.12	2.56	4.59	7.64	6.89	8.79	2.53	4.02	2.95	1.78	**47.82**
2005	2.22	2.76	3.10	2.65	5.53	5.01	8.23	1.47	1.31	5.16	2.10	3.66	**43.20**
2006	2.27	1.11	1.26	2.68	6.24	9.27	7.34	11.85	6.67	2.22	7.00	1.06	**58.97**
2007	2.13	2.14	0.75	2.73	2.83	3.36	1.32	3.76	0.71	3.07	0.61	2.17	**25.58**
2008	0.51	3.12	1.42	3.91	1.35	1.38	3.94	1.94	4.32	1.45	3.87	2.10	**29.31**
2009	1.65	0.59	4.94	1.71	3.76	4.17	8.00	9.81	3.02	0.40	7.56	5.27	**50.88**
2010	2.91	2.31	3.67	1.24	4.04	2.92	3.88	4.98	11.88	2.62	1.03	1.98	**43.46**
2011	2.69	2.45	4.71	2.02	0.58	0.79	4.50	6.40	5.51	2.08	1.72	0.94	**34.39**
2012	2.48	2.72	4.49	2.72	7.62	3.52	6.79	6.14	1.64	5.43	0.36	3.85	**47.76**
2013	1.40	3.65	1.76	2.67	1.19	6.62	6.48	6.26	0.84	5.73	2.99	5.15	**44.74**
2014	2.17	1.97	2.41	6.08	2.33	3.83	5.38	3.26	6.00	0.93	2.92	3.14	**40.42**
2015	4.01	2.79	2.97	4.11	3.42	4.87	5.56	2.45	4.25	4.18	4.21	4.01	**46.83**
2016	2.91	4.68	2.22	4.04	4.36	2.90	3.26	3.14	12.03	10.28	1.62	2.67	**54.11**
2017	3.69	0.92	3.79	2.52	6.05	3.42	8.74	6.01	2.42	3.06	0.98	3.06	**44.66**
2018	3.90	2.74	4.42	4.11	6.92	8.52	11.13	5.06	4.37	1.62	6.53	4.63	**63.95**
Mean	2.68	2.56	3.39	3.23	4.1	4.85	5.69	5.48	4.37	3.33	2.96	3.14	45.64
Max	5.32	5.96	8.6	7.21	7.73	9.27	11.13	11.85	12.03	10.28	7.56	8.25	63.95
	2002	2003	2002	2003	2000	2006	2018	2006	2016	2016	2009	2003	2018
Min	0.51	0.59	0.75	0.92	0.58	0.79	1.32	1.47	0.71	0.05	0.18	0.94	25.58
	2008	2009	2007	2001	2011	2011	2007	2005	2007	2000	2001	2011	2007

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Reply Comments of Dominion Energy North Carolina*, as filed in Docket No. E-100, Sub 158, was served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 27th day of March, 2019.

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*Attachments are voluminous and previously filed in docket system. cm

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Jul 26 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	[PUBLIC]
Rates for Electric Utility Purchases from	)	NCSEA'S INITIAL
Qualifying Facilities – 2018	)	COMMENTS

NCSEA'S INITIAL COMMENTS

I. INTRODUCTION

In its October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 148 ("*Sub 148 Order*"), the North Carolina Utilities Commission ("Commission") made significant changes to North Carolina's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), 18 U.S.C.A 824a-3. These changes were driven partially by the passage of H.B. 589, N.C. Gen. Assem., 2017 Reg. Sess., S.L. 2017-192 (N.C. 2017) ("HB 589"), and partially by the Commission's conclusion that changes to the "economic and regulatory circumstances facing qualified facilities ("QFs") and utilities in North Carolina" necessitated changes to the regulatory regime for PURPA projects in North Carolina.[1] These changes included, but were not limited to, lowering the threshold for standard-offer rates to 1 MW (with a maximum of 100 MW of project eligible); lowering the length of standard-offer contracts to 10 years; approving an 80/20% winter/summer capacity weighting; and reducing the performance adjustment factor for most QFs to 1.05.[2]

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[1] *Sub 148 Order* at 15.
[2] *See generally*, *Sub 148 Order*.

Despite making these changes, the Commission did not conclude that it would be appropriate to block all further PURPA development in the state, which would not be lawful under PURPA or consistent with Congress's intent in promoting QF development. Notably, the Commission agreed with NCSEA's witness Dr. Ben Johnson that

> in implementing PURPA, the Commission should not "slam on the brakes" in establishing rules for the development of QF resources. Rather, as the Commission's policies have resulted in North Carolina cresting the hill, it now is appropriate to moderately ease off on the regulatory accelerator and depend in part on momentum created so as to moderate the financial impact on electric rate payers.[3]

It is clear, however, that the utilities participating in this docket have no interest in further QF development of QF resources, but instead seek to shut down further QF development and also to undermine the continued economic viability of existing QFs. Rather than afford time to let the adjustments made in HB 589 and the *Sub 148 Order* play out, the utilities seek to halt independent, statutorily-mandated renewable energy[4] in the form of QF development by driving avoided energy and capacity rates so low as to make QF development financially infeasible.

As will be discussed below, the utilities' arguments constricting independent QF development are premised on several faulty assumptions, including that: (1) solar QF development in North Carolina has continued unabated even since issuance of the *Sub 148 Order*; (2) the recent trend in declining natural gas prices will continue indefinitely, such that long-term fixed-price energy contracts will never be in the interest of ratepayers; (3) increased solar generation

[3] *Sub 148 Order* at 15-16.
[4] *See* N.C. Gen. Stat. § 62-2(a)(5) and N.C. Gen. Stat. § 62-2(a)(10).

will inevitably cause costly and intractable "operational challenges"; and (4) it is incumbent on this Commission to protect ratepayers from a "distorted marketplace" for solar QF development by approving further reductions to avoided cost rates, thus providing "improved price signals" that will further discourage QF development.

NCSEA submits that these assumptions are all false, and that the far-reaching policy changes wrought by HB 589 and the *Sub 148 Order* should be given time to take effect.[5] In the meantime, the Commission should scrutinize the utilities' cost calculations closely, and not allow the practical cessation of QF development in North Carolina.

II. PROCEDURAL BACKGROUND

A. COMMISSION ORDERS AND PRIOR AVOIDED COST PROCEEDING ISSUE HOLDOVER

On June 26, 2018, in the above-captioned docket, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("*Order Establishing Biennial Proceeding*"), subsequently amended by orders dated January 4, 2019, January 25, 2019, and February 8, 2019, pursuant to the provisions of Section 210 of PURPA and the regulations of the Federal Energy Regulatory Commission ("FERC"), initiating the 2018 biennial proceeding to set avoided cost rates. The Order made Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively,

[5] It bears noting that the implementation of the two major policy components of H.B. 589 geared towards utility-scale solar – the Green Source Advantage Program and the Competitive Procurement of Renewable Energy ("CPRE") – is still ongoing. The results of the CPRE Tranche 1 have not been finalized yet, and notwithstanding the Commission's February 1 Order in Docket Nos. E-2, Sub 1170 and E-7, Sub 1169, a final Green Source Advantage Program has yet to be approved.

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"Duke"), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("Dominion," "DNCP," or "DENC") (DEC, DEP, and DENC, collectively, the "Utilities"), Western Carolina University ("WCU"), and Appalachian State University, d/b/a, New River Light and Power Company ("New River") parties to the proceedings.

In its *Order Establishing Biennial Proceeding*, the Commission pointed out that in its October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 148 (the "*Sub 148 Order*") it had ordered DEC, DEP, and Dominion to address:

> (1) A continued evaluation of capacity benefits of qualified facility ("QF") generation;
> (2) whether the utilization of a 2.0 Performance Adjustment Factor ("PAF") as approved in the Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and NC Hydro Group ("Hydro Stipulation") should continue as provided in that agreement;
> (3) the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations;
> (4) hourly combustion turbine ("CT") operational data and marginal cost data on a season-specific basis; and
> (5) consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable.[6]

With respect to a rate design considering the characteristics of power supplied by a QF, the Commission in the *Order Establishing Biennial Proceeding* stated that it expected "DEC, DEP, and Dominion to file [in their 2018 Avoided Cost initial statements] proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more

[6] *Order Establishing Biennial Proceeding*, p. 1.

granularity than the current Option A and Option B rate schedules."[7] The Commission also stated in the *Order Establishing Biennial Proceeding* that it will:

> attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony.[8]

The Commission revisited and restated this position in its January 25, 2019 *Order on Procedural Schedule and Requiring Report* ("*January 25th Order*"),[9] wherein the Chairman indicated that he would extend the deadline for the filing of reply comments and, also, suspend the deadline for the filing of proposed orders pending the determination by the Commission as to whether an expert hearing should be scheduled in this proceeding and the scope of issues to be heard at any such expert hearing. Further, the Commission required Duke to confer with all the parties in the proceeding on or before March 8, 2019 and provide a report to the Commission summarizing the subjects at issue in this proceeding including, specifically, which issues are still in controversy and have sufficient merit to be considered at an evidentiary hearing.

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[7] *Order Establishing Biennial Proceeding*, pp. 1-2.

[8] *Order Establishing Biennial Proceeding*, p. 1.

[9] The *January 25th Order* originated from Duke's request for an evidentiary hearing made on page 2 of the *Duke Energy Carolinas, LLC and Duke Energy Progress LLC's Joint Initial Statement and Exhibits* ("*Joint Initial Statement*") wherein Duke requested an evidentiary hearing on "discrete issues". The North Carolina – Public Staff ("Public Staff") then filed the *Public Staff Motion for Extension and Modified Procedural Schedule* ("*Public Staff Procedural Motion*") regarding Duke's request for an evidentiary hearing on December 31, 2018. Then, on January 4, 2019, the North Carolina Sustainable Energy Association ("NCSEA") filed its *Response to Public Staff's Motion for Extension and Revised Procedural Schedule and NCSEA's Motion for Modified Procedural Order on Testimony* ("*NCSEA's Response and Motion*"), to which Duke then filed *Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Joint Response to NCSEA's Response* on January 10, 2019. The *January 25th Order* was issued by the Commission in response to these filings.

B. THE UTILITIES' FILINGS

On November 1, 2018, Duke filed its *Joint Initial Statement* pursuant to the *Order Establishing Biennial Proceeding.*[10] In their cover letter prefacing the *Joint Initial Statement*, Duke summarizes:

> [Duke's] avoided cost rates have decreased approximately 20 percent for DEC customers and 8 percent for DEP customers from those avoided cost rates approved in the 2016 avoided cost proceeding. These decreases in the Companies' future avoided costs are driven primarily by the decrease in natural gas prices. Natural gas prices have declined approximately 16 percent since the Companies' 2016 avoided cost filing. Another contributing factor is DEP's nearer-term need for avoidable new generation or purchased capacity in 2020 versus DEC's next avoidable need in 2028. Put simply, the Companies' costs to produce power are declining due to their efficient generation fleets and lower natural gas prices, and this decline is reflected in the avoided cost rates filed in this docket.[11]

On November 1, 2018, Dominion filed the *Initial Statement and Exhibits of Dominion Energy North Carolina* ("*Dominion's Initial Statement*") pursuant to the *Order Establishing Biennial Proceeding.*[12] *Dominion's Initial Statement* provided a summary of the filing as follows:

> With this filing, [Dominion] is making proposals to (1) adjust its methodology for calculating avoided energy rates to account for re-dispatch costs associated with the avoided capacity payments to reflect the intermittent nature of these resources, addition of distributed intermittent generation to its system, (2) establish a cap on annual (3) offer more granular hours and seasons for avoided cost rates and adjust the seasonal allocation factors relevant to avoided capacity rates accordingly, to recognize winter, summer, and "shoulder" seasons, and (4) adjust the PAF applicable to avoided capacity payments to 1.07. Consistent with the Commission's directives, the Company also provides updates with regard to the increased backflow occurring on its system from distributed renewable QFs, hourly operational and marginal cost data of combustion turbines, the adjustment to avoided energy rates to

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[10] *Joint Initial Statement*, p. 1.
[11] *Joint Initial Statement*, Cover Letter, p. 1, Docket No. E-100, Sub 158 (November 1, 2018).
[12] *Dominion's Initial Statement*, p. 1.

> reflect the locational value of generation in its North Carolina service area as approved in the 2016 Avoided Cost Case, and responds to the Commission's other directives contained in the Procedural Order.[13]

In light of the foregoing, the North Carolina Sustainable Energy Association ("NCSEA"), having become a party to this proceeding pursuant to the *Order Granting Petition to Intervene* issued by the Commission on August 9, 2018, by and through undersigned counsel, respectfully submits these initial comments.

II. <u>INITIAL COMMENTS</u>

A. <u>THE UTILITIES' INITIAL STATEMENTS HIGHLIGHT A BIAS TOWARDS UTILITY-OWNED GENERATION AND AGAINST QUALIFYING FACILITIES</u>

DEC, DEP, and DENC are for-profit, investor-owned, vertically-integrated utilities. Their focus is on creating value for their shareholders while providing affordable, reliable service for their ratepayers. QFs are in direct competition to the Utilities' business model. Put simply, "PURPA allows renewable energy projects to compete directly with the primary portion of the Utilities' business that does make money – building rate base."[14] The investor-owned utility's business objective has been threatened in North Carolina, where PURPA has successfully encouraged investments by small firms, and to the benefit of ratepayers, that compete against the Utilities' monopoly power.[15] While PURPA and the rules adopted by the FERC to implement it attempt to hold the Utilities' bias in check, they do not eliminate the bias altogether. Thus, the biennial avoided cost

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[13] *Dominion's Initial Statement*, p. 5.
[14] *Testimony of Jay Lucas*, p. 8, ll. 12-16, Docket No. E-100, Sub 101 (November 19, 2018).
[15] *Affidavit of Dr. Ben Johnson*, para. 12, included as **Attachment 1**.

proceedings and the accompanying intervenor and Commission-based scrutiny, are necessary to ensure that the Utilities' bias towards their business objective to build their rate base does not compromise the Utilities' legal obligations under PURPA to enter into PPAs at fair rates with QFs and to allow interconnection to the Utilities' grids. Due to the Commission's thoughtful, forward-thinking implementation of PURPA and the FERC rules over the years, the Commission has been able to keep the Utilities' bias in check, and has led to North Carolina becoming the national leader in QF development. As the QF industry has grown in North Carolina, the projected costs to ratepayers of complying with the Renewable Energy and Energy Efficiency Portfolio Standard have decreased dramatically. The proposals made in the Utilities' respective initial statements strongly reflect this bias, as set forth below, and the Commission must again be called upon to ensure that the Utilities' proposals comply with the legal requirements of PURPA.

This proceeding is the latest battle in the war by North Carolina's investor-owned utilities to preserve their outmoded, unjustified, and uneconomic monopoly control of competition from independent generation. Furthermore, the Utilities are attempting to use this proceeding to circumvent Congress' express intent in adopting PURPA: to place a check on monopolies by creating an opportunity for independent power producers to compete with the Utilities. In this proceeding, and in previous biennial avoided cost proceedings, the Utilities have presented inaccurate, incomplete, and misleading information in an effort to make it impossible for QFs to exercise their legal right to receive fair compensation for the value they provide the electric grid. In the crossfire, the Utilities ignore the fact that

QFs reduce the rate-based expenditures that are passed on to ratepayers and contribute to meeting the State's generation needs in a reliable and cost-effective manner – and with substantially less risk to ratepayers than utility self-built generation. The Commission should reject the Utilities' assault on PURPA, and should instead encourage innovation that can increase the reliability of the electric grid and lower costs to ratepayers by encouraging competition by independent power producers in the electric generation market.

It is important to note that while Duke claims that its "costs to produce power are declining due to their efficient generation fleets and lower natural gas prices,"[16] it is also moving these natural gas generation assets into rate-base and seeking to recover the costs from ratepayers.[17] This statement also ignores the efforts of Duke to invest as much as $13 billion of its own capital in North Carolina, rather than exploring how QFs can contribute to a modernized and more cost-efficient electric grid.[18]

B. Avoided Cost Rates

Throughout their respective initial filings, the Utilities have made numerous, transparent attempts to artificially, and wrongfully decrease the avoided cost rates paid to QFs. NCSEA's review of *Dominion's Initial Statement* and Duke's *Joint Initial Statement* reveal that the Utilities' methods for calculating

[16] *Joint Initial Statement*, Cover Letter, p. 1.

[17] In addition to the recently-completed DEC and DEP general rate cases, in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142 respectively, both DEC and DEP are planning multiple rate cases between 2019 and 2022. *See generally*, *Duke Energy Winter Update 2019*, Slide 13, available at https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed February 11, 2019).

[18] *See generally*, Docket No. E-7, Sub 1146. See also, *Duke Energy Winter Update 2019*, Slide 7, available at https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed February 11, 2019).

avoided capacity costs and avoided energy costs are based upon faulty assumptions and studies, and ultimately underestimate the amount that QFs should be paid for their energy and the value that their capacity provides to the Utilities' grid. As set forth below, the Utilities' calculations should be rejected on that basis.

1. AVOIDED CAPACITY COSTS

Because Duke projected a capacity need in its 2018 integrated resource plan, it identified capacity need to be avoided in its *Joint Initial Statement*. Specifically Duke claims that "DEC's next avoidable capacity need is a planned 460 MW (winter rating) of combustion turbine unit ('CT') capacity in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020."[19] As set forth below, however, NCSEA disagrees with Duke's assertion that its 2018 IRPs "precisely recognize the capacity value associated with incremental non-dispatchable solar capacity additions" and, therefore, NCSEA requests that Commission reject Duke's assertions and instead consider NCSEA's position on capacity needs and values.

i. Existing QFs in the Generation Stack

It is undisputed that Duke currently has QFs with active PPAs in its existing generation stack. However, in their 2018 integrated resource plans, DEC and DEP assume that a QF will continue providing capacity in DEC and DEP's respective generation stacks even after the expiration of the QF's PPA.[20] While it is likely that these QFs will continue to provide capacity to the Utilities, they should not be

[19] *Joint Initial Statement*, p. 13.
[20] Attachment 1, para. 156.

forced to do so without compensation for the value that they provide. If these QFs were to stop providing capacity to the Utilities, then the Utilities would be forced to procure some other source of capacity, which would be paid for by ratepayers. Existing QFs that are already in the Utilities' generation stack reduce future capacity needs, and as such, when they renew their PPA or enter into a new PPA, existing QFs should continue to be paid for the capacity that they provide. In the unlikely event that they are unable to provide such capacity, an additional capacity need would exist that, if met by new QFs, should entitle them to payment for capacity.

ii. DEC's Capacity Needs

DEC has concluded that it has no avoidable capacity need prior to 2028.[21] However, DEC's 2018 IRP shows a 30 MW short-term market capacity purchase in 2020,[22] and uprates at existing units scheduled for 2021, 2022, 2023, 2024, and 2025.[23] Market purchases of power and uprates at existing generation units should all be relevant in determining an avoidable capacity need.[24] Duke has not shown whether or not these capacity expansions can be met by small power producers, much less what type of small power producers.[25]

iii. Timing of Energization

The Utilities' avoided capacity calculations include unrealistic assumptions about when QFs will begin providing capacity. DENC assumes that QFs eligible

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[21] Attachment 1, para. 135.
[22] *Id.* at para. 131.
[23] *Id.* at para. 137.
[24] *Id.*
[25] *Id.* at para. 139. See also, N.C. Gen. Stat. § 62-156(b)(3).

for the Sub 148 avoided cost rates will begin providing capacity in January 2019.[26] DEP assumes that such QFs will begin providing capacity on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[27] However, because of well-documented delays in the interconnection queue, these are entirely unrealistic assumptions. In reality, a QF entering into a Sub 158 PPA will not begin providing capacity until December 2021 or later.[28] When considering this reality, QFs eligible for a Sub 158 PPA will actually be providing capacity during more years in which the Utilities have shown needs for capacity.[29] It would therefore be more appropriate to use December 31, 2021 as the presumptive in-service date for the purpose of calculating avoided capacity costs (both the quantification of the costs and the determination of the number of years in which there is a capacity need).[30] The Commission should also direct the utilities to calculate avoided cost rates in negotiated PPAs based on the presumed in-service date of the QF subject to the negotiated PPA.

iv. Overstatement of Winter Peak

Duke's proposed avoided capacity costs are further skewed against QFs because Duke has overstated its winter peak. Duke has failed to adequately develop DSM programs for their winter peak, as they have for their summer peak, thus exaggerating the peak. The capacity of demand-side management available for DEC's summer peak is more than double that available for DEC's winter peak, and

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[26] Attachment 1, para. 167.
[27] *Id.* at para. 168.
[28] *Id.* at para. 169.
[29] *Id.* at para. 165-169.
[30] Similarly, avoided energy costs should be forecast beginning on January 1, 2022.

the capacity available for DEP's summer peak is nearly double that of DEP's winter peak.[31] For example, during 2017, DEP activated its Distribution System Demand Response ("DSDR") program only three times during the winter but five times during the summer.[32] As such, the Commission should reject Duke's DSM assumptions.[33] Instead, the Commission should adopt the DSM assumptions set forth in **Attachment 1**.[34]

v. Summer/Winter Allocation

In its *Sub 148 Order*, the Commission surprisingly approved an allocation ratio of 80% winter and 20% summer for capacity costs, despite uncontroverted evidence that (i) Duke's winter peak hours are very limited, (ii) Duke's winter peaks have been due to extreme weather events, and (iii) many more of Duke's peak hours occur in the summer months.[35] In the current proceeding, Duke is proposing to extend this fiction: DEC is proposing allocation ratios of 90% winter and 10% summer for capacity costs, and DEP is proposing to allocate 100% of capacity costs to winter.[36] Duke's proposed allocations are inappropriate due to the flaws in the loss of load analysis that underlies the proposed allocations,[37] flaws regarding the DSM assumptions,[38] as discussed above, a failure to consider imports,[39] and are flawed solar modeling.[40] Given these flaws, the Commission

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[31] Attachment 1, para. 117-118.
[32] *Duke Energy Progress Distribution System Demand Response Program Implementation Status Report*, p. 2, Docket No. E-2, Sub 926 (June 15, 2018).
[33] *Id.* at para. 119.
[34] *Id.* at para. 122.
[35] *Id.* at para. 123.
[36] *Id.*
[37] *Id.* at para. 124.
[38] *Id.* at para. 125.
[39] *Id.* at para. 126.
[40] *Id.* at para. 127.

should revisit the allocation ratios approved in the *Sub 148 Order* and proposed by the Utilities.

2. AVOIDED ENERGY COSTS

The Utilities have failed to provide accurate models which display the avoided energy costs that the Utilities will realize in the coming years, particularly with robust distributed energy resource integration. Namely, as set forth more fully below, Duke forecasts its natural gas usage over ten years before moving to a fundamentals forecast despite the fact that data indicates that this length of time is too long and is inappropriate. Further, the Black-Scholes approach, utilized in prior avoided cost proceedings, to evaluate hedging values does not properly ascribe the value that QFs provide to the grid now. Finally, included in **Attachment 2** is an analysis provided by R. Thomas Beach of Crossborder Energy showing that Duke should be projecting different firm pipeline capacity costs and QF capacity costs.

i. Natural Gas Forecasting

NCSEA objects to the form and methodology that Duke uses in developing its natural gas forecast. While Dominion uses a forecast that is based on gas forward market prices for the initial 18 months, then transitions to a fundamentals forecast by 36 months, Duke's gas forecast uses a full 10 years of forward market prices before moving to a fundamentals forecast. Duke's method undermines its fundamentals forecast. "Practically, this means that the fundamentals forecast does not impact the avoided energy costs for a 10-year QF power purchase agreement ("PPA")."[41]

[41] *Affidavit of R. Thomas Beach*, p. 2, included as **Attachment 2.**

Figure 1 illustrates both the current Duke and Dominion proposals, the Public Staff's proposal in Docket No. E-100, Sub 148 that the Commission adopted in that docket[42], the ICF projection used by Dominion in Dominion's Initial Filing[43], and the recently-released *2019 Annual Energy Outlook* ("*2019 AEO*") forecast from the Energy Information Administration ("EIA") – as well as an updated set of Henry Hub forward market prices from the January 10, 2019 market.[44]

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[42] *Sub 148 Order*, p. 7.
[43] *Dominion's Initial Statement*, Exhibit DENC-5.
[44] Attachment 2, p. 9.

Duke's forward market for 10 years of natural gas at fixed prices is not transparent, broadly traded, or liquid. Duke's open interest in the natural gas future prices market is almost entirely in the first two years of the ten-year window.[45] **Figure 2** shows the open interest from the natural gas future prices market on January 10, 2019 and, as shown therein, 99.0 of the open interest is in the first two years.[46] The reported prices after two years are less certain and convey far less information than the initial two years that are heavily traded.

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[45] *Id.* at p. 10.
[46] *Id.*

Duke cites to gas contracts as evidence of their forecast reasoning, but Duke's ability to purchase four small volumes of gas (a total of 10 MDth[47] per day) for 10 years at close to the published 10-year forward prices is not dispositive. As shown in **Table 1** below **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the gas that could be displaced by the amounts of solar that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Even if a liquid market for 10-year fixed-price gas supplies existed, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Under current policy, DEC hedges the price of natural gas **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and DEP hedges the price for up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but only for volumes representing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** DEP's expected solar purchases would displace **[BEGIN CONFIDENTIAL]** [redacted]

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[47] "MDth" is a thousand decatherms, or a billion Btu, or M3Btu.
[48] Attachment 2, pp. 10-11.
[49] *Id.*

[redacted]

[END CONFIDENTIAL]

Forward prices and fundamentals forecasts each play a role in a reasonable gas price forecast: forward prices provide market-based information on short-term price trends influenced strongly by (1) current demand, by (2) near-term expected demand, and by (3) the current status of gas in physical storage.[51] While forward prices represent the future price parties are willing to contract for now, these amounts are not necessarily what the price for those future supplies will be in the future. Forward prices often track current prices, and the magnitude of the forward price curve shifts up or down largely in parallel to changes in the current spot price. While there is some evidence that short-term forward prices provide a reasonable forecast of short-term spot prices, Duke does not provide evidence that ten years of forward price data is superior to forecasts that examine the fundamentals of the supply and demand of natural gas.[52]

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[50] *Id.* at p. 11.
[51] *Id.*
[52] *Id.* at pp. 11-12.

Fundamentals forecasts look at longer-term trends in the gas supply and demand balance in North America and the world market for liquified natural gas ("LNG"). For example, the *2019 AEO* provides a fundamentals forecast considering both the growing demand for U.S.-produced natural gas and the growth in production from shale gas and gas associated with tight oil production.[53] EIA expects that increases in gas demand for electric generation will be driven by retirements of coal and nuclear capacity.[54] Fundamentals forecasts tend to be higher than forward market prices in falling markets, but lag forward prices in rising markets and the trend since 2010 has been lag forward.[55] These changing trends over time also are apparent in the EIA's own analysis of the accuracy of its past AEO forecasts.

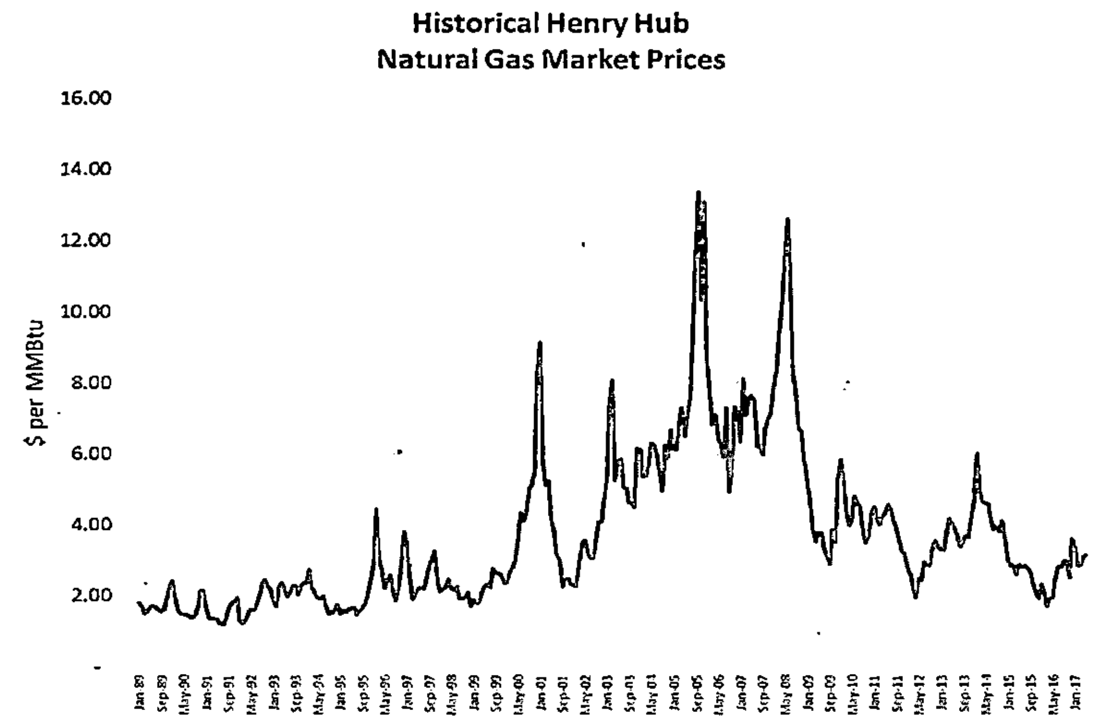
NCSEA believes that a balanced forecast that uses forward market prices for two years while the market is robust and deep, with a transition in the next three years to the average of a set of recent fundamentals forecasts, which NCSEA believes should come from (1) DNCP's forecast from ICF and (2) the new *2019 AEO* forecast from EIA, is a more appropriate forecast to use. Alternatively, NCSEA would not object to the use of Dominion's similar forecast methodology of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities.

[53] *Id.* at p. 12.
[54] *Id.*
[55] *Id.*

ii. Hedging

"Natural gas prices are volatile and uncertain, on multiple time scales. The history of Henry Hub spot price shows significant volatility over the last 30 years, as shown in **Figure 3**." [56]

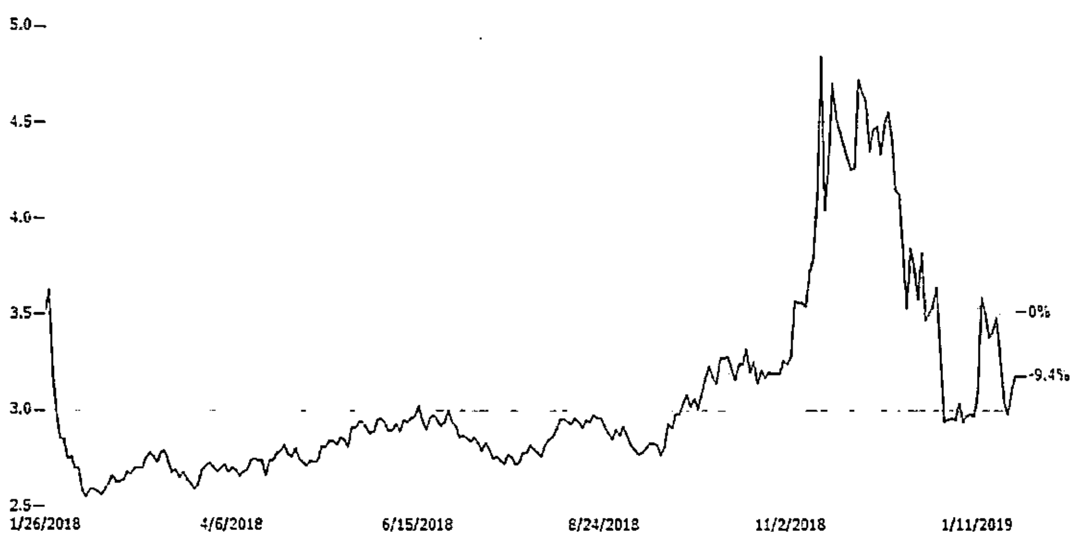
Figure 3



There can also be significant price volatility on shorter time scales, as illustrated by the most recent year of Henry Hub prices shown in **Figure 4.**[57]

[56] *Id.* at p. 13.
[57] *Id.* at p. 14.

Figure 4: *2018 Henry Hub Prices*



QFs displace natural gas-fired generation and the Utilities' use of natural gas. QFs also decrease the exposure to the volatility in natural gas prices. If the avoided cost prices paid to a renewable QF are for a fixed for the term of a PPA, the renewable QF provides a long-term physical hedge for the term of the PPA by displacing market-priced gas with fixed-price renewable power. The 3,790 MW of solar coming online in the near future in Duke's territories would displace about 143,000 Dth per day of natural gas use, assuming a system heat rate of 7,250 Btu/kWh. This solar hedge extends far longer than current utility hedging programs. Moreover, renewable generation also hedges against market dislocations or generation scarcity that can occur during an energy crisis or a drought. Renewable generation provides a hedge not available in financial markets and could be utilized as financial risk management.[58]

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[58] *Id.* at pp. 14-15.

In past avoided cost cases, the hedging benefit has been quantified using the Black-Scholes Model option pricing method.[59] The Black-Scholes approach assumes that the displaced gas is re-priced at the prevailing market price 5 or 10 times over a 10-year period, which is a far less effective hedge than the hedge provided by the renewable PPA that provides 10 years of prices fixed from the start of the contract's term.[60]

Several studies across the country have more adequately valued the hedge provided by renewable generation. In 2013, Xcel Energy's Public Service of Colorado unit estimated the long-term (20-year) hedging benefits of distributed solar resources on its system to be $6.60 per MWh.[61] Another method, the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015, calculates the additional costs to fix the fuel costs of a marginal gas-fired generator for a long-term period, compared to purchasing gas at prevailing short-term market prices on an "as you go" basis. The difference represents the hedging benefit of fixing the cost of gas, removing the market risk that volatile gas prices could make gas-fired generation at times uneconomic.[62]

Utilizing this method to calculate the 10-year hedging benefit of renewable PPAs in North Carolina, based on NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the Utilities' weighted average costs

[59] *See Sub 148 Order*, p. 73; *Sub 140 Order*, p. 7.
[60] Attachment 2, p. 15.
[61] *Id.*
[62] *Id.* at pp. 15-16.

of capital, and a marginal heat rate of 7,250 Btu per kWh, results in the avoided fuel hedging costs shown in **Table 2**:[63]

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As shown in Table 2, the NCSEA hedge provides substantially better values than the Utilities' hedge values and there are several methods across the country which are superior to the Utilities' current method and that have been used for several years.[64]

iii. Firm Pipeline Capacity Costs and QF Capacity Prices

In avoided cost calculations in North Carolina, the Utilities have utilized the "peaker method" where the capacity price in the calculation is based upon the fixed costs of a combustion turbine ("CT").[65] In this method, Utilities allocate much of the capacity price to winter peak hours, corresponding to periods of cold weather

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[63] *Id.* at p. 16.
[64] *See*, Attachment 2, pp. 15-16.
[65] *See, e.g.; Sub 148 Order*, p. 6; *Order Setting Avoided Cost Input Parameters*, p. 48, Docket No. E-100, Sub 140 (December 31, 2014) ("*Sub 140 Phase I Order*"); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 7-8, Docket No. E-100, Sub 136 (February 21, 2014).

when gas demand peaks and gas pipeline capacity is constrained. CTs need to be served with firm pipeline capacity, to be assured of receiving gas supplies, or to have a backup supply of an alternative fuel (oil) as exhibited by the Utilities pipeline capacity and capability projections for their CTs. These two options are costly, and, as a result, a reasonable premium is added to the CT costs used to set the winter capacity price. As noted in **Attachment 2**, Duke's fuel cost data, per the calculations, indicates that Duke should project additional pipeline capacity cost and that amount should be added to the avoided winter capacity rate.[66]

iv. Duke has Recognized Natural Gas Issues in Other States

Duke Energy's subsidiaries have recognized the issues in forecasting and hedging natural gas in their other territories across the United States. In 2017, Duke Energy Ohio ("Duke Ohio") requested that the Public Utilities Commission of Ohio approve subsidization of an uneconomic coal plant on the basis that it provided a hedge against natural gas price risk.[67] Duke Ohio Witness Judah Rose presented direct testimony that (i) recent declines in natural gas prices are unsustainable and cannot continue – thus over the long term gas prices will increase[68] and (ii) it is not accurate to use the price of gas futures to project gas prices more than 1-2 years in the future.[69] Witness Rose's testimony describes at length his analysis of natural

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[66] Attachment 2, p. 10.
[67] *See*, https://www.eenews.net/stories/1060082697.
[68] *Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio*, March 31, 2017, located at https://www.eenews.net/assets/2018/05/24/document_pm_01.pdf, p. 54 ("Ohio Testimony"); "Our forecast is that the recent multi-year trend (e.g., post 2008) of low 9 supply area natural gas prices will continue in the near-term, but over time, 10 natural gas prices increase in real terms and even more in nominal terms relative 11 to 2016."
[69] Ohio Testimony, p. 54.

gas prices and their recent and long-term trends. As he describes in depth, natural gas prices are currently very low, and these low prices are unsustainable. Furthermore, and perhaps most dangerously, the market for natural gas, historically, has been a volatile market amongst the commodities and susceptible to large jumps in pricing.[70]

In Florida, Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric Company ("TECO") filed a joint petition in 2016 to modify their fuel hedging programs, stating in part:

> [The] increased dependence on natural gas means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued. *While natural gas prices have trended downward in recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty.* Additionally, the recent downward trend in natural gas market prices cannot continue indefinitely. Factors such as production costs, weather, environmental regulations and exportation impact natural gas supply and demand, as well as natural gas price volatility.[71]

It's clear that Duke recognizes some of the same challenges in forecasting and hedging natural gas outlined by NCSEA as it has made some similar arguments where it suited them in Ohio and Florida. Therefore, Duke's natural gas assumptions and forecasts should be reviewed with considerable scrutiny and especially in light of NCSEA's positions set forth above.

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[70] *See generally*, Ohio Testimony at pp. 39-62.

[71] *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, Docket No. 160096-EI (Fl. Pub. Serv. Comm'm. Apr. 22, 2016), ¶ 5. (emphasis added).

C. RATE DESIGN

1. PRICE SIGNALS

The Commission recognized in its *Sub 148 Order* that stronger, more accurate price signals help market participants make better, more economically efficient decisions regarding the design, construction, and operation of QFs.[72] PURPA provides competition in power generation, even in a vertically-integrated state such as North Carolina.[73] This competition also diversifies energy supply, to the benefit of all ratepayers.[74] The Commission's role in price-setting is pivotal, because price signals can provide crucial information to QFs so that they can operate their generation assets in economically beneficial ways.[75] While HB589 reduced the availability of the standard offer PPA, this price-setting role is still important, as the standard offer PPA forms the basis of negotiated PPAs for larger QFs, as well as of critical importance in the Competitive Procurement of Renewable Energy and Green Source Advantage proceedings.[76]

i. Geographic Price Signals

Despite the Commission's guidance that the Utilities' proposals should provide more granular rate schedules, with the exception of Dominion's Schedule 19 – LMP, the utilities do not propose any rates that incorporate geographic granularity.[77] Without geographic granularity, there is no incentive for QFs to

[72] *Sub 148 Order*, p. 56. Attachment 1, para. 9.
[73] Attachment 1, para. 14.
[74] *Id.*
[75] *Id.* at para. 15.
[76] Attachment 1, para. 25. *Sub 140 Phase I Order*, p. 21. See also, *Order of Clarification*, Docket No. E-100, Sub 140 (March 6, 2015).
[77] Attachment 1, para. 171.

locate in areas where the utilities can avoid transmission and distribution costs.[78] Without some sort of geographic price signal, QFs will continue to be incented to locate where land and interconnection costs are cheapest, which may not provide the most advantage to the grid and could exacerbate the already clogged interconnection queue.[79] The Commission should direct the Utilities to develop tariffs that incorporate geographic price signals that provide an economic incentive for QFs to locate in areas that are most advantageous to the grid.[80]

ii. Seasonal Price Signals

The Utilities' proposed rate designs fail to adequately recognize how costs vary across different seasons.[81] Duke proposes two seasons, and DENC proposes three seasons.[82] All three utilities define a Summer season of May through September.[83] DENC proposes a Winter season of December through February and define the remaining months as a Shoulder season.[84] Duke combines all non-Summer months into a single season.[85] Duke's proposal not to differentiate a Winter season ignores the distinctly different patterns of electrical usage, net system load, marginal production costs, and avoided costs that occur during winter as opposed to spring and summer.[86] As such, the Commission should reject Duke's

[78] *Id.*
[79] *Id.* at para. 172.
[80] *Id.* at para. 173-174.
[81] *Id.* at para. 175.
[82] *Id.* at para. 176.
[83] *Id.*
[84] *Id.*
[85] *Id.*
[86] *Id.* at para. 178.

proposed seasonal variations and instead should adopt the seasons proposed in **Attachment 1.**[87]

iii. Time-of-Day Price Signals

The Utilities' proposed rate designs also fail to adequately recognize how costs vary across different times of day.[88] DEC, DEP, and DENC all propose oversimplified daily on-peak and off-peak rates that average time periods with distinctly different cost characteristics.[89] These proposals are made despite the fact that the Utilities have detailed avoided cost data available for all 8,760 hours for each of the next 10 years.[90] Averaging away such important detail is inappropriate, unduly discriminatory, and inconsistent with the Commission's desire for more granular rate designs.[91] Instead, the Commission should adopt the time-of-day periods proposed in **Attachment 1.**[92] In addition, the Commission should adopt an optional, real-time pricing tariff for QFs.[93] Such a real-time pricing tariff would be consistent with the Commission's recent order authorizing Duke's proposed Green Source Advantage tariff.[94]

2. ANCILLARY SERVICES

As discussed in greater detail below, the Commission should reject the Utilities' proposed Solar Integration Charges. However, if the Commission

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[87] *Id.* at para. 187.
[88] *Id.* at para. 175.
[89] *Id.* at para. 180-183.
[90] *Id.* at para. 183.
[91] *Id.*
[92] *Id.* at para. 189-192.
[93] *Id.* at para. 194-212.
[94] *See generally*, *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, p. 55, Docket Nos. E-2, Sub 1170 & E-7, Sub 1169 (February 1, 2019).

determines that the Solar Integration Charges are appropriate, the Commission should enable a market where QFs have a meaningful opportunity to avoid charges for such ancillary services as well as the opportunity to compete to provide such ancillary services.[95] NCSEA notes that nowhere in Chapter 62 of the North Carolina General Statutes are the Utilities granted a monopoly by the General Assembly for the provision of ancillary services. Given the opportunity to compete in a market, QFs may be able to provide these ancillary services at a lower cost than the Utilities, to the benefit of all ratepayers.[96] It is distinctly possible that ratepayers are overpaying for the incumbent utilities to provide ancillary services; however the answer cannot be known without a competitive market. Furthermore, creating a competitive market for ancillary services is consistent with the "intent on the part of the General Assembly to introduce an element of competitive pricing into the procurement of renewable energy and to reduce reliance on PURPA, which contains a 'must purchase' requirement for investor-owned utilities in purchasing a QF's electric output."[97] Solar QFs that are equipped with smart inverters and energy storage are strongly positioned to provide ancillary services quicker and cheaper than the conventional generators owned by the Utilities.[98] Similarly, small hydroelectric generators would also be well positioned to provide ancillary services.[99]

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[95] *Id.* at para. 77.
[96] *Id.* at para. 78.
[97] *See generally, Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, note 21, Docket Nos. E-2, Sub 1170 & E-7, Sub 1169 (February 1, 2019).
[98] Attachment 1, para. 79-80.
[99] *Id.* at para. 84.

In the *Sub 140 Phase II Order*, the Commission authorized the Utilities to charge QFs for VAR absorption.[100] However, the Utilities also direct QFs to generate VARs without compensation, in contravention of the Commission's direction that "To the extent that a smaller generator provides or absorbs reactive power at the utility's request, it is also appropriate for DEC and DEP to pay for such power to the extent they pay their own or affiliated generator."[101] Charging for VAR absorption but not paying for VAR generation is discriminatory and leads credence to the argument that the Commission should consider utilizing the differential revenue requirement methodology for calculating avoided cost rates, since this methodology would incorporate integration expenses.

3. Performance Adjustment Factor

A performance adjustment factor ("PAF") is designed to ensure that QFs are not discriminated against in favor of rate-based generation.[102] Ratepayers pay the full cost of rate-based generation, even if that capacity is not available during critical peak hours; in contract, a QF's capacity payments are tied to the amount of energy that the QF provides during specified hours.[103] Thus, the PAF should consider the actual availability of rate-based generation during all critical peak hours.[104]

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[100] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 9, 46-48, Docket No. E-100, Sub 140 (December 17, 2015) ("*Sub 140 Phase II Order*").
[101] *Sub 140 Phase II Order*, p. 48.
[102] Attachment 1, para. 88.
[103] *Id.*
[104] *Id.*

In its *Sub 148 Order*, the Commission reaffirmed its position that the availability of a CT is not determinative for the purpose of calculating a performance adjustment factor ("PAF") and instead noted that the PAF should be developed based on a "system availability metric that represents the reliability of the system during peak demand periods."[105] In this proceeding, Duke proposes a PAF of 1.05 and DENC proposes a PAF of 1.07.[106] The difference between the two is based on the months used in analyzing generation fleet availability.[107]

Duke defines the months of January, February, July and August as "peak season" for purposes of calculating the PAF.[108] However, Duke has not claimed that these are the only months when peaks can occur.[109] Perhaps most notably, this "peak season" differs from the seasons used by Duke in developing their rate design proposals.[110] As is shown in **Attachment 1**, DEC and DEP have historically had summer peaks during all months between June and September and, although less frequent, winter peaks between December and March.[111] The historical data for both DEC and DEP does not support considering only January and February as winter peak months to the exclusion of December and March. [112] Similarly, the historical data for DEC does not support considering only July and August as summer peak months to the exclusion of June and September.[113] By systematically

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[105] *Sub 148 Order*, pp. 55-56. Attachment 1, para. 85.
[106] Attachment 1, para. 86.
[107] *Id.*
[108] *Id.* at para. 91.
[109] *Id.*
[110] *Id.* at para. 95.
[111] *Id.* at para. 96
[112] *Id.* at para. 99-100.
[113] *Id.* at para. 102.

excluding these additional months, Duke has biased their PAF calculations and, if adopted, the proposal would discriminate against QFs and understate their contribution to capacity during peak months.[114] Accordingly, NCSEA recommends that the Commission reject Duke's PAF proposal and adopt the proposal of a PAF between 1.08 and 1.10 as proposed in **Attachment 1**.[115]

D. SOLAR INTEGRATION CHARGE

In its *Joint Initial Statement*, Duke proposes a new "integration services charge for intermittent Solar QF Power" ("Solar Integration Charge") purportedly as a means "to recognize the impact on operating reserves, or generation ancillary service requirements, for new variable and non-dispatchable solar capacity."[116] Similarly, Dominion proposes a "re-dispatch charge" which "adjust[s] the avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators.[117] However, the Utilities' proposals are inconsistent with previous Commission decisions and do not comply with PURPA.

1. BOTH COSTS AND BENEFITS MUST BE INCLUDED

The Commission has been clear in its directives that the Utilities must consider both the costs and benefits of solar resources when conducting an integration study. Most notably, in the Sub 140 proceeding, the Commission wrote:

> The Commission agrees that integration of solar resources into a utility's generation mix results in both costs and benefits, many of

[114] *Id.* at para. 111.
[115] *Id.* at para. 112.
[116] *Joint Initial Statement*, p. 31.
[117] *Dominion's Initial Statement*, pp. 12-13.

> which may be appropriate for inclusion in a utility's avoided cost calculations. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, may require the consideration of additional factors, such as the *potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support*. The Commission is aware that several studies regarding, and methods to calculate these costs and benefits, are currently under development. For example, the Electric Power Research Institute is set to release a study, titled The Integrated Grid – Phase II: Development of a Benefit Cost Framework, in the coming months. In light of these developments and the potential for significant amounts of solar generation to be constructed in North Carolina in the next few years, the Commission determines that it is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.[118]

While Duke acknowledges in its *Joint Initial Statement* that the *Sub 140 Phase I Order* stated that "integration of solar resources into a utility's generation mix likely results in costs and/or benefits[,]" the Astrape study used by Duke in calculating its solar integration charge consider none of the benefits identified by the Commission in its *Sub 140 Phase I Order*. In that order, the Commission also noted the limited applicability of the solar integration study that was presented by Duke in that proceeding because it failed to comprehensively investigate all aspects of the integration of solar generation.

> The PNNL study included as Exhibit 1 to DEC/DEP witness Snider's testimony provides a robust evaluation of several aspects of integrating increasing amounts of solar generation into the utility's generation portfolio, including the impacts of solar PV on ancillary services and generation production cost, as well as voltage and power flows, and a limited evaluation of avoided losses in the transmission and distribution systems. The study points out, however, that it was limited in scope in order "to produce results in a timely manner using available data and analytic tools, to identify areas of concern, measure the degree of impact, and provide

[118] *Sub 140 Phase I Order*, p. 60 (emphasis added).

> guidance for further actions. As a result, the study was limited to energy production cost modeling and steady-state power flow simulations. Potential PV impacts on dynamic system characteristics, such as frequency response and dynamic and transient stabilities, were not included the study scope."[119]

Thus, Duke's proposed Solar Integration Charge is inconsistent with the Commission's previous orders because it failed to include the benefits provided by QF generation.

Similarly, Dominion admits in its initial statement that its re-dispatch charge proposal fails to comply with the Commission's previous order, stating that "At this time, the Company is not proposing to adjust avoided cost rates to specifically account for the potential *costs* or benefits related to changes in ancillary service requirements" while going on to propose a rate that QFs must pay for re-dispatch *costs* without examining the benefits of QF generation.[120]

2. SUB 148 ORDER

The Utilities have failed to comply with the Commission's clear directive to develop additional rate schedules; instead developing single rate schedules and separate penalties for intermittent QFs. In the *Sub 148 Order*, the Commission stated the following conclusion:

> As discussed in other sections of this order, the Commission concludes that an avoided cost rate based on the characteristics of the QF-supplied power may also be appropriate going forward in future proceedings, and, therefore, will require the Utilities to include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings in the next biennial avoided cost proceeding.[121]

[119] *Sub 140 Phase I Order*, p. 61.
[120] *Dominion's Initial Statement*, p. 12 (emphasis added).
[121] *Sub 148 Order*, p. 150.

As discussed further below, the Utilities have failed to propose rates based on the characteristics of QF-supplied power, but have instead proposed a punitive charge for such QFs. However, the Utilities have also failed to provide the Commission with "data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings[.]"[122] In its *Joint Initial Statement*, Duke extensively discusses two studies performed by Astrapé,[123] but notably it fails to provide those studies to the Commission.[124] Similarly, Dominion asserts that "the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar PV penetration[]"[125] but fails to provide the Commission with this analysis.

Furthermore, the Commission was clear that it intended for the Utilities to propose multiple rate schedules based on the characteristics of a QF, and not based on the generation technology used by a QF.

> The Commission further finds that it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity.[126]

However, the Utilities have proposed integration charges that are solely based on the generation technology, and not the characteristics of a QF, in direct contradiction of the Commission's previous order.

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[122] *Id.*
[123] *Joint Initial Statement*, pp. 32-33.
[124] NCSEA obtained the Astrape studies through the discovery process. Attached as **Attachment 3** to these initial comments is *Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study* (November 2018), and attached as **Attachment 4** is *Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study* (August 27, 2018).
[125] *Dominion's Initial Statement*, p. 13 (internal citations omitted).
[126] *Sub 148 Order*, p. 98.

3. THE ASTRAPE STUDY IS FLAWED

i. Astrape Inappropriately Modeled North Carolina as an Island and Did Not Account for Regional Efficiencies

As set forth above, Duke relied upon Astrape to develop a report ("Astrape Study") that provided the basis for its decision to propose the Solar Integration Charge. NCSEA believes the Astrape Study is deficient in several ways. One of the most obvious deficiencies is that the Astrape Study views Duke's service territories as an island and not connected to neighboring grid systems. This is a fundamental misunderstanding of how the electric market functions and shows an inadequate valuation of the underlying electric market dynamics in Astrape's model. Regional cooperation among utilities is a key factor in reducing integration costs and curtailment and has been successfully adopted elsewhere in the U.S. **Attachment 2** states, in part, that:

> Experience with the new Energy Imbalance Market (EIM) on the western U.S. grid is demonstrating that expanded regional cooperation among utilities is a key to reducing integration costs and renewable curtailment, as the penetration of renewable wind and solar generation grows. The EIM market in the West includes both utilities in LMP-based markets (the three California IOUs in the CAISO) and many traditional vertically-integrated utilities in the other western states (Arizona Public Service, NV Energy, PacifiCorp, Idaho Power, Portland General Electric, and Puget Sound Energy), with more utilities planning to join the EIM in the near future. The share of renewable generation is growing on the systems of all of these western utilities, but they are sufficiently diverse in loads, resources, and geography that the expanded and more efficient interchange of power facilitated by the EIM is providing significant integration cost savings and reduced renewable curtailments across the region.[127]

[127] Attachment 2, p. 18.

Attachment 2 further states that EIM is designed to fit within each of the participating utilities' traditional hourly scheduling procedures and "focuses on finding more efficient and mutually beneficial transactions in sub-hourly time frames."[128] This design has ushered quick acceptance from a diverse set of utilities "with different market structures, different state regulators, and varying resource mixes whose service territories cover most of the western U.S. grid."[129]

The results of EIM are impossible to ignore. From 2014 through the third quarter of 2018, "the benefits to the participants [in EIM] have exceeded $500 million plus 734 GWh of avoided renewables curtailment."[130] EIM also provides savings in ramping as the balancing areas with excess ramping can supply other areas that need such ramping. Obviously, these types of interstate and inter-utility efficiencies provide savings and benefits which would offset any of the underlying data in the flawed Astrape Study supporting the proposed Solar Integration Charge. Further, the Astrape Study is flawed in several other ways: Astrape developed several inappropriate metrics, data points, and accounting results, including, notably, an improperly scaled solar plant intra-hour output variability data that fails to accurately reflect geographic diversity benefits. A detailed explanation of these defects are contained in **Attachment 2.**[131]

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128 *Id.*
129 *Id.*
130 *Id.*
131 *Id.* at pp. 17-19.

ii. Astrape Incorrectly Assumes Solar is Inflexible

The Astrape study incorrectly assumes that future solar resources will not include ancillary services and will not allow the utility any flexibility in dispatching future solar resources. This is an unreasonable assumption given the nature of currently utilized negotiated solar PPAs. Further, utility-scale solar projects have demonstrated a broad range of ancillary services available on the market, which are clear benefits to the overall grid.[132] The Astrape Study fails to provide an analysis showing solar flexibility and including these clear grid benefits.

4. SOLAR PLUS STORAGE PROJECTS MUST BE ACCURATELY REFLECTED IN ANY COST BENEFIT ANALYSIS

Duke's proposed Solar Integration Charge does not even meaningfully account for the ever-increasing adoption of storage as an add-on to distributed solar projects. Storage is more cost-effective when paired with solar as it allows for incorporation of the solar investment tax credit and, when combined, the project becomes exponentially more valuable to the grid. The Astrape Study does not model the capabilities of solar plus storage projects, which is a mistake and shows that Duke's data points in preparing the Solar Integration Charge rate design are incomplete.

The use of storage substantially reduces the variability of solar output, because storage either can be dispatched by the utility or can be pre-programmed to discharge at a specific rate in certain peak hours.[133] The storage paired with solar

[132] *Id.* at p. 19.
[133] *Id.*

also offers the best opportunity to utilize ancillary services, including load following, regulation, and fast frequency response.[134] NCSEA opposes the Solar Integration Charge wholly, but, should the Commission determine that the Solar Integration Charge is appropriate, NCSEA believes that solar plus storage projects should not be subject to such as charge as their benefits clearly and easily outpace their costs.

5. Solar Integration Provides Avoided Transmission and Distribution System Capacity Costs

Solar integration allows for utilities to avoid costs associated with transmission and distribution capacity. The Astrape Study failed to capture the benefits from integrating the distributed output of small QFs interconnected to the utilities' distribution systems. Small QF generation "can reduce peak loads on the utilities' upstream transmission and distribution systems, allowing the utilities to avoid load-related T&D capacity costs."[135]

Solar (and other distributed energy resources) interconnected directly to the distribution system produce power typically consumed on the local distribution system by the project's neighbors. This practice reduces loads on the upstream portions of the distribution system and the higher voltage transmission system.[136] Therefore, QFs displace traditional central station generation sources and makes available transmission and distribution capacity that can serve load growth and

[134] *Id.*
[135] *Id.* at p. 20.
[136] *Id.*

provide transmission capacity for future wholesale generation. This avoids avoiding the need to expand the entire transmission and distribution system.

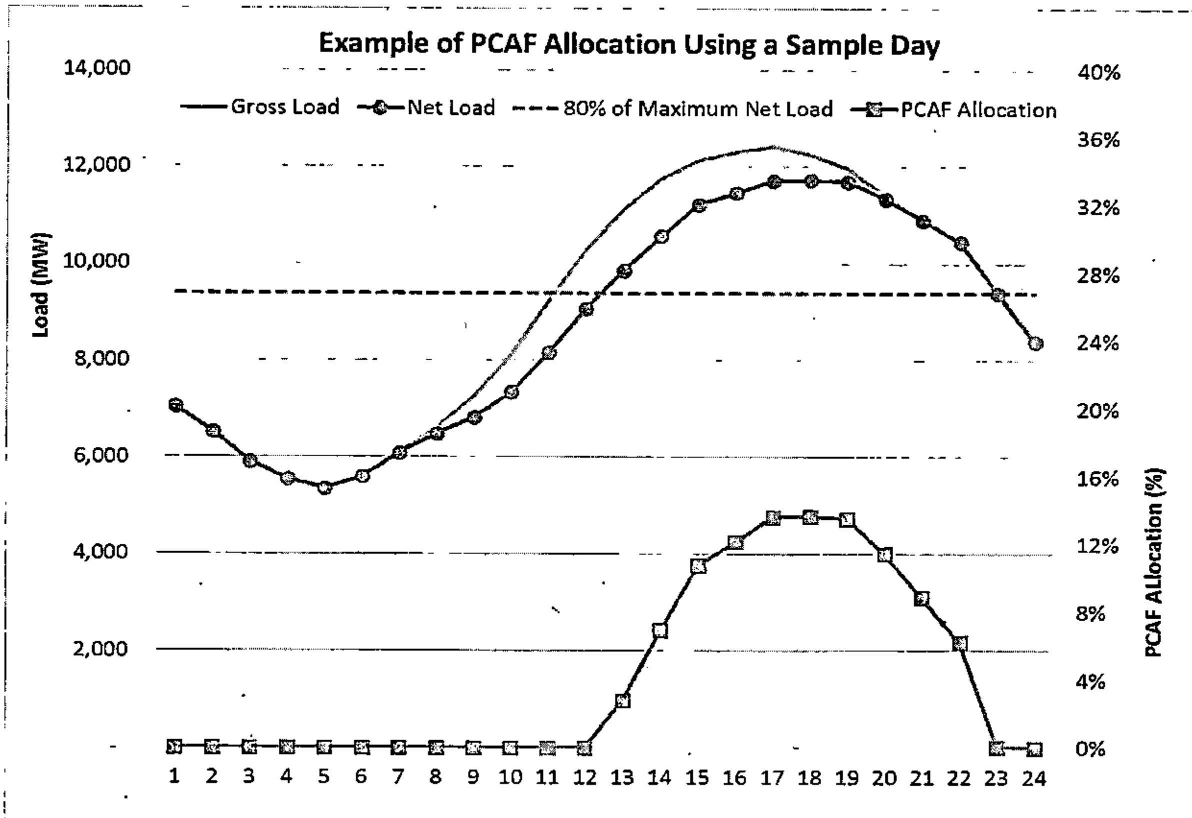
Over its 20 to 30-year useful lifespan, distributed solar can allow a utility to avoid future transmission and/or distribution costs not contained within the shorter time horizons used for transmission and distribution planning. Several areas of the U.S. are now utilizing solar and other types of distributed energy resources ("DERs") as "non-wires alternatives" that can be less expensive than grid upgrades.[137] This practice allows a utility to avoid the need to build more generation and transmission infrastructure.

Using Duke's data quantification of its avoided transmission and distribution costs, **Attachment 2** sets forth a model for avoided transmission and distribution costs resulting from solar integration. Specifically, **Attachment 2** proposes a set of "'peak capacity allocation factors' ('PCAF') based on hourly data on system net loads (for transmission) or loads at a representative sample of distribution substations (for distribution)."[138] PCAFs are hourly allocation factors that give a non-zero weight only to those system or substation loads that are within 20% of the annual peak load for the system or at each substation. All hours where the system or substation load is below 80% of the annual peak load have a PCAF of zero. The use of PCAFs is a more granular application of cost allocation methods. The threshold used to calculate PCAFs, such as 80% of the load in the system or substation peak hour, ties into planning for T&D capacity because

[137] *Id.*
[138] *Id.* at p. 21.

utilities use such thresholds to identify when to plan for possible upgrades.[139] **Figure 5** shows a simple example of how a PCAF allocation is derived.[140]

Figure 5



Attachment 2 includes hourly PCAF allocations for transmission calculated from Duke's system net loads for 2019. NCSEA believes that this method is the reasonable basis for calculating the avoided transmission and distribution rates to apply to the pricing of solar projects to be developed over the next several years.[141]

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[139] *Id.* at pp. 21-22.
[140] *Id.* at p. 22.
[141] *Id.*

Figure 6 is a heat map showing the PCAF allocation for DEC's avoided transmission costs.

Figure 6: *Heat Map of DEC PCAFs for Avoided Transmission*[142]

Hour Ending

Month / DEC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	2%	4%	4%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	3%	2%	1%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	5%	6%	6%	5%	3%	1%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	5%	4%	2%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 4 and Table 5 were developed by applying PCAF allocations and aggregating the hourly avoided transmission and distribution costs recommended in **Attachment 1**.[143] The result is the avoided transmission rates in **Table 4** and the avoided distribution rates in **Table 5**. As shown in these two tables, the integration of solar is actually a net benefit to Duke and its rate payers, and, accordingly, the owners of the QFs should receive payment.

Table 4: *Avoided Transmission Rates ($ per kWh)*[144]

Season	Summer			Winter			Other/Shoulder		
Period	1	2	3	1	2	3	1	2	3
DEC	0.0167	0.0016	--	0.0039	0.0006	--	--	0.0001	--
DEP East	0.0133	0.0005	--	0.0075	--	--	--	--	--
DEP West	--	--	--	0.0286	0.0068	0.0016	--	--	--
DENC	0.0104	0.0141	0.0008	0.0344	0.0152	0.0085	--	--	--

[142] *Id.* at p. 23.
[143] Attachment 1, paras. 187-194 and 204-235.
[144] Attachment 2, p. 24.

Table 5: *Avoided Distribution Rates ($ per kWh)*[145]

Season	Summer			Winter			Other/Shoulder		
Period	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
DEC	0.0115	0.0022	0.0004	0.0163	0.0124	0.0003	0.0002	0.0001	0.0003
DEP East	0.0048	0.0008	0.0001	0.0092	0.0042	0.0015	0.0004	0.0002	0.0002
DEP West	--	--	--	0.0114	0.0081	0.0071	--	--	--

Solar integration, and its associated technologies, has further potential to benefit the grid. "If DERs – including distributed solar, storage, or energy efficiency programs – can be targeted to the parts of the system where they are most needed, i.e. where distribution avoided costs are the highest, they can produce significantly greater benefits than what are estimated using system-wide distribution avoided costs such as those presented in Table 5."[146]

In addition, as noted in **Attachment 2**, the time profiles of distribution loads matter. Solar generation will be more effective at reducing peak loads and deferring upgrade costs at a substation that peaks in mid-afternoon in the summer than at a substation serving residential loads that peaks on summer evenings and winter mornings.[147] At the substation which peaks in the evening, the more valuable resource would be solar with enough storage to shift significant output into the peak evening hours.[148]

6. Market Price Suppression

Within their avoided cost calculations, and their accompanying rate designs including the Solar Integration Charge, the Utilities have also failed to accurately capture the effect that wind and solar resources have on market prices. Namely, the

145 *Id.*
146 *Id.*
147 *Id.* at p. 25.
148 *Id.*

"zero-variable-cost output of wind and solar resources reduces market prices."[149] New renewable generation increases electricity supplies available to the utilities and displaces the most expensive fossil-fired or market resources that would have been otherwise generated or purchased in regional power markets. The addition of local renewable generation will reduce the demand which the utility places on the regional markets for electricity and natural gas.[150] The reduction in demand will cause a corresponding reduction in the price in these markets, which benefits the Utilities when each must buy power or natural gas in these markets.

This "market price response" benefit of renewable generation "is widely acknowledged and has become highly visible in markets that now have high penetrations of wind and solar resources."[151] This benefit has been quantified since 2010 when the National Renewable Energy Laboratory (NREL) and GE Consulting undertook the Western Wind and Solar Integration Study (WWSIS). The WWSIS is "a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S."[152] This model included analysis of the impact of increasing solar penetration: the "high penetration solar cases (15% to 25% penetration) in the WECC resulted in 10% to 20% reductions in spot market prices"[153] as shown below in Figure 8 from **Attachment 2**.

[149] *Id.*
[150] *Id.*
[151] *Id.*
[152] *Id.*
[153] *Id.*

Figure 8: *Impact of Solar Penetration on AZ Spot Prices, from WWSIS*[154]

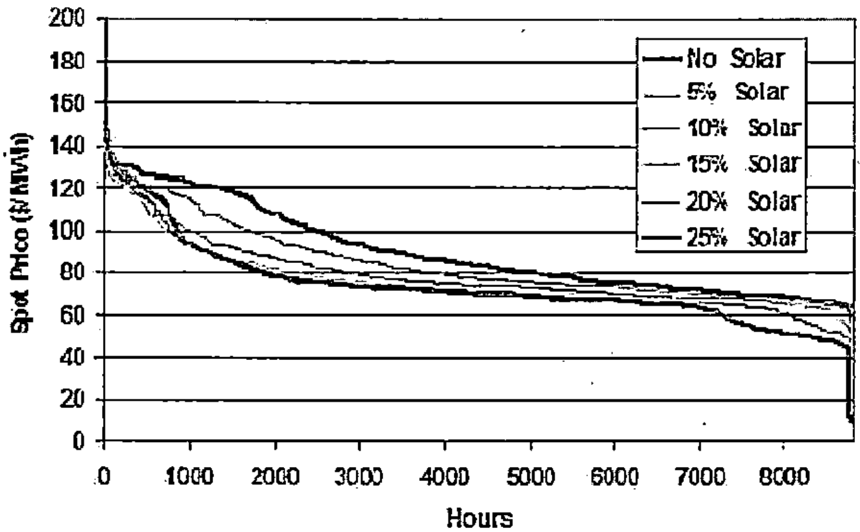

Figure 19 – Arizona Spot Price Duration Curves.

Therefore, per the results of this study, a "market price suppression benefit of about 4% of avoided energy costs has been used for distributed solar in New England."[155]

While NCSEA acknowledges that every utility is unique, and regional markets vary with regard to market price suppression to some extent, there is undoubtedly a clear economic give-and-take at play here. Namely, the introduction of distributed solar causes the prices of energy to reduce across the country, on a whole, and this practice is reflective of market economics. The Utilities in this docket have failed to account for these price benefits in their respective filings, and NCSEA requests this Commission acknowledge and require the Utilities to account for such market changes caused by distributed energy resources.

[154] *Id.* at p. 26.
[155] *Id.* at p. 26.

7. INTEGRATION CAPACITY ANALYSIS

The Utilities' proposed avoided cost plans do not call for the essential interchange of information between the Utilities, their customers, and the independent power producers. This robust interchange is integral for an efficient and least-cost methodology for determining the cost of energy. Specifically, as noted in **Attachment 2**, independent power producers and the Utilities need to exchange granular information which will allow for the most efficient and least-cost energy planning. The North Carolina interconnection queue is clogged and while HB 589 calls for thousands of megawatts of incorporated solar, the interconnection clog makes that statutory requirement difficult to timely correct. NCSEA realizes that there is no easy-fix and that issue is more appropriately addressed in the interconnection docket.[156] However, one potential repair to the interconnection queue, and also a means for the most accurate avoided cost rate, is a more robust interchange between QFs and the Utilities of granular information about the electric grid. QF developers have a strong interest in finding adequate capacity to accept their power, so they can move through the interconnection process quickly and at the lowest cost and this will benefit Utilities on a whole. "Utilities in California, Hawaii, New York, and Minnesota have completed comprehensive analyses of the ability of their systems to host distributed resources, and then have made this 'hosting capacity' data available to interested parties."[157] Hosting Capacity maps would provide developers with information necessary to

[156] *See generally*, Docket No. E-100, Sub 101, including, specifically, comments and testimony filed after the entry of the December 20, 2017 *Order Requesting Comments.*
[157] Attachment 2, p. 27.

sidestep interconnection issues and to also allow for more efficient energy production.

8. Single Issue Ratemaking

The Duke's request to implement a solar integration charge and Dominion's similar request to implement a re-dispatch charge are single-issue ratemaking and are not supported by Chapter 62 of the General Statutes or PURPA. Rates are to be set by the Commission pursuant to the requirements of N.C. Gen. Stat. § 62-133. N.C. Gen. Stat. § 62-3(24) defines "rate" to mean "every compensation, charge, fare, tariff, schedule, toll, rental and classification, or any of them, demanded, observed, charged or collected by any public utility, for any service product or commodity offered by it to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental or classification." It is uncontroverted that DEC, DEP, and Dominion are public utilities pursuant to N.C. Gen. Stat. § 62-3(23). The solar integration and re-dispatch charges are a compensation or charge, to be demanded, charged, or collected, for a service product, in this case ancillary services; as such, they are rates pursuant to N.C. Gen. Stat. § 62-3(24). As such, the solar integration and re-dispatch charges should be set during general rate cases pursuant to the requirements of N.C. Gen. Stat. § 62-133.

In addition to being inappropriate under North Carolina state law, the proposed solar integration and re-dispatch charges do not comply with PURPA and its regulations. The solar integration and re-dispatch charges are not "rates" pursuant to 18 C.F.R. 292.101(b)(5)[158] because they do not involve the sale or purchase of electric energy or capacity. Even if, for argument's sake, the solar integration and re-dispatch charges are rates pursuant to 18 C.F.R. 292.101(b)(5), they are still inappropriate; 18 C.F.R. 292.304(e)[159] lists the factors that may affect rates in determining avoided costs, and ancillary services are not listed among the factors that may be considered. NCSEA notes that Duke cites to 18 C.F.R. 292.304(e) in arguing that lower avoided capacity and energy rates may be allowed for purchases from intermittent QFs.[160] NCSEA does not dispute the plain language of 18 C.F.R. 292.304(e), which allows the listed factors that may be considered "in

[158] "Rate means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity."

[159] "Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity."

[160] *Joint Initial Statement*, p. 30.

determining avoided costs[.]" However, Duke does not propose lower avoided capacity and energy rates for intermittent QFs. Instead, it proposes to pay QFs full avoided capacity energy rates and then charge the intermittent QF for ancillary services provided by the utility. Thus, despite Duke's assertion to the contrary, its proposal is not consistent with 18 C.F.R. 292.304(e).

E. PPA RENEWAL

In this proceeding, the Commission is faced with the issue of PPA renewals for solar QFs. Solar QFs that opted for a 10-year levelized avoided cost rate under the Commission's E-100, Sub 127 rates will soon reach the end of their initial PPAs.[161] While solar QFs that opted for 15-year levelized avoided cost rates as well as those subject to E-100 Sub 136 and Sub 140 rates are not yet at the end of their initial PPAs, the Commission should begin considering how to deal with the residual rights of these solar QFs to enter into new PPAs for the balance of their useful lives.

"In balancing the costs, benefits and risks to all parties and customers, the Commission recognizes that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy."[162] As a policy matter, the Commission should try to ensure regulatory continuity and certainty for existing QFs that are seeking to renew a PPA upon its expiration or enter into a new PPA. Existing QFs have an expectation of continuity for their rights after their initial PPA expires, and the Commission should recognize these residual rights.

[161] *See generally, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127 (July 27, 2011).
[162] *Sub 140 Phase I Order*, p. 21.

Such a recognition would avoid the risks associated with QFs choosing not to continue to provide capacity to the Utilities, as discussed above.

F. PPA TERMS AND CONDITIONS

In addition to the issues discussed above regarding the Utilities' initial statements, the Utilities propose highly problematic changes to the standard offer PPA terms and conditions.

1. CURTAILMENT

In its *Sub 148 Order*, the Commission authorized nondiscriminatory curtailment of QF generation during system emergencies.[163] However, Duke has inappropriately expanded the Commission's limited authorization of utility control over QF generation. Specifically, the redlined terms and conditions call for QF compliance with all "system operator instructions provided by [DEP or DEC], including any energy storage protocols provided if applicable[.]"[164] This proposed amendment to the conditions of service for a QF is vague and Duke has offered no valid explanation for its incorporation in each of DEC and DEP's respective proposed schedules. However, it is clear that this language could allow for an increase in curtailment decision rights held on behalf of the operating utility that would violate the "nondiscriminatory" curtailment requirement and, for that reason, NCSEA strongly objects and requests the Commission deny this amendment for both DEC and DEP.

[163] *Sub 148 Order* at p. 8: "It is appropriate for DEC, DEP, and Dominion to file procedures with the Commission stating how they would curtail QFs on a *nondiscriminatory basis* when there is a system emergency." (emphasis added).
[164] *Joint Initial Statement*, DEC Exhibit 4, p. 14 and DEP Exhibit 4, p. 13

2. Material Modification

Duke's Initial Statement discusses the company's proposed changes to the terms and conditions of the standard offer PPA that would give the utility the unilateral right to terminate a PPA if a QF makes material modifications to the generating facility.[165] As an initial matter, the current proceeding is not the appropriate venue for addressing modifications to QFs after they have been interconnected to the grid. The issue of material modification is squarely an interconnection issue, and should be addressed in the ongoing interconnection proceeding.[166] The North Carolina Interconnection Procedures already address the issue of material modification,[167] and the Commission has already ruled that, in the event of a conflict between the standard offer PPA and the interconnection agreement, the interconnection agreement controls.[168] Thus, this provision proposed by Duke is wholly unnecessary.

However, in the event that the Commission determines that the provision is necessary, as proposed by Duke the material modification language is overly broad. Duke's Initial Statement states that any increase in either the AC or DC capacity of a QF will allow them to void the standard offer PPA.[169] However, Duke has already agreed that changes to the DC capacity of a QF do not constitute a material

[165] *Joint Initial Statement*, pp. 34-38. This proposed change is reflected in *Joint Initial Statement*, DEC Exhibit 4 at pp. 13, 15-18 and DEP Exhibit 4, pp. 12-15.
[166] *See generally*, Docket No. E-100, Sub 101.
[167] *See generally, Order Approving Revised Interconnection Standard*, Docket No. E-100, Sub 101 (May 15, 2015).
[168] *Sub 140 Phase II Order*, p. 9.
[169] *Joint Initial Statement*, p. 35.

modification for the purpose of interconnection.[170] In addition, Duke explicitly states that "replacing existing panels with panels with greater DC capacity[]" would constitute a material modification and allow the Utility to terminate the PPA.[171] This language is extremely problematic for solar QFs, as panels need to be replaced during the normal course of operations due to issues such as storm damage. At times, identical panels may not be available, and replacements may increase the DC capacity of the QF, even if they do not increase the AC generating capacity. Thus, if the Commission approves this provision, Duke would be allowed to terminate a QF's PPA for routine operations such as repairing storm damage.

Finally, the language proposed by Duke is likely to be discriminatory because it would allow the Utility to unilaterally terminate a PPA at its discretion, and there are insufficient safeguards proposed to protect against discriminatory use by the Utility.[172]

3. ENERGY STORAGE PROTOCOLS

Duke proposes to include in the standard offer PPA's terms and conditions a new provision that requires a QF to comply with "any energy storage protocols provided" to the QF by Duke[173] However, Duke have not provided these energy storage protocols to the Commission for review and approval. Without reviewing the protocols themselves, the Commission cannot determine that the energy storage

[170] *See, Agreement and Stipulation of Partial Settlement by and between Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion Energy North Carolina, North Carolina Pork Council and the Public Staff*, Docket No. E-100, Sub 101 (January 25, 2019).
[171] *Joint Initial Statement*, p. 35.
[172] Attachment 1, para. 159-160.
[173] *Joint Initial Statement*, DEC Exhibit 4, p. 14 and DEP Exhibit 4, p. 13. Dominion does not propose a similar addition to its PPA terms and conditions.

protocols are reasonable. Without Commission oversight, Duke could adopt energy storage protocols that are discriminatory against QFs in violation of PURPA. Duke does not discuss or otherwise attempt to justify this proposed modification anywhere in the body of its filing, nor does it specify any further detail regarding the content of such potential energy storage protocols. The effect of this undefined provision will be to prevent QFs from financing energy storage, since there is no certainty as to how the expected revenue generation opportunity could be limited or eliminated due to these undefined restrictions. As such, the Commission should reject the Utilities' proposal to require QFs that include energy storage to comply with unprovided and unapproved energy storage protocols unilaterally dictated by the Utilities.

4. Definition of Nameplate Capacity

NCSEA opposes the Utilities' proposal to add the DC capacity of a QF to the definition of nameplate capacity and contract capacity in their respective PPA terms and conditions. This proposal is utterly without merit, and is not supported by any of the other definitions of nameplate capacity that are applicable to QFs. The Commission's rules for reports of proposed construction and applications for certificates of public convenience and necessity both specify that capacity is to be listed in AC.[174] Similarly, the current version of the North Carolina Interconnection Standard specifies that capacity is to be listed in AC when submitting an

[174] *See*, Commission Rules R8-64(b) and R8-65(g).

interconnection request.[175] Furthermore, FERC Form 556 does not specify whether "capacity" is AC or DC.[176]

Adding a QF's DC generating capacity to the definition of nameplate capacity and contract capacity in the PPA's terms and conditions would have detrimental impacts on QFs. The effect of such a definition would be that a QF could not make any changes to a generation facility without the utility's approval. Thus, the impact would be the same as that of the Utilities' proposed language regarding material modifications, discussed above. For the reasons discussed here and above regarding material modifications, the Commission should reject the Utilities' proposed addition of a QF's DC generating capacity to the definitions of nameplate capacity and contract capacity in the PPA terms and conditions.

5. Estimated Energy Generation

Duke proposes in its PPA terms and conditions that it should have the unilateral authority to void a PPA if a QF increases its annual energy production above an estimated production number stated in the PPA.[177] Duke provides no limitation or qualification on this proposed authority and provides for no reasonable circumstance in which a QF's actual annual production might exceed its estimated production number, as occurs on a regular basis for QFs. As an initial matter, Duke's proposal ignores the fact that an estimate is just that, and annual production will necessarily vary up and down due to a variety of circumstances. It is

[175] North Carolina Interconnection Request, p. 5, as approved by the Commission's *Order Approving Revised Interconnection Standard*, Docket No. E-100, Sub 101 (May 15, 2015).
[176] *See generally*, https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf (last accessed February 12, 2019).
[177] *See generally*, *Joint Initial Statement*, DEC Exhibit 4, pp. 15-16 and DEP Exhibit 4, p. 14.

commercially unreasonable to require that a QF never exceed its estimated annual production without risking termination of its PPA. Duke's proposal departs from its long-standing practice, required by PURPA, of purchasing all of a QF's output provided that the QF does not exceed its nameplate capacity (expressed in AC). Moreover, it is NCSEA's understanding that Duke's interconnection studies evaluate solar facilities based on the assumption that they will generate at their full nameplate capacity during all hours studied during the interconnection study process, so there is no technical problem presented where actual energy production exceeds an estimate, provided that nameplate capacity is not exceeded. Furthermore, in part due to the fact that Duke provides no explanation or justification for the proposed change in its filing, it is unclear whether an "estimated production number" would be equivalent to an estimate of maximum potential production, average anticipated production, or otherwise, and it is unclear what, if anything, would prevent QFs from simply overestimating their production to avoid potential penalty.

In practice, Duke is arguing that a QF should lose its legally enforceable obligations ("LEO") if it repowers the generation facility.[178] Duke's claim is based on the fact that the Commission utilizes the receipt of a certificate of public convenience and necessity ("CPCN") as one of the prongs for establishing a LEO,[179] and that the Commission's form for applying for a CPCN requires a QF to identify the "gross and net projected maximum dependable capacity of the facility

[178] *Id.* at pp. 37-38.
[179] *Sub 148 Order*, p. 8.

as well as the facility's nameplate capacity[]" and "projected annual sales in kilowatt-hours[.]"[180] According to Duke, "Absent the Companies' acceptance of a change in the Facility, the QF's right to sell under the pre-existing PPA and standard offer rates should be limited to the Facility that established the LEO and originally entered into the PPA."[181]

This position has no legal support and defies common sense. The reason the Commission incorporated the CPCN requirement into North Carolina's LEO test was to ensure that QFs "would be in a position to enter into a legally enforceable obligation" before a LEO can be established, "and that requires a certificate."[182] The CPCN requirement was not intended to "lock" QFs into constructing a facility exactly as described in the CPCN application. This is supported by the fact that QFs are free to make a variety of changes to the information in the CPCN application (e.g. ownership and site layout), so long as they notify the Commission of the change. Under Duke's reasoning, even those changes would result in the QF sacrificing its LEO.

Duke's suggestion that a LEO is extinguished unless the utility "accepts" a change in the QF is also antithetical to the purpose of the LEO concept, which is to prevent utilities from interfering with QFs' PURPA rights. In making this suggestion, Duke is pushing the *Sub 148 Order* further than the Commission intended. While the *Sub 148 Order* did note that "existing regulatory and legislative policies have created a 'distorted marketplace' for solar projects and that this results

[180] Commission Rule R8-64(b)(3)(iii) and (ix).
[181] *Joint Initial Statement*, pp. 37-38.
[182] *Order on Pending Motions*, p. 3, Docket No. E-100 Sub 74 (Feb. 13, 1995).

in artificially high costs being passed on to North Carolina ratepayers[,]"[183] Duke appears to infer from this that any regulatory change that decreases the aggregate amount of QF sales is appropriate. However, the *Sub 148 Order* also made clear that the Commission was not trying to discourage QF development, but was adjusting the regulatory framework, in part based on HB 589, to "balance[e] PURPA's goals with the economic and regulatory circumstances facing QFs and utilities in North Carolina."[184] The Commission concluded that the balance struck in the *Sub 148 Order* was appropriate, and Duke has not introduced any facts or arguments to show that this balance was incorrectly struck and must be further adjusted.

Furthermore, the Commission was careful in the *Sub 148 Order* to "avoid introducing regulatory uncertainty."[185] Consequently, the *Sub 148 Order* focused on prospective changes to avoided cost rates and the regulatory structure. The *Sub 148 Order* did not focus on retrospective changes that would affect QFs that had already entered into standard offer PPAs. Duke's current proposal, in contrast, would have a dramatic impact on existing QFs and would therefore "introduce regulatory uncertainty," contrary to the goals of the Commission.

III. CONCLUSION

For all the reasons set forth above, NCSEA requests that the Commission reject the Utilities' avoided cost plans and request for new rate design including the Solar Integration Charge and require the Utilities to file new avoided cost plans

[183] *Sub 148 Order*, p. 16.
[184] *Id.* at p. 17.
[185] *Id.* at p. 18.

which provide accurate representations of the avoided cost of both energy and capacity, including highlighting the benefits of distributed generation and solar, commensurate with the findings and conclusions made in this filing and also its two attachments.

Respectfully submitted this the 12th day of February, 2019.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 12th day of February, 2019.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**NCSEA'S REPLY**
Rates for Electric Utility Purchases from	)	**COMMENTS**
Qualifying Facilities – 2018	)	

NCSEA'S REPLY COMMENTS

The North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in the above-captioned proceeding, files these reply comments pursuant to the *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing Biennial Proceeding") issued by the North Carolina Utilities Commission ("Commission") on June 26, 2018, and as subsequently modified by orders dated January 4, 2019, January 25, 2019, February 8, 2019, February 22, 2019, and March 19, 2019.

I. BACKGROUND

On November 1, 2018, Western Carolina University ("WCU") and New River Light and Power ("New River"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("Dominion" or "DENC"), and Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively, "Duke") made their initial substantive filings in this docket (Duke and Dominion, collectively, the "Utilities").

