Bonneville Power Administration Commercial Aggregator Demand Response Demonstration

Final Report

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I. Project Team Members

A. Project Team - Bonneville Power Administration

The breadth of this demonstration necessitated team members from across BPA. The core team included:

Name	Role
Mark Miller	Account Executive (Contract Signer)
Tom Brim (Contractor)	Project Manager
Cara Ford (Contractor)	Project Manager & Information Systems Lead
Jason Weinstein	Account Specialist and Settlement
Adrian Allen	Account Specialist and Settlement
Fran Halpin	Power Operations – Event Scheduling
Rob Johnson	Power – Real Time Marketing
Tony Koch	Metering and Settlement
Melanie Smith	Demand Response Operations
Frank Brown	Demand Response Advisor
Chris Sanford	Transmission - Dittmer Dispatch
Lee Hall	DER Program Manager
Scott Wilson	Power – Account Executive
Claire Hobson	Power - Account Executive
Paul Garrett	Power - Account Executive
Kevin Farleigh	Power - Account Executive
Marcus Perry	Power - Account Executive
Larry Felton	Power - Account Executive
Margaret Lewis	Power – Energy Efficiency Representative
Melissa Podeszwa	Power – Energy Efficiency Representative

Mark Ralston	Power – Energy Efficiency Representative
Boyd Wilson	Power – Energy Efficiency Representative

B. Project Team – EnerNOC

The primary project team from EnerNOC included the following:

Name	Role
Heather Andrews	Program Manager
Peter Holzaepfel	Program Manager
Alistair Ono	Regional Sales Lead
Eric Bakken	Sales Lead

C. Representatives - Participating Utilities

Key individuals from utilities that participated in the pilot included:

Name	Utility	Role
Brandon Hignite	Central Lincoln PUD	Power Analyst
Dan Bedbury	Clark Public Utilities	Director of Energy Resources
Thomas Elzinga	Consumers Power	Key Accounts Manager
Rich Sargent	Franklin PUD	Senior Power/Energy Services Analyst
Vic Hubbard	Franklin PUD	Energy Services Specialist
Gregg King	City of Port Angeles	DR Project Manager
Tom Hovde	Snohomish PUD	Customer Engagement Lead
Chuck Peterson	Snohomish PUD	Customer Engagement Lead
Tami Sinor	Umatilla Electric Cooperative	Key Account Liaison
Greg Mendonca	PNGC Power	Vice President of Power Supply

II. Executive Summary

This report details the results of a two year commercial aggregator project by the Bonneville Power Administration (BPA). BPA conceived and executed this two year demonstration to support its goal of testing Demand Response (DR) products for its Power and Transmission Services' business lines, and to test the viability of a DR commercial aggregation model with public power in the BPA service territory. For Power Services, BPA tested a winter peak shave product ("Winter Product"), and for the Transmission Services, BPA tested summer load reduction ("Summer Product") in a north-south congestion zone south of the Allston substation near Longview, Washington.

Through a Request for Offers (RFO) process BPA selected EnerNOC, the nation's largest commercial aggregator, to execute a two year demonstration starting in 2015 and concluding in April 2017. To recruit and enroll commercial, industrial and municipal retail customers, BPA constructed a model by which EnerNOC would work with public distribution utilities to first gain the utilities' acceptance to participate, and second to recruit loads to participate. If a distribution utility opted out, EnerNOC could not recruit loads in that area. All public utilities in BPA's balancing authority were eligible to participate for the Winter Product while only utilities in a prescribed area could participate for the Summer Product. Contractually, BPA signed a 'pay for performance' agreement with EnerNOC, and in turn EnerNOC signed agreements with participating utilities to cover their support costs. EnerNOC also signed agreements with participating retail customers (loads) to pay capacity and energy incentives.

The demonstration was not able to meet the minimum recruiting thresholds for the Summer Product and the 2016 and 2017 summer testing was not executed. The inability to meet the minimum MW was attributable to the non-participation of key utilities, to a small pool of utilities to choose from, and to the inability to find enough end-loads who could meet the test parameters including 60 minute notification and the diurnal event hours. For the Winter Product, EnerNOC recruited enough load to run two seasons in 2015/2016 and 2016/2017. In total, seven distribution utilities signed up and 16 end-loads were enrolled. At its peak, more than 17 MW of loads were enrolled in the demonstration.

To dispatch curtailment events, BPA used AutoGrid's Demand Response Optimization Management System (DROMS) which communicated to EnerNOC via OpenADR. One minute near real-time interval data was returned to the DROMS that had been captured via site pulse metering equipment installed by EnerNOC at the loads.

The program tested extensively with 35 events covering 95 hours over the course of the two winters using simulated triggers and situations. Events lasted up to three hours. Performance was measured in two ways at a portfolio level – first with the lowest hour of delivered MW in a multi-hour event as a % of a nominated amount ("Contractual Performance"), and second with the average hourly delivery in an event as a % of a nominated amount ("Average Performance"). For Contractual Performance, the portfolio delivered 90% of nominated amounts in 86% of the events, while for Average Performance; the portfolio achieved 136% of nomination.

At the conclusion of the event testing, BPA, EnerNOC, participating utilities and participating retail customers (loads) conducted a series of debriefs, and identified key learnings including the central role of the distribution utility in this aggregation model, the diversity of reasons load could not enroll, viewpoints on the software and equipment to support communications and metering, and the value of load diversity.

While the demonstration did not achieve the levels of participation it wanted in the summer seasons, it did achieve significant advancements that will help public power execute DR in the Pacific Northwest.

