INFORMATION SHEET

PRESIDING: Chair Mitchell and Commissioners Brown-Bland, Gray, and Clodfelter
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: July 16, 2019
TIME: 2:03 p.m. – 5:34 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: 4

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
CONFIDENTIAL:
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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 16, 2019

TIME: 2:03 P.m. - 5:34 p.m.

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: 4

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EXAMINATIONS

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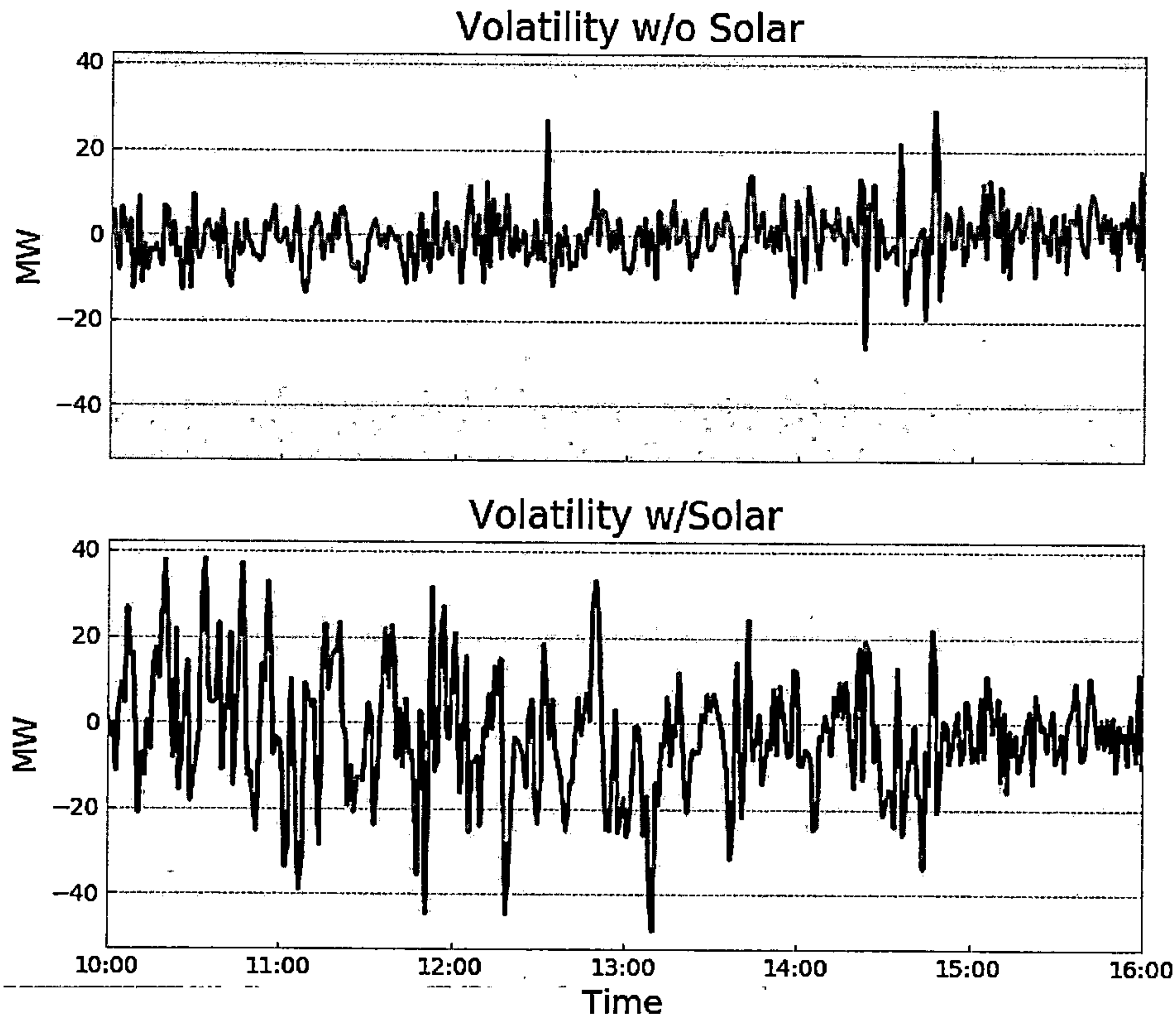
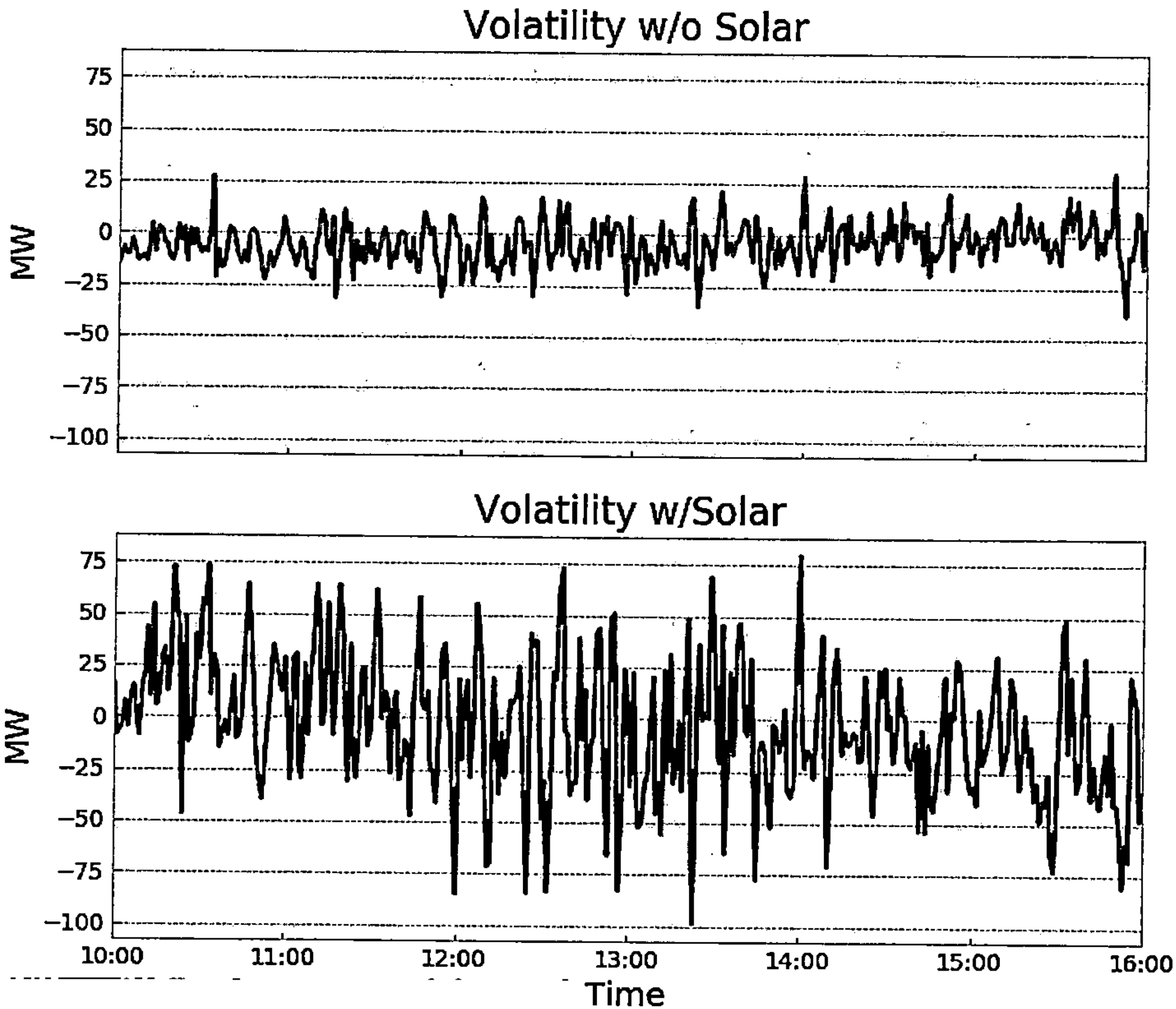
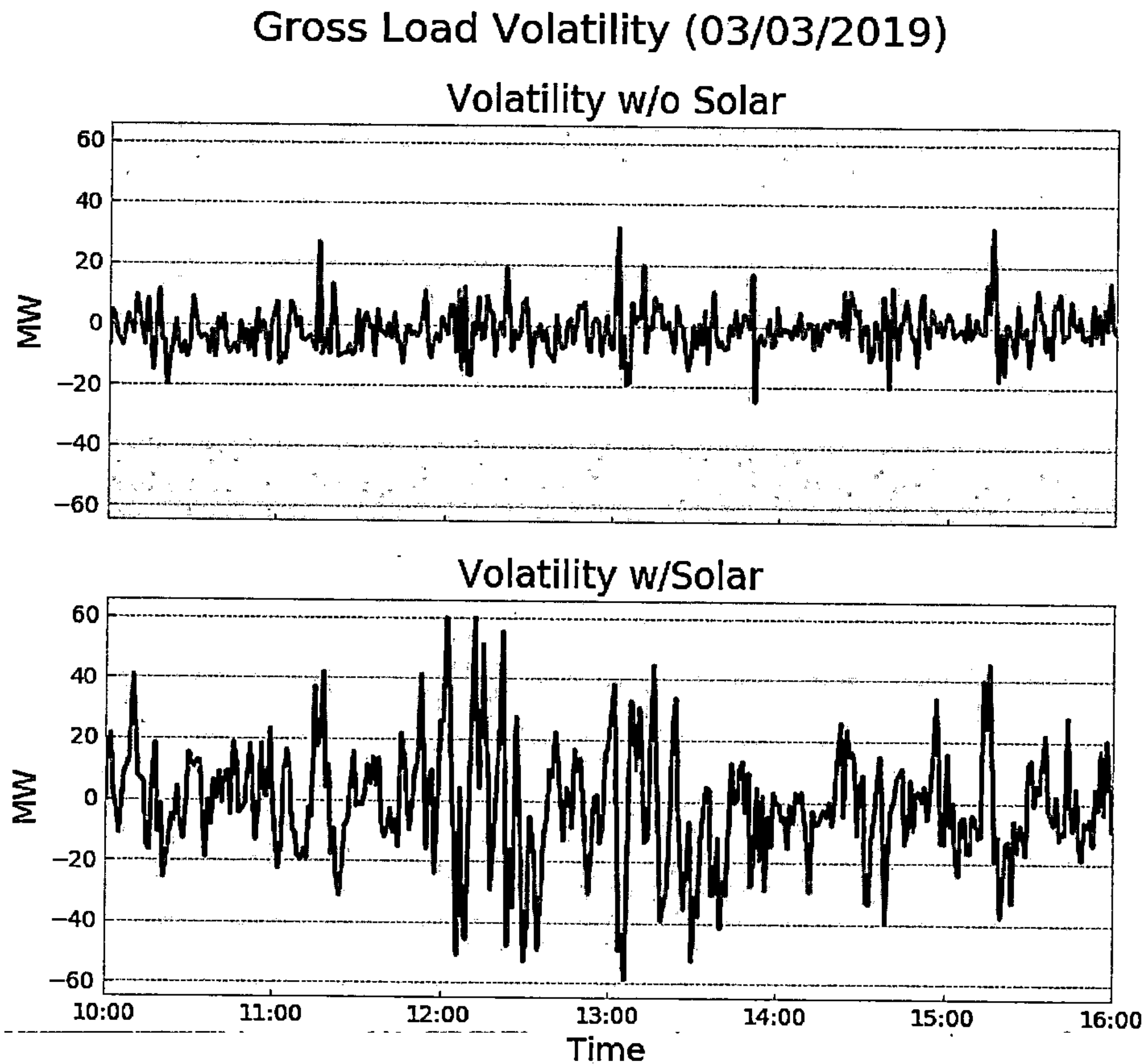
Presentation of DEP Gross Load Volatility With and Without Solar March 1, 2019—March 10, 2019

Gross Load Volatility (03/01/2019)