On February 8, 2019, NC WARN, Inc. ("NC Warn") filed initial comments. On February 12, 2019, the NC Small Hydro Group ("Hydro Group" or "NC Small Hydro"), Cube Yadkin Generation LLC ("Cube Yadkin"), NCSEA, and the Southern Alliance for Clean Energy ("SACE") filed their respective initial comments. On February 13, 2019, the

North Carolina – Public Staff ("Public Staff") filed the Initial Statement of the Public Staff ("Public Staff Initial Statement") and, also, a Motion to Deem Comments as Timely Filed, seeking for the Commission to accept the Public Staff Initial Statement as timely filed.

NCSEA stands by the positions taken in NCSEA's Initial Comments, and, as set forth more fully below, supports many positions taken by other intervenors in this docket. NCSEA also rejects some of the positions taken by intervenors in this docket and, in particular, those positions which are highlighted below.

II. Avoided Energy Costs

A. Natural Gas Forecasting

NCSEA agrees with the Public Staff and SACE that Duke's reliance on ten-year forward pricing for natural gas forwards is inappropriate. NCSEA particularly finds Public Staff's argument regarding other utilities' forecasting methods, including some which fall under the Duke Energy umbrella, compelling:

> the Public Staff's research has found a significant number of utilities, Duke Energy Florida, Duke Energy Kentucky, Duke Energy Indiana, TVA, DENC, Georgia, Power Company, Southwestern Public Service Company, Entergy Louisiana, Entergy Arkansas, PacifiCorp, and Puget Sound Energy, using a methodology with a much narrower window for the use of forwards than the ten years proposed in this proceeding by Duke. Further, DEC and DEP have been unable to provide the Public Staff with the name of any utility that incorporates the use of forward natural gas prices greater than five years for IRP or similar long-term planning purposes.[1]

NCSEA further agrees that "DEC's and DEP's proposed use of 10-years of forward prices will not be representative of Duke's actual fuel prices, thereby sending the wrong price signals to the market,"[2] and, "[t]he fact that Duke has been able to purchase ten-year

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[1] *Initial Statement of the Public Staff*, p. 25, Docket No. E-100, Sub 158 (February 13, 2019) ("Public Staff Initial Statement").
[2] *Id.* at 25.

forwards on five occasions in the last three years should not be determinative as to whether the use of ten-year forwards is appropriate. It is clearly not Duke's standard operating procedure in its fuel procurement practices to purchase ten-year forwards."[3]

While NCSEA agrees with the Public Staff regarding Duke's ten-year request, the Public Staff's proposal of allowing for up to "five years of forward market data before appropriately transitioning to the Company's fundamental forecast"[4] still inadequately captures accurate price signals. NCSEA believes that the forecast should use forward prices for up to two-years, with a three-year transition to the average of a set of recent fundamentals forecasts from either Dominion's forecast from ICF International, Inc. ("ICF") or the new *2019 AEO* forecast from the U.S. Energy Information Administration ("EIA").[5] SACE similarly believes that the Commission should "require Duke to rely on no more than two to three years of forward market price forecasts, before transitioning to a blended price forecast, and then a fundamental price forecast."[6] Also, as noted by SACE and the Public Staff, the Commission's October 11, 2017 Order in Docket No. E-100 Sub 148 ("E-100 Sub 148 Order") specifically states that a ten-year forwards forecast, as requested by Duke here, is inappropriate.[7] NCSEA believes that, especially given the spectrum of arguments against such long-term forecasting, the Commission should reject Duke's proposal to rely upon ten-year forecast and, instead, require Duke to rely upon a much shorter-in-time forward forecast before transitioning into a fundamentals forecast analysis in the current avoided cost calculation. Specifically, as stated in NCSEA's Initial

[3] Public Staff Initial Statement, p. 27.
[4] *Id.* at 28.
[5] *NCSEA's Initial Comments*, p. 19, Docket No. E-100, Sub 158 (February 12, 2019) ("NCSEA's Initial Comments").
[6] *Initial Comments of the Southern Alliance for Clean Energy*, p. 6, Docket No. E-100, Sub 158 (February 12, 2019) ("SACE's Initial Comments").
[7] SACE's Initial Comments, p. 6; Public Staff Initial Statement, pp. 21-22.

Comments, a two-year forwards forecast transitioning for three-years into a fundamentals forecast would be more appropriate and accurately reflect pertinent price signals.

B. Hedging Values

Like NCSEA, the Public Staff is concerned about Duke's removal of the hedging value:

> The Public Staff reiterates its prior support for inclusion of a hedging value for renewables found to be appropriate by the Commission in the Phase One Order, and recommends that the Commission require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing model or similar method."[8]

As the Public Staff outlines, Duke contends that PURPA provides for a "Put Option" and the associated rights to Qualified Facilities ("QF") and this obligation is being within the QF's sole discretion is the equivalent to the QF owning a "Put Option."[9] Like the Public Staff, NCSEA disagrees with this position which would, as the Public Staff puts it "require QFs to compensate utilities for the right to sell their generation."[10] NCSEA agrees with the Public Staff that the removal of any hedging benefits of renewable generation is not justified despite Duke's claims that a "risk of overpayment from extending" the put-option right to QFs needs to be offset and doing do by removing hedging benefits is appropriate.[11] As noted by the Public Staff, "[t]he risk of overpayment was directly addressed by this Commission in the 2016 Proceeding through the elimination of

[8] Public Staff Initial Statement, p. 29.
[9] *Id.* at 28.
[10] *Id.*
[11] *Id.*

capacity payments when capacity is not needed, the reduction in the PAF from 1.20 to 1.05, and the reduction of the MW threshold to be eligible to receive a Standard Contract."[12]

SACE similarly argues that Duke has improperly sought to eliminate hedging value. NCSEA agrees with SACE that Duke bears the burden in this proceeding and has failed to meet the necessary burden to eliminate fuel price hedge value.[13] NCSEA also agrees that:

> Duke attempts to obfuscate the [put-option] issue by repeatedly claiming that it is not 'recommending applying this charge to QFs at the time' while simultaneously recommending the removal of the 0.028 cents per kWh hedging value from avoided energy rates. Regardless of how Duke characterizes it, the removal of the existing hedging value would reduce the avoided energy costs paid to QFs by 0.028 cents per kWh. Duke may not circumvent its obligation to include hedging benefits in its avoided energy rates by assuming that the alleged and unsupported option premium, based on the yet-to-be calculated value of the Put Option, is identical to the existing hedging value.[14]

Duke's work-around to eliminate hedging is improper. SACE makes a further instrumental point: "Duke is not entitled to compensation for the legal right PURPA grants QFs to sell energy and capacity to the Companies at avoided cost rates. [...] a QF is not required to purchase the right to sell energy and capacity under PURPA. Congress and FERC have expressly granted QFs the right to sell energy and capacity to the Utilities at a price that is determined at the time the legally enforceable obligation is created." This argument is capped with a relevant assumption: "[i]f Congress or FERC had intended for utilities to receive compensation for a QF's right to sell energy and capacity, they could have expressly included this requirement in statute or regulations, but they did not."[15]

[12] Public Staff Initial Statement, pp. 28-29; See Section VI below for a more in-depth review of PAF allocation.
[13] SACE Initial Comments, p. 8.
[14] *Id.* at 8-9.
[15] *Id.* at 9.

NCSEA agrees with SACE and the Public Staff and believes that the Commission should disallow Duke's intended elimination of hedging benefits. For these reasons, the Commission should direct Duke to reinstate hedging benefits in a revised avoided cost proposal.

III. Avoided Capacity Costs

A. Peaker Methodology

NCSEA disagrees with the Public Staff on their analysis of the costs of a hypothetical new Duke peaker plant. Namely, the Public Staff suggests that the use of brownfield costs, rather than greenfield costs, for new peaker plants is a more accurate way to determine the avoided capacity.[16] The Public Staff bases this argument on the assumption that "DEC and DEP have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several "brownfield" sites for potential future use for both baseload and peaking needs."[17] The Public Staff goes on to state that the brownfield sites "referenced above" are "available for use to construct future generation and represent *potential* value to customers that is not reflected in the costs of a greenfield site."[18]

The Public Staff does not provide specific brownfield sites, but rather relies on recent history to make the determination that Duke should adjust its EIA formula to utilize brownfield site costs in peaker plant calculations necessary for an avoided cost calculation.

> DEC and DEP have already utilized brownfield sites for new generation construction. In fact, the last five Duke generating plants built have been at a brownfield site or in the proximity of an existing generating station, utilizing on-site infrastructure. Examples include the Sutton Combined Cycle (DEP), Sutton Black Start CT (DEP), Lee Combined Cycle (DEC),

[16] Public Staff Initial Statement, p. 67.
[17] *Id.*
[18] *Id.*

> Asheville Combined Cycle (DEP), and Lincoln County CT (DEC). It is reasonable to assume that some portion of the capacity need demonstrated over the planning period in each Utilities' 2018 IRP will be constructed on brownfield sites."[19]

The issue with the Public Staff's suggestion that Duke rely upon brownfield rather than greenfield costs is that Duke has not projected enough open brownfield locations for capacity additions. As the Public Staff notes – Duke has not proscribed the use of brownfield sites in their avoided cost calculation in their next avoided cost proposal.[20] Therefore, the Public Staff is, on its own accord, changing the avoided cost calculus in such a way that will cause it to suppress installed costs and lower the capacity payments in the next filing. To this point, in the 2018 Integrated Resource Plan filings, Duke only identified two future capacity additions that will occur at brownfield locations, and both of these facilities have already received certificates of public convenience and necessity ("CPCNs") from the Commission: in DEC, the "402 MW Lincoln CT 17 included in December 2024[;]"[21] and, in DEP, the "560 MW Asheville combined cycle addition in November 2019."[22] Given that Duke predicts only two capacity additions which may be brownfield sites, and that neither site is incorporated into its avoided cost peaker plant calculations, Duke does not appear to intend to utilize numerous brownfield sites and, instead, may have used the EIA-formula utilizing greenfield sites for good reason.

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[19] *Id.* at 68.

[20] Public Staff Initial Statement, p. 67; "DEC and DEP relied on EIA data for hypothetical overnight costs and made certain adjustments to reflect the expected economies of scale associated with the gas interconnection costs for the Carolinas service areas. The EIA costs are representative of a "greenfield" site, meaning a site with no existing infrastructure." *Id.*

[21] *Duke Energy Carolinas, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, p. 63, Docket No. E-100, Sub 157 (September 5, 2018) ("DEC IRP"). *See also*, *Order Issuing Certificate of Public Convenience and Necessity with Conditions*, Docket No. E-7, Sub 1134 (December 7, 2017).

[22] *Duke Energy Progress, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, p. 65, Docket No. E-100, Sub 157 (September 5, 2018) ("DEP IRP"). *See also*, *Order Granting Application in Part, with Conditions, and Denying Application in Part*, Docket No. E-2, Sub 1089 (March 28, 2016).

For all these reasons, NCSEA opposes the Public Staff's suggestion that Duke utilize more brownfield site data. NCSEA does not oppose Duke's utilization of brownfield sites in their next avoided cost filing but believes that such input only be utilized if Duke does plan to utilize it and will be reflective of true cost data.

B. SUMMER CAPACITY VALUES

NCSEA agrees with SACE that Duke has devalued the capacity contributions of solar QFs and eliminated the capacity benefits solar QFs can provide by overstating winter effects and undervaluing summer capacity values:

> Duke has designed its avoided capacity rates using a 100% winter / 0% summer allocation for DEP, and 90% winter / 10% summer allocation for DEC, meaning that Duke has assigned 100% of its loss of load risk in DEP to the winter months and 90% of its loss of load risk in DEC to the winter months. As a result, DEP's new rates pay all of its annual capacity value in the winter and DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer. These changes are significant because by allocating all or nearly all loss of load risk in the winter, Duke devalues the capacity contributions of solar QFs and almost completely eliminates consideration of the capacity benefits solar QFs provide during summer demand peaks.[23]

SACE's argument outlines how Duke has changed allocations in such a way as to totally undermine the value of solar QFs on the grid. Furthermore, SACE's expert found that the Duke studies related to this are flawed:

> Mr. Wilson concludes that the RA Studies and Capacity Value Study contain a number of methodological flaws that have caused Duke to over-estimate the risk of very high loads in the winter and unnecessarily inflate the winter and summer planning reserve margins. Applied to the avoided cost proceeding, these flaws have caused the Companies to greatly overstate winter resource adequacy risk compared to summer, and to inappropriately allocate 100% and 90% of winter loss of load risk in DEP and DEC, respectively.[24]

[23] SACE Initial Comments, pp. 11-12 (internal citations omitted).
[24] *Id.* at 13.

NCSEA agrees that the methodologies used in this report are flawed.

Furthermore, NCSEA wishes to highlight the following passage of SACE's Initial Comments which outlines how the Duke reports substantially overrate winter:

> This report shows that the risk of very high loads under extreme cold was substantially overstated in the 2016 RA [Resource Adequacy] Studies, primarily due to the faulty approach to extrapolating the increase in load due to very low temperatures. Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Overall, the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year. Accordingly, the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights developed and approved.[25]

NCSEA completely agrees with SACE – Duke's flawed methodologies result in an overstatement of winter risk, and, accordingly, an unnecessary and unfair reallocation of capacity values resulted in Duke's analysis. NCSEA agrees that Schedule PP should be rejected and that more balanced seasonal weights need to be developed and approved. To that end, NCSEA disagrees with the Public Staff's assertion that "Duke's seasonal allocation of capacity payments greatly reduces the risk that ratepayers would overpay for capacity from QFs due to high solar output in the summer."[26] This is simply not the case as Duke's methodologies are flawed and should be corrected to provide true capacity values.

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[25] SACE Initial Comments, Attachment B, p. 4.
[26] Public Staff Initial Statement, p. 63.

C. PPA RENEWAL AND CAPACITY DETERMINATIONS

In its Initial Comments, NCSEA requested the Commission consider how to deal with the residual rights of QFs whose power purchase agreement ("PPA") is expiring and who seek to enter new PPAs for the balance of their useful lives.[27] NCSEA further stated that "the Commission should try to ensure regulatory continuity and certainty for existing QFs that are seeking to renew a PPA upon its expiration or enter into a new PPA. Existing QFs have an expectation of continuity for their rights after their initial PPA expires, and the Commission should recognize these residual rights."[28] NCSEA's argument for continuity and predictability while PPAs expired was further explored by NC Small Hydro.

In the *Hydro Group's Initial Comments*, the NC Small Hydro made a compelling legal argument for a QF to have an expectation of a renewal of capacity from their old, expiring PPA to their new PPA. The NC Small Hydro relied upon a decision made by the Idaho Utilities Commission ("Idaho Commission"). Specifically, the Idaho Commission found that

> [i]t is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the utility's load and resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal.[29]

[27] NCSEA's Initial Comments, p. 48.
[28] *Id.* at 49.
[29] *Hydro Group's Initial Comments*, pp. 8-9, Docket No. E-100, Sub 158 (February 12, 2019) ("Hydro Group's Initial Comments"), quoting *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies For Calculating Avoided Cost Rates*, Case No. GNR-E-11-03, Order No. 32697, dated Order to Clarify Commission Final Order, Order No. 32871, dated August 9, 2013.

The Idaho Commission created an exception to the IRP capacity deficit in computing avoided cost rates under the IRP methodology and, recently, restated its position: ""[i]f a QF renews its contract with a utility, the capacity deficit date is still determined as of the date the original contract was executed."[30]

Ultimately, the NC Small Hydro requested the Commission to recognize that "renewal and extensions of QF contracts establish the need for their capacity as of the date the original contract was executed and that the Commission subject capacity deficiencies in the IRP proceeding to additional scrutiny."[31] NCSEA finds the NC Small Hydro's legal argument compelling and agrees with the requested relief. Given that the matter of the renewal of QF PPAs has not yet been mined out by the Commission and the parties involved, particularly with regard the tangential contracting factors made into law by HB589, a determination needs to be made with regard to how to handle renewal of PPAs. On that matter, the guidance brought by the Idaho docket seems a fair and reasonable way to help determine this matter. Therefore, NCSEA supports the NC Small Hydro's request that the Commission recognize the capacity need as relating back to the date of the original contract for QFs and in the manner consistent with the NC Small Hydro's request.

IV. PERFORMANCE ADJUSTMENT FACTOR

The Public Staff believes that the calculation to determine performance adjustment factor ("PAF") should look at both historical data and future projections of reliability that incorporate planned improvements.

[30] Hydro Group's Initial Comments, p. 10 quoting *In the Matter of Application of Idaho Power Company for Approval or Rejection of an Energy Sales Agreement with McCollum Enterprises, Limited Partnership, for the Sale and Purchase of Electric Energy from the Canyon Springs Hydro Project*, Case No. IPC-E-18-12, Order No. 34200, dated December 4, 2018, p. 2.

[31] Hydro Group's Initial Comments, p. 11.

> As avoided cost proceedings continue to evolve, it may be appropriate for the Utilities to use new and different techniques and assumptions, such as applying prospective, forward-looking EFOR components to the PAF calculation. Because avoided cost rates are inherently forward-looking, it is also appropriate to take a forward-looking approach when determining each Utility's overall EFOR for use in avoided cost calculations, taking into consideration future capital that is, or will be, invested in generating assets, as well as, but not limited to, new or modified O&M costs, preventive maintenance costs and protocols, and newer generation technologies.[32]

NCSEA agrees that the calculation of PAF, which accounts for potential generation reliability hiccups from QFs in the avoided cost calculation, should be forward-facing as technology improves and, hopefully, to reflect the continued upgrades to the grid accommodating more technologies which utilize smart technologies to implement distributed generation. However, NCSEA believes that the Public Staff could take a more determinative step in requesting a true reflection of the current PAF calculation. The Public Staff merely requests the Commission require the Utilities to recalculate the PAF with new inputs:

> The Public Staff recommends that the Commission direct the Utilities to perform a revised PAF calculation, including June and December EFOR data. The Public Staff believes using a critical peak load analysis to determine the critical peak period(s) of the Utilities' systems is consistent with the Commission's guidance in the *2016 Order*.[33]

NCSEA believes that Duke, at least, has biased its current PAF calculations and that the Duke avoided cost proposal discriminates against QFs and understate their contribution to capacity during peak months, but rather than recalculating on its own, NCSEA "recommends that the Commission reject Duke's PAF proposal and adopt the proposal of a PAF between 1.08 and 1.10" in NCSEA's Initial Comments.[34] Further, as

[32] Public Staff Initial Statement, p. 70.
[33] *Id.* at 72.
[34] NCSEA's Initial Comments, pp. 31-32.

stated above, NCSEA agrees with the Public Staff's position that PAF mitigates the Utilities' risk of overpayment to QFs and no further actions are necessary to offset potential overpayment such as the removal of hedging values.[35]

V. Solar Integration Charge

NCSEA restates its fundamental opposition to the solar integration charge. While NCSEA understands and agrees with some of the positions of the Public Staff, NCSEA disagrees with the Public Staff's conclusion that utilities incur costs related to intermittent generation from QFs. As set forth below, the Public Staff's position (along with Utilities' positions) do not account for the benefits incurred on the grid due to distributed generation and, accordingly, blindly attributing a fixed charge to QFs for their generation but not accounting for benefits to the grid, including specifically ancillary benefits, which can offset intermittency and upgrade generation in other ways, is bad policy and should be denied as such.

A. If a Solar Integration Charge is mandated, then NCSEA supports some of the other intervenor's positions.

1. Analysis of QF Benefits to the Grid and the Refresh Proposal

NCSEA generally agrees with the Public Staff that the Commission needs to hear evidence about other known costs and benefits that should be included in an integration charge: "it may be appropriate for the Commission to consider evidence from other parties as to what additional costs or benefits can be sufficiently known and verifiable at this time such that they should be included in avoided cost rates."[36] NCSEA also agrees with the

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[35] Public Staff Initial Statement, pp. 28-29.
[36] *Id.* at 33.

Public Staff that Duke lacks support to seek to refresh an integration "charge" every two years, this issue was discussed in Commission Docket No. E-100, Sub 148, and that such a frequent refresh would make financing for QFs difficult.[37]

The Public Staff goes on to state that if a charge were implemented, either there is no two-year refresh or, alternatively, if the Commission finds a refresh is appropriate then that there is a cap on the upper limit for the solar integration charge.[38] While NCSEA strongly opposes any solar integration charge, particularly one which does not identify the benefits brought to the grid by each individual interconnecting facility, if such a charge is mandated by the Commission, then NCSEA agrees that there should be no two-year refresh. If the Commission determines a refresh (of any type) is appropriate, NCSEA agrees with the Public Staff that there should be an upper limit as to any fixed charge proscribed by Duke against facilities looking to interconnect.

2. THE ASTRAPÉ STUDY INCORRECTLY MODELED DUKE'S SERVICE TERRITORIES

NCSEA and the Public Staff concur on the shortcoming of the Astrapé Study with regard to the islanding of utility territories: "[t]he Astrapé Study models DEC and DEP as load islands with no ability to rely on each other or on the larger Eastern Interconnection to meet intra-hour load variations."[39] NCSEA and the Public Staff also both agree that this practice does not reflect how a grid is operated:

> Practical realities of the operation of the electric grid challenge the merits of [the islanding assumption], which may result in a solar integration charge greater than the costs that are actually being incurred [...] As reflected in their IRPs, DEC and DEP are able to utilize synergies between each other's

[37] Public Staff Initial Statement, p. 37.
[38] *Id.* at 38.
[39] *Id.* at 36.

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> balancing areas such as coordinating outages and more economically dispatching the combined systems on a non-firm basis.[40]

NCSEA and the Public Staff have a similar belief on this matter and, accordingly, NCSEA requests that the Commission require Duke to correct their model so as to eliminate the islanding which may cause a potential integration charge to be higher than appropriate.

3. UTILITY-OWNED SOLAR FACILITIES SHOULD BE INCLUDED IN THE BASELINE FOR SETTING THE INTEGRATION CHARGE

NCSEA also agrees with the Public Staff that, if the Commission implements a solar integration charges, there is concern that the effect may be that Duke-owned qualified facility costs are shifted to third-party solar QFs.

> The Public Staff is concerned that this methodology could have the effect of assigning the costs that result from the integration of utility-owned solar to solar QFs. It is important that the calculations of avoided energy rates reflect the same solar integration charge-related costs for utility-owned intermittent generation that will be recognized for non-utility-owned intermittent generation. While utility customers currently pay these costs in the form of additional fuel and other ancillary services costs, the determination of these solar integration charge-related costs and the resulting avoided energy rates should incorporate the impacts from similar utility-owned intermittent generation."[41]

NCSEA echoes these concerns, and requests that the Commission, should it approve the solar integration charge in any form, require that the underlying modeling for such a charge include inputs that incorporate the impacts from utility-owned solar generation so as to show that Duke is paying its fair share for its own solar resources.

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[40] *Id.* at 39.
[41] *Id.* at 40.

4. NCSEA and the Public Staff Agree on Other Flaws in the Astrapé Study

Like NCSEA, the Public Staff is concerned about the use of a short amount of historical data in Astrapé's modeling: "[b]ecause solar volatility was modeled using only one year of historical data, assumptions made regarding solar fleet diversity could result in an inaccurate solar integration charge."[42] NCSEA agrees with the Public Staff that the short amount of historical data in the model may result in an inaccurate charge and, like above, NCSEA believes the Commission should, if it determines a solar integration charge is appropriate, require Duke to correct its underlying modeling so as to incorporate more historical data. Further, the Astrapé Study only models a single ancillary service and completely ignores other methods of addressing intermittency of generation. "The Public Staff has concerns that this modeling assumption is not valid, and that there may be other ancillary service products, or even alternative methods entirely, of handling the volatility of solar generation."[43] NCSEA believes this is integral to any discussion regarding a fixed charge for QFs to interconnect to the grid. Duke has failed to list any benefits for the interconnection of QFs to the grid and, unsurprisingly, ignored a litany of established and emerging technologies that have been or could be incorporated by QFs which could offset the alleged "costs" of solar integration due to intermittency. For these reasons, NCSEA believes that any solar integration cost analysis model should include a forward-facing model that incorporates any and all benefits currently incorporated by QFs and also those that may be incorporated in the near-future based upon analysis of the solar sector and

[42] *Id.* at 37.
[43] *Id.* at 42.

emerging technologies which have become able to be incorporated to scale of North Carolina QFs.

5. DOMINION RE-DISPATCH CHARGE

NCSEA agrees with SACE that the Dominion re-dispatch charge is based on analysis of inappropriate solar penetration levels as Dominion simply averaged re-dispatch costs of multiple solar penetration levels resulting in an inflated charge.[44] NCSEA also agrees with SACE that Dominion simply averaged multiple combinations of assumptions which conflated inputs and ultimately resulted in inaccurate and unsupported conclusions.[45]

NCSEA agrees with the Public Staff on some of the issues related to the proposed re-dispatch charge contained in Dominion's avoided cost proposal. NCSEA agrees that it's unclear whether Dominion's re-dispatch costs are an incremental or an average charge and that this calculation could impact the magnitude of the charge.[46] NCSEA shares Dominion's concern about the utilization of historic data versus average generation portfolios.[47] Finally, NCSEA agrees with the Public Staff's concern regarding modeling a charge based upon smaller systems being scaled up in profile to match a larger solar facility profile. This "scaling" may create high volatility and negatively affect the model.[48]

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[44] SACE Initial Comments, p. 18.
[45] *Id.*
[46] Public Staff Initial Statement, p. 45.
[47] *Id.*
[48] *Id.*

B. NCSEA SPECIFICALLY OPPOSES THESE INTERVENOR POSITIONS ON THE SOLAR INTEGRATION CHARGE AND THE RE-DISPATCH CHARGE

As a matter of initial concern, NCSEA opposes the concept of any fixed charge which allegedly offsets costs that accrue on the grid due to QF intermittent generation. NCSEA has long taken the position – and does so in depth in its Initial Comments – that distributed generation, including solar, causes a net benefit to the grid and to rate payers. NCSEA disagrees with the Public Staff's position to the extent that it allows for fixed charges related to solar intermittency. Furthermore, NCSEA believes that while the Public Staff acknowledges the benefits of distributed generation, including solar, to the grid, the Public Staff fails to capture the totality of such benefits given that they do not oppose the underlying structure of the Solar Integration Charge. Any review of the effect of solar on the grid must include a cost/benefit analysis of solar, including ancillary benefits, and also allow for forward-looking analysis to future benefits. NCSEA would encourage the Commission, as well as the Public Staff, to acknowledge and heavily account for the benefits of solar and the current and emerging ancillary benefits of QFs which provide net benefits to the grid. Ultimately, as ancillary benefits become more prevalent, utilities will no longer be charged with replacing energy from intermittent sources as that problem will be solve by the QFs themselves.

NCSEA also disagrees with the Public Staff's conclusions regarding the Astrapé Study and "operational challenges". "The Public Staff reviewed the Astrapé Study and generally agrees that DEC and DEP face operational challenges resulting from the current and pending amount of a single specific aggregate resource connected to its electrical grid."[49] While NCSEA will acknowledge the difficulty inherent in interconnecting QFs to the grid in a vacuum, this position is undercut by the fact that Astrapé gave no credence to the benefits of solar and did not sufficiently measure current and future ancillary services which will offset many of the alleged "operational challenges" referred to here.

Finally, the Public Staff states that the "general concept of the Astrapé Study has merit from a both a system operations perspective and a modeling methodology" and requests that "Duke, in conjunction with Astrapé, also provide analysis of other types of QFs and other distributed energy resources (DERs) in addition to solar facilities and develop similar average and incremental service cost estimates." The Public Staff further requests that a new model provided by Astrapé need to address the numerous concerns laid out in the Public Staff Initial Statement. These requests, while reasonable, are counter to the underlying point and also ignore other intervenors' positions. As stated repeatedly, the solar integration charge, and the Astrapé Study which allegedly justifies it, completely ignores the benefits of distributed generation on the grid, particularly including solar, and is inherently flawed in its approach. Further, even if a compelling argument is made to introduce a new fixed charge for QFs, the Astrapé Study is so fundamentally flawed and one-sided that it cannot plausibly be relied upon. The Astrapé Study, in fact, has a poor modeling methodology as set forth in NCSEA's comments and exhibits and also SACE's Initial Comments and attached exhibits. Should the Commission determine that an integration charge is necessary, to which NCSEA holds a continuing objection, then NCSEA believes that a completely new model, incorporating inputs and methodologies from a diverse group engineers and/or economists must be included, and this diverse group

[49] *Id.* at 34.

must represent the not only utility interest but, also, the interests of solar developers, clean energy advocates, and other groups directly impacted by the proposed charge.

VI. Rate Structures

A. The Rate Structures Need to be Refined

NCSEA and the Public Staff agree that the rate structures implemented by the Utilities currently do provide sufficient granularity to determine accurate price signals. "In light of current and future potential uses of avoided cost hours and rates, the Public Staff believes that additional granularity, beyond that proposed by Duke and DENC in this proceeding, is appropriate and beneficial to North Carolina ratepayers."[50] NCSEA agrees that

> [M]ore granular pricing would signal a dispatchable QF to provide energy during times when the Utilities are most likely to operate their highest marginal cost generation units, thus avoiding the need to run those units, and would also provide clear price signals to developers interested in adding new technologies, such as energy storage, to their intermittent facilities. Avoided energy rates that accurately reflect the Utilities' highest production cost hours (lambdas) increase the likelihood that the interests of ratepayers and developers align."51

The Public Staff, like NCSEA, has concerns about Duke's resource adequacy studies:

> As stated previously, the Public Staff raised concerns with the assumptions made in the Resource Adequacy Studies, documenting them extensively in its April 2, 2018 Joint Report filed in Docket No. E-100, Sub 147. These concerns center around assumptions made regarding the relationship between cold weather and load, estimates of load forecast error distributions, and a lack of recognition of winter hardening efforts undertaken by the utilities, among others. Many of these concerns were addressed in the Public Staff's proposed Public Staff Scenario #2 (PS-S2) that was analyzed by Duke in the 2018 IRP proceeding. [...] Because of these concerns, the Public Staff recommends that the Commission order

[50] Public Staff Initial Statement, p. 54.
[51] *Id.*

> Duke to rerun its Resource Adequacy Studies using PS-S2 to determine the effect of the Public Staff's proposed modifications on the Capacity Payment Hours and seasonal allocation.[52]

NCSEA agrees with the concerns of the Public Staff regarding the Resource Adequacy Studies and generally agrees with the Public Staff's recommended solution to modify and rerun the studies based upon the proposed modifications of both the Public Staff. NCSEA would add, for comparison's sake, any other intervenors' proposals to the new studies who have proposed modifications to rate structure of this nature. It should be noted that NCSEA specifically seeks a new model which displays the proposed, increased granularity discussed in the Public Staff Initial Statement and NCSEA's Initial Comments.

NCSEA also supports the Public Staff's position that the LOLE method to establish eligibility for capacity payments is inappropriate and generally prefers the Dominion method.[53] However, like the Public Staff, NCSEA is concerned about the future impact of Dominion's proposed capacity payments and supports the Public Staff's position that DENC should evaluate alternative seasonal allocation and Capacity Payment Hours that align to DENC's system.[54]

VI. <u>INCREASES TO ENERGY OUTPUT</u>

As has been discussed extensively in other proceedings,[55] energy storage is now cost-competitive with other resources and is likely to see substantial deployment before the next biennial avoided cost proceeding. Therefore, the decisions made by the Commission in this proceeding will set the stage for energy storage deployment in North Carolina. Given

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[52] *Id.* at 58-59.
[53] *Id.* at 57-60.
[54] Public Staff Initial Statement, p. 64.
[55] *See generally*, Docket No. E-100, Sub 101; Docket No. E-100, Sub 157.

this reality, NCSEA shares the concerns expressed by the Public Staff and SACE that Duke's proposed additions to the PPA Terms and Conditions regarding energy storage and increases to a QF's energy output are overly and unduly restrictive.[56]

NCSEA agrees with the Public Staff "that requiring a new PPA for existing facilities using the most recently approved avoided cost rates may disincentivize the adoption of new energy storage technologies at existing facilities, which have the potential to benefit ratepayers."[57] Even more importantly, NCSEA agrees with SACE that "the replacement of older solar panels with newer solar panels that does not increase the AC output capacity of the facility should not be considered a material modification to the QF, and it should not require the QF to forfeit is existing standard offer contract and enter into a new PPA."[58] Both the Public Staff and SACE note that requiring a new PPA for any such changes could mean that a QF that was previously subject to a standard contract PPA is now subject to a negotiated PPA.[59]

Despite these areas of agreement, NCSEA disagrees with the Public Staff's assertion that "the increased energy output should be subject to the rates determined in the most recently effective avoided cost docket."[60] The fact that a QF "could increase its total revenue generated through the addition of energy storage or other technologies"[61] is insufficient reason to violate the PURPA rights of QFs. A QF that is already providing

[56] *See*, Public Staff Initial Statement, pp. 74-76; SACE Initial Comments, pp. 16-17.
[57] Public Staff Initial Statement, p. 74 (internal citations omitted).
[58] SACE Initial Comments, p. 17.
[59] Public Staff Initial Statement, p. 76 ("The Public Staff also believes that designating the addition of energy storage at an existing facility as a new and separate facility may result in unintended consequences, including loss of eligibility as a standard offer QF or a FERC-certified QF."); SACE Initial Comments, p. 17 ("Because such changes would not increase the QF's nameplate capacity beyond the threshold under which the standard offer contract was available, the QF should be permitted to make such changes under its existing PPA.").
[60] Public Staff Initial Statement, p. 74 (internal citations omitted).
[61] Public Staff Initial Statement, pp. 74-75.

electricity to the grid has already met the Commission's requirements to establish a LEO,[62] and an increase in energy output does not void that LEO. No new CPCN is necessary to increase energy output; instead, a QF is required to seek a modification to the CPCN. Therefore, NCSEA respectfully disagrees with the Public Staff's suggestion that any increase in energy output should be separately metered and paid at a different avoided cost rate.[63] However, should the Commission agree with either Duke or the Public Staff's proposals, NCSEA agrees with the Public Staff that authorization to increase energy output "should not be unduly withheld."[64]

VII. CONCLUSION

As set forth herein, NCSEA supports many of the positions taken by intervenors in this docket and also opposes some positions. Accordingly, NCSEA restates its request for the Commission to reject the Utilities' avoided cost plans and require the Utilities to file new avoided cost plans, consistent with the positions taken herein and also in NCSEA's Initial Comments, and which include accurate representations of the avoided cost of both energy and capacity, including highlighting the benefits of distributed generation and solar.

Respectfully submitted, this the 27th day of March, 2019.

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[62] E-100 Sub 148 Order, p. 8.
[63] Public Staff Initial Statement, p. 75.
[64] *Id.*

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

Respectfully submitted, this the 27th day of March, 2019.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	DIRECT TESTIMONY OF
Rates for Electric Utility Purchases from	)	R. THOMAS BEACH
Qualifying Facilities – 2018	)	
	)	

Exhibit 1

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the**Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of**Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of The Vote Solar Initiative (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the Solar Alliance (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the Northern California Indicated Producers (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the Northern California Indicated Producers (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the California Cogeneration Council (R. 12-03-014—June 25, 2012)
    b. Repl y Testimony on behalf of the California Cogeneration Council (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the Southern California Indicated Producers and Watson Cogeneration Company (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the Solar Energy Industries Association (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar** Parties (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar** Energy Industries Association (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

    - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

    - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

    - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the Idaho Conservation League (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of Vote Solar (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39,October 14 and November 9, 2016).

    - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
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EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910, 1911, and 1912 — March 16, 2018).

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Curriculum Vitae

Brendan Kirby

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Professional Experience:

2008-Present: **Consulting**, Consulting privately with numerous clients including the Florida Power and Light, NextEra, Hawaii PUC, National Renewable Energy Laboratory, ESIG, AWEA, Oak Ridge National Laboratory, EPRI, and others. He served on the NERC Standards Committee. He has 44 years of electric utility experience and has published over 180 papers, articles, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy.

1994-2008: **Sr. Researcher,** Power Systems Research Program, Oak Ridge National Laboratory. Research interests included electric industry restructuring, unbundling of ancillary services, wind integration, distributed resources, demand side response, energy storage, renewable resources, advanced analysis techniques, and power system security. In addition to the research topics listed above activities included: NYISO Environmental Advisory Council, assignment to FERC Technical Staff to support reliability efforts including NERC/FERC reliability readiness audits, Technical Advisory Committee for the 2006 Minnesota Wind Integration Study, DOE Investigation Team for the 2003 Blackout, the IEEE SCC 21 Distributed Generation Interconnection Standard working group, DOE National Transmission Grid Study, staff to the DOE Task Force on Electric System Reliability, and NERC IOS Working Group. Conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

Consulting, Consulted privately with utilities, renewable generators, AWEA, ISO/RTOs, IPPs, loads, interest groups, regulators, manufacturers and others on power system reliability, ancillary services, responsive load, wind integration, electric utility restructuring and other issues. Testified as an expert witness in FERC and state litigation.

1991 to 1994: **Power Analysis Department Head,** Technical Analysis and Operations Division. Primary responsibility was to support the Department of Energy in the management of 7000 MW of uranium enrichment capacity. The most significant feature of this load was that 2000 MW were procured on the spot energy market from multiple suppliers requiring rapid response to changing market conditions. Support included technical support for power contract negotiations, development of the real-time energy management strategy, managing the development of a computer based operator assistant to aid in making real-time power purchase decisions. Conducted computer based simulations of the loads and the interconnected network which supplies them. Simulations included large scale load flows, short circuit studies, and transient stability studies. They also included extensive specialized modeling for analysis of electrical, mechanical, and thermal performance under balanced and unbalanced conditions. Responsible for maintaining close ties with technical personnel from the various utilities which supplied power to the diffusion complex to exchange data and perform joint studies.

Provided consultation services on a large range of power system concerns including: cogeneration opportunities, power supply for the Lawrence Livermore National Laboratory Mirror Fusion Test Facility, capacity at EURODIF, power supply for the Strategic Petroleum Reserve, power supply for large pulsed fusion loads, and wheeling.

1985 to 1991: **Electric Power Planning Section Head,** Enrichment Technical Operations Division with substantially the same responsibilities as stated above.

1977 to 1985: **Technical Computing Specialist,** Electrical Engineering and Small Computing Section, Computing and Telecommunications Division. Time was evenly divided between power system studies as described above and minicomputer work. The minicomputer work supported laboratory data collection and experiment control.

1975 to 1976: **Engineer,** Electrical Engineering Department, Long Island Lighting Company, Hicksville, New York. Responsible for electrostatic and magnetic field strength modeling as well as sound level testing and analysis.

Education:

1977 - M.S.E.E., power option, Carnegie-Mellon University, Pittsburgh, Pa.
Worked under a Department of Transportation contract studying more efficient means of energy use in rail systems.

1975 - B.S.E.E., Lehigh University, Bethlehem, Pa., cum laude, Eta Kappa Nu, the Electrical Engineering Honorary, and Phi Eta Sigma, the freshman Honorary.

Professional Affiliations and Awards:

- Licensed professional engineer
- Patent 7,536,240: Real Power Regulation For The Utility Power Grid Via Responsive Load
- 1985, 1986, 1987, 1990, and 1992 Awards for power system related work
- Life Senior Member of the IEEE
- Former DOE Q clearance

Publications:

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Duke Energy Proposed Solar Integration Charge

Brendan Kirby, P.E. – February 2019

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in a November 11, 2018 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" (*Ancillary Service Study*). Unfortunately, the study methodology, as implemented, is fundamentally flawed and the resulting solar integration charges are unsubstantiated, unjustified, and simply wrong.

The basic analysis methodology of comparing production cost simulations with and without solar, while adjusting reserves in order to maintain reliability, is well established and has been executed successfully by others. However, Duke's analysis is flawed because the *Ancillary Service Study*:

- Modeled DEC and DEP as isolated power systems, not their actual coordinated operation within the Eastern Interconnection;
- Applied an inappropriate loss-of-load, one-in-ten-years, long-term system adequacy metric, not normally used for operations, rather than basing reserve requirements on the mandatory North American Electric Reliability Corporation (NERC) reliability standards to which Duke actually operates;
- May not have removed data dropouts and other data anomalies, greatly overstating solar variability;
- Improperly scaled solar plant intra-hour output variability data in a way that fails to accurately reflect geographic diversity benefits;
- Incorrectly modeled contingency reserve requirements and use;
- Failed to identify under what specific operating conditions reliability was challenged; and
- Failed to identify the specific added reserve requirements or changes in operating practices needed to cost effectively maintain reliability.

As a result of these deficiencies, the solar integration costs developed in the *Ancillary Service Study* do not reflect actual increased reserve requirements or actual impacts on the operating costs that Duke will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements and operations. The solar data should be reanalyzed to reflect plant and system aggregation benefits. Simulated reserve shortfalls should be analyzed to determine the most cost-effective methods to adjust operations and/or add reserves to maintain reliability as solar generation increases.

Inappropriate Modeling of DEC and DEP as Isolated Power Systems

The *Ancillary Service Study* report states that "The utilities are modeled as islands for the Ancillary Service Study".[1] Note that treating DEC and DEP as islanded power systems in the *Ancillary Service Study* differs from how Duke actually plans and operates DEC and DEP as interconnected utilities. The stated reason for modeling DEC and DEP as islanded power systems in the *Ancillary Service Study* is that "it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements". This completely misunderstands the benefits of interconnected utility operations and the impacts on reliability reserves. Utilities started to interconnect over ninety years ago in order to increase reliability while reducing each utility's reserve requirements. This works because of the strong aggregation diversity benefits for load and generation variability under both normal and contingency conditions. Interconnected power systems are more resilient, reliable, and economic than islanded power systems. All utilities participating in an interconnection benefit from reduced reserve requirements. Additionally, DEC and DEP are members of the VACAR Reserve Sharing Group[2] (which explicitly shares contingency reserve obligations and reserves. Further, Duke acknowledges that "DEC and DEP were jointly dispatched for avoided energy cost modeling".[3] The NERC reliability standards are also based on interconnected operations. Determining reserve requirements for islanded versions of DEC and DEP is irrelevant to the way the power systems, including DEC and DEP, are actually designed, built, and operated.

Inappropriate Reliability Metrics and Requirements

The *Ancillary Service Study* attempts to compare total production costs with and without solar generation in order to determine the cost of integrating additional solar generation (after compensating for the change in solar versus conventional energy value itself). In order to make a fair comparison, it is necessary to hold reliability constant in the no-solar and solar generation cases so that calculated integration costs are not reduced (or increased) as the result of a drop (or increase) in reliability. Reliability is held constant by adding reserves to the solar cases until reliability matches the non-solar base case. This basic methodology of using security constrained unit commitment and economic dispatch modeling is well established and has been used in numerous renewables integration studies including the National Renewable Energy Laboratory (NREL) Eastern Wind Integration and Transmission Study and the Western Wind and Solar

[1] Ancillary Service Study at 13.
[2] DEC and DEP Response to SACE Data Request No. 2, Question No. 25.
[3] DEC and DEP Response to SACE Data Request No. 2, Question No. 3.

Integration Studies.[4] The methodology has also been used by utilities to develop renewables integration charges.[5,6]

The assessment methodology reported on in the *Ancillary Services Study* correctly recognizes that it is the continuous balancing of generation and load that requires reserves and drives system reliability. However, rather than basing the DEC and DEP balancing requirements on mandatory NERC standards, the study introduces a completely arbitrary pair of misnamed loss-of-load-expectation (LOLE) metrics which attempt to identify instances of insufficient generation capacity or flexibility. These metrics are misnamed because there would be no loss of load expected during the identified imbalances for DEC or DEP as they actually operate in the Eastern Interconnection. In interconnected operations, small imbalances in one BA manifest themselves as deviations from scheduled interchange flows, not loss of load; load shedding is not required. It is only the aggregation of imbalances from all the BAs in the interconnection that influence frequency and potentially impact reliability. Under normal operating conditions, imbalances in one BA tend to counteract imbalances in another BA such that the total interconnection imbalance is much less than the sum of the absolute values of the individual BA imbalances. Interconnection greatly increases reliability while dramatically reducing individual BA balancing requirements. Consequently, NERC reliability standards do not require the level of reserves or balancing operations necessary to meet the 0.1 LOLE for 5-minute balancing that is the basis of the *Ancillary Service Study* and the proposed solar integration charges. These issues are explained in further detail below.

DEC and DEP Ancillary Service Study *Balancing Metrics and Requirements*

The *Ancillary Service Study* established two LOLE metrics: $LOLE_{CAP}$ and $LOLE_{FLEX}$. As described below, the two LOLE metrics used in the study are not appropriate standards and result in inaccurate and improper conclusions.

The production cost modeling looked at each power system (DEC and DEP) as isolated islands and simulated the generation/load balance every five minutes. $LOLE_{CAP}$ looked for instances when there was insufficient generation capacity to cover total load. $LOLE_{FLEX}$ looked for instances

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[4] EnerNex, *Eastern Wind Integration and Transmission* Study, National Renewable Energy Laboratory, NREL/SR-5500-47078, Feb. 2011; GE Energy, *Western Wind and Solar Integration Study*, National Renewable Energy Laboratory, May 2010;D. Lew et al, *The Western Wind and Solar Integration Study Phase 2*, National Renewable Energy Laboratory, NREL/TP-5500-55588, Sept. 2013.

[5] See e.g. Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF.

[6] Commission and utility interest in variable renewables integration charges appears to be declining, making it difficult to find examples of well-designed integration charges. Analysts are recognizing that all generators have characteristics that impose costs on the power system. "Base load" generators, for example, are typically inflexible with high minimum loads, long startup times, and slow ramp rates. These limitations impose costs when lower-cost generation is available at low net-load times but cannot be used because the base load generators must run. Commissions are reluctant to impose integration charges on base load generators and instead allow security constrained unit commitment and economic dispatch optimization, as well as electricity markets, to optimize the utilization of the generation fleet.

when there was insufficient generation ramping capability to follow the net system load. The study imposed a 0.1 LOLE requirement which allowed one 5-minute imbalance event every ten years.

> "Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is "one day in 10 years" LOLE, or 0.1 LOLE." "To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period."[7]

While it is true that a LOLE of 0.1 is an appropriate and accepted standard for long-term planning of reserve capacity, it is completely inappropriate, unnecessary, not required by NERC standards, and excessively expensive when applied to actual operations. The *Ancillary Service Study* acknowledges that "[r]eliability targets for operational reliability are covered by NERC Balancing Standards" and are not dictated by an arbitrary LOLE of one event in ten years. The Study further states that "[t]he Control Performance Standards (CPS) dictate the responsibilities for balancing areas (BA) to maintain frequency targets by matching generation and load".[8] Most importantly, with interconnected operations a small imbalance in one BA will not result in a LOLE event, which is why NERC does not require continuous perfect balancing from each BA.

The *Ancillary Service Study* acknowledges that actual NERC reliability and balancing requirements were not modeled, and the 0.1 LOLE was substituted, presumably because the modeling capability was insufficient to represent actual balancing capabilities and requirements:

> "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2 standards is a critical component of a solar ancillary service cost impact study. However, ***simulating violations of these standards is challenging***. While the ***simulations performed in SERVM do not measure CPS violations directly***, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. ***Any periods in which generation is not able to meet load and minimum ancillary service requirements are recorded as reliability violations***." ... "So, while there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, ***there is not a standard for loss of load due to flexibility shortfalls as measured by SERVM***. Absent a standard, this study assumes that maintaining a constant operational reliability as solar penetration increases is an appropriate objective. ***Simulations of the DEC and DEP***

[7] Ancillary Service Study at 10.
[8] Id.

systems with current loads and resources were calibrated to produce $LOLE_{FLEX}$ of 0.1 events per year."[9]

The 0.1 $LOLE_{FLEX}$ requirement is unrelated to NERC reliability standards and is not a reasonable analysis proxy for the actual balancing or reliability requirements. As the *Ancillary Service Study* acknowledges, SERVM cannot accurately measure NERC reliability violations. The Study invented a $LOLE_{FLEX}$ standard that is an unreasonable proxy for actual balancing and reliability requirements.

NERC Mandatory Reliability Balancing Requirements

As the *Ancillary Service Study* acknowledges, actual power system reliability and reserve requirements are established by NERC. These requirements are laid out in mandatory NERC reliability standards which are approved by the Federal Energy Regulatory Commission (FERC) and the Canadian provincial governments. Two NERC standards are particularly relevant[10]:

- BAL-001-2 – Real Power Balancing Control Performance
- BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

These standards establish reliability and reserve requirements for Balancing Authorities (BAs) such as DEC and DEP. Importantly, and fundamentally, the reliability requirements are based on operations within an interconnection; specifically, within the 720,000 MW Eastern Interconnection in Duke's case.[11] This is fundamentally important because with interconnected utility operations, small imbalances within one BA do not result in Loss of Load events under normal conditions. In fact, imbalances are occurring all the time under normal conditions. The NERC standards limit the magnitude and frequency of allowed imbalances, but they do not attempt to eliminate them or restrict them to one-event-in-ten-years.

Obsolete CPS2 Requirement

The *Ancillary Service Study*[12] references two NERC reliability metrics: CPS1 and CPS2. CPS2 is no longer applicable, however. It was replaced in July 2016 with the BAAL requirement, discussed below, when BAL-001-02 became the effective standard. CPS2, however, was a much laxer balancing requirement than the *Ancillary Service Study* 0.1 $LOLE_{FLEX}$ requirement. CPS2 measured balancing over 10-minute intervals and required compliance only 90% of the time.

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[9] Id. (emphasis added).

[10] Additional standards, such as BAL-003-1 — Frequency Response and Frequency Bias Setting, amplify and support the balancing requirements.

[11] NERC 2018 Summer Reliability Assessment.

[12] "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and **CPS2** standards is a critical component of a solar ancillary service cost impact study." Ancillary Service Study at 10 (emphasis added).

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CPS2[13]: Monthly-$AVG_{10\text{-minute}}(ACE)<L_{10}$ Where L_{10} = 92 MW for DEC and 17 MW for DEP[14]

So, rather than allowing only one 5-minute event every ten years, CPS2 allowed ACE to remain high or low for 5,256 10-minute intervals per year and bounded average ACE to 92 MW for DEC and 17 MW for DEP for the remaining 90% of the time.

Applicable NERC Balancing Requirements

BAL-001-2 – Real Power Balancing Control Performance establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). NERC balancing requirements under contingency conditions are discussed further below.

CPS1 Reliability and Balancing Requirement

CPS1 limits the ***annual average*** 1-minute area control error deviations. ACE deviations result from difference between a BA's total instantaneous generation (plus scheduled imports) and total instantaneous load (plus scheduled exports) (plus the BA's instantaneous frequency support obligation).[15] While 100% compliance is required, this metric may be a bit deceptive. The CPS1 metric runs between 0% and 200%, meaning continuous perfect balancing would result in a CPS1 score of 200%, not 100%. Therefore, 100% compliance does not mean compliance during every minute. The CPS1 requirement is reflected in the following formula:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \epsilon_1^2$$ [16]

This formula is simpler than it at first appears. It says that the annual average of the instantaneous ACE values, times the instantaneous ΔF [frequency deviation from the scheduled frequency (usually 60 Hz)], must be less than 0.000324.[17] It is the multiplication of ACE times ΔF that makes balancing operations easier (and analysis harder). During times when frequency is exactly equal to 60 Hz then there is no CPS1 limit on ACE. When frequency is exactly equal to 60 Hz then ΔF is zero, which is multiplied by ACE and the result remains zero no matter how large ACE is. Physically this means that the BA can be far out of balance with no penalty when frequency is exactly 60 Hz. This makes sense for reliability because, if frequency is exactly equal

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[13] "BAL-001-1 — Real Power Balancing Control Performance", NERC.
[14] "BAL-003-1 Frequency Bias Setting and L10 Values for 2017", NERC, March 28, 2017.
[15] Because BA load cannot be measured directly NERC it is determined indirectly by measuring the BA's generation and interconnection flows (imports and exports). NERC defines ACE as "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias[.]" Reliability Standards for the Bulk Electric Systems of North America, NERC (updated July 3, 2018).
[16] NERC Standard BAL-001-1 — Real Power Balancing Control Performance.
[17] ϵ_1 for the Eastern Interconnection is 0.018 Hz (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018) ϵ_1^2 is 0.000324.

to 60 Hz (ΔF is zero) the overall interconnection is not experiencing an overall imbalance and an individual BA's imbalance is not a reliability threat.

Further, not all imbalances are bad. If frequency is below 60 Hz (ΔF is negative) and the BA is over-generating (excess solar, for example) then the BA's imbalance is supporting reliability by reducing the interconnection's overall imbalance and helping to push frequency back up to 60 Hz. CPS1 calculation credits the BA for that help. The excess generation is a reliability benefit and there is no requirement to reduce ACE. Conversely, if frequency is above 60 Hz (ΔF is positive) and the BA is under-generating (excess load or solar is suddenly reduced, for example) the BA is again helping overall power system reliability by reducing the interconnection's overall imbalance and helping to push frequency back down to 60 Hz, and CPS1 again credits the BA.

Frequency in the Eastern Interconnection varies constantly over a small range. It is above 60 Hz (ΔF is positive) about half the time and below 60 Hz (ΔF is negative) about half the time as shown in figure 1.1 from the November 2018 NERC report *2018 Frequency Response Annual Analysis*:

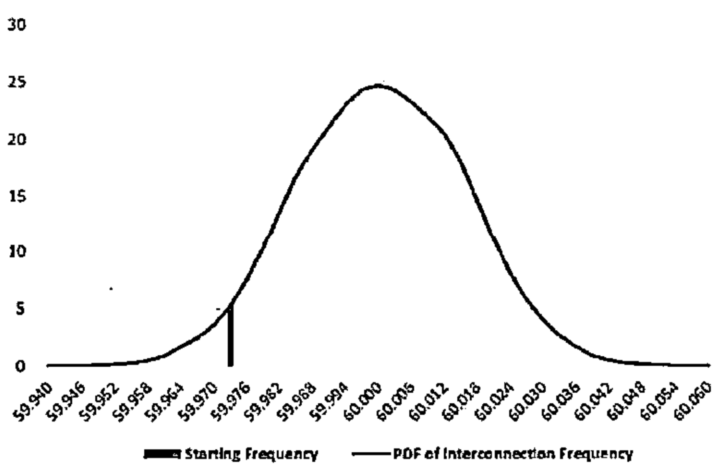

Figure 1.1: Eastern Interconnection 2014–2017 Probability Density Function of Frequency

Given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the 720,000 MW Eastern Interconnection, CPS1 does not require correction of imbalances about half of the time. This significantly reduces the balancing reserves that Duke must have available and reduces the times Duke must exercise those reserves.

BAAL Reliability and Balancing Requirement

Like CPS1, the Balancing Authority ACE Limit (BAAL) does not require perfect compliance. In fact, BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. BAAL limits are specific to each BA and depend on the actual interconnection system frequency at each time interval. As shown in Figure 2 below, ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Again, given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the very large Eastern Interconnection, BAAL does not require correction of imbalances about half of the time.

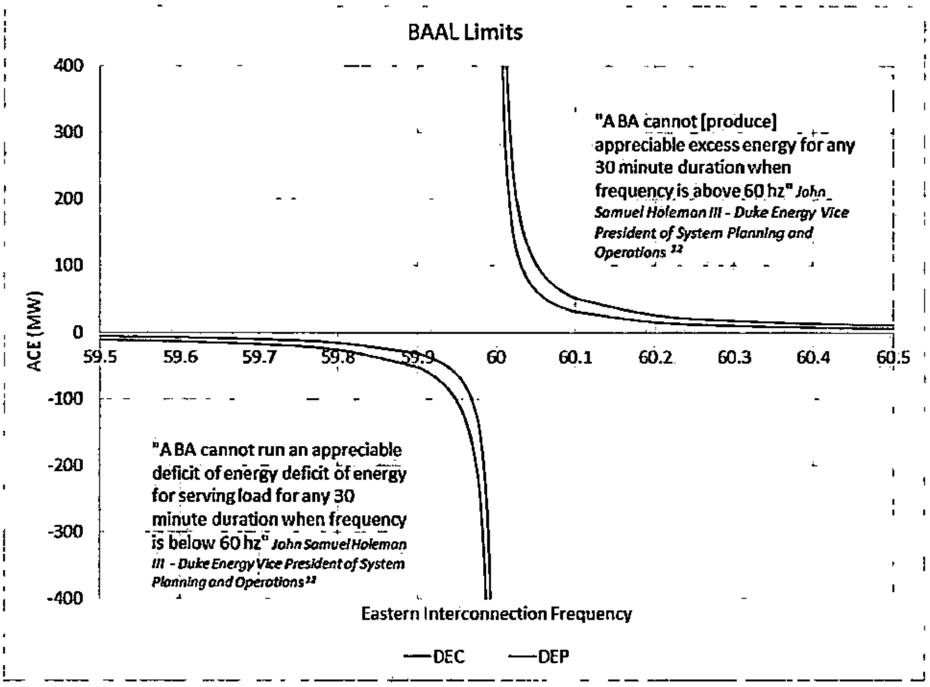

Figure 2 BAAL does not require perfect balancing

BAL-002 – Disturbance Control Standard (DCS)

NERC reliability standards recognize that large conventional generators occasionally fail unexpectedly and that the normal generation and load balance cannot be maintained by the host BA during such an event. The "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event" standard provides the requirements to restore the generation and load balance after a reportable contingency.[19] BAL-002 contains three balancing related requirements. The first requirement is to restore the generation and load balance within the Contingency Recovery Period (15 minutes) by using the Contingency Reserves. The second requirement is to have Contingency Reserves equal to or greater than the most severe single contingency available at all times. The third requirement is to restore the Contingency Reserves within 105 minutes of the start of the contingency.

[18] Direct Testimony of John Samuel Holeman III, Duke Energy Vice President of System Planning and Operations, Testimony in Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2016 Docket No. E-100, Sub 148.

[19] "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event", NERC.

There are three DCS issues that are important for the *Ancillary Service* analysis. The first is that NERC recognizes contingencies—the sudden, unexpected failure of large generators, for example—as distinct events, and NERC changes the balancing requirements during such events. The second is that NERC recognizes Contingency Reserves as specific resources that can be used during contingencies. The third is that NERC requires BAs to continuously maintain specific amounts of Contingency Reserves, even during normal conditions.

The *Ancillary Service Study* chose to specifically model conventional generation contingencies by randomly removing generators during the study runs:

> "SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. ... When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration." (page 40)

While this, at first, sounds like a modeling improvement, it is actually a needless complication for solar integration modeling that is inaccurate when done incorrectly. The problem is that Contingency Reserves are not released to help balance the power system when, and only when, the model randomly inserts a contingency. Nor are reserves restored within 105 minutes of the contingency. Further, there is no indication that the model respects the requirement to maintain contingency reserves during "normal" times. Failure to release Contingency Reserves during a contingency results in overstating the balancing problem: the model reports imbalances when none would actually occur. Failure to hold Contingency Reserves during normal, non-contingency, times results in the model using Contingency Reserves to compensate for non-contingency imbalances. This understates the normal-conditions balancing reserve requirements.

A solution that many modelers employ is to simply carry the Contingency Reserves (differentiated into spinning and non-spinning based on the Regional Reliability Council requirements) continuously and to not try to model the specific contingency events. Contingency Reserves are designed to compensate for Contingencies when they actually occur, so reliability is maintained without the need to explicitly model the random and infrequent contingency events. This more closely matches actual operating restrictions.

Solar generation plants are typically small compared with large fossil and nuclear generators and consequently do not add to contingency reserve requirements. That is, solar plants do not increase the size of the most severe single contingency, which sets the size of the contingency reserves the BA must have available. Contingency reserves must, however, be maintained in both the base-case and solar-case production cost modeling runs. It is the holding of the Contingency Reserves that is important for the production cost modeling, not the infrequent actual deployment, which is the same under base-case and solar-case conditions.

Use of Curtailed Solar Generation for Contingency Reserves

Curtailed solar (and wind) generators can be ideal *suppliers* of contingency (and other) reserves. Modern solar plants can control their output faster and more accurately than conventional generators. If they are equipped with automatic generation control (AGC) they can provide that response to the system operator during contingencies. Solar plants normally operate at their full available output, and have no reserve capacity to offer, because they have zero marginal production cost and are therefore more economic than fuel burning generators. If, however, a solar generator is curtailed for some reason it will have available generation capacity that could be called upon to support power system reliability. Any solar generator that is *supplying* contingency reserves should be compensated for provision of that service.

Interconnection Frequency Does Complicate Modeling – How to Solve That

The *Ancillary Service Study* is correct when it states that "[u]nderstanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2[20] standards is a critical component of a solar ancillary service cost impact study. However, **simulating violations of these standards is challenging.**" (page 10, emphasis added). The Study is only partly correct when it states that "[w]hile the simulations performed in SERVM do not measure CPS violations directly, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation."[21] It is correct to state that the modeling does not measure CPS violations. It is not correct to imply that the analysis effort and the LOLE reliability metric are in any way suitable substitutes for the NERC CPS1, BAAL, or DCS reliability requirements.

The difficulty in directly modeling NERC balancing requirements is because CPS1 and BAAL both require balancing *only* when ACE drives the interconnected power system frequency further away from 60 Hz: each metric uses (ACE x ΔF) in assessing instantaneous balancing performance.[22] The NERC reliability metrics *credit* generation/load imbalances when they are helping to restore the overall interconnection system frequency to 60 Hz. To do the analysis exactly, the model would have to know the power system frequency at each time step in order to directly model the NERC requirements. That would require knowing the generation and load balance for the entire Eastern Interconnection for each time step, which is currently an infeasible modeling effort.

Instead, a feasible approach is to require more realistic balancing. A recent Idaho Power study[23] of variable renewable generation integration (solar and wind) studied solar penetration levels of

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[20] Again, the correct NERC reliability requirements are CPS1, BAAL, and DCS, but the concept that it is mandatory NERC reliability standards that govern balancing requirements is correct.

[21] Ancillary Service Study 10-11.

[22] Excess generation is bad only when frequency is above 60 Hz and excess load is bad only when frequency is below 60 Hz.

[23] Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF.

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47% of peak load and wind-plus-solar penetrations of 67% of peak load. For reference, the Duke *Ancillary Service Study* only studied solar penetrations ranging from 5% to 33% of peak load.[24] The Idaho Power study also employed production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels. Idaho Power targeted reserves (in both the base and renewables cases) sufficient to compensate for 99% of the 5-minute balancing deviations. That is, Idaho Power allowed a cumulative 90 hours per year of deviations rather than one-event-in-10-years:

> "The target to capture 99 percent of deviations for this study is considered appropriate in ensuring generators have sufficient reserve requirements for all but approximately 90 hours per year. Importantly, the targeted 99 percent is the criterion held for both simulations performed for this study: the base case simulation of load combined with wind, and the test case simulation of load combined with wind and solar. This ensures both simulations are designed to bring about an equivalent level of system reliability, rendering the selected reliability level relatively immaterial from the perspective of comparing production cost differences between paired simulations."[25]

Inappropriate or Questionably Synthesized Solar Data

Of necessity, the *Ancillary Service Study* (and any planning study) modeled solar sites that do not yet exist and for which there is no actual data. Consequently, appropriate solar plant output data must be synthesized for the analysis. It is important that the synthesized data captures aspects of the actual solar plants that will be built. It is also important that the synthesized data represents data that is synchronized to the load data it is paired with to accurately represent net power system variability and uncertainty.

The Study states "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load." (page 26). This is a reasonable start. The study also notes:

> "Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, *the fact that larger units are coming on may dampen the diversity benefit*. For this study, *<u>the raw historical data volatility was utilized along with a distribution that has 75% of the raw data volatility to serve as bookends in the study for the "+1,500" MW solar scenarios</u>*."[26]

[24] Existing, transition, Tranche 1, and plus 1500 MW of solar generation for DEP and DEC.
[25] Ancillary Service Study at 8.
[26] Id. at 30-31 (emphasis added).

This is completely unreasonable. Linearly scaling (doubling variability when the solar resource capacity doubles) is not realistic. The relative intra-hour variability of an aggregation of solar plants (or loads or wind generators) *declines* as the aggregation grows. This is because the short-term variations at one solar plant are not coupled to the short-term variations at other solar plants. The geographic separation of the solar plants prevents cloud shadow edges from crossing multiple solar generators simultaneously.[27]

An examination of the historic solar output data for DEP and DEC shows this decline in relative variability.[28] For example, for the month of July 2018 DEP had a maximum solar output of 1,630 MW while DEC had a maximum solar output of 427 MW.[29] The maximum coincident solar output for the combination of DEP and DEC was 2,041 MW, just 0.8% below the sum of the DEP plus DEC maximum solar outputs. As expected, maximum solar output is closely correlated for DEP and DEC. Aggregating DEP and DEC does not greatly reduce the maximum solar output of the aggregation. By contrast, the relative short-term intra-hour variability of the aggregation of DEP and DEC is significantly lower than the sum of the variability of the two BAs. The hourly average standard deviation of the DEP intra-hour variability for July 2018 was 9.7 MW.[30] The hourly average standard deviation of the DEC intra-hour variability for July 2018 was 3.6 MW. If short-term variability scaled linearly as the *Ancillary Service Study* claims, then the hourly average standard deviation of the short-term variability for the net Duke system would be expected to be 13.3 MW. Instead, the hourly average short-term variability had a standard deviation of only 10.3 MW, just 78% of what linear scaling predicts. The 10.3 MW is also exactly what would be expected for completely uncorrelated short-term variability aggregation for DEP and DEC.

Examining all the historic data Duke provided also shows the strong aggregation benefits of reduced relative variability as the solar aggregation grows. Figure 3 shows that solar generation increased significantly in both DEP and DEC between April 2016 and July 2018. Figure 4 shows that short-term intra-hour variability increased as well. Figure 5, however, shows that short-term variability *declines* relative to the maximum solar generation, both as solar penetration increases through time and when comparing the net Duke system with DEP and DEC individually. That is, variability does not scale linearly with solar generation fleet size but instead exhibits strong aggregation benefits.

With the historic data showing the expected trend of short-term variability declining as solar penetration increases, the assumption of linear scaling is clearly unjustified.

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[27] A. Mills and R. Wiser, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Ernest Orlando Lawrence Berkeley National Laboratory, September 2010.

[28] SACE Data Request No. 2 Item No. 2-30 asked for, and Duke provided, 5-minute aggregate solar and load data for DEP and DEC for April 2016 through August 2018.

[29] Maximum solar output is used as a proxy for solar capacity because Duke did not provide data about which solar plants are included in the aggregate solar output data.

[30] The appendix discusses why the use of standard deviation for quantifying short-term variability is both appropriate and more useful for comparisons than a probability distribution.

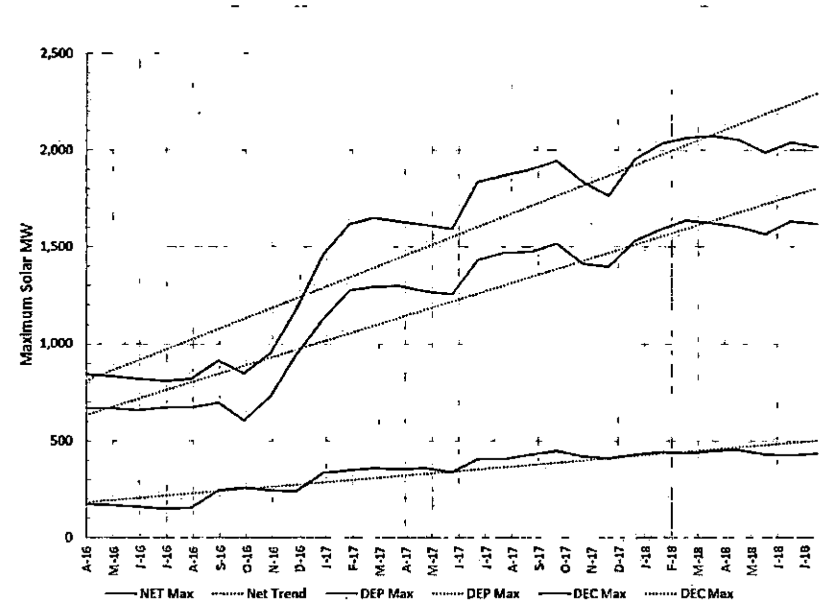

Figure 3 Solar generation increased significantly in DEP and DEC between April 2016 and July 2018

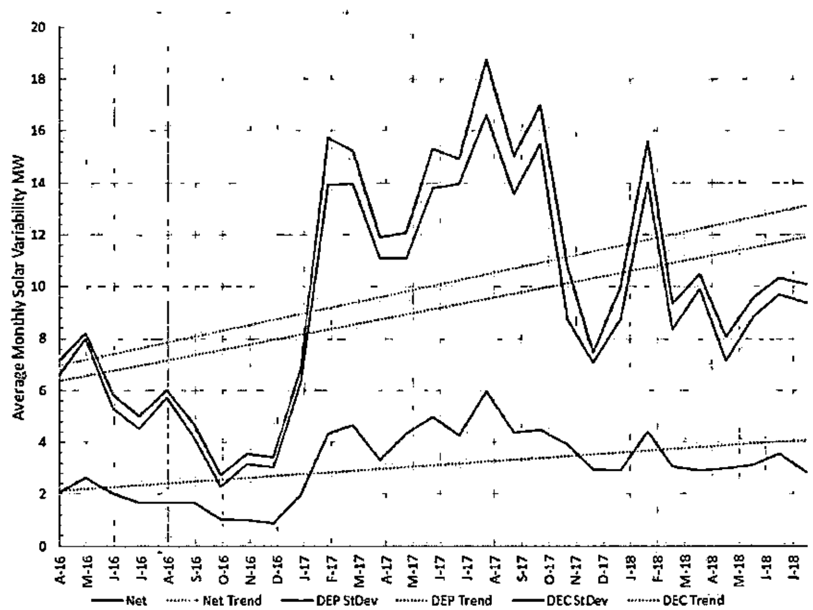

Figure 4 Short-term variability also increased in DEP and DEC between April 2016 and July 2018

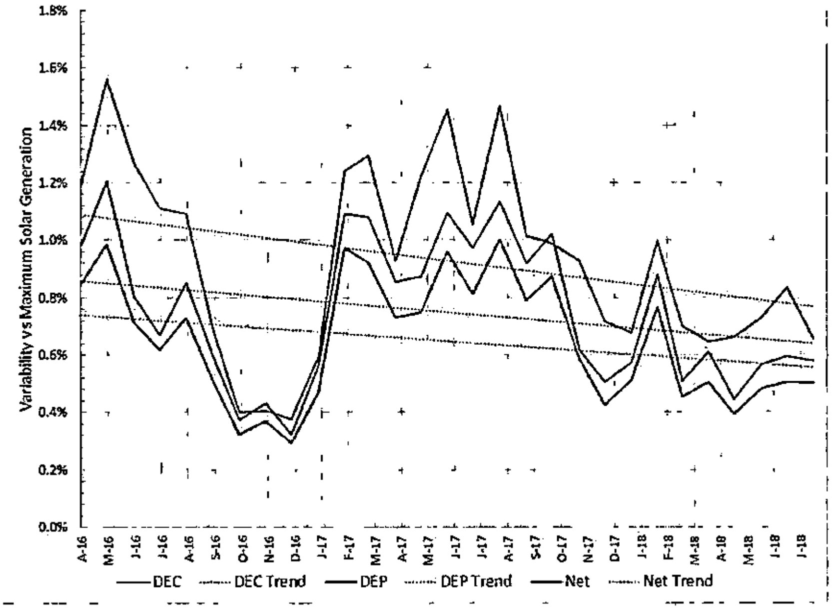

Figure 5 Variability relative to maximum solar declines as solar penetration increases.

Concerns with the *Ancillary Service Study* analysis get worse. The study says that it spread the simulated solar plants over 13 locations throughout the DEC and DEP service territories. Thirteen locations is not a lot of diversity for 7,630 MW of solar generation in the Existing + Tranche 1 + 1500 MW case. That would result in thirteen 586 MW solar plants that cover 3,000 acres (4.6 square miles) each. Further, Tables 5 and 6 show that 22% of the DEP solar plants and 24% of the DEC solar plants are at single sites (site C4 for DEP and site B3 for DEC). That represents a 791 MW solar plant in DEP and an 800 MW solar plant in DEC: 4,000 acres or 6.3 square miles of solar cells in one location. 78% of the DEP solar and 85% of the DEC solar was modeled at just four sites each. This creates a significant lack of diversity in the analysis. But even if an 800 MW solar plant covering 4,000 acres were built, it would have a significant reduction in short-term variability compared with existing solar plants simply from its own geographic size. All of this is in spite of the fact that Schedule PP only applies to solar plants with a capacity of 1 MW_{AC} or less, and that much of the solar generation in Duke's North Carolina BAs is approximately 5 MW, corresponding to the previous Schedule PP standard offer contract.

Analysis of the historic solar generation shows that it is much more reasonable to assume that the short-term (5-minute) variability and uncertainty of new solar generation plants will be uncorrelated with the short-term variability and uncertainty of the existing solar generation plants, and with each other. Further, the *Ancillary Service Study* report states: "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load"[31] and "the five-minute data used to develop intra-hour load volatility was developed from actual data ranging from October 2016 - September 2017[.]"[32] Assuming that

[31] Ancillary Service Study at 26.
[32] Id. at 27.

"the 1 year of historical five-minute data for solar resources" was also October 2016 through September 2017, then the DEC maximum solar increased from 244 MW to 431 MW during the historic calibration year while the DEP solar fleet increased from 697 MW to 1,476 MW. Total Duke solar generation thus increased from 941 MW to 1,907 MW, averaging 1,424 MW during the historic year that was apparently used to calibrate solar variability. This is significantly smaller than the 679 MW of "Existing" solar generation for DEC and 1,923 MW for DEP (2,602 MW total) listed in Table 3 of the *Ancillary Service Study* report.

The *Ancillary Service Study* analyzed total solar penetrations ranging from 2,602 MW for the "Existing" fleet to 7,630 MW for the "Existing+Transition+Tranche 1+1500". That is a range of 1.8 to 5.4 times the size of the solar fleet that was actually analyzed for short-term variability impacts. This results in short-term variability and uncertainty expectations of:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

This large increase in solar penetration creates significant diversity benefits.

Concerns with Dropouts and Data Anomalies

There are additional concerns with the *Ancillary Service Study* analysis of solar variability. While analysis of a generator's energy output is relatively insensitive to bad data, analysis of short-term variability is inherently sensitive to data dropouts and data anomalies. The *Ancillary Service Study* $LOLE_{FLEX}$ 1-in-10-year limit is especially sensitive. If metering data incorrectly showed that a 1,000 MW generator's (or generation fleet's) output dropped to zero for one 5-minute interval every month, that would have essentially no impact on the energy output assessment. The assessed output would only be understated by 0.01%. The assessment of variability, on the other hand, would show 12 massive 1,000 MW jumps in output every year, 120 times the single event allowed by $LOLE_{FLEX}$ in ten years. Data dropouts will dominate any analysis of variability and the resulting reserve requirements.

Duke warned that the 5-minute historic solar data they provided in response to SACE Data Request No. 2 Item No. 2-30 was not perfect: "[p]lease note that this data is sourced from the historian software (OSI PI), so there are some periods where data drop-outs occurred, particularly for DEP." Figure 6 shows an example where the DEP solar fleet data dropped by 1,400 MW for 15 minutes while the DEC solar and DEP load data were unaffected. This type of event is reasonably easy to identify, and it is easy to determine if the event was real. If there had been a 1,400 MW instantaneous drop in generation output it would have been a significant event not only for DEP but for the Eastern Interconnection.

Bad data is more difficult to detect if only part of the solar fleet is impacted but the only data available is for the entire aggregation. Figure 7 shows an event from March 2017 when the output for numerous DEP solar plants was erroneously reported at zero for one 5-minute interval. This event too is relatively easy to detect and eliminate from the analysis because of its 1,100 MW size. Had the data been bad for only one or two plants, the bad-data-event would not be detectable from the aggregate solar fleet data alone, and the event would be incorrectly included in the assessment of solar variability.

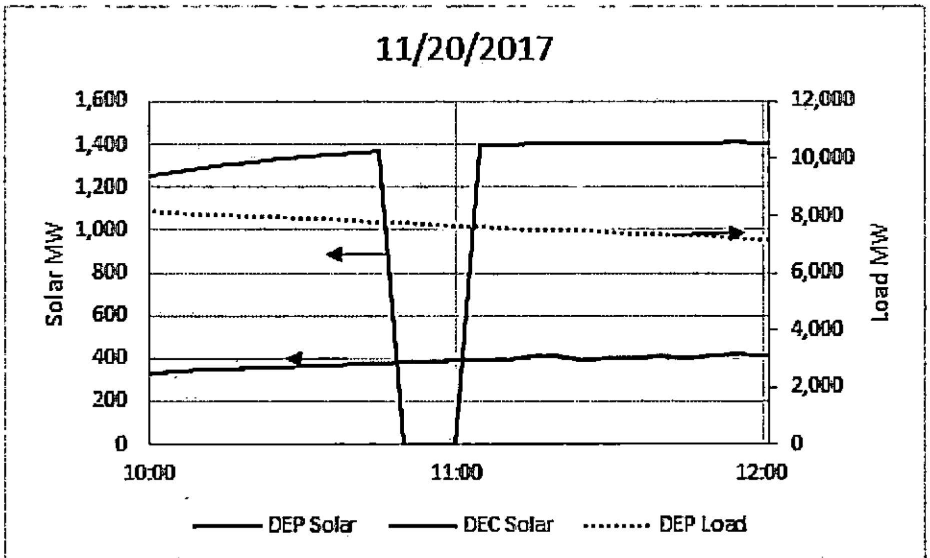

Figure 6 Solar fleet output data suffers from data dropouts.

Figure 8 shows that improbable spikes occasionally appear in the data.

Figure 9 shows a September 2016 event where DEC solar output suddenly increased by nearly 100 MW in one 5-minute interval. While not completely impossible, this sudden increase is unlikely to be real. An evaluation of the data from each solar generator included in the aggregation would clarify if the event was real.

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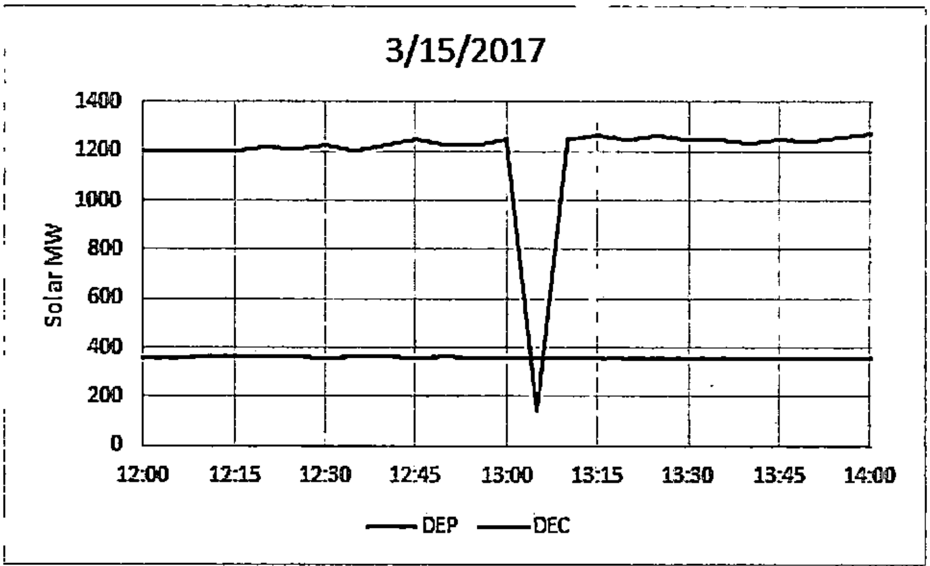

Figure 7 Data dropouts are harder to detect if they impact only art of the aggregation.

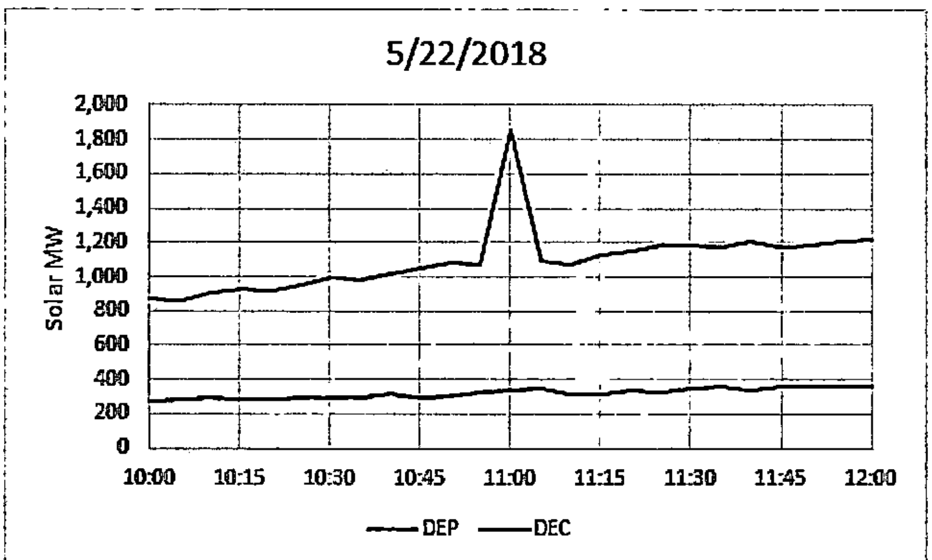

Figure 8 Solar output data occasionally shows unlikely spikes.

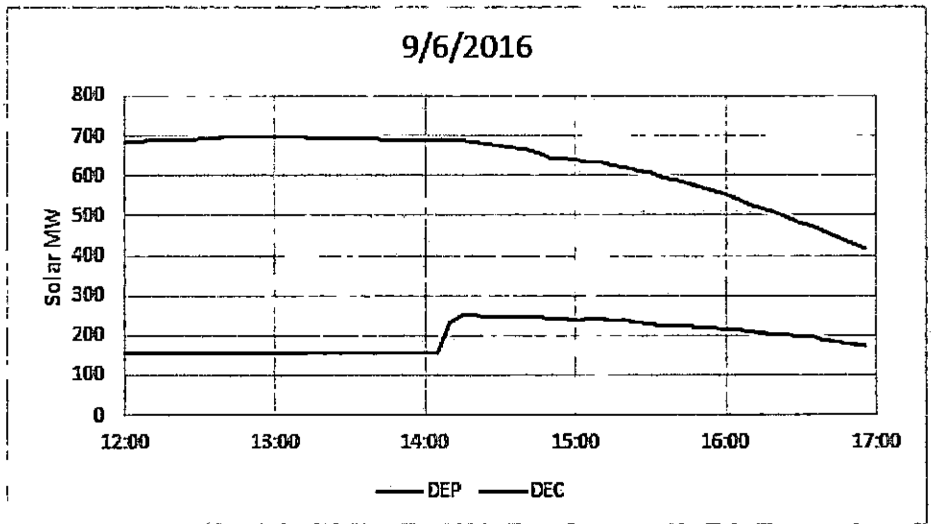

Figure 9 Data anomalies are not limited to dropouts and spikes.

Figure 10 shows hourly variability versus solar output for the data Duke provided. The 1,400 MW 15-minute drop in DEP solar output is immediately obvious.

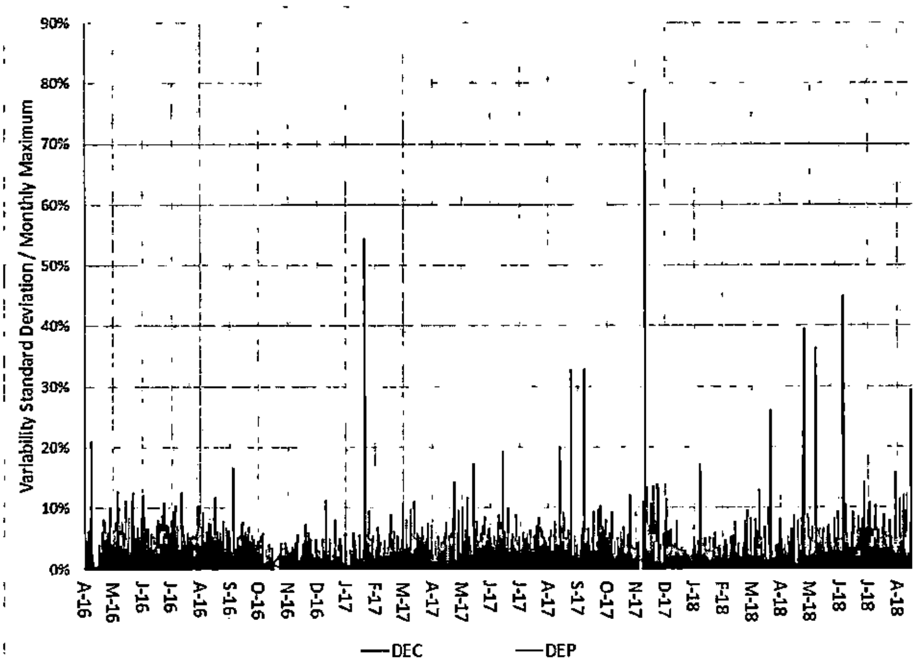

Figure 10 Spikes in hourly solar variability indicate likely data anomalies worth investigating.