The demonstration set a high bar – and achieved aggressive goals - in many ways: (1) Loads were required to respond within 60 minutes and had to be available twice a day for three consecutive days for up to three hours at a time, (2) loads were given a high number of event dispatches, (3) BPA's DROMS was integrated with EnerNOC's system with OpenADR to provide real-time one minute data, (4) a cascading contract structure was conceived that involved three parties many for the first time with demand response, and (5) multiple asset types were allowed including batteries which do not have a long history participating in DER portfolios.

III. Background

History. In 2013, BPA management made a decision to test DR at scale for a variety of emerging needs, recognizing that for BPA to use DR for commercial needs it would require both power customer utilities (and their loads) and BPA to build capability. This decision in 2013 followed four years of 15+ small scale technology pilots in the Pacific Northwest that were used primarily for early research on new technologies and product concepts.

The emerging needs included use of DR for balancing reserves to supplement the Federal Columbia River Power System (both ramping up and ramping down), peak reduction primarily in the winter months to respond to BPA capacity constraints, transmission investment deferral, and load shifting to support optimal management of the federal hydro system. In the end, BPA focused on DR that could benefit BPA Power and Transmission customers by providing the least cost alternative to meet an agency need.

To meet the objectives of testing at scale, BPA committed to build a portfolio of up to 150 MW working with utilities across the Pacific Northwest that would include multiple DR demonstrations. Each demonstration would test: 1) different acquisition models (i.e. acquiring DR directly from utility(s) or through a third party), 2) the reliability of loads to curtail when requested, 3) BPA use cases and internal processes, 4) supporting information systems, 5) contractual models,6) baseline and measurement strategies, and 7) operational parameters.

Aggregator Request for Offers (RFO) and Selection. This demonstration was designed to test commercial aggregation to meet potential winter capacity needs and flow relief on a transmission constraint. In May 2014, BPA released a RFO soliciting proposals to acquire commercial and industrial DR products for up to 50 MW of DR. This RFO was part of a broader BPA strategy between 2013 and 2017 to conduct DR demonstrations at a commercial scale.

The RFO was designed to test two DR products: a) a summer product for BPA's Transmission Services to provide flow relief for a constrained north-south transmission path south of the Allston substation near Longview, Washington, and b) a winter product for BPA Power Services to provide morning and afternoon operational flexibility. The summer product was constrained to a territory evaluated as being beneficial to South of Allston flow relief, and included 18 retail public utilities (later expanded to 22), while the winter product could be sourced from any utility within BPA's balancing authority.

After a RFO evaluation process, in the fall of 2014, BPA selected EnerNOC, a leading DR aggregator based in Boston, Massachusetts, to provide services for this demonstration. In late February 2015, BPA and EnerNOC formally signed a contract to begin the demonstration designed for two years, the summers of 2015 and 2016, and the winters of 2015/2016 and 2016/2017.

Demonstration Overview. In the winter of 2014, EnerNOC began the recruitment process which entailed gaining permission from load serving retail utilities to offer the program in their territory, agreeing with the utility on a process to recruit loads, and then approaching end-loads to participate. To conduct a first season of testing, BPA and EnerNOC set a minimum of 5 MW of aggregated load that would need to be enrolled and enabled by August 1st. This objective was not met, and the summer 2015 testing season was not conducted. By December 2015, BPA and EnerNOC were ready to begin event testing for the winter season, as EnerNOC had recruited load that met minimum requirements (8.9 MW enrolled across 5 utilities) and BPA and EnerNOC had successfully tested communication systems for dispatch and load monitoring.

After the first month of testing in the first season, BPA switched from the Distributed Energy Resources team making decisions about when to call events to having the Power real-time marketing team making these decisions based on system conditions.

Again, in 2016, EnerNOC had not enrolled enough loads in the targeted 22 utilities to conduct summer testing. (Note: winter testing was able to proceed because the majority of its load was in areas [e.g. north of the transmission constraint] outside of the summer target area.) The lack of summer load was attributable to retail utilities that chose not to participate, and the inability to find enough willing commercial and industrial participants who would sign up. The reasons for loads not participating were documented by the EnerNOC recruiting team and include: (1) potential high frequency of events, (2) operations of the target load did not match the hours of when BPA might call an event, (3) not enough controllable loads at the facility, (4) unpredictable operating schedules, and (5) incentives not high enough to offset the expected business disruption. At one point, the demonstration investigated the use of back-up generation (BUG) to provide additional capacity; however, EnerNOC found that because the BUG usage and air permitting requirements were detailed and specific to different areas, there was insufficient time to develop the potential resources.

In the winter of 2016/2017, BPA conducted the final season of testing. The season began with 16 MW enrolled, but was reduced to 4 MW as a large industrial facility was no longer able to participate due to sale of the plant to a new owner, who then closed the facility for retooling. The demonstration testing concluded on April 30, 2017, and over the summer of 2017, BPA gathered lessons learned from participating utilities, end-loads and EnerNOC.

IV. Demonstration Objectives

BPA designed this demonstration, as part of its broader portfolio of testing, with several objectives in minds:

1. **Test the commercial aggregator model** with public utilities and their loads in the Pacific Northwest, specifically market receptivity, contractual mechanisms, recruitment approach, event signals with accompanying software systems, and in general how to apply the model in which a wholesaler (BPA) is buying a service of load curtailment through retail utilities.

2. **Test the availability and reliability of a winter peak reduction** (for BPA's Power Services) product and a **transmission investment deferral** (for BPA's Transmission Services). For winter, the objective was to test the capability of loads to reduce for up to 3 straight days, morning and afternoon, while in the summer, reductions would be in afternoons for up to 5 consecutive days. These were considered aggressive testing objectives.