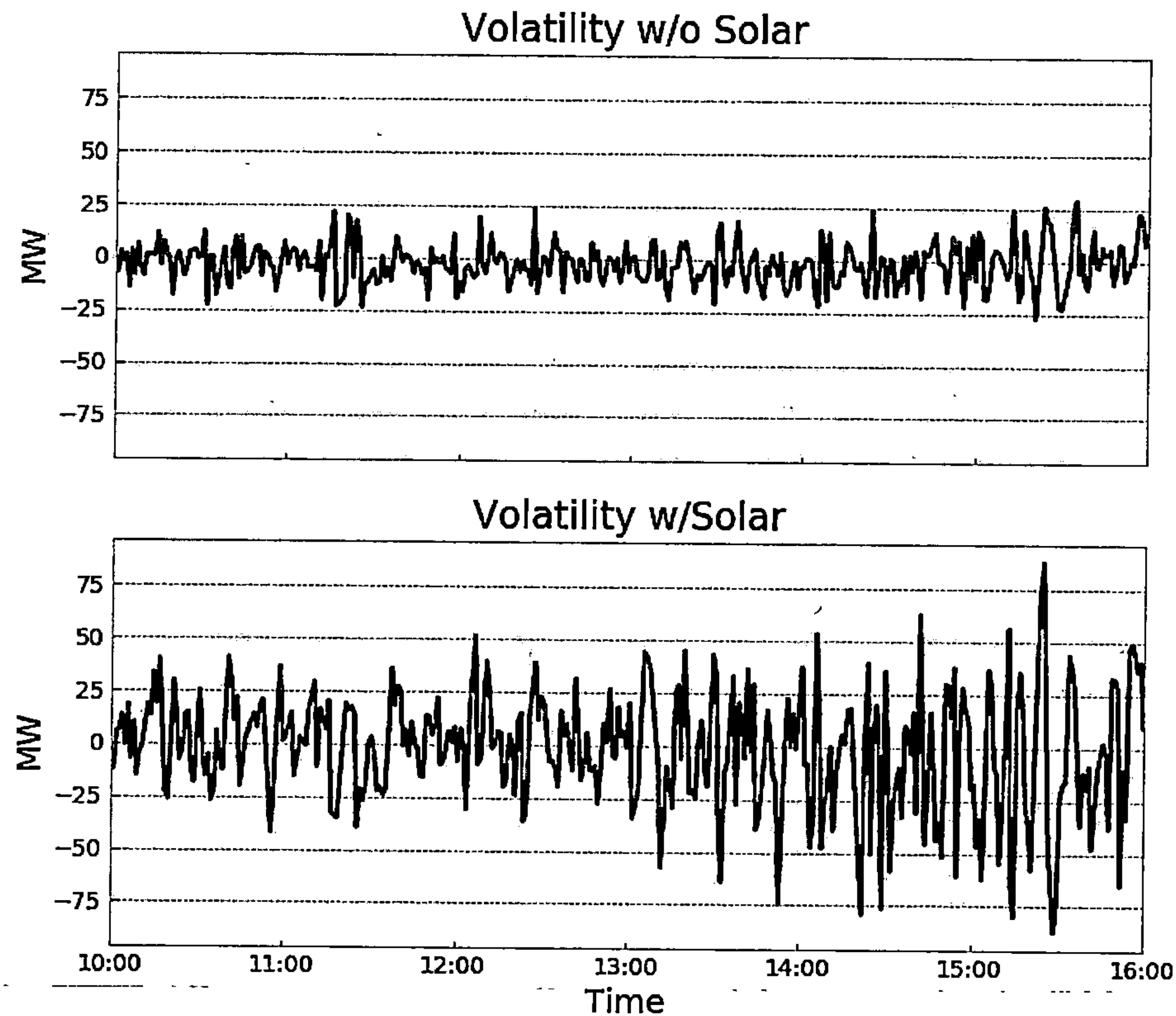


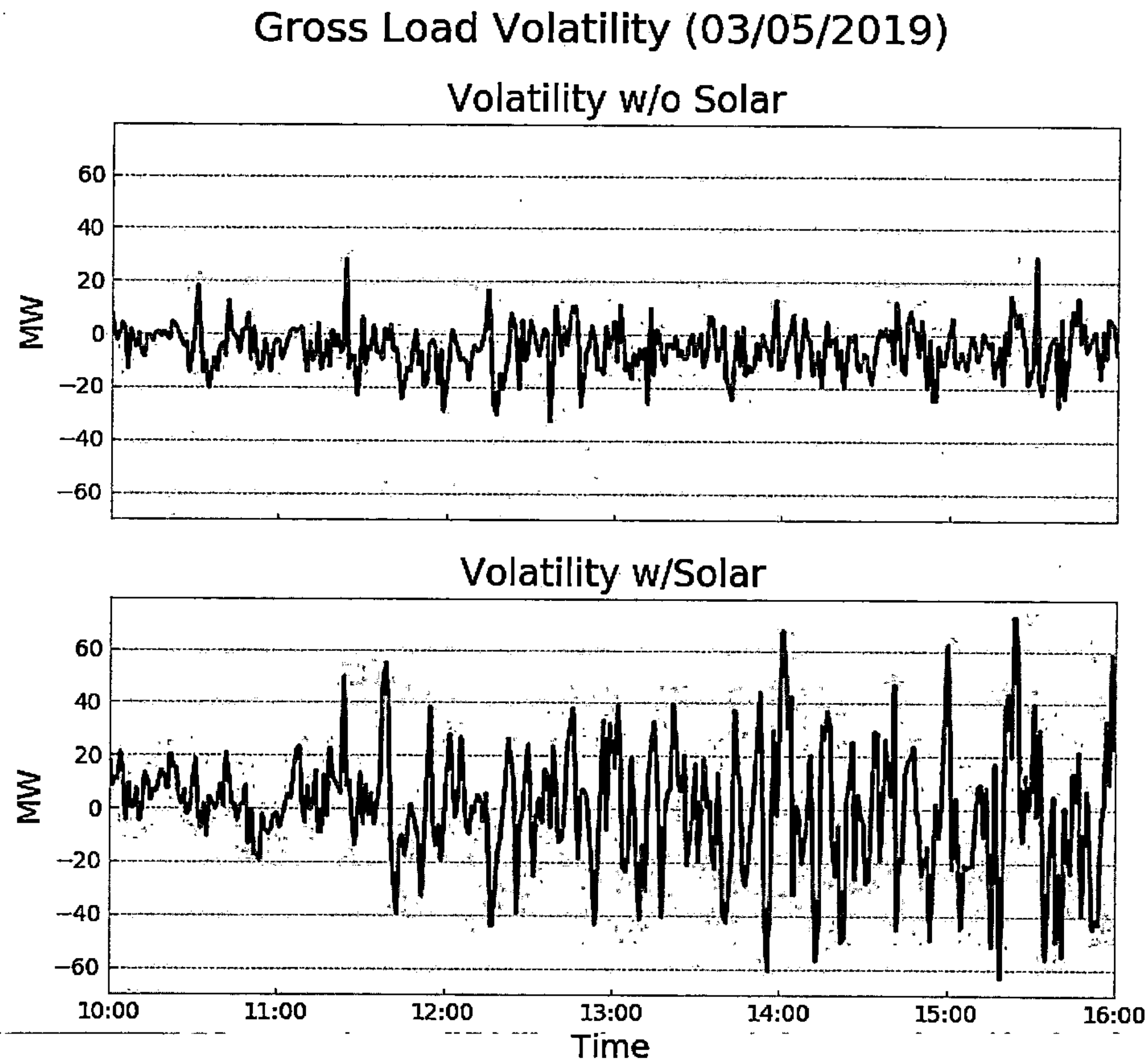
Gross Load Volatility (03/02/2019)



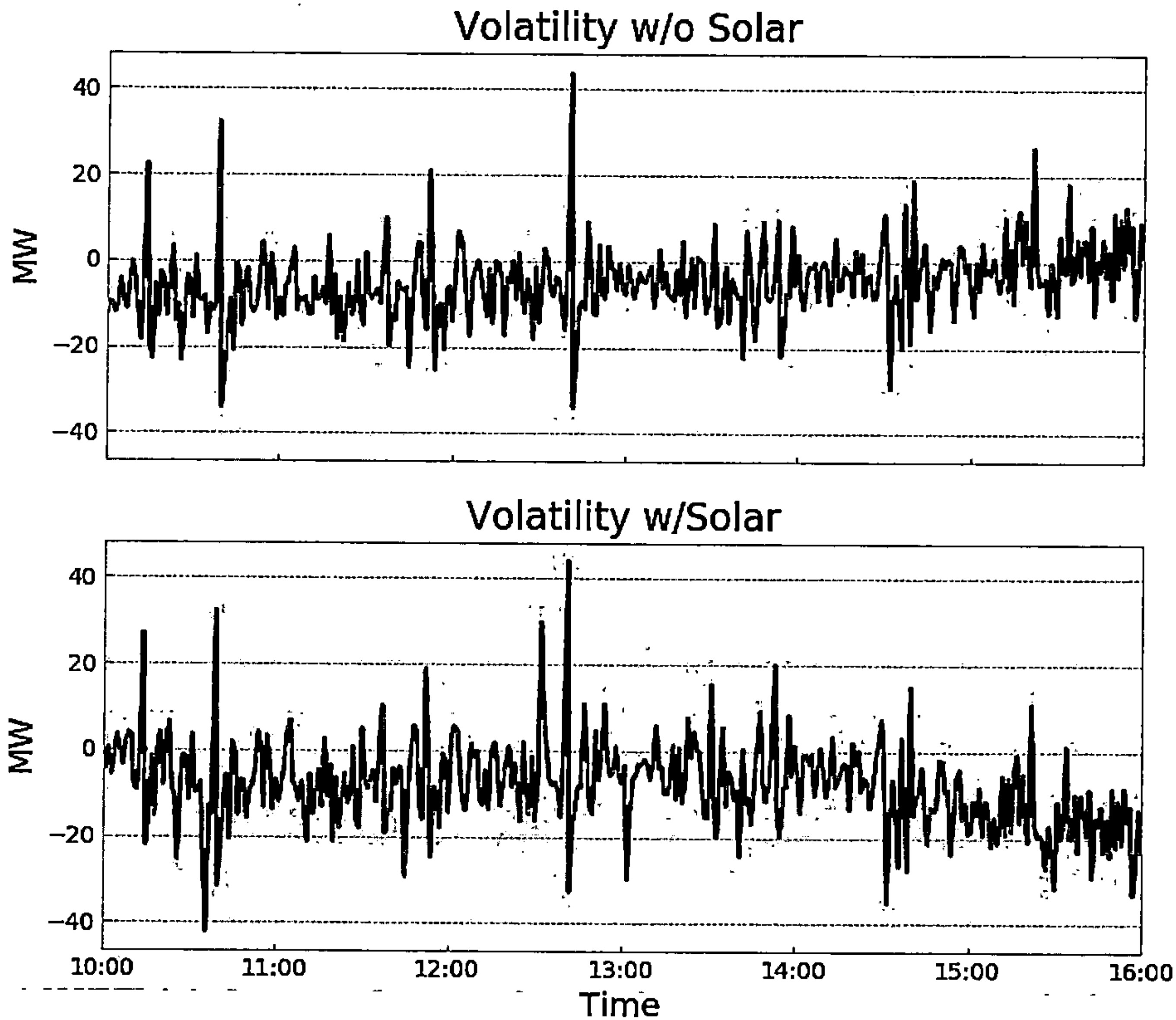

Gross Load Volatility (03/03/2019)
Volatility w/o Solar
Volatility w/Solar
MW
60
40
20
0
−20
−40
−60
10:00
11:00
12:00
13:00
14:00
15:00
16:00
Time

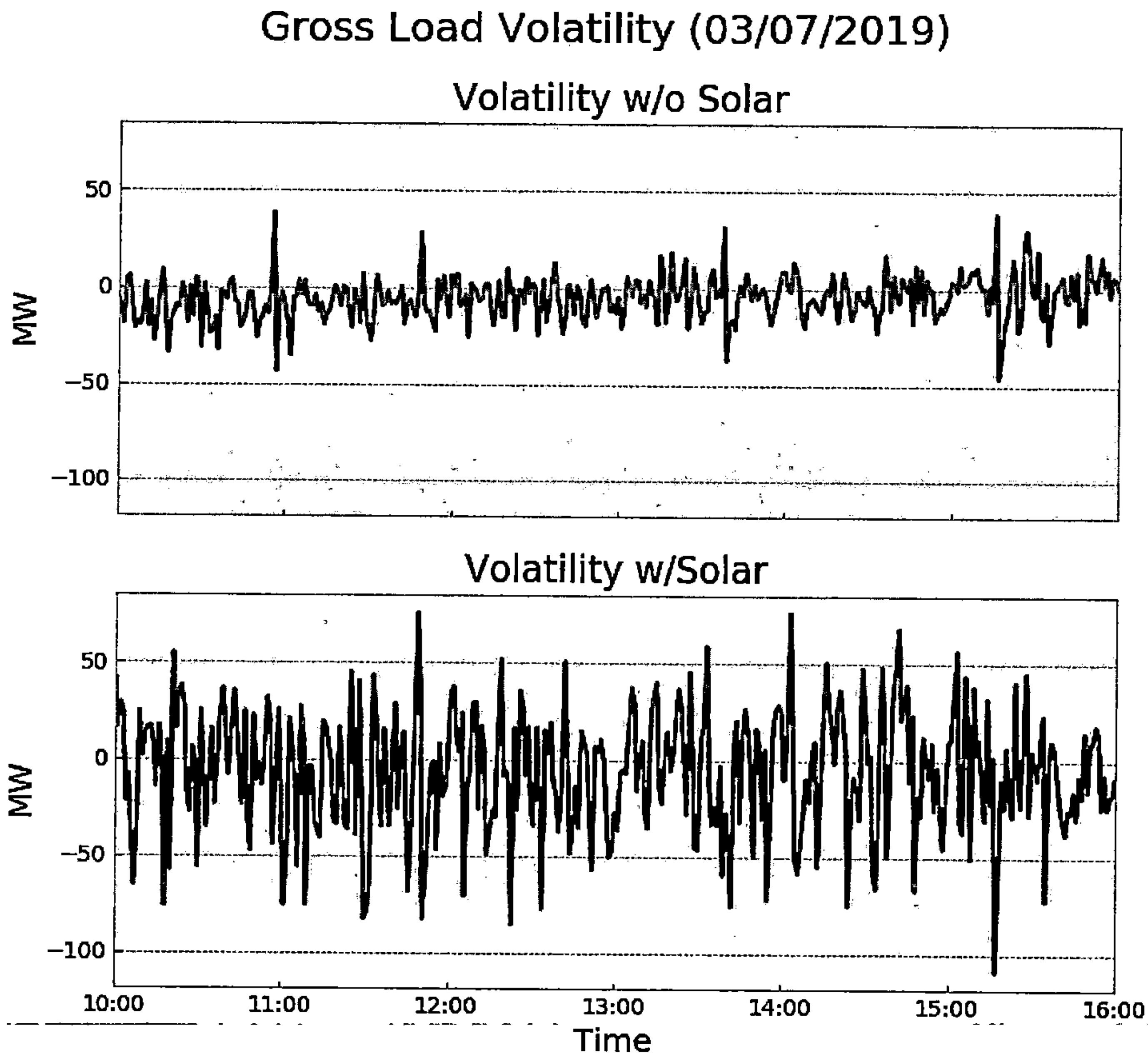
Gross Load Volatility (03/04/2019)




Gross Load Volatility (03/05/2019)
Volatility w/o Solar
MW
60
40
20
0
−20
−40
−60
Volatility w/Solar
MW
60
40
20
0
−20
−40
−60
10:00
11:00
12:00
13:00
14:00
15:00
16:00
Time

Gross Load Volatility (03/06/2019)




Gross Load Volatility (03/07/2019)
Volatility w/o Solar
MW
50
0
−50
−100
Volatility w/Solar
MW
50
0
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−100
10:00
11:00
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14:00
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16:00
Time

