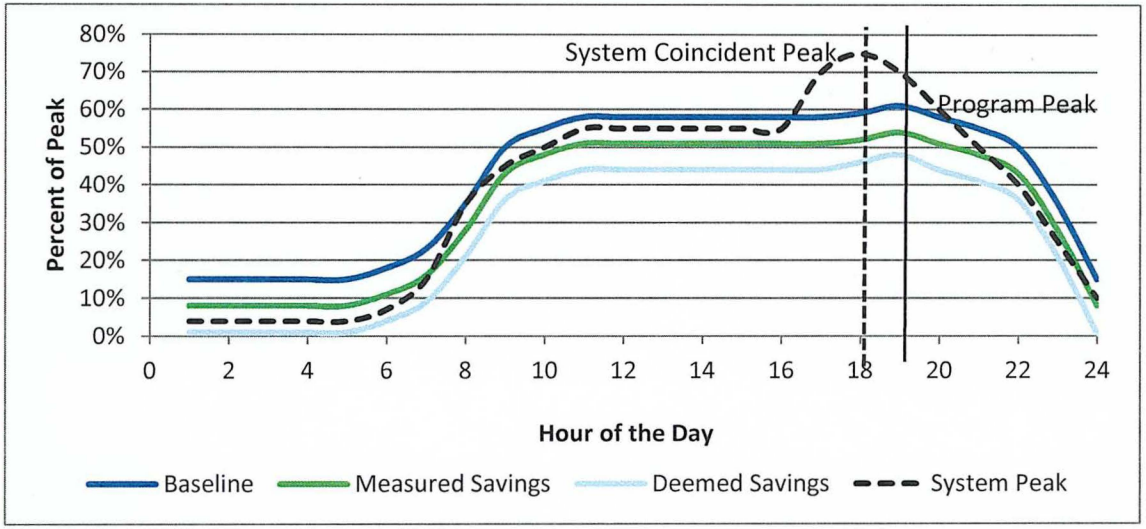
Illustrative Load Shape: Non-Residential Small Business Improvement Program



1. Baseline Estimation Approach (Dark blue line): The baseline load shape will be computed based on pre-retrofit capacity data from the rebate application data, applying Equivalent Full Load Hours (EFLH) as metered from an on-site study of installed rebated measures from a representative sample of participants.
2. Deemed Savings Approach (Light blue line): Deemed savings values will be developed and incorporated into the DNV GL Energy Standard Tracking and Engineering Protocols (STEP) Manual for planning purposes.

Non-Residential Small Business Improvement Program	
	3. Measured Savings Approach (Green line): The wattage and hours of use data for each measure will be collected and metered through an on-site study of installed efficiency measures from a representative sample of participants.
Deemed Savings Approach	Refer to the Non-Residential Small Business Improvement Program section of the STEP Manual for the standard deemed savings approaches for the measures in this program.
EM&V Measurement, Timeline and Scope of Work	• Analysis of program tracking data; Annual Report (May 1 of each year following program launch). • Annual updates to STEP Manual for updates that occurred to its referenced sources. • Develop baseline, measure savings, and efficient load shapes. • Provide regulatory support as necessary.
Document Revision History	Version 7.0 • New version
	Version 8.0 • Updated "April 1" report date to "May 1" in "EM&V Measurement, Timeline, and Scope of Work" section
	Version 9.0 • Formatting updates • Updated from DNV GL Energy to DNV GL Energy Insights

APPENDIX N. NON-RESIDENTIAL PRESCRIPTIVE PROGRAM EM&V PLAN (VERSION 9.0)

Non-Residential Prescriptive Program	
Program Summary	In the Non-residential Prescriptive program, qualifying customers are eligible to pursue one or more of the qualified energy efficiency measures through a local, participating contractor in Dominion's contractor network. To qualify for this program, the customer must be responsible for the electric bill and must be the owner of the facility or reasonably able to secure permission to complete the measures. This program is part of demand side management (DSM) Phase VI in Virginia and North Carolina.

Non-Residential Prescriptive Program	
Measures	Cooking • Commercial Convection Oven • Commercial Electric Combination Oven • Commercial Electric Fryer • Commercial Griddle • Commercial Hot Food Holding Cabinet • Commercial Steam Cooker HVAC • Duct Testing & Sealing • Unitary/Split AC & HP Tune-up • Variable Speed Drives on Kitchen Fan Plug Load • Smart Strip Refrigeration • Door Closer • Door Gasket • Evaporator Fan Control • Floating Head Pressure Control • Refrigeration Night Cover • Refrigeration Coil Cleaning • Suction Pipe Insulation • Strip Curtain • Vending Machine Miser • Commercial Freezers and Refrigerators – Solid Door • Ice Maker Low/No-Sweat Door Film
EM&V Method	International Performance Measurement and Verification Protocol (IPMVP) Option A: For physically accessible equipment measures, an EM&V method like IPMVP Option A is applied. IPMVP Option A is a partially-measured retrofit isolation study that measures the selected parameters leading to the change in energy and demand of an installed efficiency measure from a representative sample of participants, and adjusts the savings estimates derived from

engineering algorithms applied to the Company's program participation data. IPMVP Option A shall be applied to a sample of all implemented measures

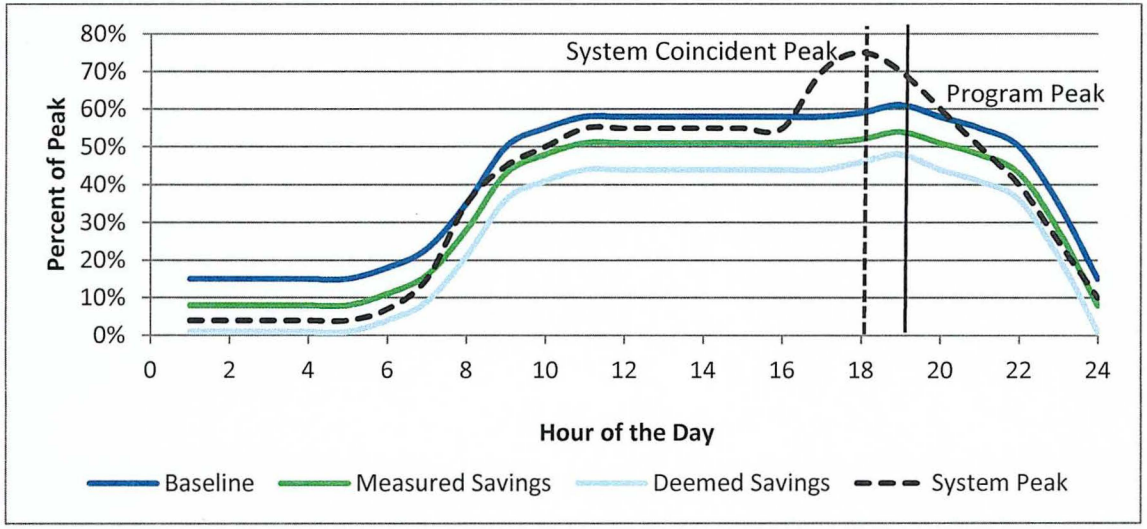
For all measures, the evaluation will select a sample for on-site verification. Savings will be based on the DNV GL Energy STEP Manual deemed values with adjustments to key inputs that can be verified while on-site. The ratio of the weighted, measured, and verified savings to the weighted deemed savings, also called a realization rate,[11] is then applied to the population of participants to estimate program savings. This approach will capture Company-specific customer usage data, which will be applied to the actual measures installed to quantify energy and peak demand savings.

The following figure illustrates the various components used to arrive at the savings estimates.

[11] The "realization rate" is the proportion of assumed or estimated energy and peak demand savings that is actually realized by a customer or project. It is expressed as a percentage, and is derived from follow-up research (on-site inspections or customer surveys) to verify that measures were in fact installed and are operating as intended, and/or actions were taken.

Non-Residential Prescriptive Program

Illustrative Load Shape: Non-Residential Prescriptive Program



1. Baseline Estimation Approach (Dark blue line): The baseline load shape will be computed based on pre-retrofit capacity data from the rebate application data, applying Equivalent Full Load Hours (EFLH) as metered from an on-site study of installed rebated measures from a representative sample of participants.
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3. Measured Savings Approach (Green line): The wattage and hours of use data for each measure will be collected and metered through an on-site study of installed efficiency measures from a representative sample of participants.