Figure 11 shows the hourly variability versus solar output after the readily identifiable data anomalies have been removed. Note that the vertical axis scale is reduced from a maximum of 90% to only 14%.

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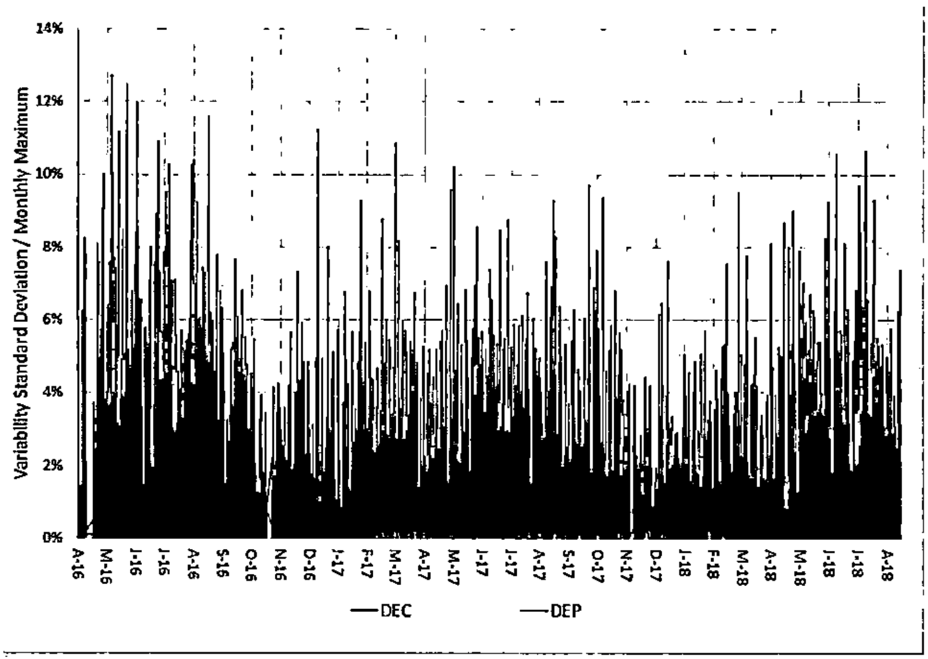

Figure 11 Solar variability is reduced after removal of data anomalies.

Over the 30 months covered by the historic 5-minute solar output data Duke provided, there were 93 events for DEP and 403 events for DEC that are almost certainly bad data that can be identified from the aggregate solar data. These events represented only 0.15% of the DEP data and 0.39% of the DEC data, but they dominate any assessment of short-term intra-hour solar variability if they are left in the analysis. Even with approximately 500 bad data events eliminated from the analysis, the short-term solar volatility is still likely overstated, perhaps significantly, because data dropouts from individual solar generators cannot unambiguously be identified from the aggregate solar data alone. It is unclear if and how solar output data dropouts were eliminated from the *Ancillary Service Study* analysis of short-term solar generator output volatility.

Unclear How Reserves Were Increased

The basic *Ancillary Service Study* methodology compares production cost simulations that include additional solar generation with base cases that have no solar. "The number of yearly simulation cases equals 36 weather years * 5 load forecast errors * 20 unit outage iterations * 6 solar profiles = 21,600 total iterations for each level of solar penetration simulated."[33]

The study methodology increased load following reserves in the with-solar cases in order to maintain the same level of reliability (as measured with the inappropriate $LOLE_{FLEX}$ metric): "To

[33] Ancillary Service Study at 44.

reduce $LOLE_{FLEX}$, additional load following is added as an input into the model."[34] The study noted the increased amount of reserves required and the resulting increased production cost to determine the proposed solar integration charge.

The *Ancillary Service Study* report does not detail how reserves were added to maintain reliability. For example, were reserve requirements increased for all 8,760 hours of the year? Were reserve requirements increased only during daylight hours? The report only states that "[i]n order to reduce $LOLE_{FLEX}$ back down to 0.1 events per year, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities."[35]

A better approach would be to determine under what conditions increased solar generation stressed power system response and to then select appropriate mitigation measures. For example, it may be that increased reserves are only needed during the morning or evening solar ramps. Alternatively, there may be specific load conditions (either very high or very low loads) that are problematic. Specific weather conditions or conventional generation configurations may prove troublesome. Added reserves may only very rarely be needed, rather than being required almost every day. This is especially true with the very tight "one day in 10 years" LOLE criteria used for the study, in which a single event in 87,600 hours is all that is allowed. The answers that would result from a more robust analysis could dramatically impact the types of reserve resources that can be used to maintain reliability at least cost.

Next Steps – What Should Be Done?

The analysis methodology should be modified, and the modeling tools upgraded if necessary:

- Production cost modeling should be based on actual NERC reliability and balancing requirements and operating practices.
- Data anomalies for individual solar generators and for the solar generation fleet aggregation should be eliminated from the analysis of short-term intra-hour variability.
- Reductions in short-term intra-hour variability for the aggregate solar generation fleet from the variability identified in the historic data should be reflected in the analysis of each level of solar penetration studied.
- Actual balancing requirements that are expected to result from increased solar penetration should be identified.
- Least-cost methods to meet any additional balancing requirements should then be determined.

Once these steps are taken, it will be possible to begin to determine if any solar integration charge is warranted.

[34] Id. at 45.
[35] Id.

Duke should also consider utilizing a Technical Review Committee (TRC), composed of outside experts on variable renewables integration. TRC's have been successfully used by many utilities to help guide their integration studies and to utilize the latest and best integration study practices.[36] The Energy Systems Integration Group has published guidelines for TRC involvement in renewables integration studies.[37]

Improvements to Production Cost Modeling Methodology
Each BA should be modeled as part of the interconnected power system, not as an isolated island. Balancing and reliability requirements based on the mandatory NERC reliability standard BAL-001-02 and metrics based on CPS1 and BAAL should be used, not the arbitrary, made-up, and unrelated "1 day in 10-year" metric of $LOLE_{FLEX}$ and $LOLE_{CAP}$. A balancing requirement of 99% or 90 hours per year is still conservative but more closely matches the actual requirements imposed by CPS1 and BAAL in the interconnected power system.

Eliminate the explicit modeling of conventional generation failure contingencies. NERC reliability standard BAL-002 and Regional Reliability Council requirements dictate the amount of spinning and non-spinning contingency reserves that must be carried continuously to respond to sudden, unexpected generation and transmission failures, regardless of the frequency of those failures. Simply model the reserve requirements, and do not attempt to artificially simulate the events themselves. This will be more accurate and will reduce the number of required production cost modeling runs by a factor of 20.

If explicit contingency modeling is still included, then: 1) release the contingency reserves to respond to each event and 2) change the balancing requirements during the event to match the DCS requirements (rebalancing in 15 minutes and reserve restoration within 105 minutes).

Any curtailed solar generators should be allowed to provide reserves, including contingency reserves. The economic benefit of solar generators providing reserves should be credited to those generators.

Improvements to Solar Variability Modeling
The historic data used to assess the variability of the existing solar generation fleet should be carefully scrubbed to eliminate data anomalies. This will require the analysis of the output of every solar plant individually.

Intra-hour solar variability should be modeled more accurately. Aggregation benefits should be accounted for. Large amounts of additional solar generation should not be assumed to be placed at only four sites within each BA. Even if the massive 800 MW solar plants that were

[36] For example: Idaho Power, Portland General Electric, Arizona Public Service, BC Hydro, Public Service Colorado, Pan Canadian Wind Integration Study, ISO-New England, Pacificorp, Public Service of New Mexico, SMUD, the Western Wind and Solar Integration Study, Eastern Wind Integration and Transmission Study.
[37] Energy Systems Integration Group, Principles for TRC Involvement in Wind Integration Studies, https://www.esig.energy/resources/principles-trc-involvement-wind-integration-studies/.

modeled in the *Ancillary Service Study* were built, their own square-mile geographic size would reduce the single plant intra-hour variability significantly. Intra-hour variability should be reduced from the measured variability of the existing solar fleet to:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

Identify Actual Balancing Requirements or Changes in Operating Practices

Once the production cost modeling methodology has been aligned with actual NERC reliability standards, and the expected solar variability has been represented accurately, the power systems can be studied to determine what additional balancing requirements additional solar generation may impose. Those balancing requirements should be analyzed to determine:

- Balancing shortfall event frequency, duration, direction, and MW amount
- Balancing shortfall event timing (early morning, midday, evening, week days, weekends, ...)
- Power system conditions during balancing shortfall events (morning/evening load ramps, morning/evening solar ramps, extreme high/low loads, during times of conventional generation maintenance outages, high/low hydro conditions, ...)
- Solar and weather conditions during balancing shortfall events

Only after the additional balancing characteristics are understood can cost effective mitigation methods be determined.

Additionally, changes in operating practices may help integrate greater amounts of solar generation more cost effectively than simply adding reserves. Changing the characteristics of which units are committed in order to increase response flexibility (lower minimum loads, faster response speeds, etc.) may be warranted. Production cost modeling, if done correctly, can effectively capture the costs of increasing flexibility and the benefits of reduced reserves.

Determine Cost Effective Methods to Maintain Reliability

Once any additional balancing requirements are understood, cost effective methods for obtaining that balancing capability can be determined. Standard utility practice is to differentiate reserve requirements based on response speed, duration, and frequency. The same criteria should be applied to additional balancing requirements for solar generation penetration. For example, fast-start combustion turbines are often used to meet non-spinning reserve requirements for infrequent events where the cost of continuously standing ready is more important than the cost of infrequent response events. Similarly, demand response is often cost effective for relatively infrequent events, especially if the events are expected to correlate with load capability.

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Once additional balancing requirements are understood and quantified, the cost of meeting those requirements with the conventional generation fleet can be determined. Once the cost of meeting the additional balancing requirements with conventional generation is understood, alternative technologies, such as demand response or storage, can be examined. Finally, once the additional balancing requirements are quantified and costed, those requirements can be made public to see if third parties can supply the needed response at a lower cost than has been assumed in the studies.

Conclusions: The *Ancillary Service Study* is Fundamentally Flawed, and the Resulting Solar Integration Charge is Unsubstantiated

The analysis methodology presented in the November 2018 Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study report is deeply flawed, and the resulting solar integration charge is unjustified. The methodology is not based on actual utility operating practices or on mandatory NERC reliability requirements. Actual balancing and reliability requirements were not considered. Solar generation intra-hour variability was dramatically overstated because geographic diversity was not accurately considered. Balancing requirements themselves were not studied, and balancing resources were not matched to requirements.

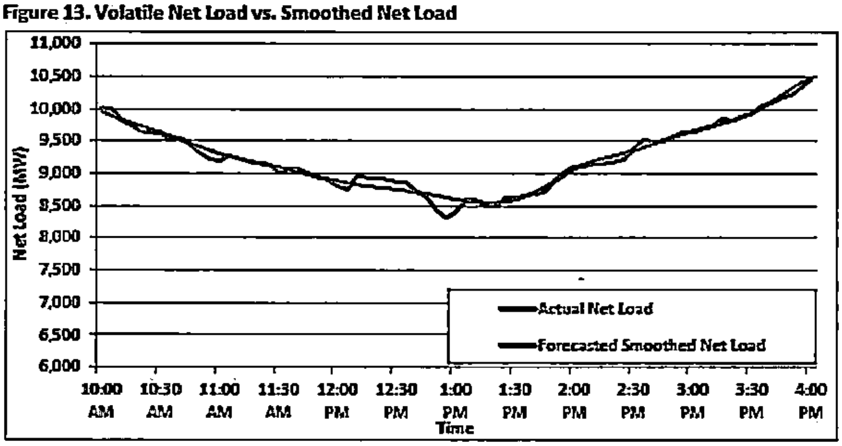
Appendix A

Quantifying Short-Term Variability

The *Ancillary Service Study* report identifies increases in the short-term variability and uncertainty in the net-load (load plus solar generation) caused by increasing amounts of solar generation as the cause for increased balancing reserves and therefore increased operating costs. The study quantifies short-term variability by comparing the actual 5-minute net-load with the longer-term trend of net-load:

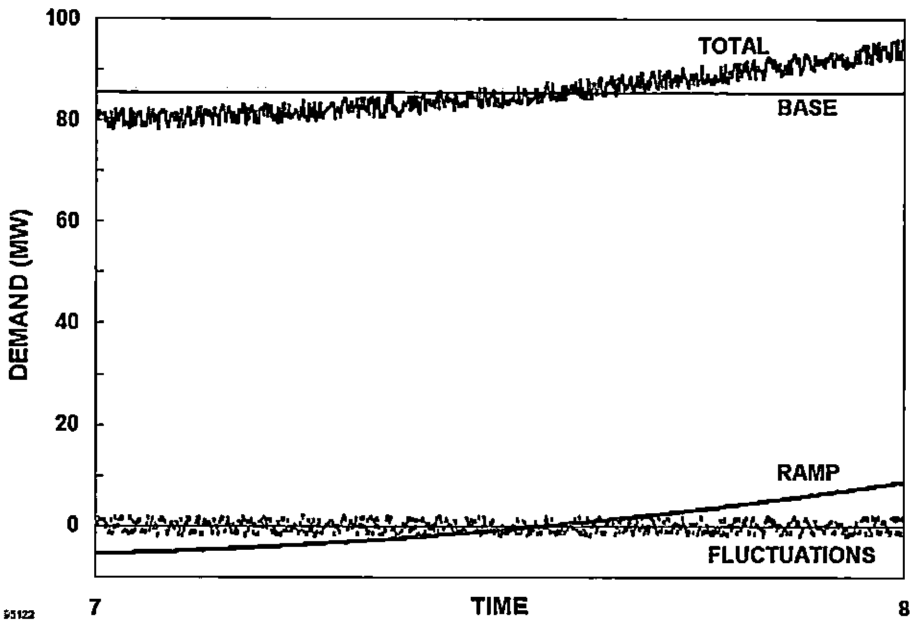
> Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. **An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 13.** The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute to minute basis. The solution to resolve the system's inability to meet load on a minute to minute basis is to increase operating reserves or add more flexibility to the system which both result in additional costs.[38]

Figure 13. Volatile Net Load vs. Smoothed Net Load



[38] Ancillary Service Study at 26 (emphasis added).

Eric Hirst and I introduced this method of quantifying the short-term variability from the raw net-load signal in 1996 when ancillary services were first being defined by FERC.[39] Recognizing that short-term volatility does not typically scale linearly for loads and almost all utility resources, we developed a method for allocating the total-utility regulation volatility burden among individuals in 2000 when we introduced the vector allocation method.[40] The analysis method recognizes the importance of the level of correlation of the short-term variability of multiple resources (loads, generators, storage devices) with each other and the net-system-load in determining the utility aggregate load and generation balancing response. It has been applied to solar and wind generation many times since.[41] Figure A1, used in both reports Oak Ridge National Laboratory reports, shows the decomposition of the total net system load into base energy, the morning ramp, and the short-term fluctuations.



Components of a hypothetical load on a weekday morning.

Figure A1 Separation of short-term volatility from base energy and ramping.

[39] E. Hirst and B. Kirby 1996, *Ancillary-Service Details: Regulation, Load Following, and Generator Response, ORNL/CON-433*, Oak Ridge National Laboratory, Oak Ridge, TN, September.
[40] B. Kirby and E. Hirst 2000, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services, ORNL/CON-474*, Oak Ridge National Laboratory, Oak Ridge TN, January.
[41] For example: Kirby, Milligan, Mararov, Hawkins, Jackson, Shui, California Renewable Portfolio Standard, 2003 – ERCOT Wind Regulation Study – Holtinnen, Milligan, Kirby, Acker, Neimans, Molinski, Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power. Wind Engineering Journal 2008 – Milligan, Ela, Hodge, Kirby, Lew, Clark, DeCesar,o Lynn, Cost-causation and wind
integration analysis. 2011 – Milligan, King, Kirby, Beuning. Impact of Alternative Dispatch Intervals on Operating
Reserve Requirements for Variable Generation. Ackermann Conference 2011 – Kirby, Milligan, Wan, Cost-causation-based tariffs for wind ancillary service impacts

The *Ancillary Service Study* uses the method of separating short-term variability from the longer-term trend to analyze regulation requirements for load, solar generation, and net-load. The study quantifies the short-term variability in probability distribution tables like Table 9 from the *Ancillary Service Study* report.

Table 9. DEP West Load Volatility

Normalized Divergence (%)	Probability (%)
-3	0.020
-2.8	0.000
-2.6	0.003
-2.4	0.001
-2.2	0.003
-2	0.010
-1.8	0.010
-1.6	0.010
-1.4	0.020
-1.2	0.084
-1	0.242
-0.8	0.704
-0.6	2.269
-0.4	10.299
-0.2	37.095
0	35.792
0.2	9.899
0.4	2.107
0.6	0.796
0.8	0.337
1	0.167
1.2	0.079
1.4	0.028
1.6	0.006
1.8	0.002
2	0.003
2.2	0.001
2.4	0.000
2.6	0.002
2.8	0.005
3	0.000

Using probability distribution tables to quantify short-term variability makes comparing various conditions difficult. Table 9 took 62 numbers to quantify the short-term variability of the DEP West load for the historic calibration year. The report uses even larger tables to quantify solar variability versus solar output.

A well-established alternative to using probability distribution tables to quantify short-term variability is to use the standard deviation of the short-term variability.[42] This has been done for

[42] For example: B. Kirby, E. Ela, and M. Milligan, 2014, Chapter 7, Analyzing the Impact of Variable Energy Resources on Power System Reserves. In L. Jones, (Ed.), *Renewable Energy Integration: Practical Management of Variability, Uncertainty, and Flexibility in Power Grids, London*: Elsevier – M. Hummon, P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, O. Ma, 2013, *Fundamental Drivers of the Cost and Price of Operating Reserves*, NREL/TP-6A20-58491, July – M. Milligan, K. Clark, J. King, B. Kirby, T. Guo, G. Liu, 2013, *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NREL/TP-5500-57115, March

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qualifying short-term variability of solar, wind, and load in numerous studies. The standard deviation provides a single number for each measurement of variability, allowing easier comparison of changes in variability from case to case or through time. Standard deviation can be meaningfully quantified for intervals as short as an hour, allowing identification of the timing of periods of high variability. This is useful for identifying under what conditions additional reserves are required (solar conditions such as high or low solar output, power system conditions such as very high or low system load or the morning or evening ramp, times of conventional generation outages, etc.). It is also useful for identifying dropouts and other anomalies with the solar data.

Figure A2 provides an example of the usefulness of the standard deviation metric as compared to probability distribution table. The figure shows the maximum and average monthly solar output for all of Duke from April 2016 through July of 2018 on the left axis. It also shows how the short-term variability changes from month to month as measured by the standard deviation of the short-term variability on the right axis. This type of graphical comparison is not possible utilizing a probability distribution for each monthly data point.

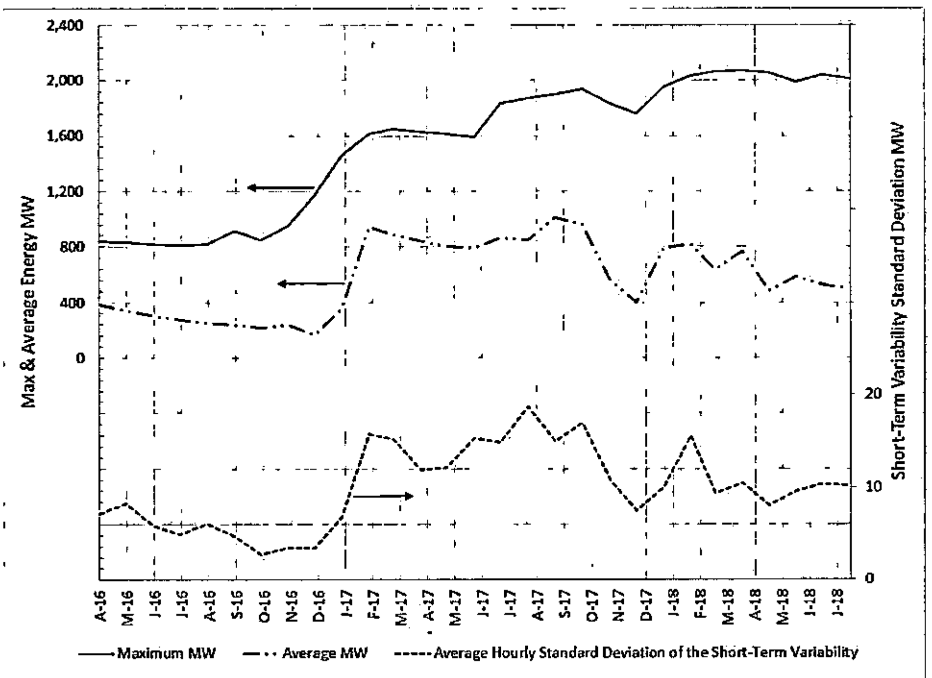

Figure A2 Monthly peak solar production, average hourly energy, and short-term variability for the combination of DEP and DEC.

Appendix B

Qualifications of Brendan Kirby, P.E.

Brendan Kirby is a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), the Utility Variable-Generation Integration Group (UVIG), the Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory, and others. He retired from the Oak Ridge National Laboratory's Power Systems Research Program. Mr. Kirby has 44 years of electric utility experience, and he has been working on restructuring and ancillary services since 1994 and spot retail power markets since 1985.

Mr. Kirby's interests include electric industry restructuring, bulk system reliability, energy storage, wind power integration, ancillary services, demand side response, renewable resources, distributed resources, and advanced analysis techniques. He has published over 180 papers, articles, and reports. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy. He served on the NERC Standards Committee and the Integration of Variable Generation Task Force. He has participated in the NERC/FERC reliability readiness reviews of balancing authorities and reliability coordinators, performed field investigations for the US/Canada Investigation Team for the 2003 Blackout, and has appeared as an expert witness in FERC and state litigation. He has conducted research projects concerning restructuring for the NRC, DOE, NREL, EEI, AWEA, UWIG, numerous utilities, state regulators, and EPRI.

Mr. Kirby is a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.

/A v.5

Kirby Exhibit C

Dominion Proposed Solar Integration Re-Dispatch Charge

Brendan Kirby, P.E. – February 2019

Dominion Energy North Carolina has proposed a solar integration re-dispatch charge of $1.78/MWH. Though Dominion has provided little information concerning how the proposed re-dispatch charge was calculated, there are significant concerns, both with the calculation itself and with the underlying concept.

Re-Dispatch Charge Based on Analysis of Inappropriate Solar Penetration Levels

Dominion's re-dispatch charge is based on production cost analysis that "was performed at three different levels of solar penetration (up to 4,000 MW) to provide a range of results."[1] Dominion references the 2018 Integrated Resource Plan (2018 IRP) for further details on the re-dispatch cost analysis, but that document also only states that the analysis was performed at three solar penetration levels. The "Solar Integration Cost – Generation (Re-dispatch) 2018 IRP" PowerPoint presentation states that "penetration levels of 80 MW, 2000 MW, and 4000 MW were chosen for the study".[2]

Solar penetration is already 823 MW in the study region and is expected to be 965 MW in 2020 and 1,063 MW in 2021.[3] Inclusion of the 80 MW Scenario in the re-dispatch calculation is inappropriate because the low-solar-penetration results dominate the calculated cost. The proposed $1.78/MWH re-dispatch cost adder is an *average* of the results from all of the production cost runs from all three solar penetration levels. Table 1 shows that Dominion's calculated re-dispatch costs drop significantly as solar penetration increases with the 2000 MW Scenario re-dispatch cost being less than a quarter of the 80 MW Scenario re-dispatch cost.

Table 1 Dominion re-dispatch cost calculation drops with increased solar penetration[4]

Final Answer Calculations

	MW Scenario		
Assumption Combo	**80**	**2000**	**4000**
All Costs	$2.26	$0.88	$0.56
No PJM Purchases/Sales	$5.58	$1.32	$0.79
No Pumping Costs/Revenues	$2.01	$0.51	$0.42
Generator Costs Only (Fuel/VOM/Emissions)	$5.41	$1.01	$0.65
Scenario Average	**$3.82**	**$0.93**	**$0.60**

[1] Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities 13, Docket No. E-100, Sub 158, (Nov. 1, 2018).
[2] Dominion Response to NCSEA Data Request No. 1, Question No. 20 at (a) (AV).ppt, slide 5.
[3] Virginia Electric and Power Company's Report of Its Integrated Resource Plan 212, May 1, 2018..
[4] Dominion Response to NCSEA Data Request No. 1 Question No. 20 at (b) (AV) CONF_COC_1_6.xlsx, sheet "MWh MatrixedResults".

Average of all Scenarios $1.78

The 80 MW Scenario results should not be included in any assessment of current or future solar penetrations. The 2000 MW Scenario is closer to current and near-term expected solar penetration.

Re-dispatch Charge an Average of "Assumption Combo[s]"

Table 1 also shows that the proposed $1.78/MWH solar re-dispatch charge is not only an average of results calculated for three solar penetration levels, it is also an average of results from four "Assumption Combo[s]". These "Assumption Combo[s]" are not described, or even mentioned, in either the 2018 IRP or in the Avoided Cost filing. They are listed (but not described) in an Attachment to Dominion's response to NCSEA Set 1-20(b). The re-dispatch results from the four "Assumption Combo[s]" differ significantly, with the maximum being 1.9 to 2.7 times as high as the minimum, depending on the MW Scenario. Rather than explaining what the assumptions are or which set of assumptions is appropriate, Dominion simply took an average of the results from all of the "Assumption Combo[s]".

It is reasonable to perform analysis under different sets of assumptions in order to better understand what conditions contribute to specific results. It does not make sense, however, to average results from different types of conditions such as "All Costs" and "No PJM Purchases/Sales". Similarly, pumping costs and revenues should either be included or not. It is hard to imagine how it makes sense to average a "No Pumping Costs/Revenues" case with three other unrelated cases.

In the absence of further explanation of what is included in each set of assumptions, the "All Costs" "Assumption Combo" appears most appropriate.

Re-dispatch Charge a Strange Average of Averages

The calculation of re-dispatch charges for each "Assumption Combo" at each of the three MW Scenario solar penetration levels is also itself an average of results with various weightings and averagings. Table 2 lists the eight sets of results that were averaged to create each of the "Assumption Combo" results that were then averaged again for each MW Scenario and averaged yet again to calculate the final $1.78/MWH solar integration re-dispatch cost.

Table 2 Each calculated solar integration re-dispatch cost result is itself an average of averages.

Simple Average of All Studied Units
Levelized Simple Average of All Studied Units
Weighted Average of All Studied Units
Levelized Weighted Average of All Studied Units
Simple Average of Studied Units excluding outliers
Levelized Simple Average of Studied Units excluding outliers

Weighted Average of Studied Units excluding outliers
Levelized Weighted Average of Studied Units excluding outliers

None of the categories listed in Table 2 were described, or even mentioned, in either the 2018 IRP or in the Avoided Cost filing. They are listed (but not described) in the Dominion's Response to NCSEA Question 1, No. 20 (b) (AV) CONF_COC_1_6.xlsx Excel workbook.

The use of different weightings, levelizations, and outlier exclusions is often appropriate. Comparing results with different exclusions and weightings can also be useful. The type of analysis, and the quality of the data, typically dictate what weighting, exclusions, and levelizing are appropriate for a given purpose. In this case it is important because results differ by 112% to 135%. It is not appropriate to average a weighted average analysis result with a levelized cost analysis result. Similarly, either outliers are excluded or they are left in the analysis. It makes no sense to average results from an analysis that excludes outliers with the results from an analysis that includes outliers. Using a weighted average and excluding outliers appears to be most appropriate.

/A v.5

Kirby Exhibit D

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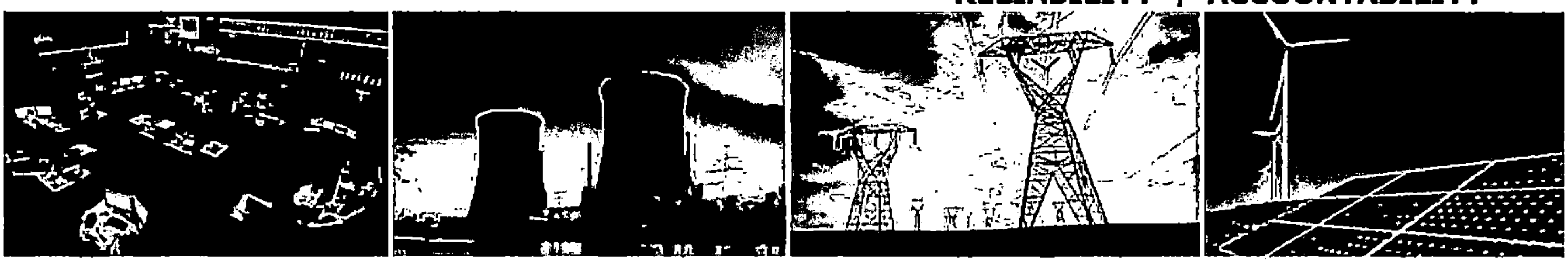
Integration and Monitoring of Distributed Energy Resources in System Operations

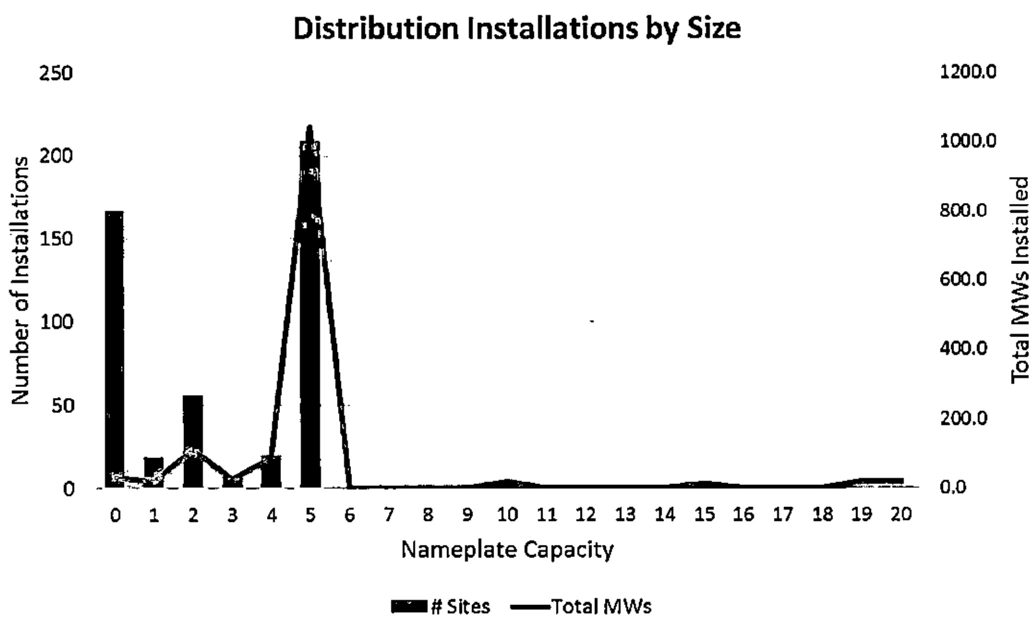
Adam Guinn, PE, REES
Duke Energy Progress
June 4-5, 2019

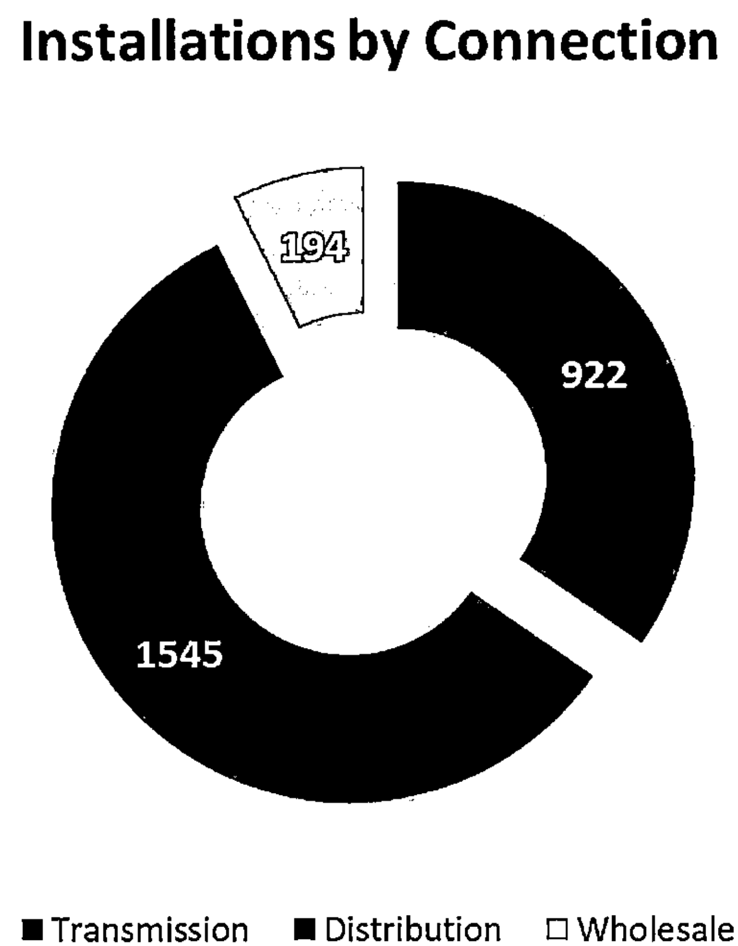
RELIABILITY | ACCOUNTABILITY



The Landscape

- DER penetration is primarily solar
  - Transmission-Connected: Sites ranging in size from 25 to 88 MW
  - Distribution-Connected: Sites range in size as follows:





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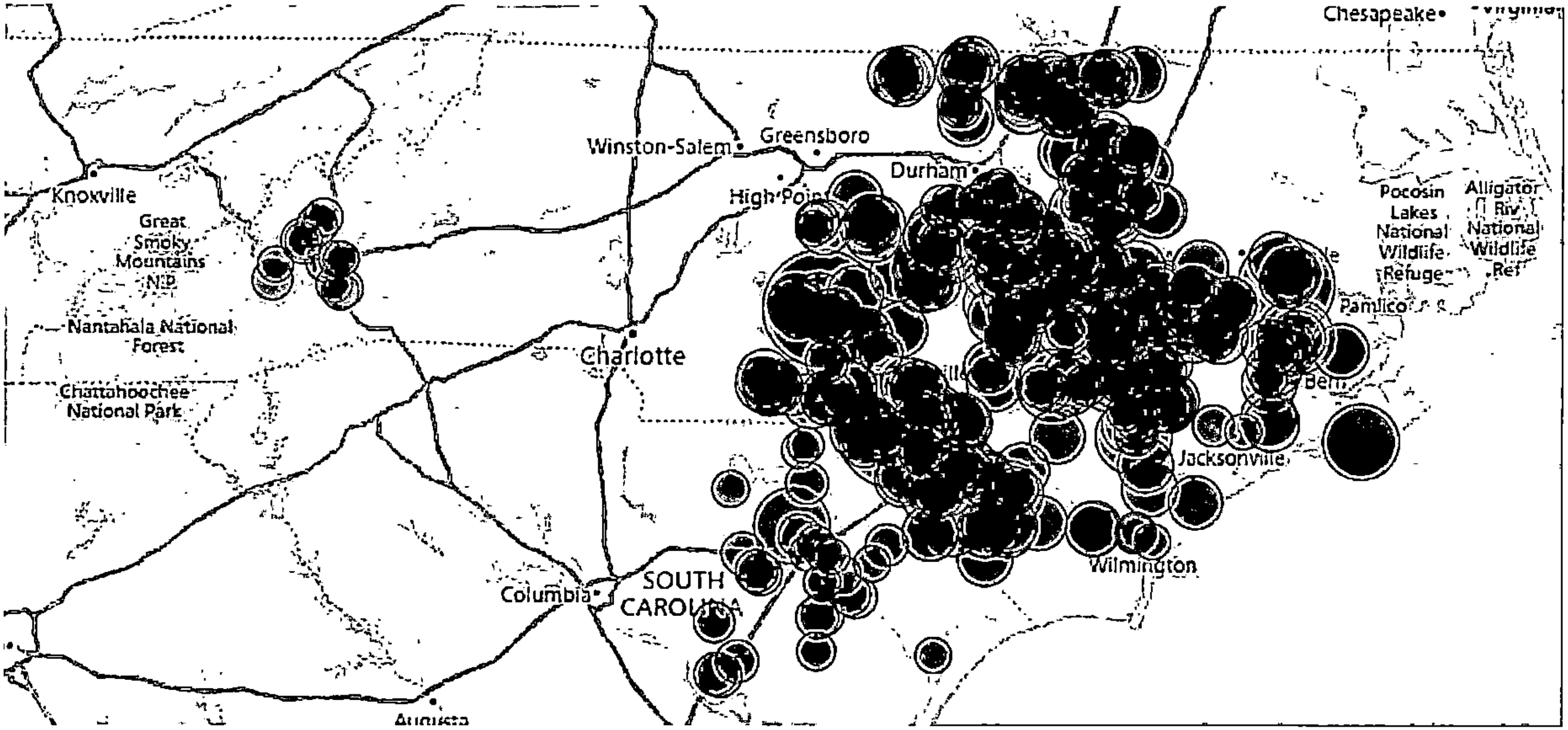
Geographical Overview of Sites



~97% of these are telemetered within the EMS in Real-Time

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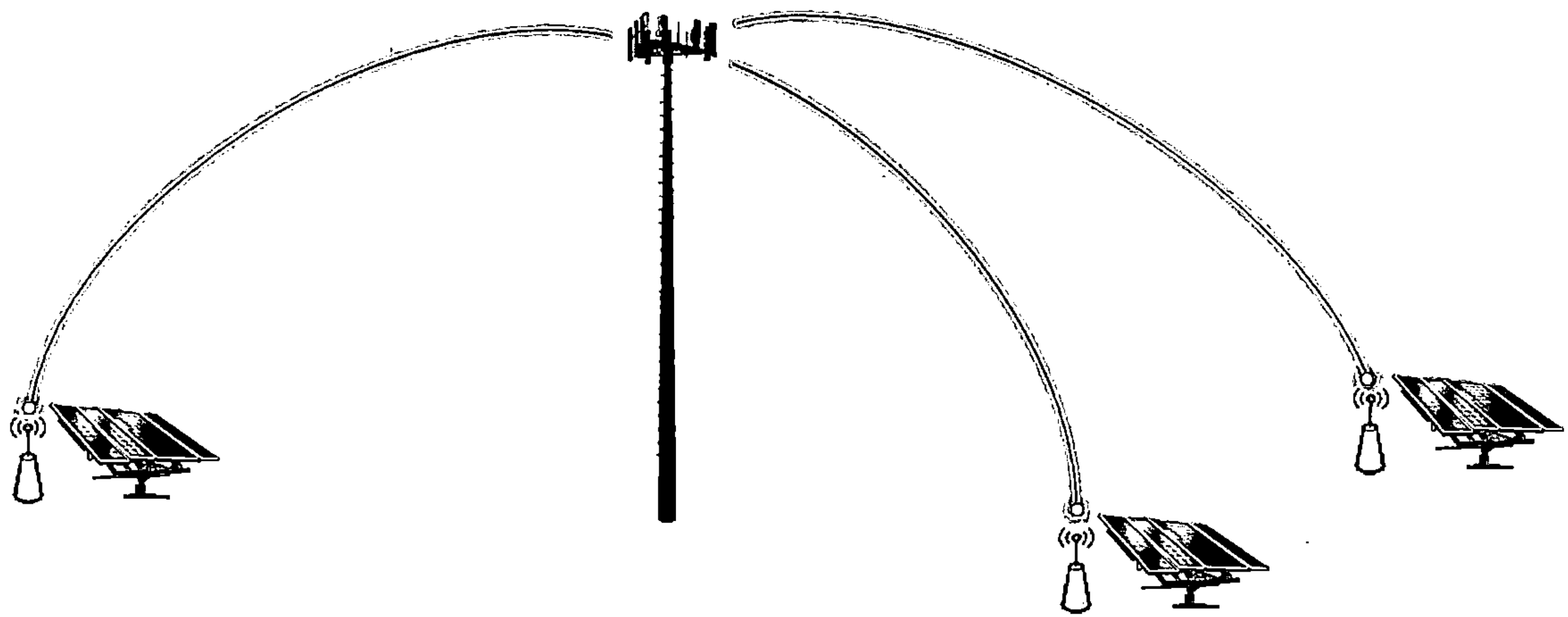
Distribution Data Acquisition

EMS at the ECC:
- *Modeled*
- *Aggregated*
- *Forecasted*
- *Appreciated*



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BA Operational Areas Impacted

Generation Commitment and Dispatch

- Net Demand Ramping
- Intermittency
- Excess Energy (Lowest Reliability Operating Limit)
- Inertial Response
- Compliance considerations

Generator Impacts

- O&M Cost from ramp demand
- Increased cycling of resources

Under-Frequency Load Shed (UFLS)

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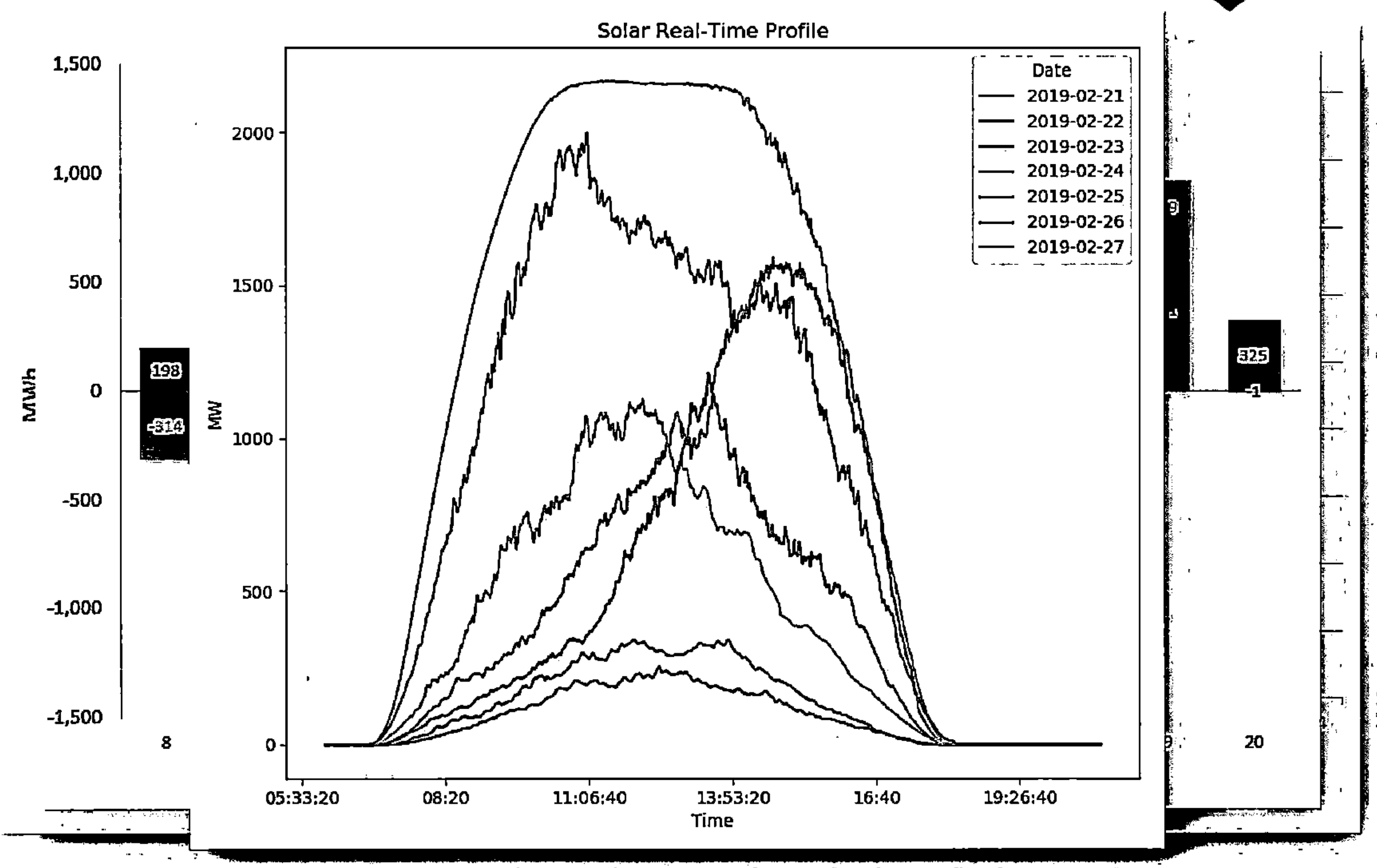
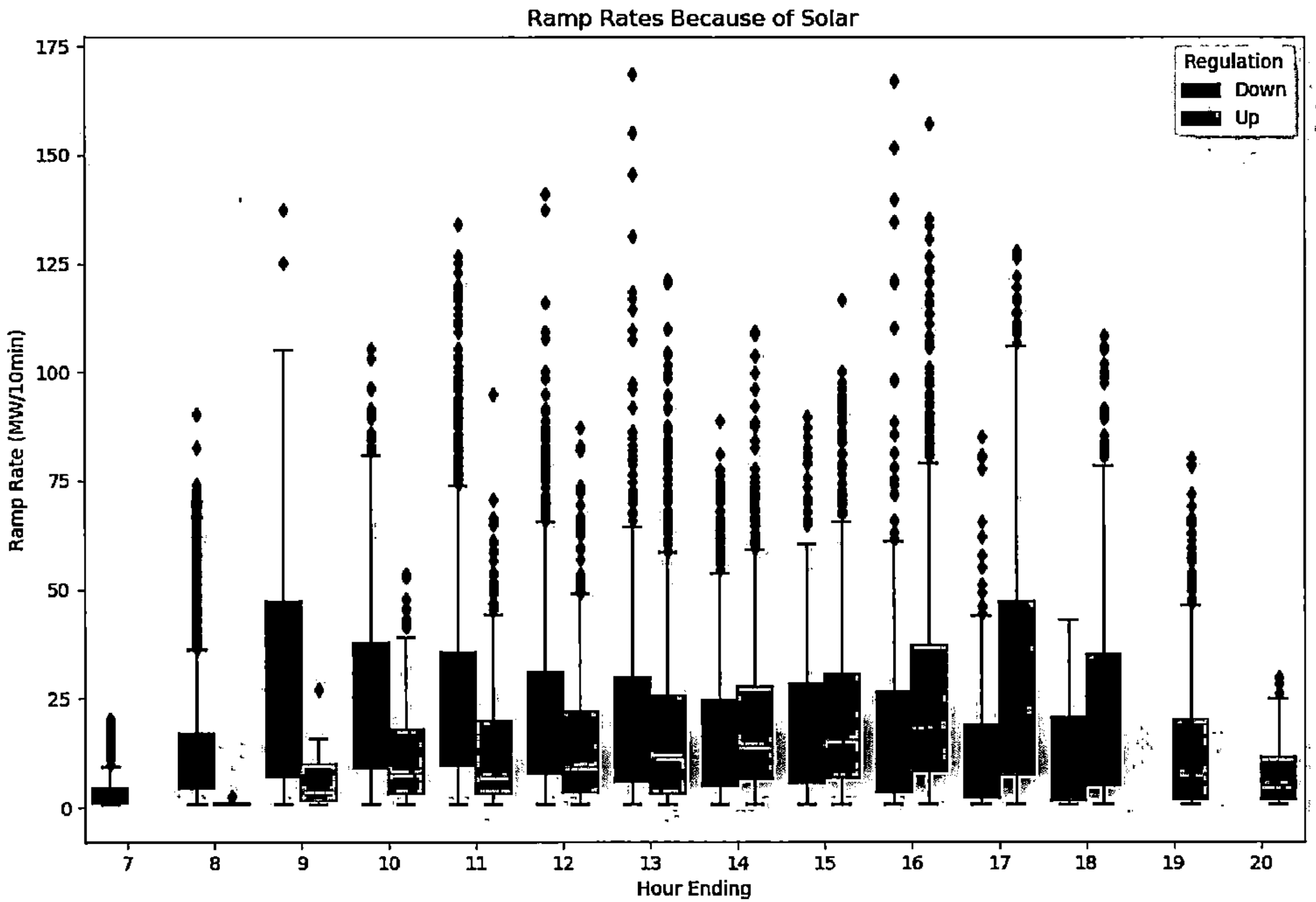
Generation Commitment and Dispatch



10-Minute Average Sustained Ramps



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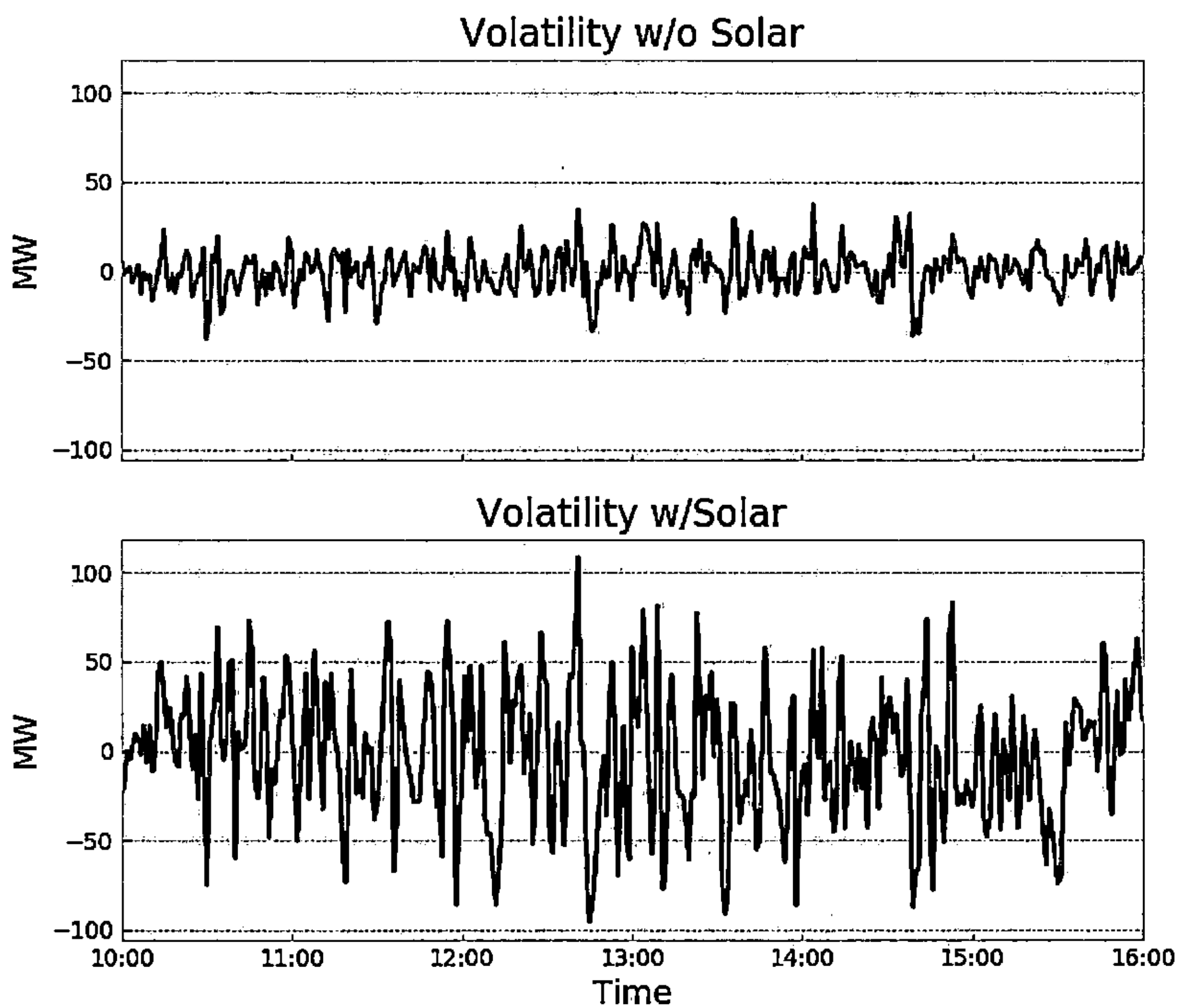
1-Minute Ramp Volatility

Gross Load Volatility (03/25/2019)



Area-Level AGC Tuning

DEP Performed Area-Level AGC Tuning in September 2018

Tuning was driven by changes in resource mix

Control bounds were relaxed to improve response performance

Generators better respond to sustained system needs

- Dispatchable generators no longer chasing fleeting events
- Reduces impacts from Variable Energy Resource 1-min volatility
- Improves fleet efficiency

Compliance benefits

- An ~20% reduction in BAAL exceedance minutes
- Negligible impacts to CPS1%

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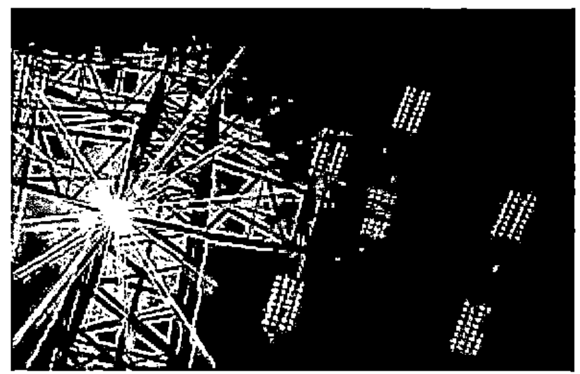
Operational Areas Impacted

Transmission

- Real-Time Network Analysis
  - State Estimation
  - Power Flow
  - Contingency Analysis
- Power Flow Studies
  - Outage Coordination
  - Planning

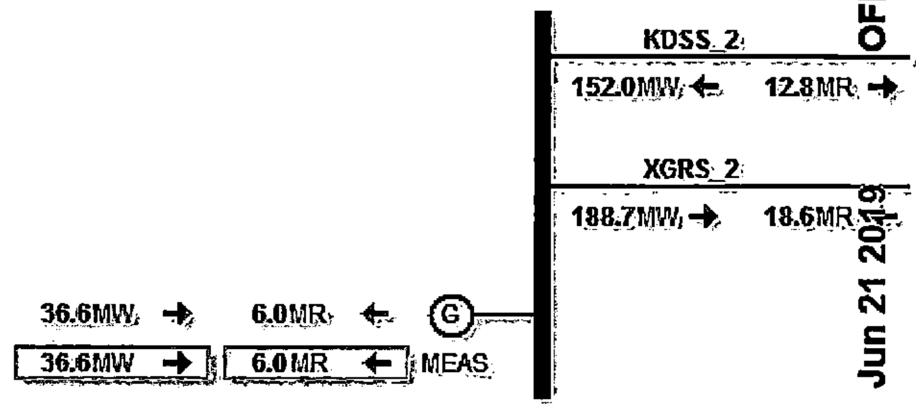
Coordination

- Tighter integration between T&D
- Tighter coordination with Planning



Transmission Site Modeling

- Modeled as actual generators in the network and generation applications
- Dedicated stations tapped from Transmission facilities
- Receive Real-Time telemetry with 4-Second scan rate data for all sites
- Sites receive a voltage schedule
- Can be regulated down like other Transmission resources



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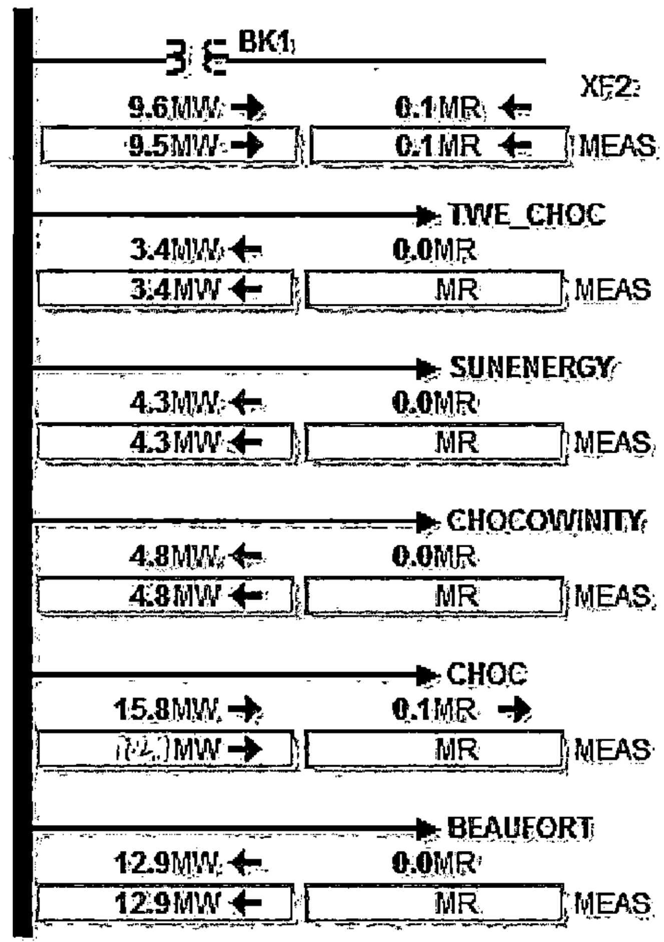
Distribution Site Modeling

- Modeling everything ≥250 kW as negative loads in the network model
- Tapped from Distribution feeders (existing or express)
- Receive Real-Time telemetry with 30-Second scan rate data for most sites
- All modeled resources are aggregated as a single value and included in the system load
- Helps State Estimator performance for site output



Data Requirements

Real-time power flow analysis requirements

- Generation and load values
- Net Interchange data
- Some generator bus voltages
- Topology

This data comes from the state estimation process that uses

- Real-Time measurements
- Some Statistics and
- Modeling assumptions

To support accurate state estimation and power flow results these inputs need to be as accurate as possible

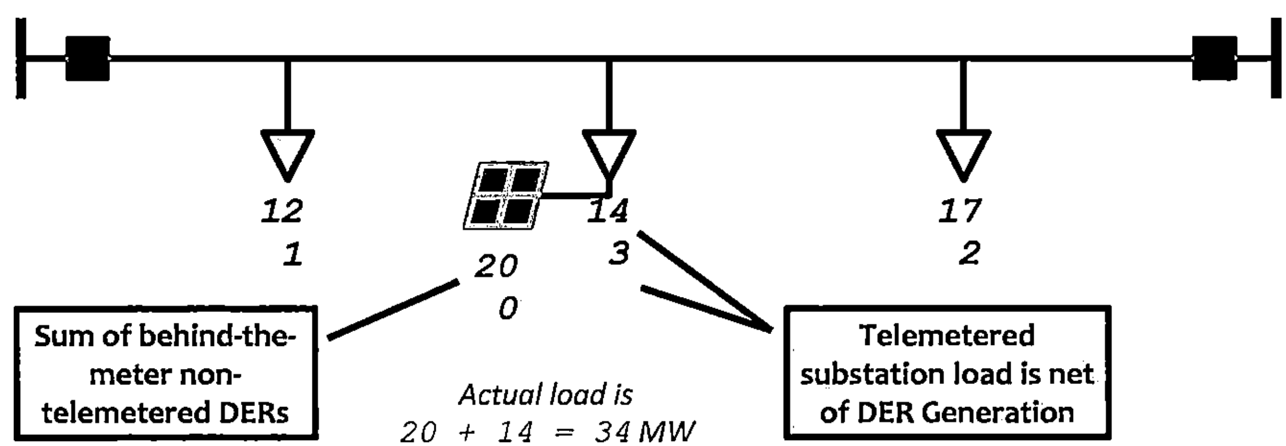
All because we asked ourselves “I wonder what happens if…?”

State Estimation Challenges

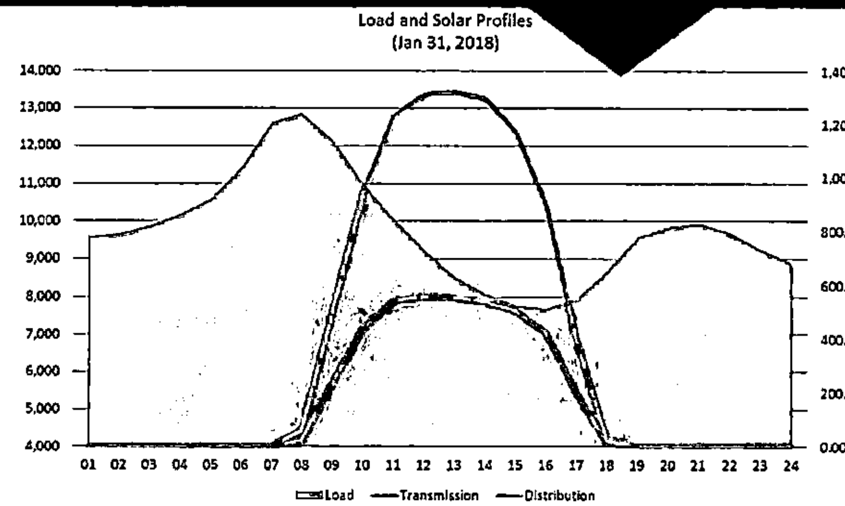
Just because a substation is not feeding power into the transmission network, does not mean it is not impactful

If the load and DER are not separated

- State Estimation will limit the amount they can change based on statistics
- Scaling an injection as gross load will result in an incorrect P/Q result



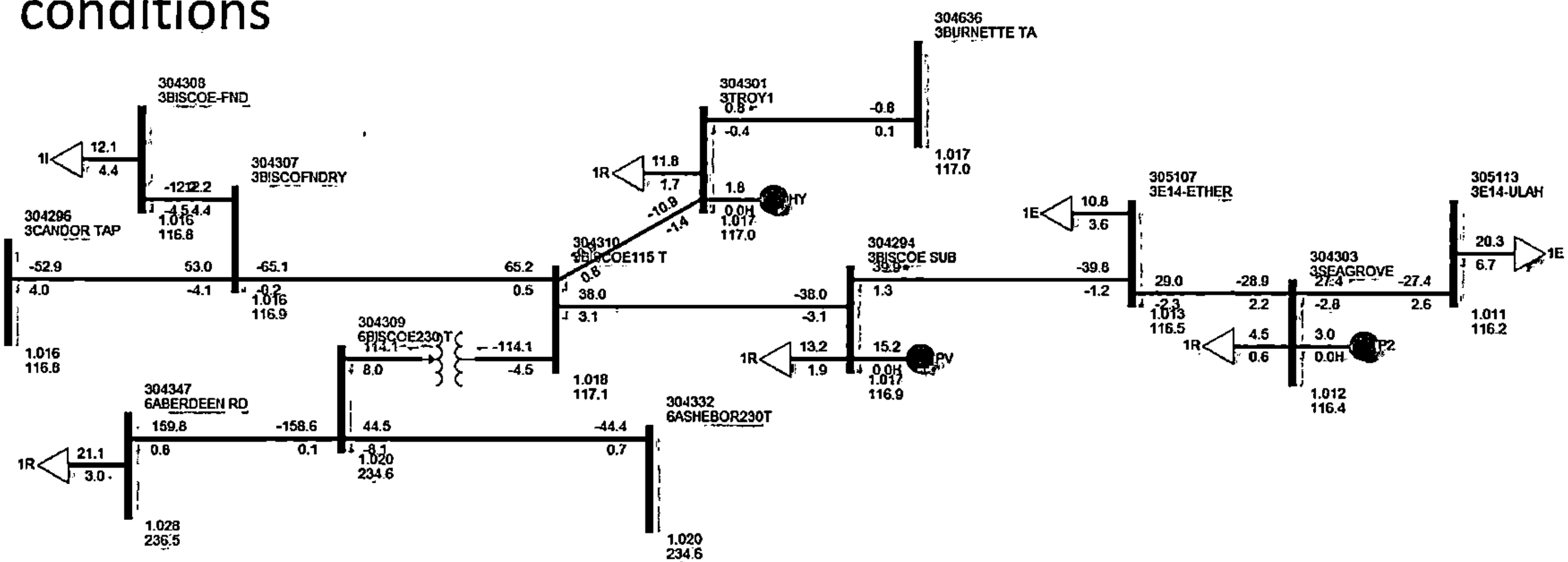
SI



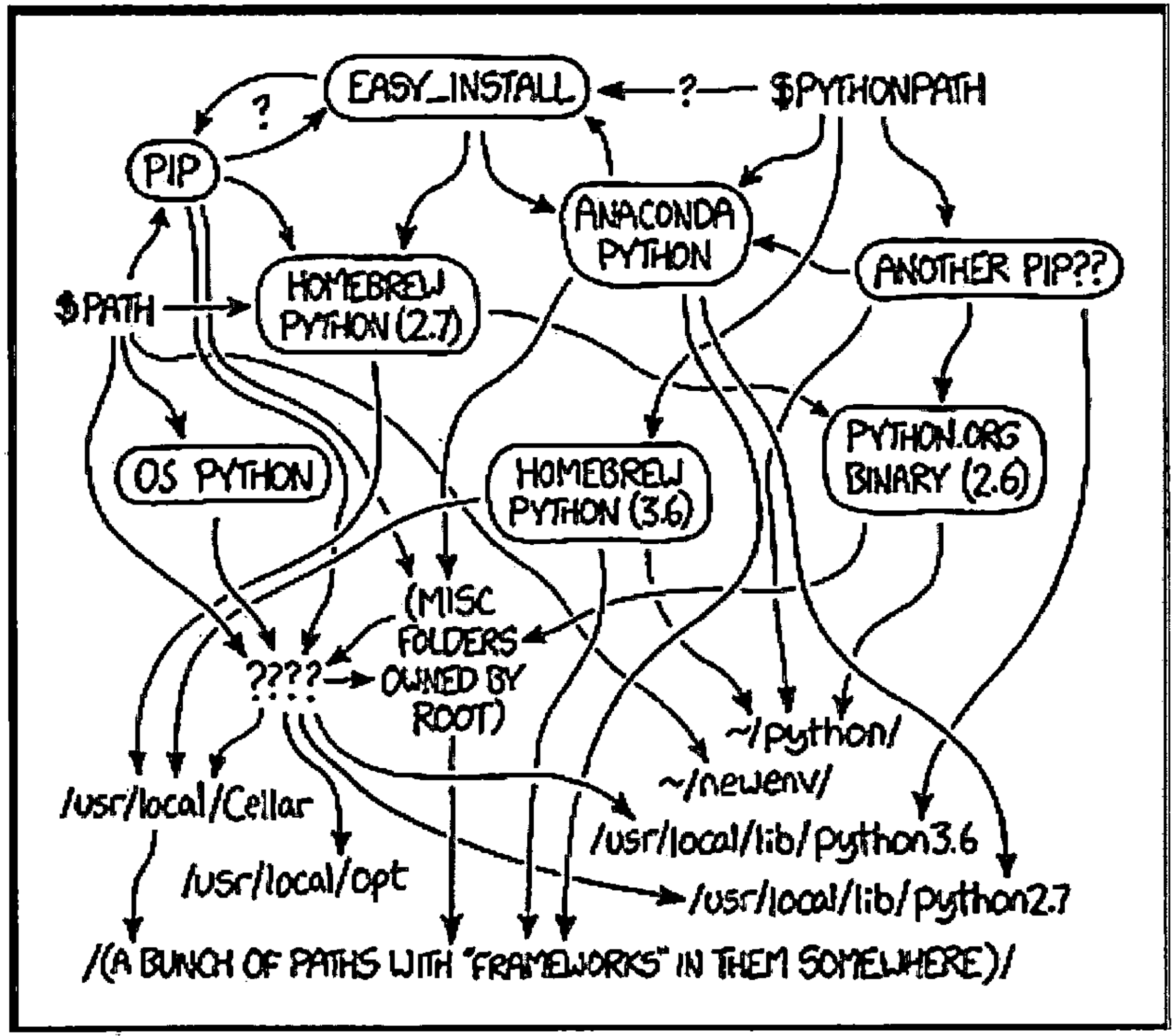
- Solar injection profiles are not coincident with load profiles
  - Affects the statistical results in state estimation
  - Requires segregation of generation from load
- Separation of generation from load improves
  - State estimation statistics, and thus power flow and contingency analysis accuracy
  - Control and granularity of power flow studies as load and generation can be altered independently

Transmission Power Flow Studies

- The resources are distributed in the model as they are in reality
- Injections from these resources drive local area power flows
- Failure to study them this way will result in unexpected loading conditions

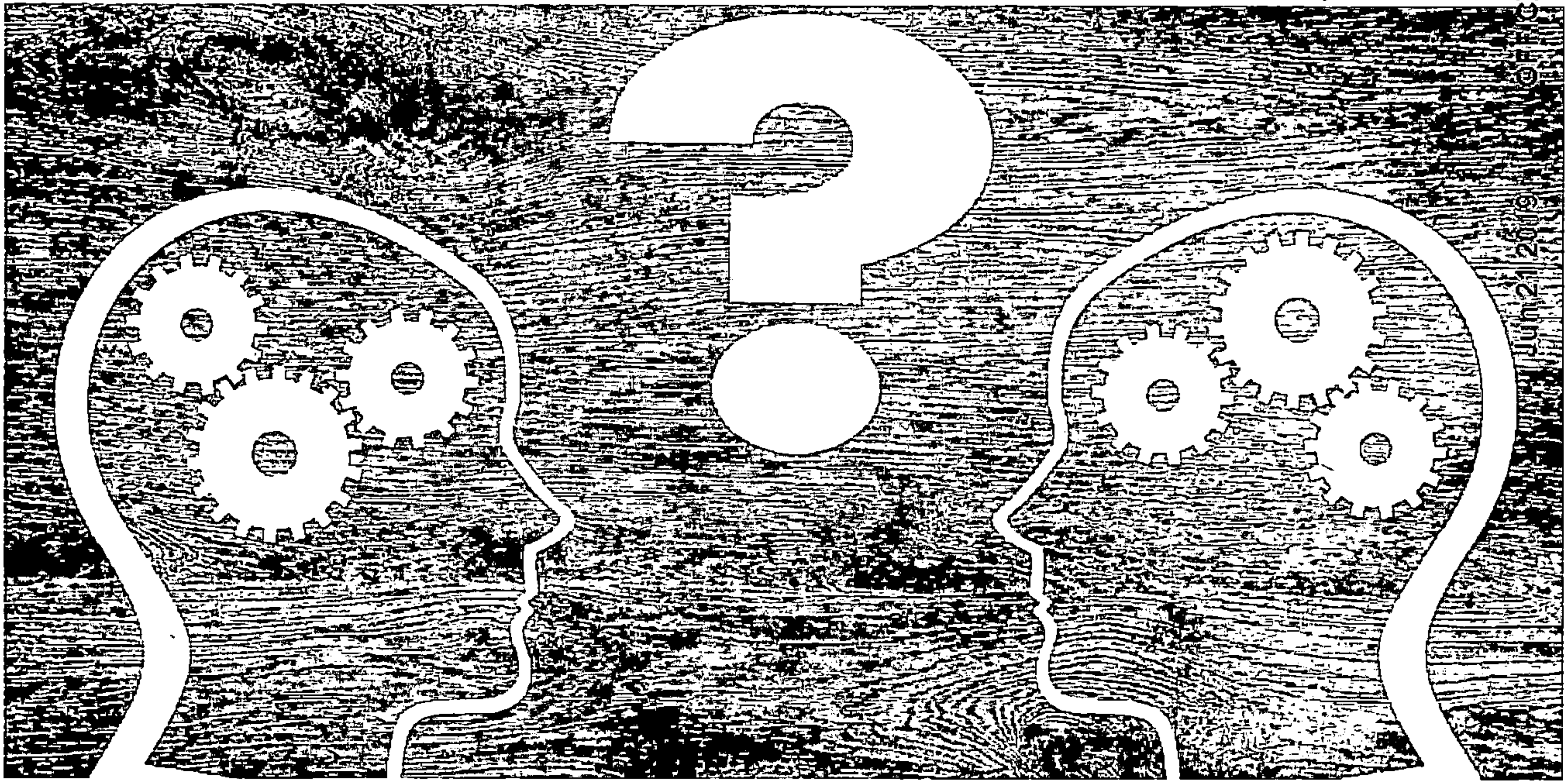


Our Design


EASY_INSTALL
?
$PYTHONPATH
?
PIP
ANACONDA PYTHON
$PATH
HOMEBREW PYTHON (2.7)
ANOTHER PIP??
OS PYTHON
HOMEBREW PYTHON (3.6)
PYTHON.ORG BINARY (2.6)
(MISC FOLDERS OWNED BY ROOT)
????
~/python/
~/newenv/
/usr/local/Cellar
/usr/local/lib/python3.6
/usr/local/opt
/usr/local/lib/python2.7
/(A BUNCH OF PATHS WITH "FRAMEWORKS" IN THEM SOMEWHERE)/

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Questions



CERTIFICATE OF SERVICE

I certify that a copy of the foregoing *Direct Testimony and Exhibits of Brendan Kirby*, as filed today in Docket No. E-100, Sub 158, was served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 21st day of June, 2019.

/s/ Maia Hutt
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Southern Environmental Law Center
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Attorney for SACE

Public Staff Kirby
Cross Examination Exhibit No. 1

/A

IDAHO POWER
An IDACORP Company

Wind Integration Study Report

Idaho Power, 1221 W Idaho Street, Boise, Idaho 83702

February 2013

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Executive Summary

As a variable and uncertain generating resource, wind generators require Idaho Power to modify power system operations to successfully integrate such projects without impacting system reliability. The company must build into its generation scheduling extra operating reserves designed to allow dispatchable generators to respond to wind's variability and uncertainty.

Idaho Power, similar to much of the Pacific Northwest, has experienced rapid growth in wind generation over recent years. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 megawatts (MW) of nameplate capacity. The rapid growth in wind generation is illustrated in Figure 1.

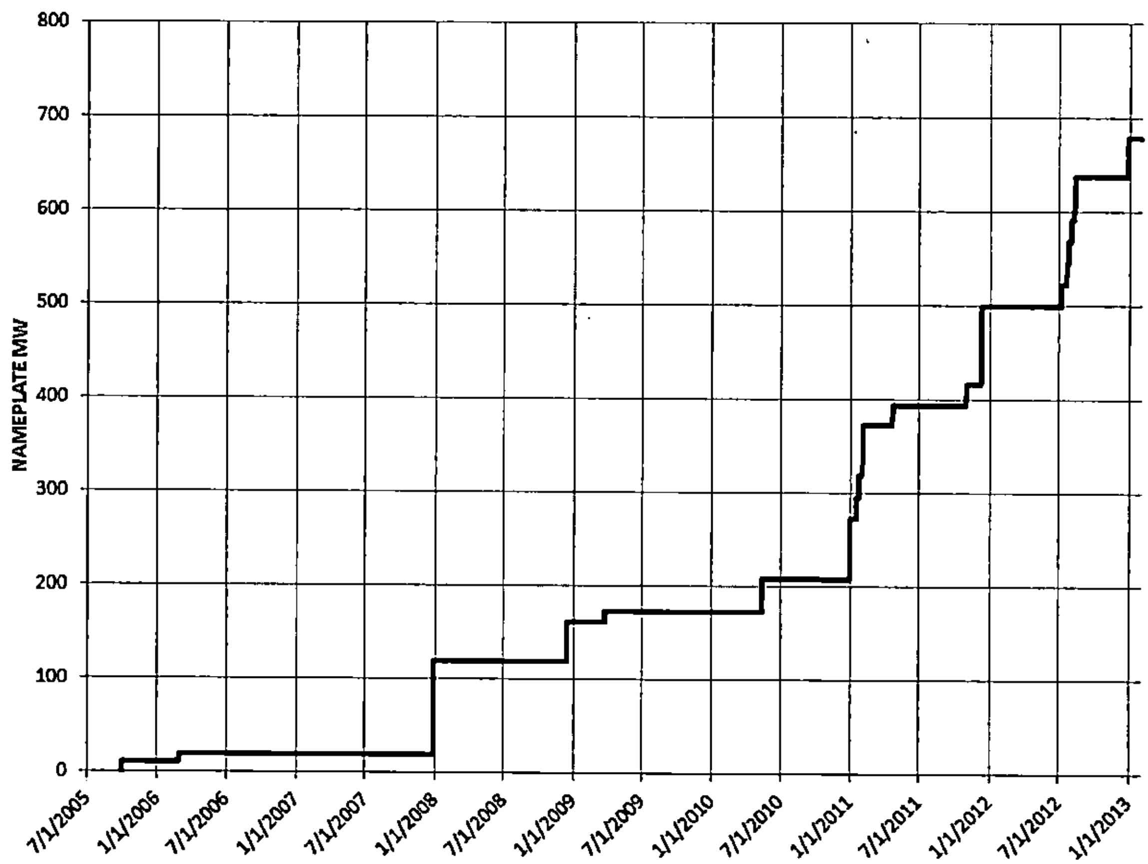

Figure 1 Installed wind capacity connected to the Idaho Power system

This rapid growth has led to the recognition that Idaho Power's finite capability for integrating wind is nearing depletion. Even at the current level of wind penetration, dispatchable thermal and hydro generators are not always capable of providing the balancing reserves necessary to integrate wind. This situation is expected to worsen as wind penetration levels increase.

Balancing Reserves

This investigation quantified wind integration costs for wind installed capacities of 800 MW, 1,000 MW, and 1,200 MW. Synthetic wind generation data and corresponding day-ahead wind generation forecasts at these build-outs were provided by Energy Exemplar (formerly PLEXOS

Solutions) and 3TIER. Based on analysis of these data, the following monthly balancing reserves requirements were imposed in system modeling.

Table 1 Balancing reserves requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for on-line generating capacity that can be turned down in response to a wind up-ramp. The balancing reserves requirements assume a 90 percent confidence level and thus are designed to cover deviations in wind relative to forecast except for extreme events comprising 5 percent at each end.

Study Design

The study employed the following two-scenario design:

- Base scenario for which the system was not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system was burdened with the incremental balancing reserves necessary for integrating wind

System simulations for the two scenarios were identical, except that generation scheduling for the test scenario included the condition that dispatchable thermal and hydro generators must provide the appropriate amount of incremental balancing reserves. Having the prescribed balancing reserves positions these generators such that they can respond to changing wind.

System simulations were conducted for a 2017 test year. Customer demand for 2017, as projected for the *2011 Integrated Resource Plan* (IRP), was used in system modeling. To investigate the effect of water conditions on wind integration, the study also considered Snake River Basin stream flows for three separate historic years representing low (2004), average (2009), and high (2006) water years.

Wind Integration Costs

The integration costs in Table 2 were calculated from the system simulations.

Table 2 Wind integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Simulations with the proposed Boardman to Hemingway transmission line were also performed, yielding the results in Table 3.

Table 3 Wind integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Curtailment

The study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Under these circumstances, curtailment of wind generation is often necessary to maintain balance. Modeling demonstrates that the frequency of curtailment is expected to accelerate greatly beyond the 800 MW installed capacity level. While the maximum penetration level cannot be precisely identified, study results indicate wind development beyond 800 MW is subject to considerable curtailment risk. Importantly, curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were assumed to not be made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 2.

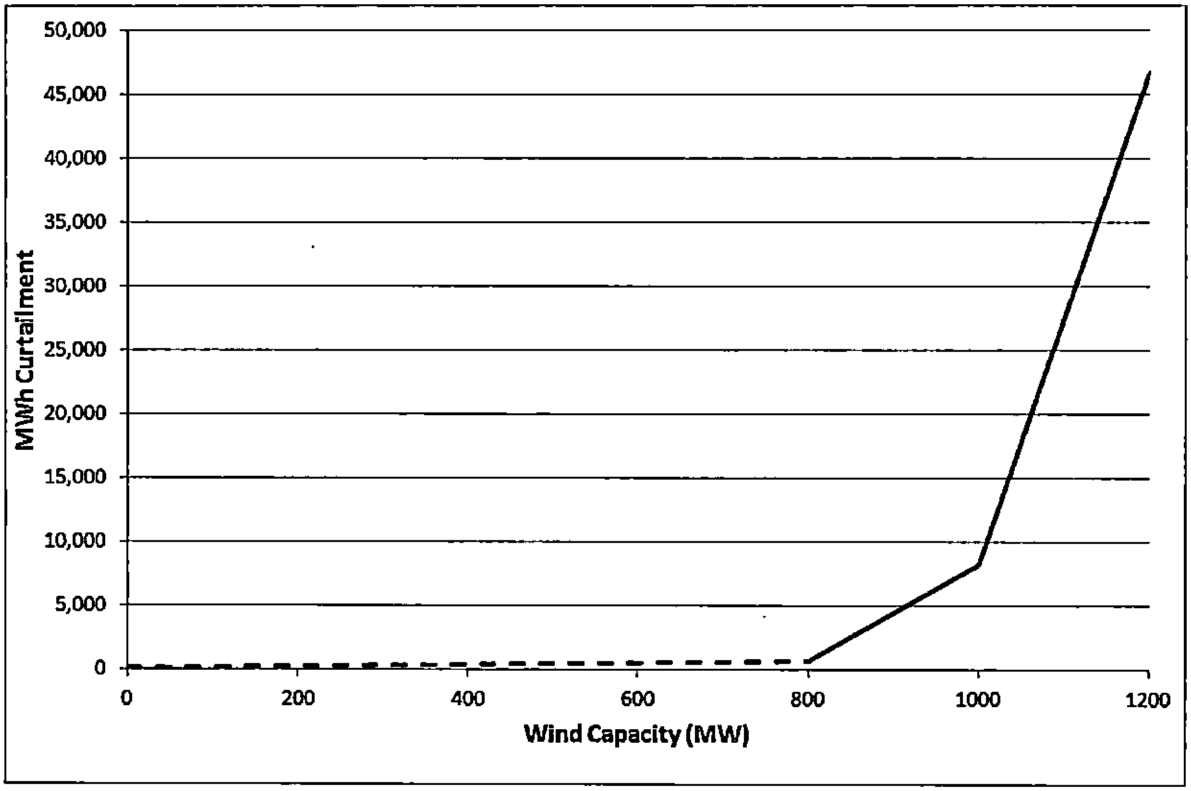

Figure 2 Curtailment of wind generation (average annual MWh)

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 2 and 3 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 2 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[1].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 3 below. The incremental integration costs are summarized in Table 4.