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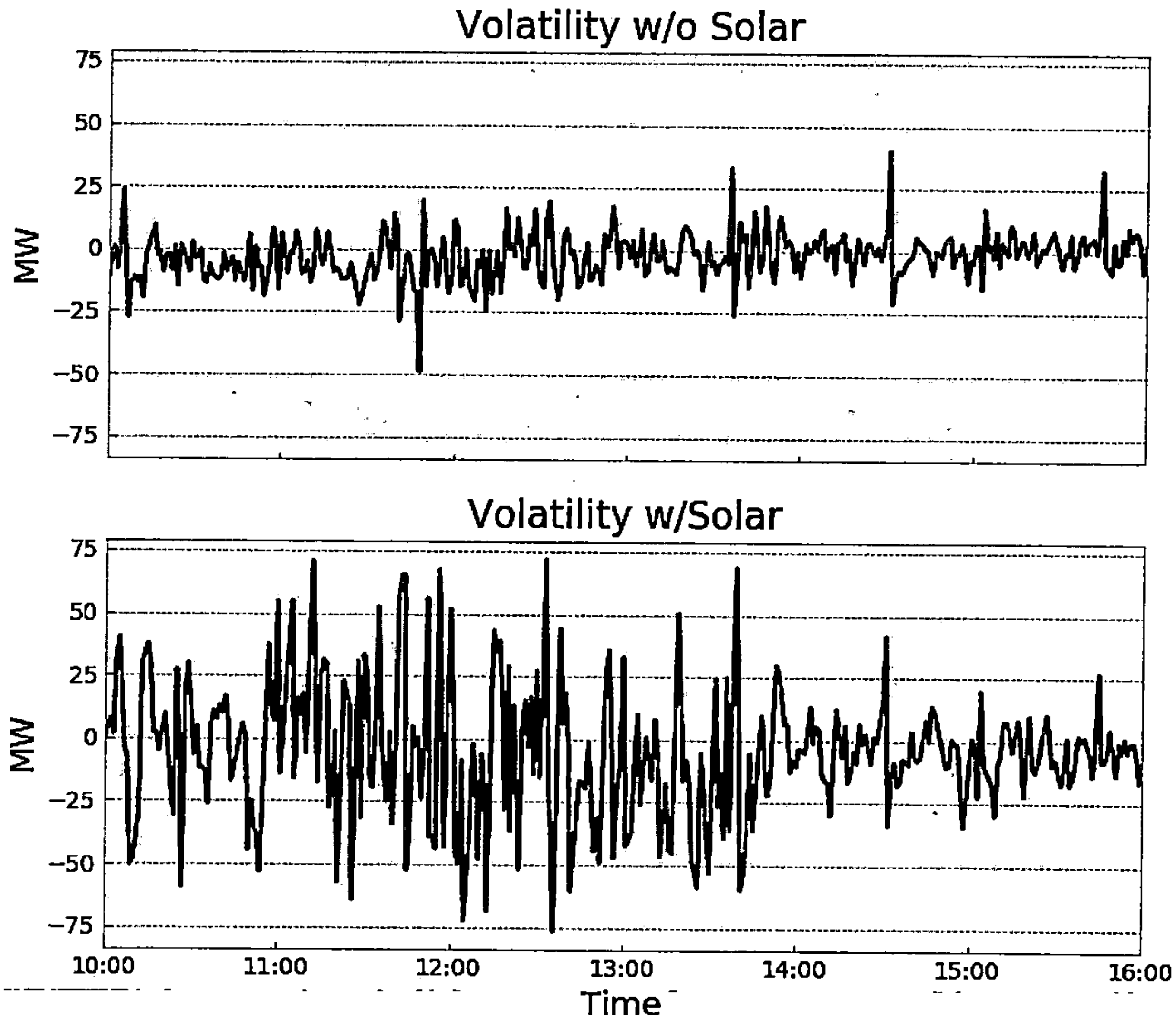
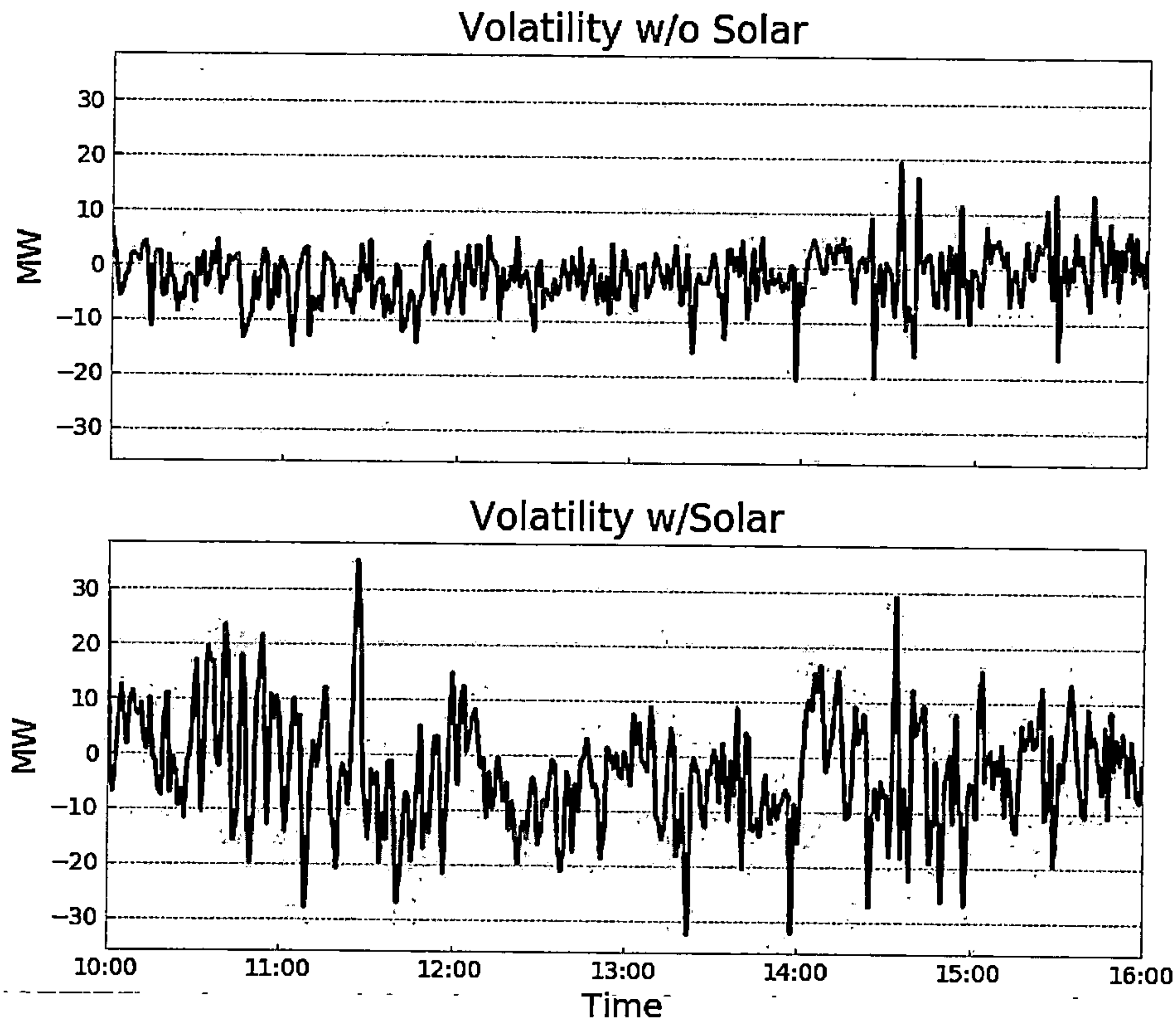
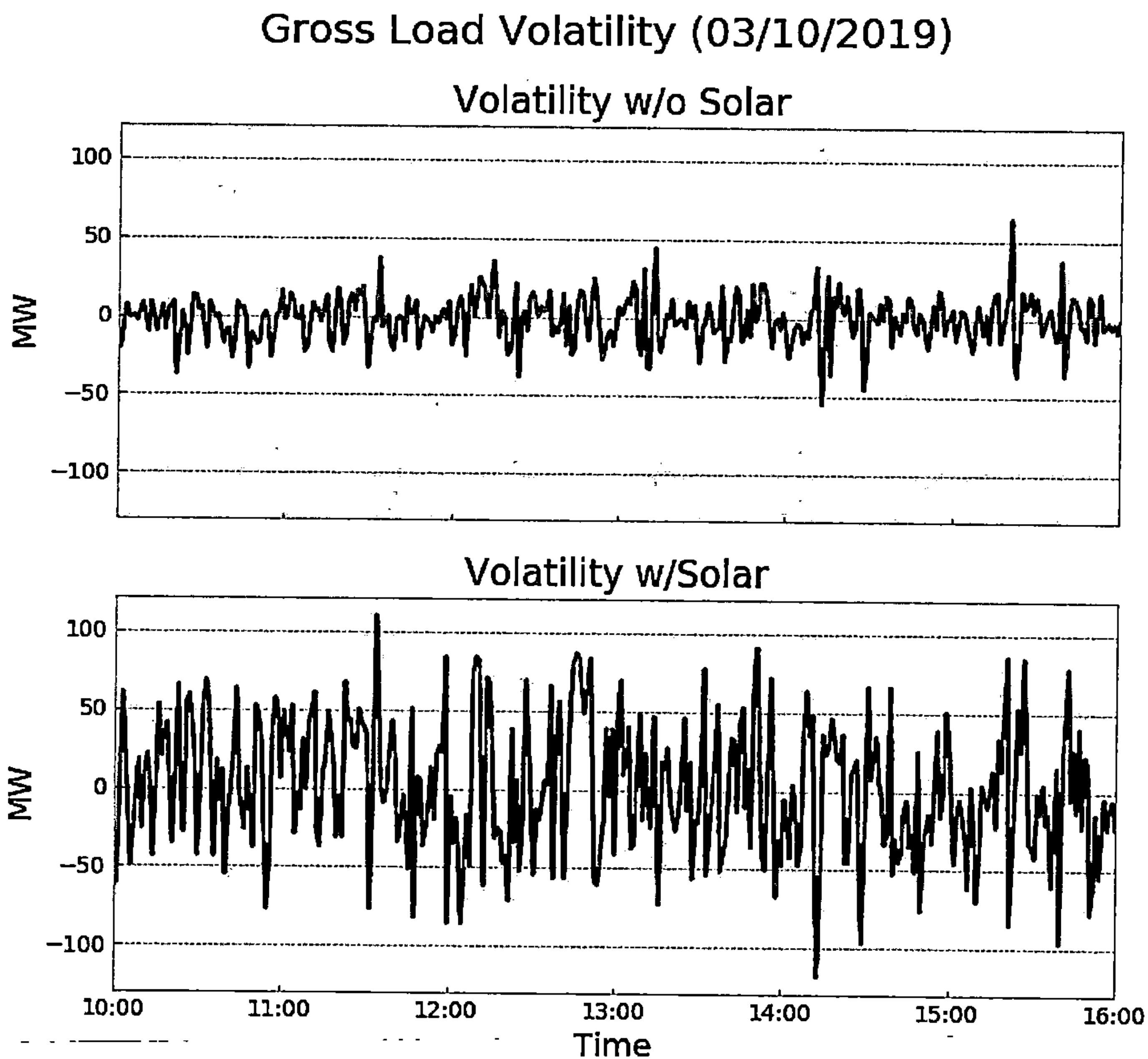


Gross Load Volatility (03/09/2019)




Gross Load Volatility (03/10/2019)
Volatility w/o Solar
MW
100
50
0
−50
−100
Volatility w/Solar
MW
100
50
0
−50
−100
10:00
11:00
12:00
13:00
14:00
15:00
16:00
Time

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Wintermantel Exhibit 1

Duke Energy Carolinas, LLC
and
Duke Energy Progress, LLC

Curriculum Vitae

Nick Wintermantel | Principal, Astrapé Consulting, LLC

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Mr. Wintermantel has 18 years of experience in utility planning and electric market modeling. Areas of utility planning experience includes utility integrated resource planning (IRP) for vertically-integrated utilities, market price forecasting, resource adequacy modeling, RFP evaluations, environmental compliance analysis, asset management, financial risk analysis, and contract structuring. Mr. Wintermantel also has expertise in production cost simulations and evaluation methodologies used for IRPs and reliability planning. As a consultant with Astrapé Consulting, Mr. Wintermantel has managed reliability and planning studies for large power systems across the U.S. and internationally. Prior to joining Astrapé Consulting, Mr. Wintermantel was employed by the Southern Company where he served in various resource planning, asset management, and generation development roles.

Experience

Principal Consultant at Astrapé Consulting (2009 – Present)
Managed detailed system resource adequacy studies for large scale utilities
Managed ancillary service and renewable integration studies
Managed capacity value studies
Managed resource selection studies
Performed financial and risk analysis for utilities, developers, and manufacturers
Demand side resource evaluation
Storage evaluation
Served on IE Teams to evaluate assumptions, models, and methodologies for competitive procurement solicitations
Project Management on large scale consulting engagements
Production cost model development
Model quality assurance
Sales and customer service

Sr. Engineer for Southern Company Services (2007-2009)
Integrated Resource Planning and environmental compliance
Developed future retail projects for operating companies while at the Southern Company
Asset management for Southern Company Services

Sr. Engineer for Southern Power Company (Subsidiary of Southern Company) (2003-2007)
Structured wholesale power contracts for Combined Cycle, Coal, Simple Cycle, and IGCC Projects
Model development to forecast market prices across the eastern interconnect
Evaluate financials of new generation projects
Bid development for Resource Solicitations

Cooperative Student Engineer for Southern Nuclear (2000-2003)
Probabilistic risk assessment of the Southern Company Nuclear Fleet

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Industry Specialization

Resource Adequacy Planning	Resource Planning	Integrated Resource Planning
Competitive Procurement	Asset Evaluation	Financial Analysis
Environmental Compliance Analysis	Generation Development	Capacity Value Analysis
Renewable Integration	Ancillary Service Studies	

Education

MBA, University of Alabama at Birmingham – Summa Cum Laude
B.S. Degree Mechanical Engineering - University of Alabama - Summa Cum Laude

Relevant Experience

Resource Adequacy Planning and Production Cost Modeling

Tennessee Valley Authority: Performed Various Reliability Planning Studies including Optimal Reserve Margin Analysis, Capacity Benefit Margin Analysis, and Demand Side Resource Evaluations using the Strategic Energy and Risk Valuation Model (SERVM) which is Astrapé Consulting's proprietary reliability planning software. Recommended a new planning target reserve margin for the TVA system and assisted in structuring new demand side option programs in 2010. Performed Production Cost and Resource Adequacy Studies in 2009, 2011, 2013, 2015 and 2017. Performed renewable integration and ancillary service work from 2015-2017.

Southern Company Services: Assisted in resource adequacy and capacity value studies as well as model development from 2009 – 2018.

Louisville Gas & Electric and Kentucky Utilities: Performed reliability studies including reserve margin analysis for its Integrated Resource Planning process.

Duke Energy: Performed resource adequacy studies for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC in 2012 and 2016. Performed capacity value and ancillary service studies in 2018.

California Energy Systems for the 21st Century Project: Performed 2016 Flexibility Metrics and Standards Project. Developed new flexibility metrics such as EUE_{flex} and $LOLE_{flex}$ which represent LOLE occurring due to system flexibility constraints and not capacity constraints.

Terna: Performed Resource Adequacy Study used to set demand curves in Italian Capacity Market Design.

Pacific Gas and Electric (PG&E): Performed flexibility requirement and ancillary service study from 2015–2017. Performed CES Study for Renewable Integration and Flexibility from 2015 – 2016.

PNM (Public Service Company of New Mexico): Managed resource adequacy studies and renewable integration studies and ancillary service studies from 2013 – 2017. Performed resource selection studies in 2017 and 2018. Evaluated storage.

GASOC: Managed resource adequacy studies from 2015 – 2018.

MISO: Managed resource adequacy study in 2015.

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SPP: Managed resource adequacy study in 2017.

Malaysia (TNB, Sabah, Sarawak)): Performed and managed resource adequacy studies from 2015-2018 for three different Malaysian entities.

ERCOT: Performed economic optimal reserve margin studies in cooperation with the Brattle Group in 2014 and 2018. The report examined total system costs, generator energy margins, reliability metrics, and economics under various market structures (energy only vs. capacity markets). Completed a Reserve Margin Study requested by the PUCT, examining an array of physical reliability metrics in 2014 (See Publications: Expected Unserved Energy and Reserve Margin Implications of Various Reliability Standards). Probabilistic Risk Assessment for the North American Electric Reliability Corporation (NERC) in 2014, 2016, and 2018.

FERC: Performed economics of resource adequacy work in 2012-2013 in cooperation with the Brattle Group. Work included analyzing resource adequacy from regulated utility and structured market perspective.

EPRI: Performed research projects studying reliability impact and flexibility requirements needed with increased penetration of intermittent resources in 2013. Created Risk-Based Planning system reliability metrics framework in 2014 that is still in use today.

Wintermantel Exhibit 2

Duke Energy Carolinas, LLC
and
Duke Energy Progress, LLC

Solar Ancillary Service Study

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Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study

11/2018

PREPARED FOR

Duke Energy

PREPARED BY

Kevin Carden
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Alex Krasny
Astrapé Consulting

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Contents

Solar Ancillary Service Study Summary

As Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) continue to add solar to their systems, understanding the impact the solar fleet has on real time operations is important. Due to the intermittent nature of solar resources and the requirement to meet real time load on a minute to minute basis, online dispatchable resources should have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Not only can solar drop off quickly but it can also ramp up quickly; unexpected movement in either direction can cause system issues. When solar drops off quickly, reliability can be an issue if other generators are not able to ramp up fast enough to replace the lost solar energy. When solar ramps up quickly, if other generators are not able to ramp down to match the solar output change, some solar generation may need to be curtailed. At low solar penetrations, the unexpected changes in solar output can be cost-effectively accommodated by increasing ancillary service[1] guidelines within the existing conventional fleet. Increasing ancillary service requirements forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up and down. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently which also increases costs. As solar penetrations continue to rise, carrying additional ancillary services to ameliorate solar uncertainty with the conventional fleet becomes incrementally more expensive. This study analyzes multiple solar penetration levels and quantifies the cost of utilizing the existing fleet to reliably integrate the additional solar generation.

For this study, the SERVM model was utilized because it not only performs intra-hour simulations which include full commitment and dispatch logic, but also because it embeds uncertainty into each

[1] Ancillary services are defined in further detail in the Input Section of the Report.

commitment and dispatch decision. At each solar penetration level, simulations were performed assuming the same ancillary service assumptions that are used in SERVM simulations with zero solar capacity. The operational reliability metrics were recorded from those simulations. Next, operational reliability was calibrated to the same reliability of the zero solar simulations by increasing ancillary services. Finally, system costs were compared between operating with the baseline ancillary services (lower cost, but poorer reliability) to operating with the required ancillary services (higher cost but achieves reliability targets). The difference in cost represents the ancillary service cost impact.

Several solar penetrations were modeled for both DEC and DEP including a case with no solar, as shown in Table ES-1. The solar penetration scenarios included existing plus transition and tranche 1 requirements under NC HB 589, and an additional scenario with an incremental 1,500 MW of solar to assess a high penetration scenario. Note however that the existing plus transition and tranche 1 scenarios discussed in this study include all utility scale requirements under NC HB 589 that were assumed at the time the study was initiated (CPRE, large customer programs and community solar).

Table ES-1. DEC and DEP Solar Penetrations Analyzed

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
No Solar	0	0	0	0
Existing Plus Transition	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
+1,500 MW	1,500	3,020	1,500	4,610

DEC and DEP solar ancillary service cost impact results are shown in Tables ES-2 and ES-3 below. The first solar penetration level (existing plus transition) shows an ancillary service cost of $1.10/MWh for DEC and $2.39/MWh for DEP, with the major difference being that DEC has 840 MW of solar in this existing plus transition block compared to 2,950 MW for DEP. For both companies, as solar penetration increased, the load following required, ancillary service cost impact and projected renewable curtailment all increased. The average ancillary service cost impact shown in the tables represents the cost impact of all the solar in the scenario whereas the incremental ancillary service cost impact only represents the cost impact of the incremental solar in the scenario. For example, the tranche 1 average ancillary service cost impact for DEC is \$1.37/MWh which represents the cost impact of the entire 1,520 MW block up to and including tranche 1, whereas the incremental cost of \$1.67/MWh represents the cost of adding the 680 MW increment of solar. The incremental cost in the final tranche of solar considered is very high suggesting that incorporation of more flexible resources may be required to economically integrate additional solar.

DEC and DEP results display similar patterns as demonstrated in the tables. The total solar penetration measured for DEP is higher than DEC, and the highest ancillary service costs are higher than in DEC. However, at roughly the same penetration of solar – 3,000 MW – DEC average ancillary service cost (\$2.90/MWh) is slightly higher than DEP (\$2.64/MWh). While the systems share many similarities, a few flexibility differences contribute to the difference in ancillary service costs. While DEC has pumped-storage hydro with significant flexibility, that resource is not always operating in a state where it can provide the necessary flexibility. Further DEP has more combustion turbine and other flexible capacity than DEC. On balance though, both studies demonstrate a significant and escalating impact on system costs as solar resources are added.

Table ES-2. DEC Ancillary Service Cost Results

Scenario	Total Solar MW	Incremental Solar MW	Average Ancillary Service Cost Impact ($/MWh)	Incremental Ancillary Service Cost Impact ($/MWh)	% of Renewable Curtailed
DEC No Solar	0	0	0	0	0
DEC Existing Plus Transition	840	840	1.10	1.10	0.21%
DEC Tranche 1	1,520	680	1.37	1.67	0.55%
DEC Add 1,500 MW[2]	3,020	1,500	2.90	4.38	1.90%

Table ES-3. DEP Ancillary Service Cost Results

Scenario	Total Solar MW	Incremental Solar MW	Average Ancillary Service Cost Impact ($/MWh)	Incremental Ancillary Service Cost Impact ($/MWh)	% of Renewable Curtailed
DEP No Solar	0	0	0	0	0.0%
DEP Existing Plus Transition	2,950	2,950	2.39	2.39	3.36%
DEP Tranche 1	3,110	160	2.64	6.80	4.15%
DEP Add 1,500 MW[2]	4,610	1,500	9.72	23.24	15.77%

The following sections of this report provide greater detail regarding the ancillary service study framework, model inputs, simulation methodology, and study results and conclusions.