Deemed Savings Approach	Refer to the Non-Residential Prescriptive Program section of the STEP Manual for the standard deemed savings approaches for the measures in this program.
EM&V Measurement, Timeline and Scope of Work	• Analysis of program tracking data; Annual Report (May 1 of each year following program launch). • Annual updates to STEP Manual for updates that occurred to its referenced sources. • Develop baseline, measure savings, and efficient load shapes. • Provide regulatory support as necessary.

Non-Residential Prescriptive Program	
Document Revision History	Version 8.0 • New version
	Version 9.0 • Formatting updates • Updated from DNV GL Energy to DNV GL Energy Insights

DNV·GL

RESIDENTIAL AC CYCLING PROGRAM

Appendix N-1

Impact Evaluation of 2018 Dispatch Events

Dominion Energy

Date: May 1, 2019

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1 EXECUTIVE SUMMARY

This report summarizes the load impacts of the 2018 Residential AC Cycling Program administered by Dominion Energy (the Company) in Virginia and North Carolina. The AC Cycling Program, marketed as Smart Cooling Rewards, began in 2010 as a resource to help the Company reduce summer peak demand.

Under the program, when AC cycling events are called, a radiofrequency (RF) paging signal is broadcast throughout the Company's service area. The signal is received by load curtailment switches installed on central air conditioners and heat pumps of participating residential customers. The dispatch of the RF signal to the load curtailment switch reduces the duty cycle of the registered AC units up to 50% during an event.

DNV GL conducts an evaluation of the AC Cycling Program on an annual basis. The objectives of the evaluation are to estimate the peak energy shaving impacts of each dispatch event and estimate the expected amount of peak kW delivered by the AC Cycling resource in different weather conditions and times of day, including The Company's summer peak planning conditions.

The ex post analysis provides estimates of the average kW impacts that occur during each event hour. The ex ante analysis uses the results of the ex post analysis to forecast kW impacts by hour, temperature, and humidity conditions.

The evaluated load impact for weather conditions observed during Dominion Energy's peak day conditions in 2018 was 0.63 kW per participant

Ex post impacts over the 2018 event season ranged from 0.33 kW to 0.73 kW per participant under varying weather conditions. The ex ante analysis yielded a program impact of 0.63 kW per participant for The Company's planned peak conditions.[1]

Cycling events can be called from June 1 through September 30 on non-holiday weekdays, and last 2-4 hours between 2:00 p.m. and 6:00 p.m. In 2018, the AC Cycling Program called a similar number of events as 2017, but controlled fewer total hours. The biggest difference between 2017 and 2018 is the number of 2-hour events that were called. In 2017, two out of 29 events were called for 2 hours; in 2018, five of 27 events were called for 2 hours.

[1] Peak conditions correspond with an 83.4 temperature-humidity index at hour ending 17. This is equivalent to a temperature of 95°F and a relatively humidity of 43%.

2 INTRODUCTION

Peak load reduction estimates for peak shaving programs are important, both for The Company's internal stakeholders, its DSM portfolio, and for registration with PJM when applicable. When the AC Cycling Program was launched in 2010, the estimated impacts were based on a statistical regression model of consumption data from other utilities in the region. Since 2011, the modeled impact estimates have used site-level interval data including the connected load of the unit, actual weather conditions during The Company's summer event season, and an adaptive 50% cycling strategy. In compliance with the order from the Virginia State Corporation Commission (the Commission), the impact evaluation transitioned from using consumption data from a random sample of participants with advanced metering infrastructure (AMI) to using consumption data from every AMI-enabled Residential AC Cycling Program participant.[2] In 2017 the evaluation was conducted with all 8,225 AMI-enabled program participants.

Comparing results of the 2018 evaluation with prior years is difficult without additional analysis. Although the relationships between temperature, humidity, and load reduction are strong, other factors drive load reduction. Long hot periods and/or stretches of consecutive event-days affect AC usage and response to events. Conversely, a single hot day in the midst of an otherwise cool period also produces different load reductions. Because load reduction is a function of both the amount of cooling demanded at the time of an event (i.e., potential load reduction) and the customer response (i.e., if the customer turns on a room AC), the complex relationship between load reduction, long-term temperature trends, and event call schedules is difficult to predict from event to event or season to season.

This report summarizes the event history between 2016 and 2018, reviews event participation in 2018, and presents the results of the ex post and ex ante impact analyses. Sample event-day plots, hourly ex post impact estimates, and modeled impacts for varying weather conditions and time of day are presented.

[2] Required as part of the Final Order, State Corporation Commission of Virginia, Case #PUE-2015-00089, April 19, 2016.

3 2018 AC CYCLING EVENTS AND PARTICIPATION

Under the program, AC cycling seasons are distinguished from year to year by the number of events, the number of controlled hours, and the number of controlled participants. This section provides a summary description of events, event hours, and controlled participants. Data from prior years are provided for context.

Table 3-1. Summary of 2018 Events

	2016	2017	2018
Number of events	24	29	27
Total controlled hours over 2018 events	79	96	75
Number events with partial population dispatched	3	8	1

3.1 Frequency

The AC Cycling program called 27 events during the summer of 2018. Four events were called in June, three in September, and the remaining 20 were spread evenly throughout July and August.

Compared to 2017, 2018 had a similar number of events, but substantially fewer event hours.

3.2 Participation

There were approximately 86,000 participant accounts and 90,000 controlled switches in the first event on June 18, 2018. Participation varied slightly from event to event. There was one event in 2018 where approximately 15% of participants were not included as part of a planned control strategy.

Table 3-2 shows the number of total and AMI-enabled participants by division. Although 2018 participation was lower than 2017, the relative proportion of AMI enabled participants has increased due to new AMI participants in Virginia and North Carolina.

Table 3-2. Total and AMI Participants by Division in 2018[3]

Division	Number of Total Participants by Division	Number of AMI Participants by Division
Eastern	35,688	124
Northwest	27,428	7,682
Central	19,469	333
North Carolina	3,157	86
Total	**85,742**	**8,225**

[3] Total and AMI participants in the first event on 18 June 2018

4 IMPACT ANALYSIS

The following sections present data sources, methodology, and ex post and ex ante results.

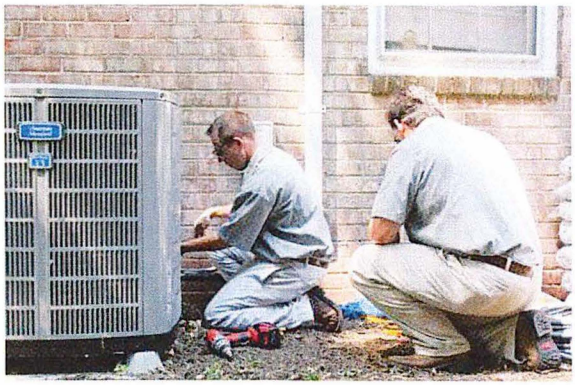
This ex post analysis estimates the kW impacts per participant achieved at the end of each event hour for the 27 events dispatched in 2018 (Section 5.2). It also reports what happened during the event. The ex ante analysis (Section 5.3) uses the results of the ex post analysis to forecast kW impacts by hour, temperature, and humidity conditions. For example, 0.63 kW is the estimated impact for The Company's peak planning conditions (Section 5.3, Table 5-2.).[4]

4.1 Data

Four sources of data are used in the impact analysis:

- Half-hourly AMI customer consumption data
- A record of controlled participants for each event
- Program tracking data
- Regional weather data[5]

Descriptions of the quality control (QC) procedures and results are provided in Section 7.



4.2 Methodology

The following steps are used to calculate the kW impact estimates for the program:

1. Half-hourly interval AMI consumption data for each participant are delivered to DNV GL monthly and subject to quality control (QC) tests.
2. AMI accounts are assigned weights based on the state, connected loads, and divisions of all participants to ensure that the AMI analysis is representative of the program population. The assigned weights and methods are included in Section 8 in Sub-Appendix II, Extrapolating the AMI-enabled Account Impacts to the Program Population.
3. AMI interval data are merged with the record of customers who participated in each event.
4. Using AMI data, event participation data, and weather data, regression analysis is used to calculate ex post impacts for each event hour. The results of the ex post analysis are provided in Section 5.2.
5. The ex ante estimates are then calculated using a regression analysis of the ex post impacts for each event-hour and temperature humidity index (THI).[6] Ex ante results are the expected impacts extrapolated to a particular hour and THI. For example, the ex ante analysis is the source of the program metric for program impacts at The Company's peak planning conditions of 95°F at 43% relative humidity at hour-ending 17 (THI 83.4). The ex ante results are provided in Section 5.3.