3. **Test BPA's operational processes** in making decisions on when to call events, sending event notifications, evaluating success, and making settlement payments.

4. **Test a range of asset types** within a demonstration, including a variety of commercial, industrial and municipal loads, as well as battery storage and non fossil based distributed generation.

Separately, each retail utility that opted in to participate also set objectives including learning more about the design and implementation of DR and the best models for assessing their customer interest in participating in DR programs, and providing an additional service offering to their customers.

V. Project Design and Implementation

BPA defined a set of potential needs to support both Power and Transmission Services, working closely with planners and operations.

A. Winter Peaking Product

For the Power Business, planners identified a potential capacity shortfall in future winter months, and described this need as a **"18 hour capacity product",** that is an extreme cold weather event that typically is shaped to last three days in the winter, with a peak up to three hours in the morning and a second three hour peak in the afternoon, when the federal hydro system is not able to provide more power and supplemental power is difficult or expensive to acquire on the market. BPA expanded the definition of winter to include the month of April to allow for a longer testing season.

The 18 hour peak metric can be expressed as:

3 consecutive days* 2 events/day * 3 hours = **18 hour capacity**

Planners noted the need may be less than 18 hours. These winter requirements were expressed in the Request for Offers as:

Parameter	Requirement
Months available	December 1 – April 30
Product Hours:	0700-1000 and 1700-2000 PT
Maximum Duration (hours)	3
Consecutive Days Available	3
Minimum Advance Notice	20 minutes
Maximum Events Per Day	2
Maximum Hours Per Year	120
Recharge Period (hours)	6
Performance Data	One minute interval data available near real time to BPA, with Complete Event Reports within 24 hours of Event.
Eligible Asset Types	Demand Response, Battery Storage, and Demand Voltage Reduction. Generation not eligible.

These test parameters were considered aggressive. Rarely are DR programs across the nation as demanding as these specifications. The RFO stated that participating loads needed to be located inside the BPA Balancing Authority Area.

B. Summer Transmission Congestion Management Product

BPA also wanted to learn more about the potential for DR to help it manage transmission congestion during summer heat waves. This was the first non-wires measure BPA would test in association with a congested South of the Allston Substation "flowgate" located near Longview, Washington. North to south energy flows into the Portland/Vancouver metropolitan area during the summer can approach system operating limits and create the potential for curtailments of generation or loads. In January 2011, BPA commissioned a non-wires screening study that listed demand response as one of several non-wires measures that could help manage transmission congestion in advance of constructing the I-5 Corridor Reinforcement project.

These summer requirements were expressed in the Request for Offers as:

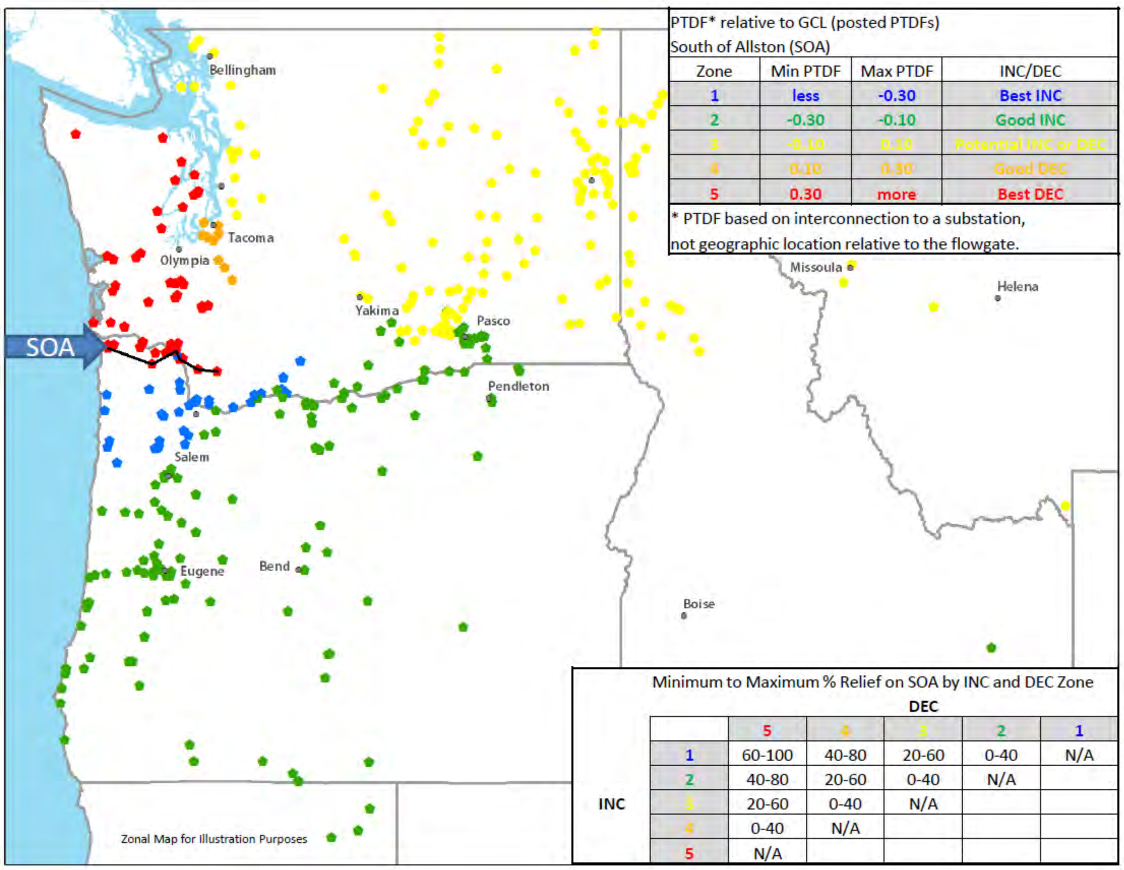
Parameter	Requirement
Months available	May 1 – October 31
Product Hours:	Late Afternoon 1200-2000 PT
Maximum Duration (hours)	4
Consecutive Days Available	5
Minimum Advance Notice	10 minutes
Maximum Events Per Day	1
Maximum Hours Per Year	100
Recharge Period (hours)	16
Performance Data	One minute interval data available near real time to BPA, with Complete Event Reports within 24 hours of Event.
Eligible Asset Types	Demand Response, Battery Storage, and Demand Voltage Reduction. Generation not eligible.