[1] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

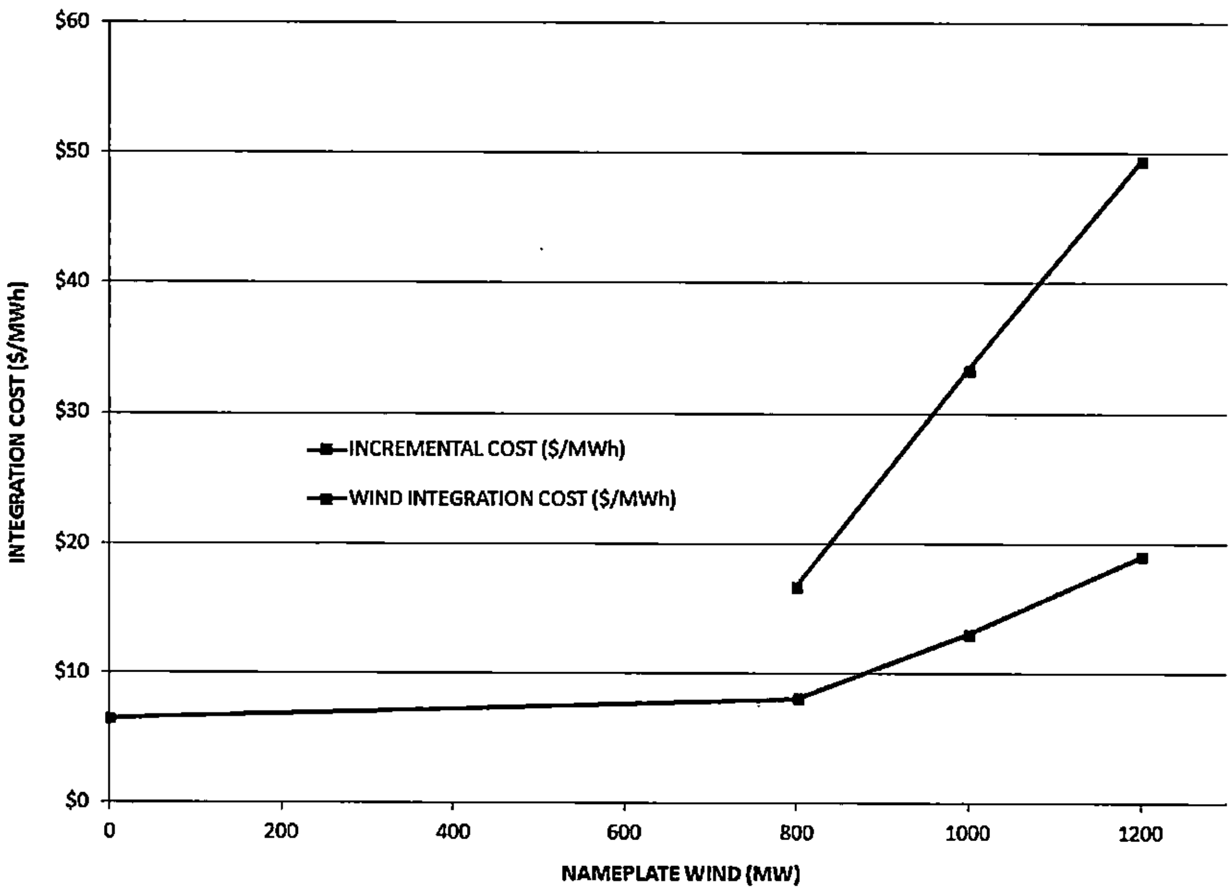

Figure 3 Integration costs with incremental integration costs ($/MWh)

Table 4 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

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INTRODUCTION

Electrical power generated from wind turbines is commonly known to exhibit greater variability and uncertainty than that from conventional generators. Because of the incremental variability and uncertainty, it is widely recognized that electric utilities incur increased costs when their systems are called on to integrate wind power. These costs occur because power systems are operated less optimally to successfully integrate wind generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the unique modifications it must make to power system operations to integrate the rapidly expanding amount of wind generation connecting to its system. The purpose of this report is to describe the operational modifications taken to integrate wind and the associated costs. The study of these costs is viewed by Idaho Power as an important part of efforts to ensure prices paid for wind power are fair and equitable to customers and generators alike.

Idaho Power first reported on wind integration in 2007. While there was a sizable amount of wind generation under contract in 2007, the amount of wind actually connected to the Idaho Power system at the time of the first study report was just under 20 MW nameplate. Over recent years, the amount of wind generation connected to the Idaho Power system has sharply risen. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 MW nameplate. The rapid growth in wind generation is illustrated in Figure 4.

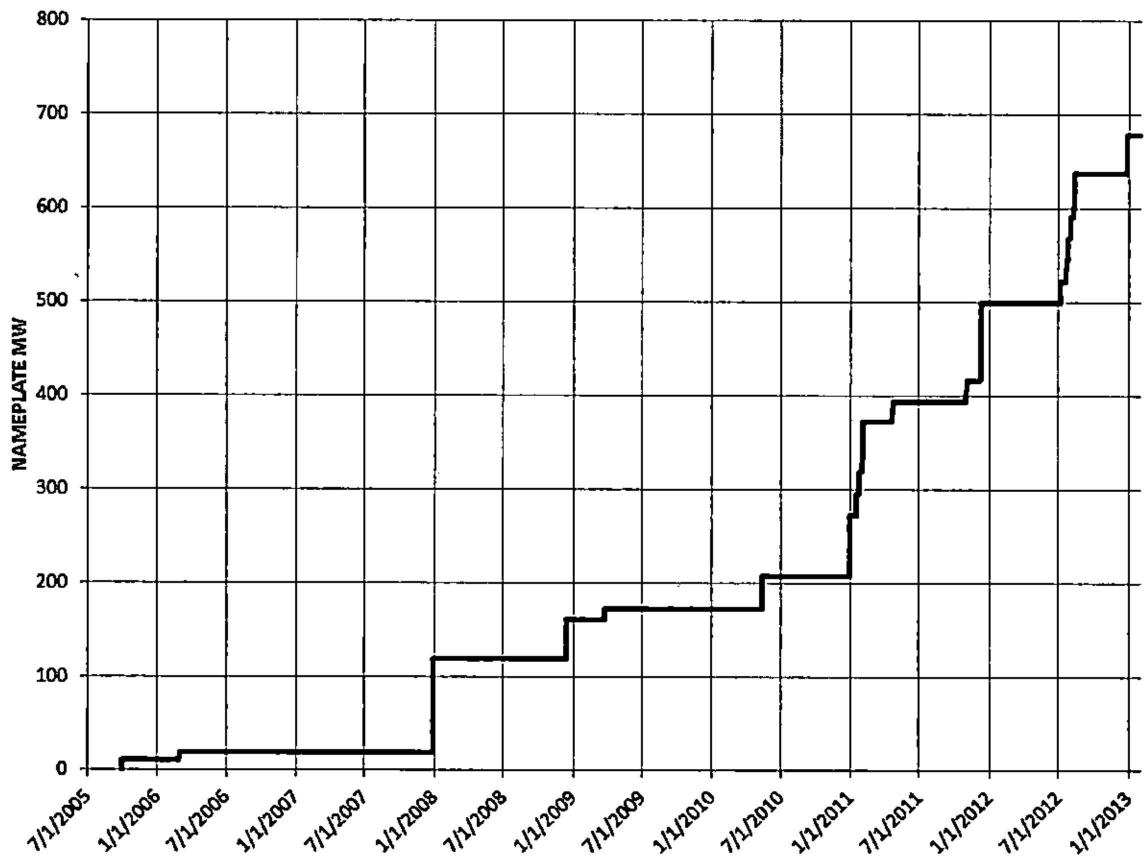

Figure 4 Installed wind capacity connected to the Idaho Power system (MW)

The steep upturn in wind generation has driven Idaho Power to expand its area of concern beyond the operational costs associated with wind integration to the consideration of the maximum wind penetration level its system can reliably integrate. Thus, the objective of the Idaho Power wind integration study is to answer the following two questions:

- What are the costs of integrating wind generation on the Idaho Power system?
- How much wind generation can the Idaho Power system accommodate without impacting reliability?

A critical principle in the operation of a bulk power system is that a balance between generation and demand must generally be maintained. Power system operators have long studied the variability and uncertainty present on the demand side of this balance, and as a matter of standard practice carry operating reserves on dispatchable generators designed to accommodate potential changes in demand. The introduction of significant wind power causes the variability and uncertainty on the generation side of the balance to markedly increase, requiring power system operators to plan for carrying incremental amounts of operating reserves, in this case necessary to accommodate potential changes in wind generation.

For the purposes of this study report, the term *balancing reserves* is used to denote the operating reserves necessary for integrating wind. A document review on wind integration indicates a variety of terms for this quantity. Regardless of term, the property being described is generally the flexibility a balancing authority must carry to reliably respond to variability and uncertainty in wind generation and demand.

A key component in the study of wind integration, as well as the successful in-practice operation of a power system integrating wind, involves the estimation of the additional balancing reserves dispatchable generators must carry to allow the balance between generation and demand to be maintained. Thus, three essential objectives of this report are to describe the analysis performed by Idaho Power to estimate the incremental balancing reserves requirements attributable to wind generation, describe the power system simulations conducted to model the scheduling of the reserves, and estimate associated costs. The study also evaluates situations where the incremental wind-caused balancing reserves exceed the capabilities of Idaho Power's dispatchable generators, putting the system in a position where it cannot accept additional output from wind generators without compromising reliability.

Technical Review Committee

Idaho Power held a public workshop on April 6, 2012, to discuss its work on wind integration. This workshop included a discussion of methodology and preliminary results, as well as a question and answer session. Following the workshop, the company began working with a technical review committee comprised of individuals selected by Idaho Power based on their knowledge of regional issues surrounding wind generation and the operation of electric power systems.

The following members agreed to serve on the committee:

- Ken Dragoon (Ecofys/Northwest Power and Conservation Council)
- Kurt Myers (Idaho National Laboratory [INL])
- Frank Puyleart (Bonneville Power Administration [BPA])
- Rick Sterling (Idaho Public Utilities Commission [IPUC])

The purpose of the work with the technical review committee was to describe in greater detail the study methodology, including an in-depth review of the model used for system simulations for the study. Given this information, the company asked the members of the committee for their specific comments upon release of this wind integration study report. These comments will be specially noted as having been provided by the technical review committee on the basis of its in-depth review of study methods.

Energy Exemplar Contribution

Idaho Power contracted with Energy Exemplar (formerly PLEXOS Solutions) for assistance with the wind integration study. Energy Exemplar's involvement was critical in the development of the wind generation data used for the study, particularly in the development of representative wind generation forecasts used in the analysis to estimate appropriate balancing reserves requirements. Energy Exemplar was also instrumental in the design of the study methodology, providing key counsel in the formulation of the two-scenario study design detailed later in this report.

With respect to system simulations for the wind study, Idaho Power has developed considerable expertise modeling the power system over recent years. In parallel with the Energy Exemplar efforts, Idaho Power developed a model that optimizes the wind, hydro, and thermal generation production. This internally-developed model was used for system simulations included in the wind study.

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Idaho Power System Overview

Idaho Power serves approximately 500,000 customers in southern Idaho and eastern Oregon through the operation of a diversified power system composed of supply- and demand-side resources, as well as significant transmission and distribution infrastructure. From the supply-side perspective, Idaho Power relies heavily on generation from 17 hydroelectric plants on the Snake River and its tributaries. These resources provide the system with electrical power that is low-cost, dependable, and renewable. Idaho Power also shares joint ownership of three coal-fired generating plants and is the sole owner of three natural gas-fired generating plants, including the recently commissioned Langley Gulch Power Plant. With respect to demand-side resources, Idaho Power has received recognition for its demand response programs, particularly the part these dispatchable programs have played in meeting critical summertime capacity needs. Finally, Idaho Power maintains an extensive system of transmission and distribution resources, allowing it to connect to regional power markets, as well as distribute power reliably at the customer level.

Hydroelectric Generating Projects

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 970 average megawatts (aMW), or 8.5 million megawatt hours (MWh), under median water conditions. The backbone of Idaho Power's hydroelectric system is the Hells Canyon Complex (HCC) in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability. The capability to respond to varying load is increasingly being called on to regulate the variable and uncertain delivery of wind generation.

Hydro is Idaho Power's wind integration resource of choice because of its quick response capability as well as large response capacity. However, the capacity of the hydro system to respond to wind variability is recognized as finite; power-system operation, in practice and as simulated for this study, indicates the hydro system is not always able to sufficiently provide the balancing reserves needed for responding to wind. Using the hydro system for wind integration also limits its availability for other opportunities. The costs of these lost opportunities are a significant part of wind integration costs.

For the wind integration study, the hydroelectric generators at the Brownlee and Oxbow dams were designated in the modeling as available for providing wind-caused balancing reserves. This is consistent with system operation in practice, where the generators at these projects are dispatched to provide the overwhelming majority of operating reserves. Under standard operating practice, the remaining hydroelectric generators of the Idaho Power system are not called on for providing operating reserves. Generators at the Lower Salmon, Bliss, and C. J. Strike plants are capable of some ramping for responding to intra-day variation in load. However, under certain flow conditions, the flexibility of the smaller reservoirs to follow even load trends is greatly diminished, and the facilities are operated strictly as run-of-river (ROR) projects.

Coal-Fired Generating Projects

Idaho Power co-owns three coal-fired power plants having a total nameplate capacity of 1,118 MW. With relatively low operating costs, these plants have historically been a reliable source of stable baseload energy for the system. The output from these plants over recent years is somewhat diminished because of a variety of conditions, including relatively high Snake River and Columbia River stream flows, lagging regional demand for electricity associated with slow economic growth, and an oversupply of energy in the region. Idaho Power is currently studying the economics of operating its coal-fired plants, specifically the cost effectiveness of plant upgrades needed for environmental compliance at the Jim Bridger and North Valmy coal plants. The Boardman coal plant in northeastern Oregon will not operate beyond 2020 and Idaho Power's 64 MW share of the plant will no longer be available to serve customer load.

Coal is one of the thermal resources Idaho Power uses to integrate wind generation. Unlike hydro, the fuel for the coal plants comes at a cost. These fuel costs, as well as the lost opportunities created by using the coal capacity to integrate wind, make up another part of the wind integration costs. The coal generators do not have the large range and rapid response provided by the hydro units.

Natural Gas-Fired Generating Projects

Idaho Power owns and operates four simple-cycle combustion turbines totaling 416 MW of nameplate capacity, and recently commissioned a 300 MW combined-cycle combustion turbine. The simple-cycle combustion turbines (located at Danskin and Bennett Mountain project sites) have relatively low capital costs and high variable operating costs. As a consequence of the high operating costs, the simple-cycle turbines have been historically operated primarily in response to peak demand events and have seldom been dispatched to provide operating reserves. Expansion of their operation to provide balancing reserves for integrating wind is projected to lead to a substantial increase in power supply costs.

Idaho Power commissioned in July 2012 the 300 MW Langley Gulch Power Plant. As a combined-cycle combustion turbine, this generating facility has markedly lower operating costs than the simple-cycle units and is consequently expected to be a critical part of the fleet of generators dispatched to provide balancing reserves for responding to variable wind generation.

Transmission and Wholesale Market

Idaho Power has significant transmission connections to regional electric utilities and regional energy markets. The company uses these connections considerably as part of standard operating practice to import and export electrical power. Utilization of these paths on a day-to-day basis is typically driven by economic opportunities; energy is generally imported when prices are low and exported when prices are high. Transmission capacity across the connections does not reduce system balancing reserves requirements. Thus, balancing reserves necessary for reliable power system operation in practice are provided by dispatchable generators. The wholesale power market, as accessed through regional transmission connections, is not able to provide balancing reserves.

Idaho Power's existing transmission system spans southern Idaho from eastern Oregon to western Wyoming and is composed of transmission facilities having voltages ranging from 115 kilovolts (kV) to 500 kV. The sets of lines transmitting power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between southern Idaho load centers such as Boise, Twin Falls, and Pocatello. Idaho Power's transmission system and paths are shown in Figure 5.

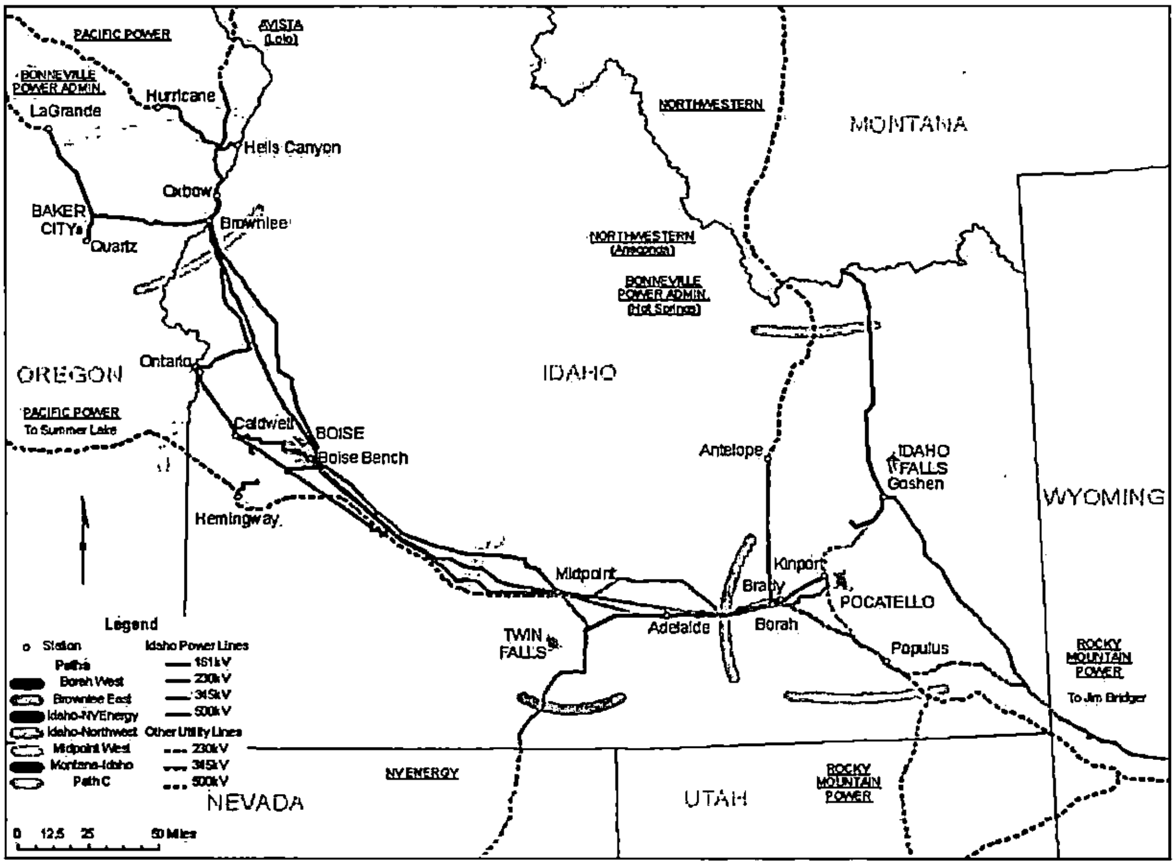

Figure 5 Idaho Power transmission paths

The critical paths from the perspective of providing access to the regional wholesale electricity market are the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. The Boardman to Hemingway transmission line identified by Idaho Power in the preferred portfolio of its 2011 IRP will be an upgrade to the Idaho-Northwest path. The combination of these paths provides Idaho Power effective access to the regional market for the economic exchange of energy.

While Idaho Power does not consider the regional market part of its day-to-day solution for integrating wind generation, it may be necessary during extreme events to use the regional transmission connections and rely on the regional energy market to accommodate wind. The company expects that at times even the regional market will be insufficient to integrate wind. During these times when Idaho Power and the regional market have insufficient balancing reserves to successfully integrate wind generation, it may be necessary to curtail wind, or even curtail customer load, to maintain electrical system stability and integrity.

Power Purchase Agreements

In addition to power purchases in the wholesale market, Idaho Power purchases power pursuant to long-term power purchase agreements (PPA). The company has the following notable firm wholesale PPAs and energy exchange agreements:

- Raft River Energy I, LLC—For up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033.
- Telocaset Wind Power Partners, LLC—For 101 MW (nameplate generation) from the Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.
- USG Oregon LLC—For 22 MW (estimated average annual output) from the Neal Hot Springs geothermal power plant located near Vale, Oregon. The contract term is through 2037 with an option to extend.
- Clatskanie People's Utility District—For the exchange of up to 18 MW of energy from the Arrowrock project in southern Idaho for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is January 1, 2010 through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

System Demand

Idaho Power's all-time system peak demand is 3,245 MW, set on July 12, 2012, and the all-time winter peak demand is 2,527 MW, set on December 10, 2009. An important characteristic of the Idaho Power system is the intra-day range from minimum to maximum customer demand, which during the summer commonly reaches 1,000 MW and occasionally exceeds 1,200 MW. Thus, generating resources that can follow this demand as it systematically grows during the day are critical to maintaining reliable system operation. Hydro generators, particularly those of the HCC, provide much of the demand following capability. Recent natural gas-fired resource additions are also instrumental in allowing the system to reliably meet system demand. An additional resource available to the system is the targeted dispatch of demand response programs. These demand-side programs have proven to dependably reduce system demand during extreme summer load events. From the perspective of system reliability, the nature of Idaho Power's customer demand places a premium on the value associated with capacity-providing resources; energy resources, such as wind, contribute markedly less towards promoting system reliability.

It is recognized that production from wind projects does not dependably occur in concert with peak customer demand. In fact, there is a tendency to experience periods during which production from wind and hydro facilities is high and customer demand is low. The coincidence of these circumstances leads to an excess generation condition, where the capability of system generators to reduce their output in response to wind is severely diminished. Such excess generation events have been observed in recent years by Idaho Power and other balancing authorities in the Pacific Northwest. System stability for the balancing authority is maintained during these events through the curtailment of generation, including that from wind-powered facilities.

System Scheduling

Idaho Power schedules its system with the primary objective of ensuring the reliable delivery of electricity to customers at the lowest possible cost. System planning is conducted for multiple time frames ranging from years/months in advance for long-term planning to hour-ahead for real-time operations planning. A fundamental principle in system planning is that each time frame should be driven by the objective of readying the system for more granular time frames. Long-term resource planning (i.e., the IRP) should ensure the system has adequate resources for managing customer demand over the 18-month long-term operations planning window. Long-term operations planning should position the system such that customer demand can be managed over the balance-of-month perspective. Balance-of-month planning should result in a system that can manage demand when scheduling generation day-ahead. Day-ahead scheduling should enable operators to meet demand from a real-time perspective. Finally, real-time energy schedulers should ensure the system is positioned hour-ahead such that reliable service is maintained within the hour.

With the possible exception of the IRP, the scheduling horizons considered by Idaho Power involve transacting with the regional wholesale market. Where the economic scheduling of system generation is insufficient to meet demand, Idaho Power enters into contracts to purchase power off-system through its transmission connections. Conversely, where economically scheduled generation exceeds customer demand, surplus power is sold into the market. Importantly, Federal Energy Regulatory Commission (FERC) rules (FERC order nos. 888/890) stipulate that surplus power sales are sourced by generating resources that have been undesignated from network load service. Undesignation of a variable generating resource, such as wind, for sourcing a third-party sales transaction results in the transacted energy being given a dynamic tag, where tag is the North American Electricity Reliability Corporation (NERC) term representing an energy transaction in the wholesale electricity market.
Balancing authorities experience considerable difficulty attracting a purchaser of dynamically tagged energy. Therefore, as a standard operating practice, Idaho Power sources off-system power sale contracts from its fleet of hydro and thermal generators. With their recognized level of dependability, hydro and thermal generators can be undesignated for sourcing surplus power sales while allowing conventional tagging procedures to be followed.

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STUDY DESIGN

Idaho Power designed its wind integration study with the objective of isolating in its operations modeling the effects directly related to integrating wind generation. A common study design used towards meeting this objective, and employed by Idaho Power for this study, is to simulate system operations of a future year with projected wind build-outs under the following two scenarios:

- Base scenario for which the system is not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system is burdened with the incremental balancing reserves necessary for integrating wind

A critical feature of this design is to hold equivalent model parameters and inputs between these two scenarios except for balancing reserves. The incremental balancing reserves built into the test scenario simulation necessarily result in higher production costs for the system, a cost difference that can be attributed to wind integration.

The test year selected by Idaho Power for its study is 2017. While in-service for the 500-kV Boardman to Hemingway transmission line is not anticipated before 2018, the study still considered scenarios to investigate the effects of the expanded transmission on wind integration costs. The study assumed customer demand and Mid-Columbia trading hub wholesale prices as projected for 2017 in the 2011 IRP.

As noted previously, as of January 2013 Idaho Power has 678 MW of nameplate wind capacity. Future wind penetrations considered in the study are 800 MW, 1,000 MW, and 1,200 MW of nameplate capacity. The synthetic wind data at these penetration levels, as well as representative day-ahead forecasts, were provided by 3TIER and Energy Exemplar. The synthetic wind data were provided for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for future projects. Further discussion of the study wind data and associated day-ahead forecasts is provided in a May 9, 2012 explanation released by the company (Appendix A).

To investigate the effect of water conditions on wind integration, the study considered Snake River Basin stream flows for three separate historic scenarios representing low (2004), average (2009), and high (2006) water years. Because of their importance in providing balancing reserves to integrate wind, the HCC projects were simulated using the study model to determine their hydroelectric generation under the selected water years. Generation for the remaining hydroelectric projects, which are not in practice called on to provide balancing reserves for integrating wind, was entered for the study as recorded in actual operations for the water years selected.

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BALANCING RESERVES CALCULATIONS AND OPERATING RESERVES

Critical to the two-case study design is the calculation of the incremental balancing reserves necessary for successfully integrating the future wind penetration build-outs considered. The premise behind these calculations is that Idaho Power's dispatchable generators must have capacity in reserve, allowing them to respond at an acceptable confidence level to the variable and uncertain delivery of wind. Estimates of the appropriate amount of balancing reserves were based on an analysis of errors in day-ahead forecasts of system wind for the wind build-outs considered in the study. In addition to the synthetic time series of hourly wind-generation data, 3TIER provided a representative day-ahead forecast of hourly wind generation. To provide a larger sampling, Energy Exemplar created 100 additional day-ahead forecasts having similar accuracy as the 3TIER forecast. Summaries of the synthetic wind data and day-ahead forecasts are included in Appendix B. An illustration of this design is given in Figure 6.

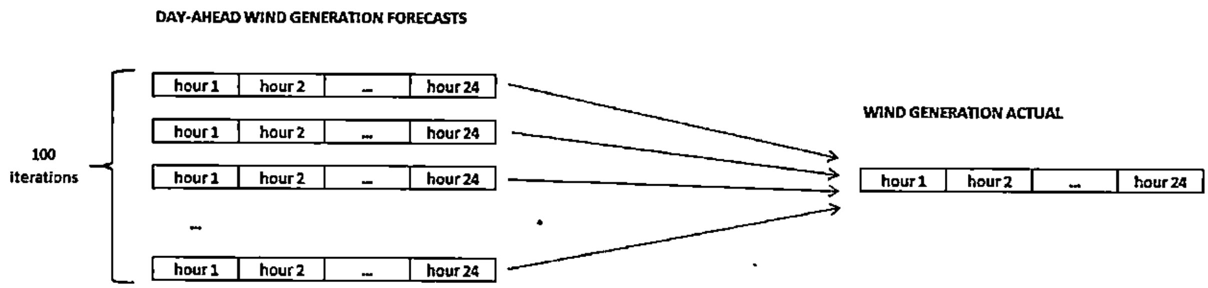

Figure 6 Wind-forecasting and generation data

In recognition of the seasonality of wind, the data were grouped by month, yielding balancing reserves estimates specific to each month. The sample size for each month was extremely large. As an example, for July there were 74,400 deviations between the day-ahead forecast and actual wind generation (100 forecasts × 31 days × 24 hours). The balancing reserves requirements were calculated as the bi-directional capacity covering 90 percent of the deviations. The use of the 90 percent confidence level for the wind integration analysis is consistent with the criterion used for hydro conditions in assessing peak-hour resource adequacy in integrated resource planning.

Figure 7 is an illustration of a full year of deviations for a single forecast iteration at the 1,200 MW penetration level. In this figure, the deviations on the positive side correspond to deviations where actual wind was lower than day-ahead forecast wind, while deviations on the negative side reflect instances where actual wind exceeded the forecast. Importantly, the balancing reserves requirements did not cover the full extent of the deviations, leaving extreme tail events in both directions uncovered.

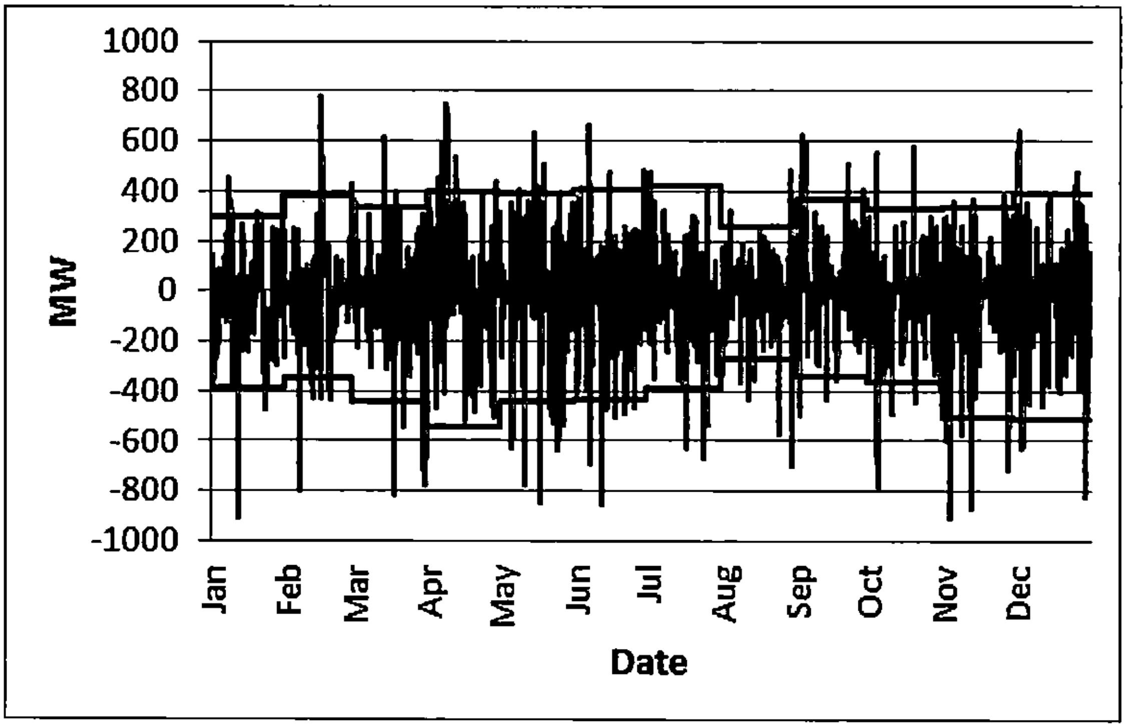

Figure 7 Deviations between forecast and actual wind generation with monthly balancing reserves requirements (MW)

The requirements are dynamic in that the forecast wind was taken into account in imposing the amount of balancing reserves. For example, the requirements suggest that for the 1,200 MW wind penetration level, 295 MW of unloaded generating capacity should be held as balancing reserves in January to guard against a drop in wind relative to the forecast. However, if the forecast wind generation is only 250 MW, then the most wind can drop relative to forecast is 250 MW, which is then the amount of balancing reserves built into the generation schedule. As a second example, if the forecast wind generation is 350 MW, the analysis of wind data indicates that balancing reserves should be held to guard against wind dropping to 55 MW. The likelihood of wind dropping below 55 MW is small (5 percent), and balancing reserves are not scheduled on dispatchable generators for covering a drop in wind to less than 55 MW.

The monthly requirements for balancing reserves are given in Table 5 for the wind penetration levels studied. The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for online generating capacity that can be turned down in response to a wind up-ramp.

Table 5 Balancing reserve requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

Balancing Reserves for Variability and Uncertainty in System Demand

As described previously, power system operation has long needed to hold bidirectional capacity for responding to variability and uncertainty in system demand. For the wind study modeling, Idaho Power imposed a balancing reserves requirement equal to 3 percent of the system demand as capacity reserved to allow for variability and uncertainty in load. This capacity was carried in equal amounts in the two scenarios modeled: the base scenario where the system was not burdened with wind-caused balancing reserves, and the test scenario where a wind-caused balancing reserves requirement was assumed necessary. For the test scenario modeling, the separate load- and wind-caused reserves components were added to yield the total bidirectional balancing reserves requirement. This approach for combining the reserves components is consistent with Idaho Power operations in practice for which system operators receive separate forecasts for wind and demand and combine the estimated uncertainty about these projections through straight addition.

Contingency Reserve Obligation

The variability and uncertainty in demand and wind are routine factors in power system operation and require a system to carry the bidirectional balancing reserves described in this section for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity for responding to system contingency events, which have traditionally been viewed as large and relatively infrequent system disturbances affecting the production or transmission of power (e.g., loss of a major generating unit or major transmission line).
System modeling for the wind study imposed a contingency reserve intended to reflect this obligation equal to 3 percent of load and 3 percent of generation, setting aside this capacity for both scenarios (i.e., base and test). The requirement to carry at least half of the contingency reserve obligation on generators that are spinning and grid-synchronized was also captured in the modeling.

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System Modeling

Idaho Power used an internally developed system operations model for this study. The model determines optimal hourly scheduling of dispatchable hydro and thermal generators with the objective of minimizing production costs while honoring constraints imposed on the system. System constraints used in the model capture numerous restrictions governing the operation of the power system, including the following:

- Reservoir headwater constraints
- Minimum reservoir outflow constraints
- Reservoir outflow ramping rate constraints
- Wholesale market activity constraints
- Generator minimum/maximum output levels
- Transfer capacity constraints over transmission paths
- Generator ramping rates

The model also stipulated that demand and resources were exactly in balance, and importantly that hourly balancing reserves requirements for variability and uncertainty in load and wind were satisfied. The incremental balancing reserves required for wind variability and uncertainty drove the production cost differences between the study's two cases.

Day-Ahead Scheduling

The hourly scheduling determined by the model was intended to represent the optimal day-ahead system dispatch. This dispatch schedule included generation scheduling for thermal and hydro generators, as well as market transactions. Key inputs to the generation scheduling were the forecasts for wind production and customer demand. These two elements of the generation/load balance commonly carry the greatest uncertainty for power system operation in practice. A fundamental premise of reliable operations for a balancing authority is the need to carry reasonable and prudent flexibility in the day-ahead generation schedule, allowing the system to respond to errors in demand and wind generation forecasts. This principle was built into the wind study modeling in the form of balancing reserves constraints the model must honor. In the two-case study design, the system modeling for the base case included constraints only for demand uncertainty, whereas constraints for the test case included the need to carry additional balancing reserves for wind uncertainty. The derivation of the balancing reserves constraints is described previously in this report.

The critical decision day-ahead generation schedulers must make involves how to schedule dispatchable generation units taking into account the following factors:

- Forecasts for demand and wind production
- Production from other non-dispatchable resources (e.g., PPAs)
- Production from ROR hydro resources
- Operating costs of thermal resources
- Water supply for dispatchable hydro resources

- Operating reserves for contingency events
- Flexibility in the schedule for dispatchable generation units allowing them to respond if necessary to deviations between forecast and actual conditions in load and wind

The essence of wind integration and the associated costs is that the amount of balancing reserves that must be carried is greater because of the uncertainty and variability of wind generation.

Demand and Wind Forecasts

The demand forecast used for the modeling was based on the projected hourly load used in the 2011 IRP for the calendar year 2017. The wind production forecast used for the modeling was based on the average of the 100 forecasts provided by 3TIER and Energy Exemplar.

The forecasts for both elements were identical between the study scenarios; the test scenario simply imposed greater balancing reserves constraints to allow for variability and uncertainty in the wind production forecast.

Transmission System Modeling

As noted in the Idaho Power System Overview section, the critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the wind-study modeling, the separate paths were combined to an aggregate path for off-system access. Every October, Idaho Power submits a request to secure firm transmission across its network based on its expected monthly import needs for the next 18 months. The maximum levels used in the modeling for firm import capacity were based on the October 2010 request. The modeling assumed additional import capacity using non-firm transmission. Non-firm imports were assessed a $50/MWh penalty designed to represent the less favorable economics associated with non-firm transmission and typical hourly pricing. The export limits were based on typical levels of outbound capacity observed in practice. The transmission constraints in Table 6 were used in the wind study modeling.

Table 6 Modeled transmission constraints (MW)

Month	Maximum Firm Import (MW)	Maximum Non-Firm Import (MW)	Maximum Export (MW)
January	179	300	500
February	35	300	500
March	0	300	500
April	0	300	500
May	320	300	500
June	262	300	500
July	149	300	500
August	230	300	500
September	217	300	500
October	0	300	500
November	113	300	500
December	325	300	500

Idaho Power's transmission network is a fundamental part of the vertically integrated power system, and allows the company to participate in the regional wholesale market to serve load or for economic benefit. However, Idaho Power does not view its transmission network with associated regional interconnections as a resource for providing balancing reserves allowing it to respond to variability and uncertainty in wind generation and customer demand. In the region, each balancing authority provides its own balancing reserves. Idaho Power provides its balancing reserves from company-owned dispatchable generation units (thermal and hydro).

Idaho Power also investigated scenarios with the 500-kV Boardman to Hemingway transmission line. For these scenarios, the maximum firm import constraint was increased by 500 MW during April through September and by 200 MW for the remainder of the year. The maximum export constraint was increased by 150 MW throughout the year. The following transmission constraints were used in the wind study modeling for the system with the proposed Boardman to Hemingway transmission line.

Table 7 Modeled transmission constraints—simulations with 500-kV Boardman to Hemingway transmission line (MW)

Month	Maximum Firm Import (MW)	Maximum Non-firm Import (MW)	Maximum Export (MW)
January	379	300	650
February	235	300	650
March	200	300	650
April	500	300	650
May	820	300	650
June	762	300	650
July	649	300	650
August	730	300	650
September	717	300	650
October	200	300	650
November	313	300	650
December	525	300	650

Overgeneration in System Modeling

At a fundamental level, the reliable scheduling of the power system is based on the following simple equation:

Forecast load=Forecast generation

An expanded form of this equation is as follows:

Forecast retail sales + Forecast wholesale sales

=

Forecast dispatchable generation + Forecast wind generation + Forecast other generation

In the expanded equation, dispatchable generation includes scheduled production from resources the balancing authority (i.e., Idaho Power) can vary at its discretion to achieve reliable and economic system operation. Built into this term of the equation is the bidirectional balancing reserves intended for use in case the forecasts for demand or wind generation are incorrect. The other generation in the expanded equation is the amount of energy that cannot be varied. This term includes minimum generation levels at baseload thermal plants, ROR hydro generation, and non-wind power purchased under contract.

At times, the left side of the equation can become very low; Idaho Power customer use is low and wholesale exports are capped by transmission capacity. During these times, providing the balancing reserves necessary for responding to wind, specifically for responding to wind up-ramps, is not possible without upsetting the balance between the two sides of this equation. In effect, the terms of the right side of the equation cannot be reduced enough to match the left. For these times, the wind study modeling assumed the wind, or potential wind, was excessive and could not be accepted; curtailment of wind energy was necessary to maintain balance. Further discussion of overgeneration and curtailment is provided in the following section.

RESULTS

As noted previously, the objective of this study is to answer two fundamental questions:

1. What are the costs of integrating wind generation for the Idaho Power system?

2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

Thus, the results produced by the study's system modeling were designed to address these two questions.

Wind Integration Costs

From a cost perspective, a comparison of annual production costs between two scenarios having different balancing reserves requirements—where the difference in balancing reserves is related to wind's variability and uncertainty—was used to estimate the costs of integrating wind. The production cost difference between scenarios was divided by the annual MWh of wind generation to yield an estimated integration cost expressed on a per MWh basis. The integration cost calculation is summarized as follows:

- Base scenario for which the system was not burdened with incremental balancing reserves necessary for integrating wind (wind integration is "not our problem", a theoretical case used as a benchmark for comparing costs)
- Test scenario for which the system was burdened with incremental balancing reserves necessary for integrating wind

The wind integration cost is the net-cost difference of the two scenarios divided by the MWh of wind generation (the amount of wind generation was the same in both scenarios):

$$\textit{Wind integration cost} = \frac{\textit{Test scenario net cost - Base scenario net cost}}{\textit{Wind generation in MWh}}$$

As noted earlier, the study included three water years and three wind penetration levels. These conditions are shown in Table 8.

Table 8 Wind penetration levels and water conditions

Wind Penetration Level (MW Capacity)	Water Year
800	Low (2004)
1,000	Average (2009)
1,200	High (2006)

A matrix of the wind integration costs on a per MWh basis is given in Table 9. These costs are based on a system without the proposed Boardman to Hemingway transmission line.

Table 9 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

The addition of the Boardman to Hemingway transmission line reduced integration costs slightly. Table 10 provides the wind integration costs for a system having the proposed Boardman to Hemingway transmission line.

Table 10 Integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 9 and 10 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 9 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[2].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 8 below. The incremental integration costs are summarized in Table 11.

[2] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

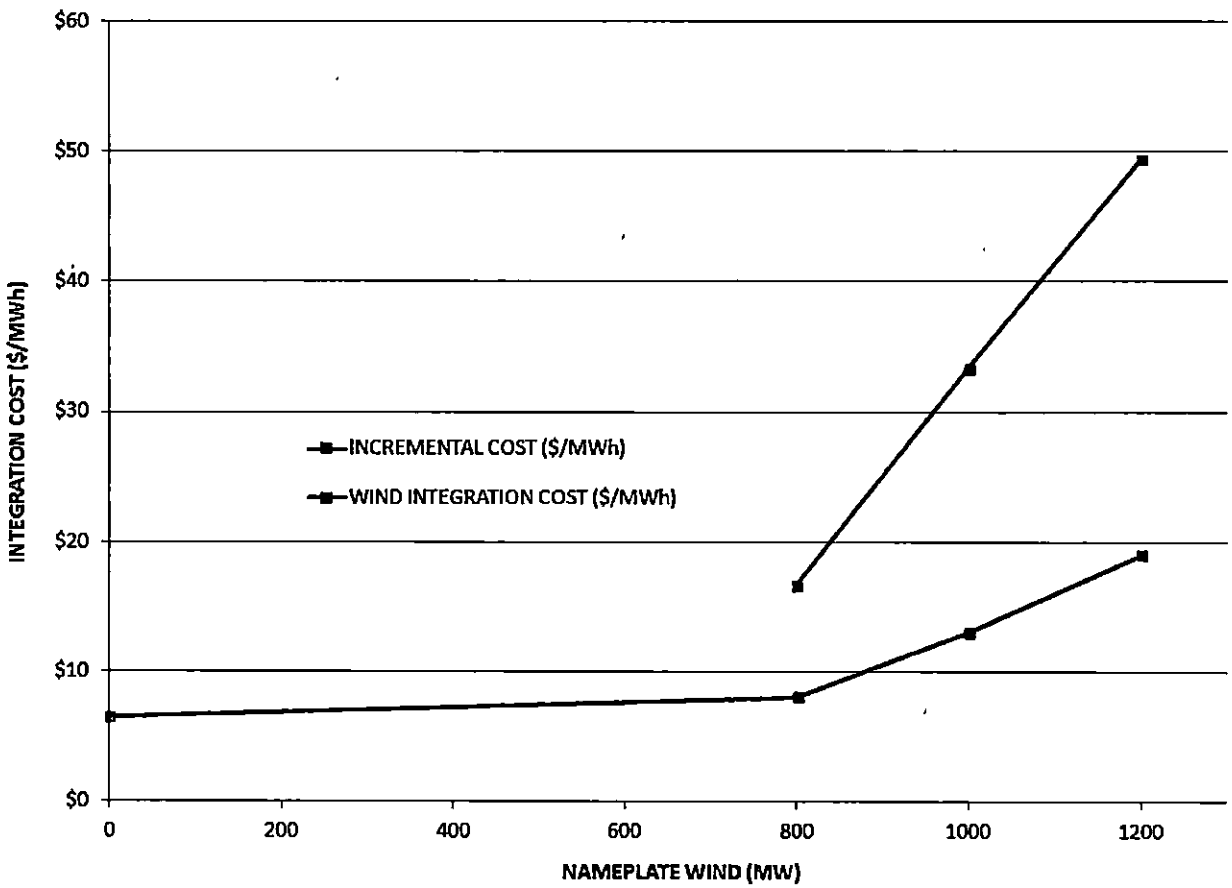

Figure 8 **Integration costs with incremental integration costs ($/MWh)**

Table 11 **Incremental wind integration costs ($/MWh)**

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

Spilling Water

The modeling suggests that providing balancing reserves to integrate wind leads to increased spill at the HCC hydroelectric projects. Spill is observed in actual operations during periods of high Brownlee Reservoir inflow coupled with minimal capacity to store water in the reservoir. Minimal storage capacity at Brownlee occurs when the reservoir is nearly full or when the reservoir level is dictated by some other constraint, such as a flood control restriction. Flow through the HCC cannot be significantly reduced during these periods; the three-dam complex is essentially operated as a ROR project during these high-flow periods. As a consequence, holding generating capacity in reserve for balancing purposes is frequently achieved only through increasing project spill, rather than reducing turbine flow. Table 12 provides the total incremental HCC spill in thousands of acre-feet (kaf) associated with integrating wind.

Table 12 Incremental Hells Canyon Complex spill (thousands of acre-feet)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	534 kaf	949 kaf	1,446 kaf
Low (2004)	33 kaf	93 kaf	255 kaf
High (2006)	2,101 kaf	2,698 kaf	2,916 kaf

Simulations for the high water condition (2006) with 800 MW of wind capacity provide a good illustration of the effect of wind integration on spill. Under the base scenario, the theoretical "not our problem" case, wind study system simulation shows spill totaling 3,590 kaf at Brownlee alone. For reference, this simulated spill is within 5 percent of the actual total Brownlee spill in 2006, which was about 3,800 kaf. By comparison, the total Brownlee spill under the test scenario, where integrating wind is Idaho Power's problem, is 4,475 kaf. The excess spill under the test scenario translates to about 185 gigawatt hours (GWh) of lost power production at Brownlee—energy that is no longer available for serving load or off-system sales.

Maximum Idaho Power System Wind Penetration

The capability of the Idaho Power system to integrate wind is finite. The rapid growth in wind capacity connecting to the system over recent years has heightened concern that the limits of this integration capability are being neared, and that development beyond these limits will severely jeopardize system reliability. The quantity of wind generation Idaho Power can integrate varies throughout the year as a function of customer load. During times of high load, Idaho Power can integrate more wind than during times of low load.

Modeling performed for the wind study has demonstrated the occurrence during low load periods where the balancing reserves necessary for responding to a wind up-ramp (i.e., generation that can be dispatched down in response to an increase in wind) cannot be provided without pushing the system to an overgeneration condition. Customer load for these periods, where load consists of sales to retail customers and to wholesale customers by way of regional transmission connections, is too low to allow for the integration of a significant quantity of wind. This situation requires curtailment of wind generation to maintain system balance. For the wind study modeling, the curtailed wind generation was removed from the production cost analysis and consequently did not affect the calculated integration cost. Curtailed wind was not integrated in the modeling and had no influence on the calculated integration costs. Not surprisingly, curtailment was found in the wind study modeling to have a strong correlation with customer load, water condition, and wind penetration levels. A summary of the amount of curtailment in the study is provided in Table 13.

Table 13 Curtailment of wind generation (annual MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	738 MWh	8,755 MWh	48,942 MWh
Low (2004)	204 MWh	3,494 MWh	29,574 MWh
High (2006)	890 MWh	12,519 MWh	61;557 MWh
Average	**611 MWh**	**8,256 MWh**	**46,691 MWh**

Figure 9 illustrates the projected exponential increase in curtailment as a function of the wind penetration level.

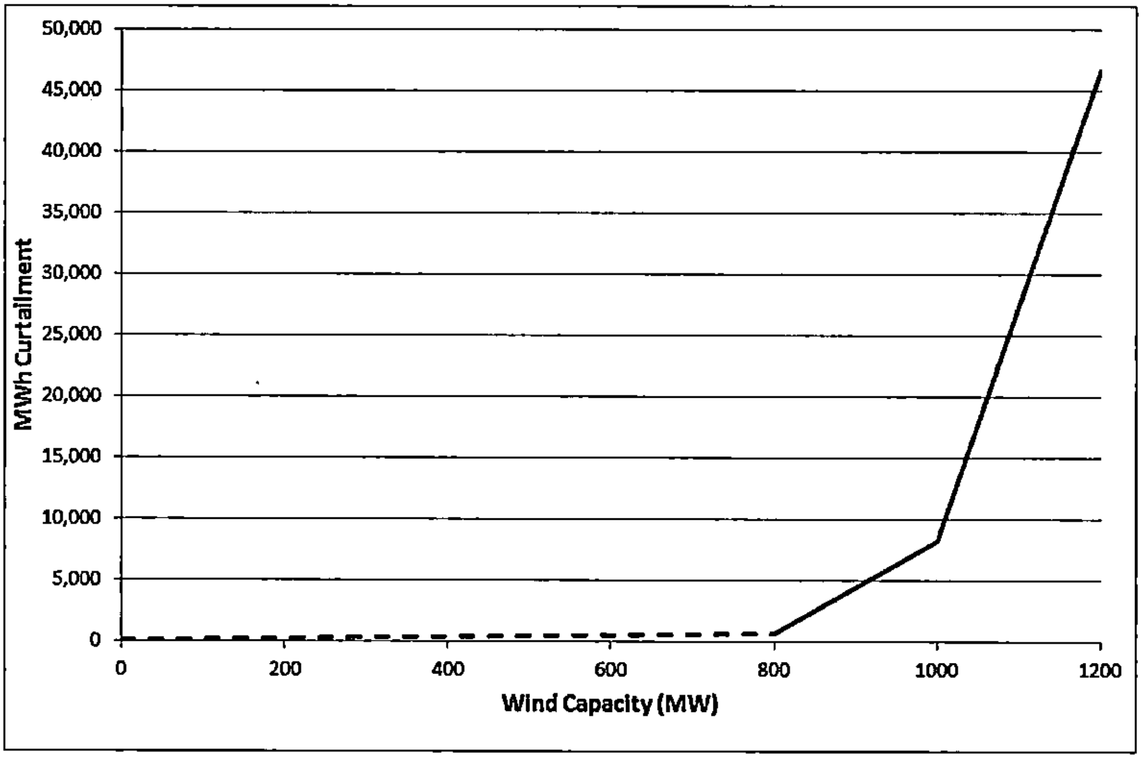

Figure 9 Curtailment of wind generation (average annual MWh)

A key feature of Figure 9 is the rapid acceleration of projected curtailment as installed wind capacity increases beyond the 800 MW level. The addition of 200 MW of installed wind capacity from 800 MW to 1,000 MW is projected to result in about 7,600 MWh of additional curtailment. Increasing the installed wind capacity 200 MW further to 1,200 MW is projected to result in another 38,000 MWh of curtailment. It is important to note the effect of a procedure for curtailment. Spreading the curtailed MWh over the full installed wind capacity of 1,200 MW results in a projected curtailment of about 1.5 percent of produced wind energy. However, if wind generators comprising the expansion from 1,000 MW to 1,200 MW are required under an established policy to shoulder the curtailment burden arising from their addition to the system, curtailment of their energy production is projected to reach nearly 8.5 percent.

The study results suggest that the occurrence of low load periods for which curtailment is necessary is likely to remain relatively infrequent for wind penetration levels of 800 MW or less. However, the results indicate that operational challenges are likely to grow markedly more severe with expanding wind penetration beyond 800 MW of installed nameplate capacity. The occurrence of low load periods for which balancing reserves cannot be provided without causing overgeneration is expected to become more frequent and require deeper curtailment of wind production. This is particularly true in that it is often necessary to maintain the operation of thermal (i.e., gas- and coal-fired) generators during periods of low load and high wind, in order to have the dispatchable generation from these resources available should customer loads increase or winds decrease.

Effect of Wind Integration on Thermal Generation

Idaho Power operates its coal resources to provide low-cost, dependable baseload energy. However, the study results suggest that the operation of the company's coal resources is likely to decrease on an annual basis with expanding wind penetration. The reduction in coal output is principally the result of displacement of coal generation by wind generation, as well as the displacement by flexible gas-fired plants required to help balance the variable and uncertain delivery of wind.

The operation of coal-fired generators has been affected by energy oversupply conditions over recent years in the Pacific Northwest. Coal plants have historically been operated less during periods of high hydro production, and maintenance is typically scheduled to coincide with spring runoff when customer demand is relatively low. However, the expansion of wind capacity over recent years in the region has caused overgeneration conditions to become more severe and longer lasting, leading to extended periods during which prices in the wholesale market have been very low or negative. The effect on coal plants has been a decline in annual energy production. However, during periods when customer load is high, such as during summer 2012, Idaho Power's coal fleet is consistently relied upon for energy to meet the high customer demand.

While the operation of baseload coal-fired power plants is expected to decline as a consequence of adding wind to a power system, this decline is offset by a marked increase in generation from gas-fired plants. The rapidly dispatched capacity from the gas-fired plants is widely recognized as critical to the successful integration of variable generation. Wind study modeling suggests that the need to dispatch gas-fired generators for balancing reserves is likely to displace the economic operation of coal-fired generators, particularly during times of acute transmission congestion.

This situation where relatively low-cost baseload resources are displaced by flexible cycling plants (i.e., gas-fired) is described in a 2010 NREL report (Denholm et al. 2010). Table 14 lists the annual generation from the wind study modeling for thermal resources for the case when Idaho Power is responsible for providing the balancing reserves and integrating the wind energy.

Table 14 Annual generation for thermal generating resources for the test case (GWh)

	Nameplate Wind		
Thermal Resource	**800 MW**	**1,000 MW**	**1,200 MW**
Coal-fired	7,568 GWh	7,291 GWh	6,851 GWh
Gas-fired	963 GWh	1,238 GWh	1,918 GWh

RECOMMENDATIONS AND CONCLUSIONS

Idaho Power has 678 MW of nameplate wind generation on its system. This is a growth in wind capacity of about 290 MW over the last two years, and 490 MW over the last three. The explosive growth in wind generation has heightened concerns that the finite capability of Idaho Power's system to integrate wind is being rapidly depleted. Because of these concerns, the objective of this investigation is to address not only the costs to modify operations to integrate wind, but also the wind penetration level at which system reliability becomes jeopardized. The questions that drove the investigation are the following:

1. What are the costs of integrating wind generation for the Idaho Power system?
2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

The study utilized a two-scenario design, with a base scenario simulation of operations for a system that was not burdened with incremental balancing reserves for integrating wind and a test scenario simulation for a system burdened with incremental wind-caused balancing reserves. Averaged over the three water conditions considered, the estimated integration costs are $8.06/MWh at 800 MW of installed wind, $13.06/MWh at 1,000 MW of installed wind, and $19.01/MWh at 1,200 MW of installed wind. A summary of the estimated costs is given in Table 15.

Table 15 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Importantly, the system modeling conducted for the study indicates a major determinant of ability to integrate is customer demand. This finding is not to be confused with the pricing of wind contracts and the wide recognition that wind occurring during low load periods is of little value. Instead, the study indicates that during periods of low load, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Modeling demonstrates that the frequency of these conditions is expected to accelerate greatly beyond the 800 MW installed capacity level, likely requiring a sharp increase in wind curtailment events. Even at current wind penetration levels, these conditions have been observed in actual system operations during periods of high stream flow and low customer demand. While the maximum penetration level cannot be precisely identified, study results indicate that wind development beyond 800 MW is subject to considerable curtailment risk. It is important to remember that curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were not made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 10.

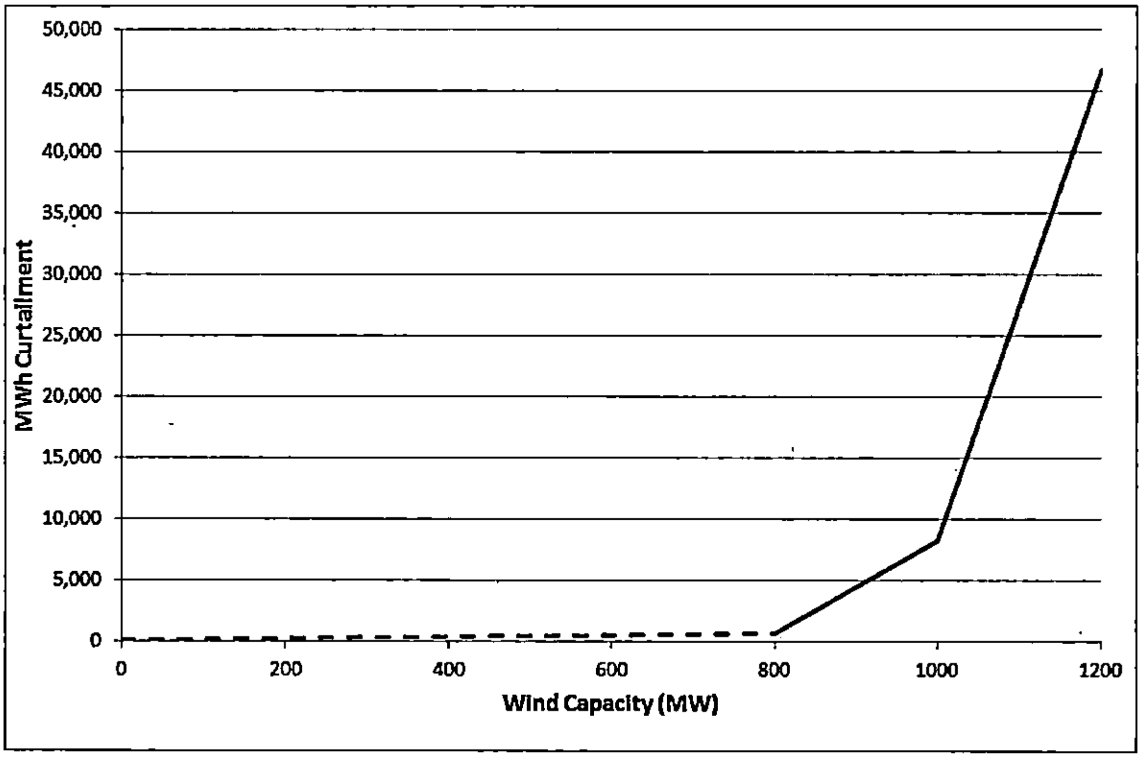

Figure 10 Curtailment of wind generation (average annual MWh)

Conversely, during periods of high customer demand, the dispatchable resources providing the balancing reserves for integrating wind are needed and thus are positioned at levels where they are ready to respond to changes in wind. While the costs to integrate wind still exist during these higher customer demand periods, the system can much more easily accommodate high levels of wind without impacting system reliability.

Issues Not Addressed by the Study

The focus of this study was the variability and uncertainty of wind generation. The study then established that these attributes of wind bring about the need to have balancing reserves at the ready on system dispatchable resources, and finally that having balancing reserves for integrating wind brings about greater costs of production for the system. A consideration not addressed by the study is the increased maintenance costs expected to occur for thermal generating units called on to frequently adjust their output level in response to changes in wind production or that are switched on and off on a more frequent basis. The effect of wind integration on these costs is likely to become evident and better understood with the expanded cycling of these thermal generators accompanying the growth in wind generation over recent years.

The control of system voltage and frequency is receiving considerable attention in the wind integration community. It is widely recognized that the addition of wind generation to a power system has an impact on grid stability. On some transmission systems, controlling system voltage and frequency during large ramps in generation within acceptable limits can be challenging. Idaho Power's system has not yet exhibited this problem at current wind penetration levels. However, growth in wind penetration beyond the current level will lead to greater challenges in maintaining system voltage and frequency within control specifications of the electric system, and likely increase the incidence of excursions where system frequency deviates from normal bands. The effects of frequency excursions may extend to customer equipment and operations.

Measures Facilitating Wind Integration

Idaho Power recognizes the importance of staying current as operating practices evolve and innovations enabling wind integration are introduced. Some changes in operating parameters include mechanisms such as Dynamic Scheduling System (DSS), ACE Diversity Interchange (ADI), and intra-hour markets. Further development of these measures will, to varying degrees, make it easier for balancing authorities to integrate the variable and uncertain delivery of wind generation. At this time, it is Idaho Power's judgment that the effect of these measures is not substantial enough to warrant their inclusion in the modeling performed for this study.

An additional measure that has been studied over recent years as a Western Electricity Coordinating Council (WECC) field trial is reliability-based control (RBC). The essential effect of RBC on operations is that a balancing authority is permitted to carry an imbalance between generation and demand if the imbalance helps achieve wider system stability across the aggregated balancing area of the participating entities. In effect, the balancing authority area is expanded, and the diversity of the expanded area allows an aggregate balance to be more readily maintained. Idaho Power has participated in the RBC field trial since the program's inception, and has recognized a resulting decrease in the amount of cycling required of generating units for balancing purposes. However, the effect of RBC was not included in the modeling for this study. This omission is in part related to the status of the program as a field trial, and related uncertainty regarding the structure of RBC in the future, or whether RBC will exist at all. Moreover, while RBC may allow balancing reserves-carrying generators to not respond to changes in load or wind in real-time operations, the scheduling of these generators must still include appropriate amounts of balancing reserves because it is not known at the time of scheduling to what extent an imbalance between generation and load will be permitted.

Future Study of Wind Integration

Idaho Power continues to grapple with new challenges associated with wind integration. The expansion in installed wind capacity over recent years has made the establishment of a best management plan for integrating wind problematic; the amount of installed wind simply keeps growing. It is commonly understood that wind does not always blow, leading to the legitimate concern about having backup capacity in place for when wind generators are not producing. Somewhat ironically, integration experience over recent years throughout the Pacific Northwest has led to heightened concerns about what to do when wind generators are producing and that production is not needed and unable to be stored in regional reservoirs because of minimal storage capacity, and the balancing reserves carried on dispatchable generators only add to the amount of unneeded generation. While it has been recognized that balancing reserves need to be carried for responding to wind up-ramps (i.e., balancing reserves need to be bidirectional), it has only recently become apparent that the Idaho Power system, and even the larger regional system, at times cannot provide these balancing reserves. This experience has shown that it is difficult to predict the integration challenges of tomorrow, but it is safe to say that there will be a need for continued analysis as additional tools, methods, and practices for integrating wind become available.

Idaho Power has experienced success in wind-production forecasting. The company has developed an internal forecast model which system operators are using with increasing confidence. It is likely that the future study of wind integration will make use of this forecast model, specifically in that its relative accuracy will ultimately lead to a reduction in the balancing reserves requirement for wind integration.

However, even accurate wind forecasting cannot eliminate the need for curtailment when wind generation creates a significant imbalance between load and generation.

Finally, the wider region beyond Idaho has added considerable wind capacity over recent years, much of the growth driven by requirements associated with state-legislated renewable portfolio standards. Most of the wind generation has been added outside of local or regional integrated resource planning efforts. The addition of this generating capacity has resulted in recurring energy oversupply issues for the region, a situation that has led the BPA to propose a protocol for managing oversupply (BPA 2013). Regional market prices during these oversupply periods have experienced pronounced declines to very low or even negative levels. Sometimes even the larger regional system and larger regional market cannot successfully integrate all of the wind energy that is produced. It is critical that future modeling for studying wind integration continues to capture the regional expansion of wind generation and its effect on the wholesale market.

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Appendix A. May 9, 2012, Explanation on wind data

WIND INTEGRATION WORKSHOP

STUDY WIND DATA EXPLANATION

MAY 9, 2012

Idaho Power received questions during the April 6 wind integration workshop related to the synthetic wind data used for its study of wind integration. The company recognizes the importance of using high-quality wind data, and consequently indicated at the workshop that it would thoughtfully review the wind data in an effort to address the questions raised. As stated at the workshop, the wind data used for the study were provided by 3TIER. 3TIER provided these data for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for purchase agreement. The 43 wind project locations are given as Attachment No. 3 to comments filed by Idaho Power with the IPUC on December 22, 2010[3]. It is important to note that 3TIER did not select from the more than 32,000 existing or hypothetical wind project sites used for the Western Wind and Solar Integration Study (WWSIS), but instead pulled new time series directly from the WWSIS gridded model data set precisely at the 43 locations requested by Idaho Power. **Thus, the geographic diversity of the synthetic wind data provided by 3TIER is representative of the geographic diversity for projects proposed to Idaho Power.**

3TIER also provided a synthetic day-ahead forecast for the wind generation time series. In providing this forecast, 3TIER notes that a bias found in the forecast during completion of the WWSIS was corrected on a site-by-site basis for the Idaho Power wind study, as opposed to the regional bias correction used for the WWSIS. The site specific correction is preferable to the regional correction because it mimics real forecasting practice, where project data at each site would be used to eliminate long-term bias from the forecast. With respect to accuracy of the synthetic day-ahead forecast, 3TIER reports that hourly wind speed forecast errors for ten operational sites in Idaho or neighboring states were compared to similarly calculated errors for the synthetic day-ahead forecast. 3TIER reports that this comparison yielded values for mean absolute error and root mean squared error for the synthetic day-ahead forecast only about 15% higher than equivalent statistics for the real errors at the ten operational sites in the Idaho vicinity. **This result suggests that the error characteristics of the synthetic forecasts are very similar to those of actual wind forecasts.**

To validate the synthetic actual wind time series, 3TIER has completed validation reports describing the results of comparisons between the synthetic wind data and public tower data. The complete set of validation reports for the WWSIS can be found through the NREL website[4]. Five of the validation towers are located in Idaho. Review of these reports indicates that the synthetic actual wind time series capture the seasonal and diurnal wind cycles fairly well; however, the synthetic time series are consistently low biased, at a 3TIER-reported average level of about -1.2 m/s at the five validation sites. There is basis in suggesting that the low bias, while reducing the total production of modeled wind projects, would have minimal impact on the overall variability of the synthetic actual wind time series, and would consequently have little effect on the estimated integration cost.

[3] Idaho Power Comments, Idaho Public Utilities Commission Case GNR-E-10-04, Attachment No. 3.

[4] http://wind.nrel.gov/public/WWIS/ValidationReports/wwis_vrpts.html#vmap

However, Idaho Power recognizes the critical nature of the synthetic wind data used for the study, and will discuss this low bias further with the technical review committee it has formed.

Finally, the synthetic actual wind time series created for the WWSIS have been found to exhibit excessive ramping as described in the WWSIS final report and as reported by NREL[5]. The excessive ramping in the WWSIS wind data occurs because the mesoscale model used to generate the synthetic wind data was run in 3-day sections. Smoothing techniques were used to reduce the ramping across the seam at the end of each third day; however, 3TIER reports that excessive variability remains in the WWSIS wind data. 3TIER also reports that review of the synthetic actual wind time series data pulled for the Idaho Power study indicates similar excessive ramping, with ramps tending to be 1.5 to 2.0 times larger from two hours before to eight hours after the start of every third day. While Idaho Power intends to discuss this condition with its technical review committee, the company believes that only a small fraction of hours are affected, and that consequently the impacts on integration cost are likely small.

Idaho Power hopes that this follow-up helps to address questions on the wind data raised at the April 6 workshop. We value the questions and feedback received from workshop participants, and welcome remaining questions related to the wind data or other features of the wind study. We are planning a meeting with our technical review committee in early May, and are looking forward to the added value this group will bring to our effort.

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email:*IPC_Wind_Study@IdahoPower.com*

[5] http://www.nrel.gov/wind/integrationdatasets/pdfs/western/2009/western_dataset_irregularity.pdf

Appendix B. Wind data summaries

Table B1 Monthly and annual capacity factors (percent of installed nameplate capacity)

	Nameplate Wind		
Month	**800 MW**	**1,000 MW**	**1,200 MW**
January	30%	30%	30%
February	20%	20%	19%
March	31%	32%	32%
April	38%	38%	37%
May	24%	24%	24%
June	29%	29%	29%
July	20%	19%	19%
August	17%	17%	17%
September	18%	18%	18%
October	23%	23%	23%
November	36%	35%	35%
December	38%	38%	38%
Annual	27%	27%	27%

Note: Wind generation data for study provided by 3TIER.

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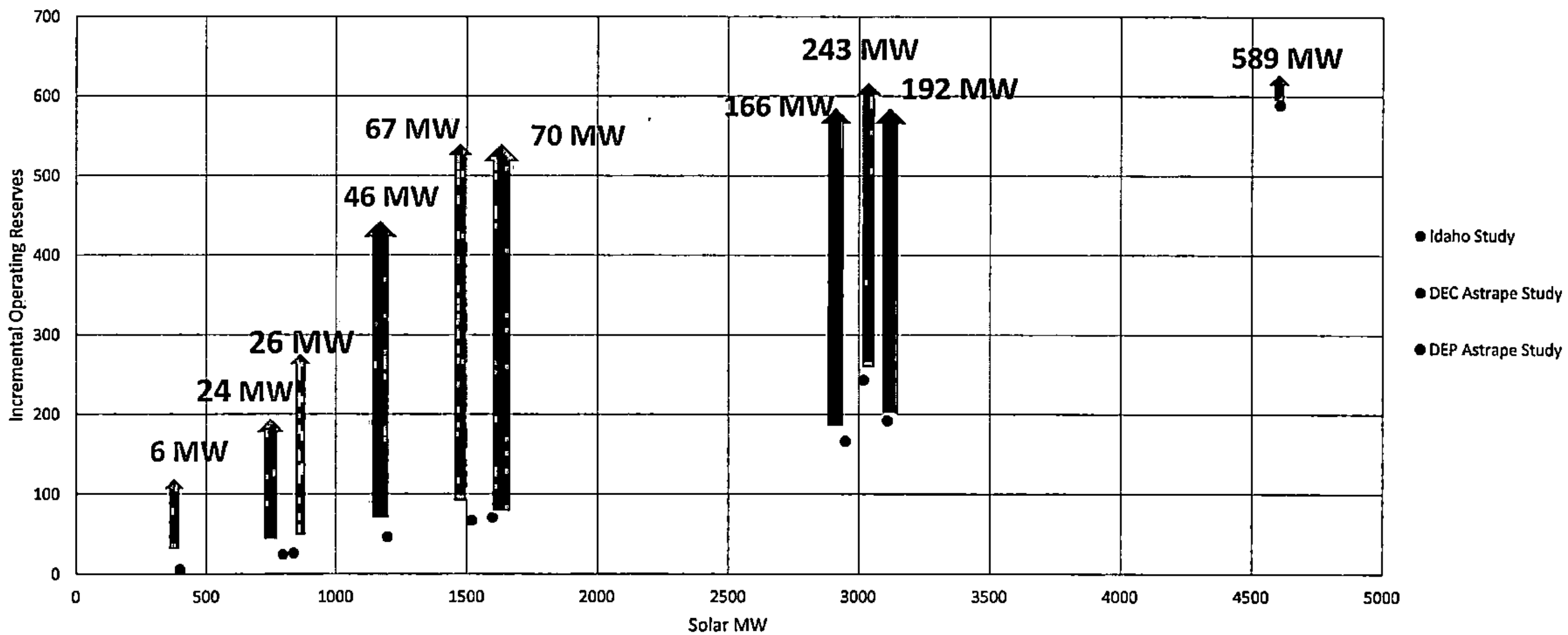
I/A

DEC/DEP Kirby
Cross Exhibit No. 1

Figure. 7. Comparison of Astrapé Study VS Idaho Study



DEC/DEP Wintermantel Direct Testimony, at 14.

2/11

DEC/DEP Kirby
Cross Exhibit No. 2

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Solar Integration Study Report

April 2016 ©
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EXECUTIVE SUMMARY

The development of solar photovoltaic (PV) resources has received markedly increased attention over recent years. The increased attention given to solar PV is a result of multiple factors:

1. Decline in solar PV module prices
2. Federal energy policy, including tax incentives, favoring carbon-free generation resources
3. Electricity customers interest in self generation
4. Increase in number of *Public Utility Regulatory Policies Act of 1978* (PURPA) solar projects under contract in Idaho Power's service area

Electric power from solar PV resources is widely acknowledged to exhibit greater uncontrolled variability and near-term uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when the existing dispatchable generators are called on to integrate PV solar plant generation. The increased costs occur because power systems are operated less optimally to successfully plan for and react to solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the operational modifications it must make to integrate solar PV power plant generation connecting to its system.

The objective of this solar integration study is to estimate the costs of the operational modifications necessary to integrate the intermittent generation from solar plants, where the operational modifications are in the form of differing system reserve requirements. This study determines these costs for four solar build-out scenarios provided in Table 1.

Table 1
Solar build-out scenarios studied

		Installed Capacity of Solar Build-Out Scenarios			
Site	**Data Source**	**400 megawatts (MW)**	**800 MW**	**1,200 MW**	**1,600 MW**
Parma, ID	USBR AgriMet	50	100	150	200
Murphy Flats, ID	SolarAnywhere	25	50	75	100
Boise, ID	USBR AgriMet	25	50	75	100
Grand View, ID	SolarAnywhere	75	150	225	300
Orchard, ID	SolarAnywhere	100	200	300	400
Bliss, ID	SolarAnywhere	25	50	75	100
Twin Falls, ID	USBR AgriMet	50	100	150	200
Aberdeen, ID	USBR AgriMet	50	100	150	200
Total MW		**400**	**800**	**1,200**	**1,600**

The study determines solar integration costs through paired simulations of the Idaho Power system for each solar build-out scenario. Each pair of simulations consists of a test case in which extra capacity in reserve is required of dispatchable generators to allow them to respond to unplanned changes in solar generation and a base case in which no extra capacity in reserve is required. The solar integration costs indicated by the simulations are provided in Table 2.

Table 2
Average integration cost per megawatt-hour (MWh) for solar build-out scenarios

	0–400 MW	0–800 MW	0–1,200 MW	0–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.57/MWh	$0.69/MWh	$0.85/MWh

ACKNOWLEDGMENTS

Idaho Power acknowledges the important contribution of the Technical Review Committee (TRC) in this solar integration study. The TRC has been involved from the study outset in February 2015 and has provided substantial guidance. Idaho Power especially thanks the TRC for the collegial discussions of solar integration during TRC meetings. These discussions helped shape the study methods followed and are consistent with the TRC guidelines as provided by the Utility Variable-Generation Integration Group (UVIG) and the National Renewable Energy Laboratory (NREL) (UVIG and NREL n.d.). The following are members of the Idaho Power solar integration study TRC:

- Brian Johnson, University of Idaho
- Cameron Yourkowski, Renewable Northwest
- Clint Kalich, Avista Utilities
- Kurt Myers, Idaho National Laboratory
- Barbara O'Neill, NREL
- Michael Milligan, NREL

Above representatives from NREL participated in the early stages of the study, and contributed to the study's foundational development. However, NREL funding did not permit their active participation through study completion. Idaho Power continued to include NREL on electronic correspondence related to the study through study completion.

Staff from the Idaho and Oregon regulatory commissions have participated as observers throughout the process. The following staff have been observers of the process:

- Brittany Andrus, Public Utility Commission of Oregon (OPUC) staff
- John Crider, OPUC staff
- Rick Sterling, Idaho Public Utilities Commission (IPUC) staff

TRC members and regulatory observers serve either voluntarily or are paid by their own employers and receive no compensation from Idaho Power. The company is grateful for the TRC's time spent supporting the study and recognizes this support has led to a better study.

INTRODUCTION

The development of solar photovoltaic (PV) resources has received markedly increased attention over recent years. The increased attention given to solar PV is a result of multiple factors:

1. Decline in solar PV module prices
2. Federal energy policy, including tax incentives, favoring carbon-free generation resources
3. Electricity customers interest in self generation
4. Increase in number of *Public Utility Regulatory Policies Act of 1978* (PURPA) solar projects under contract in Idaho Power's service area

Idaho Power currently has 320 megawatts (MW) of utility-scale solar PV from PURPA contracts scheduled to be on-line by year-end 2016. Idaho Power also currently has about 5 MW of solar PV systems interconnected through the company's net metering service. However, while the prevalence of rooftop solar PV systems is growing, the far greater magnitude of potential capacity from utility-scale solar PV necessitates this study's focus on the integration of utility-scale solar PV alone. This solar integration study did not analyze rooftop solar and potential integration impacts on Idaho Power's distribution system.

Electric power from solar PV resources is widely acknowledged to exhibit greater uncontrolled variability and near-term uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when the existing dispatchable generators are called on to integrate PV solar plant generation. The increased costs occur because power systems are operated less optimally to successfully plan for and react to solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the operational modifications it must make to integrate solar PV power plant generation connecting to its system. The objective of this solar integration study is to estimate the costs of the operational modifications necessary to integrate the intermittent generation from solar plants, where the operational modifications are in the form of differing system reserve requirements. This report is intended to describe the operational modifications and the resulting costs.

Idaho Power organized the study into four primary steps:

1. Data gathering and scenario development
2. Statistical-based analysis of solar characteristics
3. Production cost simulation analysis
4. Study conclusions and results

These steps were formulated based on an article published by the Institute of Electrical and Electronics Engineers (IEEE) describing methods for studying wind integration (Ela et al. 2009). While the IEEE article, which was authored by leading researchers at NREL, was written from the perspective of studying system integration of wind generation, the principles underlying the study of wind integration are readily transferrable to the study of solar integration. Both wind and solar bring increased variability and uncertainty to power system operation, and a key objective of an integration study for each is to understand how variability and uncertainty lead to system impacts and changed costs.

Geographic Dispersion

It is recognized that the variability and uncertainty from solar PV resources, just like wind resources, are less severe where the installed capacity is geographically dispersed as compared to clustered. Analysis conducted for this study supports this principle. The solar futures, or build-outs, considered for this study are widely dispersed; solar PV capacity is spread east to west along the Snake River Plain from Aberdeen, Idaho to Parma, Idaho (Figure 2). The effect of dispersion is exemplified in Figure 1, which shows production for July 5, 2013 for three time series: 1) the 400-MW solar PV build-out assumed for the study, 2) a highly clustered build-out with 400 MW of solar PV sited at Grand View, Idaho, and 3) a less clustered build-out with 400 MW of solar PV sited evenly between Grand View, Idaho and Orchard, Idaho. A comparison of the plotted production for the three time series clearly indicates greater challenges associated with integration of the clustered build-outs; the steeper and more dramatic changes in production for the clustered build-outs are indicative of potential challenges in system integration. The solar integration costs identified in this study are relatively small. The small costs suggest solar PV resources can be inexpensively integrated without significant impact to system operations. However, these results are highly dependent on the level of dispersion in the solar PV resource. Impacts and costs associated with build-outs more clustered than assumed for this study are likely markedly greater than found by this study.

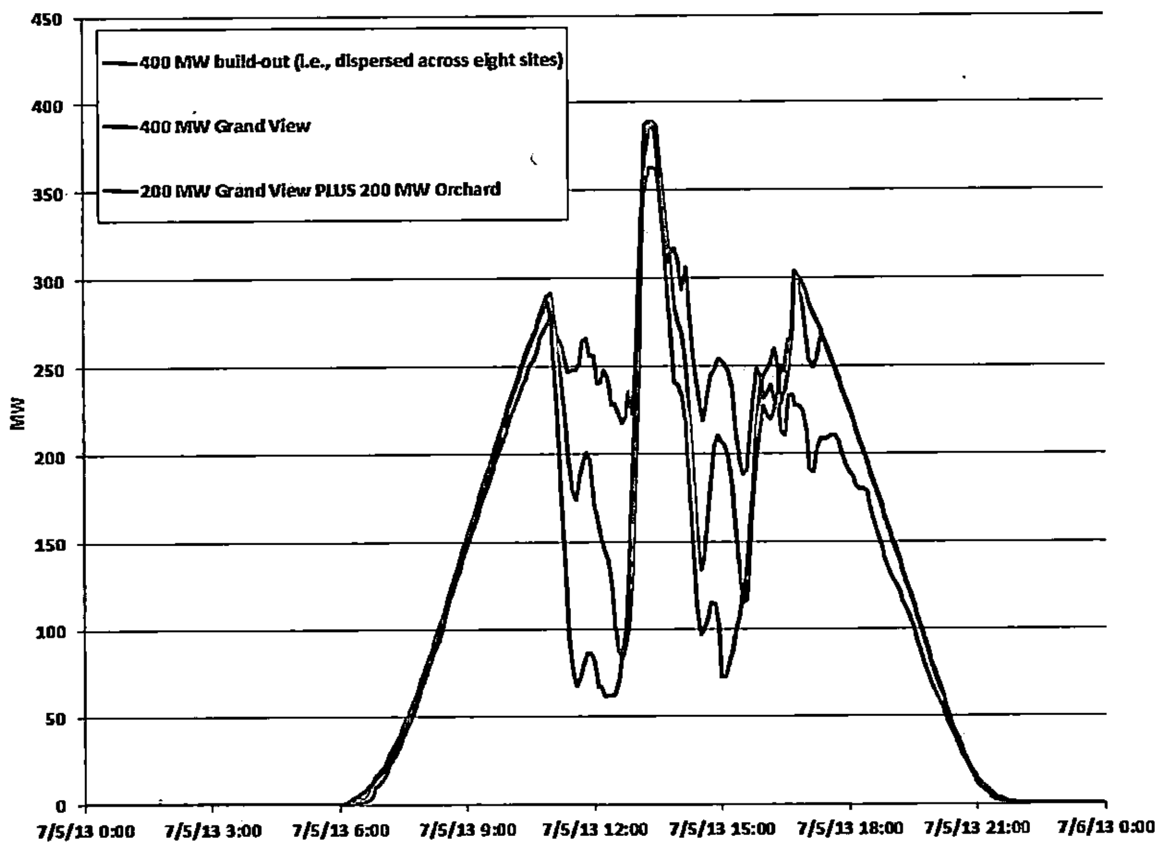

Figure 1
A comparison of 5-minute solar PV production on July 5, 2013.

2014 Solar Integration Study

The first Idaho Power solar integration study was completed in June 2014. The first study investigated integration of four solar PV build-outs: 100 MW, 300 MW, 500 MW, and 700 MW. The costs from the first study were the basis for solar integration costs included in Idaho Public Utilities Commission (IPUC) Schedule 87, which was part of a settlement stipulation approved by the IPUC in Order No. 33227 in February 2015 (Case No. IPC-E-14-18). In addition to Schedule 87, the parties to the settlement stipulation agreed that a second study of solar integration was to be initiated in January 2015 and completed as "expeditiously as possible with the goal of not exceeding 12 months". The parties also agreed that Idaho Power and the Technical Review Committee (TRC) formed for the second solar integration study will determine whether the following issues should be included as part of the second study:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies
- Gas price forecasts
- Modeling of sub-hourly scheduling of load and generation
- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges

Idaho Power solicited from the TRC their feedback, including a prioritization, on the above issues. Idaho Power's reporting on this feedback is included in Appendix 1 as the Technical Review Committee Study Plan. The settlement stipulation is also provided in Appendix 1.

This study's treatment of correlation between solar, wind, and load is particularly noteworthy. Specifically, Idaho Power's statistical analysis accounted for combining effects occurring when these three components of the load and resource balance—solar, wind, and load—are netted.

Data Gathering and Scenario Development

A critical element of the solar integration study is the solar generation data developed for the studied solar build-out scenarios. For Idaho Power's solar integration study, the solar build-out scenarios in Table 3 were studied.

Table 3
Solar build-out scenarios studied

		Installed Capacity of Solar Build-Out Scenarios			
Site	**Data Source**	**400 MW**	**800 MW**	**1,200 MW**	**1,600 MW**
Parma, ID	USBR AgriMet	50	100	150	200
Murphy Flats, ID	SolarAnywhere	25	50	75	100
Boise, ID	USBR AgriMet	25	50	75	100
Grand View, ID	SolarAnywhere	75	150	225	300
Orchard, ID	SolarAnywhere	100	200	300	400
Bliss, ID	SolarAnywhere	25	50	75	100
Twin Falls, ID	USBR AgriMet	50	100	150	200
Aberdeen, ID	USBR AgriMet	50	100	150	200
Total MW		**400**	**800**	**1,200**	**1,600**

The above build-out scenarios were developed in consultation with the TRC to represent geographically dispersed build-outs of solar power plant capacity as informed by locations of proposed solar power plants in southern Idaho and eastern Oregon. Three years of solar data were developed for each build-out scenario: water years 2011, 2012, and 2013. By convention, a water year is from October 1 to September 30 and is designated by the calendar year in which the 12-month period ends. For example, water year 2013 is the 12-month period from October 1, 2012 through September 30, 2013.

The sites from the solar build-out scenarios are part of the established United States Bureau of Reclamation (USBR) AgriMet Network (AgriMet) and modeled data from SolarAnywhere. AgriMet is a satellite-based network of automated agricultural weather stations operated and maintained by the USBR. The stations are located in irrigated agricultural areas throughout the Pacific Northwest and are dedicated to regional crop water-use modeling, agricultural research, frost monitoring, and integrated pest and fertility management. Idaho Power worked directly with the USBR Pacific Northwest Region AgriMet manager to obtain data for the sites. AgriMet data was augmented with data from the University of Oregon Solar Radiation Monitoring Laboratory when AgriMet data was incomplete.

An alternative data-gathering approach was necessary for the Grand View, Murphy, Orchard, and Bliss sites, for which only 15-minute or no data was available. To acquire 5-minute data for these sites, Idaho Power contracted with SolarAnywhere to provide high-resolution modeled solar data. SolarAnywhere uses hourly satellite images processed using the most current algorithms developed and maintained by Dr. Richard Perez at the University at Albany (SUNY). The algorithm extracts cloud indices from the satellite's visible channel using a self-calibrating feedback process capable of adjusting for arbitrary ground surfaces. The cloud indices are used to modulate physically-based radiative transfer models describing localized clear-sky climatology.

The eight sites are spread across southern Idaho and cover over 220 miles from east to west (Figure 2). Sites represent elevations ranging from 2,300 feet to 4,900 feet (Table 4). All data used in the integration study are 5-minute interval global horizontal irradiance data from each site. The use of high-resolution (5-minute interval) data is critical to characterizing the variability of solar.