[4] Dominions Energy's peak planning condition is hour-ending 17 at 95°F at 43% RH, or 83.4 THI.

[5] National Oceanic and Atmospheric Association (NOAA), National Centers for Environmental Information, Local Climatological Data.

[6] THI is defined as follows: Temperature Humidity Index = THI = Td – (0.55 – 0.55*RH) * (Td – 58) where Td is dry bulb temperature and RH is relative humidity. Source: PJM Glossary: http://www.pjm.com/Glossary.aspx

5 RESULTS

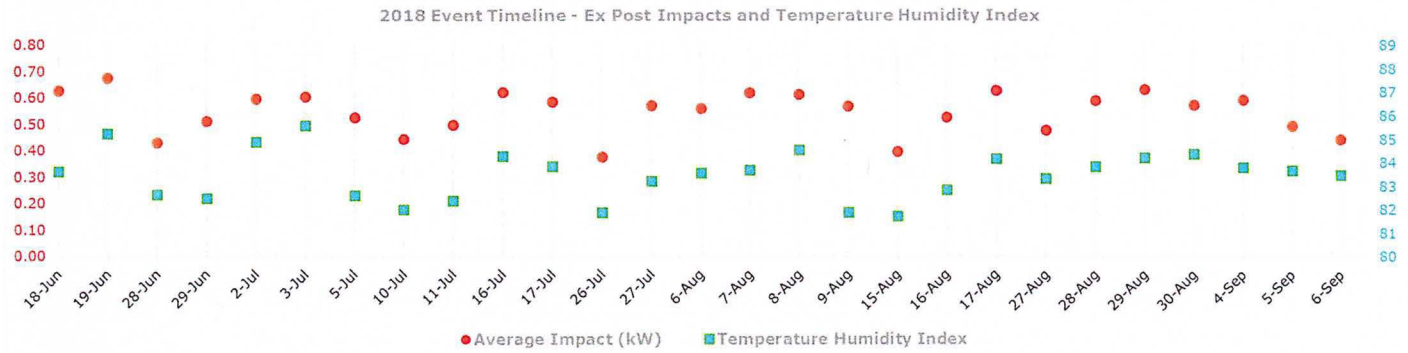
This section presents the results of the 2018 ex post and ex ante analyses. The presentation of the ex post analysis begins with a seasonal timeline showing the impacts and THI for each event (Figure 5-1), moves to event-level plots illustrating the event days with the highest and lowest impacts (Figure 5-2 and Figure 5-3), and ends with the ex post impacts calculated for each event hour (Table 5-1).

5.1 Ex Post Impacts

The 2018 timeline in Figure 5-1 shows the average impact (in kW) and THI for each event. For most events, the magnitude of the impacts moves with temperature and humidity. This suggests that event days could be called based on favorable weather conditions if impacts are the primary goal.

However, because load reduction is a function of both the amount of cooling demanded at the time of an event (i.e., potential load reduction) and the customer response (i.e., if the customer turns on a room AC), the complex relationship between load reduction, long-term temperature trends, and event call schedules is difficult to predict. Gaining insight into how these factors may have influenced 2018 impacts would require further analysis.

Figure 5-1.Timeline of 2018 Events with Impacts (Red) and THI (Blue)



5.1.1 Event-Day Plots

Figure 5-2 and Figure 5-3 on the next pages plot two events with the highest and lowest impacts, respectively. The plots are described briefly below.

The ex post estimate, or what happened during the event, is the difference between the adjusted baseline during the event (solid red line) and the pre- and post-event baseline (purple line). Impacts are calculated at the end of each event hour and referred to as "hour ending."

Results are illustrated in time-series representations of:

- ***Event-day load profile for the AC Cycling Program participant population (solid purple line).*** The beginning of events is clearly visible and are typically followed by a post-event load spike (snapback or rebound) before load resumes to non-event levels.
- ***Baseline during the event (solid red line)***. The solid red line plots the baseline for the event-day load curve during the event. The baseline is modeled from the non-event days.

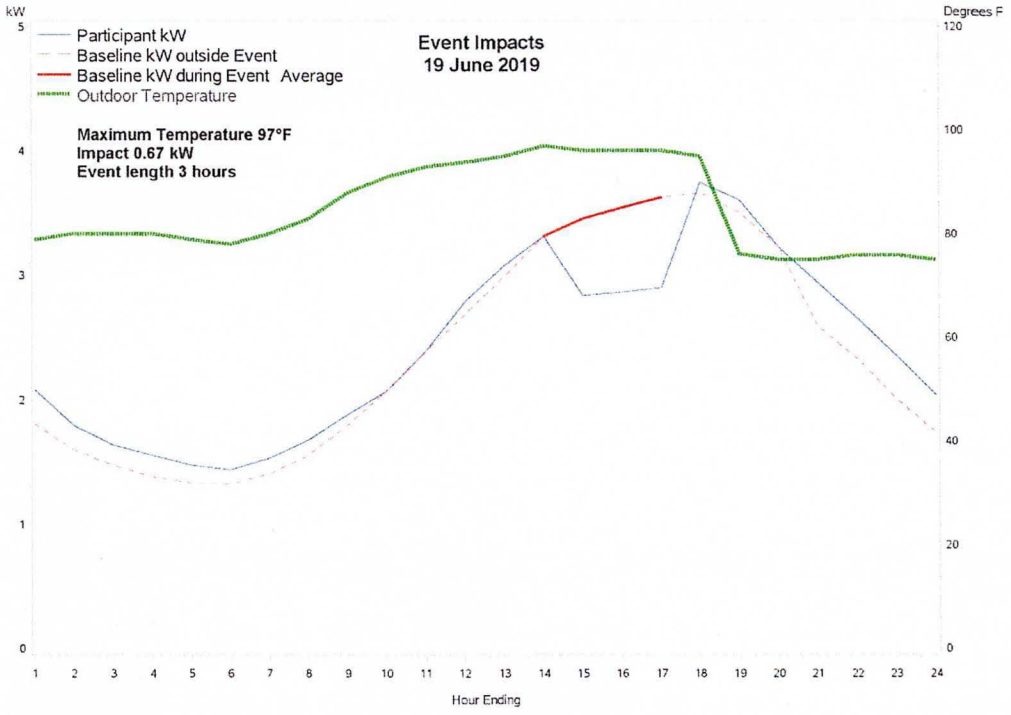
- ***Reference load outside the event (dashed red line).*** This line plots the baseline load profile before and after the event.
- ***Event-day temperature*** **(green line)**. Hourly temperatures are plotted to give context for the load curves.

Load Profile with High Impacts

The highest impact for 2018 occurred June 19, the event day with the second highest THI (85). The event was called at 14:00 with load reduction clearly visible at hours ending 15, 16, and 17 (Figure 5-2). The estimated average impact was 0.63 kW per participant.

The sudden drop in temperature occurring at hour ending 18 preceded thunderstorm activity and resulted in only a moderate load spike (or rebound), likely because cooling loads were reduced following the event.

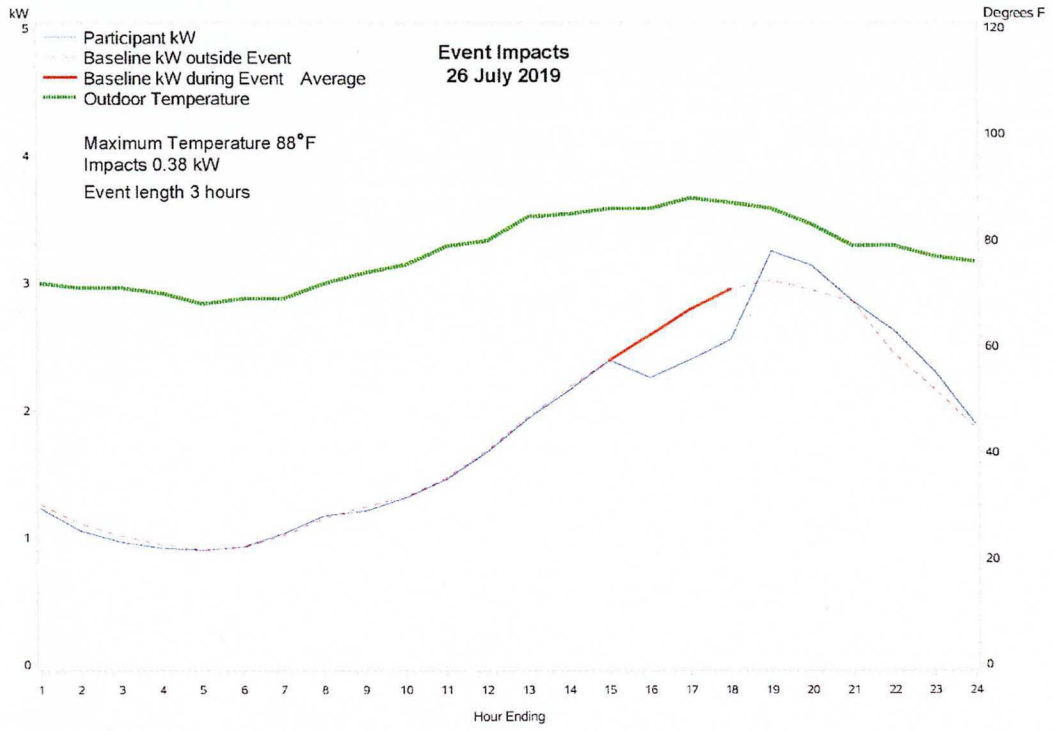
Figure 5-2. Load Profile for the Event Day with the Highest Impacts (June 19, 2018)