As was the case for the Winter Product, this Summer Product had very aggressive parameters, much more challenging than most DR programs implemented across the USA.

BPA transmission planners conducted analyses of where demand reductions would have the most flow relief impact for the South of Allston flowgate. Using Grand Coulee Dam as a base point, planners calculated the incremental/decremental change in power flows using Power Transfer Distribution Factors (PTDFs) for substation points throughout the region. Recognizing the system must be kept in balance (that is for a decrease in generation north of the cutplane, a corresponding decrease in load is required south of the flowgate); planners then developed a matrix that showed the effect of load reductions made in concert with generation reductions throughout the region.

The map below (Figure 1) shows the relative impact of load reduction by area. The Blue markers indicate areas with the greatest positive impact (primary locations) with the green markers (secondary locations) showing the next most impact.

Figure 1: Relative impact of load reduction for the South of Allston Substation constraint



Based on this analysis, BPA then mapped utilities to these areas that yield the greatest flow relief results from load reduction.

Primary Locations:

- City of Cascade Locks, Electric Dept.,
- Clark Public Utilities,
- City of Forest Grove, Light & Power Dept.,
- McMinnville Water & Light Commission,
- Skamania County PUD (Columbia Gorge loads, Washougal to Underwood),
- Tillamook People's Utility District, excluding the northern 20% of its service area, from Garibaldi to Nehalem,
- West Oregon Electric Cooperative (PNGC Member) from Vernonia south through Timber to Gales Creek and Lee's Camp.

Secondary Locations:

- Blachly-Lane Electric Cooperative (PNGC Member),
- Central Lincoln PUD, Florence north to Lincoln Beach & Depoe Bay,
- Consumers Power, Inc. (PNGC Member),
- Emerald People's Utility District, excluding the Creswell area south through Cottage Grove,
- Eugene Water and Electric Board,
- Franklin PUD,
- Hood River Electric Cooperative, including Farmers and Middle Fork Irrigation Districts,
- Hermiston Energy Services,
- Lane Electric Cooperative (PNGC Member),
- City of Monmouth, Power and Light Dept.,
- Northern Wasco County PUD,
- US Dept. of Energy, National Energy Technology Laboratory, Albany Research Center,
- Salem Electric Cooperative,
- Springfield Utility Board,
- Umatilla Electric Cooperative,