[2] Assumes reduction in unitized volatility to reflect the diversity benefit of large solar fleet.

I. Study Framework

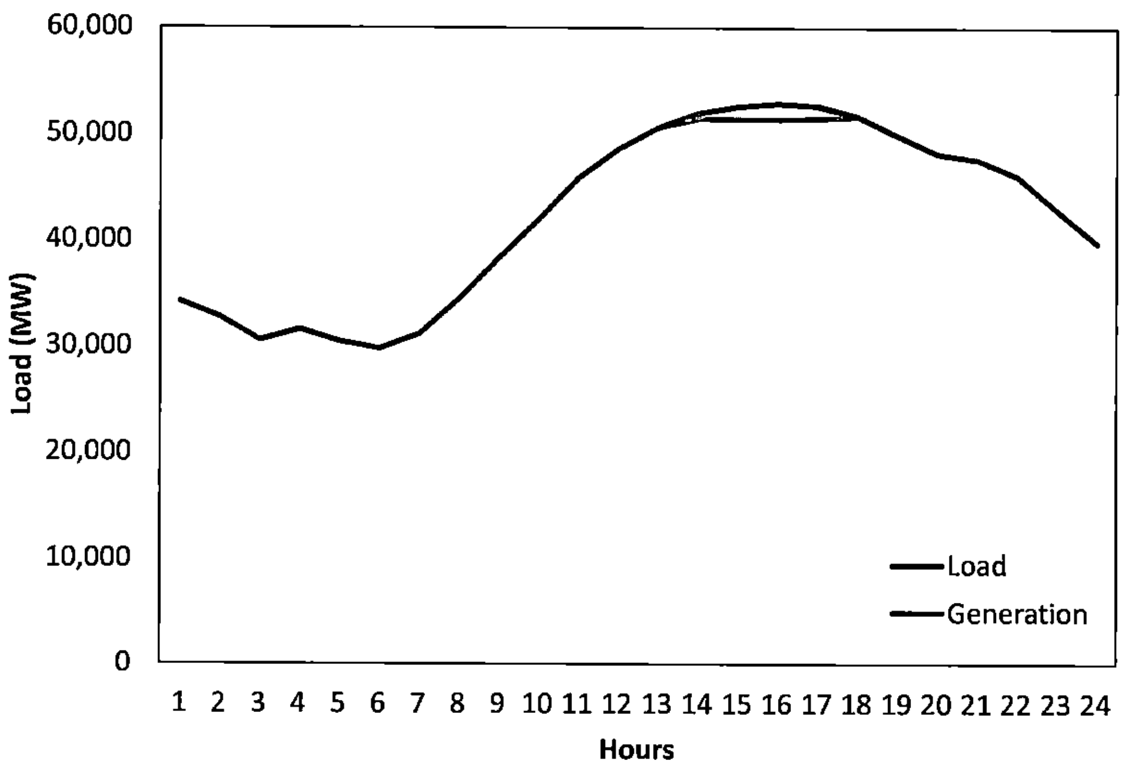
The economics of adding significant solar generation to a fleet are generally analyzed in a production cost simulation model. These models perform a commitment and dispatch of the conventional fleet against the gross load minus the expected renewable generation. Comparing the economic results from simulations with significant solar against simulations with more conventional resources allows planners to assess the economic implications of these additions. However, these analyses typically commit and dispatch resources with an exact representation of the load and solar patterns. This perfect knowledge aspect of the simulations overstates the value of resources such as solar that have significant inherent uncertainty. This study layers in the inherent uncertainty and forces the production cost model to make decisions without perfect knowledge of the load, wind, solar, or conventional generator availability. In this framework, the objective function of the commitment and dispatch is still to minimize cost, but with an added constraint of maintaining operational reliability.

The enforcement of reliability requirements in simulation tools with perfect foresight is generally through a reserve margin constraint; each year is required to have adequate capacity to meet a particular reserve margin requirement. These types of simulations are unlikely to recognize reliability events partly because of their perfect foresight framework, but also because they use simplified generator outage logic. The outages at any discrete hour in the simulations typically represent average outages. In actual practice, reliability events are driven by coincident generator outages much larger in magnitude than the average. In the simulations performed for this study, the SERVM model incorporates both load and solar uncertainty, as well as generator outage variability. In this framework, testing the capability of the conventional fleet to integrate solar resources is much more reflective of actual conditions.

The types of reliability events that are driven by solar output variability and volatility are different from those analyzed in a typical resource adequacy analysis; they are reliability events that could have been addressed by operating the conventional fleet differently. If solar output in a hypothetical system were to drop unexpectedly by 1,000 MW in a 10-minute period, only resources that are online with operating flexibility would be able to help alleviate the loss of the solar energy. So, for this analysis, the model differentiates reliability events by their cause. Inputs are optimized such that both reliability events driven by a lack of capacity and reliability events driven by a lack of flexibility achieve specific targets at minimum cost.

(1) $LOLE_{CAP}$: number of loss of load events due to capacity shortages, calculated in events per year. Figure 1 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 1. $LOLE_{CAP}$ Example



(2) $LOLE_{FLEX}$: number of loss of load events due to system flexibility problems, calculated in events per year. In other words, there was enough capacity installed but not enough flexibility to meet the net load ramps, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps.

Figures 2 and 3 show $LOLE_{FLEX}$ examples. Figure 2 shows a multi-hour ramping problem in which load could not be met whereas Figure 3 shows an intra hour ramping problem. Both of these loss of load events are categorized as $LOLE_{FLEX}$ events. The vast majority of $LOLE_{FLEX}$ events fall under the intra hour problems seen in Figure 3. These events are typically very short in duration and are caused by a rapid decline in solar or wind resources over a short time interval.

Figure 2. Multi Hour $LOLE_{FLEX}$

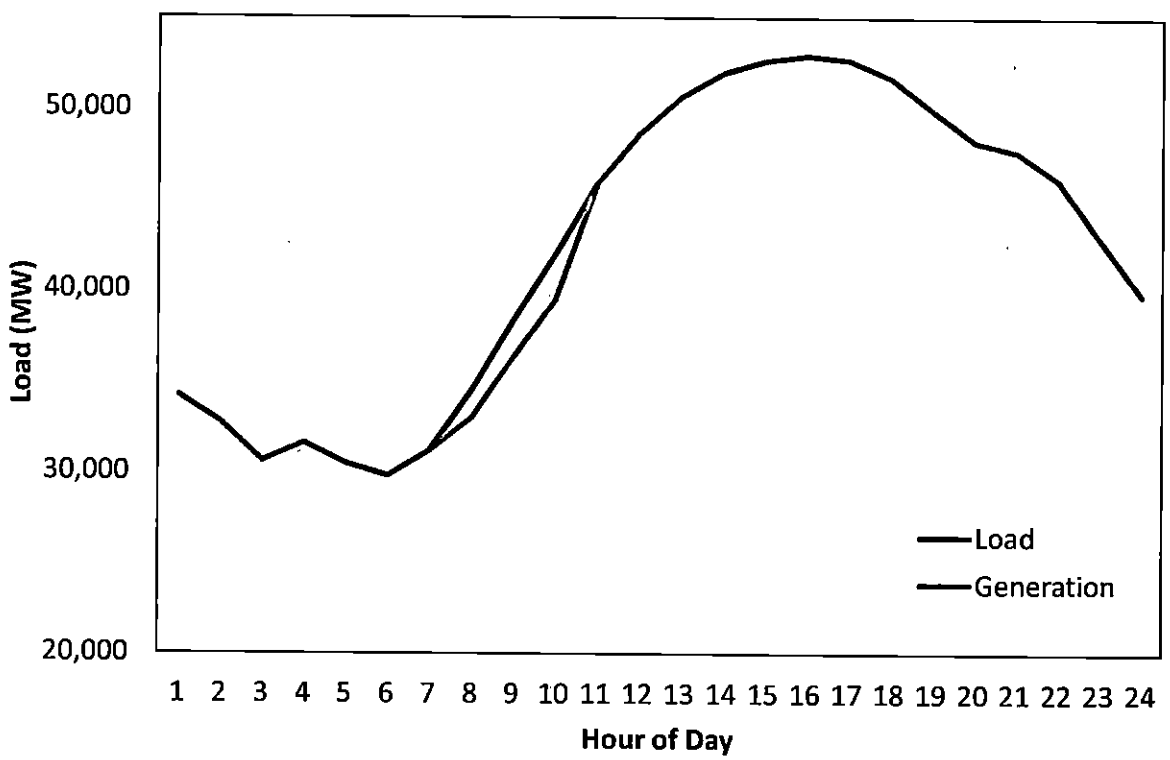
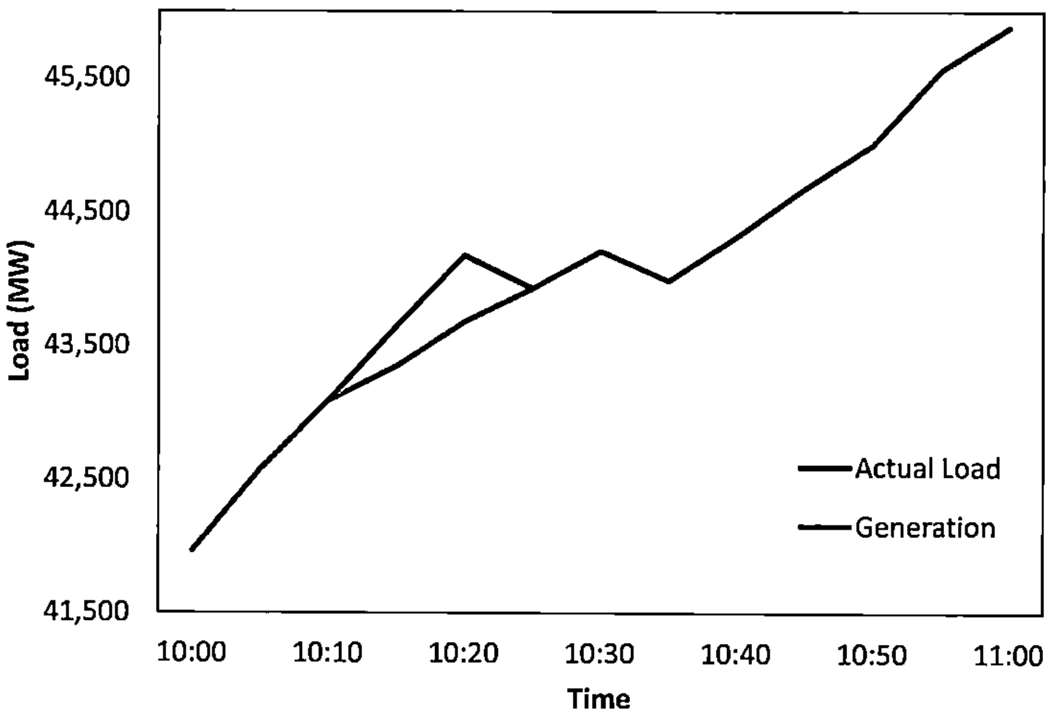


Figure 3. Intra Hour $LOLE_{FLEX}$



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. Since we differentiate LOLE events by cause, these will be referred to consistently as $LOLE_{CAP}$. 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. Reliability targets for operational reliability are covered by NERC Balancing Standards. The Control Performance Standards (CPS) dictate the responsibilities for balancing areas (BA) to maintain frequency targets by matching generation and load.

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. These violations are significantly more serious than what CPS1 and CPS2 measure but occur with much lower frequency. SERVM effectively only attempts to capture violations of system ramping when net load is significantly missed and not higher resolution real-time load following violations. While these events rarely occur, the operational reliability is impacted when additional solar is added requiring additional ancillary services to return back to the operational reliability that existed before the solar was added. 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 systems with current loads and resources were calibrated to produce $LOLE_{FLEX}$ of 0.1 events per year.

For each renewable penetration level analyzed, changes were made to the level of ancillary services targeted to keep $LOLE_{FLEX}$ events at the 0.1 events per year threshold achieved in the base case with no solar. With more capacity available in ancillary services to ramp up, the unexpected drops in solar output are not as likely to create reliability events. However, this change in operating cost has an impact on system costs. Comparing the total production costs assuming the same ancillary services targets used before the solar was added to production costs calculated using higher ancillary services, which brings

$LOLE_{FLEX}$ back to 0.1, reflects the ancillary service cost impact of the additional solar capacity on the system.

The more solar resources that are added, the more challenging and more expensive carrying additional ancillary services becomes. In hours with significant solar output, the burden of carrying significant ancillary services requires shutting down cost-effective baseload resources and instead cycling more expensive peaking units. In some hours, all conventional generation is dispatched near their minimum generation level in order to provide the targeted operating reserves, and yet the total generation is still above the load. This situation results in solar curtailment. Solar curtailment may not harm reliability, but it adds expense to system costs since generation is produced but not used. At high penetrations, the percentage of incremental solar that is curtailed is significant. Ultimately, the incremental costs of carrying additional ancillary services is assigned to the incremental solar as an ancillary service cost impact.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the Solar Ancillary Service Study. The majority of inputs are consistent with the Solar Capacity Value Study that Astrapé previously completed for DEC and DEP in 2018 with the exception of two major inputs:

(1) The model was simulated on 5-minute time intervals versus hourly intervals to capture the flexibility requirements of the system given imperfect knowledge around load, solar, and generating units. Simulating at 5-minute intervals requires additional information on generating resources and volatility distributions on load and solar as discussed in the following sections.

(2) The utilities are modeled as islands for the Ancillary Service Study. For Resource Adequacy and Solar Capacity Value studies, neighbor assistance capacity plays a significant role in the results. Weather diversity and generator outage diversity are benefits that are always available to DEC and DEP regardless of the type of capacity neighboring regions build. Also, it is required to capture this assistance to achieve a 0.1 $LOLE_{CAP}$. To achieve close to a 0.1 $LOLE_{CAP}$ in this study, additional purchases at costs above a gas CT were included in both DEC and DEP systems. However, for understanding the flexibility of the system, it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements. In addition, the additional load following and ancillary service cost impacts are based on a Base Case and solar change case to determine the incremental impact of solar on the DEC and DEP systems. If neighboring systems were modeled and included in both the Base and solar cases, it is expected that the incremental load following and costs would be similar to the values found in this study.

A. Load Forecasts and Load Shapes

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs and behind the meter solar for 2020 for both DEC and DEP.

Table 1. 2020 Peak Load Forecast

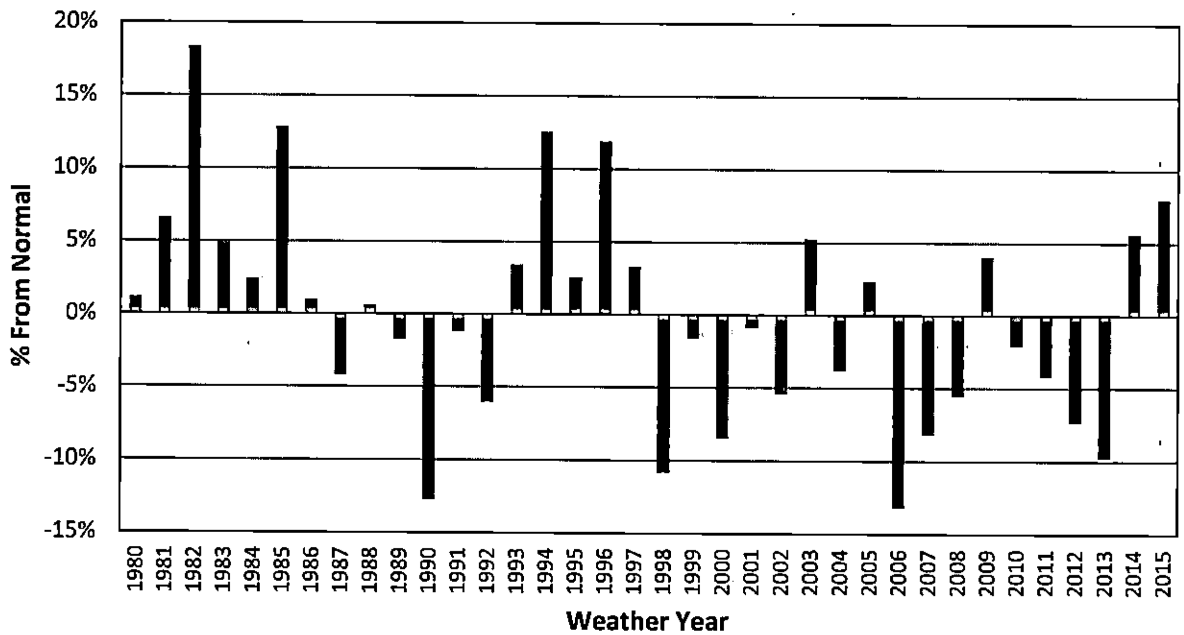
	DEC	DEP East	DEP West	Coincident DEP
2020 Summer	18,260 MW	12,503 MW	828 MW	13,289 MW
2020 Winter	17,924 MW	12,866 MW	1,128 MW	13,946 MW

To model the effects of weather uncertainty, 36 historical weather years (1980 - 2015) were developed to reflect the impact of weather on load. These were the same 36 load shapes used in the 2016 Resource Adequacy Study. Based on historical weather and load, a neural network program was used to develop relationships between weather observations and load. Different weather to load relationships were built for each month. These relationships were then applied to the last 36 years of weather to develop 36 load shapes for 2020. Equal probabilities were given to each of the 36 load shapes in the simulation. The load shapes were scaled to align the normal summer and winter peaks to the Company's projected load forecast for 2020. Thus the "normal" summer peak reflects an average of the summer peak demands from the 36 load shapes. Similarly, the "normal" winter peak reflects an average of the winter peak demands from the 36 load shapes.