Load Profile with Low Impact

The lowest impact for 2018 occurred July 26, the event day with the lowest THI (82). The event was called at 15:00 with load reduction clearly visible at hours ending 16, 17, and 18 (Figure 5-3). The estimated average impact was 0.38 kW per participant.

Figure 5-3. Load Profile for the Event Day with the Lowest Impact (July 26, 2018).



5.2 Ex Post Impacts

Ex post impacts by day and hour are presented in Table 5-1. Also shown are the maximum THIs during the event, the opt-out percent, and a day number indicating the event's order in a series of consecutive events.

The average opt-out percent for 2018 was 0.04%. The highest number of opt-outs for any given event was 150 out of 88,000 participants. The maximum impact for a single interval in 2018 was 0.73 kW on June 19, the same event that is plotted in Figure 5-2. For comparison, the highest impact for a given interval in 2017 was 1.13 kW.

Table 5-1. AC Cycling Impacts by Event-Day and Hour (June 1 through July 27, 2018)

Event Date	18-Jun	19-Jun	28-Jun	29-Jun	2-Jul	3-Jul	5-Jul	10-Jul	11-Jul	16-Jul	17-Jul	26-Jul	27-Jul
Consecutive Event-days	1	2	1	2	1	2	1	1	2	1	2	1	2
Opt-out Percent	0.08%	0.17%	0.02%	0.05%	0.12%	0.05%	0.03%	0.004%	0.01%	0.01%	0.01%	0.01%	0.01%
THI	84	85	83	82	85	86	83	82	82	84	84	82	83
15:00		0.61									0.54		
16:00		0.68		0.48	0.45	0.56	0.52		0.52	0.51	0.63	0.33	0.49
17:00	0.59	0.73	0.43	0.51	0.66	0.64	0.53	0.47	0.55	0.66		0.40	0.61
18:00	0.68		0.43	0.54	0.68	0.62	0.53	0.42	0.43	0.70		0.39	0.61
19:00	0.61												
Average Impact (kW)	0.63	0.67	0.43	0.51	0.59	0.61	0.53	0.44	0.50	0.62	0.58	0.38	0.57

Table 5-1. AC Cycling Impacts by Event-Day and Hour (August 6 through August 30, 2018)

Event Date	6-Aug	7-Aug	8-Aug	9-Aug	15-Aug	16-Aug	17-Aug	27-Aug	28-Aug	29-Aug	30-Aug
Consecutive Event-days	1	2	3	4	1	2	3	1	2	3	4
Opt-out Percent	0.02%	0.02%	0.06%	0.04%	0.01%	0.01%	0.03%	0.02%	0.02%	0.04%	0.04%
THI	84	84	85	82	82	83	84	83	84	84	84
15:00							0.55				
16:00	0.59	0.58	0.62	0.53		0.48	0.67		0.55	0.57	0.53
17:00	0.59	0.66	0.62	0.60	0.38	0.53	0.66	0.48	0.64	0.66	0.61
18:00	0.49	0.62	0.59	0.58	0.41	0.57		0.51	0.58	0.67	
19:00								0.45			
Average Impact (kW)	0.56	0.62	0.61	0.57	0.40	0.53	0.63	0.48	0.59	0.63	0.57

Table 5-1. AC Cycling Impacts by Event-Day and Hour (September 4 through September 6, 2018)

Event Date	4-Sep	5-Sep	6-Sep
Consecutive Event-days	1	2	3
Opt-out Percent	0.04%	0.04%	0.05%
THI	84	84	83
15:00			
16:00	0.55	0.46	0.42
17:00	0.64	0.49	0.47
18:00	0.59	0.54	
19:00			
Average Impact (kW)	0.59	0.50	0.44

5.3 Ex ante Impacts

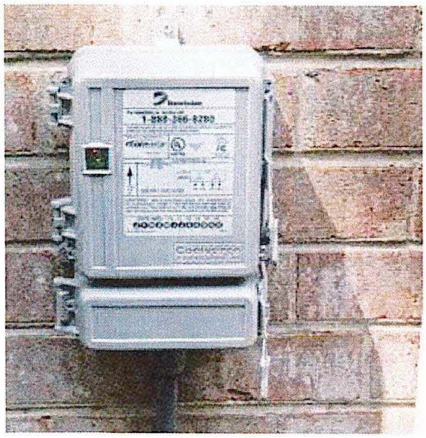
The primary metric of the impact analysis is the ex ante impact estimates for the program year. The ex ante analysis models event impacts for a range of THI values. A regression model was fit for each of the event hours ending 15, 16, 17, 18, and 19, with THI as a predictor variable. Like the 2017 model, the 2018 ex ante model was based solely on 2018 ex post impacts. The ex ante impact for The Company's peak planning conditions was 0.63 kW.

Table 5-2 shows the predicted values from the regression models aggregated by whole-hour intervals and tabulated by hour and THI.

Table 5-2. Ex Ante Impacts by THI and Hour Ending Per Participant (2018)

	Event Hour Ending				
THI	**15**	**16**	**17**	**18**	**19**
79	0.49	0.46	0.46	0.51	-0.19
80	0.51	0.48	0.50	0.54	0.06
81	0.53	0.50	0.54	0.56	0.32
82	0.55	0.52	0.57	0.58	0.57
83	0.57	0.55	0.61	0.60	0.83
84	0.59	0.57	0.65	0.62	1.09
85	0.61	0.59	0.69	0.64	1.34
86	0.64	0.62	0.73	0.66	1.60
87	0.66	0.64	0.76	0.68	1.85
88	0.68	0.66	0.80	0.71	2.11

6 CONCLUSION



This purpose of this evaluation was to estimate the average kW impacts that occur during each event hour, and forecast kW impacts by hour, temperature, and humidity conditions, including for The Company's peak planning conditions.

Ex post impacts over the 2018 event season ranged from 0.33 kW to 0.73 kW per participant. The ex ante analysis yielded a program impact of 0.63 kW per participant for The Company's planned peak conditions.

As discussed earlier, the THI during a given event has a strong influence on impacts. However, comparing results of the 2018 evaluation with prior years is difficult without additional analysis.

7 SUB-APPENDIX I: DATA

7.1 AMI Data – Quality Control

Four sources of data are used in the impact analysis: half hourly AMI customer consumption data, a record of controlled participants for each event, program tracking data, and regional weather data. To prepare the AMI consumption data for the analysis, a series of QC procedures are performed on the AMI data and event control logs. This section describes these QC procedures which for some tests rely on a cross reference between the AMI consumption data, the event control logs, and business intelligence (BI) data.

The event control log lists all dispatched accounts and the start and stop time of the event. Participants who were not dispatched in selected events are not included in the event control log. A participant will not be included in the event control log if they opt out of an event or were not dispatched during a partial-dispatch event.

The AMI data undergoes QC tests to ensure that the AMI data is complete, and that only active participants are included in the analysis. This requires that active participants are identified in the event control logs and the subset of AMI accounts can be linked to the control logs and be considered active participants. Additionally, the AMI account must include consumption data for May through October for it to be included in the analysis. The following specific conditions must be met for a participant to be included in the impact analysis:

- An AMI account must be associated with a corresponding account in the event control log.
- An account in the event control log must be associated with a participant in the BI data.