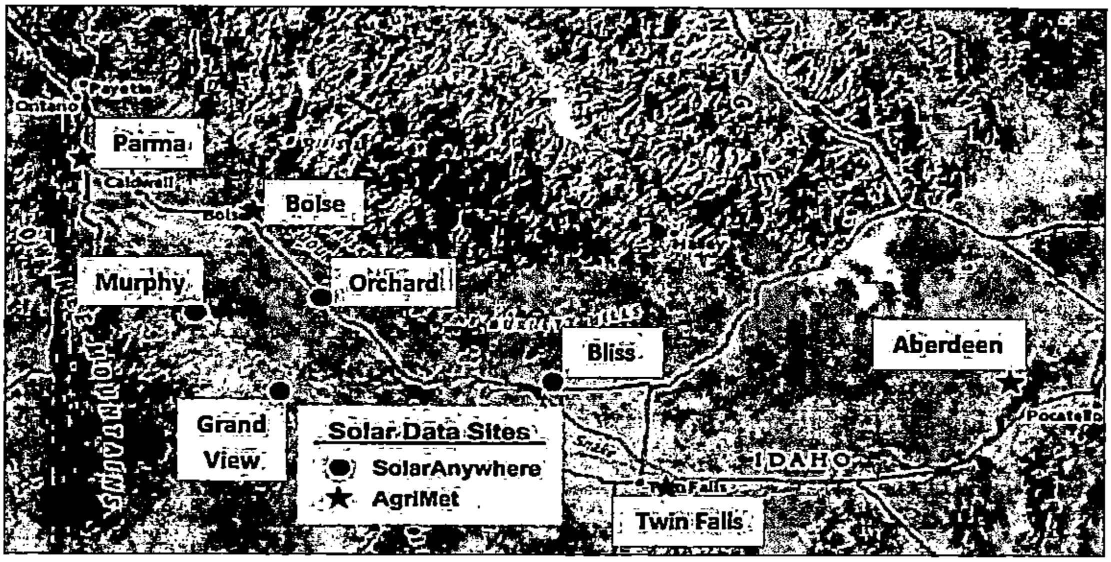

Figure 2
Solar data sites used in IPC's solar integration study

Table 4
Solar data site latitude, longitude, and elevation used in IPC's solar integration study

Station	Latitude (N)	Longitude (W)	Elevation (feet)	Elevation (meters [m])
Parma, ID	43.80	116.93	2,305	702
Murphy Flats, ID	43.21	116.43	3,029	923
Boise, ID	43.60	116.18	2,720	829
Grand View, ID	42.91	116.06	2,580	786
Orchard, ID	43.27	115.88	3,223	982
Bliss, ID	42.95	114.85	3,443	1,049
Twin Falls, ID	42.55	114.35	3,920	1,195
Aberdeen, ID	42.95	112.83	4,400	1,341

Wavelet-Based Variability Model

The available solar data represents conditions at a single point. To better reflect conditions at a solar plant size, Idaho Power used the wavelet-based variability model (WVM) developed by Dr. Matt Lave of Sandia National Labs (Lave et al. 2013a,b). WVM is designed for simulating solar PV power plant output given a single irradiance point-sensor time series. The application of the WVM to the point-sensor time series produces a variability reduction reflecting an upscaling of the point-source data to a solar plant-sized area. Research and use of the WVM showed it is not useable at time steps (intervals) greater than 10 minutes and that time steps greater than 5 minutes may under-represent variability in dispersed systems.

Solar Plant Characteristics

This study assumes solar plants comprising the build-out scenarios occupy 7 acres per MW of installed capacity. Solar plant sizes in the build-out scenarios, as well as figures presented for solar generation, are in terms of AC (alternating current) MW. PV panels are assumed to be of standard crystalline silicon manufacture. Panels are assumed to be single-axis tracking and tilted at latitude. Illustrations and data summarizing the solar production of the studied build-outs are provided in Appendix 1.

Statistical-Based Analysis of Solar, Wind, and Load Data

The impacts and costs of integrating an intermittent energy source, such as solar, are driven by the inherent variability and uncertainty in level of production. The variability and uncertainty in level of production has the impact of requiring dispatchable generators to carry additional capacity in reserve to enable the bulk power system to maintain a balance between customer demand and generation. Thus, the two critical components of studying the integration of solar, or other intermittent energy sources, are as follows:

1. The statistical-based analysis to determine the extent to which solar brings additional variability and uncertainty to system balancing
2. The follow-on analysis to translate the additional variability and uncertainty to additional capacity in reserve required on dispatchable generators.

In considering the impact of variability and uncertainty from the perspective of integration impacts and costs, the focus is primarily on shorter-term operations. That is, for the system operator responsible for maintaining system balancing, integration impacts arise because of variability and uncertainty over the coming minutes, hours, or perhaps days. Viewed from this perspective, the relevant components of system balancing which bring variability and uncertainty are customer demand (load) and intermittent sources of energy (solar and wind). Because of the relevance of these three components—load, solar, and wind—to the challenges with maintaining shorter-term system balancing, the statistical-based analysis performed for this study takes into account variability and uncertainty for the three components, as well as possible interrelationships in variability and uncertainty between the three.

The statistical-based analysis for the study first focused on separate characterizations of variability and uncertainty for load, wind, and solar. The products of the separate characterizations are defined mathematical relationships expressing the extent of variability and uncertainty for each of load, wind, and solar as functions of certain conditions. An August 2012 NREL Conference Paper (Ibanez et al. 2012) describes this approach as defining the operating reserves needed for each of load, wind, and solar as a function of explanatory variables, where differences in the amount of needed reserves can be expressed as a function of the explanatory variables.

After defining the amount of reserves needed separately for each of load, wind, and solar, the statistical-based analysis focused on determining how to combine the separately defined reserve amounts in an appropriate manner for the combination of load with wind, and for the combination of load with wind and solar. This step of the analysis necessarily takes into account the combining effects occurring when netting load with wind, or load with wind and solar. Because of the combining effects that occur when netting load, wind, and solar, the separately determined reserve amounts for each of the three are not added arithmetically, but instead are added through mathematical operations that properly account for the combining effects taking place (e.g., root-sum-of-squares operation). The derivation of the mathematical operations is described later in this section of the report.

Hour-Ahead Forecasting

This study was focused on the assessment of variability and uncertainty as occurring from the perspective of hour-ahead forecasting. This assessment for each of load, wind, and solar was based on the extent to which 5-minute observations differ from hour-ahead forecasts. These differences, or deviations, between intra-hour observations and hour-ahead forecasts drive the need to carry operating reserves to maintain system balancing. Thus, at a fundamental level, the statistical-based analysis to characterize variability and uncertainty was an analysis of deviations between 5-minute observations and hour-ahead forecasts. Further, explanatory variables were identified that explain patterns in the deviations, and these explanatory variables were then used to more precisely define the operating reserve requirements.

Load—Analysis of Variability and Uncertainty

This study found the amount of operating reserve necessary for load variability and uncertainty can be expressed as a function of the following explanatory variables:

- Month (January, February, ..., December)
- Clock hour of day (00:00-01:00, 01:00-02:00, ..., 23:00-00:00)

Hour-ahead forecast for load is based on a persistence of load occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast, with a scaling factor applied equal to the percentage change for the same hour for the previous day. For example, the load forecast for June 15, 12:00–13:00 would be the observed load during the period from 11:15–11:30 multiplied by the ratio of 12:00–13:00 load to 11:15–11:30 load for June 14.

Deviations are calculated as the difference between observed 5-minute load and the corresponding hour-ahead hourly average load forecast (observed minus forecast). A positive deviation represents intra-hour load greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond. Conversely, a negative deviation represents intra-hour load less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. The period of record for the load data analyzed is December 2009 through November 2015.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). The deviation data were binned based on month and then clock hour. Two values were then calculated for each bin: 1) P0.5, which is the 0.5th-percentile value for the deviation data, and 2) P99.5, which is the 99.5th-percentile value for the deviation data. Thus, for each combination of month and clock hour (12 x 24 = 288 combinations), the amount of load-caused bidirectional reserve can be specified.

For the purposes of this study, Idaho Power adopted the term INC for the up-direction reserve and DEC for the down-direction reserve. In the assessment of load variability and uncertainty, the P0.5 value represents DEC reserve and the P99.5 value represents INC reserve.

The target to capture 99 percent of deviations for this study is considered appropriate in ensuring generators have sufficient reserve requirements for all but approximately 90 hours per year. Importantly, the targeted 99 percent is the criterion held for both simulations performed for this study: the base case simulation of load combined with wind, and the test case simulation of load combined with wind and solar. This ensures both simulations are designed to bring about an equivalent level of system reliability, rendering the selected reliability level relatively immaterial from the perspective of comparing production cost differences between paired simulations.

Wind—Analysis Variability and Uncertainty

This study found the amount of operating reserve necessary for wind variability and uncertainty can be expressed as a function of the following explanatory variable:

- Hour-ahead forecast for wind production

Hour-ahead forecast for wind production is based on a persistence of wind production occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast. For example, the wind production forecast for June 15, 12:00–13:00 would be the observed wind production during the period from 11:15–11:30.

Deviations are calculated as the difference between observed 5-minute wind production and the corresponding hour-ahead hourly average wind production forecast (observed minus forecast). To illustrate, the population of deviations for the wind production data analyzed is plotted in Figure 3. The plot illustrates the magnitude of deviations as a function of hour-ahead forecast wind production on the horizontal axis. The plot notes that a positive deviation represents intra-hour wind production greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. Conversely, a negative deviation represents intra-hour wind production less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond. The period of record for the wind production data analyzed is December 2012 through November 2015. The wind production data are observed production for wind projects having long-term energy sales agreements with Idaho Power during the period of record. The energy sales agreements are both through PURPA and power purchase agreement (PPA), and total installed capacity of the wind projects analyzed is 678 MW.

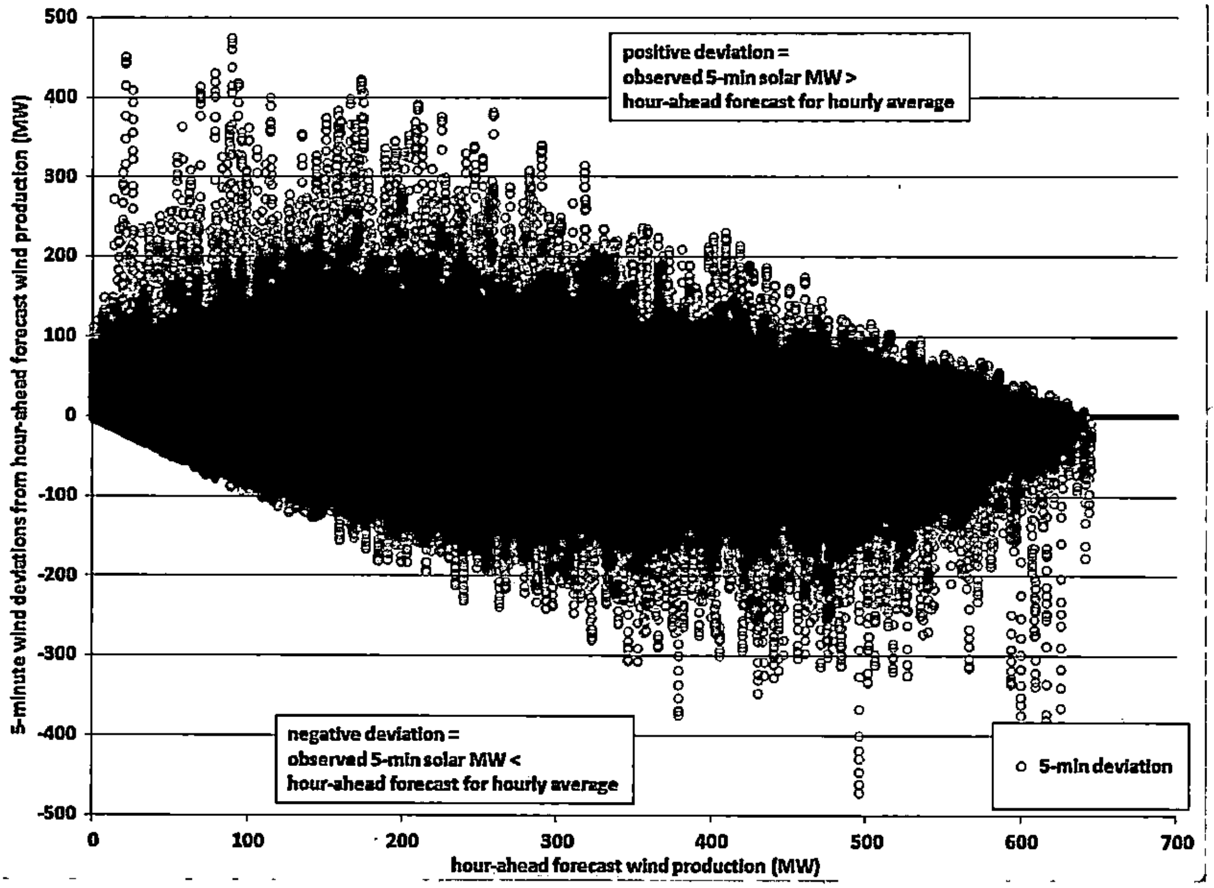

Figure 3
Wind production deviations (5-minute wind production minus hour-ahead forecast hourly average wind production). Period of record December 2012 through November 2015.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). It is evident from the plot in Figure 3 that the magnitude of deviations varies as a function of hour-ahead forecast wind. Thus, the bidirectional reserve amounts can be more precisely defined if calculated after binning the data based on the level of hour-ahead forecast wind production.

The deviation data were divided into 20 equal-sized bins based on level of hour-ahead forecast wind production. Three values were calculated for each bin: 1) the median hour-ahead forecast, 2) P0.5, which is the 0.5th-percentile value for the deviation data, and 3) P99.5, which is the 99.5th-percentile value for the deviation data. Figure 4 illustrates the P0.5 and P99.5 values for the example deviations, as well as third-order polynomial trend lines fitted to both data streams.

The fitted trend lines were used to define the amounts of bidirectional reserve associated with wind variability and uncertainty. In the assessment of wind variability and uncertainty, the P0.5 value represents INC reserve, dispatchable generating capacity in reserve that can be turned up in response to lower than expected wind production. The P99.5 value represents DEC reserve, dispatchable generating capacity in reserve that can be turned down in response to higher than expected wind production.

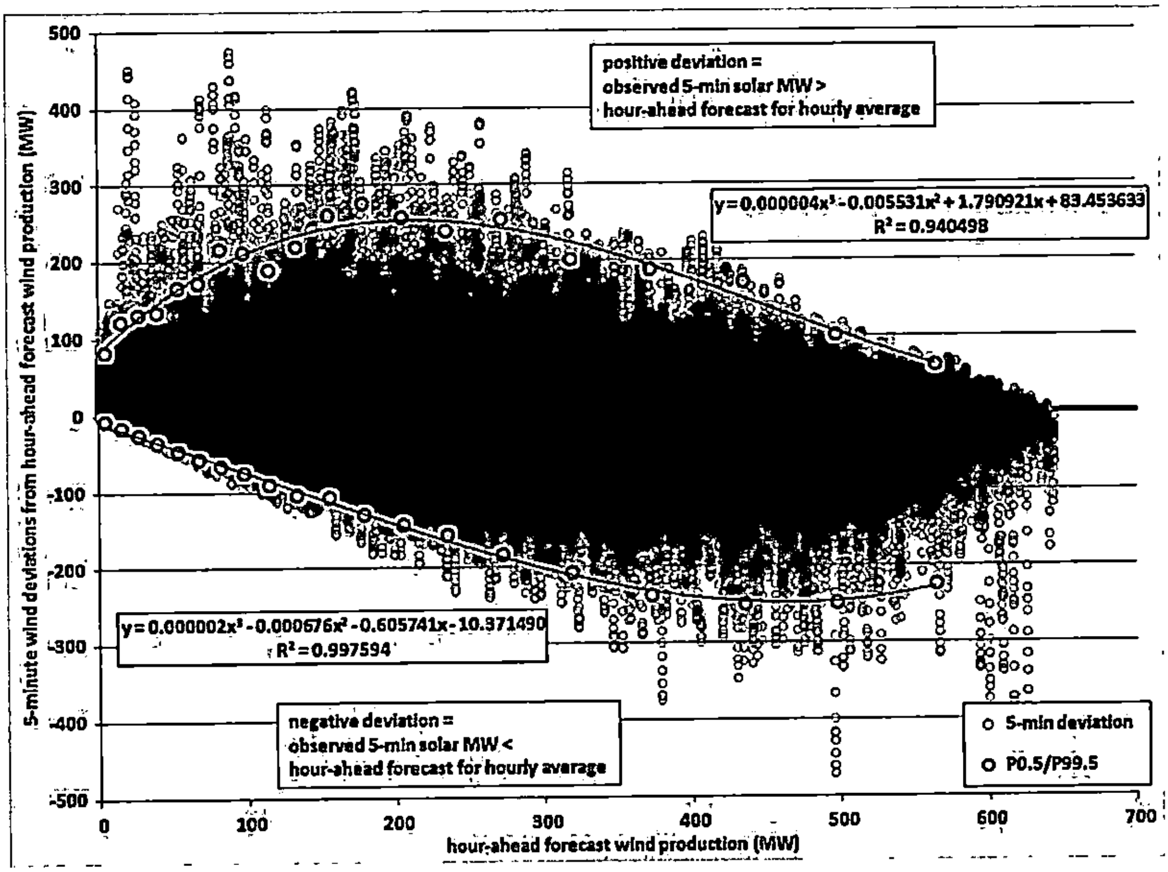

Figure 4
Wind production deviations with fitted trend lines for bidirectional wind reserve as function of hour-ahead forecast wind production

As a result of the analysis of wind production data, the amount of wind-caused bidirectional reserve can be defined for any given hour based on the level of hour-ahead forecast wind production.

Solar—Analysis of Variability and Uncertainty

This study found the amount of operating reserve necessary for solar variability and uncertainty can be expressed as a function of the following explanatory variables:

- Hour-ahead forecast for solar production
- Time of day (eight, 3-hour blocks: 00:00–03:00, 03:00–06:00, …, 21:00–00:00)

Hour-ahead forecast for solar production is based on a persistence of percentage of clear-sky production, where clear-sky production is the physically determinable maximum production level for a given date and time. The forecast is based on the observed percentage of clear-sky production occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast. For example, the solar production forecast for June 15, 12:00–13:00 would be the observed percentage of clear-sky production during the period from 11:15–11:30.

Deviations are calculated as the difference between observed 5-minute solar production and the corresponding hour-ahead hourly average solar production forecast (observed minus forecast). To illustrate, the population of deviations for the three years of solar production data at the 800-MW build-out for the time of day from 12:00–15:00 is plotted in Figure 5. The plot illustrates the magnitude of deviations as a function of hour-ahead forecast solar production on the horizontal axis. The plot notes that a positive deviation represents intra-hour solar production greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. Conversely, a negative deviation represents intra-hour solar production less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond.

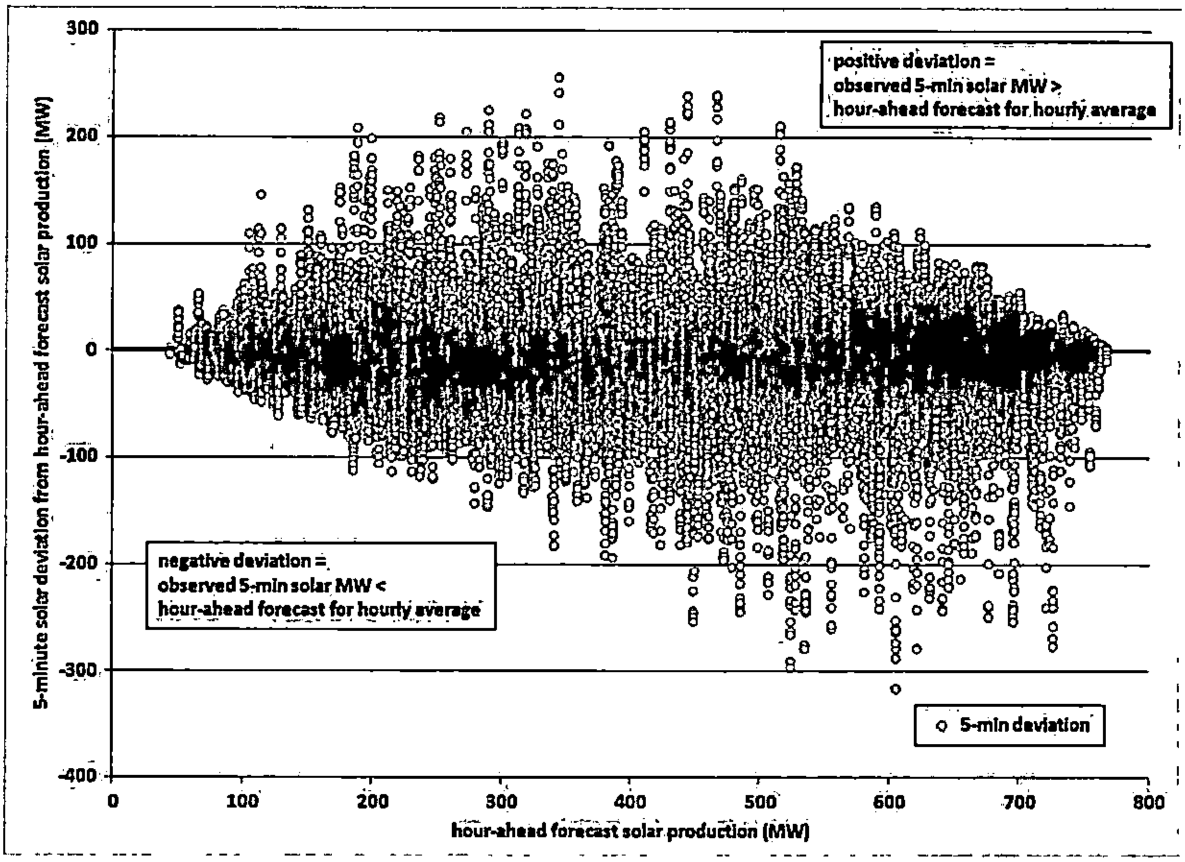

Figure 5
Solar production deviations (5-minute solar production minus hour-ahead forecast hourly average solar production). Period of record October 2010 through September 2013. 800-MW solar build-out. Period of day 12:00–15:00.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). It is evident from the plot in Figure 5 that the magnitude of deviations varies as a function of hour-ahead forecast solar. Thus, the bidirectional reserve amounts can be more precisely defined if calculated after binning the data based on the level of hour-ahead forecast solar production.

The deviation data were divided into 24 equal-sized bins based on the level of hour-ahead forecast solar production. Three values were calculated for each bin: 1) the median hour-ahead forecast, 2) P0.5, which is the 0.5^{th}-percentile value for the deviation data, and 3) P99.5, which is the 99.5^{th}-percentile value for the deviation data. Figure 6 illustrates the P0.5 and P99.5 values for the example deviations, as well as second-order polynomial trend lines fitted to both data streams. The fitted trend lines were used to define the amounts of bidirectional reserve associated with solar variability and uncertainty. Similarly derived trend lines were determined for the other seven time-of-day periods, although it is noted that the first two time-of-day periods (00:00–03:00, 03:00–06:00) have no deviation data and consequently no solar-caused reserve requirements, and the last time-of-day period (21:00–00:00) has minimal data and small solar-caused reserve requirements. The process was replicated for each solar build-out.

In the assessment of solar variability and uncertainty, the P0.5 value represents INC reserve, dispatchable generating capacity in reserve that can be turned up in response to lower than expected solar production. The P99.5 value represents DEC reserve, dispatchable generating capacity in reserve that can be turned down in response to higher than expected solar production.

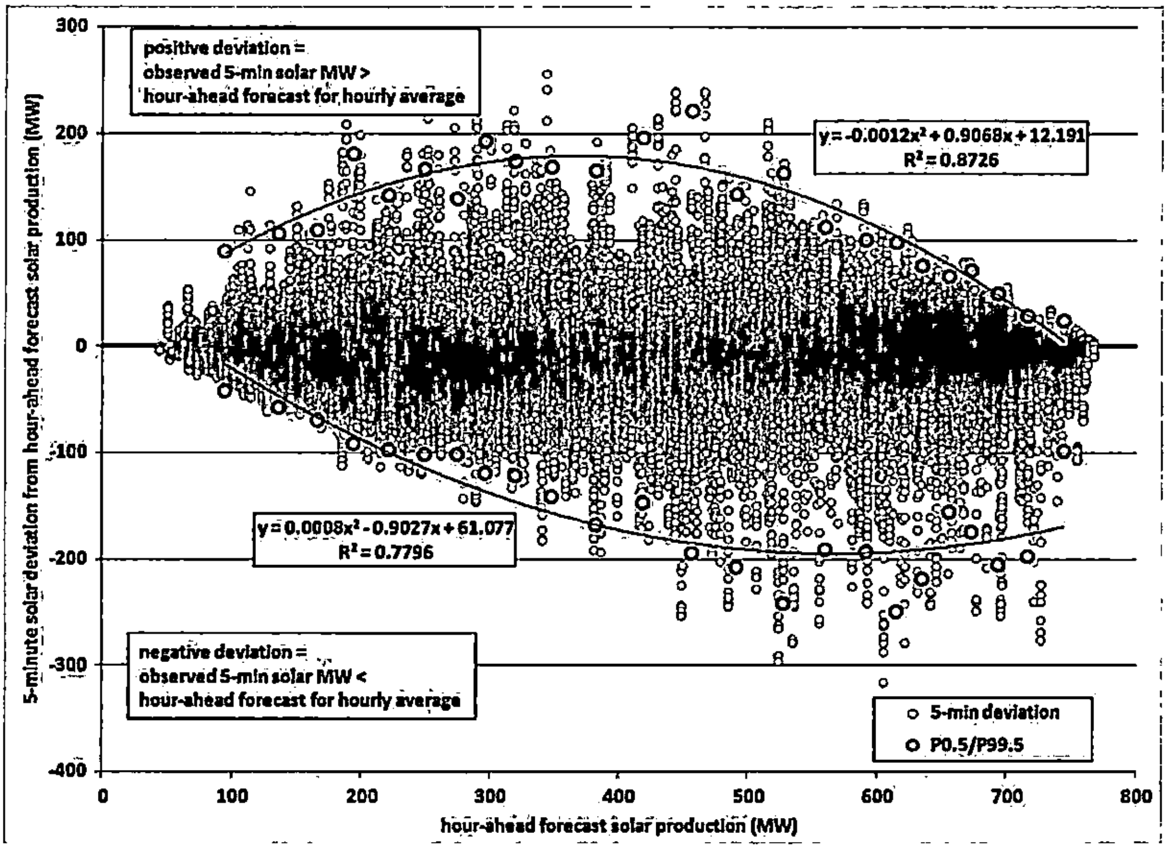

Figure 6
Solar production deviations (5-minute solar production minus hour-ahead forecast hourly average solar production). Period of record October 2010 through September 2013. 800-MW solar build-out. Period of day 12:00–15:00. Fitted trend lines for bidirectional solar reserve as function of hour-ahead forecast solar production.

As a result of the analysis of solar production data, the amount of solar-caused bidirectional reserve can be defined for any given hour based on two explanatory variables: 1) hour-ahead forecast solar production, and 2) time of day.

Reserve for Load Combined with Wind

The base case production cost simulations assumed operating reserve necessary to manage variability and uncertainty for load combined with wind. As noted earlier in this section, because of combining effects that occur when netting load and wind, the amount of operating reserve necessary for the combination is not the arithmetic addition of the separately determined operating reserve amounts. In fact, wind and load are widely recognized as independent (near zero correlation), and the operating reserve for the combined wind and load is commonly considered to be theoretically formed by combining the separately determined operating reserve amounts for load and wind through the root sum of squares (RSS) operation (Ela et al. 2009).

The RSS formulas for INC and DEC are stated as follows:

$$INC_{load\ with\ wind} = sqrt(INC_{load}^2 + INC_{wind}^2)$$

$$DEC_{load\ with\ wind} = sqrt(DEC_{load}^2 + DEC_{wind}^2)$$

Thus, for any given hour in the study's production cost simulations, the separate amounts of INC/DEC associated with load and wind variability can be determined based on the explanatory variables occurring for the hour (e.g., level of wind production forecast), and the amount of INC/DEC for the combined load and wind is then based on combining the separate amounts through the RSS operation provided above.

The effectiveness of the RSS operation in covering variability and uncertainty occurring when load and wind are combined was tested by applying the RSS to observed load and wind data for water year 2013. When the separate INC/DEC amounts are combined through the RSS operation, the percentage of intra-hour (i.e., 5-minute) observations for load combined with wind occurring outside of the hourly INC/DEC reserve levels are 0.4 and 0.3 percent for the INC and DEC reserve bounds, respectively. Recalling that the separately determined INC/DEC reserve amounts for load and wind are based on a 99 percent confidence level (P99.5 and P0.5), the percentages of observations *not* covered by the RSS-determined INC/DEC reserve levels support the appropriateness of the RSS operation.

Reserve for Load Combined with Wind and Solar

The base case production cost simulations are compared to test case simulations, where the test case simulations have INC/DEC necessary to manage variability and uncertainty in load netted with wind *and solar*. As noted previously, because of combining effects, the amount of INC/DEC reserve necessary when load, wind, and solar are netted is not the arithmetic sum of the separately determined INC/DEC amounts. The preceding subsection of this report describes the appropriateness of the RSS operation in determining the amount of INC/DEC reserve for load combined with wind.

A challenge in deriving the amount of reserve for the test case (i.e., for load combined with wind and solar) is determining the amount of solar-caused INC/DEC reserve to add to the RSS-determined base case amount. Because of combining effects, the use of 100 percent of the solar-caused INC/DEC is excessive, and results in fewer occurrences of insufficient INC/DEC reserves than occurring in the base case. However, because of the incremental variability and uncertainty associated with solar, it is also recognized that ignoring the solar-caused INC/DEC (i.e., using 0 percent) is incorrect, and results in a frequency of insufficient INC/DEC reserves exceeding that of the base case. Idaho Power determined the amount of incremental solar-caused INC/DEC reserve to add to the RSS-determined base case level empirically by adjusting the amount of solar-caused INC/DEC reserve (between 0 and 100 percent) until the frequency of INC/DEC reserve insufficiencies matches that of the base case (0.4 and 0.3 percent respectively for INC and DEC reserve bounds). This empirical approach ensures base and test case simulations are held to the same standard with respect to stringency of reserve obligations.

The formula statements for INC/DEC reserve for the load combined with wind and solar are as follows:

$INC_{\text{load with wind and solar}} = \text{sqrt}(INC_{\text{load}}^2 + INC_{\text{wind}}^2) + X \cdot INC_{\text{solar}}$

$DEC_{\text{load with wind and solar}} = \text{sqrt}(DEC_{\text{load}}^2 + DEC_{\text{wind}}^2) + Y \cdot DEC_{\text{solar}}$

Where: Coefficients X and Y are determined empirically such that INC/DEC insufficiencies for load with wind and solar match the frequency of INC/DEC insufficiencies for load with wind

The empirically determined coefficients applied to solar-caused INC/DEC are provided in Table 5. It is noted that for the 400-MW solar build-out the coefficient yielding the equivalent frequency of DEC insufficiencies is 0.00.

Table 5
Coefficients for bidirectional solar reserve by solar build-out

Solar Build-Out	INC Coefficient	DEC Coefficient
400 MW	0.23	0.00
800 MW	0.43	0.25
1,200 MW	0.56	0.37
1,600 MW	0.64	0.40

The amounts of INC/DEC averaged over all hours for the three simulated water years for the two cases are provided in Table 6.

Table 6
Average INC/DEC base and test cases by solar build-out (water year [WY] 2011–2013)

Solar Build-Out	Base Case Average INC (MW)	Test Case Average INC (MW)	Base Case Average DEC (MW)	Test Case Average DEC (MW)
400 MW	169	175	226	226
800 MW	169	193	226	242
1,200 MW	169	215	226	263
1,600 MW	169	239	226	279

Example Reserve Application

A key objective of the statistical analysis of variability and uncertainty is the development of operating reserve guidelines, or rules, which provide to the system scheduler the appropriate amount of reserve for any given load, wind, and solar combination. This subsection of the report illustrates an example application of the operating reserve rules.

The following conditions are assumed for the example hour:

- Hour being scheduled: June 15, 13:00–14:00
- Hour-ahead wind forecast: 400 MW
- Hour-ahead solar forecast: 500 MW (assume 800 MW of installed solar capacity)
- Hour-ahead load forecast: 2,100 MW

For wind, Figure 4 provides that for an hour having a 400 MW hour-ahead forecast:

- $Wind_{INC} \approx 250$ MW (based on third-order polynomial below the zero axis)
- $Wind_{DEC} \approx 180$ MW (based on third-order polynomial above the zero axis)

For solar, Figure 6 provides that for an hour during the period 12:00–15:00 and having a 500 MW hour-ahead forecast:

- $Solar_{INC} \approx 190$ MW (based on third-order polynomial below the zero axis)
- $Solar_{DEC} \approx 155$ MW (based on third-order polynomial above the zero axis)

For load, analysis of deviations in hour-ahead load forecasts for June hour 13:00–14:00 provides:

- $Load_{INC} \approx 95$ MW
- $Load_{DEC} \approx 85$ MW

Given this information, the hour-ahead system scheduler for this example hour would schedule the following reserve amounts on dispatchable generators for the base case (i.e., for the load combined with wind case):

- INC = $\text{sqrt}(95^2 + 250^2) = 267$ MW
- DEC = $\text{sqrt}(85^2 + 180^2) = 199$ MW

The reserve amounts for the test case (i.e., for the load combined with wind and solar case) are:

- INC = 267 MW + 0.43*($Solar_{INC}$) = 267 MW + 0.43*190 MW = 349 MW
- DEC = 199 MW + 0.25*($Solar_{DEC}$) = 199 MW + 0.25*155 MW = 238 MW

Finally, the system scheduler for both cases is assured of the appropriateness of the reserve amounts on the basis of the rigor of the supporting statistical analysis of load, wind, and solar data. That is, the statistical analysis indicates scheduling the above-calculated reserve amounts positions the system in both cases to cover approximately 99 percent of possible observations for both time series (load combined with wind, and load combined with wind and solar).

PRODUCTION COST SIMULATION ANALYSIS

Hourly production cost simulations for the study were performed using a paired, base case versus test case design. The critical difference between the cases is the amount of capacity in reserve (i.e., INC/DEC). The amount of capacity in reserve for the base case simulation is based on that carried for the load combined with wind time series described in the preceding section, whereas the amount of capacity in reserve for the test case is based on that carried for the load combined with wind and solar time series. All other inputs are identical between the paired simulations.

The incremental reserve requirements of the test case (summarized in Table 6) lead to production cost differences between it and the base case. Over a simulated year, the test case costs exceed those of the base case. Because inputs between the cases are identical with the exception of the amount of capacity in reserve, the greater costs of the test case can be attributed to its incremental reserve requirements. This production cost difference is considered the cost to integrate solar.

Design of Simulations

Three water years were simulated for the production cost simulations: water years 2011, 2012, and 2013. The three simulated water years correspond well to high-type (2011), medium-type (2012), and low-type (2013) water years for the Snake River Basin. An illustration of the water conditions for 2011–2013 in relation to other historical years is provided in Appendix 1.

The Idaho Power generating and transmission system as it exists at the time of issue of this report is assumed for the production cost simulations. Critical elements of the simulated system of generating resources include 17 hydroelectric facilities totaling 1,709 MW of nameplate capacity, 3 coal-fired facilities totaling 1,118 MW of nameplate capacity, and 3 natural gas-fired facilities totaling 762 MW of nameplate capacity. An illustration of the generating resources is provided in Appendix 1.

Idaho Power's critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the solar integration study modeling, the separate paths were combined to an aggregate path for off-system access. Purchases from the regional market are treated separately from sales to the regional market. Net firm purchases from the market are limited on a monthly basis to only the capacity and energy required to serve Idaho Power's retail load. Sales to the market are limited to 500 MW in every hour. This profile of purchases and sales reflects the current capabilities of Idaho Power's transmission system.

Idaho Power is pursuing the development of the Boardman to Hemingway Transmission Project (B2H), which will increase Idaho Power's access to the Northwest to make additional purchases and sales. However, the transmission line's current in-service date is at least five years into the future. Previous integration studies have shown that unless there is a liquid capacity balancing market, B2H will not significantly impact the solar integration cost. Idaho Power is actively engaged in discussions about regional markets that could exist when B2H is completed. The benefits of a market are highly dependent on its design. This study investigated as a sensitivity analysis a market design similar to that existing for the California Independent System Operator (CAISO) Energy Imbalance Market (EIM).

Simulation Inputs

Table 7 provides key inputs to the solar integration study hourly production cost simulations of water years 2011, 2012, and 2013. To capture interrelationships between variables, inputs to the simulations are synchronous, with the exception of production from non-wind PURPA resources and geothermal PPAs, which is not interrelated to the other inputs.

Table 7
Inputs for the solar integration study hourly production cost simulations

Input	Water Year 2011	Water Year 2012	Water Year 2013
Solar production	Water year 2011	Water year 2012	Water year 2013
Snake River streamflows	Water year 2011	Water year 2012	Water year 2013
Customer demand	Water year 2011	Water year 2012	Water year 2013
Nymex—Natural gas prices	Water year 2011	Water year 2012	Water year 2013
Mid-C—Electric power market prices	Water year 2011	Water year 2012	Water year 2013
Non-wind PURPA[1]	-----------Forecast calendar year 2016---------		
Wind (PURPA and PPA)[1]	Water year 2011	Water year 2012	Water year 2013
Geothermal PPAs	---------------Water year 2015-----------------		

[1] PPA and PURPA represent facilities from which generation is contractually purchased as a PPA or under PURPA.

Wind capacity under contract more than tripled during the three consecutive water years being simulated; capacity under contract was 208 MW at the start of water year 2011 and grew to the current level of 678 MW by January 2013. Because of the substantial growth in wind capacity, observed wind generation occurring prior to reaching the current capacity level was adjusted upwards to normalize this production to the current capacity level. For example, observed wind production occurring during October through December 2010 was adjusted upwards by a factor of 3.3 (678 MW ÷ 208 MW) to normalize the observed production from the 208 MW actually on-line during the 3-month period to the current capacity level of 678 MW. The expansion in wind capacity under contract is illustrated as Figure 7. Monthly wind energy production used in the modeling, at unadjusted and adjusted levels, is included in Appendix 1.

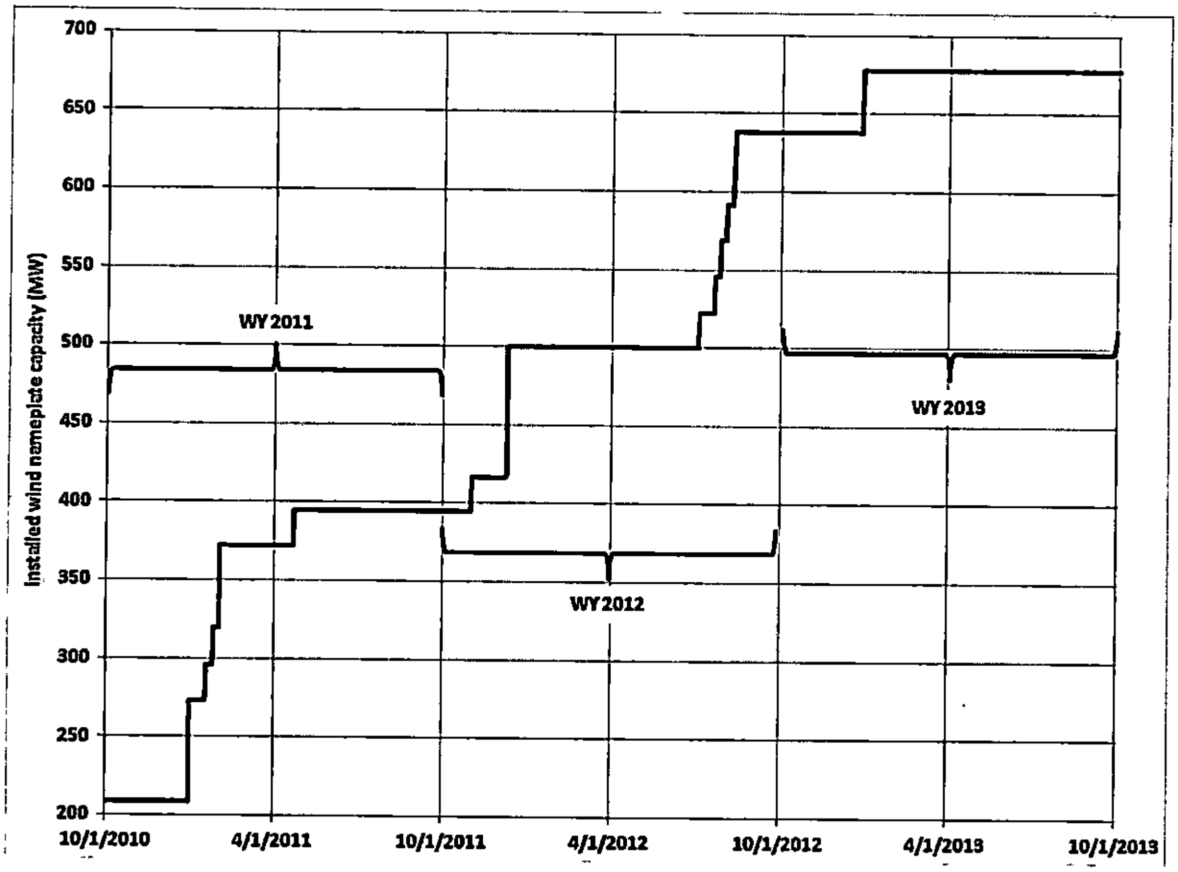

Figure 7
Installed nameplate wind capacity under contract, water years 2011–2013.

Energy purchased from non-wind PURPA qualifying facilities is input to the simulations as forecast in April 2015 for calendar year 2016. The monthly energy from the non-wind PURPA facilities is included in Appendix 1.

Baseload generation from geothermal facilities contractually selling to Idaho Power under PPAs is input as currently projected from these facilities. The amount of baseload generation delivered from these facilities varies seasonally. The amount used in the production cost simulations ranges from 22 MW to 32 MW.

Simulation model

Idaho Power used an internally developed system operations model for the solar integration study. The model determines optimal hourly scheduling of dispatchable hydro and thermal generators with the objective of minimizing production costs while honoring constraints imposed on the system. System constraints used in the model capture numerous restrictions governing the operation of the power system, including the following:

- Reservoir headwater constraints
- Minimum reservoir outflow constraints
- Reservoir outflow ramping rate constraints

- Generator minimum/maximum output levels
- Market purchase/sale constraints
- Generator ramping rates

The model also stipulated that load and resource were exactly in balance and, importantly, that hourly reserve requirements were satisfied. The differing amount of capacity in reserve held to manage variability and uncertainty in solar production drives the production cost differences between the study's two cases. The derivation of the capacity in reserve for the two simulation cases is described previously in this report.

Contingency Reserve Obligation

The study of integration impacts and costs focuses on the need to carry bidirectional capacity in reserve for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity in reserve for responding to system contingency events, which have traditionally been viewed as large and relatively infrequent system disturbances affecting the production or transmission of power (e.g., the loss of a major generating unit or major transmission line). System modeling for the solar integration study imposes a contingency reserve intended to reflect this obligation equal to 3 percent of load and 3 percent of generation, setting aside this capacity for both study cases (i.e., base and test).

Flexible Capacity Resources

The focus of the production cost simulations for the solar integration study is the real-time market activities occurring as part of hour-ahead system scheduling. The study assumes hour-ahead schedulers require the delivery of hour-ahead forecasts for load, wind, and solar 30 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is then assumed binding, and excursions from hour-ahead forecast levels occurring during the operating hour being scheduled must be managed by Idaho Power's system.

To manage the excursions from hour-ahead forecasts during the operating hour, Idaho Power must schedule bidirectional (INC/DEC) capacity in reserve on dispatchable generators. In the modeling for the study, this capacity in reserve is scheduled on Hells Canyon Complex (HCC) hydroelectric generators (Brownlee, Oxbow, and Hells Canyon), natural gas-fired generators (Langley Gulch, Danskin, and Bennett Mountain), and Jim Bridger coal-fired generators. The allocation of reserve to these generators matches Idaho Power's practice for balancing variations in wind production and load.

RESULTS

The objective of the Idaho Power solar integration study is to determine the costs of the operational modifications necessary to integrate solar PV power plant generation. The integration costs are driven by the need to carry extra capacity in reserve to allow bidirectional response from dispatchable generators to unplanned changes in solar production. The simulations performed for the Idaho Power solar integration study indicate the following costs associated with holding the extra solar-caused capacity in reserve (Table 8). Integration costs are provided in nominal terms for the simulated years and in terms assuming a base year of 2016. The costs are not averaged or levelized over the life of a solar plant.

Table 8
Integration cost per MWh for solar build-out scenarios

Solar Build-Out Scenario	Water Year with Hydro Level	Test – Base Cost Difference	Solar MWh	Nominal Solar Integration Costs per megawatt-hour (MWh)	2016$ Solar Integration Costs per MWh[1]
400 MW	2011 (high)	$303,954	607,961	$0.50	$0.56
	2012 (med)	$85,288	607,960	$0.14	$0.15
	2013 (low)	$58,014	607,529	$0.10	$0.10
800 MW	2011 (high)	$1,079,810	1,219,244	$0.89	$0.99
	2012 (med)	$338,632	1,225,743	$0.28	$0.30
	2013 (low)	$496,770	1,217,423	$0.41	$0.44
1,200 MW	2011 (high)	$1,654,781	1,831,956	$0.90	$1.01
	2012 (med)	$730,371	1,844,933	$0.40	$0.43
	2013 (low)	$1,088,246	1,828,441	$0.60	$0.64
1,600 MW	2011 (high)	$2,492,214	2,451,006	$1.02	$1.13
	2012 (med)	$1,307,219	2,475,258	$0.53	$0.58
	2013 (low)	$1,914,841	2,451,870	$0.78	$0.83

[1] Escalation to 2016 base year using 2015 *Integrated Resource Plan* (IRP) general operations and maintenance (O&M) escalation rate of 2.2%.

The integration costs provided in Table 8 indicate a consistent pattern of higher integration costs for higher water conditions. Idaho Power has discussed this result with the TRC, and has communicated that during higher water years system flexibility can be highly constrained. Averaging over the three simulated water years yields the following integration costs (Table 9).

Table 9
Average integration cost per MWh for solar build-out scenarios

	0–400 MW	0–800 MW	0–1,200 MW	0–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.57/MWh	$0.69/MWh	$0.85/MWh

The integration cost results in Table 9 are the cost per MWh (2016$) to integrate the full installed solar power plant capacity at the respective scenarios studied. For example, the integration cost results indicate the total solar power plant capacity making up the 400 MW build-out scenario brings about costs of $0.27 for each MWh integrated.

Integration costs can be expressed alternatively in terms of incremental costs. Integration costs when expressed incrementally assume early projects are assessed lesser integration costs, and later projects need to make up the difference to allow full cost recovery for a given build-out scenario. For example, if solar plants comprising the first 400-MW build-out are assessed integration costs of $0.27/MWh, then plants comprising the increment between 400 MW and 800

MW need assessed integration costs of $0.88/MWh to allow full recovery of the $0.57/MWh costs to integrate 800 MW of solar plant capacity. Incremental solar integration costs are provided in Table 10.

Table 10
Incremental integration cost results for solar build-out scenarios

	0–400 MW	400–800 MW	800–1,200 MW	1,200–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.88/MWh	$0.92/MWh	$1.31/MWh

Energy Imbalance Market Sensitivity Analysis

Idaho Power is currently investigating costs and benefits of participation in EIMs such as that managed by the Western EIM (formerly referred to as the California Independent System Operator or CAISO). Among the benefits commonly associated with an EIM is its capability to provide flexibility for balancing variable energy sources, such as solar. It is noted that Idaho Power's current investigation of EIM costs and benefits is a comprehensive analysis focusing on benefits beyond those associated with integration of variable energy sources.

Idaho Power conducted a sensitivity analysis for the solar integration study to provide preliminary assessment of EIM benefits related to solar integration. For this preliminary EIM sensitivity analysis, the company assumed wholesale energy market trading is performed on a 15-minute window instead of hourly. The shortened trading window is assumed to allow a reduction in operating reserve requirements. The EIM sensitivity analysis indicates potential integration benefits associated with EIM participation, including the potential for reduced integration costs. Idaho Power emphasizes that contemplated EIMs are not expected to trade capacity products (i.e., operating reserves); thus, the capability to satisfy all or part of INC/DEC reserve requirements through EIM participation is not anticipated.

The sensitivity's indication of integration benefits is considered preliminary. Idaho Power will continue its ongoing investigation of costs and benefit of participating in an EIM. Once that investigation is completed, the company will have more information for estimating the potential level of impact an EIM might have on solar integration costs.

Study Findings

Hour-ahead Solar Production Forecasting

Analyses suggest a persistence-based forecast with adjustment to account for known changes in the sun's position provides a reasonable production forecast for hour-ahead operations scheduling. The persistence-based, hour-ahead solar production forecast used for the study is based on observed production and, consequently, could be readily adopted in practice.

While a day-ahead solar production forecast would be necessary in practice for a balancing authority integrating solar, this study assumes deviations from the day-ahead forecast can be managed through a combination of market transactions and operations modifications, and, consequently, the study imposes no reserve requirement to cover deviations for day-ahead solar production forecasts.

Compared to wind, system operators managing a balancing authority integrating solar would have the benefit of at least 6 hours at the start of day with no or little solar production. During this period of no or little solar production, system operators could evaluate the day-ahead solar production forecast using information from updated weather forecast products and begin to plan for necessary actions to manage deviations from the day-ahead solar production forecast.

Figure 8 plots daily production (MWh) versus month for the 678 MW of wind capacity Idaho Power integrates (January 2013–September 2015 data) and for the 800-MW solar build-out (data for water years 2011–2013). The graph (Figure 8) demonstrates that daily production for solar follows an intuitive seasonal pattern of high summer and low winter production, and that the distribution of daily production is markedly narrower for solar compared to wind. The lower variability in daily solar production, evident by the narrower distribution for all months, is indicative of the relative challenges associated with day-ahead forecasting of wind and solar production.

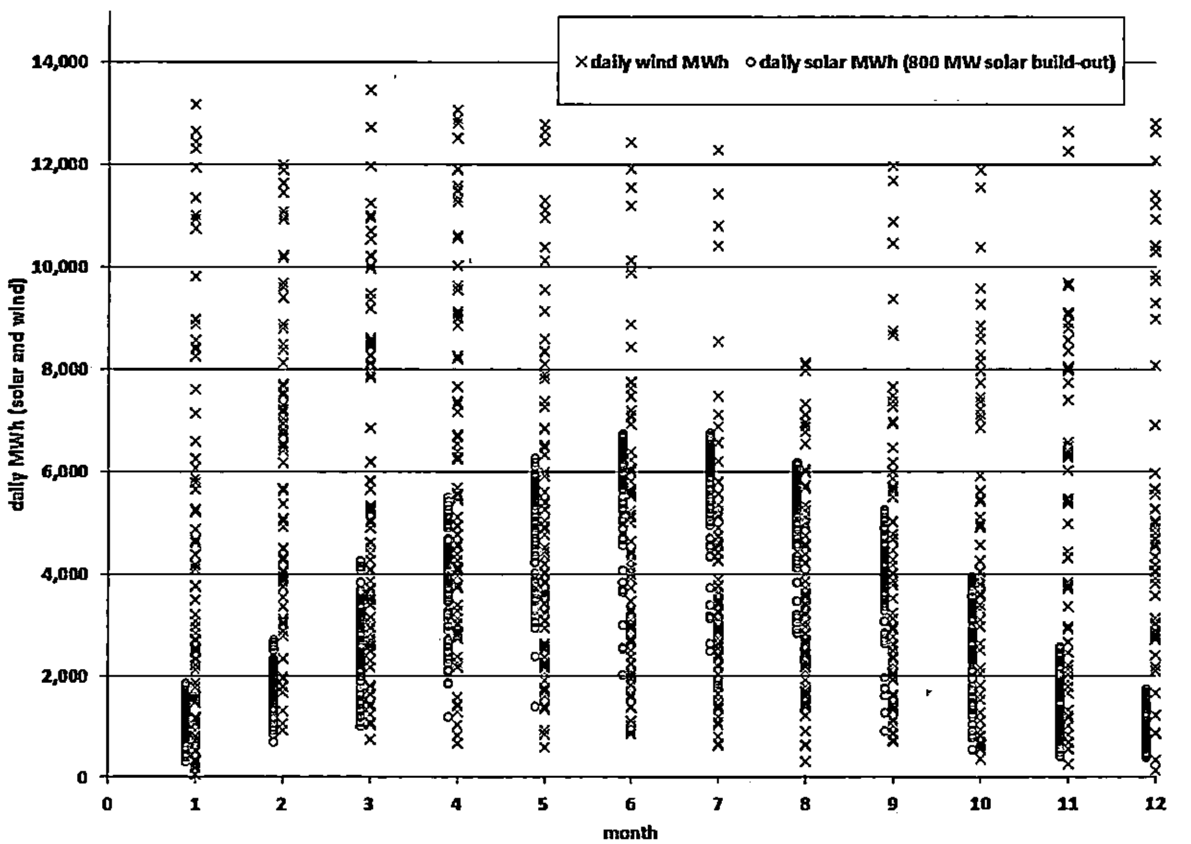

Figure 8
Distributions of daily MWh by month for wind and solar (800-MW solar build-out).

In contrast to day-ahead production forecasting, deviations from the hour-ahead solar production forecast can only be covered by Idaho Power's dispatchable generators. By design, the analysis for the solar integration study determines the amounts of bidirectional capacity in reserve that system operators would need to schedule to position dispatchable generators to cover possible deviations from the hour-ahead solar production forecast. The integration costs found by the study are a result of the solar-caused capacity in reserve, specifically the sub-optimal scheduling of dispatchable generators associated with the extra reserve amounts.

Comparison to Wind Integration

This study indicates solar plant integration costs are substantially lower than wind plant integration costs found by Idaho Power studies of wind integration. The lower integration costs associated with solar are fundamentally the result of less variability and uncertainty.
As described in the preceding section, the study assumes deviations in solar plant production from day-ahead forecast levels can be managed through a combination of market transactions and operations modifications, allowing day-ahead generation scheduling to avoid extra reserve burden. Therefore, reserve carried for solar generation can be focused on readying dispatchable generators to respond to unplanned solar excursions from hour-ahead production forecasts.

Qualitatively, the study data suggest solar is more predictable than wind generation connected to the Idaho Power system. Sunrise and sunset times, as well as the time of solar noon, are a certainty. The theoretical maximum level of production can be readily derived, reflecting patterns on daily, monthly, and seasonal time scales. Finally, land requirements for a solar power plant are likely to promote a relatively high level of dispersion, which is critical to the mitigation of impacts from severe and abrupt ramps in production exhibited by individual panels in response to passing clouds. The effects of geographic dispersion are discussed further in the following section.

Geographic Dispersion and Solar Variability

Production for a single solar PV panel exhibits severe and abrupt intermittency during variably cloudy conditions. The effect of severe and abrupt intermittency is commonly attributed to the absence of inertia in the PV process. While the intermittency effect is severe for a single panel, dampening occurs when considering the production from a solar plant-sized aggregation of panels, and even further dampening occurs when considering the production from several solar plants spread over a region such as southern Idaho. Therefore, geographic dispersion has significant influence on solar integration impacts and is perhaps of greater importance for solar than wind.

The four studied solar build-out scenarios each have capacity installed at eight southern Idaho locations spread over more than 220 miles from east to west. Because of the substantial geographic dispersion, severe instantaneous ramps in solar production for the study data are relatively infrequent. If solar plant development in southern Idaho occurs in a more clustered fashion than assumed for this study, actual integration impacts and costs will be higher than the results of this study.

The study's characterizations of solar variability and uncertainty are based on solar production time series as derived from AgriMet and SolarAnywhere point-source data; actual production data for solar power plant locations in the southern Idaho area were not available for the study. As production data become available over the coming years from solar projects connecting to the Idaho Power system, the actual production data will be analyzed to compare their variability and uncertainty characteristics to those of the derived production data used for the study.
The evidence of significant disparities in variability and uncertainty between the actual and study production data will require a re-examination of the results of this study.

Transmission and Distribution

The focus of Idaho Power's solar integration study is a macro-level investigation of the operations modifications necessary to maintain balance between power supply and customer demand for a balancing authority integrating PV solar plant generation. The objective is to understand the impacts and costs of the sub-optimal operation of dispatchable generating capacity. The study is not an investigation of integration issues related to the delivery of energy from proposed solar PV power plants to the retail customer; these issues are addressed in individual interconnection studies performed on a plant-by-plant basis.

Solar Integration Cost Elements

Idaho Power and the TRC engaged in several conceptual-level discussions on solar integration as part of TRC meetings. These discussions are valuable opportunities to further the collective conceptual-level understanding of Idaho Power and the TRC with respect to factors driving solar integration costs and impacts. These discussions also highlighted the need to provide a listing of those factors, or elements, considered to influence costs, and conversely those elements *not* considered to influence costs. Based on this solar integration study, Idaho Power considers the following as key elements influencing solar integration costs:

- The need to carry bidirectional capacity in reserve on dispatchable generators to respond to next-hour variability and uncertainty
- Incremental Hells Canyon Complex spill attributable to solar-caused capacity in reserve requirements

Conversely, the following are not considered as elements influencing solar integration costs:

- Uncertainty in day-ahead forecasting of solar production
- Solar production profiles, specifically coincidence between solar production and high/low load, or coincidence between solar production and high/low wholesale electric power market prices

Hells Canyon Complex Spill

The results indicate that spill at the Hells Canyon Complex increases with increasing solar build-out. Corresponding to the increase in spill is a decrease in Hells Canyon Complex production. For example, the decrease in simulated Hells Canyon Complex production for water year 2012 from the 400 MW to 1,600 MW solar build-out was about 250,000 MWh, which represents approximately 13 percent of the incremental generation of the additional 1,200 MW of installed solar capacity. The 250,000 MWh of lost Hells Canyon Complex generation is not included in the integration costs in this report.

The finding of increased spill with increasing solar build-out is roughly equivalent for the paired simulations; that is, spill increases for the base cases and test cases alike. This suggests that the increased spill is more the result of energy oversupply than driven by solar-caused operating reserves, noting that the paired simulations are energy equivalent and differ only in their INC/DEC reserve requirements.

The lost hydro generation is partially an artifact of a modeling assumption of keeping the weekly volumetric reservoir releases in the simulations equal to the historical record and partially a cost that would be borne by the excessive development of solar via the avoided cost process. The historic hydro operation would likely be modified in anticipation of the solar energy in an attempt to use the hydro in the most economic way possible and reducing the spilled energy. The avoided cost process with an increase of zero marginal cost energy has more hours where the highest cost marginal resource is zero. The solar energy value during these hours is zero and consequently does not "cost" the system anything. The solar is valued at the cost of the displaced hydro which is zero.

Spring-Season Integration

The production cost simulations suggest reserve requirements are particularly problematic when hydroelectric resources are highly constrained, such as frequently occurs during spring-season periods characterized by high water, low customer demand, and high generation from variable generating resources, such as wind and solar. Experience has shown wind integration to be particularly challenging during these periods, and the simulations suggest similar challenges integrating solar. This study finding is corroborated by NREL in the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013), which reports the need for flexibility is notably high during the spring and that during these periods the curtailment of variable generation is one source of flexibility along with dispatchable generators enabling the balancing of generation and customer demand. Under futures with high penetrations of solar and wind, the production from the solar and wind resources could conceivably exceed customer demand for the Idaho Power system. Even for the current system without high penetrations of solar, issues related to energy oversupply are periodically encountered because of high wind production and must-run generation (e.g., run-of-river hydro).

CONCLUSIONS

The cost to integrate the variable and uncertain delivery of energy from solar PV power plants is driven by the need to carry extra capacity in reserve. This extra capacity in reserve is necessary to allow bidirectional response from dispatchable generators to unplanned excursions in solar production relative to hour-ahead forecasting. The simulations performed for this Idaho Power solar integration study indicate costs as provided in the Results section associated with holding the extra capacity in reserve (Tables 8 through 10).

The four studied build-outs have solar capacity dispersed widely across southern Idaho. The extent of this geographic dispersion is considered to strongly influence the impacts and costs of integration. As solar capacity is developed in the coming years, Idaho Power will evaluate the geographic dispersion of the built-out capacity in comparison to that assumed for this study. In particular, observed production data will be reviewed when available to verify this study's assessment of solar variability and uncertainty.

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Appendix 1
Solar integration study appendix

Table of Contents

INTRODUCTION

This appendix contains supporting data and explanatory materials used to develop Idaho Power's *2016 Solar Integration Study*.

The main document, the *2016 Solar Integration Study*, contains a full narrative of Idaho Power's process for studying solar integration costs. For information or questions concerning the study, contact Idaho Power:

Idaho Power—Power Supply Planning
1221 W. Idaho St.
Boise, Idaho 83702
208-388-5365

TECHNICAL REVIEW COMMITTEE

The Technical Review Committee (TRC) was formed during early 2015 to provide input, review, and guidance for the study. It is comprised of participants from outside Idaho Power that have an interest and/or expertise with the integration of intermittent resources onto utility systems.

Representatives from National Renewable Energy Laboratory (NREL) participated in the early stages of the study, and contributed to the study's foundational development. However, NREL funding did not permit their active participation through study completion. Idaho Power continued to include NREL on electronic correspondence related to the study through study completion.

List of TRC Members

Brian Johnson..................University of Idaho

Cameron Yourkowski......Renewable Northwest

Clint Kalich......................Avista Corporation

Kurt Myers.......................Idaho National Laboratory

Barbara O'Neill................National Renewable Energy Laboratory

Michael Milligan..............National Renewable Energy Laboratory

Regulatory Commission Staff Observers

Brittany Andrus................Public Utility Commission of Oregon (OPUC) staff

John Crider.......................OPUC Staff

Rick Sterling ....Idaho Public Utilities Commission (IPUC) staff

DATA INPUTS AND ASSUMPTIONS

Natural Gas Price Assumptions

Table 1
Actual monthly average Idaho Citygate natural gas price for water years 2011–2013

Month	Water Year (WY) 2011 Average Monthly Price	WY 2012 Average Monthly Price	WY 2013 Average Monthly Price
October	$3.15	$3.30	$3.32
November	$3.63	$3.33	$3.48
December	$4.00	$3.18	$3.35
January	$4.22	$2.68	$3.38
February	$3.91	$2.53	$3.32
March	$3.76	$2.05	$3.71
April	$3.93	$1.83	$3.92
May	$3.98	$2.21	$3.82
June	$4.23	$2.16	$3.22
July	$4.00	$2.55	$3.36
August	$3.80	$2.61	$3.05
September	$3.73	$2.63	$3.21

Market Power Price Assumptions

Table 2
Actual average Mid-Columbia dollars/megawatt-hour (MWh) for water years 2011–2013

Month	WY 2011 Average Monthly Price	WY 2012 Average Monthly Price	WY 2013 Average Monthly Price
October	$28.78	$24.27	$26.92
November	$31.13	$27.40	$25.42
December	$31.59	$28.96	$20.04
January	$25.22	$24.51	$27.37
February	$20.70	$21.64	$25.24
March	$15.78	$13.61	$27.89
April	$16.93	$7.02	$20.10
May	$16.57	$6.56	$19.99
June	$13.09	$4.40	$25.15
July	$18.51	$7.90	$27.68
August	$25.29	$19.16	$31.28
September	$28.14	$22.63	$29.80

IPC Customer Load Data

Table 3
Actual average megawatt (MW) for water years 2011–2013

Month	WY 2011 Average Monthly Load	WY 2012 Average Monthly Load	WY 2013 Average Monthly Load
October	1,417	1,400	1,453
November	1,577	1,559	1,474
December	1,699	1,731	1,640
January	1,745	1,683	1,912
February	1,650	1,600	1,624
March	1,509	1,463	1,442
April	1,411	1,505	1,502
May	1,489	1,737	1,802
June	1,823	2,111	2,162
July	2,275	2,393	2,419
August	2,128	2,200	2,232
September	1,807	1,683	1,660

Idaho Power Existing Generation

Thermal Facilities And Capacities

Coal	
▲ Jim Bridger	770.5 MW*
▲ North Valmy	283.5 MW*
▲ Boardman	64.2 MW*
Total	1,118.2 MW
Natural Gas	
▲ Bennett Mountain	172.8 MW
▲ Danskin	270.9 MW
▲ Langley Gulch	318.5 MW
Total	762.2 MW
Diesel	
▲ Salmon Diesel	5.0 MW
Total	1,885.4 MW

Hydroelectric Facilities and Nameplate Capacities

1 Hells Canyon	391.5 MW
2 Oxbow	190.0 MW
3 Brownlee	585.4 MW
4 Cascade	12.4 MW
5 Swan Falls	27.2 MW
6 C. J. Strike	82.8 MW
7 Bliss	75.0 MW
8 Lower Malad	13.5 MW
9 Upper Malad	8.3 MW
10 Lower Salmon	60.0 MW
11 Upper Salmon	34.5 MW
12 Thousand Springs	8.8 MW
13 Clear Lake	2.5 MW
14 Shoshone Falls	12.5 MW
15 Twin Falls	52.9 MW
16 Milner	59.4 MW
17 American Falls	92.3 MW
Total	1,709.0 MW

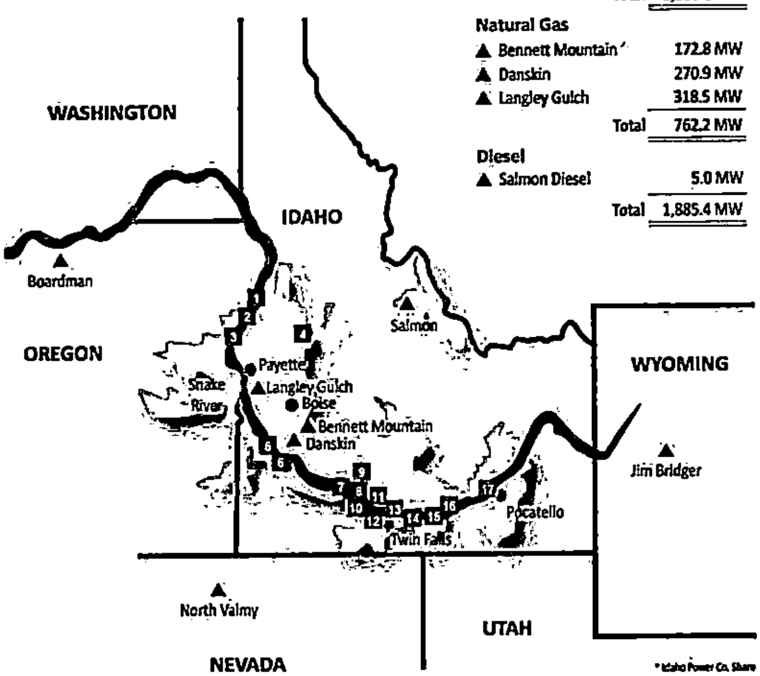


Figure 1
Existing Idaho Power generating resources

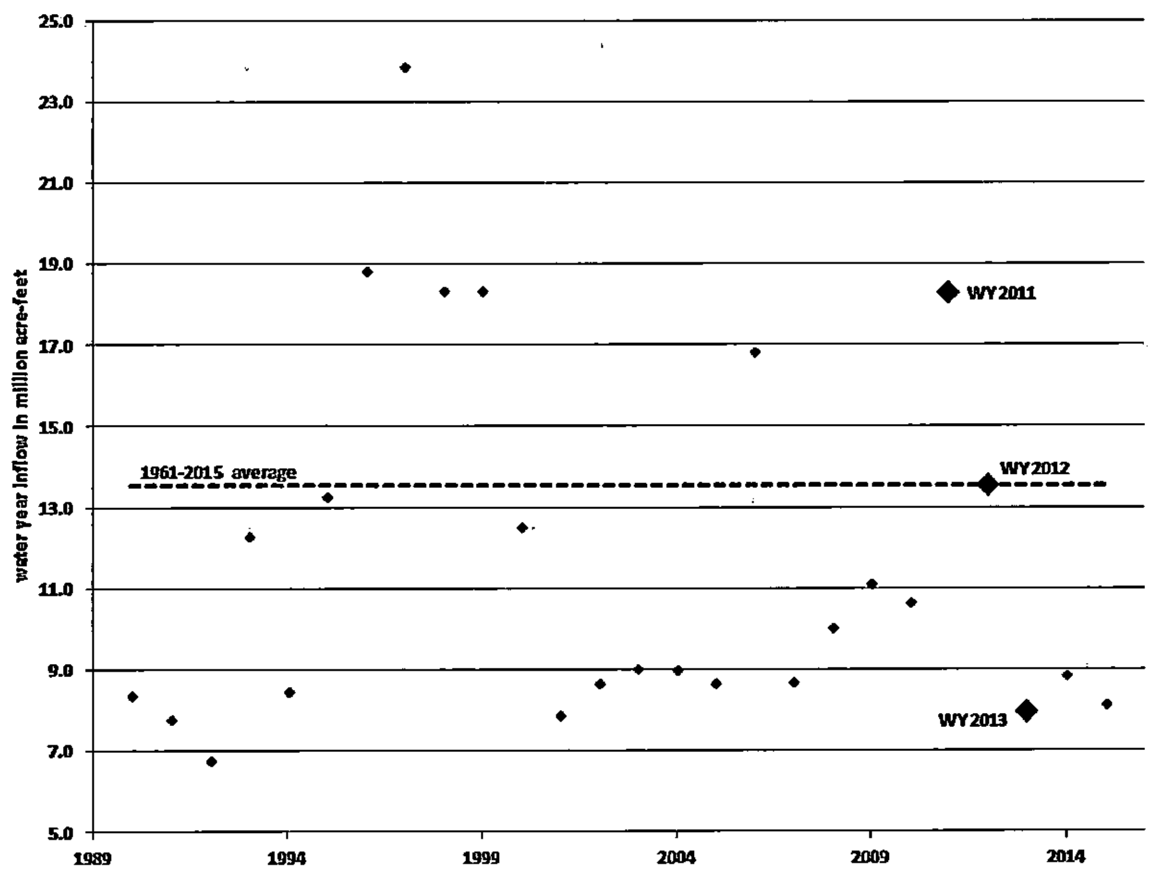


Figure 2
Brownlee Reservoir inflow by water year

Hydroelectric Generation Data

Run-of-River Projects

Table 4
Actual monthly average MW (aMW) for water years 2011–2013

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
October	435	451	191
November	374	423	166
December	470	419	177
January	346	360	178
February	373	369	188
March	348	383	178
April	505	391	164

Table 4 (Continued)

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
May	517	256	351
June	510	341	231
July	418	295	227
August	435	254	218
September	458	211	197

Wind Generation Data

Aggregate PPA and PURPA Projects

Table 5
Actual monthly aMW for water years 2011–2013, unadjusted and adjusted (normalized) to 678 MW on-line capacity level

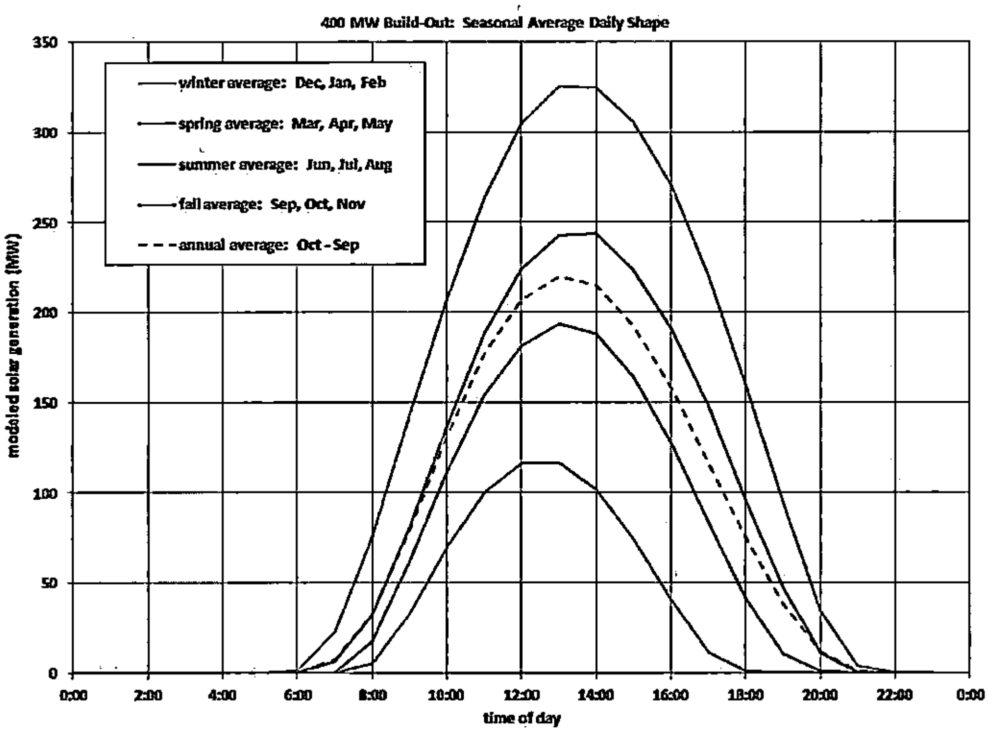
	WY 2011			WY 2012			WY 2013		
Month	**aMW**	**Online capacity**	**Adjusted aMW**	**aMW**	**Online capacity**	**Adjusted aMW**	**aMW**	**Online capacity**	**Adjusted aMW**
October	51	208	167	95	395	164	151	638	161
November	74	208	241	190	417	309	201	638	214
December	84	208	272	120	500	162	221	638	234
January	80	273	200	194	500	264	181	678	181
February	110	373	200	167	500	227	261	678	261
March	125	373	228	191	500	259	240	678	240
April	141	373	257	172	500	233	267	678	267
May	141	395	241	166	500	225	209	678	209
June	119	395	205	163	500	221	176	678	176
July	93	395	160	144	523	187	152	678	152
August	79	395	135	131	638	139	141	678	141
September	73	395	125	116	638	123	196	678	196

Non-Wind PURPA Generation Data

Table 6
Based on April 2015 projections for calendar year 2016

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
October	78	78	78
November	49	49	49
December	48	48	48
January	45	45	45
February	47	47	47
March	51	51	51
April	81	81	81
May	122	122	122
June	127	127	127
July	125	125	125
August	119	119	119
September	108	108	108

Solar Production Data



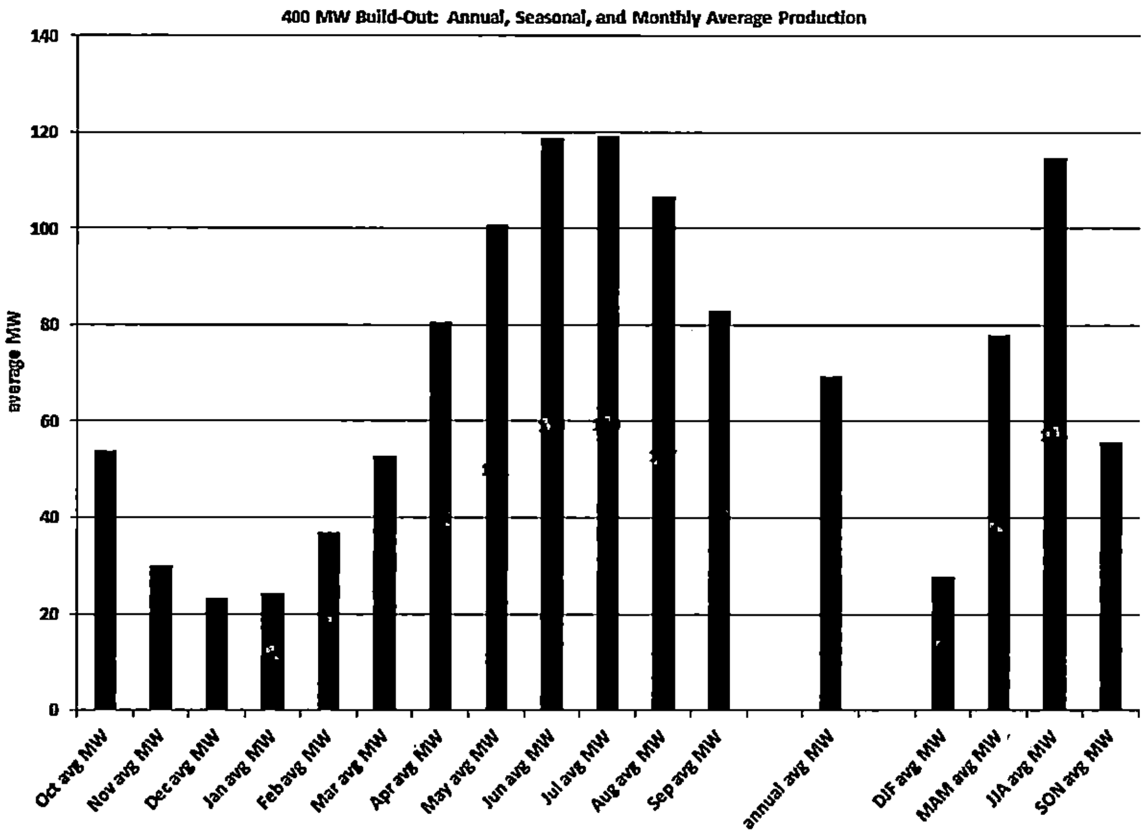


Figure 3
400 MW build-out production graphs

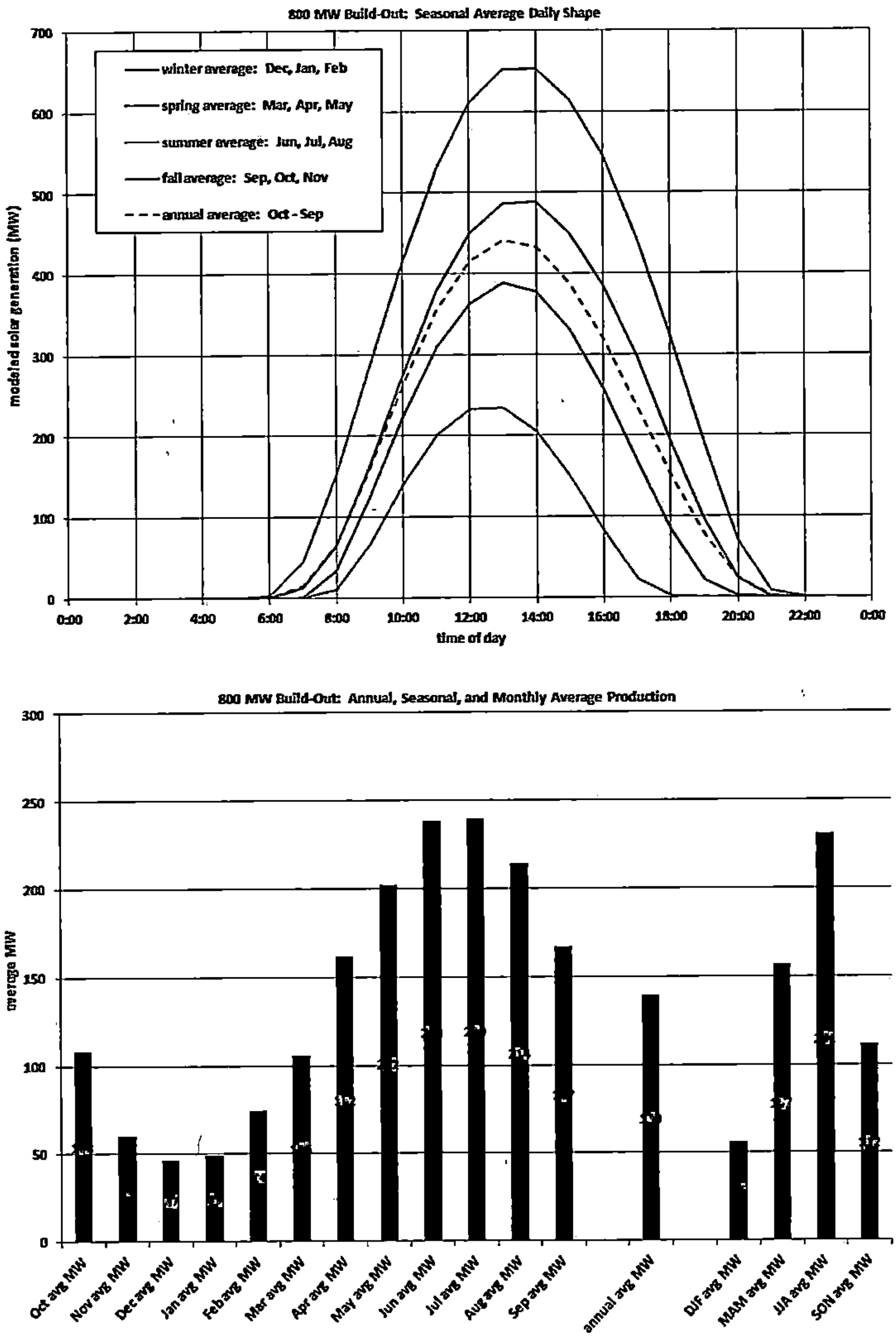
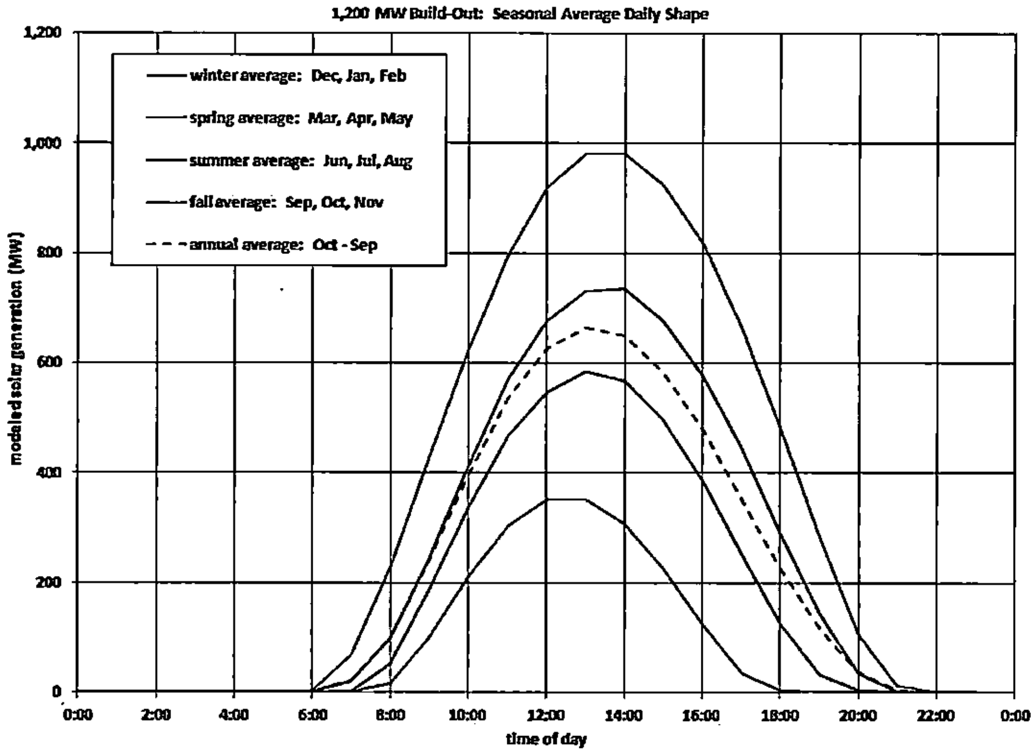


Figure 4
800-MW build-out production graphs



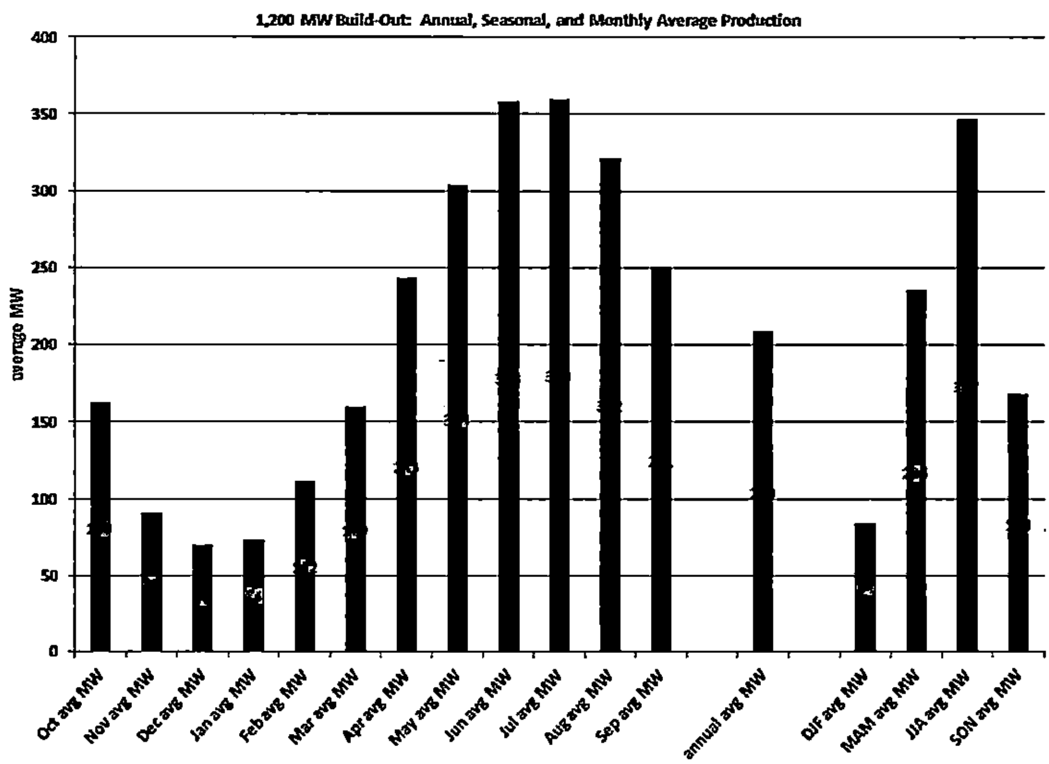
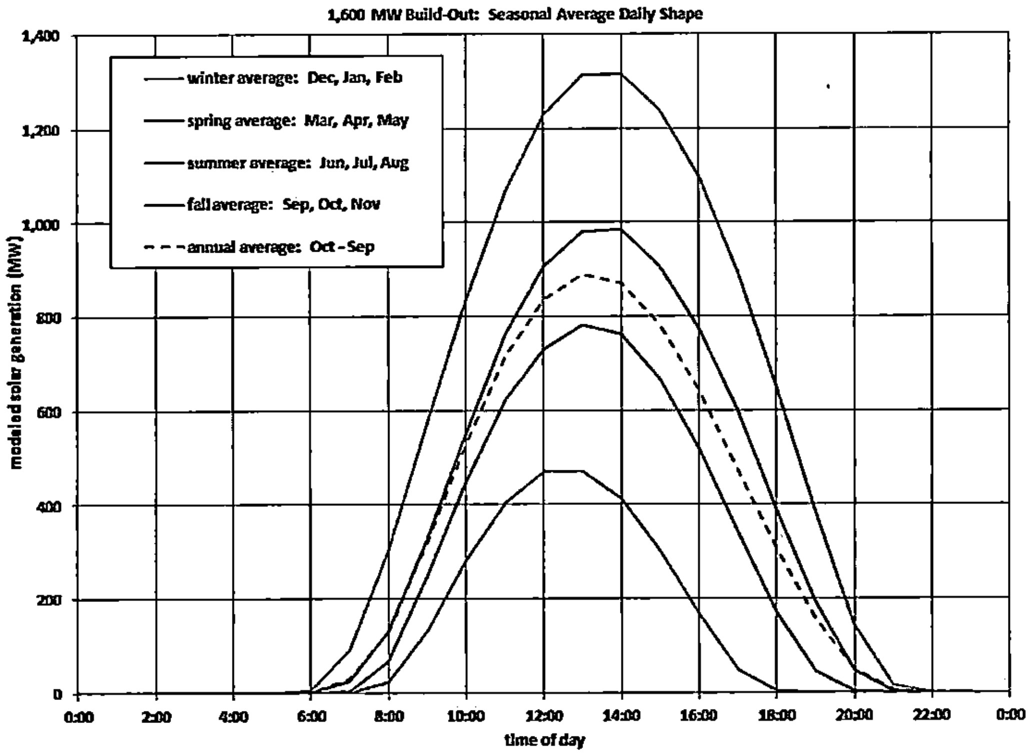


Figure 5
1,200-MW build-out production graphs



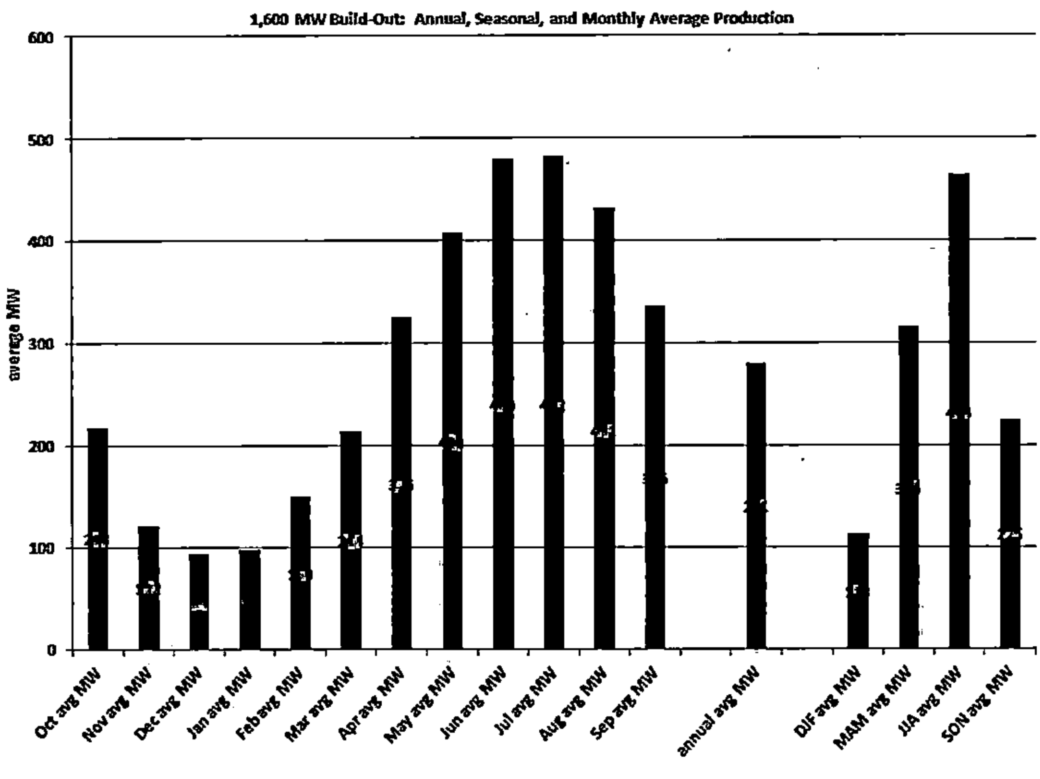


Figure 6
1,600-MW build-out production graphs

SETTLEMENT STIPULATION

The first Idaho Power solar integration study was completed in June 2014. The first study investigated integration of 4 solar PV build-outs: 100 MW, 300 MW, 500 MW, and 700 MW. The costs from the first study were the basis for solar integration costs included in the IPUC Schedule 87, which was part of a settlement stipulation approved by the IPUC in February 2015 (IPUC Case No. IPC-E-14-18). The settlement stipulation associated with the first Idaho Power solar integration study is provided here.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO IMPLEMENT SOLAR INTEGRATION RATES AND CHARGES.	CASE NO. IPC-E-14-18 SETTLEMENT STIPULATION AND MOTION TO APPROVE SETTLEMENT STIPULATION

This settlement stipulation ("Settlement Stipulation") is entered into between Idaho Power Company ("Idaho Power" or "Company"); Idaho Public Utilities Commission Staff ("Staff"); the Idaho Conservation League ("ICL"), the Sierra Club, and the Snake River Alliance ("SRA"), hereafter jointly referred to as "Parties." The Parties hereby agree as follows.