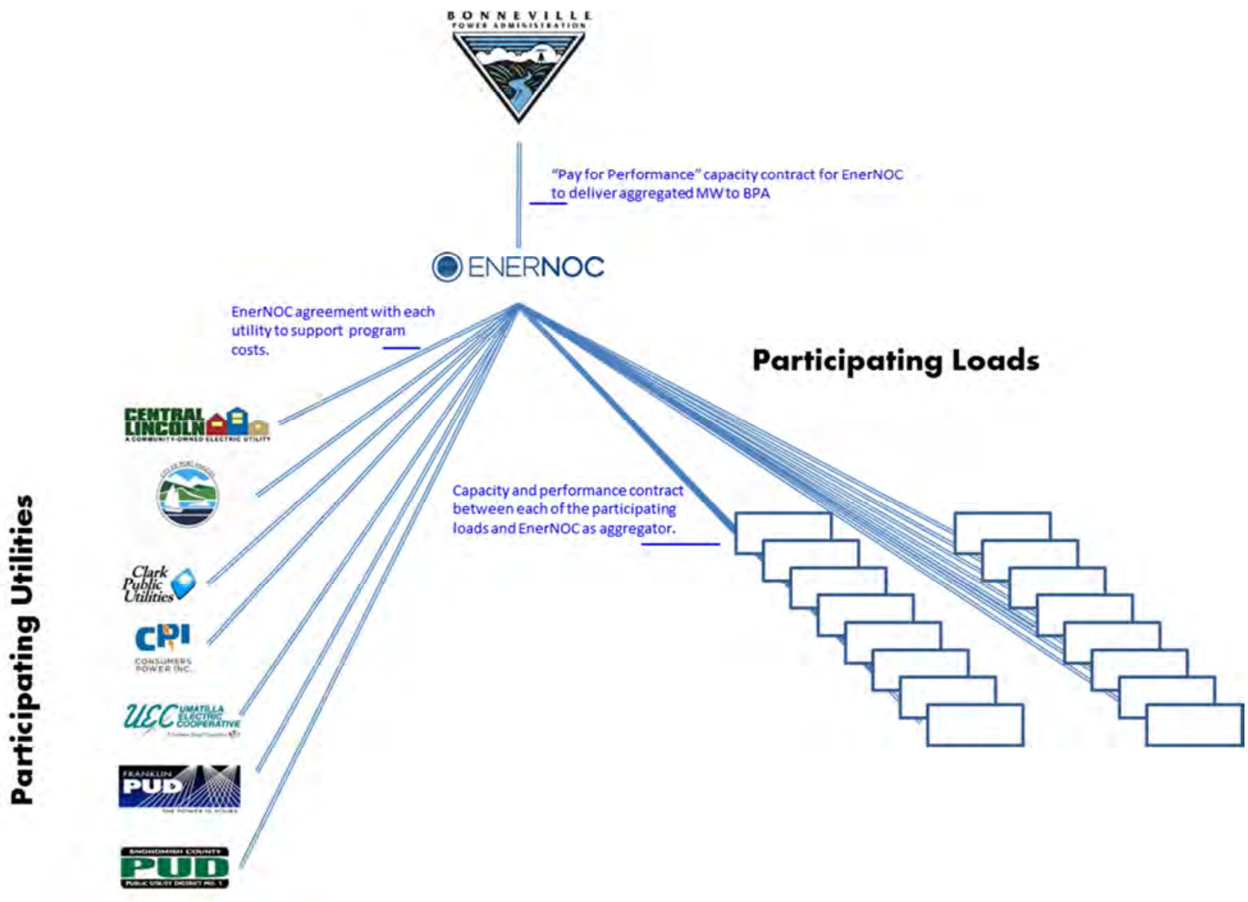
C. Contractual Structure

Multiple layers of contracts were put in place to support the demonstration, and were executed in the sequence described here.

- BPA contracted with EnerNOC to act as an aggregator and deliver a specified quantity of load for an agreed sum subject to reductions for non-performance.
- EnerNOC in turn contracted with each participating utility to acknowledge the utility's participation in the program and to help defray utility costs associated with load recruitment, provision of data, metering and verification, and on-going support.
- EnerNOC then contracted with end-loads in these utility service areas to perform to program requirements in consideration of a capacity payment and energy payment.

The structure is depicted in the figure 2 below.

Figure 2: Contractual Structure



D. Recruitment

The demonstration necessitated "multi-tier" participant recruitment once the BPA and EnerNOC relationship was put in place. A core principle of the project was that the serving distribution utility was central to success, and only in those territories where the distribution utilities opted in would EnerNOC be able to enroll loads.

The role of the distribution utility was to work with EnerNOC to identify 'candidate loads' that could meet requirements (such as a minimum 150kW load curtailment, hours of operation, and response time with 60 minutes), support metering and communications installations, provide data as needed for validating performance, and troubleshoot issues with EnerNOC and loads.

The recruitment steps were as follows:

1. EnerNOC worked the BPA Distributed Energy Resources (DER) team to introduce the demonstration to BPA Power Account Executives and Energy Efficiency Representatives.

2. BPA Power Account Executives introduced EnerNOC to serving utilities for the summer and winter products.
3. EnerNOC met with serving utilities to encourage their participation by allowing EnerNOC to approach their customers to participate. EnerNOC requested that an agreement be signed with serving utilities that identified responsibilities and would allow EnerNOC to pay serving utilities for each MW nominated.
4. EnerNOC approached participants whose utilities signed up to enroll in program. Meetings were a mix of utilities in attendance and not in attendance. EnerNOC also approached national account EnerNOC C&I customers.
5. Participants enrolled through signing a contract with EnerNOC. EnerNOC (and in some cases the utility) installed EnerNOC Site Servers at participant facilities to record usage and provide energy profiling through the EnerNOC platform as well as working through curtailment plans and testing curtailment capabilities.

As this was a two year demonstration, EnerNOC and the utilities continued to recruit loads after the first year, and four additional participants signed up for the 2016/2017 winter.

E. Participants

BPA. The Bonneville Power Administration is a nonprofit federal power marketing administration based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric projects in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington. BPA provides about 28 percent of the electric power used in the Northwest and its resources — primarily hydroelectric — make BPA power nearly carbon free.

BPA also operates and maintains about 75% of the high-voltage transmission in its service territory. BPA’s territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

EnerNOC. EnerNOC was founded as a private company in 2001, went public on NASDAQ in 2007 and was acquired by the Enel Group in 2017. EnerNOC’s core business since its inception has been C&I demand response and it remains the backbone of EnerNOC today as an Enel Group Company. EnerNOC’s headquarters is in Boston, MA with more than 20 satellite offices around the world. EnerNOC has 15 years of experience designing and implementing C&I demand response programs globally.

Autogrid. Established at Stanford University in 2011, AutoGrid offers a suite of Energy Internet applications that allow utilities, electricity retailers, renewable energy project developers and energy service providers to deliver clean, affordable and reliable energy in a distributed energy world. AutoGrid has a team of software architects, electrical and computer engineers, data scientists and energy experts who apply cutting-edge analytics and in-depth energy data science to solve critical energy problems.

Distribution Utilities.

Central Lincoln People's Utility District. Central Lincoln PUD has a service area of about 700 square miles, encompassing 112 miles of Oregon's central coastline, and serves portions of four counties: Coos, Douglas, Lane, and Lincoln. Central Lincoln serves more than 32,734 residential customers and approximately 5,625 commercial and industrial customers.

City of Port Angeles. The City of Port Angeles located on the north end of the Olympic Peninsula in Washington State, formed a municipal utility in 1891 making it the fourth oldest electric utility on the West Coast. The city serves 11,200 residential and business customers in the City of Port Angeles.

Clark Public Utilities. Clark Public Utilities is a customer-owned public utility that provides electricity service to more than 193,000 customers throughout Clark County, and water service to about 30,000 homes and businesses in unincorporated areas of Clark County.

Consumers Power Inc. Consumers Power is a privately owned nonprofit rural electric cooperative serving 22,000 members in parts of six counties in Oregon: Benton, Lincoln, Lane, Linn, Polk, and Marion. Consumers is a member of the Pacific Northwest Generating Cooperative (PNGC).