Section 7.1.1 summarizes QC results for the AMI data.

7.1.1 QC Results

Half-hourly AMI consumption data for AC Cycling participants was delivered monthly to DNV GL from April through December 2018. Table 7-1 shows the stages of QC for the 2018 AMI data. Of the 9,331 AMI accounts delivered, 625 (7%) were not used in the analysis. This does not indicate that the AMI contained poor quality data since the accounts that were removed were non-participants.

Table 7-1. Quality Test Results for the AMI Data (2018)

Quality Test	Number of Accounts Removed	Remaining Population
Number of AMI accounts delivered		9,331
Number of account numbers with no match to participants in the BI data	515	8,815
Number of accounts not included in events	110	8,706

8 SUB-APPENDIX II: EXTRAPOLATING THE AMI-ENABLED ACCOUNT IMPACTS TO THE PROGRAM POPULATION

The distribution of the AMI-enabled participants among divisions and connected loads does not match the distribution of all participants for these same characteristics. To extrapolate the AMI account impacts to the participant population, the AMI-enabled accounts are assigned weights based on their division and connected load relative to all participants. The distribution of AMI enabled participants to all participants by division is shown in Table 8-1.

Table 8-1. Total and AMI Participants by Division[7]

Division	# Total Participants by Division	# AMI Participants by Division
Eastern	35,688	124
Northwest	27,428	7,682
Central	19,469	333
North Carolina	3,157	86
Total	85,742	8,225

Due to the uneven distribution of AMI meters across divisions, The Company commissioned a customer load modeling analysis, a new recruit trend study, and a non-AMI comparison. In turn, all were included in the Final Order of the State Corporation Commission on April 19, 2016. The results of these studies are found in the 2016 evaluation of dispatch events.[8]

To create the weights, participants are categorized by division, connected load, and whether the account is AMI-enabled using the BI data, event control logs, and AMI consumption data.

The weights assigned to the AMI enabled group for the June 18 event are listed in Table 8-2. The weights are unique to each event to reflect slight differences in participation levels, or larger variances that occur during partial-dispatch events. The weight can be understood as the number of program customers represented by each meter in the AMI group. The following steps were taken to build the 2018 weights:

1. Construct a list of all event participants by address, division, and connected load. The program tracking data, or BI data, is the source of the addresses and connected loads.
2. Stratify the participants based on state, division, and connected load.
3. Calculate weights based on the number of AMI participants for each event relative to all participants within each stratum.[9]

[7] Total and AMI participants in the first event on 18 June 2018. Although 8,611 AMI accounts are included in the overall analysis only 8,225 participated on 18 June 2019

[8] Evaluation, Measurement, and Verification Report for Virginia Electric and Power Company, May 1, 2017, Appendix R-1: Impact Evaluation of 2016 Dispatch Events, Appendices A through C

[9] The weight within each stratum is the population divided by the total number of AMI meters in the study group.

Table 8-2. Weights by State, Division and Connected Load for June 18, 2018

State	Division	Load (kW)	# AMI meters	Population	Weight
VA	Northwest	Not Available	2,880	11,426	4
VA	Northwest	< 4kW	2,658	8,241	3
VA	Northwest	≥4kW	2,144	7,761	4
VA	Eastern	Not Available	36	11,302	314
VA	Eastern	< 4 kW	52	15,293	294
VA	Eastern	>= 4 kW	36	9,093	253
VA	Central	Not Available	103	6,399	62
VA	Central	< 4kW	132	7,691	58
VA	Central	≥4kW	98	5,379	55
NC	NC	Not Available	22	669	30
NC	NC	< 4kW	26	1,411	54
NC	NC	≥4kW	38	1,077	28
		Total	**8,225**	**85,742**	

About DNV GL

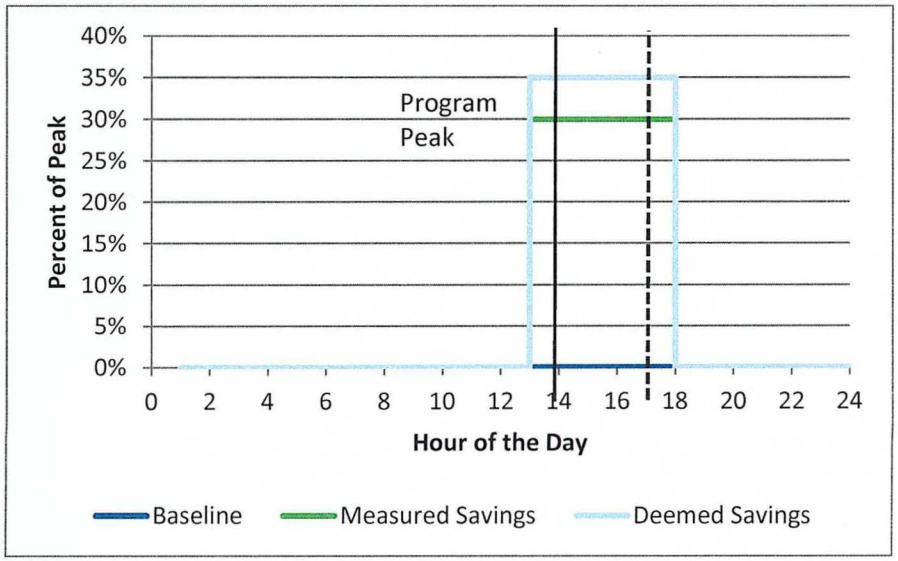
Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.

Appendix O

APPENDIX O. NON-RESIDENTIAL DISTRIBUTED GENERATION PROGRAM EM&V PLAN (VERSION 9.0)

Non-Residential Distributed Generation Program	
Program Summary	The Non-residential Distributed Generation Program provides qualifying commercial customers with an incentive to curtail load by operating backup generation at the request of the Company, up to a limited number of hours per year. Participants must have at least 200 kW demand to be eligible for this program. The program implementer is responsible for installing remote generation equipment controls, monitoring the customer's generators, and dispatching load under the direction of the Company. The program implementer is notified of a dispatch event 30 minutes in advance of the event either by e-mail or phone. Monthly average site-level load curtailment must be at least 95% of registered/enrolled kW to receive the incentive. Average monthly site level load curtailment must be at least 50% of registered/enrolled kW for continued program participation.
Measures	On-site generation capacity
EM&V Method	International Performance Measurement and Verification Protocol (IPMVP - Option B): Because impacts are calculated from metered energy consumption, IPMVP Option B is the appropriate EM&V method. Program participants are known and the load curtailment will be metered directly. The following load shape illustrates the components used to calulate program impacts.

Illustrative Load Shape: Non-Residential Distributed Generation

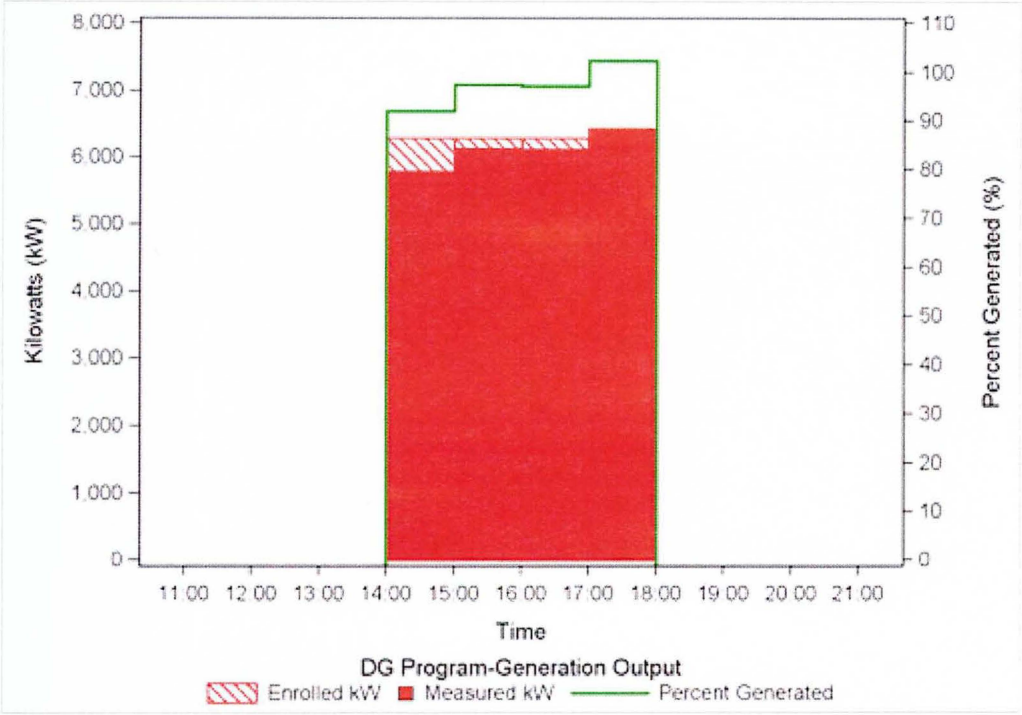


1. Baseline estimation approach (dark blue line): The baseline for this program is 0 kW because the power generators are considered non-operational at the begining of each event.