Figures 4 to 7 below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for each company. The y-axis represents the percentage deviation from the average peak. For example, a simulation using the 1985 DEC load shape would result in a summer peak load approximately 4.7% below normal and a winter peak load approximately 12.9% above normal. Thus, the bars represent the variance in projected peak loads for

2020 based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. Extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation. Based on the neural net modeling, the figures show that DEC and DEP summer peak loads can be almost 8% higher than the forecast due to weather alone, while winter peak can be about 18% higher than the forecast for DEC and more than 20% higher than the forecast for DEP in an extreme year.

Figure 4. DEC Winter Peak Weather Variability



Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

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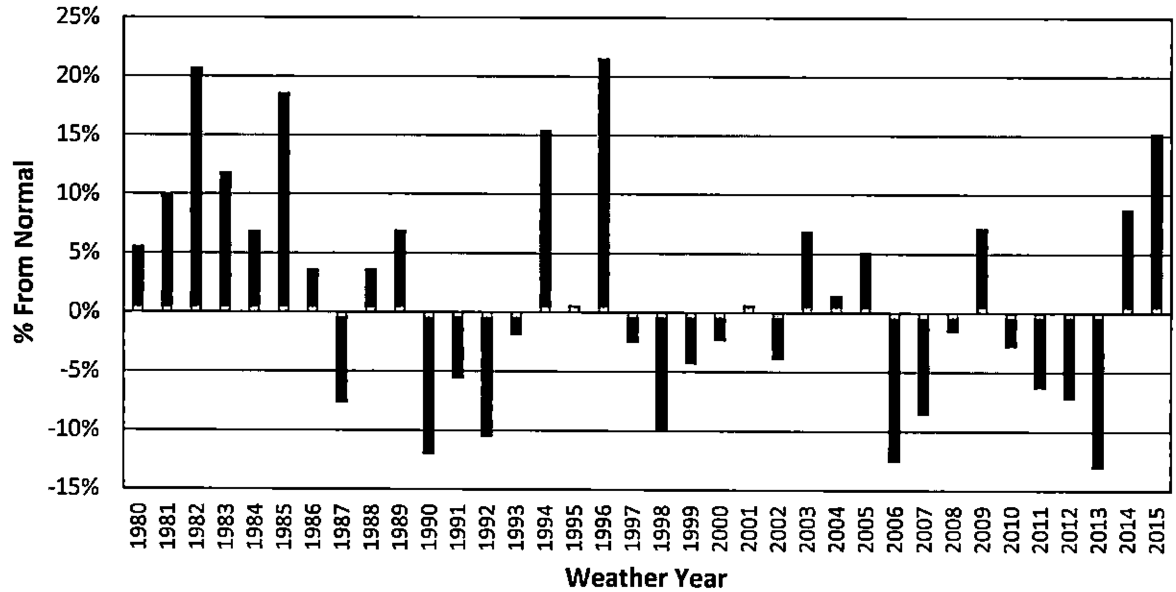
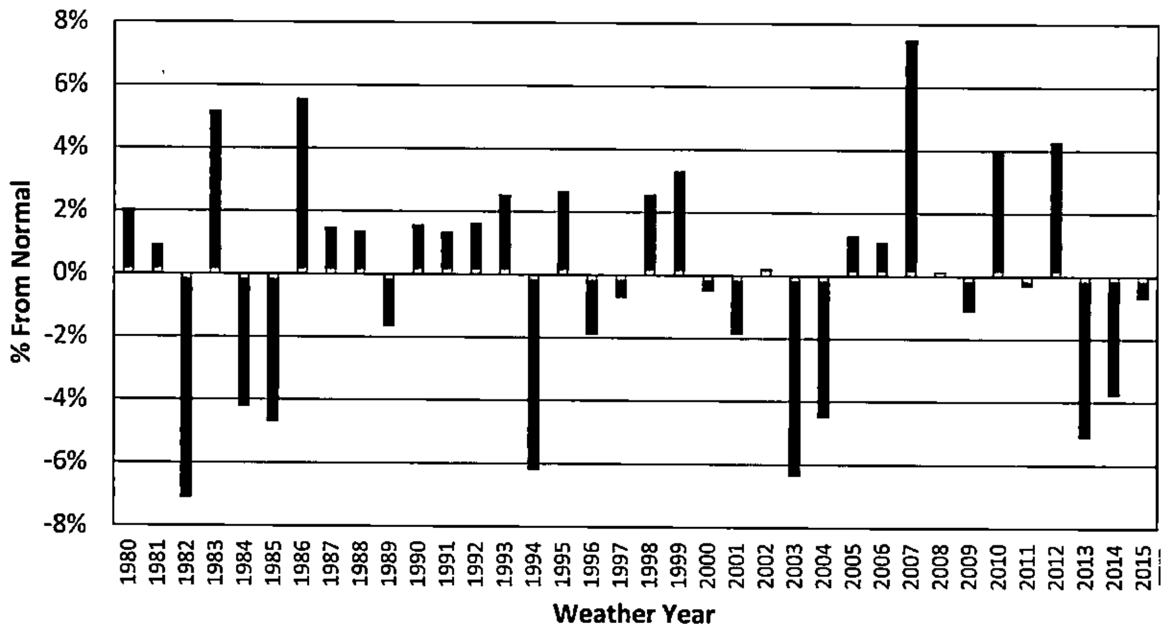
Figure 5. DEP Winter Peak Weather Variability



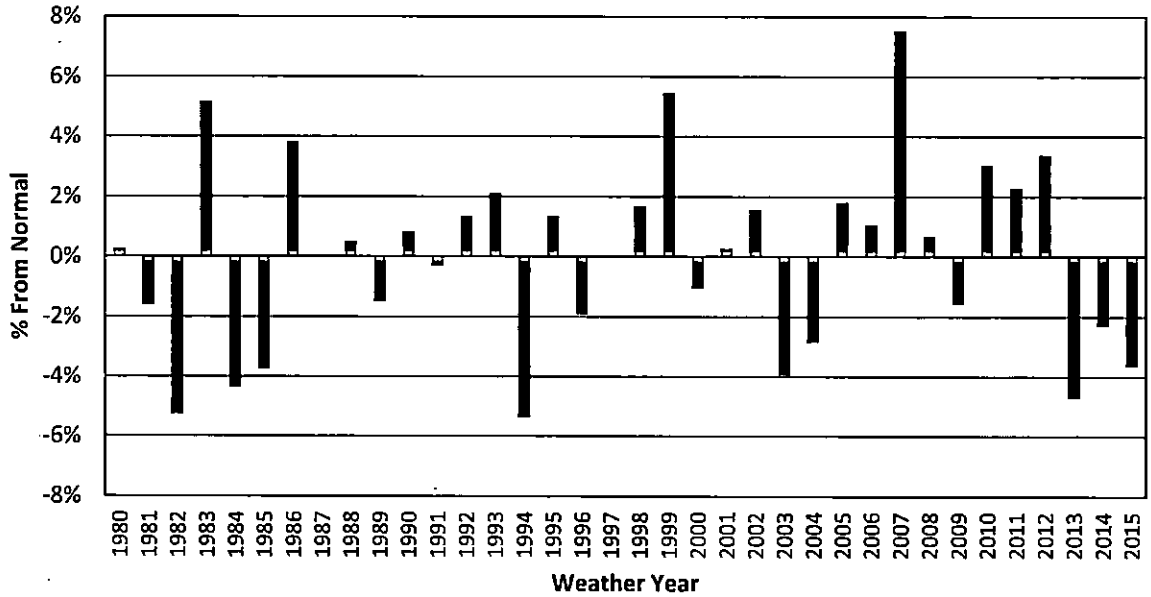
Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Figure 6. DEC Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the highest temperature occurred. Therefore, the loads are not always in the same order as the max temperature ranking.

Figure 7. DEP Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their three year-ahead load forecasts. Three to five years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) GDP forecasts three years ahead and actual data was fit to a normal distribution. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 2 shows the economic load forecast multipliers and associated probabilities. As an illustration, 7.9% of the time, it is expected that load will be under-forecasted by 4%. Within the simulations, when DEC under-forecasts load, the external regions also under-forecast load. The SERVM model utilized each of the 36 weather years and applied each of these five load forecast error points to create 180 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability (%)
0.96	7.9%
0.98	24.0%
1.00	36.3%
1.02	24.0%
1.04	7.9%

B. Solar Shape Modeling

Table 3 lays out the solar capacity levels that were analyzed in the study along with the inverter loading ratios (ILR) assumed. The solar penetration scenarios included existing plus transition and tranche 1 requirements under NC HB 589, and an additional scenario with an incremental 1,500 MW of solar to assess a high penetration scenario. Note however that the existing plus transition and tranche 1 scenarios discussed in this study include all utility scale requirements under NC HB 589 that were assumed at the time the study was initiated (CPRE, large customer programs and community solar). The existing and transition capacity includes 840 MW in DEC and 2,950 MW in DEP. As discussed earlier, loads were already reduced for behind the meter solar. The tranches of solar analyzed assumed 75% of the capacity was fixed-tilt and 25% was single-axis-tracking capacity, all with a 1.40 inverter loading ratio.

Table 3. Solar Capacity Penetration Levels

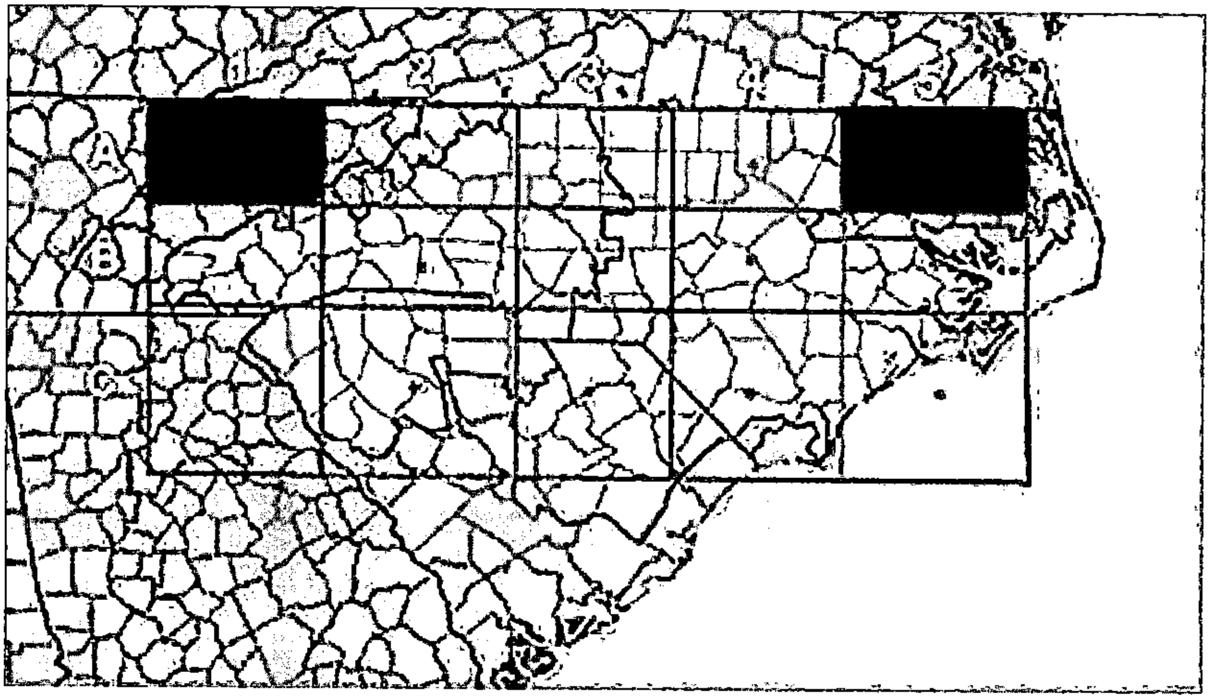
	DEC MW	DEP MW
Existing	679	1,923
Transition	161	1,027
Existing Plus Transition	840	2,950

Type	Technology	Inverter Loading Ratio	DEC MW	DEP MW
Existing: Utility Owned	Fixed-Tilt	1.40	130	154
Existing: Standard PURPA	Fixed-Tilt	1.30	549	1,769
Transition	Fixed-Tilt	1.43	121	770
Transition	Single-Axis Tracking	1.30	40	257
Total Existing Plus Transition			**840**	**2,950**

Tranche	Technology	Inverter Loading Ratio	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
Tranche 1	75% fixed/25% Tracking	1.40	680	1,520	160	3,110
+1,500 MW	75% fixed/25% Tracking	1.40	1,500	3,020	1,500	4,610

Fixed and tracking solar profiles for the 36 weather years were developed in detail for each grid as shown in Figure 8.

Figure 8. Solar Profile Locations



Data was downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer using the 13 latitude and longitude locations, detailed in Table 4, for the available years 1998 through 2015. Solar shapes were developed for the 1980 - 1997 time frame by matching the closest peak load day from the two periods (1980 - 1997, 1998 - 2015) and using the same daily solar profile that was developed from the NREL dataset. An additional five solar shapes were calculated as variations of the "Actual Closest" peak load day to create additional variability among the solar shapes. The shapes were calculated by sorting the peak loads for the proper day (actual day +/- 1 day) in ascending order and offsetting the closest daily load shapes by choosing the days that most closely matched the load profiles plus or minus 1 or 2 days.

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Table 4. Locations for Solar Profiles

Description	Latitude	Longitude
A2	36.13	-81.70
A3	36.17	-80.02
A4	36.09	-78.62
B1	35.33	-83.34
B2	35.41	-81.70
B3	35.41	-80.10
B4	35.45	-78.66
B5	35.41	-76.86
C1	34.57	-83.46
C2	34.53	-81.74
C3	34.49	-80.18
C4	34.45	-78.66
C5	34.57	-76.90

The solar capacity for DEP and DEC were modeled across the 13 location grid as shown in Tables 5 and 6.

Table 5. DEP Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1 and additional 1,500 MW of solar
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.40	1.30	1.43	1.30	1.40
Capacity MW	154	1,769	770	257	160 - 635
Location Breakdown %					
A2	0%	0%	0%	0%	0%
A3	0%	1%	1%	1%	1%
A4	20%	23%	14%	14%	14%
B1	0%	1%	1%	1%	1%
B2	0%	0%	0%	0%	0%
B3	7%	9%	7%	7%	7%
B4	14%	26%	8%	8%	8%
B5	11%	8%	9%	9%	9%
C1	0%	0%	0%	0%	0%
C2	0%	0%	1%	1%	1%
C3	23%	6%	35%	35%	35%
C4	23%	23%	21%	21%	21%
C5	1%	3%	2%	2%	2%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Table 6. DEC Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1 and additional 1,500 MW of solar
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.40	1.30	1.43	1.30	1.40
Capacity MW	130	549	121	40	680 - 2,660

Location Breakdown %

A2	15%	7%	3%	3%	3%
A3	6%	22%	22%	22%	22%
A4	0%	9%	2%	2%	2%
B1	0%	0%	0%	0%	0%
B2	47%	33%	12%	12%	12%
B3	6%	16%	26%	26%	26%
B4	0%	1%	1%	1%	1%
B5	0%	0%	0%	0%	0%
C1	0%	1%	0%	0%	0%
C2	0%	7%	27%	27%	27%
C3	25%	2%	5%	5%	5%
C4	0%	1%	1%	1%	1%
C5	0%	0%	0%	0%	0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Figures 9 and 10 show the January average daily solar profiles from 1980 to 2015 for tracking and fixed technologies, respectively. The tracking files have more output in the earlier and later hours than the fixed profile which ultimately provides additional capacity value as shown in the results.