Franklin Public Utility District. Franklin PUD is a publicly owned utility headquartered in Pasco, Washington (Franklin County Washington) that serves 25,000 customers. The service territory covers 435 square miles.

Snohomish County Public Utility District. Snohomish PUD is the second largest publicly owned utility in Washington that serves over 341,000 electric customers and about 20,000 water customers. The service territory covers over 2,200 square miles, including all of Snohomish County and Camano Island.

Umatilla Electric Cooperative (UEC). UEC serves a large portion of the Columbia Basin and Blue Mountain country of Northeastern Oregon, and serves more than 14,800 accounts on nearly 2,257 miles of power lines. The cooperative's territory is located west of Boardman in Morrow County and covers much of Umatilla County surrounding the cities of Hermiston and Pendleton and into the Blue Mountains. UEC is a member of PNGC.

PNGC. PNGC Power is a Portland-based electric generation and transmission (G & T) cooperative owned by 15 Northwest electric distribution cooperative utilities with service territory in seven western states (Oregon, Washington, Idaho, Montana, Utah, Nevada and Wyoming). UEC and Consumers Power, who participated in the project, are two members of PNGC.

Participating Loads.

16 loads were recruited through the course of the demonstration with water and wastewater treatment (six participants) being the leading load type given the inherent storage/time flexibility of these processes. During the course of the demonstration, three participants unenrolled given changes in ownership, challenges in meeting the hour windows of event calls (e.g., no people on site), and changes in business operations, while four loads were added in the second year. The change in the load composition was not unexpected as this is the nature and advantage of having an aggregated portfolio. As the demonstration had a 65 kW minimum, there were no residential loads enrolled in the project.

Table 1: Demonstration Participant List

#	Participant	Utility	Industry	Participant Description
1	**Great Western Corp**	Central Lincoln	Industrial	Perform maintenance on bridge
2	**Andersen Plastics**	Clark	Industrial	Produce milk and plastics
3	**Kizer Farms**	Consumers	Agriculture	Sod Farm
4	**City of Vancouver Water**	Clark	Water	Provides water service to Vancouver, WA
5	**Port of Morrow**	Umatilla	Port	Port authority in Boardman, OR with three industrial parks
6	**Cascade Specialties**	Umatilla	Agriculture	Produce dehydrated onions
7	**Pacific Ethanol**	Umatilla	Agriculture	Produces ethanol, wet distillers grains, corn oil, and CO2
8	**Nippon Paper**	Port Angeles	Pulp	Pulp and paper mill
9	**City of Edmonds**	Snohomish	Water and wastewater	Wastewater treatment center for Edmonds, WA
10	**Kenyon Zero Storage**	Franklin PUD	Cold storage	Provides freezing and cooling storage
11	**Alderwood Water and Wastewater District**	Snohomish	Water and wastewater	Provides water service and wastewater treatment in Snohomish County
12	**Zen noh hay**	Franklin PUD	Agriculture	Produces forage products (hay)
13	**City of Everett**	Snohomish	Water and wastewater	Provides water service in Snohomish County
14	**Snohomish PUD Battery**	Snohomish	Battery	1MWh battery
15	**Clark Utilities Water**	Clark	Water and wastewater	Provides water service to Clark County
16	**King County, Brightwater**	Snohomish	Water and wastewater	Wastewater treatment plant for King County, WA

Monthly Nominations. Each month, EnerNOC provided to BPA a report of loads that would be participating and their nominated kWs of curtailment. This monthly nomination process was designed to accommodate business fluctuations.

Table 2: Nomination Amounts by Month

	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16
Season 1 - Aggregated Nomination (kW)	8,990	9,000	13,000	13,000	13,000

	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
Season 2 - Aggregated Nomination (kW)	17,480	17,380	4,195	4,195	3,995

During the second season, a single large load (13,000 kW) was no longer able to participate and the total nomination fell to the 4,000 kW range.

F. Metering and Verification

Intervals. EnerNOC contractors or the serving utility placed data pulse equipment at each end-load to capture metering data in order to provide the requisite 1 minute interval data to BPA. EnerNOC registered and enrolled each meter from participating facilities in BPA's DR Management System (DRMS) on a monthly basis providing a file to BPA and to Autogrid, BPA's DRMS provider.

Baseline Methodology. A **"5 of 10" baseline** with a day-of-load adjustment was used to measure event performance. This baseline is described as follows:

> For each participating load, the facility baseline usage for any interval during a Program Event was determined (subject to the Day-of Load Adjustment described below) as the average of the participating load's measured demand, in kilowatts (kW), during the same time interval as the program event in each of the participating load's five highest energy usage days (as defined below) of the immediate past ten capacity delivery days; provided, however, that the past ten capacity delivery days excluded any capacity delivery day in which a program event was dispatched. In the event ten capacity delivery days' worth of meter data were not available, EnerNOC used meter data from the maximum number of available capacity delivery days, but in all cases EnerNOC would use no fewer than 5 capacity delivery days' worth of meter data for a participating load in order to establish a baseline.
>
> The 5 highest energy usage days for a given participating load were defined as those days having the highest average kW usage for that participating load during program availability hours. For winter events, the program availability hours used to calculate the 5 highest energy usage days for a given participating load corresponded to either the morning or afternoon event window (i.e. morning events had a window of 7:00 - 10:00, while afternoon events used 17:00 – 20:00).

A “Day-of Load Adjustment” was applied to each participating load for each interval during a program event, which equaled the average difference between the participants’ baseline usage and the participating load’s actual energy usage during the two-hour period ending with the 5-minute interval immediately preceding EnerNOC's notification of a program event. The Day of Load Adjustment could result in an increase or a decrease to the participant’s baseline usage but could not result in the participant’s usage being less than zero.