Non-Residential Distributed Generation Program	
	2. Deemed savings approach (Light blue line): Deemed savings values based on evaluated impacts are incorporated into the DNV GL Energy Standard Tracking and Engineering Protocols (STEP). 3. Measured savings approach (Green line): The program participants are known, generated kW is metered, and impacts are calculated using regression models.
EM&V Summary	Customer data regarding backup generation equipment will be collected prior to enrollment and will be used to determine customer eligibility. Metered generation data is collected from the implementor using Company and implementor owned equipment. Impacts are evaluated on the census of particpants

Non-Residential Distributed Generation Program

Sample Plot



EM&V Measurement, Timeline, and Scope of Work

- Analysis of program tracking and metered data: Annual Report (May 1 of each year following program launch).
- Semi-annual program tracking summary table (ending July 2015). 2015 will be final year of semi-annual reporting, as North Carolina submissions will be changing next year to line up with Virginia. Semi-annual program tracking summary table (July of each year).
- Annual event season report (November of each year).
- Annual updates to DNV GL Energy Standard Tracking and Engineering Protocols (STEP) for updates that occurred to its referenced sources.
- Develop baseline, measure savings, and efficient load shapes.

Non-Residential Distributed Generation Program	
	• Provide regulatory support as necessary.
EM&V Summary and Sampling Strategy	• A census of participant data will be evaluated since electrical output from 100% of enrolled generators will be metered, the event times are known, and the load and run time hours will be directly metered and reported. • Missing meter data will be replaced to the extent possible with redundant meter data. Analysis of program tracking and metered data: Annual Report (May 1 of each year following program launch). • Semi-annual program tracking summary table (ending July 2015). 2015 will be final year of semi-annual reporting, as North Carolina submissions will be changing next year to line up with Virginia. Semi-annual program tracking summary table (July of each year). • Annual event season report (November of each year). • Annual updates to DNV GL Energy Standard Tracking and Engineering Protocols (STEP) for updates that occurred to its referenced sources. • Develop baseline, measure savings, and efficient load shapes. • Provide regulatory support as necessary.
Sampling Confidence Level, Relative Precision, and Assumed Error Ratio	• A census of participant data will be evaluated since electrical output from 100% of enrolled generators will be metered, the event times are known, and the load and run time hours will be directly metered and reported. • Missing meter data will be replaced to the extent possible with redundant meter data.
Lost Revenue Methodology	• Not applicable
Document Revision History	Version 1.0 • Added semi-annual program tracking summary table in the "Frequency of EM&V Measurement & Timeline" section. Not applicable
	Version 2.0 • No material changes to the content. • Added semi-annual program tracking summary table in the "Frequency of EM&V Measurement & Timeline" section.
	Version 3.0

- No material changes to the content.

Version 4.0

- Updated program requirements with more details, as shown below:
  - Added minimum kW demand requirement of 200 kW to be eligible for this program to the "Program Summary" section.
  - Added customer notification process of each DG event through e-mail or phone 30 minutes in advance.
  - Added compliance requirement that participants must be within +/- 5% of committed peak shaving enrolled kW.
- Changed "KEMA" to "DNV KEMA."
- Changed "Program Penetration & Initial Baseline Assumptions" section title to "Program Penetration" and removed initial baseline assumptions.
- Updated program penetrations and added "Source" column to the "Program Penetration" table.
- Changed "Revision History" section title to "Document Revision History."
- Updated planned penetration table based on 2013 IRP.

Version 5.0

- Removed 2013 planned customer penetration numbers.

Added sentence on PJM requirements to end of "EM&V Method."

- Updated program requirements with more details, as shown below:
  - Added minimum kW demand requirement of 200 kW to be eligible for this program to the "Program Summary" section.
  - Added customer notification process of each DG event through e-mail or phone 30 minutes in advance.
  - Added compliance requirement that participants must be within +/- 5% of committed peak shaving enrolled kW.
- Changed "KEMA" to "DNV KEMA."
- Changed "Program Penetration & Initial Baseline Assumptions" section title to "Program Penetration" and removed initial baseline assumptions.
- Updated program penetrations and added "Source" column to the "Program Penetration" table.
- Changed "Revision History" section title to "Document Revision History."
- Updated planned penetration table based on 2013 IRP.

Version 6.0

- Updated DNV KEMA to DNV GL Energy.
- Clarified that compliance is defined by total monthly average load curtailment that is at least 95% of committed peak shaving enrolled kW (rather than +/- 5% of enrolled kW).
- Renamed "Frequency of EM&V Measurement and Timeline" section title to "EM&V Measurement, Timeline and Scope of Work" to more accurately reflect the content in that section
- Added on-going scope that was not explicitly mentioned to "EM&V Measurement, Timeline and Scope of Work" section.
- Deleted program penetrations section
- Removed 2013 planned customer penetration numbers.
- Added sentence on PJM requirements to end of "EM&V Method."

Version 7.0

- Clarified that compliance for program participation is 50% of enrolled, but compliance for payments is 95% of enrolled kW. Updated bullet "Semi-annual program tracking summary table (as required)." to "Semi-annual program tracking summary table (ending July 2015). 2015 will be final year of semi-annual reporting, as North Carolina submissions will be changing next year to line up with Virginia.
- Updated DNV KEMA to DNV GL Energy.
- Clarified that compliance is defined by total monthly average load curtailment that is at least 95% of committed peak shaving enrolled kW (rather than +/- 5% of enrolled kW).
- Renamed "Frequency of EM&V Measurement and Timeline" section title to "EM&V Measurement, Timeline and Scope of Work" to more accurately reflect the content in that section
- Added on-going scope that was not explicitly mentioned to "EM&V Measurement, Timeline and Scope of Work" section.
- Deleted program penetrations section
- Updated bullet "Semi-annual program tracking summary table (as required)." to "Semi-annual program tracking summary table (ending July 2015). 2015 will be final year of semi-annual reporting, as North Carolina submissions will be changing next year to line up with Virginia."
- Clarified difference between payment compliance (95% of enrolled load) and program participation compliance (50% of enrolled load)

Version 8.0

- Updated "April 1" report date to "May 1" in "EM&V Measurement, Timeline, and Scope of Work" section

	Version 9.0 • Minor edits • Formatting updates • Updated from DNV GL Energy to DNV GL Energy Insights