Figure 9. January Daily Tracking Solar Profile

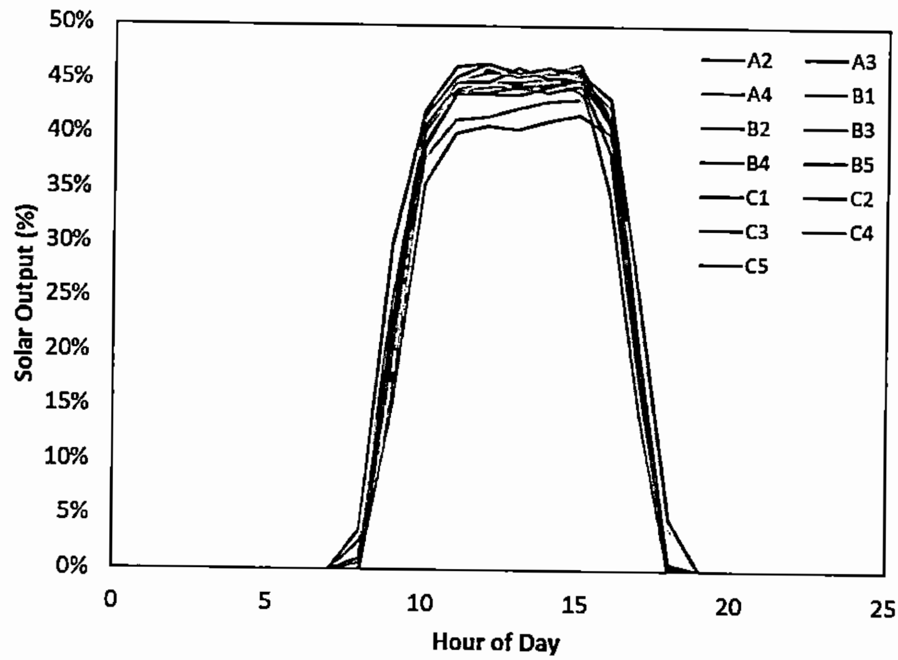
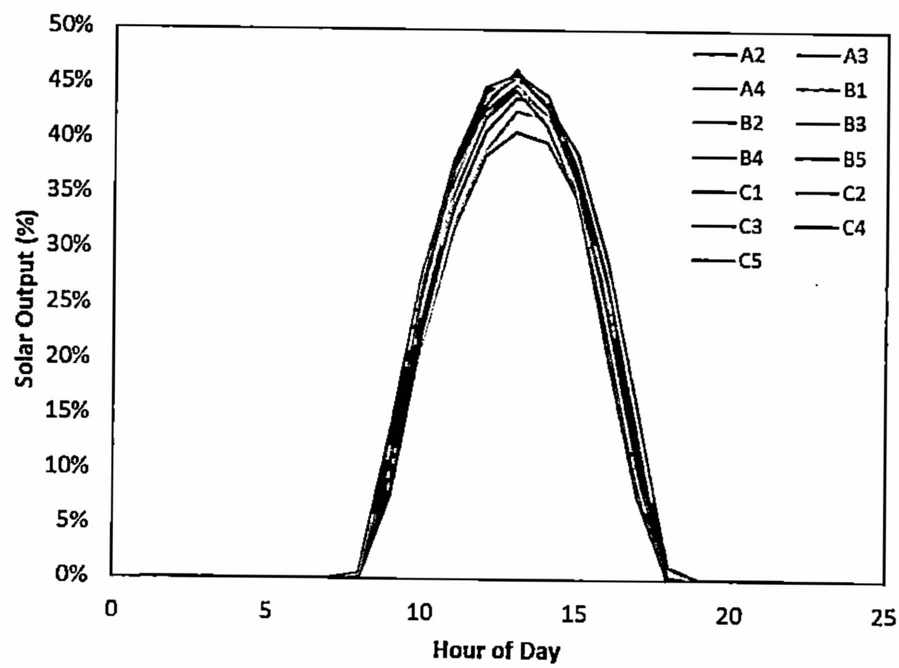


Figure 10. January Daily Fixed Solar Profile



Figures 11 and 12 show the August average daily solar profiles from 1980 to 2015 for tracking and fixed technologies, respectively.

Figure 11. August Daily Tracking Solar Profile

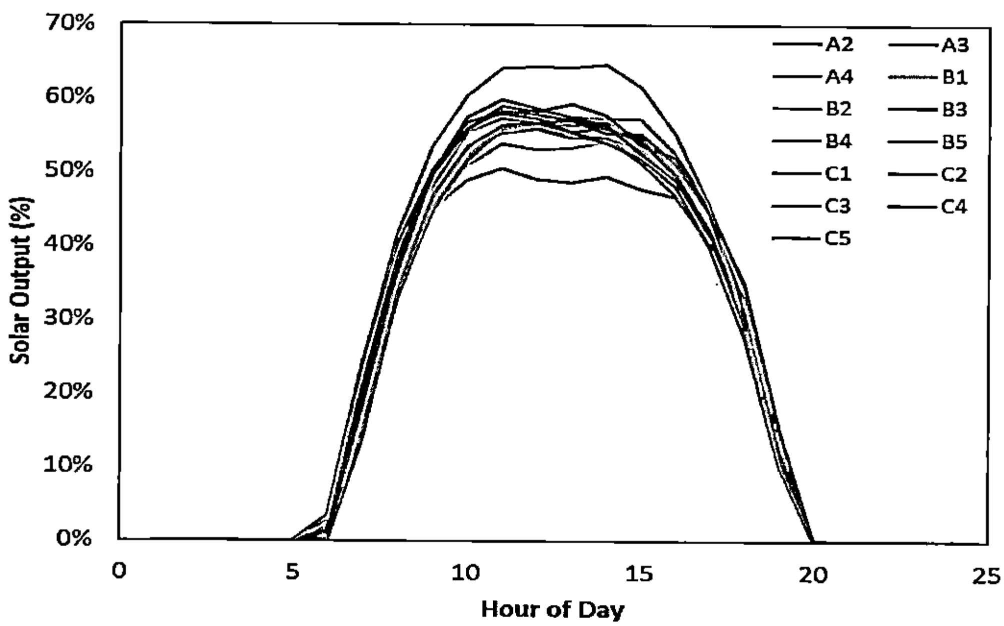
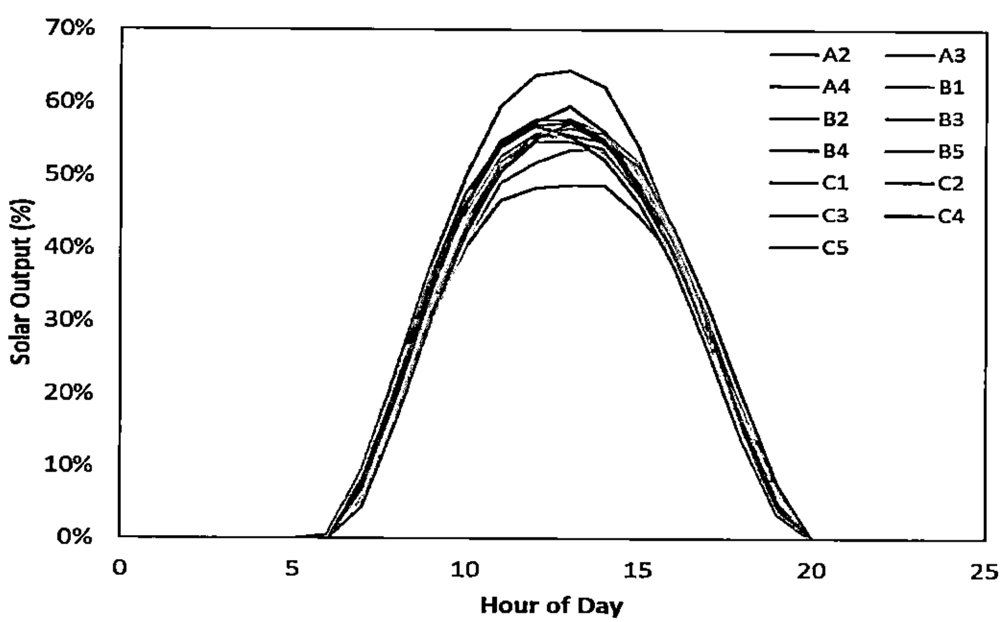


Figure 12. August Daily Fixed Solar Profile



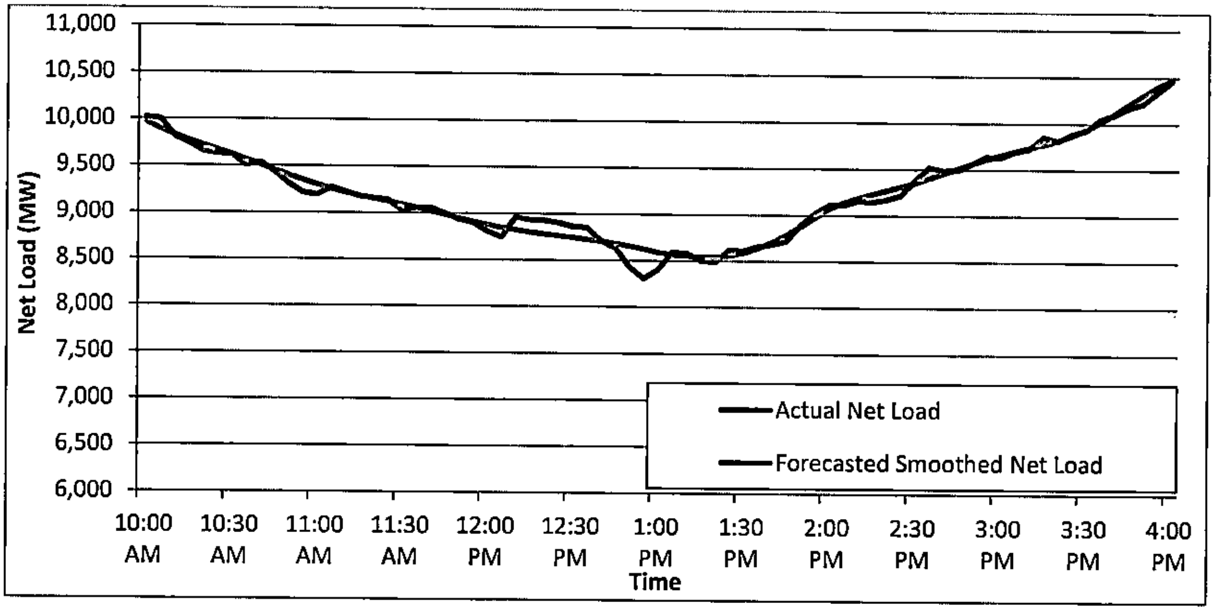
C. Load and Solar Volatility

For purposes of understanding the economic and reliability impacts of net load uncertainty, SERVM captures the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history which may include ramping units suddenly or starting quick start units.

Intra-Hour Forecast Error and Volatility

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.

Figure 13. Volatile Net Load vs. Smoothed Net Load



The five-minute data used to develop intra-hour load volatility was developed from actual data ranging from October 2016 - September 2017. The intra-hour distribution for load for both companies is shown in Tables 7, 8, and 9. The 5-minute variability in load is quite low ranging mostly between +/-2% on a normalized basis. If no intermittent resources were on the system, this would be the net load volatility seen on the system.

Table 7. DEC Load Volatility

Normalized Divergence (%)	Probability (%)
-2.2	0.000
-2	0.007
-1.8	0.007
-1.6	0.007
-1.4	0.016
-1.2	0.058
-1	0.205
-0.8	0.624
-0.6	1.578
-0.4	6.886
-0.2	42.055
0	39.243
0.2	6.500
0.4	1.590
0.6	0.591
0.8	0.361
1	0.170
1.2	0.066
1.4	0.009
1.6	0.003
1.8	0.001
2	0.024
2.2	0.000

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Table 8. DEP East Load Volatility

Normalized Divergence (%)	Probability (%)
-2.2	0.000
-2	0.016
-1.8	0.001
-1.6	0.004
-1.4	0.010
-1.2	0.033
-1	0.200
-0.8	0.709
-0.6	2.504
-0.4	12.605
-0.2	38.955
0	26.894
0.2	12.606
0.4	3.896
0.6	0.977
0.8	0.346
1	0.158
1.2	0.046
1.4	0.017
1.6	0.003
1.8	0.003
2	0.019
2.2	0.000

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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	0.008
-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	0.008
2.2	0.001
2.4	0.000
2.6	0.002
2.8	0.005
3	0.000

The variability of solar is much higher ranging from +/-13% with the majority of the movements ranging between +/-4%. 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, 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. The following tables show each for both DEC and DEP.

Table 10. DEC Base Solar Volatility

		Normalized Output (%)									
		0	10	20	30	40	50	60	70	80	90
Normalized Divergence (%)	-13					0.0			0.0		
	-12				0.0	0.0	0.1				
	-11			0.0	0.0	0.0	0.1	0.1		0.0	
	-10			0.0	0.0	0.2	0.2	0.1	0.0	0.0	
	-9			0.0	0.1	0.3	0.2	0.2	0.2	0.0	
	-8		0.0	0.1	0.2	0.4	0.3	0.3	0.3	0.0	
	-7		0.0	0.2	0.3	0.5	0.8	0.5	0.5	0.1	
	-6		0.1	0.3	0.6	0.7	1.3	1.0	1.0	0.3	0.1
	-5		0.3	0.5	1.4	1.3	2.0	1.8	2.1	0.6	0.2
	-4		0.7	1.5	2.0	2.6	3.5	2.7	3.6	1.6	0.3
	-3	0.1	2.5	3.8	4.2	5.0	5.3	5.5	5.9	3.7	1.5
	-2	0.5	9.2	12.2	13.7	10.9	11.3	9.8	11.4	10.3	6.4
	-1	16.0	39.6	29.5	27.2	25.8	24.4	28.1	26.6	35.6	42.0
	0	82.8	35.9	31.7	28.2	28.3	25.5	28.8	25.1	32.5	41.2
	1	0.5	8.9	13.7	12.5	13.2	11.3	10.2	9.6	7.6	5.2
	2	0.1	2.3	3.8	5.2	5.2	5.8	4.6	5.2	3.8	2.0
	3		0.4	1.7	2.0	2.4	3.4	3.0	3.2	1.8	0.7
	4		0.0	0.6	1.4	1.3	1.5	1.3	2.0	1.1	0.2
	5			0.2	0.4	0.9	1.0	1.0	1.4	0.4	0.1
	6			0.0	0.3	0.3	1.1	0.5	0.9	0.3	0.0
	7				0.1	0.3	0.5	0.4	0.4	0.1	
	8				0.0	0.2	0.3	0.1	0.3	0.1	
	9				0.1	0.1	0.1	0.1	0.1	0.0	
	10				0.0	0.1	0.1	0.1	0.1	0.0	
	11				0.0	0.0	0.0	0.0	0.1		
	12								0.0	0.0	
	13				0.0			0.0	0.0		0.0

Table 11. DEC Base Solar Volatility

Normalized Divergence (%)	Probability (%)
-13	0.002
-12	0.004
-11	0.010
-10	0.021
-9	0.041
-8	0.073
-7	0.118
-6	0.225
-5	0.442
-4	0.812
-3	1.692
-2	4.531
-1	22.247
0	61.977
1	4.326
2	1.698
3	0.811
4	0.414
5	0.234
6	0.146
7	0.079
8	0.044
9	0.022
10	0.017
11	0.007
12	0.003
13	0.004
14	0.000

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Table 12. DEC 75% Solar Volatility