G. Demand Response Management Systems (DRMS) and Event Dispatch

- BPA leveraged AutoGrid’s Demand Response Optimization Management System (DROMS) to support the EnerNOC program. DROMS was initially implemented in 2014 for the BPA Energy Northwest demonstration. However, the EnerNOC program was significantly different in its requirements and integration with EnerNOC’s system. BPA engaged AutoGrid early on in the contracting process with EnerNOC to identify the best way to approach this program with out of the box DROMS functionality. This early engagement allowed the team to identify any gaps that existed between the program requirements and DROMS current feature set and plan for them in upcoming product releases. The following describes the system functionality and integration necessary to support the EnerNOC program.
- Product Management: DROMS allowed for creation of products and managed availability of the product based on constraints such as number of events allowed per week, and days of the week. This feature in DROMS had to be enhanced to support multiple event periods in one day.
- Event Scheduling: DROMS enabled BPA operations the flexibility to schedule events ahead of time or enter them in real time.
- Event Dispatch - Events were dispatched to Enernoc's VEN/VTN over OpenADR 2.0. Just as in BPA’s aggregated DER demonstration with Energy Northwest, the signal sent over OpenADR 2.0 was a simple level (0, 1, 2, 3). Both Energy Northwest and EnerNOC VEN/VTN were supported from a single BPA tenant.
- Participant Registration - Since EnerNOC was sending individual meter data, customer registration was required to get the individual meter IDs into DROMS, and correctly associated with each program. EnerNOC leveraged DROMS' customer information CSV upload method.
- Meter Data: EnerNOC provided load actual data for each individual participant in their program(s). AutoGrid calculated load shed data through usage of an X of Y baseline (more details on baseline included in “Baseline” section below).
    - *Integration Method:* EnerNOC posted zipped CSV files using AutoGrid’s MDM WebServices API.

- *Data Type:* Load actuals (not load shed actuals, as in the case with aggregator Energy Northwest/RAI).
- *Data Interval:* 1-minute, both for load actual inputs, and calculated load shed outputs.

- Baseline: An X of Y baseline with a day of adjustment was configured in AutoGrid to match EnerNOC's contractual baseline methodology. Enhancements were required to accommodate the morning of adjustment.
- Reporting: During an event, operators were able to view performance in near real time. Reports were also available after the fact via the AutoGrid reporting feature.
- Hosting: Both DROMS and EnerNOC's VTN/VEN were hosted in the Amazon Web Services (AWS) Federal Cloud environment. A Virtual Private Network (VPN) was required to access the system from BPA and for all communications between systems.