I. INTRODUCTION AND MOTION

1. The terms and conditions of this Settlement Stipulation are set forth herein. The Parties agree that this Settlement Stipulation represents a fair, just, and reasonable compromise of the dispute(s) between the Parties and that this Settlement Stipulation is in the public interest. The Parties maintain that the Settlement Stipulation as a whole and its acceptance by the Idaho Public Utilities Commission ("Commission") represent a reasonable resolution of all issues between the Parties identified herein.

Therefore, the Parties hereby respectfully move the Commission, in accordance with RP 56 and RP 274-76, for an Order approving the Settlement Stipulation executed between the Parties and all of its terms and conditions without material change or condition.

II. BACKGROUND

2. On July 1, 2014, Idaho Power filed an Application with the Commission requesting Commission approval of Idaho Power's proposed implementation of solar integration rates and charges as set forth in the proposed Schedule 87, Variable Generation Integration Charges, as indicated by the 2014 Solar Integration Study Report ("Solar Study") filed with the Application. On July 23, 2014, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 33079. ICL, the Sierra Club, and SRA petitioned for intervention which was granted. Order No. 33090; Order No. 33097.

3. On September 24, 2014, the Commission issued a Notice of Scheduling and Notice of Technical Hearing, Order No. 33137, setting forth deadlines for testimony and setting the Technical Hearing for November 13, 2014. On November 6, 2014, the Commission approved the Parties' request to suspend the procedural schedule by striking the rebuttal testimony filing deadline and Technical Hearing. The Parties agreed to meet for settlement discussions and that if settlement discussions were unsuccessful to re-establish mutually agreeable dates for the submission of rebuttal testimony and a Technical Hearing. Order No. 33173.

4. The Parties met on November 17, 2014, for settlement discussions and reached agreement resolving the issues in this case and between the Parties. Based upon the settlement discussions, as a compromise of the respective positions of the

parties, and for other consideration as set forth below, the Parties agree to the following terms:

III. TERMS OF THE SETTLEMENT STIPULATION

5. Implementation of Schedule 87, Variable Generation Integration Charges - The Parties agree to Commission approval and implementation of Schedule 87, Variable Generation Integration Charges, including the rates and charges as proposed and filed by Idaho Power in this proceeding to implement solar integration charges.

6. Initiation of a Second Solar Integration Study – The Parties acknowledge that there are disagreements with respect to the methodology used in the 2014 Solar Study. The Parties agree that Idaho Power will initiate a second solar integration study in January 2015. This second solar integration study should be completed as expeditiously as possible with the goal of not exceeding 12 months. Upon completion of the second solar integration study Idaho Power will file the same with the Commission seeking to update Schedule 87 with the results of said study.

7. Conduct of the Second Solar Integration Study - The Parties agree that the second solar integration study should utilize a Technical Review Committee ("TRC") that generally adheres to the *Principles for Technical Review Committee Involvement in Studies of Wind Integration into Electric Power Systems* authored by the National Renewable Energy Laboratory and the Utility Wind Integration Group. The TRC should include members with expertise in solar generation, variable energy integration, and electrical grid operations. The Parties also anticipate participation in the second solar integration study from the Idaho Public Utilities Commission Staff, the Public Utility Commission of Oregon Staff, the appropriate personnel from Idaho Power, and a technical expert designated by each of the Parties herein. The Parties agree that the

TRC will assist in developing the scope of the second solar integration study and provide advice on the best available methods to analyze solar integration needs, strategies, and costs on Idaho Power's system. The Parties agree and acknowledge that Idaho Power is ultimately responsible for determining how the study is conducted, the content of the study, and any results therefrom. If Idaho Power declines TRC member suggestions for the conduct of the study, Idaho Power shall provide explanation and basis for the same in writing as part of the study process.

8. Consideration of Issues in the Second Solar Integration Study - The Parties agree that Idaho Power, together with the TRC, will consider whether the second solar integration study should include the following – and if so, what would be the appropriate methodology to be used in connection with the following:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error.
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies

- Gas price forecast(s)
- Modeling of sub-hourly scheduling of load and generation
- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges.

9. The Parties submit this Settlement Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274-76. The Parties shall support this Settlement Stipulation before the Commission and shall not appeal a Commission order approving the Settlement Stipulation or an issue resolved by the Settlement Stipulation. If this Settlement Stipulation is challenged by anyone who is not a Party, then each Party reserves the right to file testimony, cross-examine witnesses, and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Settlement Stipulation. Notwithstanding this reservation of rights, the Parties agree that they will continue to support the Commission's adoption of the terms of this Settlement Stipulation.

10. If the Commission or any reviewing body on appeal rejects any part or all of this Settlement Stipulation or imposes any additional material conditions on approval of this Settlement Stipulation, then each Party reserves the right, upon written notice to the Commission and the other Party to this proceeding within fourteen (14) days of the date of such action by the Commission, to withdraw from this Settlement Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Settlement Stipulation and each Party shall be entitled to seek reconsideration of the Commission's

order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of IPUC Case No. IPC-E-13-25, and the Parties agree to cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

11. The Parties agree that this Settlement Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

12. No Party shall be bound, benefited, or prejudiced by any position asserted in the negotiation of this Settlement Stipulation, except to the extent expressly stated herein, nor shall this Settlement Stipulation be construed as a waiver of rights unless such rights are expressly waived herein. Except as otherwise expressly provided for herein, execution of this Settlement Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation or cost recovery, including the methodology employed for the 2014 solar integration study upon which the rates and charges contained in Schedule 87 are based. No Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Settlement Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Settlement Stipulation. This Settlement Stipulation sets forth the complete understanding of the Parties, and this Settlement Stipulation includes no other promises, understandings, representations, arrangements or agreements pertaining to

the subject matter of this Settlement Stipulation, or any other subject matter, not expressly contained herein.

13. The obligations of the Parties are subject to the Commission's approval of this Settlement Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction. All terms and conditions of this Settlement Stipulation are subject to approval by the Commission, and only after such approval, without material change or modification, has been received shall the Settlement Stipulation be valid.

14. This Settlement Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

IV. PROCEDURE

15. Pursuant to RP 274, the Commission has discretion to determine the manner with which it considers a proposed settlement. In this matter, the Parties have reached agreement on a final resolution to this case. This Settlement Stipulation is reasonable and in the public interest. The Parties request that the Commission approve the Settlement Stipulation without further proceedings.

16. In the alternative, should the Commission determine that further proceedings are required to consider the Settlement Stipulation, pursuant to RP 201, the Parties believe the public interest does not require a hearing to consider the issues presented by this Motion and request it be processed as expeditiously as possible by Modified Procedure, without waiving the right to a hearing on the previously disputed matters in this proceeding should the Commission reject the settlement.

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 7th day of January 2015.

Idaho Power Company

By
Donovan E. Walker
Attorney for Idaho Power Company.

Commission Staff

By Kristine Sasser
Kristine A. Sasser
Attorney for IPUC Staff

Sierra Club

By
Dean J. Miller
Attorney for Sierra Club

Idaho Conservation League

By
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By
Kelsey Jae Nunez
Attorney for Snake River Alliance

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 6 day of January 2015.

Idaho Power Company

By____________________________
Donovan E. Walker
Attorney for Idaho Power Company.

Commission Staff

By____________________________
Kristine A. Sasser
Attorney for IPUC Staff

Sierra Club

By____________________________
Dean J. Miller
Attorney for Sierra Club

Idaho Conservation League

By____________________________
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By____________________________
Kelsey Jae Nunez
Attorney for Snake River Alliance

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 7th day of January 2015.

Idaho Power Company	Commission Staff
By Donovan E. Walker Attorney for Idaho Power Company.	By Kristine A. Sasser Attorney for IPUC Staff
Sierra Club	Idaho Conservation League
By Dean J. Miller Attorney for Sierra Club	By Ben Otto Benjamin J. Otto Attorney for Idaho Conservation League

Snake River Alliance

By Kelsey Jae Nunez
Kelsey Jae Nunez
Attorney for Snake River Alliance

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 9th day of January 2015 I served a true and correct copy of the SETTLEMENT STIPULATION AND MOTION TO APPROVE SETTLEMENT STIPULATION upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Kristine A. Sasser Deputy Attorney General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email kris.sasser@puc.idaho.gov
Idaho Conservation League Benjamin J. Otto Idaho Conservation League 710 North Sixth Street (83702) P.O. Box 844 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email botto@idahoconservation.org
Snake River Alliance Kelsey Jae Nunez Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email knunez@snakeriveralliance.org
Ken Miller Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email kmiller@snakeriveralliance.org
Sierra Club Dean J. Miller McDEVITT & MILLER LLP 420 West Bannock Street (83702) P.O. Box 2564 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email joe@mcdevitt-miller.com heather@mcdevitt-miller.com

Matt Vespa
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_X_U.S. Mail
____Overnight Mail
____FAX
_X_ Email matt.vespa@sierraclub.org

Christa Bearry

Christa Bearry, Legal Assistant

TECHNICAL REVIEW COMMITTEE STUDY PLAN

The following document was shared as a draft with the TRC after receiving their input on prioritization of issues for this solar integration study.

IDAHO POWER®
An IDACORP Company

"Second" Idaho Power Solar Integration Study

Technical Review Committee Study Plan

Sponsored by:

Idaho Power Company

May 28 , 2015

Table of Contents

1. Objective

Study the integration of Solar onto the Idaho Power System.

2. Project Background

On July 1, 2014, Idaho Power filed an Application with the Idaho Public Utilities Commission requesting Commission approval of Idaho Power's proposed implementation of solar integration rates and charges as set forth in the proposed Schedule 87, Variable Generation Integration Charges, as indicated by the 2014 Solar Integration Study Report ("Solar Study") filed with the Application. On July 23, 2014, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 33079. The Idaho Conservation League ("ICL"), the Sierra Club, and the Snake River Alliance ("SRA") petitioned for intervention which was granted. Order No. 33090; Order No. 33097.

The Parties met on November 17, 2014, for settlement discussions and reached agreement resolving the issues in this case and between the Parties. On January 9, 2015, pursuant to Rules of Procedure 56 and 274 through 276, the parties filed a Joint Motion for Approval of a Settlement Stipulation. The Stipulation, in Order No. 33227, calls for the formation of a Technical Review Committee ("TRC"), see section 3.

The parties agree that the second solar integration study should utilize a Technical Review Committee (TRC) that generally adheres to the *Principles for Technical Review Committee Involvement in Studies of Wind Integration into Electric Power System* authored by the National Renewable Energy Laboratory and the Utility Wind Integration Group. The TRC will advise Idaho Power of the scope and methods use in the analysis, however, Idaho Power is ultimately responsible for determining how the study is conducted, the content of the study, and any results therefrom.

This Study plan will guide the development of a second Solar Integration Study to be filed with the Idaho Commission by the first quarter 2016.

2.1 2014 Solar Integration Study

The 2014 study performing an integration analysis of four solar penetration levels (100 MW, 300 MW, 500 MW, and 700MW). The analysis took each penetration level and completed two production cost simulations, one with the solar forecast assumed to be perfect and the other including the same level of energy but also holding capacity available in the Idaho Power system to accommodate a predicted level of uncertainty for any given hour. By using the difference method, the value of the energy produced due to the production uncertainties does not get incorporated into the integration cost result.

Idaho Power integration studies use a production cost model developed internally by Idaho Power to closely simulate operation of the Hells Canyon Complex (Brownlee, Oxbow and Hells Canyon hydro plants), the Idaho Power gas and coal thermal generation, and the Idaho Power transmission interconnections. The simulation model represents the three generation facilities in the Hells Canyon Complex in a cascaded fashion where water flows from Brownlee, through Oxbow, and then through the Hells Canyon dam, recognizing that many hydro constraints placed on the complex including flood control and environmental fish mitigation measures. The cascaded simulation means that each dam has separate dispatch considerations yet the dispatch decisions of the upstream plants constrain the dispatch decisions of the downstream plants.

3. Technical Review Committee (TRC)

The following members have agreed to participate in the TRC:

Cameron Yourkowski
Senior Policy Manager
Renewable Northwest
421 SW 6th Ave, Suite 1125
Portland, OR 97204
503-223-4544
971-634-0143
cameron@renewablenw.org

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Rick Sterling
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Rick.Sterling@puc.idaho.gov
208-334-0351

John Crider
Oregon Public Utilities Commission
John.crider@state.or.us
503-373-1536

3.1 TRC Principles

Based on the "Principles for Technical Review Committee (TRC) Involvement in Studies of Variable Generation Integration into Electric Power Systems" Paper:

What will the TRC Provide?

A properly constituted TRC will assist the project sponsors in ensuring that the quality of the technical work and the accuracy of results will be as high as possible. TRC participation will also enhance the credibility and acceptance of the study results throughout the affected stakeholder communities. And TRC members will be qualified to carry the key messages of the study to their respective sectors.

What is a Properly Constituted TRC?

TRC membership should include individuals that collectively provide expertise in all of the technical disciplines relevant to the study. A TRC facilitator should be selected from among the TRC membership. Sponsorship and facilitation of the TRC should be independent from, but closely coordinated with, the project sponsors and the team conducting the work. Observers from relevant government agencies and other interested parties may attend TRC meetings and be included in TRC communication at the discretion of the project sponsors. Alternatively, a separate stakeholder group can be considered in order to update interested parties on study progress and key results.

What are the TRC's Functions & Requirements?

The TRC will:

- Review study objectives and approach, and offer suggestions when appropriate to strengthen the study.
- Help ensure that the study:
    - Builds upon prior peer-reviewed variable generation integration studies and related technical work;
    - Receives the benefit of findings from recent and current variable generation integration study work;
    - Incorporates broadly supported best practices for variable generation integration studies;
    - Is developed with broad stakeholder input.
- Engage actively in the project throughout its duration. In general, project review meetings should be held nominally on a regular basis.
- Engender collegial discussions of methods and results among TRC members, the study team, project sponsors and other interested parties. The aim of these discussions is to improve accuracy, clarity and understanding of the work, and reach consensus resolution on issues that arise.

- Avoid public disclosure of meeting discussions and preliminary results. In general, findings should not be released until accepted and generally agreed upon by project sponsors, the study team and the TRC. When advisable, possible and agreed to by all project participants, interim progress reports can be provided to a broader stakeholder group.
- Ensure that findings are based entirely on facts and accurate engineering and science. Project sponsors need to embrace this aim so that the results and findings are objectively developed and not skewed to support any desired outcome.
- Document results of TRC meetings and distribute meeting presentations and minutes.

To carry out these functions, the TRC requires

- Access to all relevant information needed to properly evaluate the work and the results. When required, TRC members will enter into confidentiality agreements to protect this information. In no case can certain information needed by the TRC be declared "off-limits."
- Assurance that the study results will be made public through published documentation or other suitable means, with the understanding that business-sensitive information will not be made public.

4. Consideration of Issues

Parties agree that Idaho Power, together with the TRC, will consider whether the second solar integration study should include the following – and if so, what would be the appropriate methodology to be used in connection with the following:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or carried fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies
- Gas price forecast(s)
- Modeling of sub-hourly scheduling of load and generation

- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate there events and reduce integration costs and charges.

4.1 Discussion

As with the prior study, there continue to be challenges in studying the effects and associated costs of integrating variable generating resources, such as solar, onto a vertically integrated power system. Unfortunately Idaho Power and the TRC do not time to achieve resolution of all issues. Idaho Power and the TRC addressed the study scope and the issues in the stipulation that can be addressed given desire to complete the study by the end of 2015. Idaho Power and the TRC jointly agreed to limit the scope of the solar integration study.

4.2 Conclusion

Following a discussion and input from the TRC, Idaho Power and the TRC agreed to address the following issues in the second integration study:

- Correlation between solar, wind, and load variability, uncertainty, and forecasting error.

  Idaho Power will update the integration study method to replace plus or minus three percent load variability with time varying data. Idaho Power will study the correlation between solar, wind, and load variability, uncertainty, and forecasting error. In particular, Idaho Power will study the effects that different solar penetration levels will have on Idaho Power's system variability considering the existing load and wind on the Idaho Power system.

- Clustered solar build-out scenarios

  Idaho Power will review build-out scenarios to align the scenarios to the expected solar development. Additional solar data will be acquired by Idaho Power. Idaho Power will perform a separate set of sensitivity cases at the 800 MW penetration level.

- Higher Penetration Levels

  With 320 MW under contract and many 100s more in study. Requests have surpassed the 2014 study levels. Idaho Power will analyze the integration costs at the 400 MW, 800 MW, 1200 MW and 1600 MW quantities to address a wide range of futures.

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year

  Idaho Power will use the water year data for 2011, 2012 and 2013 coincident with other wind and market data for those periods.

- Frequency and effect of low occurrence events

  Idaho Power will perform the analysis on higher penetration levels where the events may significantly exceed the reserve capacity held for such events.

The following issues that are more difficult to assess, or are of lower priority, these will be addressed by:

Rather than performing detail studies, using west wide system models for example, sensitivity cases at 800MW will be performed by adjusting the regulation requirement by an appropriate percentage. These sensitivities will provide some indication of the relative effect the issue has on the integration costs.

- Issues that require an interconnection-wide view of the system are costly and time consuming:
  - Intra-hour trading opportunities
  - Energy imbalance markets (EIM) or other market structures
  - Modeling of sub-hourly scheduling of load and generation

  Idaho Power applied the Plexos interconnection-wide model in the 2013 wind integration study, the study cost was high (over $100,000) and failed to produce reliable and rational results. There is no current active intra-hour market in the Pacific Northwest and any study involves numerous assumptions including how to represent current operations and whether the modeling package closely simulates an assumed intra-hour trading market.

  Idaho Power participated in the development of a joint initiative project with over fifteen other utilities called ITAP or Intra-hour Transaction Accelerator Platform. ITAP is an internet based tool designed to facilitate expedited energy trading. The ITAP tool has not been successfully deployed by the participating utilities.

  Sub-hourly dispatch affects the real-time market value. Resource capacity is still necessary to follow the uncertain output. Contemplated energy imbalance markets in the west are not expected to trade capacity products or perform unit commitment decisions. Capacity and unit commitment decisions are the focus of integration studies including the Idaho Power integration studies.

- Reducing the hour-ahead forecast lead time from 40 minutes to 30 minutes

  Power purchases and sales must be acquired and tagged by 20 minutes before the top of the hour. A 30 minute lead-time leaves 10-minutes to acquire and tag a transaction. The 10-minute interval is possible in some hours, but in high transaction volume hours, a ten-minute interval is problematic.

The following are of a lower priority that will not be addressed in this integration study:

- Improved forecasting methods

  As described in section 2, Idaho Power in the 2014 Solar Study did an excellent near-term forecast of the variability of expected solar production. Idaho Power does not see much opportunity for improvement.

- Voltage/Frequency regulation

  From a voltage perspective, Voltage and frequency issues may be considerations in some geographic locations, but voltage and frequency regulation is beyond the scope of this integration study. Idaho Power is performing other studies considering regulation issues.

  Solar production technology is displacing more typical resources that have governors making the generation resource responsive to large changes in frequency due to the loss of generation. As greater penetrations of solar are achieved in the western interconnection, system reliability may necessitate requiring inverters with frequency response. Voltage and frequency regulation is beyond the scope of this integration study.

- Gas Price Forecast(s)

  Different gas price forecasts can be considered, however, current data (2010-2013) is time synchronized. Changing Gas data will affect market prices and the dispatch of most resources. The selected simulation years contain a range of actual natural gas prices.

- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)

  Integration costs would not be generally affected because most solar uncertainty is a result of atmospheric conditions. Different solar plant technologies would likely affect energy value of the solar generation project.

- Increased transmission capacity, changes in operation of hydroelectric facilities, and addition of demand-side technologies

  The Idaho Power transmission system capacity is fully subscribed and no new construction is planned until Boardman to Hemingway. Idaho Power anticipates updating the solar integration study as conditions change.

  Restrictions at Hells Canyon would likely reduce the capability of the Idaho Power system to integrate variable generation resources.

Demand-side technologies reduce load and affect Reg Up capacity where intermittent generation output is below forecast. Present demand-side technologies are less useful when the intermittent generation exceeds the forecast.

- Energy storage with energy scheduling method to eliminate integration cost

Battery storage of two hours of intermittent generation nameplate output may reduce integration costs. No integration study is required, but designing scheduling protocols would be necessary. Large-scale battery storage is not anticipated in the 2015 Idaho Power Integrated Resource Plan.

5. Study Approach

As with prior integration studies, the assessment will be made from the difference between two production cost cases:

1. one with capacity reserved for uncertainty,
2. and the other case assuming output follows a perfect forecast.

5.1 Solar Data

Solar data will be developed for 400 MW, 800 MW, 1200 MW and 1600 MW penetration levels. These data will be developed using information and patterns seen in signed and unsigned contracts. Idaho Power will acquire additional solar data to assist in the development of the generation profiles. Idaho Power will use the uncertainty forecasting method developed in the 2014solar integration study to establish the uncertainty capacity requirements at the solar generation levels at 400 MW, 800 MW, 1200 MW and 1600 MW of solar generation. Schedule

The following table presents a schedule for conducting this Solar Study starting in January 2015 and completing the study less than 12-months later in December 2015.

Activity	Period
TRC Formation	Jan 26 – Feb 15
TRC Kick Off Call	March 6
Develop Study Scope & Study Plan	March 6 - 31
Data Analysis	March 1 – May 31
TRC Meeting	May 5
TRC Call	June
Integration Study Analysis	July 1 – August 31
TRC In-Person Meeting	July
TRC Call	August
Draft Report	Sept 1 – Nov 15
TRC Call	September

TRC Call	October
TRC Review Draft Report	Nov 15 – Dec 1
Study Workshop	November
File Study at Idaho Commission	December 15

Table 1: Solar Integration Study #2 Schedule

Appendix A: Invitation/Introduction Letter

February 19, 2015

Subject: Second Solar Study Technical Review Committee

To: Potential Technical Review Committee Members

As part of a settlement stipulation approved by the Idaho Public Utilities Commission in Case No. IPC-E-14-18, Idaho Power has agreed to perform a second solar integration study. I have been asked lead this study for Idaho Power. The study is expected to be complete by December 2015 as outlined in the attached stipulation agreement. I am contacting you and others, as shown in the attached proposed Technical Review Committee ("TRC") membership list. Your willingness to participate as a member of the TRC is much appreciated.

I anticipate the committee will meet via conference call or face to face once a month on average through the completion of the study. Initially the committee will meet to discuss the study issues, the study focus/scope, and the plan to accomplish the study. Later meetings will be used to discuss study progress and finally to review a draft study report in late fall. Idaho Power will strive to document the discussion of the issues and rational for any decisions made that impact the study. As the stipulation states, Idaho Power is ultimately responsible for the study.

As with the prior study, there continue to be challenges in studying the impacts and associated costs of integrating variable generating resources, such as solar, onto a vertically integrated power system. One significant challenge the TRC will have to address is the study scope and how many of the issues in the stipulation can be addressed given the compressed schedule. Unfortunately we do not have unlimited resources, the capability, or the time to achieve resolution of all these issues. To that end, we have attached a matrix list of the issues in the stipulation. I would like the TRC members to rank each issue with their view of the priority and complexity (High, Medium, Low rankings). For example, to address some issues it will be very complex and time consuming yet yield results of lesser value than other issues that are less complex and of higher value. Another question is whether there are other issues of high value that should be added to this list.

We understand that your time is valuable, and we will strive to minimize your time commitment. We will be using the doodle website to schedule the first kick-off conference call for everyone that is capable of web conferencing. If you have a preference for a face-to-face meeting, that can be arranged. We are extremely grateful for your participation as a member of the TRC. If you have additional questions, please don't hesitate to contact me.

Best Regards,

Ronald Schellberg
Transmission Policy and Development
Idaho Power Company
Phone 208-388-2455

Appendix B: Settlement Stipulation Issues

Issue	Priority	Complexity
Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year		
Intra-hour trading opportunities		
Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes		
Clustered solar build-out scenarios		
Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)		
Correlation between solar, wind, and load variability, uncertainty, and forecasting error.		
Improved forecasting methods		
Energy imbalance markets, or other market structures		
Voltage/frequency regulation		
Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies		
Gas price forecast(s)		
Modeling of sub-hourly scheduling of load and generation		
Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges.		

NAVIGANT

Cost of Variable Integration

Cost of Variable Integration

Prepared for South Carolina Electric & Gas Company

SCE&G is becoming

Dominion Energy®

Submitted by:
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Washington, DC 20036

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February 2019

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DISCLAIMER

NOTICE

This report was prepared by Navigant Consulting, Inc. (Navigant) for South Carolina Electric & Gas Company (SCE&G). The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

EXECUTIVE SUMMARY

This study was commissioned by SCE&G in order to estimate the impacts that solar installations will have on system operation and the resulting incremental costs. The study considers the variable integration costs for 3 different scenarios of solar generation installed on the system. Due to the variable nature of solar generation, SCE&G needs to ensure that there are sufficient reserves on the system to be able to meet load when less solar is generated than was forecasted. This study evaluates the uncertainty in the solar generation, the resulting reserve requirement for SCE&G, and the added operating costs from holding those reserves. The study also considers whether alternative mitigation options such as adding new battery storage or gas combustion turbine units can reduce this cost.

SCE&G's challenge is that the utility combines both a large proportion of inflexible baseload (coal and nuclear) generation with high penetration of solar installations. This causes operational challenges due to the limits of the baseload generation for ramping up or ramping down in response to solar generation.

Study Approach

For this analysis, Navigant first benchmarked its PROMOD model to SCE&G's system to create a baseline. Three solar penetration scenarios were then run to analyze the impacts that various levels of solar would have on the system. Each scenario included different amounts of solar and is described below.

- Baseline Scenario (Baseline)– 336 megawatts (MW) of solar generation interconnected with SCE&G's system by the end of 2018.[1]
- Solar Case 1 (SC1)– 637 MW of solar generation interconnected with SCE&G's system by the end of 2019.
- Solar Case 2 (SC2)– 1,044 MW of solar generation interconnected with SCE&G's system by the end of 2020.

The following methodology was used to evaluate the impacts of solar generation and the variable integration costs:

1. PROMOD production cost software was benchmarked to the existing SCE&G system to provide a baseline of system operation in each of the solar penetration scenarios.
2. Solar generation uncertainty and forecast error was estimated.
3. The additional reserves needed to integrate the solar generation was calculated.
4. PROMOD was used to calculate the production costs with additional reserves required and the resulting levelized variable integration costs.

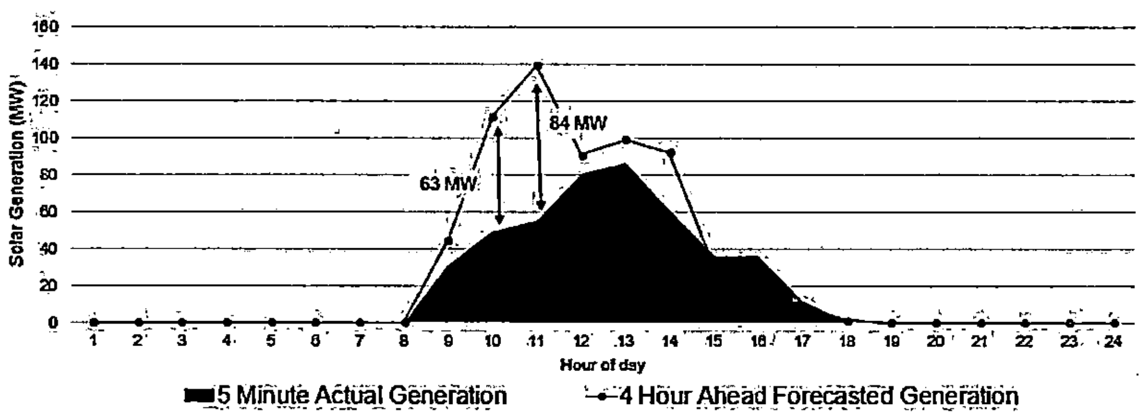
[1] This is a conservative case. Actual installations by the end of 2018 already exceed this amount.

5. Alternative mitigation options were evaluated.

Renewable Uncertainty and Need for Additional Reserves

SCE&G must operate the system differently in order to maintain reliability when solar generation increases. The following figure gives an example of how solar forecast error and uncertainty can cause actual generation to be less than forecasted generation. In this case, SCE&G must have the capability to ramp generation up to meet load when the solar generation is less than expected.

Figure 1. Solar Generation Variability Example



The following table shows the results of the analysis of the maximum expected drop in solar generation as it relates to the level of expected generation.

Table 1. Solar Forecast Uncertainty

Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

The mechanism to ensure that SCE&G can meet load when solar generates less than forecast is to hold additional operating reserves with units that can either start up quickly or are operating at less than full load. The following table shows the operating reserves that SCE&G holds now as "Business as Usual" (BAU) and would have to hold in each solar case.

Table 2. Maximum Additional Reserves Needed

Year	BAU	Baseline	SC1	SC2
2019	240	347	421	420
2020	240	348	445	529
2021	240	349	447	579
2022	240	351	448	581
2023	240	352	450	582
2024	240	354	451	584
2025	240	356	453	586
2026	240	358	456	588
2027	240	360	458	590
2028	240	363	460	593
2029	240	365	463	595
2030	240	368	466	598
2031	240	371	469	601
2032	240	375	472	605

Conclusions

There are two broad mechanisms for SCE&G to ensure that there are sufficient reserves on the system:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[2]

Holding reserves increases costs by causing less efficient units to operate more and by having units operate at less than full capacity. This increases variable operating and maintenance (VOM), fuel costs, emissions costs, and start up costs. The following table shows how the overall production costs change

[2] Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because SCE&G cannot implement it unilaterally but only with technological changes by the solar facility owners.

for SCE&G and how this leads to a 15 year (2020 -2034) levelized variable integration cost of $3.96/megawatt-hour (MWh).

Table 3. Breakdown of Incremental Costs in SC2

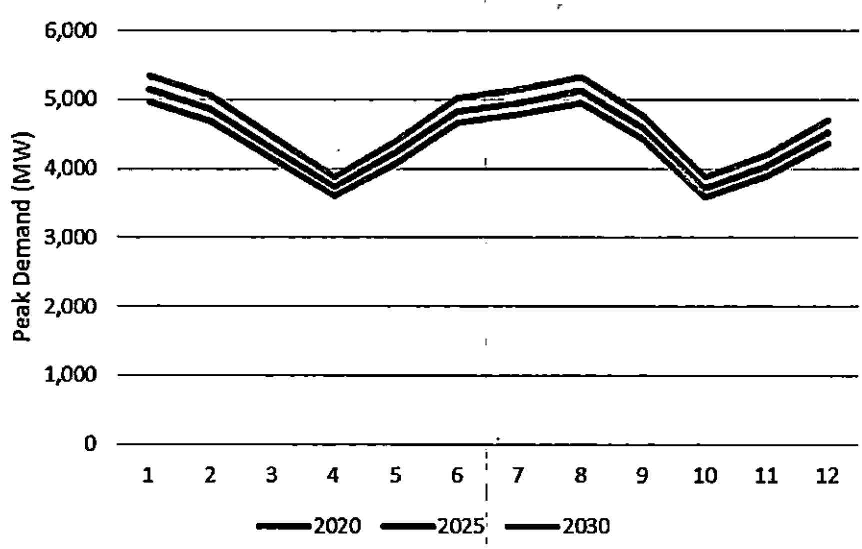
	VOM	Fuel	Emission	Start-up	Total
Cost Difference NPV ($)	$13,941,615	$40,320,211	$48,760	$19,103,954	$73,242,219
Generation NPV (MWh)			18,495,510		
Levelized Cost ($/MWh)	$0.75	$2.18	$0.003	$1.03	$3.96
% of Total Cost	19%	55%	0%	26%	100%

1. IMPACT OF SOLAR ON SCE&G OPERATION

1.1 The SCE&G Power System

SCE&G provides electric services for a large portion of South Carolina, with forecasted hourly demand typically ranging from approximately 2,000 to 5,000 MW, and forecasted monthly peak demand between approximately 3,500 and 5,000MW depending on the year and before accounting for demand-side resources. SCE&G experiences both winter and summer peaks, as shown in Figure 2, with the highest demand occurring during January and August. This trend is expected to remain consistent over time.

Figure 2. Monthly SCE&G Peak Demand[3]



SCE&G operators must ensure that both system load and operating reserves are met in all normal conditions. SCE&G is required to hold 200 MW of reserves at all times to meet their requirements within VACAR to be able to respond to the loss of the single-largest unit on the system.[4] An additional 40 MW of reserves are held for load-following. Due to the need for self-sufficiency, SCE&G must rely on its own generators to meet generation and reserves, and cannot rely on external sources.

Reserve requirements are met by operating the system in a manner to maintain the capability to increase generation quickly up to the level of reserves that are required. For example, many of SCE&G's combustion turbine (CT) units are able to start within 15 minutes. These units provide reserves even

[3] Not including demand-side resources.

[4] VACAR is the balancing authority that SCE&G is a part of. VACAR must maintain NERC reliability standards including holding sufficient contingency reserves in order to respond to the single largest contingency on the system. The 200 MW of reserves for SCE&G is its share of these contingency reserves.

when they are not operating. The combined cycle (CC) units require two hours or more to start if they are not operating. These units can only provide reserves if they are turned on and operating below their full capability (holding some capability in reserve). Operating units below full capacity is less efficient both economically and environmentally.

A summary of SCE&G's resources can be found in the table below; solar is not included as new resources are still being considered and would vary case to case for the scenarios run. SCE&G also has 100 MW of interruptible load that can be used to meet reserve requirements.

Table 4. Summary of SCE&G Resources

Technology	Name Plate Capacity (MW)	Avg. Ramp Rate (MW/hr)	Quick Start	Avg. Start Cost ($)
Combined Cycle	2,430	302	No	$17,101
CT Gas	389	76	Yes[1]	$0
ST Gas[2]	796	186	No	$3,466
ST Coal[2]	1,881	62	No	$10,317
Nuclear	650	480	No	$0
Hydro	239	239	No	$0
Pumped Storage	576	576	No	$0

1. *Urqhart CT Gas #4 is not capable of providing quick start reserves.*
2. *The Cope Steam Turbine plant runs on natural gas during the summer and on coal during winter, due to fuel availability.*

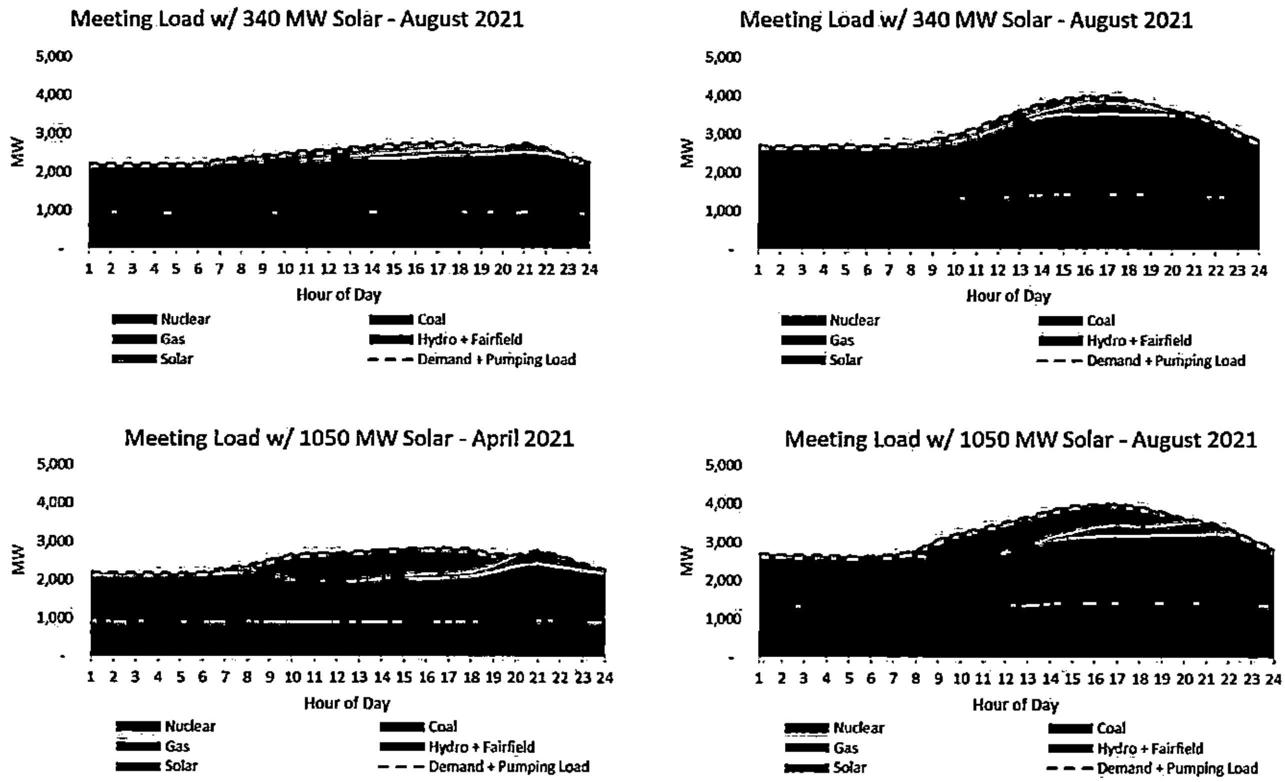
Compared to other power systems such as those in Florida or Duke Energy Carolinas, SCE&G has a high proportion of "baseload" generating capability from nuclear and coal plants. The key characteristic of baseload plants is that they have limited ability to change their generation quickly and are unable to start-up or shut-down without a long lead-time.

1.2 Changes to System Operation with Solar

As the amount of solar on the SCE&G system increases, the existing generators will be operated differently to ensure that load can be met and reliability criteria can be maintained. Power from solar generation rises in the morning, is at its peak throughout the day, and decreases when the sun sets. Furthermore, solar generation is intermittent meaning that solar generation is not fully controllable by SCE&G and can be either higher or lower than expected. To operate the system, other generators will need to be turned down in the middle of the day when solar generation is highest and sufficient reserves will need to be held so that SCE&G can maintain operation if solar generation is less than expected.

Some examples of how daily operation changes by season and as solar generation on the system increases are shown in Figure 2.

Figure 3. Average Daily Operation - Baseline and C2



Adding solar to SCE&G's system generally reduces the marginal cost of generating power as solar has no fuel costs associated with generation and adding it allows the SCE&G system operators to reduce the generation at other units. These direct impacts are calculated in the PR-1 and PR-2 avoided cost filings and show the benefits from solar to reduce fuel use and other operating costs.

However, SCE&G must also ensure that sufficient system reserves are available to replace generation when the actual solar generation is below the forecast. This would result in holding additional reserves on top of the 240 MW already required; SCE&G would have to change their system operation to ensure that these reserves can be met.

Depending on how the system is operating, there are several potential outcomes for SCE&G operation:

- There may already be sufficient online flexibility to meet the additional reserves in which case there would be no change to the operation.
- It may be necessary to generate more from less efficient resources to ensure that other units that can provide ramping capabilities are at less than full capacity.

- It may be necessary to start-up less efficient generation in order to be able to provide the reserves.

The costs to ensure this flexibility is what is estimated in this study and are separate from the system costs calculated in the PR-1 and PR-2 avoided cost filings.

The following two examples shows how system operation can change when additional reserves are required. With the current amount of reserves that SCE&G holds, the lowest cost way to operate the system is to have the CC units generate at almost full capacity while providing few reserves. Most of the system reserves are provided by Saluda Hydro and the CT gas units. When additional reserves are needed, the operators must turn down the CC units to provide reserves and turn up Steam Turbine (ST) Coal units to provide energy. This increases the cost to operate the system.

Figure 4. SCE&G Operation with Business-as-Usual Reserves Required

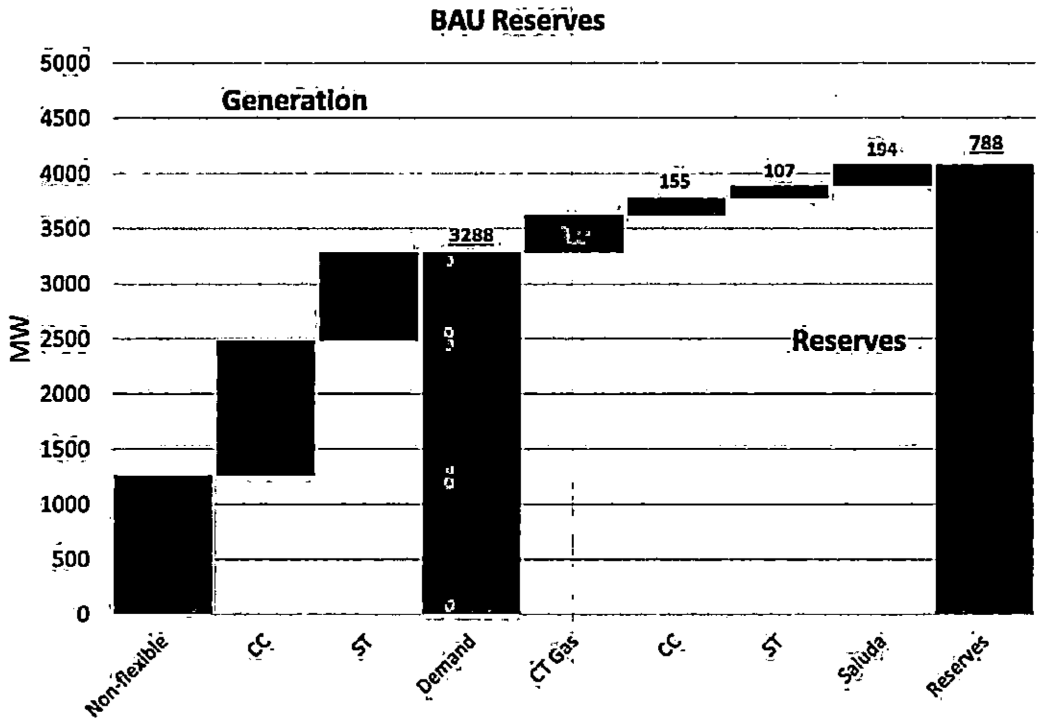
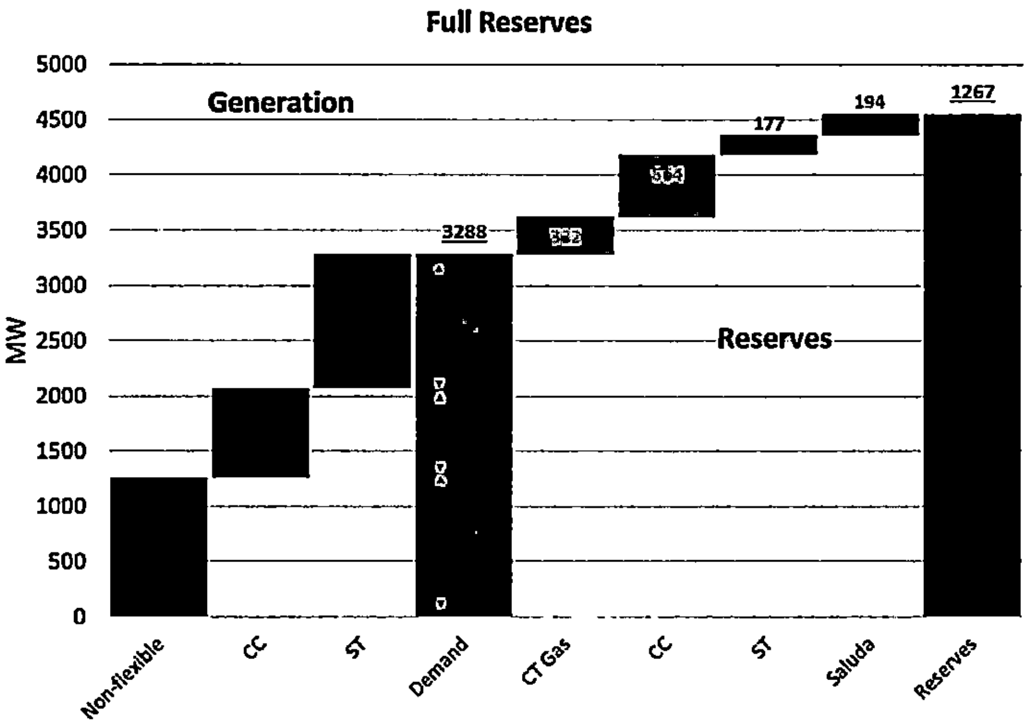


Figure 5. SCE&G Operation with Additional Reserves



2. STUDY METHODOLOGY

As discussed in Section 1, operating SCE&G's system with increasing solar installations will require the utility operators to maintain sufficient operating reserves and ensure that load can be served even when actual solar generation is less than expected generation. Mechanically, this means that SCE&G operators will need to maintain sufficient operating reserves (the ability to ramp units up) to both meet VACAR requirements and to cover any unexpected shortfall of solar generation.

The general approach to calculate the costs of this additional requirement is to simulate system operation with and without the additional operating reserves, compare system costs in the two scenarios, and evaluate if there are any other potential mitigation alternatives that could result in lowered system costs. The study forecasts system integration costs for 15 years from 2020 -2034. The following describes the full study methodology and assumptions in detail.

2.1 Key Study Assumptions

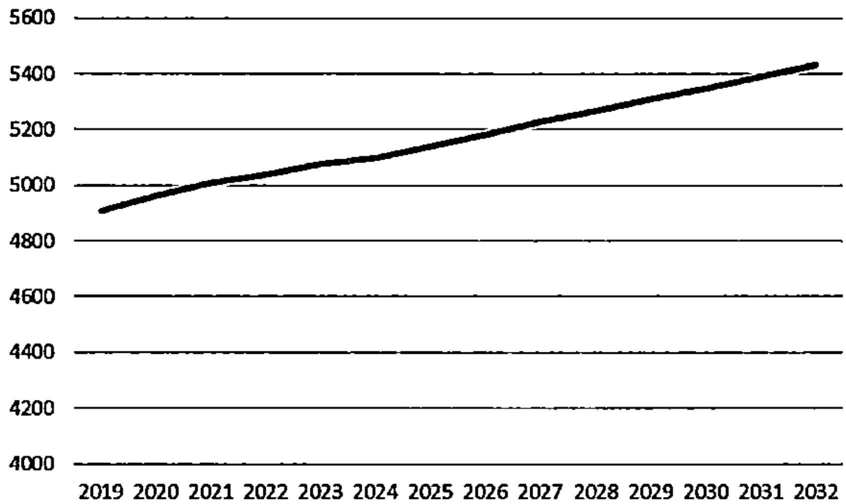
As a baseline, this study uses the same assumptions as SCE&G's Integrated Resource Plan (IRP). The key assumptions of the IRP include the forecasted system load and the existing and new resources needed to meet this load requirement.

2.1.1 System Load

The following chart shows the forecasted annual system peak load[5] for the study period of 2019 to 2032. Annual load grows at a constant and relatively low rate, with a CAGR of approximately 0.8% over the study period.

[5] The system was simulated hourly and the forecasted load is used on an hourly basis.

Figure 6. Annual SCE&G Peak Demand



2.1.2 SCE&G Generating Resources

Below is the list of SCE&G units. Solar units are not included as they vary between the cases analyzed by Navigant. The combined-cycles, ST Coal, ST Gas, and V.C. Summer nuclear plant provide the majority of baseload generation needed in SCE&G, with the ST Gas and CCs able to ramp up their output during peak hours. The CT Gas and Saluda plants are used for reserves and peaking needs.

Table 5. SCE&G Dispatchable Units

Plant	Units	Technology	Name Plate Capacity (MW)	Ramp Rate (MW/hr)	Quick Start	EFOR (%)	Start Cost ($)
Columbia Energy Center	1	CC	540	540	No	1.67	$17,534
Jasper	1	CC	920	190	No	2.4	$26,301
Urquhart CC	1 & 2	CC	450	450	No	0.9	$17,534
SCE&G Unnamed CC (2029 onward)	1	CC	520	127	No	2.4	$0
Coit	1 & 2	CT Gas	26	26	Yes	5	$0
Hagood	4	CT Gas	99	99	No	2	$0
Hagood	5 & 6	CT Gas	42	42	Yes	5	$0
Parr	1 & 3	CT Gas	73	73	Yes	5	$0
Urquhart CT	1 - 4	CT Gas	97	97	Yes	5	$0
Williams	1 & 2	CT Gas	52	52	Yes	5	$0
V.C. Summer	1	Nuclear	650	480	No	2	$0
Fairfield	1	Pumped Hydro	576	576	No	0	$0
Wateree	1 & 2	ST Coal	780	0	No	3.6	$15,286
Williams	1	ST Coal	615	0	No	4.3	$8,772
Cope	1	ST Coal	486	240	No	2	$4,299
Cope	1	ST Gas	420	240	No	1.1	$4,299
McMeekin	1 & 2	ST Gas	272	150	No	1	$2,923
Urquhart ST	3	ST Gas	104	60	No	12.2	$1,522
Saluda	5	Hydro	194	194	Yes	0	$0
Other Hydro Units*	-	Hydro	45	45	Yes	0	$0

Note: Hydro units are Neal Shoals, Parr Hydro, Saluda Hydro, and Steven's Creek

2.1.3 Solar Penetration Scenarios

Navigant ran three scenarios to analyze the impacts that various levels of solar would have on the SCE&G system. Each scenario included different amounts of utility-scale solar and is described below.

- Baseline Scenario – 336 MW of solar generation interconnected with SCE&G's system by the end of 2018.[6]
- Solar Case 1 – 637 MW of solar generation interconnected with SCE&G's system by the end of 2019.

[6] This is a conservative case. Actual installations by the end of 2018 already exceed this amount.

- Solar Case 2 – 1,044 MW of solar generation interconnected with SCE&G's system by the end of 2020.

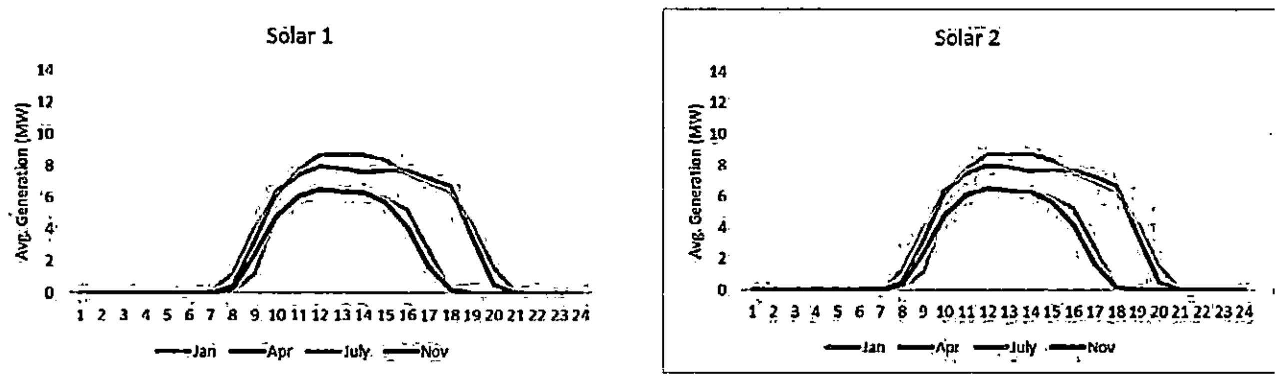
The maximum utility-scale solar nameplate facility rating for all three cases and the DER solar nameplate facility rating by year is shown in Table 6.

Table 6. Maximum SCE&G Solar Capacity

Solar	Maximum Nameplate Facility Rating (MW)				
	2019	2020	2021	2025	2030
Utility - Baseline	336	336	340	363	404
Utility - Solar Case 1	637	637	641	664	705
Utility - Solar Case 2		1,044	1,048	1,071	1,112

Navigant models all generation on an hourly basis; solar is modeled in PROMOD using a fixed 8760 hourly shape for generation. The 8760-shapes were based on historical hourly generation data provided by SCE&G. Figure 7 shows typical daily generation for two typical SCE&G solar plants,

Figure 7. Example Daily Solar Generation



2.2 Modeling the SCE&G System with PROMOD

Production cost models are a class of models that are used to complete analyses of electricity system costs. These models are appropriate for evaluating how system costs change when aspects of those systems change.

For this study, PROMOD was used. PROMOD is a widely licensed Production Cost Model used by many utilities and ISOs including PJM and MISO. There are other available Production Cost Models and consistent results can be expected if a different model was used for the study.

Like all production cost models, PROMOD simulates system operation hourly to minimize the total operating cost while ensuring that generation and load are matched and that operating reserve requirements are met. The model also takes into account generator operating limits and transmission constraints. The key outputs of the system simulation are the hourly details of system operation including generation by unit and the hourly operating costs.

From PROMOD, the production costs can be calculated by summing:

- Fuel costs
- Variable operating costs
- Start-up costs
- Emissions costs

In this study, SCE&G is modeled as a mostly isolated system without dynamic transmission connections to surrounding systems. This is appropriate for a planning study as it captures the requirement for SCE&G to maintain self-sufficiency in planning. As SCE&G does have the ability to contract for external power, emergency power imports were allowed at a cost of $300/MWh.

2.3 Forecasting Requirements to Integrate Solar

The necessary additional operating reserves that are needed with solar on the system are estimated using data sets providing by the National Renewable Energy Lab (NREL) specifically for solar integration studies.[7] These data sets provide forecasted and real-time solar generation data at sites across South Carolina. In the future, as SCE&G gains experience operating with solar generation, the solar uncertainty analysis can be updated with actual operating data rather than the data provided by NREL.

The operating reserve requirements from solar are driven by the level of forecast uncertainty in solar generation. The NREL dataset provides the 4 hour-ahead forecast of hourly solar generation. This is the forecast that SCE&G system operators would use to schedule their units and determine which generators are required to be line. The forecasted solar is compared to the real-time solar generation dataset to calculate the generation variance from the forecast. SCE&G needs to hold sufficient reserves to be able to respond to the worst-case downward variance of solar generation while maintain their reserve requirements.

An outcome of the solar uncertainty analysis, described in more detail in Section 3, is that the level of solar generation uncertainty depends on the level of solar generation. The amount of reserves that need to be held by SCE&G for variable integration depend on the level of forecasted solar generation. This

[7] https://www.nrel.gov/grid/solar-integration-data.html

dynamic is incorporated into the study analysis by blending the production costs of several cases operating the system with different levels of operating reserves to account for the day-to-day variability in the overall requirements.

2.4 Estimating Integration Costs

To calculate the integration costs of the various mitigation options, PROMOD was run with different levels of operating reserves calculated as a mitigation option and the production costs were compared to the Business as Usual scenario, which is the PROMOD scenario benchmarked to the actual SCE&G system operation.

The study includes a comparison of the system costs as operating reserves increase to handle solar uncertainty. These costs are compared for each of the three solar penetration scenarios and up to four different levels of operating reserves. Table 7 shows the full set of study scenarios. The BAU reserves are the 240MW currently required. The other reserve levels are those required for the uncertainty associated with the varying levels of solar penetration.

Table 7. Solar and Reserve Scenarios

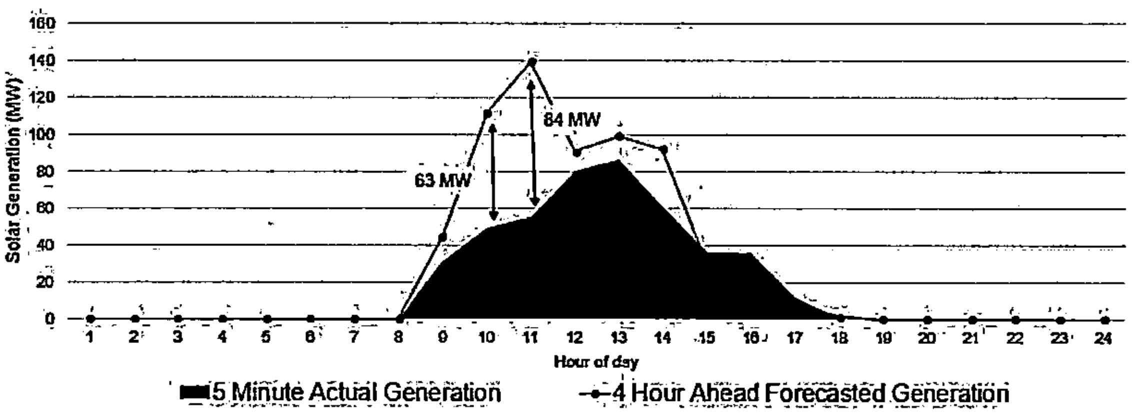
Baseline Solar (~350 MW)	SC1 Solar (~725 MW)	SC2 Solar (~1050 MW)
BAU Reserves	BAU Reserves	BAU Reserves
Baseline Reserves	Baseline Reserves	Baseline Reserves
	C1 Reserves	C1 Reserves
		C2 Reserves

Beyond simply holding additional reserves with the current power system, SCE&G has the ability to add new resources such as CT gas or storage that can provide reserves. If new units are added as a mitigation option, then new resources are added to the set that is available to SCE&G to meet load and reserve requirements. The capital costs of the new resources would be added to the total mitigation costs for comparing between the BAU and change scenarios. The study tests whether additional resources can be used to reduce the total integration costs.

3. SOLAR GENERATION VARIABILITY IN SCE&G SERVICE TERRITORY

Solar generation is intermittent, meaning that actual operation cannot be perfectly forecasted and there is nearly continuous variation in generation that must be reacted to by SCE&G operators. The following chart shows the difference between a 4-hour ahead forecast and actual 5-minute operation of solar in South Carolina. The forecasted generation varies by as much as 84 MW for a single hour which could be an issue in maintaining system reliability for SCE&G and would require adequate reserves that can be called in to maintain supply and demand balance in the region. The chart below captures total solar generation at four different locations in the system to provide a system-wide variability whereas variability at a single solar site can be much higher in terms of percentage of solar generation shortfall.

Figure 8. Solar Generation Variability Example



3.1 Data Sources

The amount of solar variability that SCE&G operators will need to be able to respond to is driven by the level of forecast uncertainty for solar generation in the territory. The challenge is that there is a very short track record in the system for how much solar uncertainty there is. SCE&G does not have data that can be used to calculate the distribution of the difference between solar generation forecasts and the actual solar generation.

To be able to complete the study, Navigant used two sources of solar data:

- The hourly shape for solar generation that is inputted into PROMOD is developed from an aggregation of real solar generation hourly shapes from SCE&G.

- The forecast uncertainty is developed from the National Renewable Energy Lab's (NREL) Solar Integration Dataset.[8] This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites around the U.S.

3.2 Detailed Approach

The solar forecast error is calculated as the difference between the 4-hour ahead forecast generation and the 5-minute actual solar generation. This is appropriate because as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, SCE&G will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield, Saluda, the CTs, and the CCs and STs that are already online.

The following methodology is used to calculate the solar forecast error.

1. Calculate the 4-hour ahead solar forecast as the average of 4 potential solar sites located around the SCE&G service territory.
2. Calculate the 5-minute actual generation as the average of the actual generation at the same 4 sites.
3. Calculate the 5-minute variance in solar generation as the difference between the forecast and the actual in every 5-minute period.
4. Calculate the solar variance the SCE&G must respond to as the 15-minute moving average of the 5-minute forecast error.[9]

The result of this analysis is a comprehensive set of data that gives the amount that solar generation varied from the forecast. This can be evaluated by season and time period to determine how operators would need to plan for solar uncertainty.

3.3 Solar Generation Variability Results

SCE&G's operators need visibility on the levels of solar at risk of not showing up given the forecasted solar. To maintain reliability, it is necessary to have sufficient reserves to replace the missing solar generation under the worst-case scenario. The difficulty for operating the system is that SCE&G not only does not know when solar will generate less than forecasted but also does not want to overestimate the uncertainty and then hold more reserves than needed, which would increase costs. The uncertainty that needs to be estimated is the likelihood and worst case for solar generating less than forecasted given the amount of solar that is expected to be on the system.

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[8] https://www.nrel.gov/grid/solar-integration-data.html

[9] SCE&G must meet NERC Reliability Based Control Standards which give the utility up to 30 minutes to respond to any large deviation between load and generation. 15 minutes is chosen for this study as SCE&G would want to respond well before 30 minutes to ensure sufficient time to avoid exceeding the 30-minute limit.

One outcome of this analysis is that the level of solar variability depends the amount of solar that is generating. At a high level, the higher the percentage of the total installed nameplate facility rating of solar that is generating, the lower the proportion of generation that is at risk.

Table 8 shows the full results of this analysis. The rows give the forecasted solar generation as a percentage of the installed nameplate facility rating. The columns give the percentage drop in solar generation. The cells give the conditional probability of a given drop in solar generation given the level of forecasted generation.

For example, if 1000 MW of solar was installed on the system and it was forecasted to generate 400 MW, the highlighted cells show:

- There is a 1% chance of a 75% drop – equivalent to 300 MW of solar not showing up (only 100 MW is generated).
- There is a 9% chance of a 25% drop- equivalent to 100 MW of solar not showing up (only 300 MW is generated)

Table 8. Conditional Probability of Solar Variability

Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since SCE&G must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

Table 9. Solar Forecast Uncertainty

Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

3.4 Geographic Diversity

An important part of this analysis is to consider geographic diversity when forecasting the solar uncertainty. Even in a service territory as geographically compact as SCE&G's, spreading solar generation geographically can reduce the uncertainty.

Without considering geographic diversity, the solar uncertainty would be much higher. To avoid this, the forecast error analysis was completing using NREL data located at four points around the SCE&G territory chosen to be near load centers. Averaging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by SCE&G.

The table gives an example of the expected probability of losing solar generation when operating at 50% of maximum generation for the average of the four NREL points used, and for a single NREL point located near Columbia. The key result is that the uncertainty is significantly higher when estimated at a single point.

Table 10. Impact of Geographical Diversity on Solar Uncertainty

NREL Location	Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
SCE&G Avg.	**50%**	0.1%	0.6%	1.1%	2.1%	3.4%	7.4%	12.9%	21.8%
Columbia, SC	**50%**	3.2%	4.2%	5.2%	7.3%	10.8%	14.7%	21.3%	35.4%

4. DEMONSTRATING THE NEED FOR ADDITIONAL RESERVES

SCE&G reliability is threatened when there is insufficient system ramping capability to meet potential drops in solar generation while maintaining the required reserves.

4.1 Reliability Challenges without Adding Reserves for Variable Integration

In each hour of the forecast, the following process is used to calculate whether SCE&G has any reliability issues from solar generation that need to be mitigated.

1. Calculate the total amount of ramping capability on the system.
   - This is the sum of the ramping up capability of online units and the capacity of quick start units that can be turned on.
   - This will be at least the total reserve requirement (240 MW) but is typically more depending on how the system is operating.
2. Calculate the potential lost solar generation due to forecast uncertainty.
3. Subtract the lost solar generation from the system ramping capability.
4. Flag any hours in which the minimum reserve requirement is not met as reliability violations.

The table below shows 3 hours in which there are reserve shortfalls if the system only requires 240 MW reserves but includes risk of solar generation being out. These sample hours are the reason that SCE&G operators must hold more reserves for the solar uncertainty.

Table 11. Example of Hours with Reserve Shortages

Hour	Load	CC Ramp (Gen)	CT Ramp (Gen)	Saluda Ramp (Gen)	Fairfield Ramp (Gen)	Interruptible Load for reserves	Total Reserves Online	Risk of Solar Out	Reserves Shortage after Solar
3/1/20, 10am	3793MW	0MW (1685MW)	74MW (216MW)	164MW (30MW)	42MW (246MW)	100MW	281MW	60MW	30MW
9/10/24, 3PM	4240MW	96MW (1274MW)	67MW (265MW)	8MW (186MW)	0MW (576MW)	100MW	271MW	44MW	24MW
8/1/25, 3PM	4653MW	0MW (1777MW)	96MW (235MW)	126MW (68MW)	0MW (576MW)	100MW	322MW	133MW	62MW

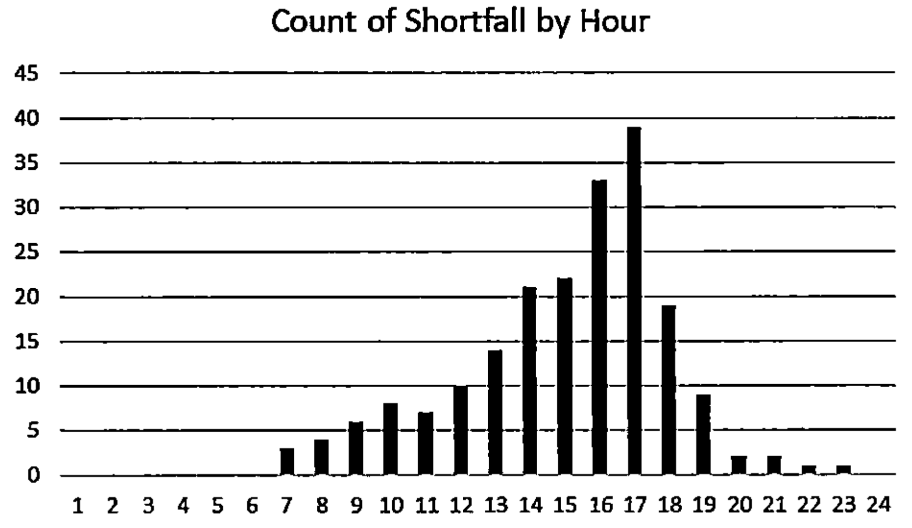
While in most hours there are more than the minimum reserves, there are a material number of hours in each scenario for which additional reserves would need to be held for the solar generation.

PROMOD was used to simulate the system operation in each solar penetration scenario and the number of hours in the forecast period in which SCE&G was not holding sufficient reserves to account for solar uncertainty was calculated. In each of these scenarios, the hours with insufficient reserves occurred in all seasons across the year.

- Baseline scenario – 74 hours
- Solar Case 1 – 102 hours
- Solar Case 2 – 201 hours

Figure 9 shows the distribution by hour of the reserve shortfalls. These hours are concentrated during the evening when solar is ramping down.

Figure 9. Reserve Shortfalls by Hour in SC2



4.2 Calculating the Additional Reserve Requirements

The analysis in Section 4.1 demonstrates that if SCE&G does not hold additional reserves then there will be a significant number of hours in which reliability violations occur. That analysis does not show the amount of additional reserves that must be held.

When planning operation, SCE&G only knows the forecast for solar generation and must plan for the worst case. This means that the utility must hold sufficient reserves in each case to be able to respond to the worst case drop in solar given the forecast.

For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met. The reserve requirement changes by year rather than month because the maximum in each month is nearly constant.

Table 12 shows the maximum additional reserves needed in each solar penetration scenario plus the BAU level of reserves held by SCE&G.

Table 12. Maximum Additional Reserves Needed

Year	BAU	Baseline	SC1	SC2
2019	240	347	421	420
2020	240	348	445	529
2021	240	349	447	579
2022	240	351	448	581
2023	240	352	450	582
2024	240	354	451	584
2025	240	356	453	586
2026	240	358	456	588
2027	240	360	458	590
2028	240	363	460	593
2029	240	365	463	595
2030	240	368	466	598
2031	240	371	469	601
2032	240	375	472	605

One aspect of holding reserves is that SCE&G knows the level of expected solar generation prior to setting the reserves to be held, so the required reserves needed to compensate for a potential drop in solar would be adjusted on a daily or hourly basis.

Table 12 shows the maximum needed reserves necessary, but when calculating the costs, it is important to consider that many individual days within each case have lower forecasted solar than the maximum and hence need fewer reserves.

For SC2, the analysis shows:

- SC2 level of reserves is needed for 38% of the days
- SC1 level of reserves is needed for 51% of the days
- Baseline level of reserves is needed for 12% of the days

To ensure that the analysis does not overestimate the costs to integrate the SC2 reserves, PROMOD was run with each of these levels of reserves and then the results were blended using the weighted average of costs tied to the number of days that each level of reserves was required.

5. MITIGATION OPTIONS AND INTEGRATION COSTS

5.1 Potential Mitigation Options

The mitigation needed to integrate solar generation is to hold additional reserves that will be available if actual solar generation is less than forecasted. There are two broad mechanisms for SCE&G to do this:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[10]

In this analysis, the cost of holding additional reserves is calculated first. This is then compared to the cost of adding new resources to check whether there is a lower cost approach to procuring the needed reserves. The integration cost for the solar resources is the levelized cost difference of the system costs with and without additional reserves.

5.2 System Impacts of Holding Additional Reserves

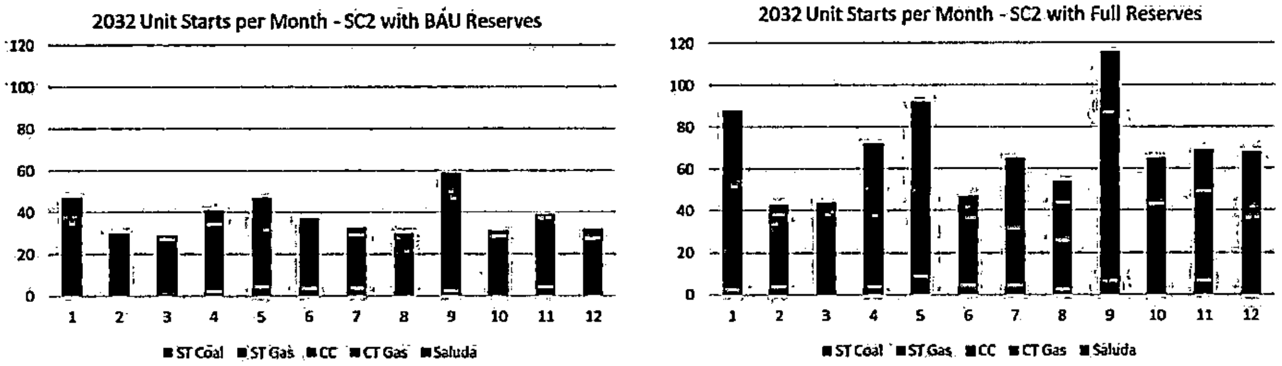
In most hours, especially overnight, SCE&G holds more than the minimum necessary reserves through their least-cost security constrained operation. This means that adding to the reserve requirement in the simulation does not materially influence the system operation in those hours. However, in hours in which SCE&G holds the minimum or close to the minimum amount of reserves, some resource generation levels will have to be changed.

PROMOD solves for the least-cost dispatch while respecting the additional reserve requirements. To a large extent, additional reserves come from reducing the generation from CC units so that they are providing more flexibility. ST units are turned on to ensure that load can be met. Figure 10 shows the comparison of the starts per month in case SC2 with and without additional reserves being held. As would be expected, the cycling increases with the additional reserves as the CTs and STs must turn on to be available.[11]

[10] Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this possibility has not been considered in this analysis because SCE&G cannot implement it unilaterally but only with technological changes by the solar facility owners.

[11] Note that Saluda is allowed to cycle more in the alternate case than according to the current operating agreement. This is a **conservative** assumption. If Saluda were more limited as per the current operating agreement, then other units would have to make up the difference and integration costs would increase.

Figure 10. Comparison of Unit Cycling



To a large extent, the driver of the integration costs are increased fuel and operating costs. This is because less efficient units must be online to provide energy, units must operate at less efficient power levels, and there are increased start-up costs due to additional cycling.

One point of conservatism in this analysis is that there are additional maintenance and fuel costs from ramping generating resources up and down very quickly when renewable generation varies. This analysis only considered the costs to maintain reserves and excluded the costs from the additional stress and reduced efficiency from matching solar generation short-term variability.

5.3 Cost of Holding Additional Reserves without Other Changes

As described, the cost of holding additional reserves is calculated by comparing the PROMOD production costs with and without holding additional reserves required to meet solar uncertainty.

One concern is to ensure that there is no double counting with the costs reported in the PR-1 and PR-2 avoided cost study. In that study, there are increased costs from Energy Not Served and Reserve Deficits. A side-benefit of holding additional reserves for variable integration is that both Energy Not Served and Reserve Deficits would likely be decreased. Conservatively, for this study, the entire cost of Energy Not Served ($0.682/MWh) and the entire cost of Reserve Deficits ($0.284/MWh) ($0.97/MWh rounded total) are assumed to be eliminated with the extra reserves needed for solar.

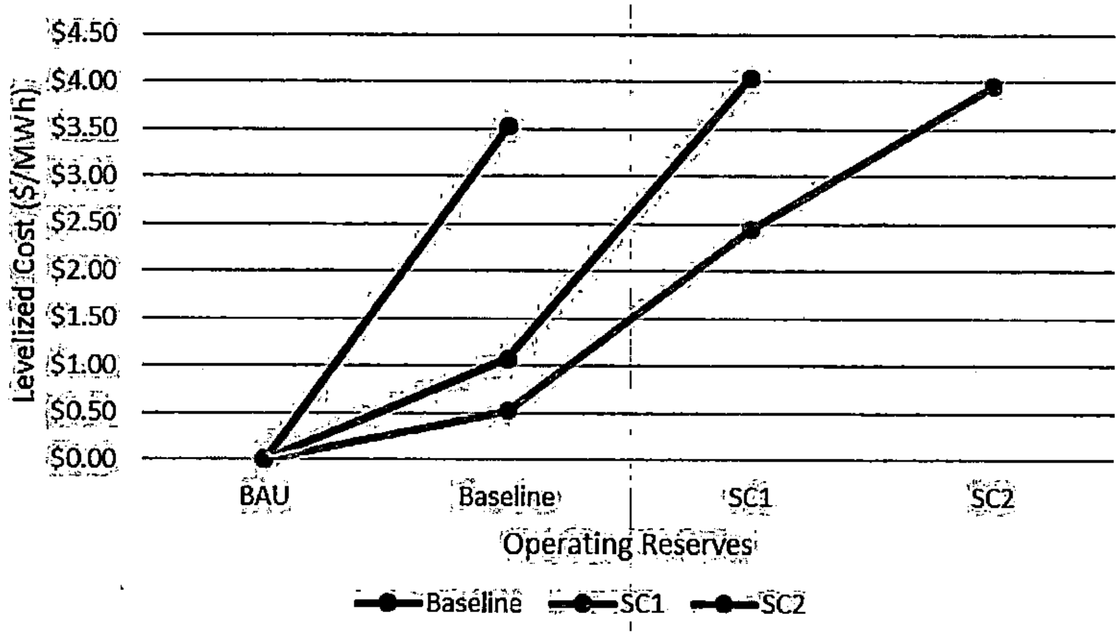
The comparison of system production costs in the three solar penetration scenarios are given in Table 13. The Net Present Values (NPV) are calculated over a 15-year period (2020 – 2034) using SCE&G's discount rate of 7.9%. The results show that the costs increase relatively linearly between the 3 cases as more solar is added to the system resulting in a variable integration cost between $3.52/MWh and $4.04/MWh. The total incremental system costs in SC2 is approximately $73.2M.

Table 13. Cost to Integrate Variable Generation

	Baseline	SC1	SC2
Cost Difference NPV (2020 $)	$21,441,812	$46,878,790	$73,242,219
Solar Generation NPV (MWh)	6,091,424	11,603,661	18,495,510
Levelized Cost (2020 $/MWh)	$3.52	$4.04	$3.96

Figure 11 shows the incremental levelized cost as reserves are added in each scenario. For example, in SC2, the results show that integration cost are approximately $0.50/MWh if only the baseline solar reserves are needed. These costs increase to $4.02/MWh when all of the reserves required for the SC2 case are required. The expectation is that as solar continues to be added to the system and additional reserves continue to be needed that these costs would increase.

Figure 11. Levelized Costs as Reserves are Added



The breakdown of the cost drivers in SC2 are shown in Table 14. The majority of costs are from additional fuel cost costs but VOM and start-up costs are also material increases in system costs.

Table 14. Breakdown of Incremental Costs in SC2

	VOM	Fuel	Emission	Start-up	Total
Cost Difference NPV ($)	$13,941,615	$40,320,211	$48,760	$19,103,954	$73,242,219
Generation NPV (MWh)			18,495,510		
Levelized Cost ($/MWh)	$0.75	$2.18	$0.003	$1.03	$3.96
% of Total Cost	19%	55%	0%	26%	100%

5.4 Screening the Potential to Mitigate with Additional Resources

In SC2, the NPV of the cost of holding additional reserves for variable integration is $73.2M driven by the need for additional reserves of approximately 350MW.

If SCE&G can add resources that can provide these reserves for less than incremental cost, then it would be possible to reduce the overall integration costs of solar to the system.[12] For providing reserves, the best options are quick-start gas CTs or battery storage. This study considered the following resources and costs:

- Quick-start CT - $700/kW overnight cost
- 1-hour Lithium-Ion Battery - $800/kW overnight cost[13]
- 2-hour Lithium-Ion Battery - $1000/kW overnight cost

At a high level, this implies that SCE&G could add approximately 110 MW of quick-start CT, approximately 95 MW of 1-hour battery, or approximately 75 MW of 2-hour battery. None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation.[14]

[12] Note that if solar units were operated to provide flexibility to the system, the integration costs borne by SCE&G would be reduced.