Normalized Divergence (%)	Normalized Output (%)									
	0	10	20	30	40	50	60	70	80	90
-13										
-12				0.0						
-11						0.0				
-10			0.0		0.1	0.1	0.0	0.0		
-9				0.0	0.1	0.2	0.1	0.0		
-8			0.1	0.0	0.1	0.2	0.2	0.1	0.1	
-7		0.0	0.1	0.2	0.5	0.6	0.5	0.3	0.0	
-6		0.1	0.2	0.7	0.5	1.1	0.9	0.8	0.1	
-5		0.2	0.6	0.8	1.4	1.6	1.5	1.5	0.4	0.1
-4		0.6	1.2	2.3	2.4	3.5	3.1	3.8	1.2	0.4
-3	0.0	2.5	4.9	4.9	5.3	6.5	5.4	6.7	3.9	0.7
-2	0.5	10.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6.1
-1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	0.6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10.9	[illegible]	9.2	5.3
2	0.0	1.4	4.9	5.9	6.3	6.8	5.8	6.0	3.7	1.7
3		0.1	1.2	2.6	3.1	3.1	2.8	3.2	1.6	0.3
4			0.3	0.8	1.0	1.9	1.7	1.9	0.4	0.1
5			0.0	0.4	0.5	1.4	1.0	1.0	0.6	0.0
6			0.1	0.1	0.3	0.5	0.4	0.3	0.1	
7				0.1	0.1	0.2	0.2	0.3	0.1	
8				0.0	0.1	0.1	0.1	0.1		
9						0.0	0.0	0.1	0.0	
10				0.0				0.1		
11							0.0			
12							0.0			0.0
13										

Table 13. DEC 75% Solar Volatility

Normalized Divergence (%)	Probability (%)
-13	0.000
-12	0.002
-11	0.001
-10	0.008
-9	0.015
-8	0.032
-7	0.097
-6	0.181
-5	0.343
-4	0.803
-3	1.827
-2	5.071
-1	21.689
0	61.506
1	5.085
2	1.845
3	0.772
4	0.352
5	0.210
6	0.082
7	0.045
8	0.018
9	0.010
10	0.004
11	0.001
12	0.002
13	0.000
14	0.000

Table 14. DEP Base Solar Volatility

Normalized Divergence (%)	Normalized Output (%) 0	10	20	30	40	50	60	70	80	90
-13										
-12								0.0		
-11					0.0	0.0				
-10		0.0				0.0	0.0		0.0	
-9				0.0	0.0	0.0	0.1	0.0	0.0	
-8		0.0			0.0	0.1	0.1	0.2	0.0	
-7		0.0	0.0	0.1	0.1	0.2	0.4	0.4	0.1	0.0
-6			0.1	0.1	0.3	0.6	0.7	0.8	0.2	
-5		0.1	0.2	0.3	0.7	1.0	1.6	1.4	0.7	0.1
-4		0.2	0.7	1.3	1.9	2.2	2.8	2.6	1.9	0.2
-3	0.0	0.8	2.1	3.8	4.2	4.5	6.0	4.7	4.3	1.4
-2	0.4	7.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5.5
-1	7.6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	0.3	8.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8.9	8.6	5.0
2	0.0	0.9	1.6	3.8	4.6	4.7	5.5	4.6	4.2	1.6
3		0.1	0.5	1.3	1.5	2.1	2.6	2.8	1.9	0.3
4		0.1	0.1	0.5	0.4	1.1	1.4	1.1	0.7	0.2
5		0.1	0.0	0.1	0.4	0.5	0.7	0.7	0.5	0.0
6		0.0	0.0	0.0	0.1	0.2	0.5	0.5	0.2	0.0
7			0.0		0.1	0.2	0.1	0.2	0.1	0.0
8		0.0	0.0		0.0	0.0	0.1	0.1	0.0	
9				0.0			0.1	0.0	0.0	
10						0.0				0.0
11							0.0	0.0		
12							0.0	0.0	0.0	
13										

Table 15. DEP Base Solar Volatility

Normalized Divergence (%)	Probability (%)
-13	0.000
-12	0.001
-11	0.002
-10	0.004
-9	0.009
-8	0.024
-7	0.063
-6	0.124
-5	0.278
-4	0.625
-3	1.427
-2	4.046
-1	18.396
0	68.435
1	4.003
2	1.427
3	0.598
4	0.257
5	0.142
6	0.076
7	0.035
8	0.017
9	0.007
10	0.002
11	0.002
12	0.003
13	0.000
14	0.000

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Table 16. DEP 75% Solar Volatility

Normalized Divergence (%)	Normalized Output (%): 0	10	20	30	40	50	60	70	80	90
-13										
-12										
-11										
-10										
-9		0.1	0.1	0.0	0.2	0.0		0.0		
-8			0.0		0.0	0.1	0.1	0.0	0.0	
-7		0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.0	
-6	0.0	0.1	0.1	0.1	0.2	0.4	0.6	0.3	0.1	
-5		0.1	0.3	0.3	0.7	1.0	1.4	1.3	0.4	0.1
-4	0.0	0.4	0.9	1.5	2.1	2.4	2.9	2.5	1.7	0.3
-3	0.1	1.7	3.4	5.3	6.0	5.8	6.7	6.2	4.9	1.0
-2	0.4	9.9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6.6
-1	7.9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	0.4	10.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6.3
2	0.1	1.5	2.9	4.8	5.6	5.9	6.9	6.0	4.7	1.3
3	0.0	0.2	0.7	1.6	1.6	2.3	2.8	2.4	1.4	0.5
4	0.0	0.1	0.2	0.4	0.6	0.9	1.2	1.3	0.8	0.0
5		0.0	0.0	0.1	0.2	0.4	0.4	0.4	0.2	0.0
6		0.0			0.1	0.1	0.3	0.2	0.1	
7			0.0	0.0	0.0		0.1	0.1	0.0	0.0
8		0.0	0.0			0.0	0.0	0.0	0.0	
9		0.0	0.1		0.1		0.0	0.1	0.0	
10										
11										
12										
13										

Table 17. DEP 75% Solar Volatility

Normalized Divergence (%)	Probability (%)
-13	0.000
-12	0.000
-11	0.000
-10	0.000
-9	0.021
-8	0.015
-7	0.033
-6	0.087
-5	0.256
-4	0.675
-3	1.860
-2	4.984
-1	17.112
0	66.992
1	5.137
2	1.803
3	0.612
4	0.258
5	0.079
6	0.040
7	0.016
8	0.006
9	0.015
10	0.000
11	0.000
12	0.000
13	0.000
14	0.000

D. Conventional Thermal Resources

Conventional thermal resources owned by the company and purchased as Purchase Power Agreements were modeled consistent with the 2020 study year. These resources are economically committed and dispatched to load on a 5-minute basis. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. Full winter rating is achieved at 35°F. SERVM dispatches resources on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve regulation, spinning, and load following reserves as long as the minimum capacity level is less than the maximum capacity.

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages

The actual schedule for 2019 was used.

To illustrate the outage logic, assume that the historical GADS data reported that a generator had 15 full outage events and 30 partial outage events. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data and their respective inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons based on history which contain Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter. Further, assume the generator is online in hour 1 of the simulation. 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. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. 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. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Planned maintenance events are modeled separately and dates are entered in the model representing a typical year.

E. Hydro and Pump Storage Modeling

The hydro portfolios in DEC and DEP are modeled in segments that include Run of River (ROR) and Scheduled (Peak Shaving). The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. By modeling the hydro resources in these two segments, the model captures the appropriate amount of capacity dispatched during peak periods. On average, the DEC hydro generates 400 to 600 MW during peak conditions while DEP generates approximately 200 MW during peak conditions.

In additional to conventional hydro, DEC owns and operates a Pumped-Storage fleet that includes expected upgrades to be made in the early 2020's. However, for purposes of this study, the upgrades were assumed to be in place for the study year in order to capture the operating benefits that the upgrades will provide. The total capacity included was 2,400 MW. (1) Bad Creek at a 1,620 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions. While the Pumped-Storage units have fast ramping capability, the range from minimum to maximum capacity is fairly low.

F. Demand Response Modeling

Demand Response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For 2020, DEC assumed 1,031 MW of Demand Response in the summer and 406 MW in the winter. DEP assumed 1,015 MW of summer capacity and 512 MW of winter capacity.

G. Study Topology

As discussed previously, the companies were modeled as islands for this analysis. By modeling in this manner, the required operating reserves and flexibility requirements are calculated for each Company. While resource adequacy assistance will always be available from neighbors due to weather diversity and generator outage diversity, the same is not true for flexibility needs. As surrounding neighbors also add intermittent resources, it is aggressive to assume that flexibility needs can also be met by surrounding neighbors. For this reason, this study focuses on the flexibility needs of each individual company as solar resources are added.

H. Ancillary Services

Ancillary service assumptions are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Table 18 shows the definition of ancillary service for each study. Spinning reserves and load following up reserves are identical and represent the sum of the 60-minute ramping capability of each unit on the system. To maintain operational reliability as solar resources are added, the load following up reserves are increased and compared to the Base Case level of load following required to meet $LOLE_{FLEX}$ of 0.1 events per year in the scenario without any solar. The load following up reserves represent an increase in 60-minute ramping capability of the fleet meaning that more resources are turned on so that they can be operated further away from their maximum capacity level allowing for more ramping capability.

Table 18. Ancillary Services

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	60 Min Product served by units who have minimum load less than maximum load
Load Following Down Reserves	60 Min Product served by units who have minimum load less than maximum load
Load Following Up Reserves	60 Min Product served by units who have minimum load less than maximum load
Quick Start Reserves Requirement	Served by units who are offline and have quick start capability

I. Firm Load Shed Event

A firm load shed event is calculated by the model as any day where resources could not meet load even after utilizing neighbor assistance and Demand Response programs. Regulating reserves of 216 MW in DEC and 134 MW in DEP were always maintained.

III. Simulation Methodology

Since firm load shed events are high impact, low probability events, a large number of scenarios must be considered to accurately project these events. For this study, SERVM utilized 36 years of historical weather and load shapes, 5 points of economic load growth forecast error, 6 differing solar shape patterns, and 20 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. 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. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This set of cases was simulated for each of the solar penetration levels in Table 19.

Table 19. Solar Penetration Levels

	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Additional 1,500 MW of Solar	1,500	3,020	1,500	4,610

For each case, and ultimately each iteration, SERVM commits and dispatches resources to meet load and ancillary service requirements on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around load and renewable output is gained. Ultimately, SERVM forces the system to react to these uncertainties while maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, Loss of Load Expectation (LOLE) is calculated and the model splits LOLE into two categories: (1) $LOLE_{CAP}$ and (2) $LOLE_{FLEX}$.

Other key metrics recorded for each iteration are (3) renewable curtailment and (4) total costs.

(3) Renewable curtailment: Renewable curtailment occurs during over-generation periods when the system cannot ramp down fast enough to meet net load.

(4) Total Costs: Fuel Costs + O&M Costs + Startup Costs

These reliability and cost components are calculated for each of the 21,600 iterations and weighted based on probability to calculate an expected total cost for each study simulated. As the systems are simulated from 0 MW of solar to several thousand MWs of solar, the net load volatility increases causing $LOLE_{FLEX}$ to increase. In 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.

IV. DEC Results

The following table shows the results of the DEC modeling over several solar penetration levels. As solar increases, net load volatility increases causing $LOLE_{FLEX}$ to increase. To reduce $LOLE_{FLEX}$, additional load following is added as an input into the model. SERVM now commits to a higher load following target which causes an increase in costs and an increase of periods when generation is greater than load causing additional renewable curtailment. The results show that as solar increases from 0 MW to 840 MW, 26 MW of additional load following is required to maintain the same $LOLE_{FLEX}$ that was seen in the 0 MW solar scenario. The increase in load following also increases renewable curtailment slightly by

3,268 MWh. The costs of the 26 MW of load following spread out over the incremental 840 MW of solar generation is $1.10 /MWh. As tranche 1 is added to the analysis, which includes an additional 680 MW, 67 MW of additional load following is required compared to the 0 MW solar case. The ancillary service cost impact of the incremental tranche 1 solar is $1.67/MWh while the total average of the "existing plus transition" solar plus tranche 1 solar is $1.37/MWh. Finally, an additional 1,500 MW of solar was added to the DEC system to understand the impact on the current flexibility of the system. It was simulated assuming the actual historical volatility and the 75% volatility distributions to provide a range of required load following and ancillary service cost impacts. In this scenario, the curtailment begins to ramp up significantly as 243 MW of additional load following are required to manage the 3,020 MW of solar on the system. Assuming the Base volatility distribution, the load following required is 634 MW. The average ancillary service cost impact of these two scenarios is $2.90/MWh assuming the discounted volatility distribution and $9.75/MWh assuming the volatility distribution does not benefit from the diversity of additional projects. The incremental ancillary service cost impact for this last 1,500 MW becomes more expensive at $4.38/MWh assuming the discounted volatility distribution and $17.78/MWh if the Base volatility distribution is used. Renewable curtailment also begins to ramp up exponentially which is ultimately a component of the ancillary service cost impact since some of the additional solar is not utilized to serve load.

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Table 20. DEC Ancillary Service Study Results

	Solar Scenario				
	DEC No Solar	DEC Existing Plus Transition	DEC Tranche 1	DEC Add 1,500 MW 75%	DEC Add 1,500 MW
Incremental Solar MW	0	840	680	1,500	1,500
Total Solar MW MW	0	840	1,520	3,020	3,020
LOLE Flex Events Per Year	0.10	0.10	0.10	0.10	0.10
Average Ancillary Service Cost Impact $/MWh	0	1.10	1.37	2.90	9.75
Incremental Ancillary Service Cost Impact $/MWh	0	1.10	1.67	4.38	17.78
Total Load Following Addition MW	0	26	67	243	634
Additional Renewable Curtailment MWh	0	3,268	16,238	114,657	229,475
Renewable Generation MWh	0	1,556,350	2,949,446	6,022,045	6,022,045
% of Renewable Curtailed %	0	0.2%	0.6%	1.9%	3.8%
Solar Volatility Assumption	Base	Base	Base	75% Assumption	Base

*LOLE Cap was targeted at 0.1 events per year (1 day in 10-year standard)

Figures 14, 15, and 16 show the average ancillary service cost impact, load following additions, and additional renewable curtailment as a function of solar capacity. The charts are very similar across the different outputs as all metrics increase exponentially as more solar is added to the system. At the higher levels of solar, the impacts may be better mitigated by adding additional flexible generation rather than solely increasing load following reserves. The impact of adding additional flexible generation such as battery or fast start CT capacity was not analyzed as part of this study.