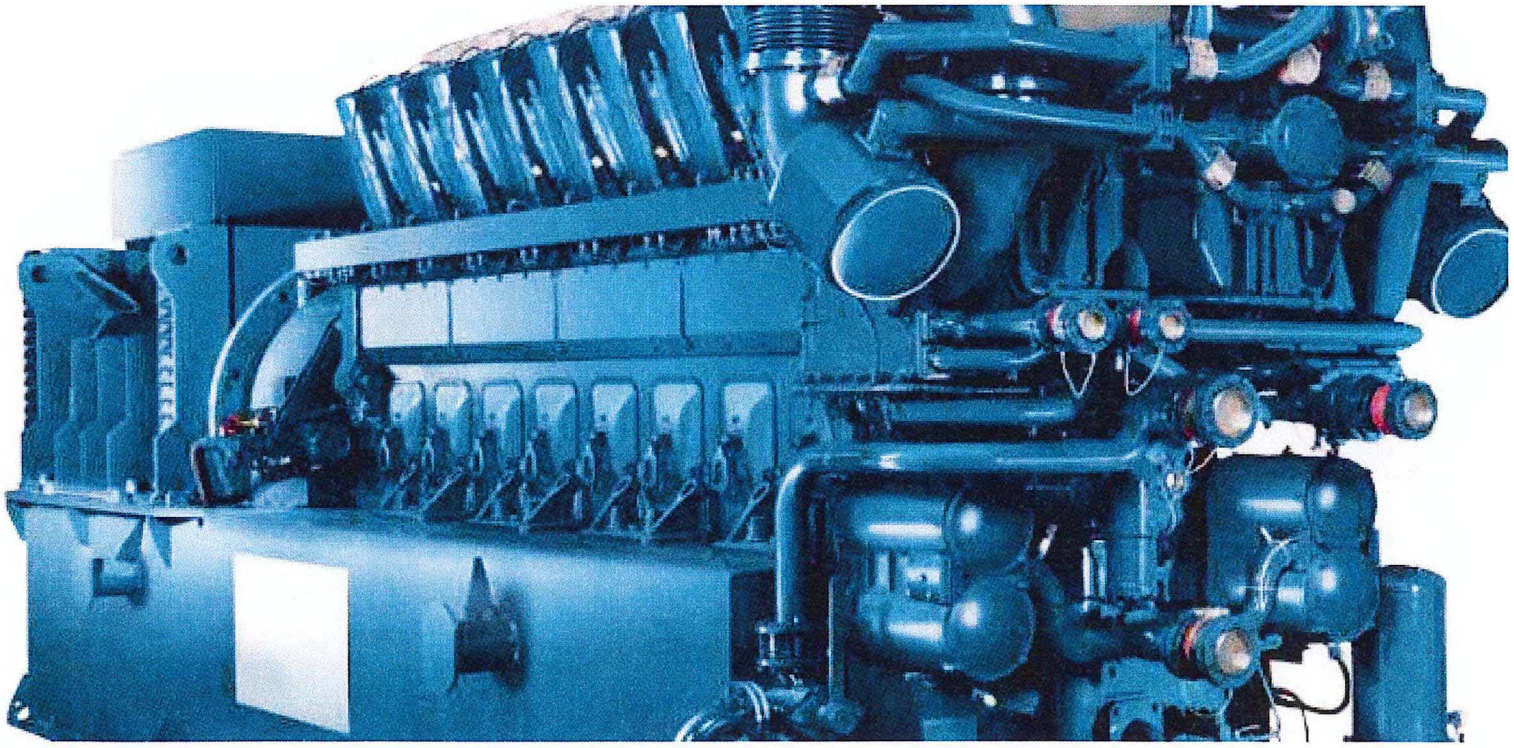
DNV·GL

DISTRIBUTED GENERATION PROGRAM

Appendix O-1
Impact Evaluation of 2018 Dispatch Events

Dominion Energy

Date: May 1, 2019



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1 EXECUTIVE SUMMARY

This report presents the results of the annual impact analysis of Dominion Energy's (hereafter referred to as "the Company") Non-residential Distributed Generation (DG) Program for 2018.

The program began in June 2012 with the objective of curtailing peak load. During periods when demand for electricity is particularly high, the Company calls upon participating large non-residential customers to provide a supply resource to the company by operating backup power to curtail load on the Company's grid. Customers must meet specific eligibility requirements to participate in the program and receive an incentive from the Company in exchange for their participation.

For the non-residential DG program, total and average dispatched generation is the amount of load curtailment, in kilowatts (kW), requested by the Company, per event-hour interval, aggregated to the day, month, season or year. Total and average measured generation is site-metered generation and is the amount of load delivered to the Company per event-hour interval, aggregated to the day, month, season or year. The realization rate is calculated by dividing the average monthly measured generation by the average monthly dispatched generation for participating sites.

The 2018 monthly realization rates shown in Table 1-1 range from 65% in May to 106% in September. May's realization rate was significantly lower than the next lowest month, January (85%), because in May only three sites were dispatched on a single day. The remaining months had three events or more and participation by virtually all sites. Despite the limited dispatch in May, the program's 97% realization rate through November 30th met the planned target of 95%. Summer events averaged 100%, and winter events averaged 85%.

The three objectives of the impact analysis are to:

- Compute the aggregate and site-level curtailed load, in kW for each event-hour and event-day
- Compute program realization rates annually, seasonally and for each event interval by comparing dispatched generation to measured generation
- Report monthly program performance and planned values

Table 1-1 shows DG Program performance and planned values for 2018. The table provides the planned and actual participants in megawatts (MW) and the average dispatched and measured generation in kW.

Table 1-1. DG Program Performance (2018)

2018	Planned (MW)	Enrolled (MW)	Net kW Planned	Net kW Enrolled	Event Days	Average Dispatched (kW)	Average Generation (kW)	Average Realization Rate
Jan	8.15	5.95	8,149	5,950	4	4,757	4,026	85%
Feb				No Events				
March				No Events				
April				No Events				
May	8.15	2.46	8,149	2,460	1	2,460	1,610	65%
June	8.15	5.67	8,149	5,670	5	5,638	5,296	94%
July	8.15	6.13	8,149	6,130	7	5,967	5,906	99%
August	8.15	5.75	8,149	5,750	11	5,606	5,851	104%
Sept	8.15	5.36	8,149	5,360	3	5,360	5,696	106%
Oct				No Events				
Nov				No Events				
Dec				No Events				

2 INTRODUCTION AND BACKGROUND

The Virginia State Corporation Commission approved the Non-residential DG Pilot on January 17, 2008. The Non-residential DG Pilot subsequently achieved program status on April 30, 2012. The pilot ran through the end of 2014. In June 2017, the DG program was extended for an additional 5 years through May 31, 2022.[1]

During periods when demand for electricity is particularly high, the Company calls upon participating large non-residential customers to provide a supply resource to the Company by operating backup power to curtail load on the Company's grid. Customers must meet specific eligibility requirements to participate in the program and receive an incentive from the Company in exchange for their participation.

As of November 15, 2018, there were 21 enrolled sites representing a potential 6.1 MW of resources to the Company. Large non-residential customers with at least 200 kW of demand and sufficient generation capacity are eligible to participate in the program. Details of the DG Program are as follows:

- A participant equals 1,000 kW of enrolled onsite generation, and the level of incentive corresponds with the kW of enrolled generation capacity.[2] 1 customer can qualify as multiple participants.
- Participating customers are compensated if the average measured on-site generation is at least 95% of the dispatched target for each event day.[3]
- The Company has the right to adjust the incentive paid to customers based on historical performance if the average realization rate falls below the 95% target.

The day of an event is called an event day, even though an event only lasts several hours. Multiple events may be called during a single event day. The length of events varies by event day. The length of an event interval is one hour. Event intervals are reported at hour ending. For example, hour ending 17 corresponds to the interval between 16:00 and 17:00. The number of dispatched sites during a given event day also varies.

For the Non-residential DG program, total and average dispatched generation is the amount of load curtailment, in kW, requested by the Company, per event-hour interval, aggregated to the day, month, season or year. Total and average measured generation is site-metered generation and is the amount of load delivered by the participants per event-hour interval, aggregated to the day, month, season or year. The realization rate is calculated by dividing the average monthly measured generation by the average monthly dispatched generation for participating sites. If there is measured generation at a site prior to or following a dispatched event, the measured generation is not attributed to the DG Program.

The monthly realization rates shown in Table 1-1 range from 65% in May to 106% in September. May's realization rate was significantly lower than the next lowest month, January (85%), because in May only three sites were dispatched on a single day. The remaining months had three events or more and participation by virtually all participating sites. Despite the limited dispatch in May, the program's 97%

[1] Case No. PUE-2016-00111. Commonwealth of Virginia, State Corporation Commission, "Final Order" on the subject "For approval to implement new, and to extend existing, demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia." June 1, 2017.

[2] Customers who do not have exact multiples of 1,000 kW of onsite generation are credited with fractional levels of participation and incentive, e.g., 1,500 kW is considered 1.5 participants.

[3] 8 pilot sites were eligible for the incentive based on participation alone and were not required to meet the 95% realization target.

realization rate through November 15th met the planned target of 95%. Summer events averaged 100%, and winter events averaged 85%.

Performance indicators for DG Pilot participants were reported through the end of the pilot (2014). Therefore, results reported in 2015–2018 are not directly comparable to the results of combined pilot and program reported in 2013 and 2014.

3 IMPACT ANALYSIS METHODOLOGY

The key performance indicator used to measure program performance is the realization rate. The site-level realization rate for a given event interval is the on-site measured generation for that interval divided by the amount of generation dispatched during the interval. The program realization rate during an event interval is the total measured generation divided by the total dispatched generation for all sites. For participants indexed by i, and for an event interval j,

$$Realization\ Rate_j = \frac{\sum_i Measured\ Generation\ (kW_{i,j})}{\sum_i Dispatched\ Generation\ (kW_{i,j})}$$

The aggregate dispatched and measured generation across the program is calculated by event interval and day.