[13] Note that this cost assumes technology improvement and cost declines through 2025

[14] To do a full analysis of mitigation with additional resources it would be necessary to also calculate additional benefits and costs associated with owning and operating these resources. The current analysis is only a screening to demonstrate that the additional of these resources is not able to reduce the overall integration costs.

APPENDIX A. MARKET MODELING PROCESS

Navigant's market modeling approach relies on a multifaceted approach for modeling and simulating the energy market and studying the performance of energy assets in the marketplace. Navigant's approach relies on the involvement of numerous subject matter experts with specific knowledge and understanding of several fundamental assumptions, such as fuel pricing, generation development, transmission infrastructure expansion, asset operation, environmental regulations, and technology deployment. From our involvement in the industry, Navigant has specific and independent views on many of these fundamental assumptions based on our knowledge and understanding of the issues. Provided below is an overview of the modeling process.

A.1 Electric Market Simulation

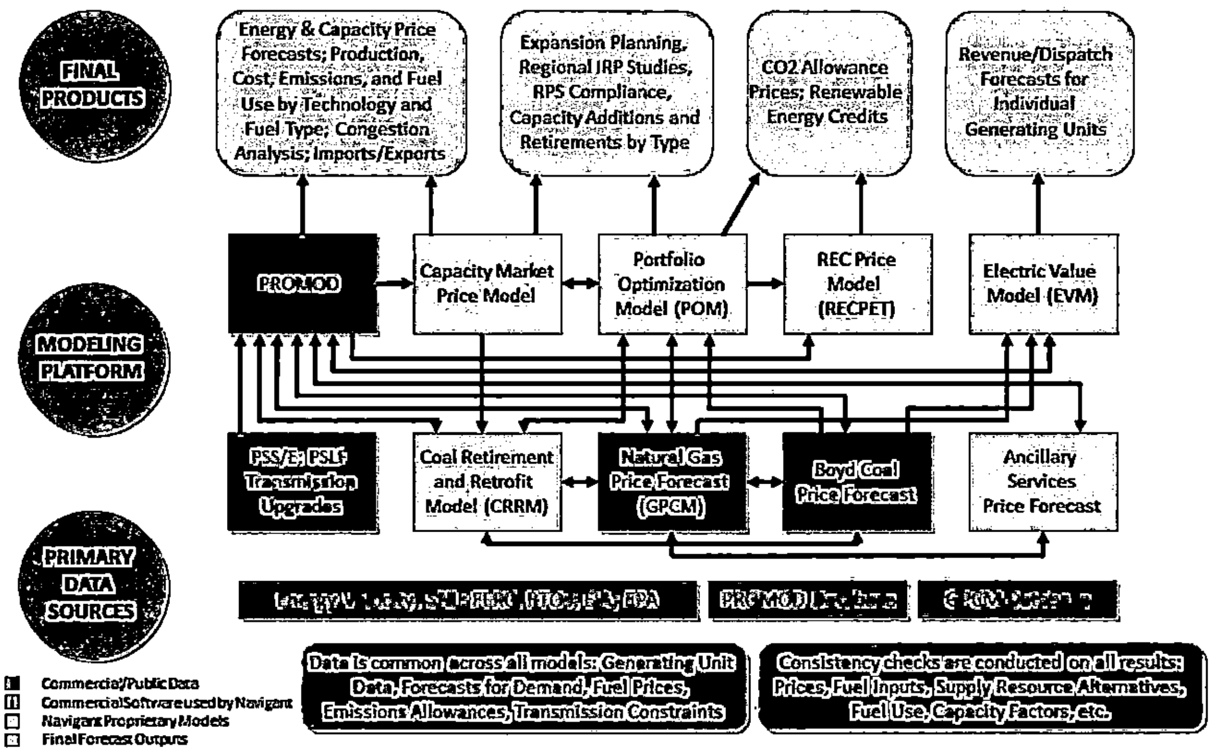
A diagram depicting the models used in Navigant's market modeling can be seen in Figure A-1. Navigant's proprietary Portfolio Optimization Model (POM) is a linear optimization model used for capacity expansion. POM simulates economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, RPS, fuel costs, fixed and variable operations and maintenance costs, emissions allowance costs, and zonal transmission interface limits. This model incorporates the same generation base, demand forecasts, fuel prices, other operating costs, and plant parameters that are utilized throughout the market simulation modeling process. The model simultaneously performs least-cost optimization of the electric power system expansion and dispatch in multi-decade time horizons. POM can perform multivariate optimization, which can consider value propositions other than cost minimization, such as sustainability, technological innovation, or impacts on other sectors, such as natural gas. The generation expansion results from POM are used in the fundamental energy price forecast.

Navigant uses PROMOD, a commercially-available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission resources on a nodal basis in wholesale electric markets. PROMOD dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The choice of generation is determined by the generator's total variable cost given operating constraints such as ramp rates (for fossil resources) or water availability (for hydraulic resources), and transmission constraints. The total variable cost of the marginally dispatched unit in each hour sets the hourly market clearing price. All generators in the same market area that are selected to run receive the same hourly market clearing price adjusted for losses and congestion, regardless of their actual costs. The LMPs produced by PROMOD compose Navigant's structural market price forecasts. Navigant does not employ bid-adders or other exogenous adjustments to prices in the PROMOD forecast.

Within PROMOD, production costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up time and downtime, and other characteristics are factored into the simulation. Supply offer prices are simulated for each unit within PROMOD that correspond to the minimum price the unit owner is willing to accept to operate the unit. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each unit's fuel price multiplied by the incremental heat rate, plus variable operations, emissions, and variable maintenance costs.

Where relevant (primarily for thermal units), the unit offer price also incorporates the unit's start-up and no-load costs. The start cost component includes fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The no-load cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

Figure A-1. Navigant's Market Simulation Modeling Process



Source: Navigant

PROMOD has several distinguishing features that qualify it for application in electric power forecasting and related studies. These features include the following:

- Individual transmission line modeling
- Detailed and flexible unit commitment and dispatch modeling
- Modeling of operational transmission constraints (e.g., operating nomograms)
- Calculation of security-constrained dispatch schedules
- Hourly modeling of loads and resource operation

When preparing market price forecasts, Navigant first forecasts a fundamental, or structural, hourly energy price series for the applicable node or zone using PROMOD. Structural prices represent expected day-ahead market clearing prices under conditions of perfect foresight about load, generator and transmission availability, and fuel costs. As such, they lack information about additional price volatility in the market that can stem from intra-month volatility in fuel and emissions prices, stochastic variations in demand, and deviations of market bidding away from marginal cost bidding. In order to account for this missing volatility and any model error, Navigant incorporates adjustment factors to correlate power price volatility from simulated ex post "backcasts" in PROMOD with historical volatility experienced in the market. Using benchmarks derived from historical data for a rolling three-year period, the PROMOD hourly price forecasts are adjusted to account for the relative difference between actual market prices and PROMOD's (simulated) prices by season and time period. The actual prices and the simulated prices are grouped and averaged in 18 time blocks differentiated by season (summer, winter, shoulder) and time-of-day (4 hour blocks corresponding to off-peak and peak periods). After eliminating historical price spikes deemed to be unpredictable (two standard deviations outside the time-block average), time-block ratios of actual prices to simulated prices are used to adjust the PROMOD forecast, and these are the final adjusted market prices provided in this report.

Navigant also uses GPCM to develop our Reference Case Gas Price Forecast. GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Navigant applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Navigant's view, insight, and detailed knowledge of the US and Canadian natural gas markets. Adjustments are made to the model to reflect accurate infrastructure operating capability and the rapidly changing market environment regarding economic growth rates, energy prices, gas production growth levels, demand by sector and natural gas pipeline, storage, and LNG terminal system additions and expansions. To capture current expectations for the gas market, this long-term monthly forecast is combined with near-term New York Mercantile Exchange average forward prices for the first two years of the forecast.

*pg 1 of 140 pgs previously filed in the docket supplem. kpm

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	**INITIAL COMMENTS OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY**

PURSUANT TO the Commission's June 26, 2018 Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing, as modified by its January 4, 2019 Order Granting Extension of Time, its January 25, 2019 Order on Procedural Schedule and Requiring Report, and its February 8, 2019 Order Granting Extension of Time, the Southern Alliance for Clean Energy ("SACE") files these initial comments on the proposed rates and standard form contracts filed on November 1, 2018 by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (together, "Duke" or the "Companies"), and Dominion Energy North Carolina ("DENC" or "Dominion") (collectively, "the Utilities").

Background

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") requires electric utilities to purchase available electric energy and capacity from cogeneration and small power production facilities that obtain "qualifying facility" ("QF") status under Section 210 of PURPA. <u>See generally</u> 16 U.S.C. § 2601 <u>et seq.</u> PURPA requires electric utilities to pay qualifying cogenerators and small power

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))))))	**REPLY COMMENTS OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY**

PURSUANT TO the Commission's June 26, 2018 Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing, as modified by its March 19, 2019 Order Granting Extensions of Time, the Southern Alliance for Clean Energy ("SACE") files the following comments in reply to the initial comments filed by several intervening parties regarding the proposed rates and standard form contracts filed on November 1, 2018 by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (together "Duke" or the "Companies"), and Dominion Energy North Carolina ("DENC") (collectively, "the Utilities").

I. INTRODUCTION

On February 12, 2019, the Public Staff, the North Carolina Sustainable Energy Association ("NCSEA"), Cube Yadkin Generation, LLC ("Cube Yadkin"), NC Small Hydro Group ("Small Hydro Group"), and NC WARN Inc. ("NC WARN") filed initial comments in this proceeding responding to the proposals the Utilities made in their respective initial avoided cost filings. SACE has reviewed these comments and offers the following reply comments to address arguments made in the initial comments regarding avoided energy and avoided capacity rates and inputs; avoided cost rate design; proposed solar integration charges; and standard offer contract terms and conditions.

II. REPLY TO SPECIFIC ISSUES RAISED IN INITIAL COMMENTS

A. Avoided Energy

1. Natural Gas Forecast

The Public Staff and NCSEA both challenge Duke's natural gas forecast methodology and propose alternative natural gas forecasts.[1] As an initial matter, SACE agrees with the Public Staff and NCSEA that Duke has failed to comply with the Commission's E-100 Sub 158 Order on its face by relying upon a 10-year fundamental natural gas forecast to calculate its avoided energy rates.

The Public Staff recommends that the Commission require Duke to use no more than five years of forward market data before transitioning to the Company's fundamental forecast.[2] The Public Staff evaluated Duke's practices in other states and found that in those states, Duke affiliates use a methodology of blending forwards—for no more than five years—with the fundamental forecast.

NCSEA proposes a balanced forecast that uses forward market prices for two years, with a transition in the next three years to the average of a set of recent fundamentals forecasts, derived from (1) DENC's forecast from ICF and (2) the new *2019 AEO* forecast from EIA. Alternatively, NCSEA indicates that applying DENC's

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[1] North Carolina Utilities Commission Docket No. E-100, Sub 158, Initial Statement of the Public Staff at 21-28 ("Public Staff Initial Comments"); North Carolina Utilities Commission Docket No. E-100, Sub 158, NCSEA's Initial Comments at 14-19 ("NCSEA Initial Comments").
[2] Public Staff Initial Comments at 28.

similar forecast methodology of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities would also be acceptable.[3] SACE considers the proposals of both the Public Staff and NCSEA be more appropriate than the natural gas forecast methodology proposed by Duke.

2. Fuel Price Hedge

The Public Staff and NCSEA both oppose Duke's proposal to eliminate the 0.028 cents per kWh fuel hedge value included in Duke's avoided energy rates. The Public Staff reiterates its prior support for the inclusion of a hedging value for renewables, adopted by the Commission in the E-100 Sub 140 Phase One Order, and states that the risk of overpayment that Duke cites in support of removing the hedging value was already addressed through the elimination of avoided capacity payments in certain years, by the reduction in the PAF, and by the reduction of the MW threshold to be eligible to receive a Standard Contract.[4] The Public Staff recommends that the Commission require Duke to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing model or similar method.[5]

NCSEA argues that, while the Black-Scholes model has been used to establish a fuel hedge value in prior avoided cost proceedings, the Black-Scholes approach assumes that displaced natural gas is re-priced at the prevailing market price multiple times over a 10-year period, which NCSEA notes is a far less effective hedge than the hedge value

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[3] NCSEA Initial Comments at 18-19.
[4] Id.
[5] Public Staff Initial Comments at 28-29. The Public Staff also state that Duke's proposal regarding an alleged "Put Option" "would essentially require QFs to compensate utilities for the right to sell their generation." Id. at 28.

provided by renewable PPAs that provide 10 years of fixed prices.[6] NCSEA recommends the use of an alternative fuel hedge value method, such as the methods applied by Xcel Energy or by the Maine Public Utilities Commission, the latter of which "calculates the additional costs to fix the fuel costs of a marginal gas-fired generator for a long-term period, compared to purchasing gas at prevailing short-term market prices on an 'as you go' basis."[7] NCSEA asserts that these types of alternative methodologies for determining the fuel hedge value are superior to the Utilities' current method that has been used for several years.[8]

Cube Yadkin also critiqued Duke's proposal to eliminate the hedging value approved in the E-100 Sub 140 docket.[9] Cube Yadkin explained that the purpose of fuel hedging is to insulate ratepayers from fuel volatility, not to reduce fuel costs, and that the hedge's function as an insurance policy for ratepayers is not eliminated by the fact that natural gas prices have declined in recent years.[10]

SACE agrees with the Public Staff, NCSEA, and Cube Yadkin that Duke should continue to calculate and include a fuel hedge value as part of its avoided energy calculations. SACE was one of the parties that advocated for the application of the Black-Scholes model during the E-100 Sub 140 proceeding, and SACE considers the Black-Scholes model to be an industry-accepted methodology for calculating fuel hedging costs. However, to the extent the Utilities are able to apply a more accurate methodology—such as those recommended by NCSEA—for determining the fuel hedge value provided by

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[6] NCSEA Initial Comments at 22.
[7] Id.
[8] Id.
[9] North Carolina Utilities Commission Docket No. E-100, Sub 158, Initial Comments of Cube Yadkin Generation LLC at 4 ("Cube Yadkin Initial Comments").
[10] Id.

long-term renewable qualifying facility ("QF") power purchase agreements ("PPAs"), that would also be appropriate. For example, SACE considers the Maine PUC method that NCSEA describes and applies in its initial comments to be a reasonable approach and SACE does not object to this methodology as an alternative to the Black-Scholes model.

B. Avoided Capacity

The Public Staff, NCSEA, the Small Hydro Group commented on the Utilities' proposals regarding avoided capacity need. NCSEA's initial comments dispute whether Duke's 2018 integrated resource plans ("IRP") accurately reflect the Companies' future capacity needs.[11] NCSEA recommends that the Commission require Duke to consider the capacity provided by existing QFs currently selling energy and capacity to Duke under PPAs that are scheduled to expire in coming years.[12] NCSEA argues that Duke's 2018 IRPs improperly assumed that even after the expiration of a QF's PPA the QF will continue to provide capacity, and therefore the expiration of a QF's PPAs does not create a capacity need.[13]

The Small Hydro Group also argues that Duke's IRP should be required to account for capacity contributions of existing hydropower facilities that seek extension or renewal of their contract and that the Commission should carefully scrutinize the Utilities' IRPs due to their newly increased role in determining avoided capacity payments pursuant to HB 589.[14]

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[11] NCSEA Initial Comments at 10.
[12] Id. at 10-11.
[13] Id.
[14] North Carolina Utilities Commission Docket No. E-100, Sub 158, NC Small Hydro Group's Initial Comments at 8 ("Hydro Group's Initial Comments").

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SACE agrees with NCSEA and the Small Hydro Group that the expiration of a QF's existing PPA should be considered a capacity need in the IRPs and that this need should be reflected in the calculation of avoided capacity payments available to QFs. SACE also agrees with NCSEA's recommendation that the presumptive in-service date for QFs, for the purpose of calculating avoided capacity costs, should more accurately reflect the time at which those QFs are likely to actually begin providing capacity.[15] NCSEA recommends that the Commission use December 31, 2021 as the date on which QFs signing E-100 Sub 158 contracts are considered to begin providing capacity. SACE considers this a reasonable approach and does not object to the use of this date.

The Public Staff recommends that "to the extent utility inputs change, such as the anticipated date of the first capacity need, then it is expected that the Utilities would update their avoided capacity calculations for negotiated contracts."[16] SACE does not object to avoided capacity rates being updated for negotiated contracts in between biennial avoided cost proceedings to accurately reflect utility capacity needs, but SACE recommends that any such adjustments resulting from capacity additions of utility-acquired resources must have been included in the utility's most recently approved IRP.[17]

NCSEA also disputes DEC's conclusion that it has no avoidable capacity need prior to 2028.[18] NCSEA notes that DEC's 2018 IRP shows a 30 MW short-term market capacity purchase in 2020, and uprates at existing units scheduled for 2021, 2022, 2023, 2024, and 2025.[19] SACE agrees that, in addition to including the planned uprates –

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[15] NCSEA Initial Comments at 11-12.
[16] Public Staff Initial Comments at 66.
[17] For example, if a utility enters into a PPA for a peaking unit for economic reasons in the interim period, such a capacity addition would not be used to update avoided capacity calculations.
[18] NCSEA Initial Comments at 11.
[19] Id.

which SACE addressed in initial comments – the short-term market capacity purchase in 2020 should also be considered an avoidable capacity need and reflected in the avoided capacity rates.

Furthermore, SACE has also subsequently filed comments on Duke's IRP in which it presents evidence that Duke's IRP neglected to evaluate the potential to retire aging fossil plants in its modeling.[20] SACE recommended in those comments that the Commission direct Duke to revise its IRP by allowing its modeling to evaluate the cost-effectiveness of retiring fossil plants in the near term. If the Commission adopts SACE's recommendation in the IRP proceeding, SACE recommends that the Commission also direct Duke to concurrently revise its avoidable capacity need to include any capacity need identified as a result of additional or accelerated plant retirements.

NCSEA also recommends that the Commission reject Duke's Demand Side Management ("DSM") assumptions, which NCSEA argues exaggerate Duke's winter peak and undervalue QF capacity contributions made in the summer.[21] As also discussed in greater detail in SACE's comments on Duke's IRP, SACE agrees that Duke's existing DSM programs should be re-evaluated and updated to enhance their technical and economic potential for winter demand response, which would increase Duke's ability to more effectively manage and mitigate winter peaking events.

<u>1.</u> <u>Performance Adjustment Factor</u>

The Public Staff and NCSEA commented on the Performance Adjustment Factor ("PAF") proposed by the Utilities in this docket. Both the Public Staff and NCSEA

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[20] North Carolina Utilities Commission Docket No. E-100, Sub 157, Initial Comments of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council at 5.
[21] NCSEA Initial Comments at 12-13.

critique the Utilities' designations of peak months.[22] In its initial filings, Duke defined January and February as peak winter months and July and August as peak summer months.[23] DENC defined January and February as peak winter months and June, July, and August as peak summer months.[24]

NCSEA proposes that based on historical data regarding the distribution of summer and winter peaks, the summer peak months should include June and September, and the winter peak months should include March and December.[25] NCSEA notes that Duke's proposed peak season differs from the seasons used by Duke in developing rate design proposals.[26] SACE agrees with NCSEA that Duke's exclusion of shoulder months understates the contribution to capacity that QFs make during peak months. SACE supports NCSEA's proposal that June, September, December, and March be considered peak months.

The Public Staff also notes that the Utilities' proposed peak seasons are overly restrictive, but concludes that historical data support the use of June through August as summer peak months and December through February as winter peak months.[27] The Public Staff recommends that the Commission direct the Utilities to revise their PAF calculations including June and December. SACE agrees with both NCSEA's and the Public Staff's recommendation that the Commission require the Utilities to perform a revise PAF calculation including the shoulder month data.

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[22] Id. at 31; Public Staff Initial Comments at 71-72.
[23] North Carolina Utilities Commission Docket No. E-100, Sub 158, DEC and DEP Joint Initial Statements and Exhibits at 16 ("Duke Initial Statements").
[24] North Carolina Utilities Commission Docket No. E-100, Sub 158, DENC Initial Statement and Exhibits at 32-33.
[25] NCSEA Initial Comments at 31.
[26] Id.
[27] Public Staff Initial Comments at 71-72.

C. Avoided Cost Rate Design

The Public Staff and NCSEA both proposed alternative avoided cost rate designs and methodologies in initial comments. SACE finds merit in both parties' proposed methodologies, as discussed below.

The Public Staff notes that avoided cost rate design would benefit from greater granularity and applies the principle that, to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost.[28] SACE agrees with the Public Staff's position that more accurate price signals to QFs, especially dispatchable QFs, will increase each QF's relative value to the grid and, ultimately, to ratepayers, and increase the likelihood that the interests of ratepayers and developers align.[29] The Public Staff developed a three-step process which it used to develop its proposed avoided energy rate design. The process included: (1) establishment of seasons using historical load data; (2) establishment of off-peak, on-peak, and premium peak hours using a blend of five years of historical marginal pricing and five years of projected marginal pricing (Blended Hourly Prices); and (3) classification of premium peak hours as those with Blended Hourly Prices within the 90th percentile, and classification of on-peak hours as those with Blended Hourly Prices above the seasonal average.[30]

SACE considers the Public Staff's avoided energy rate design proposal to be sound, and is generally supportive of the methodology that the Public Staff has developed. SACE considers the application of blended historic and forecast rates to be appropriate, and the three-season approach and the addition of premium peak hours to be

[28] Id. at 54.
[29] Id.
[30] Id. at 55.

reasonable. Regarding the establishment of seasons and hours, SACE also recommends the Commission consider how to better align the process for updating avoided cost rate design with the similar process for updating time-variable customer tariffs.

With respect to Duke's avoided capacity rate design, the Public Staff notes its concerns with the application of the 2016 Resource Adequacy Studies to the determination of avoided capacity months and hours, including assumptions made regarding the relationship between cold weather and load, estimates of load forecast error distributions, and a lack of recognition of winter hardening efforts undertaken by the utilities, among others.[31] Consistent with the expert report of James F. Wilson filed in SACE's initial comments, SACE agrees with the Public Staff's recommendation that Duke be required to rerun its Resource Adequacy Studies, the results of which will impact avoided capacity months and hours.[32]

NCSEA emphasizes the importance of providing accurate and granular price signals for QFs.[33] NCSEA recommends the development of tariffs that incorporate geographic price signals in order to incentivize QFs to locate in areas where the utilities can avoid transmission and distribution costs and are otherwise advantageous to the grid.[34] SACE agrees with NCSEA that alternative avoided cost tariffs that incorporate geographic price signals would likely help achieve this goal and could provide benefits both to QF owners and to ratepayers.

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[31] Id. at 58.
[32] SACE does not adopt the Public Staff's specific recommendation in Public Staff Scenario #2 ("PS-S2") presented by the Public Staff in IRP Docket No. E-100 Sub 147 and referenced in Public Staff's Initial Comments at p. 59. SACE maintains its recommendation that Duke be required to revise the Resource Adequacy Studies pursuant to the recommendations in the expert report of James F. Wilson, attached to SACE's initial comments in this proceeding.
[33] NCSEA Initial Comments at 26.
[34] Id. at 27.

NCSEA also suggests the development of seasonal and time-of-day pricing.[35] NCSEA argues that Duke and DENC both propose over-simplified daily on-peak and off-peak rates that average time periods with distinctly different cost characteristics. SACE agrees that avoided energy rates should more granularly incorporate utility cost characteristics and does not object to NCSEA's proposed seasonal and time-of-day pricing.

SACE also does not object to NCSEA's proposal for the Utilities to develop an optional real time pricing tariff for QFs.[36] Under NCSEA's proposed tariff, real time pricing would be applied to QFs in limited hours when system costs are extremely high or low, while fixed prices would continue to be applied during the majority of hours each year in order to provide sufficient revenue predictability. SACE considers this type of rate structure to provide a greater level of granularity and specificity that would allow QFs that opt into the tariff the chance to benefit from the tariff, while also benefitting ratepayers. SACE does not oppose the availability of an optional tariff of this type in addition to the traditional long-term fixed standard offer contract.

SACE also agrees with NCSEA's recommendation with respect to avoided capacity rates and seasonal weighting allocation that the Commission reject Duke's proposed winter/summer allocation and move towards a seasonal allocation that accurately reflects the capacity contributions of solar QFs during summer peaks.[37]

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[35] Id. at 28-29.
[36] Id. at 29.
[37] Id. at 13-14.

D. Solar Integration Charge

The Public Staff and NCSEA both critique Duke's and DENC's proposed solar integration charges in their initial comments. The Public Staff raises a number of issues with the Utilities' proposed charges, including how the application of such a charge would impact other renewable energy and energy efficiency programs, modeling inputs used to develop the charges, and whether the Utilities have considered the costs and the benefits of solar generation on their systems. NCSEA argues that the Utilities' solar integration charges should be rejected by the Commission. NCSEA addresses flaws in the Utilities' methods for developing the integration charges, argues that the Utilities have failed to include a number of benefits provided by solar QFs, and asserts that the proposed integration charges do not comply with applicable state and federal law.

1. Costs and Benefits

Both the Public Staff and NCSEA note that the Commission's E-100, Sub 140 Phase One Order provides that it would only be appropriate for the Utilities to include the costs and benefits related to solar integration in their avoided cost calculations "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[38] The Public Staff states that it "may be appropriate for the Commission to consider evidence of what additional costs or benefits can be sufficiently known and verifiable at this time such that they should be included in avoided cost rates."[39] NCSEA argues that the Utilities' proposed Solar Integration Charges are inconsistent with the Commission's directive in

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[38] North Carolina Utilities Commission Docket No. E-100, Sub 140, "Order Setting Avoided Cost Input Parameters" at 60-61 ("Phase One Order"); Public Staff Initial Comments at 32; NCSEA Initial Comments at 33.
[39] Public Staff Initial Comments at 33.

the E-100 Sub 140 Phase One Order because they fail to include the benefits provided by QF generation in addition to any costs.[40]

SACE agrees that the Utilities' failure to include an analysis of potential benefits of solar integration does not comply with the Commission's prior orders. SACE also agrees with NCSEA's assertion that Duke has failed to consider the potential benefits of solar paired with storage in its integration study analysis.[41] NCSEA argues that because of the ancillary services that storage is capable of providing, including load following, regulation, and fast frequency response, solar plus storage projects should not be subject to a solar integration charge.[42] SACE agrees that a solar QF with storage should not be subject to an integration charge because the operational characteristics of the facility should negate the need for any such charge. At a minimum, the Utilities have not adequately demonstrated that any integration charge is warranted, and in fact, solar QFs with storage may be entitled to additional payment for avoided costs associated with operating reserves.

NCSEA also argues that Duke has failed to consider the benefits that solar QFs provide to the transmission and distribution systems.[43] NCSEA recommends that the Commission require Duke to quantify and compensate QFs for these benefits, which NCSEA presents in its initial comments and in the report of Thomas Beach.[44]

SACE agrees that QFs should be compensated for the full range of costs that they allow the purchasing utility to avoid, including applicable transmission and distribution

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[40] NCSEA Initial Comments at 34.
[41] Id. at 38.
[42] Id. at 39.
[43] Id.
[44] Id. at Attachment 2.

costs. The Federal Energy Regulatory Commission ("FERC") has previously upheld a state utility commission's decision to include a 10% avoided cost "adder" for QFs located in transmission-constrained areas to reflect the savings from deferred transmission- and distribution-related costs. *See, California Pub. Utilities Comm'n*, 133 FERC ¶ 61,059 (2010).[45] NCSEA's proposed avoided transmission and distribution system cost analysis is consistent with FERC's precedent on this issue under PURPA, which has acknowledged a state's ability to consider these types of benefits in avoided cost calculations.

NCSEA also argues that the Commission should evaluate opportunities for QFs to receive compensation for ancillary services they are capable of providing to the grid.[46] SACE agrees with NCSEA that North Carolina law does not provide the Utilities a monopoly with regard to ancillary services, and to the extent QFs are able to provide services at rates that are competitive with services the Utilities are able to provide themselves, QFs should have the opportunity to earn revenue for those services, while decreasing costs to ratepayers by establishing a competitive ancillary services market.

<u>2.</u> <u>Administration of Proposed Integration Charge</u>

The Public Staff highlights certain administrative issues regarding the Utilities' proposed solar integration charges, including the charge's impact on the administration of the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") and the

[45] FERC stated that "if the CPUC bases the avoided cost 'adder' or 'bonus' on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an 'adder' or 'bonus' would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations." *California Pub. Utilities Comm'n S. California Edison Co. Pac. Gas & Elec. Co. San Diego Gas & Elec. Co.*, 133 FERC ¶ 61,059, 61,268.
[46] NCSEA Initial Comments at 29.

Competitive Procurement of Renewable Energy ("CPRE") program.[47] The Public Staff argues that it is appropriate to collect and administer any integration charge separately from the avoided energy rate that is paid to these QFs, as proposed by Duke, rather than including any integration charge as a decrement on the avoided cost rate itself, as proposed by DENC.[48]

NCSEA argues that the integration charge should be rejected, but that if an integration charge is approved, imposing the charge on QFs as a separate charge, as proposed by Duke, constitutes single-issue rate making, and any integration charge should only be established as part of a general rate case.[49] NCSEA also argues that imposing an integration charge independent of the avoided cost rate is not supported by FERC's PURPA regulations.

SACE recognizes the Public Staff's concerns regarding an integration charge's potential impact on the REPS and CPRE administration if the charge is embedded in the avoided cost rate. However, SACE also agrees with NCSEA that the imposition of a stand-alone integration charge on solar QFs could represent "single-issue ratemaking" contrary to North Carolina law and that FERC's regulations implementing PURPA do not appear to contemplate a standalone integration charge as a component of the avoided cost. SACE maintains its position presented in initial comments that the Commission should reject Duke's and DENC's proposed integration charges because both utilities have failed to adequately support their respective charges. However, if the Commission did ultimately approve an integration charge, the decrement approach as proposed by

[47] Public Staff Initial Comments at 31-32.
[48] Id. at 30.
[49] NCSEA Initial Comments at 47.

DENC appears less legally suspect than the stand-alone charge as proposed by Duke. In implementing such a decrement charge, the Commission could establish a procedure by which to remove any integration charge in the administration of the applicable REPS and CPRE programs, to address the concerns raised by the Public Staff.

The Public Staff also takes issue with Duke's proposal to impose updated solar integration charges on existing QFs every two years.[50] SACE agrees with the Public Staff that updating a solar integration charge every two years would create significant financial uncertainty for QFs who have entered into long-term fixed contracts to whom the integration charge applies. This is particularly true when, as the Public Staff notes, Duke's proposed charge has no cap.[51]

The Public Staff notes that in E-100 Sub 148 the Commission rejected a proposal by Duke to update avoided cost rates within long-term contracts every two years, reasoning that changing a QF's rates every two years would be inconsistent PURPA's requirement that QFs have the option to enter into long-term fixed contracts with the avoided cost established at the time the legally enforceable obligation is created.[52] SACE agrees with the Public Staff that a two-year integration charge refresh would, similarly, undermine FERC's and this Commission's previous holdings and would insert significant economic uncertainty into future QF project planning.

SACE also agrees with NCSEA's recommendation that the Utilities be required to develop and provide public access to hosting capacity maps. SACE concurs with NCSEA's assertion that the type of hosting capacity map that NCSEA describes in its

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[50] Public Staff Initial Comments at 36.
[51] Id. at 38.
[52] Id. at 37-38.

initial comments would allow QFs to more accurately site projects in geographical locations that will improve the efficiency of energy generation in the Utilities' service territories.

E. Terms and Conditions

The Public Staff, NCSEA, and NC WARN all commented on Duke's proposed terms and conditions included in the Initial Statement and Exhibits. In general, SACE agrees with the positions of the Public Staff, NCSEA, and NC WARN that a number of Duke's proposed amendments to the Schedule PP terms and conditions are insufficiently clear and will likely discourage QF development, including the addition of battery storage.

The Public Staff states that an existing QF that seeks to add storage may ultimately change the timing and quantity of energy and capacity output from the project, but disagrees with Duke's proposal to require a QF that adds storage to forfeit its existing PPA and sign a new PPA under the present avoided cost rate.[53] As an alternative, the Public Staff suggests that under these circumstances, Duke could separately meter any additional output from the QF and compensate the additional output at the then-current Commission approved avoided cost rates without requiring the existing facility to forfeit payments for the original output under the terms of its pre-existing PPA.[54]

SACE agrees that it is not appropriate to require a QF adding storage to forfeit its existing PPA. As SACE discussed in its initial comments, battery storage has the potential to add significant value to the grid, and disincentivizing the adoption of

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[53] Id. at 74.
[54] Id. at 75.

beneficial technologies is inefficient and inappropriate. SACE also agrees with the Public Staff that it would be problematic and inappropriate to characterize the addition of energy storage as a new and separate facility.[55]

SACE does not consider it appropriate at this time to require existing QFs that add storage or replace existing solar panels, but which do not exceed their AC capacity, to enter into new contracts with new avoided cost rates. As NCSEA notes in initial comments, PURPA and FERC's implementing regulations require utilities to purchase all energy and capacity produced by qualifying facilities unless the utility has received a waiver of its purchase obligation.[56] Requiring QFs to enter into bifurcated avoided cost rates when the QF is not exceeding its original AC capacity is inconsistent with PURPA's requirements.[57] Similarly, SACE agrees with both the Public Staff and NCSEA that Duke's proposal to include the delivery of energy excess of the estimated annual energy production should not be grounds for PPA termination.[58]

With respect to Duke's proposal that it may terminate a PPA for "any material modification to the Facility without the Company's consent or otherwise delivering energy in excess of the estimated annual energy production of the Facility", SACE agrees with the Public Staff that "material modification" is undefined and that the term should be defined for the purposes of avoided cost contracts, with stakeholder input.

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[55] Id. at 76.
[56] NCSEA Initial Comments at 55.
[57] Other types of qualifying facilities may operate at different capacity factors over the course of their useful life without facing similar restrictions. For example, non-solar generating facilities can vary substantially in output from year to year. Based on U.S. Energy Information Administration Forms 860 and 923, the UNC Chapel Hill Cogen Facility has capacity factors varying from 10% to 27%, and Ingredion Winston Salem has capacity factors that vary between 53% and 76% (disregarding the 2017 value of 12%).
[58] Public Staff Initial Comments at 79; NCSEA Initial Comments at 54-55.

NCSEA argues that the material modification issue is properly addressed through the applicable interconnection proceeding. SACE agrees with NCSEA that to the extent that the Commission determines it is appropriate to include "material modification" language in the avoided cost contracts, in addition to the context of interconnection, the "material modification" criteria proposed by Duke is overly broad. SACE also agrees with NCSEA that Duke has already agreed that changes to the DC capacity of a QF do not constitute a material modification for the purposes of interconnection.[59] SACE supports NCSEA's argument that Duke should not be permitted to add the DC capacity of a QF to the definition of nameplate capacity and contract capacity in their respective PPA terms and conditions.[60]

NC WARN's Initial Comments also recommend that the Commission reject Duke's amended terms and conditions with respect to battery storage.[61] NC WARN explains that Duke's proposed terms would give the Companies the ability to unilaterally deny a QF's request to add battery storage to an existing project.[62] Moreover, NC WARN notes that Duke's proposed terms would allow the Company to refuse to purchase energy from battery storage at peak times, undermining the key benefit of solar plus storage projects.[63] SACE shares the concerns voiced by NC WARN in initial comments.

Finally, on March 22, 2019, Duke circulated a draft "Energy Storage Protocol" to parties in this proceeding. Duke indicated that it plans to file this document as an

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[59] NCSEA Initial Comments at 51-52.
[60] Id. at 53.
[61] North Carolina Utilities Commission Docket No E-100, Sub 158, NC WARN's Initial Comments at 3.
[62] Id.
[63] Id.

attachment to its reply comments. SACE appreciates Duke's efforts to draft and distribute these protocols in response to comments from parties to this proceeding. However, SACE has not yet had adequate time to review, evaluate, and prepare comments in response to the proposed Energy Storage Protocol, and SACE requests that the Commission provide parties the opportunity to respond to the Energy Storage Protocol, and any other new documents the Utilities include in reply comments, at a future stage in this proceeding.

III. Conclusion

SACE thanks the Commission for the opportunity to submit these reply comments for the Commission's consideration. SACE looks forward to the opportunity to participate further in this proceeding to assist the Commission in its determination regarding these important issues.

Respectfully submitted this 27th day of March, 2019.

s/Peter D. Stein
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Attorney for SACE

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Reply Comments of the Southern Alliance for Clean Energy, as filed today in Docket E-100, Sub 158 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 27th day of March, 2019.

s/ Peter D. Stein

EXHIBIT A
TO SUPPLEMENTAL
TESTIMONAY OF
MICHAEL R. WALLACE
E-100, SUB 158

1A vol. 5

MICHAEL R. WALLACE, PE, CEM, GBE

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Ecoplexus, Inc, Vice President, Southeast Development

Versatile and outcome-oriented individual with 14+ years' achievement in progressively responsible engineering and business leadership and a proven history of success at the helm of challenging, multimillion-dollar projects. Multidisciplinary engineer and business owner who effectively manages clients, vendors and staff, excels at building teams, and delivers process improvement initiatives that fuel bottom-line growth. Adept in all aspects of construction management, field engineering, design engineering and process engineering. Wholehearted leader with the business and financial planning acumen to conduct reliable forecasting and complete projects on-time and under-budget. Core stakeholder responsible for identifying risk, secure funding, project procurement and managing resources. Professional Engineering (PE), Certified Energy Manager (CEM), Green Building Engineer (GBE).

Areas of Expertise:

OPERATIONS MANAGEMENT, INVESTMENT STRATEGIES, PROJECT MANAGEMENT, DESIGN, NEW CONSTRUCTION, RENOVATIONS, STRATEGIC PLANNING & ANALYSIS, P&L, COMPLIANCE, CONTINUOUS IMPROVEMENTS, BUDGETING, REPAIRS, CAPITAL REPLACEMENT PROJECTS, REPORTING, TRAINING, INSPECTIONS, CONTRACT NEGOCIATION, LEASE NEGOCIATIONS, REQUEST FOR PROPOSAL, BUSINESS PLANNING, PURCHASE POWER AGREEMENTS, INTERCONNECTION AGREEMENTS; DEVELOPMENT STRATEGY

PROFESSIONAL EXPERIENCE

Ecoplexus, Inc. – Durham, NC — May 2017 to Present
A Better Energy Future — *mwallace@ecoplexus.com*

Vice President, Ecoplexus, Inc.

Ecoplexus believes in a better energy future. We are a leader in the development, design, construction, and financing of solar power projects for the commercial, municipal, non-profit and utility markets in the US and key International markets. The Company's energy services capabilities, and strong analytical and project finance expertise are the foundation from which we have successfully developed, built and financed many solar energy facilities in a short period of time. We focus on distributed generation and utility scale projects in the 2MW-AC to 100MW-AC range and are currently working a pipeline of over 3000 MW-AC of projects in the US and Internationally.

Ecoplexus currently has employees in San Francisco CA, Dallas TX and Raleigh NC in the United States, as well as International offices in Japan, Mexico, Turkey and Thailand. The EcoPlexus project teams have completed, or currently have under construction, over two hundred (350) MWs of projects, and include Licensed General Contractors (B), Licensed Electrical Contractors (C-10), Specialty Solar Contractors (C-46), and NABCEP certified professionals.

The finance team has originated over ($300m) three hundred million in projects to date under Power Purchase Agreements with excellent returns for investors.

- http://www.ecoplexus.com/
- Lead business planning, business development, and design expertise in all aspects of utility scale solar with a focus on projects designed for distribution and transmission interconnections ranging from 2 MW AC to 300 MW AC in the Eastern US. Manage a team of 8-12 individuals who initiate projects from concept through development and onto construction to deliver to long term value to Stakeholders.
- Responsible for strategy and business planning in Southeast United States. Currently managing a pipeline of approximately 3000 MW-AC. Responsible for origination of projects with utilities including Duke Energy, Florida Power & Light, South Carolina Electric & Gas, Dominion, Southern Company, Tampa Electric, Seminole, and Santee Cooper.
- Responsible for complete development of utility scale projects to construction including negotiation and Purchase Power Agreement and Interconnection Agreement.

Sunlight Partners – Portland, ME — 2015 to 2017
Our Mission + Your Land = Environmentally Friendly Clean Energy — *Michael.Wallace@sunlightpartners.com*

Senior Vice President, Sunlight Partners, LLC

Led business planning, business development, operations and design expertise in all aspects of utility scale solar with a focus on projects designed for distribution and transmission interconnections ranging from 2 MW AC to 40 MW AC. Manage a team of 6-10 people who initiate projects from concept through development to deliver to long term owners/investors at "Notice to Proceed" (NTP) status ready for construction. Responsible for creating and maintaining a P&L plan for Sunlight Partners. Responsible for managing all consultants and vendors in states of operation. Understanding of solar tax equity structures critical for financing solar projects. Key development areas and tasks include:

– SUNLIGHT PARTNERS – NC, GA, and NY | UTILITY SCALE SOLAR DEVELOPER: Developed of over 425 MW AC of solar in North Carolina consisting of two portfolios. Ongoing development efforts for distribution and transmission scale projects in North Carolina, Georgia and New York. Over 300 leases secured and ongoing, approximately 80 projects developed or in various development stages. Strong communicator and networker which has led to the growth and recognition of Sunlight Partners in the industry across the United States. Created and maintain Sunlight Partners business plan, development strategy, development schedule and execution. Total portfolios value to date of approximately $50 MM.

– Managed and provided development expertise of each individual site including; identifying sites, interconnection application, power purchase agreement, interconnection agreement, site single line drawings, site layout design, site engineer of record, state regulatory and legislative knowledge, PVsyst power output analysis, phase 1 & phase 2 environmental site assessment, wetland delineation including jurisdictional determination, site surveying, Nation Environmental Policy Act (NEPA) permitting, over 200 planning board & County Commissioner hearings resulting in Special Use permits, Utilities Commission Applications and management, FERC Applications and management, Archaeological Survey, EPC management to establish baseline pricing.

– Currently continuing to work with Sunlight Partners as a Senior Vice President to finalize a 170 MW-DC with Duke Energy Progress in North Carolina. www.sunlightpartners.com

Cate Street Capital – Portland, ME — 2014 to 2017
Intelligent Investing For a Sustainable Future. — *mwallace@catecapital.com*

Managing Director, Engineering Cate Street

Provided engineering and project management expertise and guidance across multiple business ventures for Cate Street Capital.

– BURGESS BIOPOWER – BERLIN, NH | ENGINEERING DESIGN & PROJECT MANAGEMENT: Served as a professional engineer to evaluate and offer assistance for a 75 MW bio-mass facility in northern New Hampshire. Duties included:
a.) Preparation and review of the site Spill Prevention Plan.
b.) Physical review of punch list items during project close to assists Babcock and Wilcox to get to substantial completion.
c.) Managed a landfill gas and natural gas feasibility study in which both were considered to help offset the rising cost of biomass fuel. Project involved looking at new sub gun assemblies for the existing bubbling fluidized bed as well as a combine heat and power unit at 5.4 MW AC to help offset the parasitic loads. Based on the projects return on investment, a landfill gas pricing model was derived to understand how much Burgess Power could afford to pay for this technology.

– ORGANIC NUTRITION INDUSTRIES – RATON BOCCA, FL | FACILITY DESIGN: Served as a professional engineer to assists in the design and construction of a facility intended to convert organic waste streams into edible protein for animals. Duties include assisting with a complete design package to provide finance, engineering, construction management, permitting, regulatory affairs and operational support to prepare the site commercial operation.

– THERMOGEN – MILLINOCKET, ME | ENGINEERING DESIGN & MANAGEMENT: Served as a professional engineer to assist and support in the design of a 330 metric ton/yr black pellet plant in Millinocket, Maine. Duties included:
a.) Working with outside engineers to develop a plant layout and process flow.
b.) Directing and working with vendors to identify equipment necessary to meet the project pro-forma material output.
c.) Review, input and guidance of the plant mass balance.

D.E.E.P. Engineering Solutions LLC – Scarborough, ME 2013 to 2017

Design, Evaluate, Execute, Performance – Engineering Design Company. Michael.wallace@deepengsolutions.com

Owner & President/Principal Engineer

Provide design and operational expertise in all aspects of commercial and industrial engineering with a focus on industrial process and energy conservation. Manage project teams of 5-10 people for an engineered wood product facility, commercial building design and process piping design. Effectively analyze the task presented, construct a scope based on available budget and client expectation and complete the task in the time allotted. The company has expanded in revenue 30%-35% since its inception with 100k + of contracts on the books in 2016.

D.E.E.P. Engineering Solutions is a multi-discipline engineering consulting firm with professional liability insurance to handle projects valued up to $10 MM. D.E.E.P. utilizes Paragon Management for CPA and financial services as well as Brann & Isaacson for legal advice and contracting. Key clients and projects include:

- SUNLIGHT PARTNERS, LLC – PORTLAND, ME | ENGINEER OF RECORD: Principal Engineer in charge of all solar design work which is submitted to the utility and local jurisdictions for approval. These tasks include preliminary single line drawings, site layouts, FERC applications, Public Utility Applications, and Utility Applications.

- IDEXX LABORITORIES, INC. – WESTBROOK, ME | CHILLED WATER UPGRADE OWNERS ENGINEER: Owners Engineer responsible for reviewing a chilled water tie-in between the East and West buildings. Duties include P&ID review, pumping requirements review, site layout & piping design review, control narrative review.

- LOUISIANA PACIFIC – HOULTON, ME | LOG DECK & SLASHING MODERIZATION: Principal Engineer in charge of new log deck and slashing system. Reviewed the existing log deck and slashing system design as intended during the Laminated Strand Lumber, (LSL) upgrade. Current log singulation and pendulum slashing design did not meet LSL board output. Worked with the plant team to confirm the existing mass balance and desired throughput. Developed a vendor specification and worked with three equipment suppliers on various layouts which were reviewed and graded. Based on equipment cost, schedule and functionality a vendor was selected to assists in the final design. The project is scheduled to be implemented in early 2018. Project valued at $4MM.

- LOUISIANA PACIFIC – HOULTON, ME | REGENATIVE THERMAL OXIDIZER STACK EVALUATION: Principal Engineer in charge. Reviewed the existing 100 foot process stack for structural integrity. Ultra-Sonic thickness measurements were taken in six locations every 5 to 6 feet in height. Measurements where compared to ASME-STS-1-2000 and revision ASME-STS-1a-2003 for code compliance. Anchor bolts were evaluated and a recommendation made to protect the integrity of the bolts.

- STEEL-PRO INCORPORATED – ROCKLAND, ME | ASME VESSEL DESIGN REVIEW: Provided review of filter and accumulator assembly design per ASME standards and client design specifications. Upon completion of review, provided Professional Engineering Stamp for construction and installation. Have completed these reviews in Washington and California.

- RAMSAY WELDING & MACHINE – LINCOLN, ME | CONVEYOR DESIGN & RECORD DRAWINGS: Serving as the Principal Engineer responsible for working with an engineered wood products company on behalf of Ramsay Welding & Machine. Design of a heavy industrial Oriented Strand Board sanding line including rolls conveyor, chain conveyor, jump chain conveyor, paint both conveyor, paint booth, boxing ring conveyor, strapper and discharge rolls. Responsible for all equipment design and shop drawings. Shop drawings supplied to Ramsay Welding & Machine to construct and install the approved design. Sizing of conveyor structural members was a key to the success of the project. Drawings were finalized as record prints and stamped with Professional Engineering Seal. Project valued at $330k.

- RAMSAY WELDING & MACHINE – LINCOLN, ME | COMMERCIAL BUILDING FLOOR ANALYSIS: Served as the Principal Engineer responsible for evaluating an existing 2nd story floor to determine additional beam sizes needed to support a client requested live and dead load while maintaining proper deflection per code. Final stamped calculations were provided to Ramsay Welding & Machine with Professional Engineering Seal.

WOODARD & CURRAN – Portland, ME 2011 to 2013

840-person, integrated engineering, science, and Operations Company.

Project Manager

Provided expertise in all aspects of project management, construction management, field engineering, design engineering, and process engineering. Managed 3–15-person project teams on diverse engagements, including: process design for engineered wood product facilities; paper and tissue manufacturing design; water room treatment design; food and beverage utility and process design; steam design; and boiler systems design. Effectively managed client expectations, carefully monitor scheduling, and ensure accurate reporting. Implement broad-spectrum process improvements and spearhead compliance initiatives for diverse clientele. Key clients and projects included:

- IDEXX LABORATORIES – WESTBROOK, ME | FACILITY BOILER STUDY, DESIGN & INSTALLATON: Lead Principal Engineer of record, responsible for completing a detailed energy study of a campus boiler system. The campus was composed of two buildings covering 200,000 sqft and 350,000 sqft respectively. The study included steps necessary to combine the East 550 HP boiler system with West 800 HP boilers system. Five boilers total. Responsible for complete design including friction loss, pipe routing, pipe sizing, boiler lifespan analysis and overall system efficiency. Effectively managed the engineering, procurement and installation within the purposed scope, schedule and budget. Responsible for holding daily project meetings with 3-5 contractors, the client and engineering staff throughout the 6 month project. Total project savings were calculated at $300k and are on target as three of the five boilers were placed on backup once the two buildings were combined.

- CON EDISON – NEW YORK, NY | POWER ENGINEERING BOILER DESIGN: Serving as lead Project Engineer on $500K, year-long component of $46MM project for one of the nation's largest investor-owned utility companies. Proactively managed client expectations while directing 6–7-person team and ensuring on-time project scheduling. Reviewed piping and instrumentation diagram (P&ID) for a new, 12-inch Natural Gas line addition for 5 boilers on West 59th Street and 7 boilers on East 74th Street and created functional test procedures for commission team. Conceived, managed, and maintained project schedule comprising 300+ procedures and codes, including NFPA 54, NFPA 56, NFPA 85 and American Gas Association Purging 2001.

- COCA-COLA – ATLANTA, GA | STEAM & POWER COGENERATION DESIGN: Built full facility from scratch, serving as lead Project Engineer on intensive year-long project. Held directly management responsibility for 2–4 engineers throughout all phases of implementation. Designed utility connections for GE-supplied engine. Completed stress analysis of 6" steam line utilizing Caesar II, checking codes B31.1 and B31.3. Determined and identified anchor points, expansion joints, and valve locations. Performed hydraulic calculations relating to engine's high- and low-cooling circuits for pump selection, potable water system for booster pump selection, process waste for pump selection, feed water line for pump skid selection and condensate line for pump skid selection. Developed P&IDs for the compressed air system, potable water system, process waste system, feed water system, condensate return system and steam system. Drafted mechanical specifications for the contractor to purchase and install piping, valves, insulation and components.

- COCA-COLA – NATIONWIDE | 1881 CLOSURE UPGRADES: Lead Project Engineer to convert 32 small PET lines to 1881 closures, which improved sustainability (utilizing a single thread start) and reduced closure inventory levels across North America. Managed 9 plant conversions across the U.S. and assisted on others. Supported plant maintenance teams in assessments of cappers. Developed plant shutdown schedule for implementations of key improvements, with the duration of outages ranging from 2–5 days. Personally supervised all shutdowns and startups.

D&S ENGINEERING, INC. – Millinocket, ME 2009 to 2010
Offering broad-spectrum construction services as well as designs and studies.

Project Engineer

Assisted process design in paper mills and surrounding industrial facilities throughout Maine for a small, multidisciplinary firm. Identified inefficiencies and implemented process improvement initiatives.

Signal achievements as project engineer at D&S Engineering, Inc. (2009–2010):

- HOSPITAL – MAINE: Evaluated an existing hospital kitchen and measured heat loads generated throughout normal day. Calculated sensible and latent heat loads; subsequently selected appropriate cooling coil for an existing air makeup unit.
- POWER PLANT – NORTH CAROLINA: Identified Reverse Osmosis (RO) system that could effectively treat the water supply that the plant received from the city (and used to produce steam). Assisted vendors in selecting an RO system and submitted pricing for selection.
- CORRECTIONAL FACILITY – MAINE: Designed 6" return-and-supply hot water line, transferring water to new 1.2-MMBTU/hr pellet boiler stationed in a building approximately 100 ft. from existing mechanical room. Installed pipe outside at 10'-elevation and placed in compliance with new pipe stands. Produced detailed design, encompassing valving, insulation, wall penetrations and thermal expansion

LOUISIANA PACIFIC CORPORATION – Houlton, ME 2004 to 2008
Leading manufacturer of quality engineered wood building materials.

Senior Plant Engineer/Project Manager (2005 to 2008)

Served as in-house engineer and project manager, leading all phases of capital projects ranging in scope from $20K to $3.5M. Ran pre-bid and construction meetings to ensure clear communication and strategic alignment between the plant, contractors and all vendors for each project. Acted as construction manager, POC, and field-engineer throughout implementation. Leveraged financial planning skillset to assist in the calculation of ROI for each project. Managed 14 maintenance personnel during internal plant projects, while holding indirect management responsibility for up to ~115 workers across 3 shifts during day-to-day operations. Undertook plant wide process improvements initiatives, designed structural supports for equipment/catwalks, and implemented product storage systems.

- OVERSAW $7M in capital expenditures in 2007, including $3.5M replacement of a Regenerative Thermal Oxidizer for the plant's dryer gases.
- MANAGED phases of large-scale project to flush and refill 45K gallons of thermal oil fluid from an LP plant's energy system. Captured 33% increase in capacity by designing conveyor modifications for 8-belt and drag-chain conveyors.
- DESIGNED AND INSTALLED new wet-bin distribution conveyors to transport wood flakes to various bins for storage, forecast to increase capacity by 25%.
- KEY CONTRIBUTOR on 2-year, $150M design and build of new Laminated Strand Lumber (LSL) line at the New Limerick facility. Performed design reviews during execution of LSL line and at various OEM facilities and conducted extensive field engineering during LSL construction phase. Served as plant representative on all subsequent design changes as the project developed and managed small pieces up to $250K.
- LED project team in overhauling 6K gallon propane farm, bringing the system into compliance with NFPA 58.
- DIRECTED project teams of 5–50 direct reports—and as many as 80 during shutdowns.

Plant Engineer II /Project manager (2004 to 2005)

Efficiently coordinated diverse capital projects for Louisiana Pacific, with management responsibilities spanning budgeting, scheduling, and engineering. Reviewed the equipment proposals of OEMs for all processes within the plant. Led teams within the facility to modify and improve existing equipment and processes. Directed plant shutdown activities and created a work schedule governing all plant functions.

PROFESSIONAL PROFILE

Organizations	Town of Scarborough Maine Energy Committee, North Carolina Clean Energy Business Alliance, North Carolina Sustainable Energy Association, South Carolina Clean Energy Business Alliance, South Carolina Solar Business Alliance.
Education	Bachelor of Science in Mechanical Engineering – University of Maine – Orono, ME
Associations	American Society of Heating, Refrigeration & Air Conditioning Eng (ASHRAE) American Society of Mechanical Engineers(ASME) Project Management Institute (PMI) Association of Energy Engineers (AEE)
Technical Skills	Microsoft Office (Word, Excel, PowerPoint, Outlook & Project 2013), Adobe Acrobat 9 Professional Design software: Micro Station, Math Cad, Auto Cad 2013, Pipe-Flo (Hydraulic Modeling), Mechanical Desktop, TRANE – TRACE 700, Compress Codeware, Caesar II Stress Analysis, PVsyst Computer Programming: FORTRAN & Q-Basic
Registrations	Licensed Professional Engineer, ME, 12281; Registered Professional Engineer: NH, 13239; VT, 72395; MA, 48926; GA, 35979; CA, 35984; NY, 091268; the Commonwealth of Virginia, 052010; WA 50397; North Carolina, 041311; Florida, 77501 | Certified Energy Manager-CEM# 20388 | Green Building Engineer-GBE

1A
vol. 5

MESA
Open Standards for Energy Storage

MESA-ESS Specification

DRAFT

Released December, 2018

Version Control

Revision	Date	Purpose	Originator
	2016-11-15	Draft for preliminary release	Frances Cleveland
	2018-12-20	Update reflecting the DNP3 AN2018	Frances Cleveland

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1. Introduction

1.1 Scope and Purpose

The MESA-ESS specification defines the communication requirements for utility-scale energy storage systems (ESS), including ESS configuration management, ESS operational states, and a profile of the IEEE 1815 (DNP3) standard based on the IEC 61850-7-420 information model for advanced DER functions. These advanced DER include all of the functions defined in IEEE 1547:2018, California's Utility DER Electric Rule 21 Interconnection, and the European ENTSO-E DER interconnection requirements (2016), as well as additional functions of particular interest to ESS. This specification references the DNP3 Application Note AN2018-001 which is based on a DNP3 Mapping Spreadsheet, which directly maps the IEC 61850 data objects for basic and advanced DER functions to DNP3 data objects.

The purpose of this MESA-ESS specification is to support the use of communication standards, promote interoperability, and minimize the amount of non-recurring engineering that is required to integrate ESS into utility operations using DNP3. It is expected that profiles of other communication standards will also be developed for different types and purposes of ESS (see Section 2). It is also expected that the IEC 61850-DNP3 profile will become an IEC document in the future.

For more information on MESA, please visit the MESA web site: http://www.mesastandards.org

1.2 References

The documents in Table 1 are either referenced in this document or provide additional information that may be useful when reading this document.

Table 1: Referenced Specifications and Standards

Document	Description
DNP3 Application Note: 2018 (AN2018)	DNP3 Profile for Advanced Distributed Energy Resource (DER) Systems
IEC/CD 61850-7-420: 2018	Communication networks and systems for power utility automation – Part 7-420: Basic communication structure - Distributed energy resources logical nodes (*currently available as a Committee Draft (CD)*)
IEEE 1547:2018	IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
California Rule 21	http://www.cpuc.ca.gov/Rule21/
IEEE 1815	IEEE Standard for Electric Power Systems Communications—Distributed Network Protocol (DNP3)
IEEE 1815.1	IEEE Standard for Exchanging Information between networks Implementing IEC 61850 and IEEE Std 1815™ (Distributed Network Protocol - DNP3)
EPRI 3002008217	Common Functions for Smart Inverters, Version 4

1.3 Process Used for Mapping IEC 61850-7-420 information model to DNP3 Data Points

After determining that the DNP3 AN2013-001 did not meet all of the requirements for MESA-ESS, in 2017 a collaborative effort between MESA and EPRI was initiated to develop an updated version, DNP3 AN2018: DNP3 Profile for Advanced Distributed Energy Resource (DER) Systems. At the same time, IEC 61850-7-420, the information model for DER, was being updated to reflect the new DER "grid code" requirements from California's Rule 21, IEEE 1547:2018, and Europe's ENTSO-e requirements. It was determined that not only should the DNP3 Application Note be updated to reflect ESS requirements, but that it should also include the new DER "grid code" requirements.

The basic procedure for developing the DNP3 AN2018 consisted of the following steps:

- The functional requirements for each DER "grid code" were defined (over the years 2013-2018) in the updates to California Rule 21 and in the revision of IEEE 1547.
- As the grid code functional requirements were defined and refined, the data exchange requirements were determined by the MESA-EPRI team and the IEC TC57 WG17 which is responsible for updating IEC 61850-7-420. These data objects were updated in the Enterprise Architect model of IEC 61850-7-420.
- The MESA-EPRI team created a DNP3 spreadsheet which was used to map each relevant data object from the IEC 61850-7-420 model to a DNP3 data point.
- Since both the IEEE 1547 and the IEC 61850-7-420 standards were being updated "simultaneously", there were many iterations to ensure the functional requirements were clear, the information model was valid, and the mapping to DNP3 data points was correct.
- When IEEE 1547:2018 was released in April 2018, the IEC 61850-7-420 was also submitted to the IEC as a Committee Draft (this is the normal process for creating a standard). At the same time, the update to the DNP3 AN2018 was started, using the DNP3 spreadsheet.

1.4 Scope Constraints

Although the MESA-ESS specification can be used by any type or size of DER, including photovoltaic systems, any type of energy storage system, and combined PV plus storage, this profile is focused initially on utility-scale battery energy storage systems, so battery-specific terminology is sometimes used.

Some ESS requirements are discussed which may or may not involve the use of DNP3. For instance, although DNP3 is used to monitor operational states, the permissions associated with those states may be implemented manually or through some other protocol. It is also expected that some implementations may use DNP3 to collect historical data (as opposed to SCADA data), while other implementations may choose to use other protocols.

1.5 Terminology

The terms in Table 2 are used throughout this document.

Table 2: Terminology

Term	Definition
Battery Bank	A collection of battery cells which can be used to store energy. Connected to a single inverter. A bank may be a shipping container full of lithium ion battery modules, or it may be a redox flow battery string.
Battery Management System (BMS)	An integrated electronic management system for monitoring, measurement, reporting, and protection of a battery storage bank at cell-, module-, and bank-levels.
Distributed Energy Resource (DER)	generation, storage, and controllable load connected at the low or medium voltage distribution level. Note 1: DER may include associated protection, control, and monitoring capabilities, and may consist of aggregated DER units. Note 2: DER may interact with the area and/or local electric power systems (EPS) by providing energy through the EPSs, by adapting their behaviour based on EPS conditions, and/or by providing other EPS-related services for regulatory, contractual, or market reasons.
DER System	One or more DER units that have a common DER controller (e.g. PV unit plus energy storage unit with a single controller, multiple energy storage units with a single controller)
DER Unit	A physical DER entity of one single type (e.g. photovoltaic unit, energy storage unit, or controllable load).
Distribution System Operator (DSO)	Utility managing the distribution power system
DNP3	Protocol standardized in IEEE 1815 and used by most US utility SCADA systems for monitoring and controlling substation equipment
Electrical Connection Point (ECP)	The point of electrical connection between a DER system and any electric power system (EPS)
Electric Power System (EPS)	The facilities that deliver electric power to a load or from generation
EPS, Area	The electric power system (EPS) that serves Local EPSs
EPS, Local	An EPS contained entirely within a single premises or group of premises
Energy Storage System (ESS)	A system that can store energy and release that energy as electricity
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
Independent System Operator (ISO)	Utility managing the balancing of generation and load within a control area by reflecting the bulk power market while still meeting the power system reliability requirements

Term	Definition
Inverter	Device that converts DC electricity into AC electricity, equipment that converts direct current from the array field to alternating current, the electric equipment used to convert electrical power into a form or forms of electrical power suitable for subsequent use by the electric system. For battery storage systems, it is typically 4-quadrant and is usually connected to a single battery bank.
Referenced ECP	The ECP that a DER's function references as the source of power system measurements. Usually this is either the ESS's ECP or the PCC, but other ECPs may be referenced.
Regional Transmission Operator (RTO)	Utility managing the transmission power system
Supervisory Control and Data Acquisition (SCADA)	System used by utilities and other facilities for controlling and monitoring power system equipment
Transmission System Operator (TSO)	Utility managing the transmission power system

2. Information Management for ESS Configurations

2.1 Economic Drivers for ESS Functions

There are many economic drivers for implementing and interfacing Energy Storage Systems. Based on work by the "More Than Smart" efforts, more specific discussions in the Sandia "*Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*" document[1], and discussion with the MESA members, an assessment of the ESS functions identified in this document is shown in Figure 1.

[1] http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

Utilities Incentivize ESS to Provide Grid Support Services

ESS Actions and Functions for Supporting the Grid Services / Utilities Grid Support Services that ESS May Provide, as Incentivized		A: Install: ESS under Direct Utility Control	B: Install: ESS under Contract, but 3rd Party Control	C: Install: ESS to Respond to Market	D: Market: ESS tariff items	E: Market: ESS contractual arrangements	F: Market: ESS bids into Day Ahead Bid-Ask Market	G: Market: ESS bids into Spot Market	H: Market: ESS responds to Demand Response	I: Monitor: Register ESS identity	J: Monitor: Determine operational characteristics	K: Monitor: State-of-Charge, status, and measurements	L: Monitor: Short-term forecast of ESS capabilities	M: Monitor: Historical information	N: Monitor: Metered information	O: Monitor: ESS detailed data	P: Control: Enable/disable modes	Q: Control: Set Mode Parameters and Curves	R: Mode: Set real power charge / discharge rate	S: Mode: Limit ESS real power to max discharge	T: Mode: Limit ESS real power to min charge rate	U: Mode: Load Following	V: Mode: Generation Following	W: Mode: Ramp rates for different situations	X: Mode: Real power smoothing of spikes and sags	Y: Control: Follow schedule real power and modes	Z: Mode: Price and Time-based Charge/Discharge	AA: Control: Automatic Generation Control (Up &	BB: Control: Regulation Up	CC: Control: Regulation Down	DD: Mode: Frequency smoothing	EE: Mode: Fixed power factor	FF: Mode: Power factor correction	GG: Mode: Volt-var control	HH: Mode: Volt-watt control	II: Mode: Fast var support	JJ: Mode: Watt-Power Factor	KK: Control: Start / stop ESS	LL: Control: Permit reconnection	MM: Preset: Frequency Ride-Through	NN: Mode: Frequency-watt (Emergency e.g. spinning	OO: Preset: Voltage Ride-Through	PP: Mode: Dynamic reactive current support	QQ: Mode: Soft-Start Reconnection	RR: Control: Separate into islanded microgrid	SS: Control: Provide black start capability	TT: Mode: Backup power
		Install			Market					Situational Awareness									[illegible] Power									Frequency				Voltage						Contingency and Resiliency									
ISO and Transmission Near Real-Time Operations (Day Ahead to Real-Time)																																															
Energy Capacity Adequacy																																															
Provide real power	53				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x	x																				
Limit energy (load or generation) on constrained transmission paths	54				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x																				
Minimize transmission losses	55				x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x																							
Smooth real power deviations	56				x	x	x	x	x	x	x	x	x	x	x	x	x	x							x																						
Frequency Support																																															
Provide regulation up and/or down	57				x	x	x	x	x	x	x	x	x	x	x	x	x	x										x	x	x																	
Provide synthetic inertia (frequency smoothing)	58				x	x	x	x	x	x	x	x	x	x	x	x	x	x													x																
Voltage Support																																															
Maintain voltage levels on transmission circuits	59				x	x	x	x	x	x	x	x	x	x	x	x	x	x														x	x	x	x	x	x										
Provide voltage smoothing on transmission circuits	60				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x										
Coordinate voltage support with distribution automation equipment	61				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x										
Support power quality requirements	62				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x										
Provide power factor support	63				x	x	x	x	x	x	x	x	x	x	x	x	x	x														x	x				x										
Contingency and Resiliency Support																																															
Provide long term reserves (e.g. non-spinning)	64				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x																					
Provide fast short term reserves (e.g. spinning and instantaneous)	65				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x																					
Provide emergency frequency support	66				x	x	x	x	x	x	x	x	x	x	x	x	x	x										x	x	x	x									x	x						
Provide emergency voltage support	67				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x					x	x				
Support microgrid islanding	68				x	x	x	x	x	x	x	x	x	x	x	x	x	x																											x		
Disconnect or cease the export of energy generation	69				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x																			x	x								
Provide black start support	70				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x																				x	
Distribution Systems Near Real Time Operations (Day Ahead to Real-Time)																																															
Energy Capacity Adequacy																																															
Provide real power at PCC	71				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x																							
Provide a schedule of real power at PCC	72				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x	x																				
Limit energy (load or generation) on constrained distribution circuits	73				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x					x	x																				
Minimize distribution losses (e.g. match local generation and loads)	74				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x																				
Avoid or minimize demand peaks	75				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x																				
Smooth real power deviations	76				x	x	x	x	x	x	x	x	x	x	x	x	x	x				x	x	x	x		x																				
Voltage Support																																															
Maintain voltage levels on distribution circuits (e.g. CVR)	77				x	x	x	x	x	x	x	x	x	x	x	x	x	x														x	x	x	x	x	x										
Provide voltage smoothing on distribution circuits	78				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x										
Coordinate voltage support with distribution automation equipment	79				x	x	x	x	x	x	x	x	x	x	x	x	x	x														x	x	x	x	x	x										
Support power quality requirements	80				x	x	x	x	x	x	x	x	x	x	x	x	x	x																		x											
Provide power factor support	81				x	x	x	x	x	x	x	x	x	x	x	x	x	x														x	x				x										
Contingency and Resiliency Support																																															
Provide long term reserves (e.g. non-spinning)	82				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x																					
Provide fast short term reserves (e.g. spinning and instantaneous)	83				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x																					
Provide emergency voltage support	84				x	x	x	x	x	x	x	x	x	x	x	x	x	x																x	x	x	x					x	x				
Minimize number and length of outages	85				x	x	x	x	x	x	x	x	x	x	x	x	x	x																											x	x	x
Disconnect or cease energy generation export	86				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x																			x	x								
Provide black start support	87				x	x	x	x	x	x	x	x	x	x	x	x	x	x	x							x																			x	x	

Figure 1: Economic Drivers: Near-Real-Time Energy Services Mapped to ESS Actions and Functions

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2.2 Overview of DER Hierarchical Configurations

Direct control of Distributed Energy Resources (DER) by distribution system operators (DSOs) is neither technically feasible nor contractually acceptable for the thousands if not millions of DER systems interconnected with the distribution power system. At the same time, utilities are responsible for meeting the reliability and electrical requirements within their distribution systems and therefore require information on the locations, capabilities, and operational status of these DER systems. In addition, these DER systems can greatly assist in meeting these utility requirements effectively and efficiently, thus making them proactive stakeholders in managing the electric power system.

Information exchange is critical to accommodate these complex and dynamic power system requirements, and management of these information exchanges needs to be organized and interoperable. Specifically, a hierarchical approach is necessary for the various stakeholders (utilities, aggregators, facilities, markets, and DER systems) to exchange information. At the local level, DER systems generally manage their own generation and storage activities autonomously based on local conditions, pre-established settings, and DER owner preferences. DER systems can also be active participants in power system operations and must be coordinated with other DER systems and distribution equipment. In addition, the DSOs must interact with transmission system operators (TSOs), also known as regional transmission organizations (RTOs) and/or independent system operators (ISOs), for reliability and market purposes. In some regions, retail energy providers, aggregators, or other energy service providers are responsible for managing groups of DER systems either through operational actions or market actions.

This hierarchical approach can be described as hybrid combinations of five (5) levels across multiple domains, as illustrated in the five-level hierarchical DER system architecture shown in Figure 2 and described below. The circled numbers identify the various logical information exchanges.

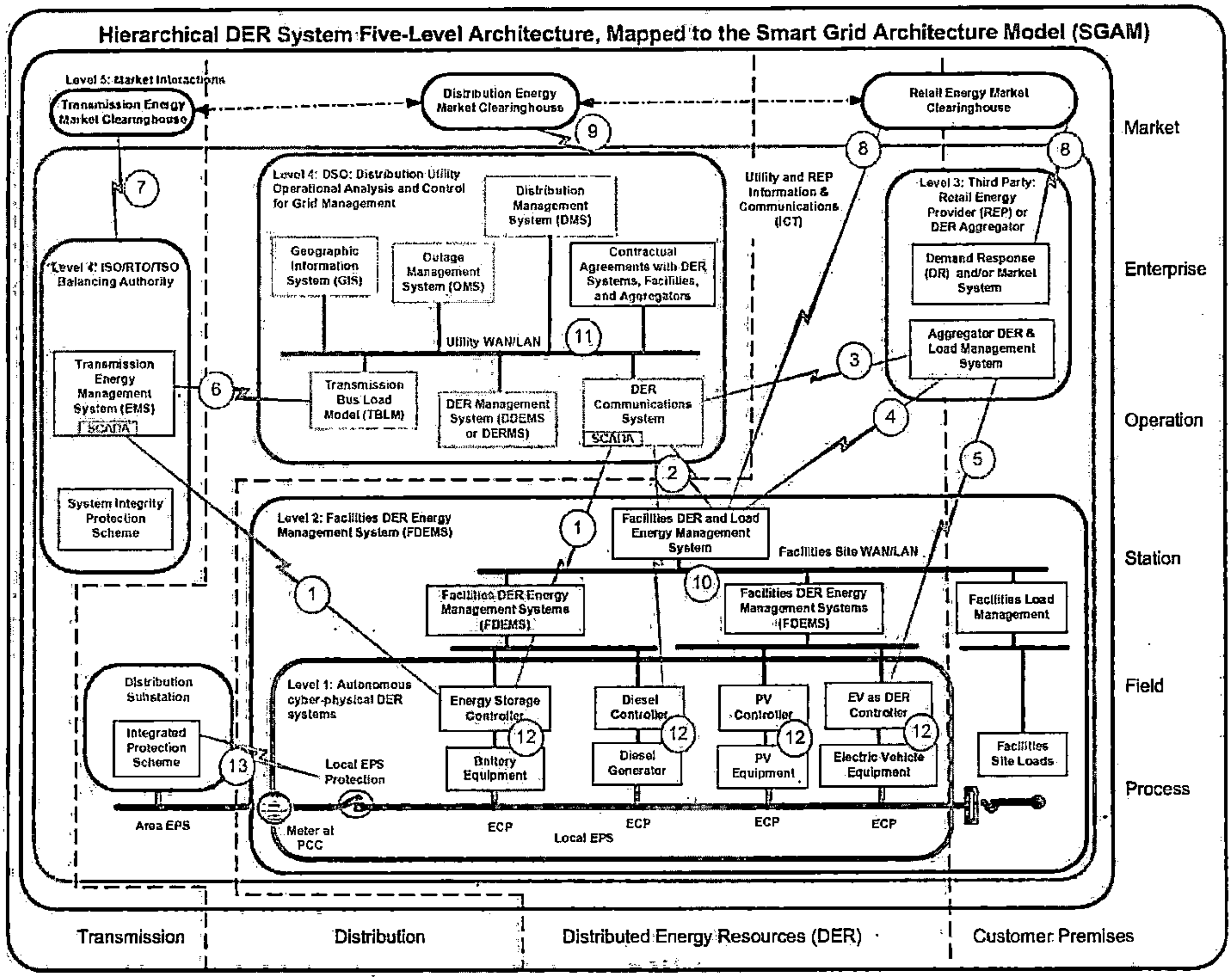

Figure 2: Hierarchical management of information exchanges for DER systems

1. **Level 1 DER Systems** (green in the Figure) is the lowest level and includes the actual cyber-physical DER systems themselves. These DER systems will be interconnected to local grids at Electrical Connection Points (ECPs) and to the utility grid through the Point of Common Coupling (PCC) (the ECP and the PCC may be the same if the DER is directly grid-connected). These DER systems will usually be operated autonomously. In other words, these DER systems will be running based on local conditions, such as photovoltaic systems operating when the sun is shining, wind turbines operating when the wind is blowing, electric vehicles charging when plugged in by the owner, and diesel generators operating when started up by the customer. This autonomous operation can be modified by DER owner preferences, pre-set parameter, and commands issued by utilities and aggregators.

2. **Level 2 Facility DER Management** (blue in the Figure) is the next higher level in which a facility DER management system (FDEMS) manages the operation of the Level 1 DER systems. This FDEMS may be managing one or two DER systems in a residential home, but more likely will be managing multiple DER systems in commercial and industrial sites, such as university campuses and shopping malls. Utilities may also use a FDEMS to handle DER systems located at utility sites such as substations or power plant sites. For utilities, FDEMS are viewed as field systems and shown at the Station level of the SGAM; however, from a facility's point of view, they may be seen as enterprises in their own right, and they could then be shown at the Enterprise and Operations levels.

3. **Level 3 Third Parties: Retail Energy Provider or Aggregators** (red in the Figure) shows market-based aggregators and retail energy providers (REP) who request or even command DER systems (either through the facility's FDEMS or via aggregator-provided direct communication links) to take specific actions, such as turning on or off, setting or limiting output, providing ancillary services (e.g., volt-VAr control), and other grid management functions. Aggregator DER commands would likely be price-based either to minimize customer costs or to respond to utility requirements for safety and reliability purposes. The combination of third parties (this level) and facilities (level 2) may have varying configurations, responsibilities, and operational scenarios but, overall, still fundamentally provide the same services.

4. **Level 4 Utility Operational Grid Management** (yellow in the Figure) applies to utility applications that are needed to determine what requests or commands should be issued to which DER systems. Distribution System Operators (DSOs) must monitor the distribution power system and assess if efficiency or reliability of the power system can be improved by having DER systems modify their operation. This utility assessment involves many utility control center systems, orchestrated by the Distribution Management System (DMS) and including the DER database and management systems (DERMS), Geographical Information Systems (GIS), Transmission Bus Load Model (TBLM), Outage Management Systems (OMS), and Demand Response (DR) systems. Transmission System Operators (TSOs), regional transmission operators (RTOs), or independent system operators (ISOs) may interact directly with larger DER systems and/or may request services for the bulk power system from aggregated DER systems through the DSO or through the REP/Aggregators. Once the utility has determined that modified requests or commands should be issued, it will send these either directly to a DER system, indirectly through the FDEMS, or indirectly through the REP/Aggregator.

5. **Level 5 Market Operations** (purple in the Figure) is the highest level, and it involves the larger energy environment where markets influence which DER systems will provide what services. The TSO markets are typically bid/offer transaction energy markets between individual DER owner/operators and the TSO. At the distribution level, the markets are not yet well-formed, and, over time as they evolve, they may be based on individual contracts, special tariffs, demand response signaling, and/or bid/offer transaction energy markets.

2.3 ESS Structures and Configurations

Energy storage systems come in many shapes and sizes. A simple ESS may consist of a single battery, a power conversion system, and one or two meters as shown in Figure 3. More complex energy systems might include multiple inverters and battery pairs, and they may utilize additional meters to ensure the proper monitoring and control of the ESS. Figure 4**Error! Reference source not found.** provides an example of a more complex energy storage system.

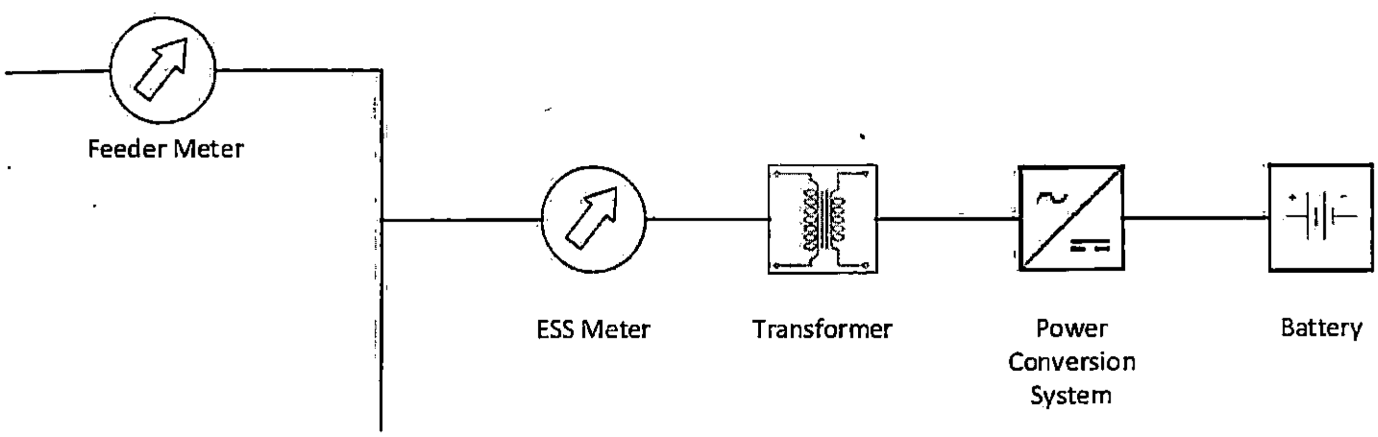

Figure 3: A simple energy storage system

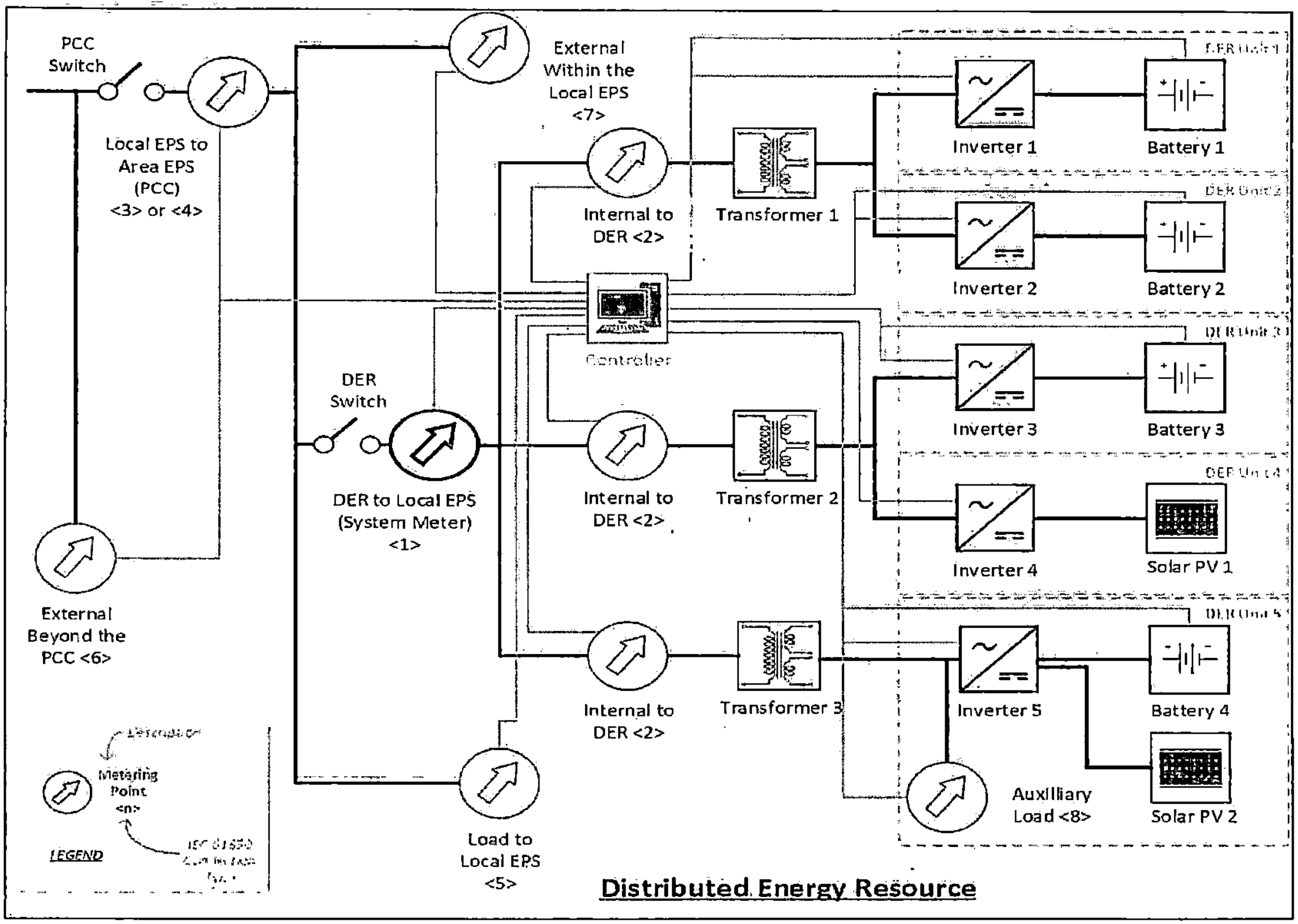

Figure 4: A more complex energy storage system

The MESA-ESS specification has been designed to support these different ESS configurations. In particular, MESA-ESS recognizes that energy storage systems typically consist of one or more inverters connected to a like number of energy storage components (e.g. battery banks). A MESA-ESS compatible ESS may have one or more inverter and battery bank pairs.

To ensure maximum utilization of more complex energy storage systems, the MESA-ESS specification provides monitoring and control points which allow an inverter and battery pair to be taken offline for maintenance while the rest of the system continues to operate normally. For example, for the ESS shown in **Error! Reference source not found.**, it is possible to place Inverter 3 and Battery 3 into maintenance mode and continue to use the rest of the system normally.

MESA-ESS also recognizes that energy storage systems typically use multiple power meters to ensure the safe and effective operation of an ESS. These meters typically fall into one of the following categories:

- ESS Meters, such as Meter 1 and Meter 2, monitor the output of the ESS itself. Aside from providing key measurements to the operator, these meters may be used in conjunction with feedback loops to ensure consistent power output from the ESS.
- Feeder Meters and other power meters at electrical connection points provide valuable operational data. It is often desirable to use the data from these meters to drive the behavior of the operational modes provided by the ESS.
- Auxiliary power meters measure the auxiliary power needed to operate the inverters, batteries, chillers, HVAC systems, etc. within the ESS.