Figure 14. Average Ancillary Service Cost Impact

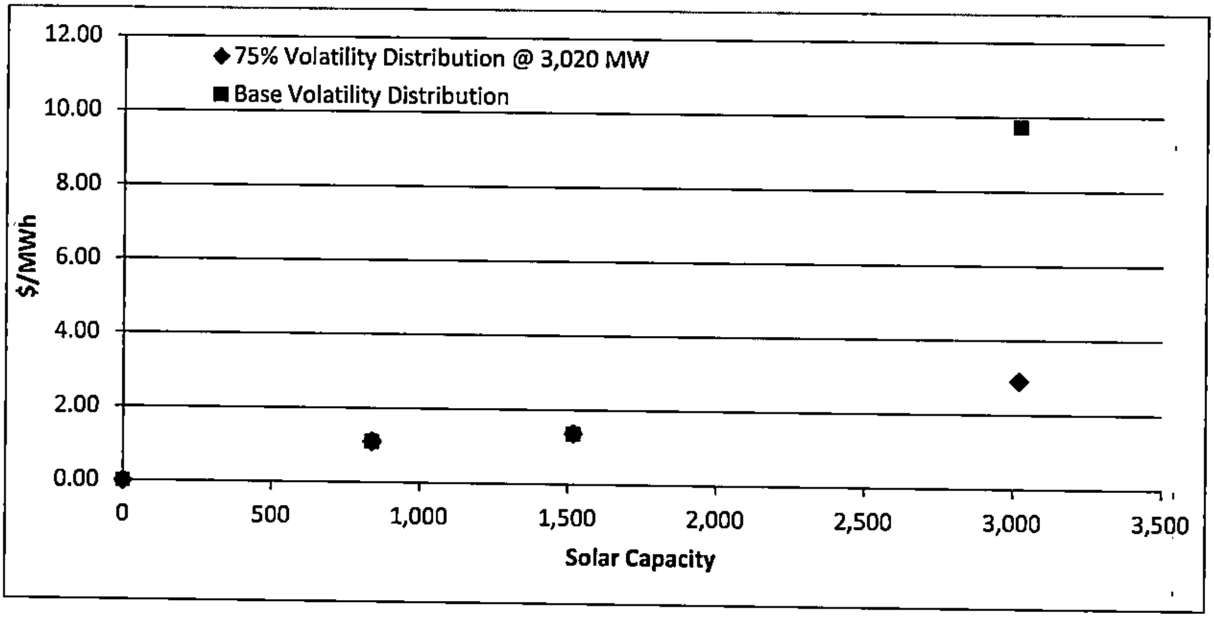


Figure 15. Incremental Load Following Requirements

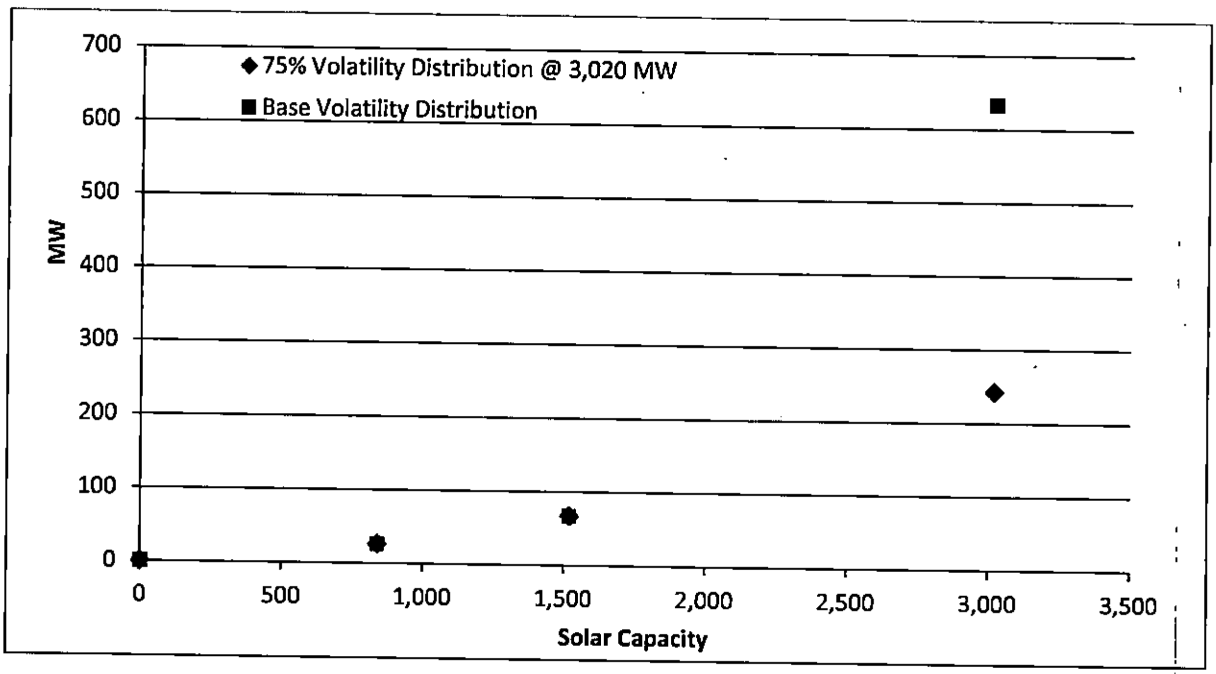
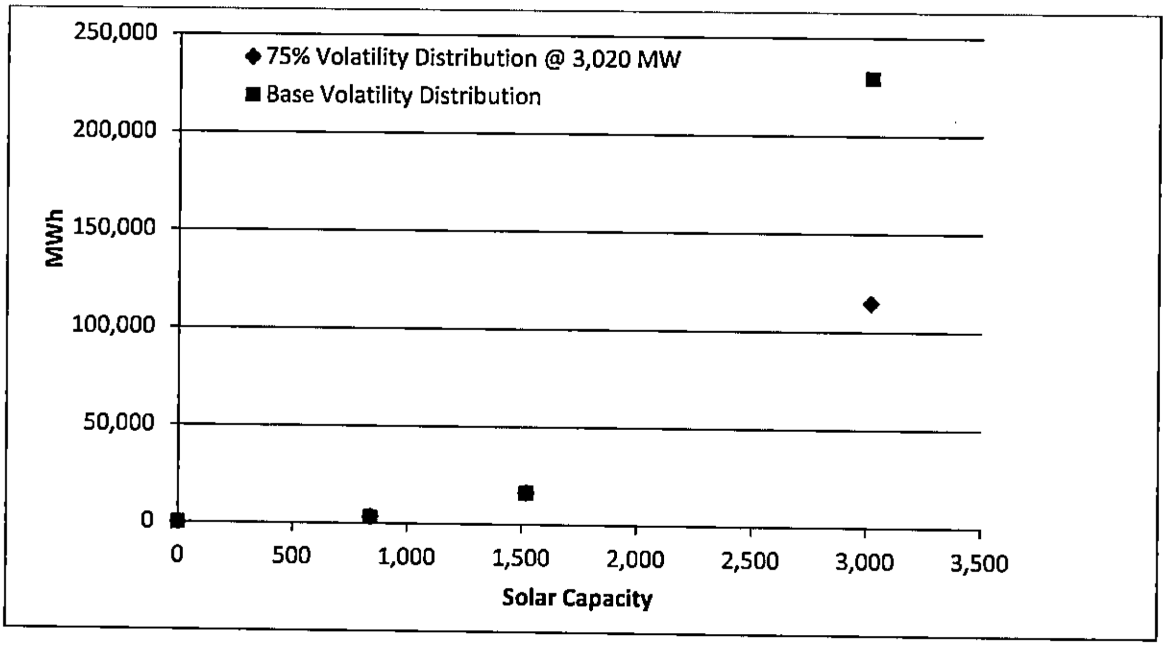


Figure 16. Incremental Renewable Curtailment



V. DEP Results

Similar to the DEC results, Table 21 shows the results of the DEP modeling. As solar increases from 0 MW to 2,950 MW, 166 MW of additional load following is required which increases renewable curtailment by approximately 189,000 MWh. The costs of the 166 MW of load following spread out over the incremental 2,950 MW of solar generation is $2.39 /MWh. As tranche 1 is added to the analysis which includes an additional 160 MW, 192 MW of additional load following is required. The ancillary service cost impact of the incremental tranche 1 solar is $6.80/MWh while the total average of "existing plus transition" solar plus tranche 1 solar is $2.64/MWh. Finally, an additional 1,500 MW of solar was added to the DEP system. Similar to the DEC analysis, it was simulated assuming the actual historical volatility and the 75% volatility distributions. In this scenario, the curtailment begins to ramp up significantly as 589 MW of additional load following are required to manage the 4,610 MW of solar on the system. Assuming the Base volatility distribution, the load following required is 832 MW. The average ancillary service cost impact of these 2 scenarios is \$9.72/MWh assuming the discounted volatility distribution and \$14.91/MWh assuming the volatility distribution does not benefit from the diversity of additional projects.

Table 21. DEP Ancillary Service Study Results

			Solar Scenario		
	DEP No Solar	DEP Existing Plus Transition	DEP Tranche 1	DEP Add 1,500 MW 75%	DEP Add 1,500 MW
Incremental Solar MW	0	2,950	160	1,500	1,500
Total Solar MW MW	0	2,950	3,110	4,610	4,610
LOLE Flex Events Per Year	0.107	0.10	0.10	0.10	0.10
Average Ancillary Service Cost Impact \$/MWh	0	2.39	2.64	9.72	14.91
Incremental Ancillary Service Cost Impact \$/MWh	0	2.39	6.80	23.24	38.34
Total Load Following Addition MW	0	166	192	589	832
Additional Renewable Curtailment MWh	0	188,827	246,582	1,428,797	1,921,068
Renewable Generation MWh	0	5,614,112	5,945,439	9,059,760	9,059,760
% of Renewable Curtailed %	0	3.36%	4.15%	15.77%	21.2%
Solar Volatility Assumption	Base	Base	Base	75% Assumption	Base

*LOLE Cap was targeted at 0.1 events per year (1 day in 10 year standard)

Figures 17 to 19 show the average ancillary service cost impact, additional load following requirements, and renewable curtailment as a function of solar output.

Figure 17. Average Ancillary Service Cost Impact

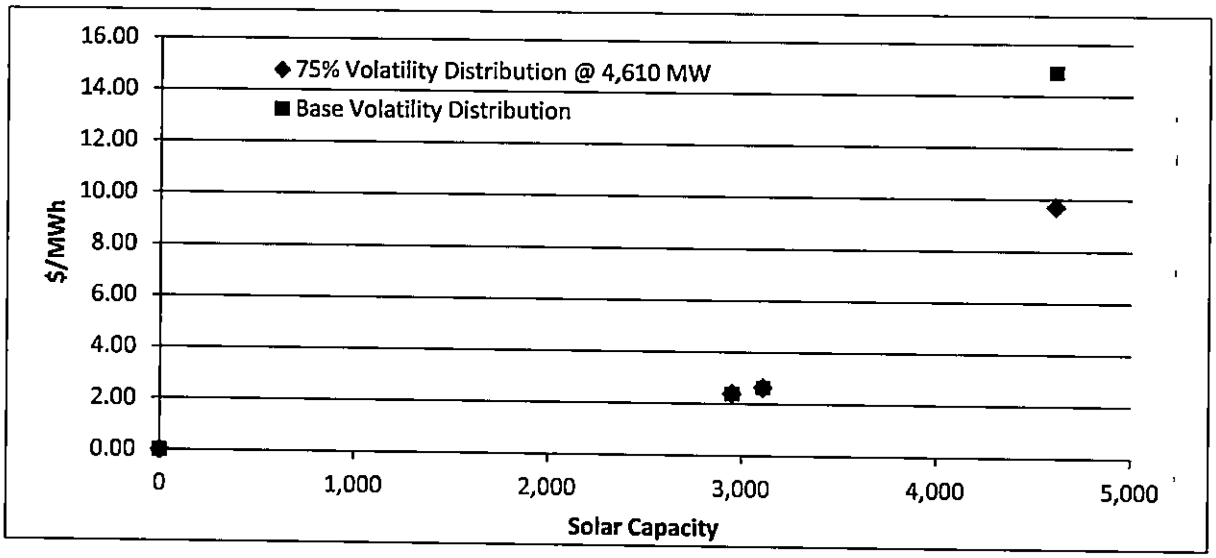


Figure 18. Incremental Load Following Requirements

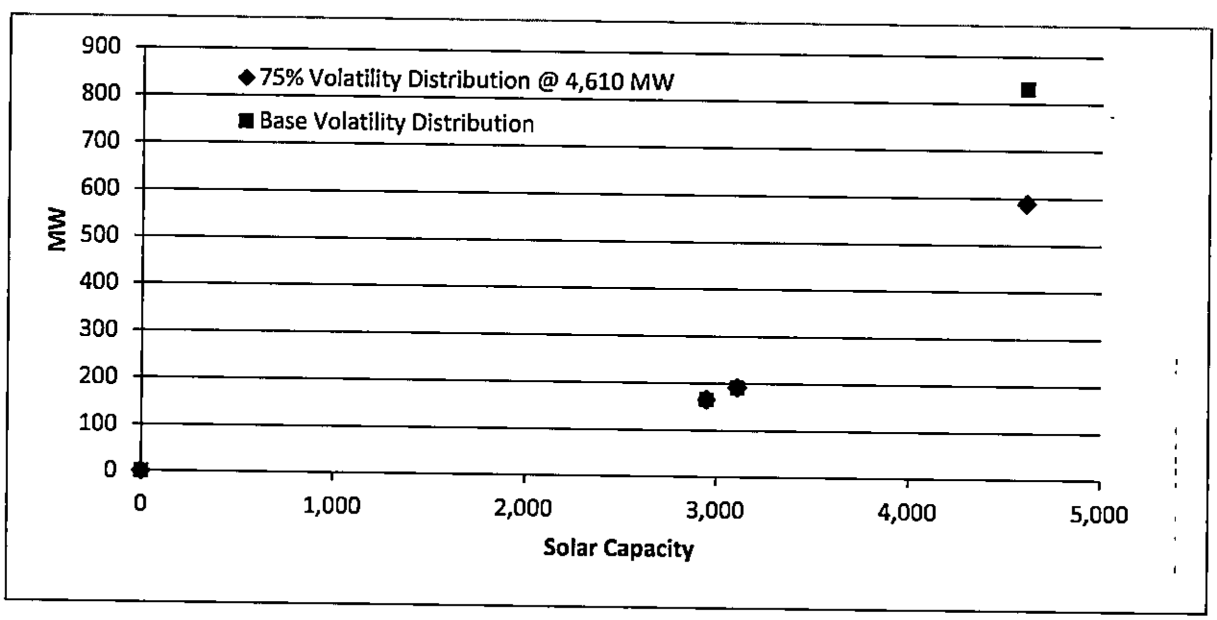
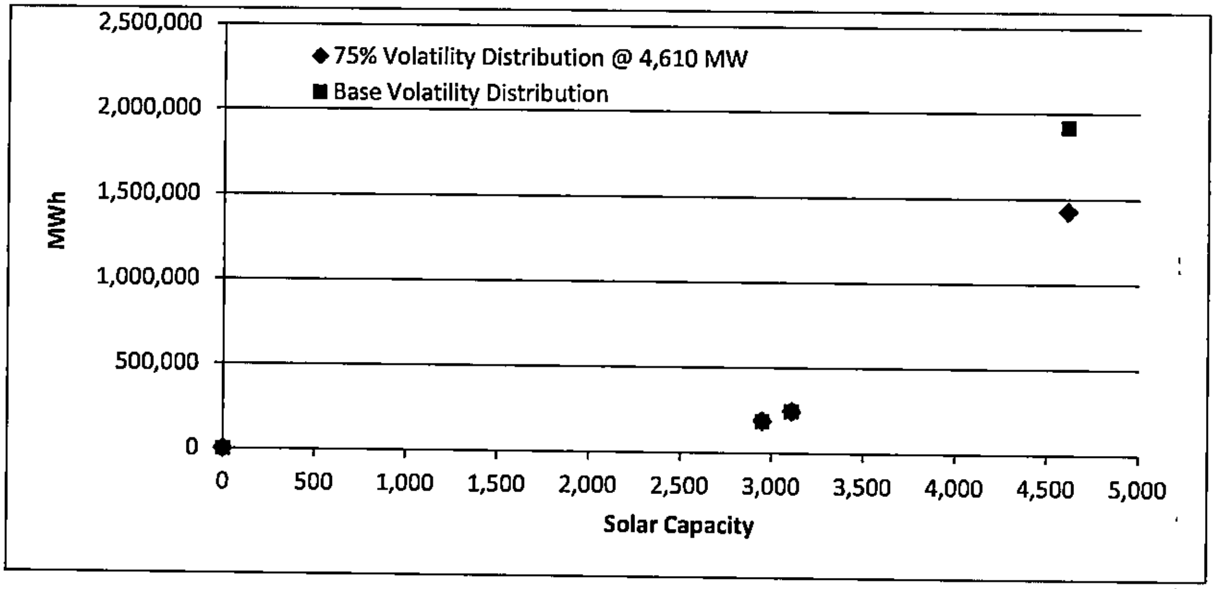


Figure 19. Renewable Curtailment



VI. Conclusions

The study results show the impact solar has on the DEC and DEP systems. As more solar is added, additional ancillary services are required to meet load in real time. This study simulated both the DEC and DEP systems to determine the amount of ancillary services that were needed to maintain the same level of reliability the system experienced before the solar was added. Then, the costs of the additional ancillary services were calculated to determine the ancillary service cost impact. The average ancillary service costs impact of existing plus transition blocks was $1.10 /MWh for DEC and $2.39/MWh for DEP with the major difference being that DEC has 840 MW of solar in this existing plus transition block compared to 2,950 MW for DEP. As penetration increases, the load following required, cost impact, and renewable curtailment all increase dramatically. The plus 1,500 MW case results are more uncertain than the existing plus transition and tranche 1 analyses because it is difficult to project intra-hour solar volatility for these higher penetration levels without historical data. While the study contemplated bookend intra-hour volatility distributions using the Base Case volatility distribution and 75% of the Base Case which assumes additional diversity, additional data over the coming years should be used to update these distributions and better project the ancillary service cost impact of higher solar penetrations.

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Jul 26 2019

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** **BAL-001-2**
3. **Purpose:** To control Interconnection frequency within defined limits.
4. **Applicability:**

4.1. Balancing Authority

4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

5.1. First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision
1	December 19, 2012	Adopted by NERC Board of Trustees	
2	August 15, 2013	Adopted by the NERC Board of Trustees	
2	April 16, 2015	FERC Order issued approving BAL-001-2	

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

$$CPS1 = (2 - CF) * 100\%$$

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.
A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{RACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum RACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10B}$$

And,

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

$$CF_{\text{clock-minute}} = \left[\left(\frac{RACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor (CF $_{\text{clock-hour}}$).

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF $_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF $_{\text{month}}$):

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

To calculate the 12-month compliance factor (CF $_{\text{12 month}}$):

$$\text{CF}_{\text{12-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$$

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where:

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)

$BAAL_{High}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as $F_S - 3\varepsilon 1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as $F_S + 3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

* FOR INFORMATIONAL PURPOSES ONLY *

Effective Date of Standard: BAL-001-2 — Real Power Balancing Control Performance

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
BAL-001-2	All	07/01/2016		

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