In many cases, seasonal results are reported. The winter season spans October–March, while the summer season spans April–September.

4 RESULTS

This section summarizes program performance from 2013 to 2018 and presents a detailed impact analysis for the 2018 events.

A total of 32 events were called during 31 event days in 2018. Five events were called during 4 event days in January (winter) and the remaining 27 events were called on 27 event days between May and September (summer). Table 4-1 presents an annual summary of the number of event days, average dispatched generation, average measured generation, and realization rates. For event days through November 15, the 2018 realization rate slightly exceeded the program's planned 95% target.

Table 4-1. DG Performance Indicators (2013–2018)

Year	Number of Event Days	Average Dispatched (kW)	Average Measured Generation (kW)	Realization Rate
2013	12	6,239	6,306	102%
2014	23	5,862	5,978	101%
2015	26	5,899	5,457	93%
2016	37	5,215	5,524	106%
2017	27	5,603	6,054	108%
2018	31	5,296	5,140	97%

Table 4-2 presents an overview of yearly DG program impacts broken out by season. In 2018, winter's 85% realization rate was maintained from the record high rates reached in 2017. The 2018 summer realization rate was lower than 2017 but still met the 95% target.

Table 4-2. DG Performance Indicators for Winter and Summer (2013–2018)

	Number of Event Days		Average Dispatched (kW)		Average Generation (kW)		Realization Rate	
Year	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2014	14	9	5,798	6,060	6,305	3,954	109%	65%
2015	20	6	5,958	5,846	5,903	4,515	99%	78%
2016	34	3	5,171	5,911	5,602	4,281	108%	72%
2017	24	3	5,564	6,130	6,114	5,234	110%	85%
2018	27	4	5,438	4,757	5,432	4,026	100%	85%

Section 4.1 reports dispatched and measured generation by event-hour and day. Section 4.2 reports realization rates by event-hour and day. Section 4.3 provides site-level realization rate details by event day.

4.1 Program Event Impacts

The total dispatched generation for all DG participants during the 2018 winter and summer event intervals are shown in Table 4-3 and Table 4-4. The total and average dispatched generation is summarized by event day. The total hourly dispatched capacity ranged from 4,160 kW to 5,950 in winter (5 events during 4 event days) and between 2,460 and 6,130 in summer (27 events). The fully enrolled program capacity is 6,130 kW.

Dispatched kW is the amount of load curtailment requested (called) by the Company during an event. It is not a measure of participants' committed load and varies by event.

Table 4-3. Dispatched Generation by Event Day and Hour Ending–Winter

Dispatched Generation by Event Day and Hour Ending (kW)														
Event Day	**Hour Ending**												**Total**	**Avg**
	5	**6**	**7**	**8**	**9**	**10**	**11**	**18**	**19**	**20**	**21**	**22**		
2-Jan-18	5,950	5,950	5,950	5,950	5,950	5,950	5,950						41,650	5,950
5-Jan-18			4,160	4,160	4,160			4,160	4,160	4,160	4,160	4,160	33,280	4,160
6-Jan-18			4,160	4,160	4,160								12,480	4,160
7-Jan-18			4,160	4,160	4,160								12,480	4,160

Table 4-4. Dispatched Generation by Event Day and Hour Ending–Summer

Dispatched Generation by Event Day and Hour Ending (kW)								
Event Day	Hour Ending						Total	Average
	15	16	17	18	19	20		
3-May-18	2,460	2,460	2,460	2,460	2,460	2,460	14,760	2,460
18-Jun-18			5,670	5,670	5,670		17,010	5,670
19-Jun-18	5,670	5,670	5,670				17,010	5,670
28-Jun-18			5,670	5,670			11,340	5,670
29-Jun-18		5,670	5,670	5,670			17,010	5,670
30-Jun-18			5,520	5,520	5,520		16,560	5,520
1-Jul-18			6,130	6,130	6,130		18,390	6,130
2-Jul-18		6,130	6,130	6,130			18,390	6,130
3-Jul-18		6,130	6,130	6,130			18,390	6,130
5-Jul-18		6,130	6,130	6,130			18,390	6,130
10-Jul-18			6,130	6,130			12,260	6,130
16-Jul-18		5,770	5,770	5,770			17,310	5,770
27-Jul-18		5,400	5,400	5,400			16,200	5,400
6-Aug-18		5,750	5,750	5,750			17,250	5,750
7-Aug-18		5,750	5,750	5,750			17,250	5,750
8-Aug-18		5,570	5,570	5,570			16,710	5,570
9-Aug-18		5,420	5,420	5,420			16,260	5,420
15-Aug-18			5,380	5,380			10,760	5,380
16-Aug-18		5,420	5,420	5,420			16,260	5,420
17-Aug-18	5,510	5,510	5,510				16,530	5,510
27-Aug-18			5,750	5,750	5,750		17,250	5,750
28-Aug-18		5,750	5,750	5,750			17,250	5,750
29-Aug-18		5,750	5,750	5,750			17,250	5,750
30-Aug-18		5,510	5,510				11,020	5,510
4-Sep-18		5,360	5,360	5,360			16,080	5,360
5-Sep-18		5,360	5,360	5,360			16,080	5,360
6-Sep-18		5,360	5,360	5,360			16,080	5,360

Table 4-5 and Table 4-6 report the program level measured generation by event day and interval for winter and summer events, respectively.

Total and average measured generation are given across all events during each event day. The average measured generation was (as expected) higher in the summer (6,845 kW) than in the winter (4,182 kW). This is consistent with program expectations. Dispatched kW per site reflects the Company's higher summer peak since winter heating demands are also served by oil and gas end-uses.

Table 4-5. Measured Generation by Event Day and Hour Ending–Winter

Measured Generation by Event Day and Hour Ending (kW)														
Event Day	**Hour Ending**												**Total**	**Average**
	5	**6**	**7**	**8**	**9**	**10**	**11**	**18**	**19**	**20**	**21**	**22**		
2-Jan-18	3,468	3,892	4,373	4,636	4,308	4,328	4,272						29,277	4,182
5-Jan-18			2,868	3,934	4,359			3,900	4,284	4,224	4,142	3,977	31,688	3,961
6-Jan-18			3,155	4,243	4,427								11,825	3,942
7-Jan-18			3,214	4,147	4,392								11,754	3,918

Table 4-6. Measured Generation by Event Day and Hour Ending–Summer

Measured Generation by Event Day and Hour Ending (kW)								
Event Day	**Hour Ending**						**Total**	**Average**
	15	**16**	**17**	**18**	**19**	**20**		
3-May-18	1,662	1,655	1,649	1,619	1,579	1,499	9,662	1,610
18-Jun-18			4,856	5,284	5,238		15,378	5,126
19-Jun-18	5,554	5,755	5,803				17,112	5,704
28-Jun-18			4,920	5,512			10,432	5,216
29-Jun-18		5,136	5,338	5,329			15,803	5,268
30-Jun-18			4,993	5,247	5,184		15,423	5,141
1-Jul-18			6,353	6,815	6,445		19,612	6,537
2-Jul-18		6,397	6,716	6,378			19,491	6,497
3-Jul-18		6,553	7,090	6,892			20,535	6,845
5-Jul-18		4,693	5,057	5,076			14,826	4,942
10-Jul-18			5,626	6,307			11,933	5,966
16-Jul-18		3,800	6,413	6,263			16,475	5,492
27-Jul-18		5,022	5,315	4,919			15,255	5,085
6-Aug-18		5,196	5,736	5,571			16,503	5,501
7-Aug-18		5,376	5,865	5,909			17,150	5,717
8-Aug-18		5,838	6,657	6,552			19,048	6,349
9-Aug-18		6,033	6,141	6,237			18,410	6,137
15-Aug-18			4,838	5,434			10,273	5,136
16-Aug-18		4,859	4,992	4,900			14,752	4,917
17-Aug-18	5,681	5,999	6,045				17,725	5,908
27-Aug-18			6,037	6,283	6,202		18,522	6,174
28-Aug-18		6,183	6,469	6,419			19,071	6,357
29-Aug-18		5,811	6,274	6,156			18,241	6,080
30-Aug-18		5,638	6,056				11,694	5,847
4-Sep-18		5,703	6,047	6,036			17,786	5,929
5-Sep-18		5,932	6,362	6,184			18,479	6,160
6-Sep-18		6,203	6,270	2,530			15,003	5,001