?.4 ESS Actual and Usable Capacity

The definition of the capacity of an ESS depends upon what is important to different types of users. For instance, the vendor of an ESS is concerned about the actual capacity of the ESS, while an operator is only interested in what capacity is available to be used. Therefore, as illustrated in Figure 5, two types of capacities are envisioned: the actual ESS capacity and the usable ESS capacity. The actual ESS capacity is the nameplate information, possibly modified over time if the ESS characteristics change. The usable ESS capacity is what users are permitted to have access to, which is based on the decisions of ESS manufacturers or ESS owner/operators.

In addition to usable capacities, ESS owner/operators may choose to establish maximum and/or minimum reserve capacities (as a percentage of usable capacity) that would normally not be used, but could be used either for emergency situations or other special circumstances.

State-of-charge (SoC) would be based on these capacity definitions, in which the "actual state of charge" is the percentage of actual capacity, while the "usable state of charge" is the percentage of usable capacity.

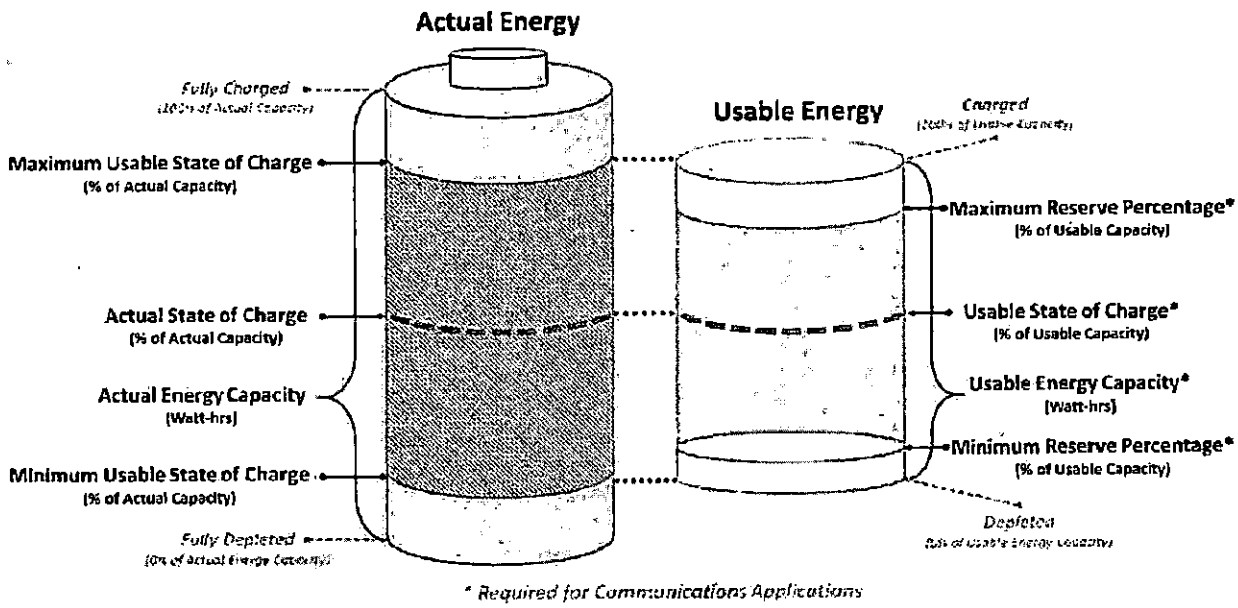

Figure 5: ESS State of Charge: Difference between Actual Capacity and Usable Capacity

2.5 Protocol Alternatives for Information Exchanges with ESS Systems

IEC 61850-7-420 has been developed as the data model for interactions of DER systems, but can use different communication protocols to transport the data. A number of protocol alternatives exist that are based on or mapped from this IEC 61850 information model. These protocols generally have specific purposes and characteristics, although there are overlapping areas across them (see Table 3). The numbers represent the circled numbers in Figure 2.

Table 3: Protocol Alternatives for DER Systems

Protocol	Domain	#	Data Format	Availability	Latency	Cyber Security
IEC 61850-8-1 (GOOSE)	Protective relaying and substation status signals	12, 13	MMS	Very high	Very low latency	In IEC 62351 standards
Modbus (SunSpec Alliance mappings)	Widely used between DER components	12	Simple data structures	High	Low latency	None in Modbus, but may use bump-in-the-wire
IEC 61850-8-2 (61850 IoT)	Interactions with DER systems	2, 3, 10	XML/XER, using XSDs	High	Low to Medium latency	In IEC 62351 standards
IEEE 1815 (DNP3)	Widely used by utilities for SCADA interactions with field devices	1	Simple data structures	High	Low latency	In IEEE 1815 standard but not widely implemented
IEEE 2030.5 (SEP2)	Originally home area networks, now being expanded to utility interactions with DER systems	2, 3, 10	XML, using XSD structures using RESTful HTTP	Medium	Medium latency	In IEEE 2030.5 standard

Some existing protocols, such as OpenADR and BACnet, may be mapped to appropriate portions of the IEC 61850 Information Model in the future, while other alternatives are under development, such as the Open Field Message Bus (OpenFMB) framework.

Figure 6 illustrates where the protocol alternatives might be used.

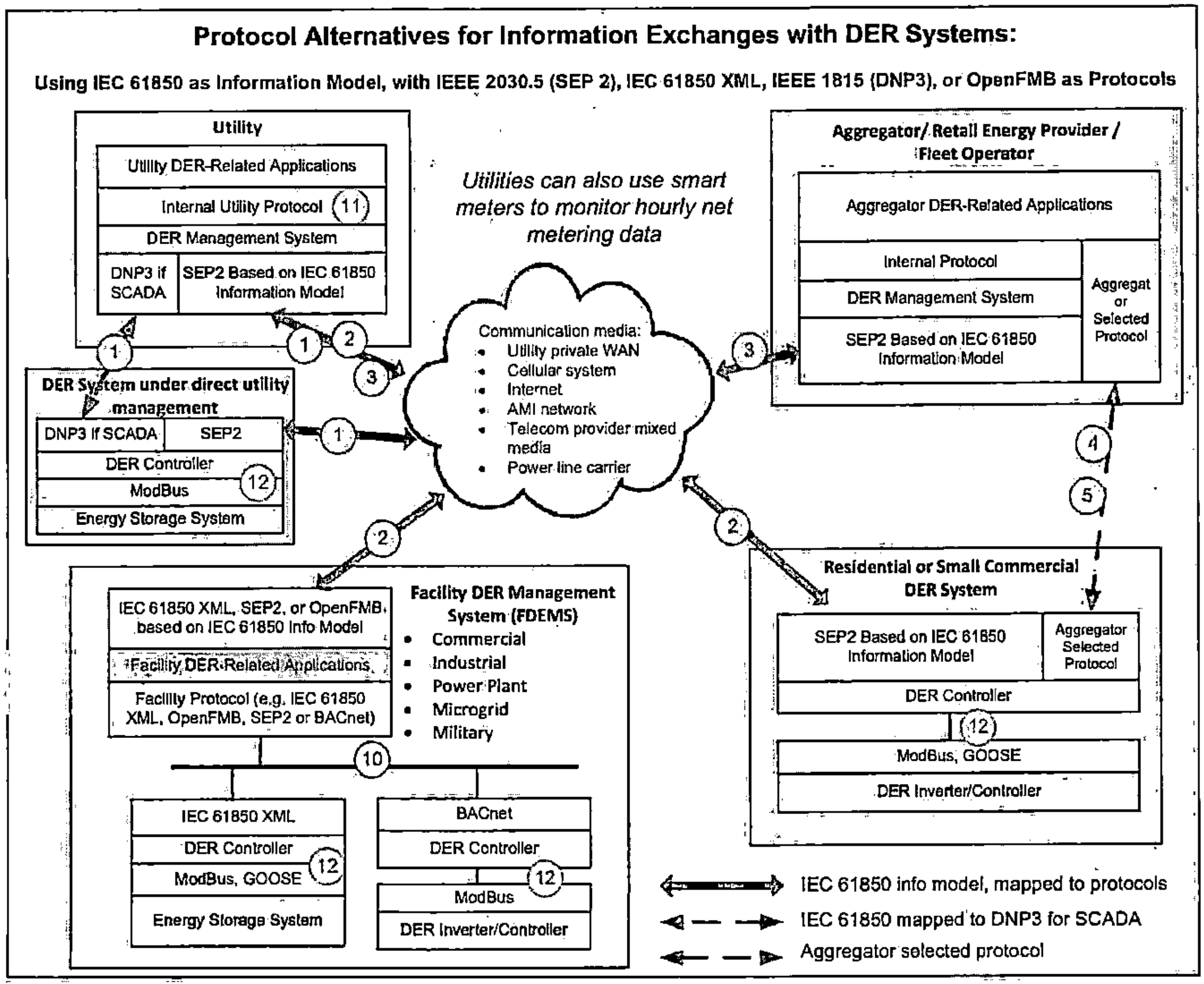

Figure 6: Protocol Alternatives for Information Exchanges with DER Systems, Including ESS

2.6 ECP and PCC Concepts

The electrical connection point (ECP) of a DER system defines its point of electrical connection to any electric power system (EPS). Usually, there is a switch, a circuit breaker, and/or a meter at this point of connection.

ECPs can be hierarchical. Each DER system has an ECP connecting it to its local power system. Groups of DER systems have an ECP where they interconnect to the power system at a specific site or plant. A group of DER systems plus any non-controllable loads have an ECP (termed the point of common coupling (PCC)) where they are interconnected to the utility power system.

In a simple DER configuration, there is one ECP between a single DER system and the utility power system. However, as shown in Figure 7, there may be more ECPs in a more complex DER plant installation. In this figure, ECPs exist between:

- Each single DER system and the local EPS

- Groups of DER systems and the local EPS
- Multiple groups of DER systems and the utility area EPS at the PCC
- An external ECP and the area EPS

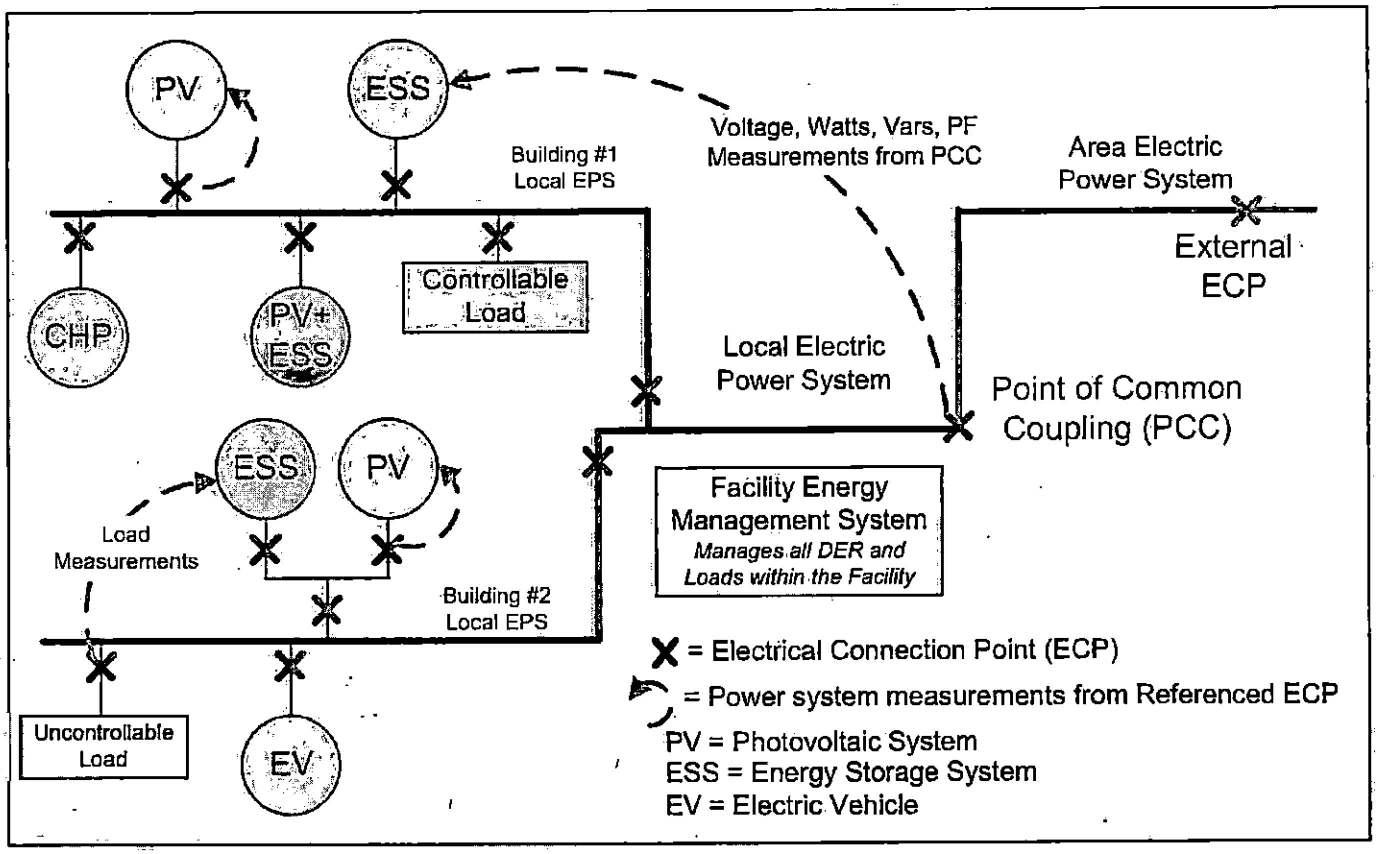

Figure 7: Concept of DER systems (colored circles), electrical connection points (ECP), and the Referenced ECP

The importance of the ECP concept lies in the fact that DER systems may need to use measurements or other information from ECPs that they are not necessarily directed connected to. For instance, if a DER system is providing peak power limiting, it must receive power measurements from the relevant remote ECP (e.g. the PCC as usually required by utilities). Or if an ESS is counteracting generation fluctuations from an external solar plant, it must receive those measurements from that external ECP.

In some deployments, one specific ECP is configured at installation time to be used for all functions. However, in other deployments, different functions may be able to use different ECPs, depending upon the operational requirements. In those cases, the ECP to be used must be identified as part of each function's settings. Therefore, for each function where different ECPs may be indicated, the data object "Referenced ECP" is used to identify the desired ECP.

2.7 Signal Meters

Many of the functions in this profile operate autonomously using data provided by a meter or some other sensor at a Referenced ECP. For example, the Frequency-Watt operational mode described in Section **Error! Reference source not found.** adjusts the Active Power output of the ESS based on frequency values read from a meter. In this specification, meters which provide signal data which is used by an autonomous function are referred to as "signal meters."

Each meter that is part of the energy storage system or that will be used by one of the ESS operational modes should be assigned a unique identifier (a positive integer). When a function is configured, a signal meter identifier will be specified, which identifies the meter that will provide values to the function.

2.8 Relationship to Other MESA Communication Specifications

As can be seen in Figure 8, MESA-ESS may be combined with MESA-Device communication specifications in the construction of a MESA-compliant energy storage system. Where MESA-ESS is a specification for the DNP3 interface to an energy storage system as a whole, the MESA-Device interfaces (MESA-PCS [1], MESA-Storage [2] and MESA-Meter [3]) provide standardization for the Modbus interfaces that are exposed by many of these devices.

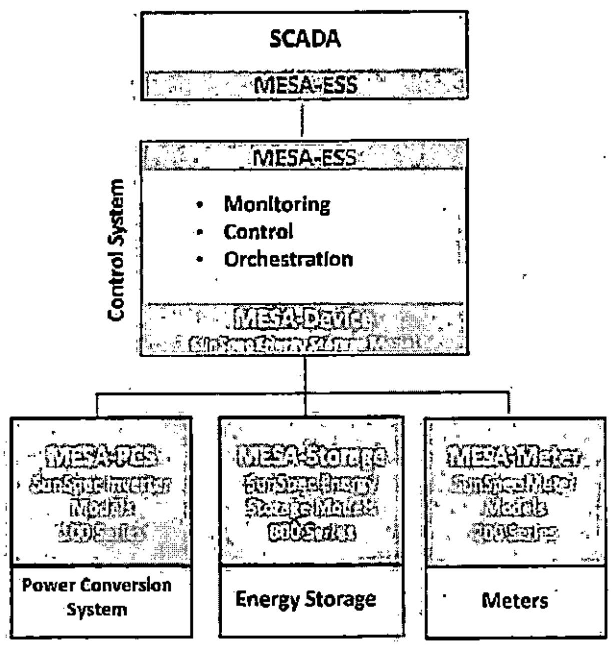

Figure 8: Conceptual Diagram of MESA-ESS

While MESA-ESS and MESA-Device have been designed to work well together, the use of MESA-ESS does not mandate the use of MESA-Device. An ESS that implements MESA-ESS alone still provides significant value to the asset owner.

3. Operational State Model

3.1 Roles, Permissions, and ESS Operational States

There are multiple ways that an electric utility may control a grid-connected energy storage system and different utilities have different operating procedures and contractual arrangements. Therefore, the operating model must be flexible enough to include these differences, while still maintaining interoperability. One method for providing this flexibility is to establish different roles, which are assigned "permissions" for those actions they are allowed to perform in the different operational states. Users are then assigned to one or more roles when they log into the ESS.

Figure 9 provides a generic overview of Role-Based Access Control (RBAC) based on the international standard IEC 62351-8. This overview shows a list of generic roles, the basic permissions that can be assigned, and how these permissions are modified by Areas of Responsibility (AOR) (equivalent to operational states).

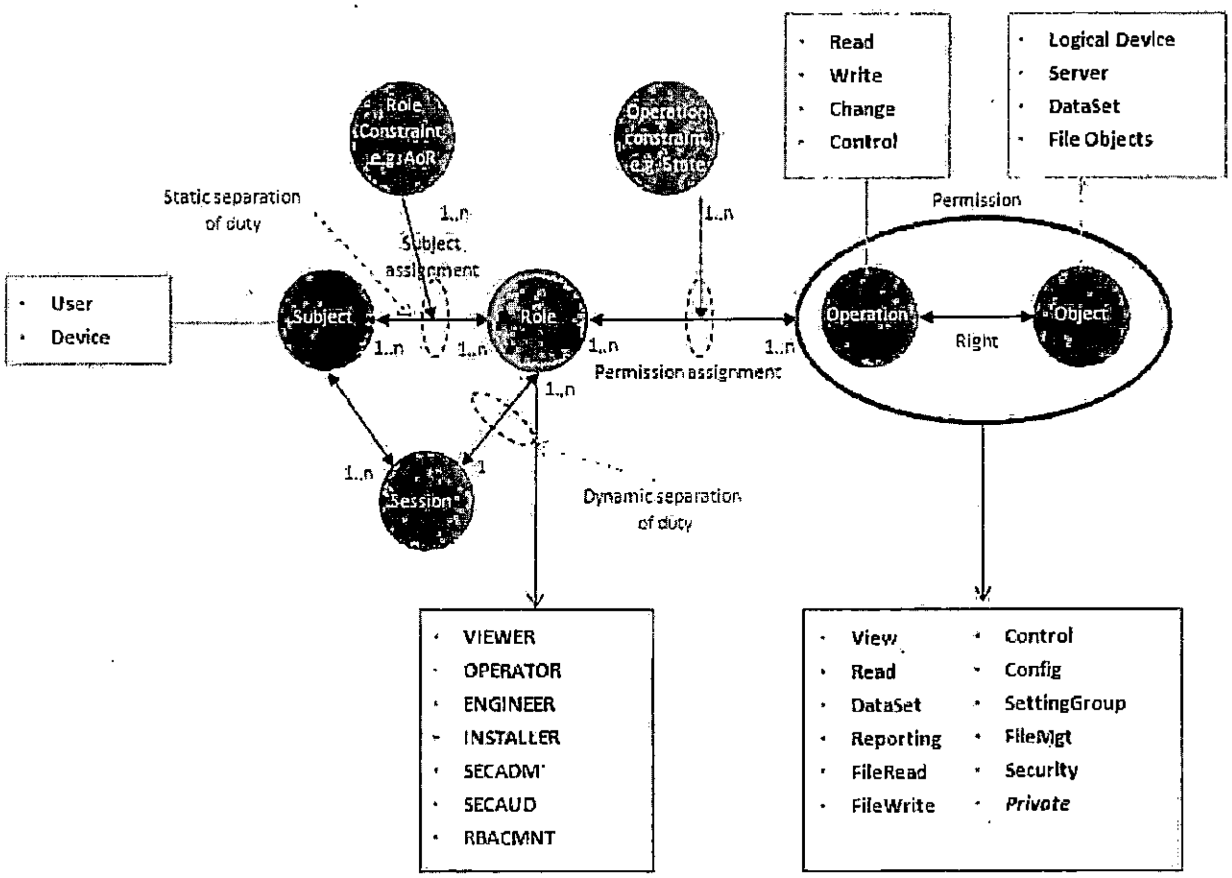

Figure 9: Roles, Permissions, and Operational States

3.2 Default Roles

For ESS user interactions, at least one of each of the roles in the list below is recommended to be implemented with additional roles permitted. Although different mechanisms may be used to assign users to roles, at a minimum, login credentials (e.g. unique username and password) shall be used during the assignment.

- Utility ESS operator
- Utility power scheduler
- Third party aggregator
- Facility ESS operator
- ESS maintenance personnel
- ESS vendor
- Guest viewer

Some role permissions may be different based on whether a user logs in locally or remotely – that situation may be handled by the ESS detecting whether the login is initiated locally or remotely, or may be handled by defining separate roles in which the local roles are only available at the local ESS HMI. For example, in some implementations, there could be two Facility ESS operator roles; one of which is remote, and the other is local. The local Facility ESS operator may be then given permission to perform tasks not allowed for the remote Facility ESS operator for safety reasons.

3.3 Operational States

To ensure the safety of the asset owner's personnel and to help in coordinating control of the ESS across operator roles, the ESS shall support the following mutually exclusive operational states:

- Normal Operations
- Lockout Operations
- Maintenance Operations

The following sections describe these Operational States in further detail.

3.3.1 Normal Operational State

In Normal Operational state, the ESS can respond to authorized commands from utility operators, facility operators, and third party aggregators, as determined by their roles and permissions.

In transitions to and from the Normal Operational state, all ESS settings and actions will remain as they were until modified by an authorized command.

3.3.2 Lockout Operational State

When the energy storage control system (the controller) is powered up for the first time, it should be set to Lockout Operational state. In this state, only authorized personnel with the appropriate permissions will be allowed to control the ESS. In general, a small subset of the ESS operators will be granted permission to control the ESS when it is in Lockout Operation. For example, a manufacturer might specify that only local, onsite operators will be able to control the ESS when it is in the Lockout Operational state.

See Section 3.4 for more information on Roles and Permissions and how they relate to Operational States.

3.3.3 Local or Maintenance Operational State

An engineer who is performing maintenance on site will use the local HMI to control the ESS. If this operator wishes to make maintenance-related changes to the ESS in any way, he or she may need to enable this Local/Maintenance Operational state. Once this occurs, remote users are locked out, as are any scheduled operations, helping to ensure the safety of the on-site personnel and the ESS itself. Upon completion of the maintenance work, the engineer returns the ESS to either Lockout Operational state or Normal Operational state.

It is important to note that the Local/Maintenance Operational state may also be used for system-wide maintenance operations, such as upgrading the ESS software or conducting tests on the ESS as a whole. MESA-ESS also supports maintenance on a subsystem within the ESS.

During normal operations, actions initiated by the controller and its operational modes affect all inverter and battery bank pairs that are under control. When maintenance is required on an inverter or battery bank, the operator performing the maintenance must be able to safely work with the inverter and its batteries without interference from ongoing controller processes. Rather than shutting down the entire ESS to perform maintenance on a single inverter or battery, a given DER unit (i.e., an inverter and battery bank pair) may be placed into the maintenance operational state.

When a DER unit is in the maintenance operational state, the **DER Unit #N Is In Maintenance Operational State** Binary Input should return a value of 1 which indicates that the unit is not currently online. While the DER unit is in this state, the unit is removed from autonomous control, and the inverter no longer responds to actions initiated by operational modes. Any operational modes which are executed while the DER unit is in the maintenance operational state will only apply to other DER units which are not in the maintenance operational state. Additionally, the **System Available Apparent Power** and **State of Charge** Analog Inputs should both be updated automatically by the controller to indicate that the system is running at reduced capacity.

No facility is provided by the profile to allow an operator to place a DER unit into the maintenance operational state using DNP3. However, it is reasonable for a local HMI to provide this ability to the local operator. Additionally, a local HMI may choose to provide functions which operate directly on the unit under maintenance such as:

- Stopping and starting the inverter.
- Disconnecting (opening connectors) and connecting (closing connectors) the battery bank.
- Charging and discharging the battery bank.

The exact behavior of the local HMI and the functionality that it provides for DER units in the maintenance operational state is not specified here as it is outside the scope of this document.

4.4 Default Permissions for Default Roles

Default assignments of permissions to roles are shown in Table 4, but these may be changed or expanded as necessary for different implementations. In order for different implementations to assign different permissions to different roles, each of these assigned permissions should be visible (able to be monitored and/or visible locally) and should be either preset upon installation and/or possibly modifiable after installation.

Table 4: Default Assignment of Permissions to Roles within Different ESS Operating States

Permissions / Roles	Utility ESS Operator	Utility Power Scheduler	Third-Party Aggregator	Facility ESS Operator	Maintenance Personnel	ESS Vendor	Guest Viewer
When ESS is in Normal Operational State							
• View current operational state	X	X	X	X	X	X	
• Set ESS to lockout operational state				X			
• Set ESS subsystem to maintenance/test mode				X	X		
• View roles and permissions	X	X	X	X	X	X	
• Modify roles and permissions				X		X	
• Monitor site-level ESS information				X	X	X	
• Monitor ESS status, modes, and measurements	X	X	X	X	X	X	X
• Monitor operational logs	X	X	X	X	X	X	
• Monitor security logs				X			
• Monitor historical data	X	X	X	X			
• Monitor configuration information				X	X	X	
• Update parameters of functional modes	X	X	X	X			
• Enable functional modes	X		X	X			
• Disable functional modes	X		X	X			
• Issue disconnect command from grid	X		X	X	X		
• Issue connect command to grid				X			
• Issue operational control command	X		X	X			
• Send schedule	X		X	X			
• Enable schedule	X		X	X			
• Disable schedule	X		X	X			
• Add item to operational log	X		X	X	X		
• Execute diagnostic tests					X		
• Issue test commands							
• Patch or update ESS software							
• Update security measures							
• Modify configurations							

Permissions \ Roles	Utility ESS Operator	Utility Power Scheduler	Third-Party Aggregator	Facility ESS Operator	Maintenance Personnel	ESS Vendor	Guest Viewer
When ESS is in Lockout Operational State							
• View current operational state	X	X	X	X	X	X	
• Set ESS to normal operational state				X			
• Set ESS to subsystem maintenance/test mode				X	X		
• View roles and permissions				X	X	X	
• Modify roles and permissions				X		X	
• Monitor site-level ESS information				X	X	X	
• Monitor ESS status, modes, and measurements	X		X	X	X	X	X
• Monitor operational logs				X	X	X	
• Monitor security logs				X	X		
• Monitor historical data				X	X		
• Update parameters of functional modes				X			
• Enable functional modes				X			
• Disable functional modes				X			
• Issue disconnect command from grid	X		X	X	X		
• Issue connect command to grid				X			
• Issue operational control command				X			
• Send schedule				X			
• Enable schedule				X			
• Disable schedule				X			
• Add item to operational log				X	X		
• Execute diagnostic tests					X		
• Issue test commands							
• Patch or update ESS software							
• Update security measures							
• Modify configurations							

Permissions \ Roles	Utility ESS Operator	Utility Power Scheduler	Third-Party Aggregator	Facility ESS Operator	Maintenance Personnel	ESS Vendor	Guest Viewer
When ESS (or subsystem) is in Maintenance/Test Operational State							
• View current operational state	X	X	X	X	X	X	
• Set ESS to normal operational state				X			
• Set ESS to lockout operational state				X	X		
• View roles and permissions				X	X	X	
• Modify roles and permissions				X		X	
• Monitor site-level ESS information				X	X	X	
• Monitor ESS status, modes, and measurements				X	X	X	X
• Monitor operational logs				X	X	X	
• Monitor security logs				X	X		
• Monitor historical data				X	X		
• Update parameters of functional modes				X	X	X	
• Enable functional modes							
• Disable functional modes				X			
• Issue disconnect command from grid				X			
• Issue connect command to grid							
• Issue operational control command							
• Send schedule							
• Enable schedule							
• Disable schedule							
• Add item to operational log				X	X		
• Execute diagnostic tests					X	X	
• Issue test commands					X	X	
• Patch or update ESS software					X	X	
• Update security measures					X	X	
• Modify configurations					X	X	

4. MESA-ESS DNP3 Interface

4.1 MESA-ESS DNP3 Profile Scope and Constraints

The MESA-ESS DNP3 profile has been designed to allow an energy storage system to be integrated into existing control and monitoring systems. In most installations, it will be most important to expose control and monitoring points to allow the ESS to be integrated into SCADA. For installations that support ESS scheduling, additional points exist in the profile to allow this functionality. Finally, in some installations it may be desirable to expose historical information through the DNP3 profile so that this data may be easily imported into an operational historian.

To support all of these scenarios, the points in the MESA-ESS DNP3 profile fall into one of five distinct categories: Configuration, SCADA, Scheduling, Historical, and Vendor Specific. These categories are described below in Table 5.

Table 5: MESA-ESS DNP3 Point Categories

Category	Description	Examples
Configuration	Configuration data which describe how a given energy storage asset has been configured and which features are enabled.	Power Factor Operating Quadrant, Supports Active Power Smoothing Mode, Reference Voltage
SCADA	Key operational points which allow the energy storage asset to be integrated into SCADA.	System Is In Lockout Mode, System Is Starting Up, System Has P1 Alarms, Charge/Discharge Active Power Target
Scheduling	Points which allow power scheduling personnel to effectively control the behavior of the energy storage system over a distinct time period.	Selected Schedule Is Enabled, Selected Schedule Priority, Selected Schedule Start Time
Historical	Detailed measurement and performance data which may be valuable to record in an operational historian	ESS Is Charging, Meter Active Power, Battery Bank State of Charge
Vendor Specific	Vendor specific data, including implementation-specific data that is not included in other categories	

4.2 MESA-ESS Implementation Levels

For many energy storage system installations, it will be necessary to implement the points in all point categories to ensure complete integration to existing systems. In other installations, only a subset of the points may be required. For example, if the asset owner does not maintain a historian, the points in the Historical category may be unnecessary.

To ensure broad compatibility across a variety of energy storage system controllers and installation types, the MESA-ESS specification includes the notion of "implementation levels." These implementation levels allow an implementer to subset the DNP3 profile so that only required point categories are implemented. The levels of support are described in Table 6.

Table 6: MESA-ESS Implementation Levels

Level	Summary	Description
1	Configuration + SCADA Points Only	Only the points identified as Configuration or SCADA points are implemented by the MESA-ESS controller.
2	Configuration + SCADA + Scheduling Points	Only the points identified as Configuration, SCADA or Scheduling points are implemented by the MESA-ESS controller.
3	Configuration + SCADA + Scheduling + Historical Points	All points in the MESA-ESS profile are implemented by the controller

A MESA-compatible ESS controller which has decided to implement all three categories will be described as supporting MESA-ESS Level 3—the highest level of compatibility. Another MESA-compatible ESS controller may decide that integrating with SCADA is the only requirement, and, accordingly, only the Configuration and SCADA points will be implemented. This type of controller will be described as support MESA-ESS Level 1.

The points for Level 1 shall start at index 0 for all DNP3 point types. If Level 2 is implemented by the outstation, those points must start at the index which immediately follows the last Level 1 point in that point type. Similarly, if Level 3 is implemented, the first Level 3 point must be placed immediately following the last Level 2 point as shown in Figure 10. Vendor points are placed at the end of the points list after the last block of points from this profile.

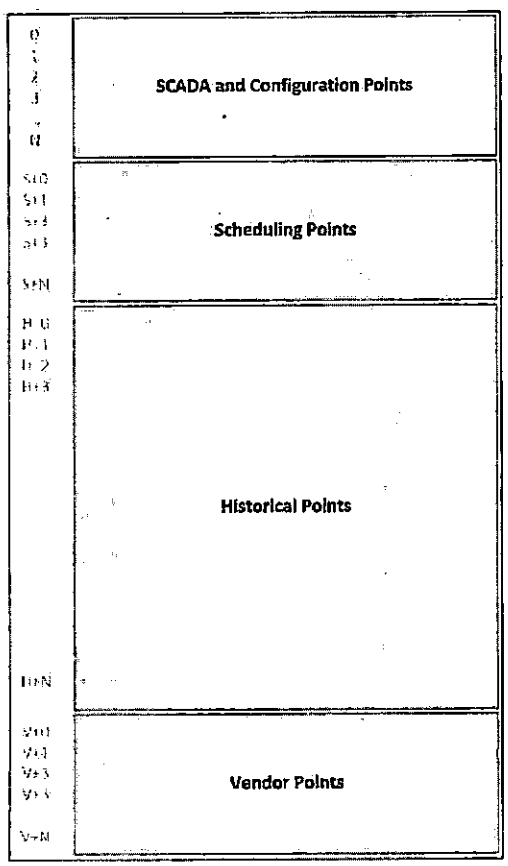

Figure 10: Indexing of DNP3 Categories

Note that in the figure above the points in the Vendor Points section are shown immediately following the points in the Historical Points section. While this is certainly a valid approach, this profile does not mandate that vendor specific points *immediately* follow the last point from the profile.

4.3 Repeating Blocks

Level 2 and Level 3 implementations must represent one or more repeating elements in the DNP3 point map. For example, Level 2 implementations will repeat three analog inputs for each schedule in the system as shown in the table below.

Table 7: Repeating Schedule Analog Inputs

Analog Input	Meaning
Schedule 1 Status	The status of the first stored schedule.
Schedule 1 Priority	The priority of the first stored schedule.
Schedule 1 Active Time Value	The active time value of the first stored schedule.
Schedule 2 Status	The status of the second stored schedule.
Schedule 2 Priority	The priority of the second stored schedule.
Schedule 2 Active Time Value	The active time value of the second stored schedule.
...	...
Schedule N Status	The status of the nth stored schedule.
Schedule N Priority	The priority of the nth stored schedule.
Schedule N Active Time Value	The active time value of the nth stored schedule.

For Level 3 implementers, blocks of analog inputs and analog outputs will be repeated for each meter, DER unit, inverter, and battery in the configured system as shown in Figure 11.

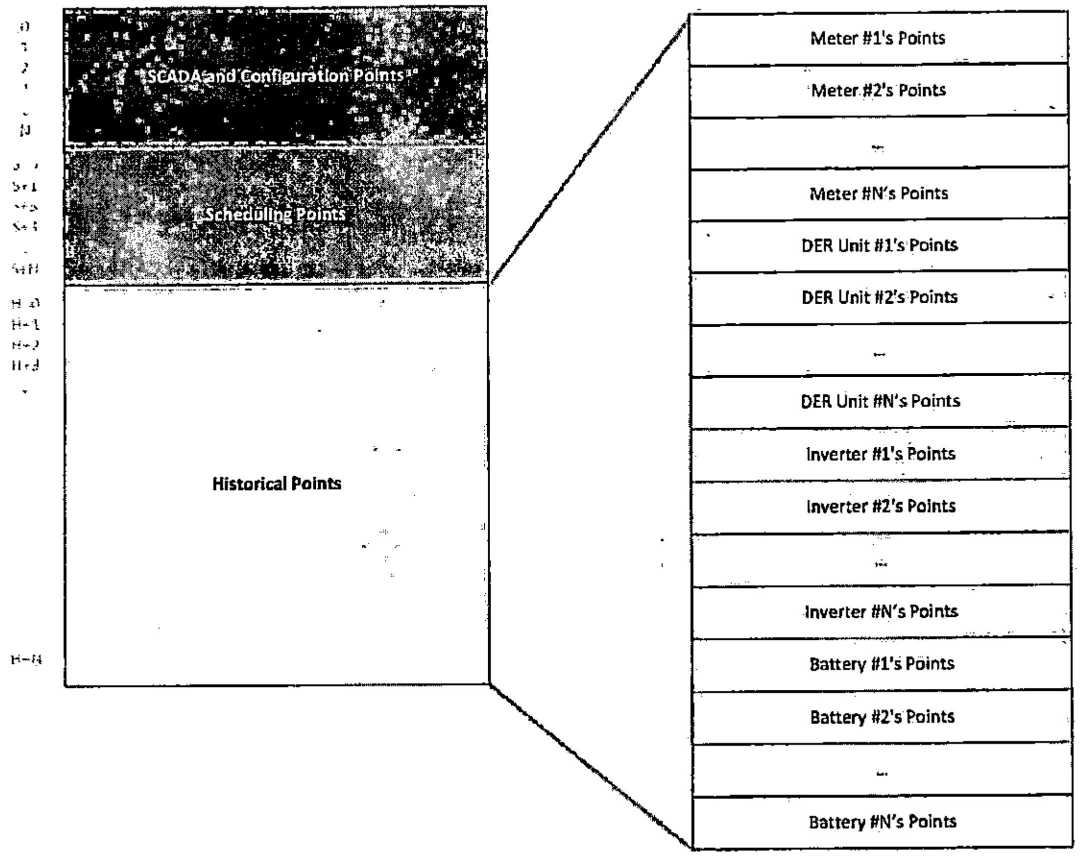

Figure 11: Level 3 Repeating Elements

Because the number of elements in these repeating blocks will vary by installation, the total length of the point lists for Level 2 and Level 3 implementations will also vary. However, Level 1 analog input points exist in the profile which can be used to deterministically calculate the total number of points in the profile. These points are shown in Table 8 below.

Table 8: Profile Information Analog Input Points

Analog Input Point	**Description**
DER Profile Version Number	Indicates what version of the profile has been implemented by the outstation.
DER Profile Implementation Level	Indicates whether the outstation has implemented Level 1, Level 2 or Level 3.
Number of System Schedules	The number of system schedules stored by the outstation.
Number of Meters	The number of meters that are monitored by the outstation.
Number of Inverters	The number of inverters that are monitored and controlled by the outstation.
Number of Batteries	The number of batteries that are monitored and controlled by the outstation.
Number of DER Units	The number of DER units which are connected to the outstation.

4.4 Profile Background

Unlike DNP3 AN2013-001, the MESA-ESS profile targets DNP3 Level 2. MESA partners and early adopters have indicated that a number of electric utilities that are exploring energy storage have infrastructural limitations which prevent the adoption of more advanced DNP3 features (e.g. Double-Bit Binary Inputs). While a MESA-compatible ESS controller may choose to offer more advanced functionality in some cases, these features are by no means required by MESA-ESS.

For reference, the following DNP3 Level 3 and 4 features are avoided by MESA-ESS:

- DNP3 Level 3 Features
  - Certain specific objects and variations
  - Group 0 (Device Attributes) read and write requests
  - The larger range of function codes specified by Level 3 and Level 4
  - Enabling and disabling of unsolicited responses by class
  - Dynamically reassigning data objects to classes (e.g., at runtime)
- DNP3 Level 4 Features
  - Self-address reservation
  - Double-bit binary input objects
  - The larger range of function codes specified by Level 4
  - Variations with time for frozen counters, frozen counter events, and analog input events
  - Floating-point variations for both analog inputs and analog outputs
  - Analog input reporting deadband
  - Event objects for binary and analog outputs
  - Device attributes
  - LAN time synchronization method

4.5 DNP3 Classes

MESA-ESS uses the criteria in Table 9 for assigning points to default classes.

Table 9: Criteria for Assigning Points to Default Classes

Class	Criteria
1	Critical data. Alarms and other events requiring immediate action.
2	Feedback
3	Measurements and configuration

4.6 Curves and Schedules

A MESA-ESS compatible outstation will typically need to include support for curves (e.g. Volt-VAr curves) and schedules. These objects are similar in that they can be thought of as a two-dimensional graph. For example, a Volt-VAr curve specifies a voltage measurement on the X-axis and a VAr output requirement on the Y-axis. Similarly, a Charge/Discharge schedule is represented with time on the X-axis and power output on the Y-axis.

For the most part, curves and schedules are modeled as a series of points, where each point has an X-value and a Y-value. In DNP3, each of these characteristics maps to a single point in the profile. For a schedule with 100 points, the total number of DNP3 points will be 2 * 100 = 200. Additionally, curves and schedules often have a few top-level properties which translate into a small number of additional DNP3 points per curve/schedule.

It is a design goal of MESA-ESS to allow multiple curves and schedules to be created, updated, and read through the profile. But in order to keep the DNP3 point lists manageable, the points for each curve/schedule are not repeated for every supported curve schedule. Instead, a "selector model" is used for these objects.

In the selector model, the DNP3 master must first indicate which curve or schedule should be read or updated. This is done by writing an index value to a selector analog output. For example, to view or update the 13th schedule in the set of schedules, the master begins by setting the Schedule to Edit Selector point to the value 13. When this occurs, the outstation updates the schedule points (BIs, BOs, AIs, and AOs) to reflect the value in schedule at index 13. In effect, the schedule points in the DNP3 profile act as a window into the full set of schedules. The same is true for curves.

More details on the selector model for curves and schedules are found in the DNP3 Technical Bulletin, Section 2.3.3.

4.7 Ramp Rates, Ramp Times, and Time Constants

Different functions may use ramp rates, ramp time, or time constants to modify or characterize the responses of the devices due to the function. Additional default ramp rates have been included to include ramp up and ramp down while generating and while charging.

More details on the use of these time-based parameters are found in the DNP3 Technical Bulletin, Section 2.3.4.

4.8 Mode Priorities

Each mode also has a priority field, allowing them to indicate which modes may have precedence over other modes if they might otherwise conflict (see Table 12). Lower numbers are higher priority than higher numbers, but there are no preset numbers for any mode.

4.9 Alarm Aggregation and Priorities

Each of the devices within an energy storage system may raise alarms when abnormalities occur. Additionally, the energy storage system itself may raise alarms under certain conditions (e.g., failure to communicate with a device). The Historical category of DNP3 points provides detailed alarm and warning information for the ESS and the devices that make up the ESS.

Because this detailed alarm information is generally not desired in SCADA, MESA-ESS exposes aggregate alarm information for the system as a whole. This aggregate data is provided in the following binary inputs:

Table 10: Aggregate Alarm Points

Binary Input	Description
CALH1.GrAlm	System Has P1 Alarms
CALH2.GrAlm	System Has P2 Alarms
CALH3.GrAlm	System Has P3 Alarms

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As seen in Table 10, three aggregate alarm points are exposed in the DNP3 Profile, each with a different priority. How individual alarms are mapped to the different priorities is left to the implementer. One MESA-ESS controller may choose to map alarms to priorities based on severity (e.g., Fire Alarms are P1, Fan Warning is P3), while another may choose to map these priorities to roles (e.g., The Facility Operator will handle all P1 alarms, while the Remote Operator will handle all P2s and P3s).

5. ESS Functions

5.1 Table of ESS Functions

For the purposes of this specification, a *function* is a capability that is typically performed due to human intervention, and does not repeat unless it is requested again. A *mode* is automatic behavior which is pre-configured, enabled, and then operates either periodically or continuously.

Modes usually entail the DER system:

- Receiving some measurement either from a meter at the DER's ECP, from a meter at a remote ECP within the facility, from the PCC, or from an external ECP (termed the "Referenced ECP"), or
- Reacting to some event, and then responding to that measurement or event according the mode's parameters.

The MESA-ESS profile supports the configuration and operation of the functions and modes shown in Table 11. The table also indicates where the functions and modes are described in the EPRI Common Functions report, IEC 61850-7-420, and the DNP3 Application Note 2018.

Implementations are not required to include all of the functions or modes since configuration data objects are used to indicate those supported. Each of these functions and modes can be invoked or enabled/disabled by authorized operators. In addition, some of these functions or modes may be controlled by a schedule.

Table 11: MESA-ESS functions and modes

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
	Support for functions and modes General information on supportive capabilities.	Support for Modes and Functions Mode Enabling Timing Parameters Multiplexed Generic Curves and Schedules Limiting Response: Ramp Rates, Ramp Times and Time Constants Use of Broadcasting Time Synchronization	Section 2.3.1 Section 2.3.2 Section 2.3.3 Section 2.3.4 Section 2.3.5 Section 2.4.7	Section 4.3 Section 4.4
	Interactive Functions		Section 2.4	
1.	**Monitoring Function** The ESS provides nameplate, configuration, status, measurements, and other requested data	Monitoring Use of Signal Meters Alarm Grouping and Reporting DER States Event/History Logging Function	Section 2.4.1 Section 2.4.2 Section 2.4.3 Section 2.4.6 Section 2.4.8	LN DGEN LN DSTO LN DBAT LN DRAT LN MMXU

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
2.	**Disconnect/Connect Function** Disconnect or connect the ESS from the grid at its ECP.	The disconnect command initiates the galvanic separation (usually via switches or breakers) of the ESS at its ECP. The connect command initiates the reconnection of the ESS at its ECP.	Section 2.4.4	LN DSTO or (for separate switch), LN CSWI, LN XCBR
3.	**Cease to Energize and Return to Service** Cease any current flow at the ECP or PCC Allow current flow at the ECP or PCC	"Cease to energize" is a different function from disconnect/connect. The purpose is to prevent the flow of current at the ECP or PCC. It may use the Active Power Limit mode with the Active Power output value set to zero. "Return to service" allows current flow at the ECP or PCC.	Section 2.4.5	LN DCTE
	Emergency Modes		Section 2.5	
4.	**Low/High Voltage Ride-Through Mode** The ESS rides through temporary fluctuations in voltage	The ESS follows the utility-specified voltage ride-through parameters to avoid tripping off unnecessarily. Although normally enabled by default, this ride-through mode may be updated, enabled, and disabled.	Section 2.5.1	LN DVRT
5.	**Low/High Frequency Ride-Through Mode** The ESS rides through temporary fluctuations in frequency	The ESS follows the utility-specified frequency ride-through parameters to avoid tripping off unnecessarily. Although normally enabled by default, this ride-through mode may be update, enabled, and disabled.	Section 2.5.2	LN DFRT
6.	**Frequency-Watt Emergency Mode** The ESS responds to large frequency excursions during H/LFRT events at a Referenced ECP by changing its charging or discharging rate	The ESS is provided with frequency-watt curves that define the changes in its watt output based on frequencies outside the normal range during H/LFRT events. When the emergency frequency-watt mode is enabled, the ESS monitors the frequency and adjusts its discharging or charging rate to follow the specified emergency frequency-watt curve parameters. New data points are provided multiple times per second.	Section 2.5.3	LN DWHZ
7.	**Dynamic Reactive Current Support Mode** The ESS reacts against rapid voltage changes (spikes and sags) to provide dynamic system stabilization	The ESS provides dynamic reactive current support in response to voltage spikes and sags, similar to acting as inertia against rapid changes. This mode may be focused on emergency situations or may be used during normal operations. When the dynamic reactive current support mode is enabled, the ESS monitors the voltage at the Referenced ECP and responds based on the parameters.	Section 2.5.4	LN DRGS

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
8.	**Dynamic Volt-Watt Mode** The ESS system dynamically absorbs or produces additional watts	The ESS system dynamically absorbs or produces additional watts in proportion to the instantaneous difference from a moving average of the measured voltage. This function utilizes the same basic concepts and settings as the Dynamic Reactive Current function, but uses active power as an output rather than reactive current.	Section 2.5.5	LN DVWD
	Active Power Modes		Section 2.6	
9.	**Active Power Limit Mode** Limits the discharging and/or charging level of the ESS based on the Referenced ECP	The discharging and/or charging of the ESS is limited at the Referenced ECP, indicated as absolute watt values. Separate parameters are provided for discharging or charging limits to permit these to be different.	Section 2.6.1	LN DAMG
10.	**Charge/Discharge Mode** Set the ESS to charge or discharge at the Referenced ECP	The ESS is set to a percentage of maximum charge or discharge rate at the Referenced EC). A positive value indicates discharge, and a negative value means charge.	Section 2.6.2	LN DCHD
11.	**Coordinated Charge/Discharge Management Mode** The ESS determines when and how fast to charge or discharge so long as it meets its target state of charge level obligation by the specified time	The ESS is provided with a target state of charge and a time by which that SOC is to be reached. This allows the ESS to determine when to charge or discharge based on price. The ESS takes into account not only the duration at maximum charging / discharging rate, but also other factors, such as, at high SOC, the maximum charging rate may not be able to be sustained, and vice versa, at low SOC, the maximum discharge rate may not be able to be sustained.	Section 2.6.3	LN DTCD
12.	**Peak Power Limiting Mode** The ESS limits the load at the Referenced ECP after it exceeds a threshold target power level	The Active Power output of the ESS limits the load at the Referenced ECP if it starts to exceed a target power level, thus limiting the power that needs to be imported from the grid. The discharging output is a percentage of the excess load over the target power level. The target power level is specified in percentage of maximum watts.	Section 2.6.4	LN DPKP
13.	**Load Following Mode** The ESS counteracts the load by a percentage at the Referenced ECP, after it starts to exceed a threshold target power level	The Active Power output of the ESS follows and counteracts the load at the Referenced ECP if it starts to exceed a target power level, thus resulting in a flat power profile. The discharging output is a percentage of the excess load over the target power level. The target power level is specified in percentage of maximum watts.	Section 2.6.4	LN DLFL

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
14.	**Generation Following Mode** The charging and/or discharging of the ESS counteracts generation power at the Referenced ECP.	The Active Power output of the ESS follows and counteracts the generation measured at the Referenced ECP if it starts to exceed a target power level. The charging and/or discharging output is a percentage of the excess generation watts over the target power level. The target power level is specified in percentage of maximum watts.	Section 2.6.4	LN DGFL
15.	**Automatic Generation Control (AGC) Mode** The ESS responds to raise and lower power level requests to provide frequency regulation support	When AGC mode is enabled, the ESS responds to signals to increase or decrease the rate of charging or discharging every 4 to 10 seconds, with the purpose of managing frequency.	Section 2.6.5	LN DAGC
16.	**Active Power Smoothing Mode** The ESS produces or absorbs Active Power in order to smooth the changes in the power level at the Referenced ECP.	The ESS follows the specified smoothing gradient which is a signed quantity that establishes the ratio of smoothing Active Power to the real-time delta-watts of the load or generation at the Referenced ECP. When the power smoothing mode is enabled, the ESS receives the watt measurements from a meter (or another source) at the Referenced ECP. New data points are provided multiple times per second.	Section 2.6.6	LN DWSM
17.	**Volt-Watt Mode** The ESS responds to changes in the voltage at the Referenced ECP by changing its charging or discharging rate	The ESS is provided with voltage-watt curves that define the changes in its watt output based on voltage deviations from nominal, as a means for countering those voltage deviations. When the volt-watt mode is enabled, the ESS receives the voltage measurement from a meter (or another source) at the Referenced ECP. The ESS adjusts its discharging or charging rate to follow the specified volt-watt curve parameters. New data points will be provided multiple times per second.	Section 2.6.7	LN DVWC
18.	**Frequency-Watt Mode** The ESS responds to changes in frequency at the Referenced ECP by changing its charging or discharging rate based on frequency deviations from nominal, as a means for countering those frequency deviations	The ESS is provided with frequency-watt curves that define the changes in its watt output based on frequency deviations from nominal, as a means for countering those frequency deviations and smoothing the frequency. When the frequency-watt mode is enabled, the ESS monitors the frequency and adjusts its discharging or charging rate to follow the specified frequency-watt curve parameters. New data points are provided multiple times per second.	Section 2.6.8	LN DFWS

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
	Reactive Power Modes		Section 2.7	
19.	**Constant VArs Mode** The ESS power factor is set to a fixed value.	The ESS VArs are set to the specified VArs, as a percentage of either the maximum reactive power or the available reactive power.	Section 2.7.1	LN DVAR
20.	**Fixed Power Factor Mode** The ESS power factor is set to a fixed value.	The ESS power factor is set to the specified power factor. A leading power factor is positive and a lagging power factor is negative, as defined by the IEEE sign convention.	Section 2.7.2	LN DFPF
21.	**Volt-VAr Control Mode** The ESS responds to changes in voltage at the Referenced ECP by supplying or absorbing vars in order to maintain the desired voltage level	The ESS is provided with voltage-VAr curves that define the vars for voltage levels. When the Volt-VAr Control Mode is enabled, the ESS receives the voltage measurements from a meter (or another source) at the Referenced ECP. The ESS responds by supplying or absorbing vars according to the specified Volt-VAr curve in order to maintain the desired voltage level. New data points are provided multiple times per second.	Section 2.7.3	LN DVVC
22.	**Watt-VAr Mode** The ESS responds to changes in power at the Referenced ECP by changing its power factor	The ESS is provided with watt-reactive curves that define the changes in its power factor based changes of power. When the Watt-Power Factor Mode is enabled, the ESS modifies its power factor setting in response to the power level at the Referenced ECP.	Section 2.7.4	LN FPFW
23.	**Power Factor Correction Mode** The ESS supplies or absorbs VArs to hold the power factor at the Referenced ECP	When the PF Correction mode is enabled, the ESS is provided with the target PF. The ESS supplies or absorbs vars in order to maintain the PF at the Referenced ECP within the target PF.	Section 2.7.5	LN DPFC
	Additional Capabilities			
24.	**Pricing Signal Mode**	The ESS uses the pricing signal for determining other actions. The details are not defined on how or when these other actions might be undertaken.	Section 2.8	(Not defined yet)
25.	**Scheduling of Power Settings and Modes**	The ESS follows the schedule which consists of a time offset (specified as a number of seconds) from the start of the schedule and is associated with: • a power system setting ◦ the enabling/disabling of an operational mode • a price signal	Section 2.9	LN FSCH LN FSCC

#	Functions or Modes	Description	DNP3 App Note 2018	IEC 61850-7-420
26.	**Historical Information**	Detailed measurement and performance data which may be valuable to record in an operational historian	Parts of Section 2.2.5 and Section 2.28	LN MMXU
27.	**Microgrid Separation Control** *{Not included}*	Process for normal separation, emergency separation, and reconnection	Section 2.11	LN DMIC (not defined yet)
28.	**Provide Black Start Capability** *{Not included}*	Ability to start without grid power and the ability to add significant load in segmented groups		(Not defined yet)
29.	**Provide Backup Power** *{Not included}*	Ability to provide power to local loads when not connected to the grid		(Not defined yet)

5.2 Compatibility, Coexistence, and Mutual Exclusivity of ESS Modes

Most modes are compatible with each other although some are mutually exclusive. A few could possibly co-exist, but the priority of one mode over the other must be established. For example, all emergency modes could be set with higher priority than modes that would operate during normal conditions. Active Power modes are compatible with reactive power and frequency modes. However, the AGC mode is mutually exclusive with most of the other Active Power modes, but may possibly co-exist with limiting Active Power charge/discharge rates if the latter is given higher priority.

The ESS cross-mode compatibility is shown in Table 12.

Table 12: Compatibility, possible coexistence, and mutually exclusive ESS modes

ESS Modes: Compatible (c), Possibly Coexist (P), or Mutually Exclusive (M) In all cases, emergency modes take precedence over other modes. For (P) situations, priority may be by agreement		Emergency					Real Power							Reactive Power			
		Voltage Ride-Through	Frequency Ride-Through	Dynamic reactive current support	Frequency-watt emergency	Limit real power discharge/charge rate	Peak Power Limiting	Load / generation following	Real power smoothing	Volt-watt control	AGC (utility sends Reg /down)	Charge-by management	Frequency-watt smoothing	Fixed power factor	Volt-var control	Watt-PF	Power factor correction
4	Voltage Ride-Through		c	c	c	c	c	c	c	c	c	c	c	c	c	c	c
5	Frequency Ride-Through			c	c	c	c	c	c	c	c	c	c	c	c	c	c
6	Dynamic reactive current support				c	c	c	c	c	c	c	c	c	c	c	c	c
19	Frequency-watt emergency					c	c	c	c	c	c	c	c	c	c	c	c
7	Limit real power discharge/charge rate						P	P	P	P	P	c	c	c	c	c	c
8	Peak Power Limiting							M	P	P	M	c	c	c	c	c	c
9	Load / generation following								P	P	M	c	P	c	c	c	c
10	Real power smoothing									P	M	c	c	c	c	c	c
11	Volt-watt control										M	c	c	c	c	c	c
12	AGC (utility sends Reg up and down commands)											c	c	c	c	c	c
13	Charge-by management												c	c	c	c	c
18	Frequency-watt smoothing													c	c	c	c
14	Fixed power factor														M	M	M
15	Volt-var control															P	P
16	Watt-PF																P
17	Power factor correction																

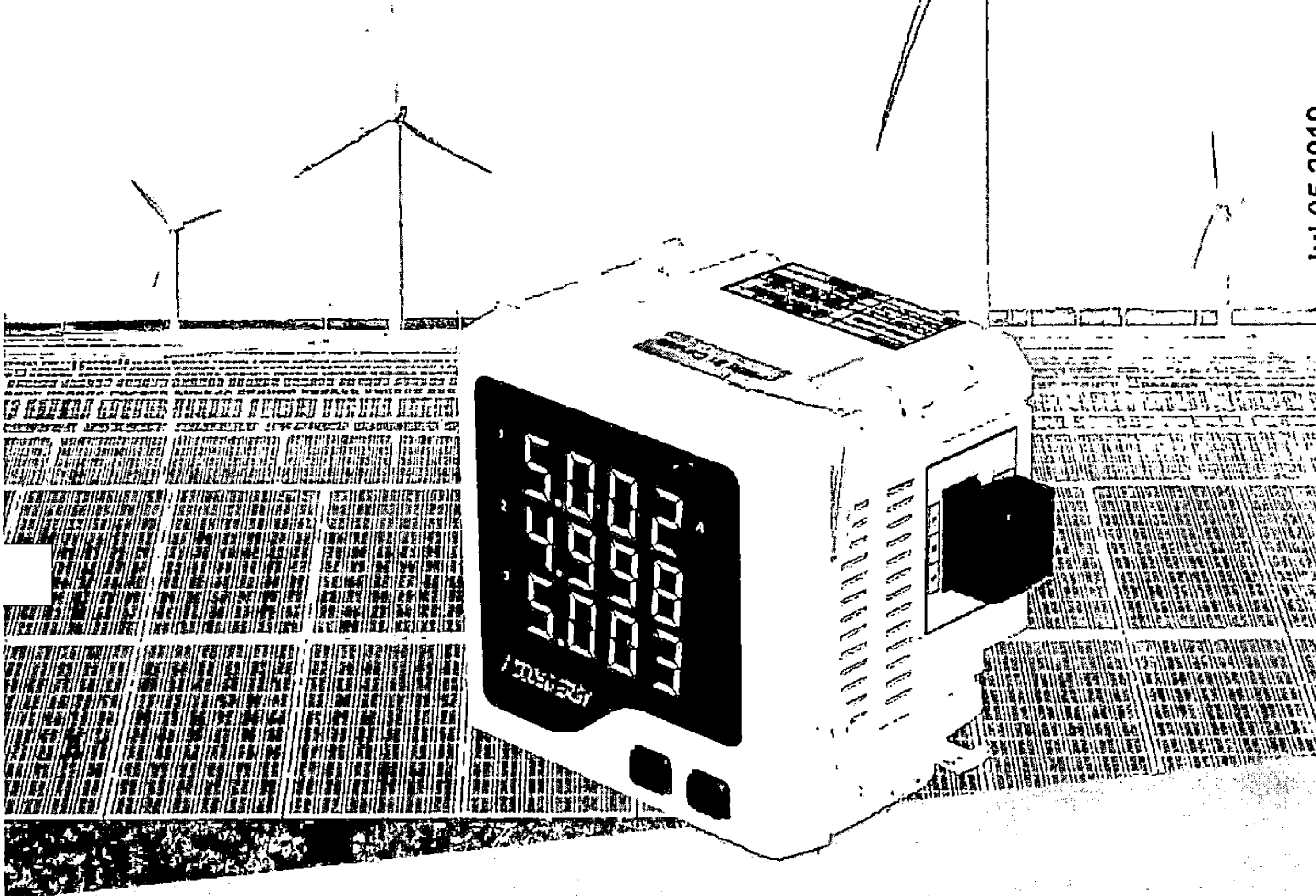
6. Bibliography

1. MESA-PCS, available at http://mesastandards.org/mesa-downloads/
2. MESA-Storage, available at http://mesastandards.org/mesa-downloads/
3. MESA-Meter, available at http://mesastandards.org/mesa-downloads/

Amis

AcuDC 240 Series

DC Power and Energy Meters

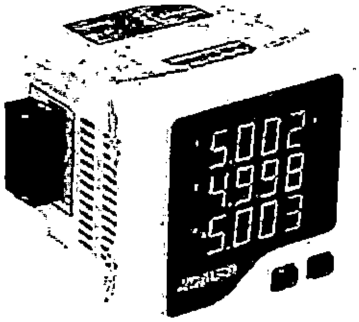


- DC Energy Management Systems
- Power Distribution for Telecommunication Room
- Solar Photovoltaic Systems
- Wind Power Generation
- DC Excitation System
- Industrial DC Control Systems
- Metallurgy and Electroanalysis Industries
- EV Charging Monitoring
- Data Center
- Cellular Tower Energy Monitoring

CE c UL us TÜV CERT ISO9001 Certified

ACCUENERGY

AcuDC 240 Series DC Power Meter



INTRODUCTION

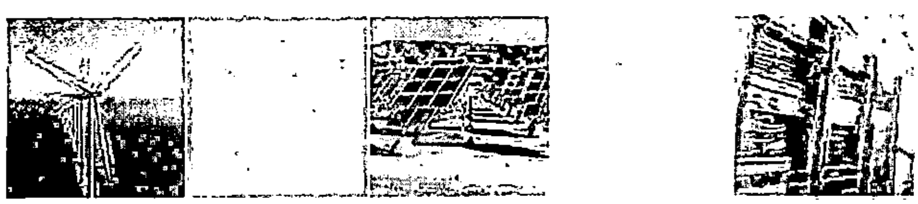
AcuDC 240 series power meter can be used for monitoring and controlling in DC systems. These meters can measure a wide range of parameters such as voltage, current, power and energy. It supports bi-directional current measurement, digital inputs for switch monitoring and relay outputs for remote controlling as well as an over-range alarming feature for voltage and current. Large signals, such as voltage and current can be converted to smaller signal using analog output. All data in the meter is accessible via RS485 using open Modbus RTU protocol. The large 3 line LCD display also provides easy to read real-time data directly on the meter front.

APPLICATIONS

- DC Energy Management Systems
- Power Distribution for Telecommunication Room
- Solar Photovoltaic Systems
- Industrial DC Control Systems
- Metallurgy and Electroplating Industries
- Wind Power Generation
- DC Excitation Systems
- Light Rail Transit Systems
- EV Charging Monitoring
- Data Center
- Cellular Tower Energy Monitoring

FEATURES

- DC power system metering
- Monitor and control power switches
- Alarming and analog output
- Standard 72x72mm, allows for drawer type panel installation
- Three line high-definition LCD display
- Accessible with SCADA, PLC systems
- Easy installation, simple wiring
- Data Logging: Offers 3 assignable historical logs where the all of the metering parameters can be recorded.
- The onboard memory is up to 4 MB and each log size is adjustable.

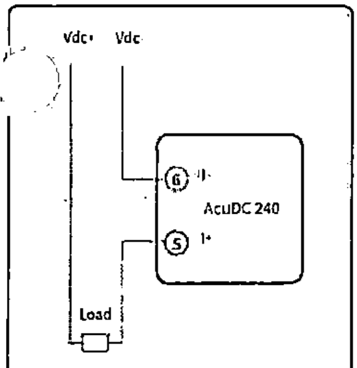


SPECIFICATIONS

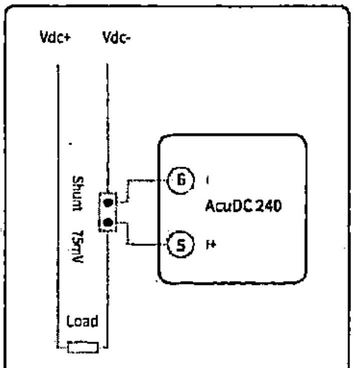
	[illegible]		[illegible]	[illegible]	[illegible]
METERING	Voltage	V	●		●
	Current	I		⊙	●
	Power	P			●
	Energy	E			●
	Ampere-hour	Ah			⊙
I/O	2DI+2AO	Support DI count	⊙	⊙	⊙
	2DI+2RO		⊙	⊙	⊙
	2DI+2DO		⊙	⊙	⊙
	2DI+ ±15Vdc		⊙	⊙	⊙
DATALOGGING	All metering parameters can be recorded (Voltage, Current, Power, Energy, Ampere-hour, DI Count); Interval 1 minute; Can record 4 months				⊙
COMMUNICATION	RS485 , Modbus RTU		⊙	⊙	⊙
DISPLAY	LCD		●	●	●
DIMENSIONS	72×72×64.5mm (Cutout: 68×68 mm) / 2.835×2.835×2.539 inch (Cutout: 2.677×2.677 inch)				

Note: ●Standard; ⊙Optional Blank: Not Available

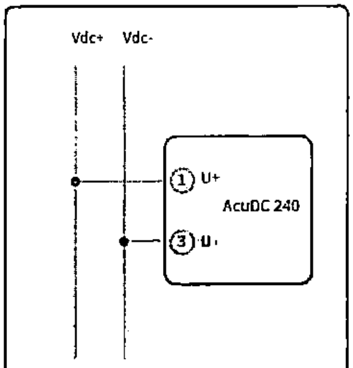
TYPICAL WIRING



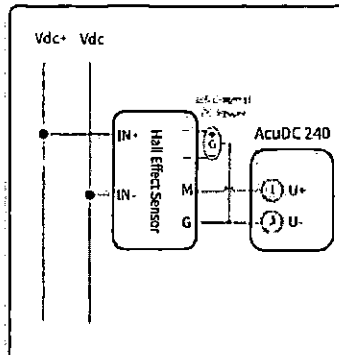
Current Direct Wiring



Current Wiring using Shunt

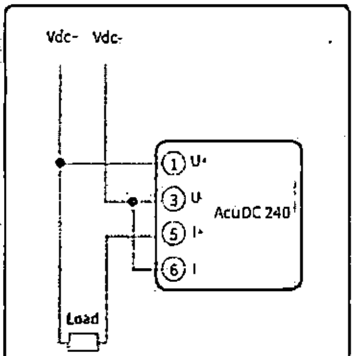


Voltage Direct Wiring

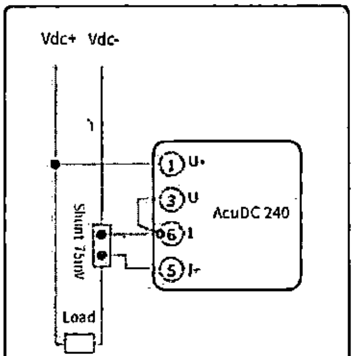


Voltage Wiring using
Voltage Hall Effect Sensor

NOTE: Hall effect sensor can also be powered using the ±15V power supply from the X5 module.

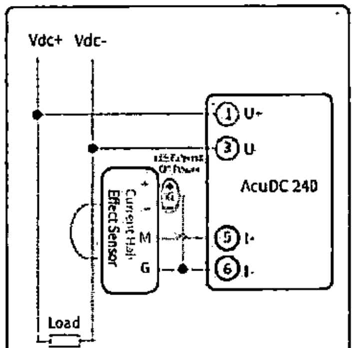


Voltage & Current Direct Wiring



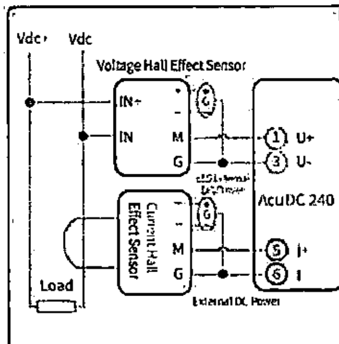
Voltage & Current Wiring using Shunt

NOTE: A physical jumper from terminal 3 to 6 must be connected.



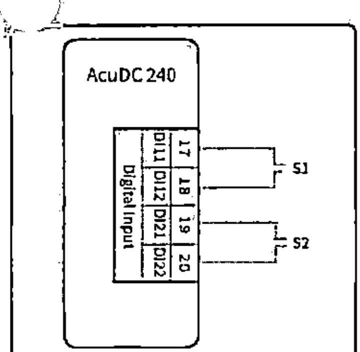
Voltage & Current Wiring using Current
Hall Effect Sensor

NOTE: Hall effect sensor can also be powered using the ±15V power supply in the X5 module.

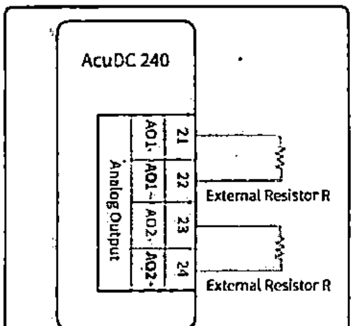


Voltage & Current Wiring using Hall
Effect Sensors

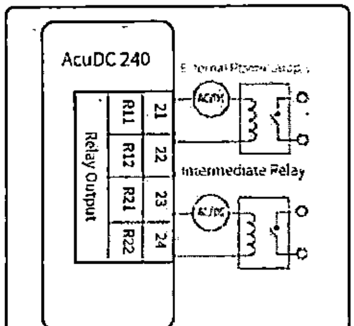
NOTE: Hall effect sensor can also be powered using the ±15V power supply from the X5 module.



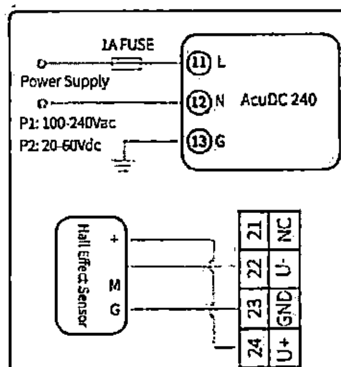
Digital Input



Analog Output
4~20mA, R<500Ω



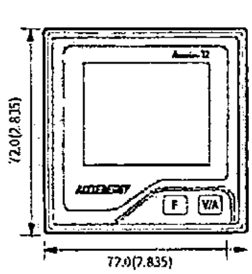
(External Power Supply < 250Vac
or 30Vdc I<3A)



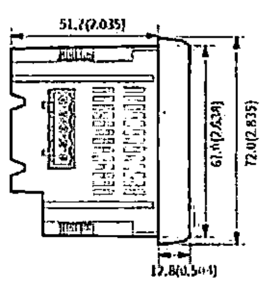
Power Supply Wiring

DIMENSIONS

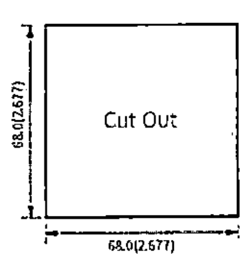
Unit: mm (inch)



FRONT



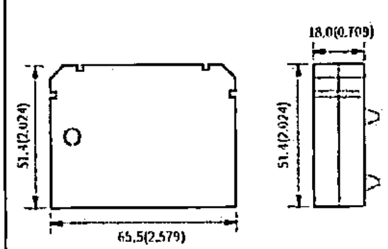
SIDE



PANEL CUTOUT

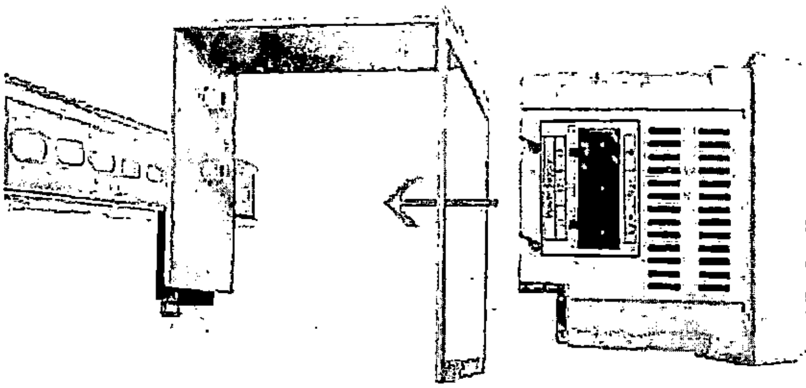
I/O Module

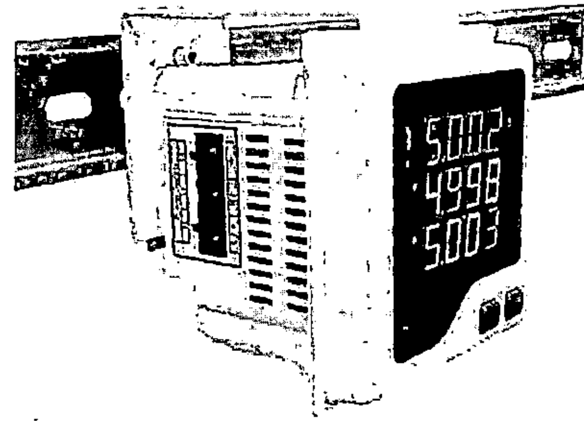
Unit: mm (inch)

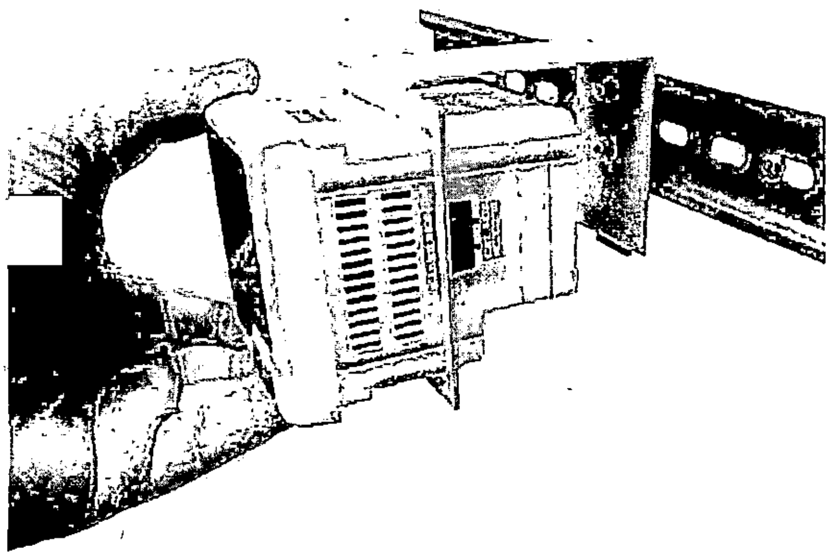


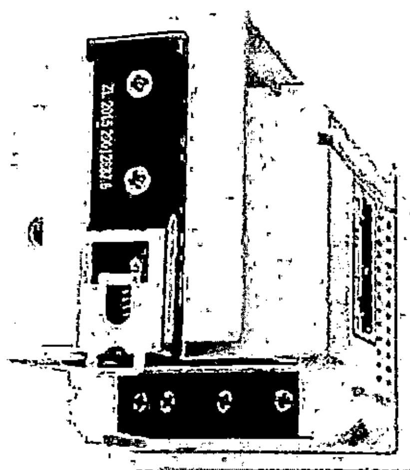
AcuDC 240 Series *DIN Rail Mounting Adapter*

AcuDC 240 Series DIN Rails adapter provide easy installation of panel-mount AcuDC 240 series meter on [illegible] rail in all models and IO options.



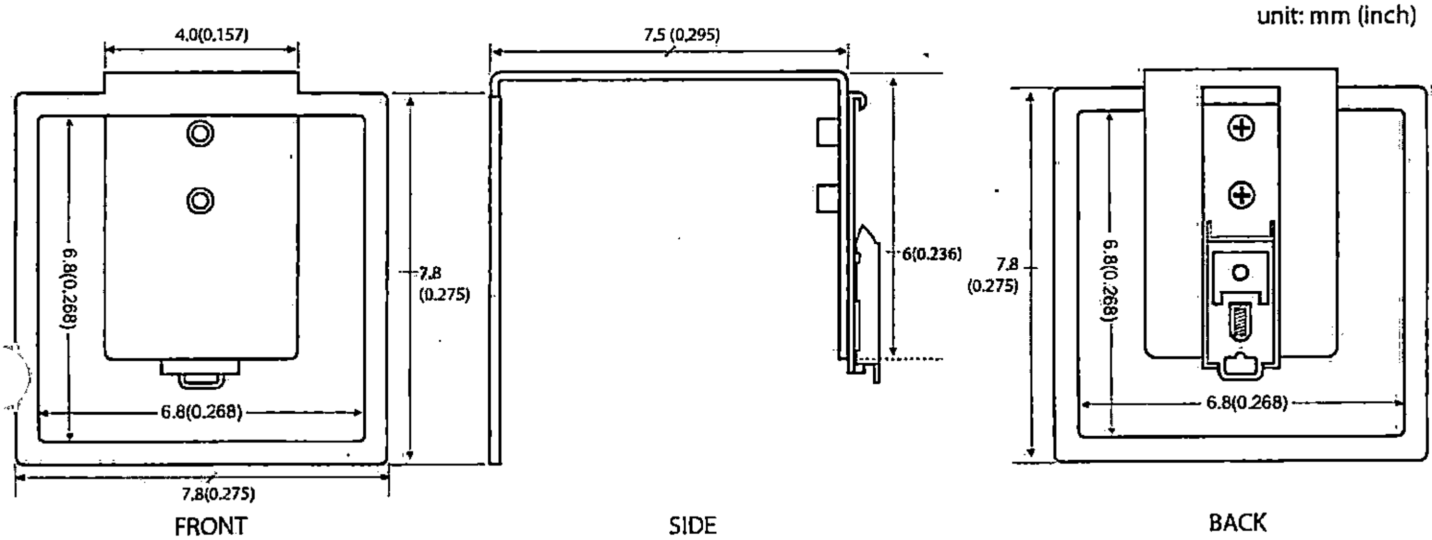






DIMENSIONS

unit: mm (inch)



TECHNICAL SPECIFICATIONS

Parameter	Accuracy	Resolution	Range
Voltage	0.2%	0.001V	0~1200V
Current	0.2%	0.001A	0~±50000A
Power*	0.5%	0.001kW	0~±60000kW
Energy*	0.5%	0.01kWh	0~9999999.99kWh
Drift with Temperature	<100ppm/°C		
Stability	0.5‰/year		

* 0.2% accuracy on Power and Energy available upon request

Voltage

Input Range

Voltage	Direct Input0~1000V; Via Hall Effect Sensor0~1200V
Input Impedence	2MΩ
Load	<0.6W
Accuracy	0.2%

Current

Input Range	0~±10A(Direct Input, pick up current 0.01A) 0~±50000A(Via Shunt or Hall Effect Sensor, programmable range)
Shunt	50~100mV(programmable)
Hall Effect Sensor	0~±5V/0-±4V, 4~20mA/12mA±8mA
Power Consumption	2W(Max)
Accuracy	0.2%

Digital Input

Type	Dry Contact
Isolation Voltage	2500Vac

Communication

Type	RS485, half duplex, Optical Isolated
Protocol	Modbus-RTU
Baud rate	1200~38400bps
Isolation Voltage	2500Vac

Output

Relay Output (RO)

Type	Mechanical contact, Form A
Max Load Voltage	250Vac/30Vdc
Max Load Current	3A
On Resistance	100mΩ (Max)
Isolation Voltage	4000Vac
Mechanical Life	5×10^6 times

Digital Output (Photo-Mos)

Load Voltage Range	0~250Vac/dc
Load Current	100mA(Max)
Max Output Frequency	25Hz, 50% duty cycle
Isolation Voltage	2500Vac

Analog Output (AO)

Range	4-20mA/0~20mA; 0~5V/1-5V
Accuracy	0.5%
Load Capacity	Current type, max load resistance: 750 Ohm Voltage type, max load current: 20 mA

Power Supply

Input	(P1)100-240Vac, 50/60Hz, 100-300Vdc (P2) 20-60Vdc
Consumption	3W (typical value)

Environment

Operation Temperature	-25°C ~ +70°C
Storage Temperature	-40°C ~ +85°C
Humidity	5%~95%Non-condensing

Standard Compliance

Safety Standard	IEC 61010-1
EMC Standard	IEC 55011,IEC 61000-6-2,IEC 61000-3-2 IEC 61000-3-3

ORDERING INFORMATION

AcuDC 240 — □ — □ — □ — □ — □ — □

- Model
  - AcuDC 241: Voltage Meter
  - AcuDC 242: Current Meter
  - AcuDC 243: Multifunction
- Voltage Option
  - 1000V: Nominal Input Voltage 1000Vdc
  - 600V: Nominal Input Voltage 600Vdc
  - 300V: Nominal Input Voltage 300Vdc
  - 60V: Nominal Input Voltage 60Vdc
  - 5V: Via Hall Effect Sensor (0-5V/0-4V), ratio settable
- Current Option
  - A0: 0~±10A
  - A1: Shunt (50~100mV)
  - A2: Current Hall Effect Sensor (4~20mA/12mA±8mA)
  - A3: Voltage Hall Effect Sensor (0~±5V/0~±4V)
- Power Supply Option
  - P1: 100-240Vac 50/60Hz, 100-300Vdc
  - P2: 20-60Vdc
- I/O Option
  - X0: No I/O
  - X1: 2DI+2AO (4~20mA/0~20mA)
  - X2: 2DI+2AO (0~5V/1~5V)
  - X3: 2DI+2RO
  - X4: 2DI+2DO
  - X5: 2DI+±15Vdc
- Communication
  - NC: No Communication
  - C: RS485, Modbus RTU
- Datalogging
  - ND: No Datalogging
  - D: Datalogging (AcuRC 243 Only)

Example: AcuDC 243 - 300 - A2 - P1 - X1 - C - D

VOLTAGE HALL EFFECT SENSOR ORDERING INFORMATION (0-5V output)

0.2% accuracy for Power and Energy

Special Order

Please contact your local Accuenergy representative for further details

CURRENT HALL EFFECT SENSOR ORDERING INFORMATION (4-20 mA output)

Special order

Please contact your local Accuenergy Representative for further details

Note:

When the input voltage is above 1000V, or the system design requires an isolation sensor, the voltage input can be selected as Via Hall Effect Sensor (0~5 V). The Voltage Hall Effect Sensor output range requires 0~5 V.

ORDERING INFORMATION

Model	DC DIN

Accuenergy Corp.

Los Angeles-Toronto-Beijing

North America Toll Free: 1-877-721-8908

Web: www.accuenergy.com

Email: marketing@accuenergy.com

ACCUENERGY

Make Energy Usage Smarter

Revision Date: Sep., 2013 | Document #1534E1112

ACCUENERGY

Accuenergy (Canada) Inc.
2 Lansing Sq. Suite 700
Toronto Ontario M2J4P8
Canada
Phone: 4164974100
Fax: 4164974130
www.accuenergy.com

Quote

TQ00016352

OFFICIAL COPY
OFFICIAL COPY
Jul 05 2019
Jul 26 2019

Bill To
Ecoplexus
Ecoplexus
Phone: 207-217-2216

Estimate Date : 01 Jul 2019
Expiry Date : 01 Aug 2019
Reference# : Michael Wallace - State NC Utility Battery Tiered

#	Item & Description	Internal ID1	Qty	Rate	Amount
1	AcuDC 243-1000V-A1-X5-C-.2 AcuDC 243 multifunction DC power and energy meter; 3-Line LCD display; Nominal Input Voltage 1000Vdc, Current input via Shunt (50~100mV), Power supply 100-240Vac 50/60Hz, 100-300Vdc, Modbus RTU, 15V+/- Power supply + 2DI 0.2% accuracy on Power and Energy		1.00	758.00	758.00
2	AcuLink 810-X Data acquisition server and gateway; Ethernet gateway for Modbus RS485 and pulse devices; 8GB Memory; Dual Ethernet Ports; WiFi; Access energy information remotely via web server, IP based master, data post to remote cloud server	S6941, S7621, S6751	1.00 Pieces	855.00	855.00

Sub Total	1,613.00
No Tax (0%)	0.00
Total	**$1,613.00**

Notes

All prices are in USD unless otherwise specified

Terms & Conditions

When order is shipped via Accuenergy UPS account, the shipment is insured by default.
The shipping cost in this quote include insurance plus discounted shipping rate.
Insurance cost is 1.5% of total order.
If you opt-out for shipping insurance, please contact email info@accuenergy.com and specify with this quote attached.
Insurance is provided by UPS Capital.