Figure 3: System Architecture Diagram

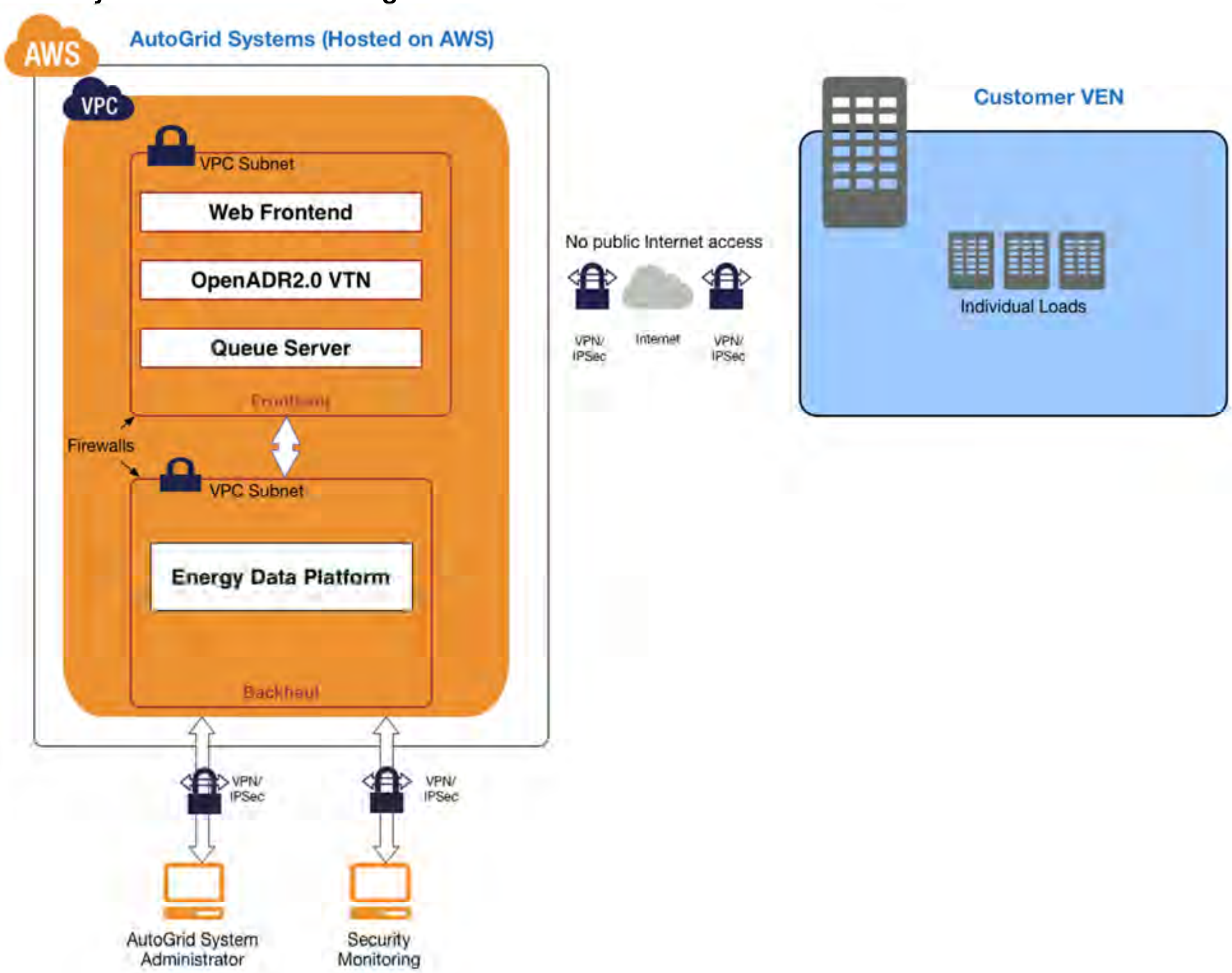
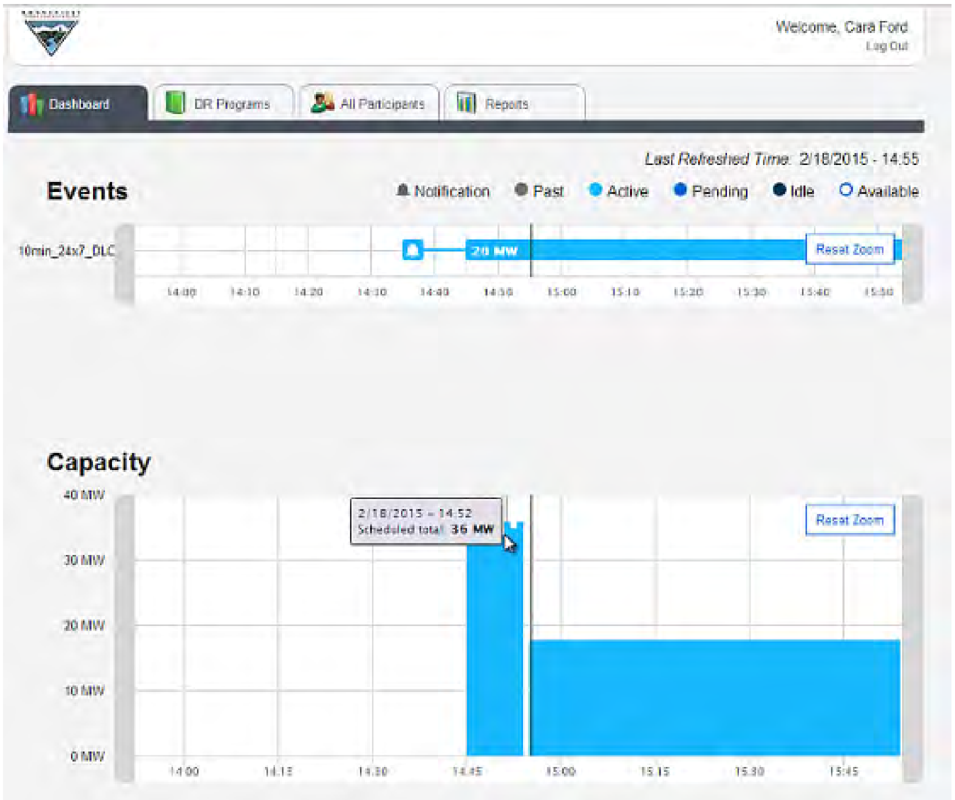


Figure 4: AutoGrid Operator Dashboard



H. Settlement

At the conclusion of each month, EnerNOC provided to BPA a summary file that included a "preliminary" invoice, the nominated amount of load at a participant and at an aggregated level, performance data for events called during the month both at a participant and aggregated level, and payment calculations. BPA reviewed this summary file, and upon validation paid EnerNOC per the contract terms. BPA paid EnerNOC both a capacity payment ($/kW-month) and an energy payment ($/kW) for invoices which were declared as "preliminary" in case any meter data was missing and needed extra review.

Separately, EnerNOC settled with its customers per the contract terms between EnerNOC and the customers. EnerNOC provided a capacity payment ($/kW-month) and energy payment ($/kW) on a quarterly basis based upon performance from events during that quarter, after the customer performance from the events had been finalized.

VI. Performance Results

A. Performance Evaluation Methods.

BPA measured performance in two ways for this demonstration; both methods centered on the quantity of actual load curtailment that EnerNOC delivered in aggregate against nominated load.

1. **Contractual Performance**. For contractual payments to EnerNOC, BPA set contract performance bands such that the monthly capacity payment was decremented for each event which fell below 100%.

Contract Performance Bands		
Max	Min	Penalty to Monthly Capacity Payment
	100%	0
100%	90%	1%
90%	80%	6.50%
80%	0%	13%

To determine the overall performance of an event, the sum of the all participating sites' lowest performing hour was divided by the sum of all participating sites' weighted average of committed load reduction.

2. **Average Performance.** BPA also looked at the average hourly performance, not just the lowest hour, to calculate performance over the course of a multi-hour event. This method gives a sense of typical hour results.

B. Testing Regimen

Per the contract, 60 hours of events could be called in each season, the winter of 2015/2016 and the winter of 2016/2017. An individual event could be up to three hours in length. In the first winter season (December 1, 2015 to April 30, 2016), 21 events were called totaling 55 hours of a possible 60 contractual hours. In the second winter season (December 1, 2016 to April 30, 2017), 16 events were called totaling 39.75 hours of a possible 60 contractual hours.

Each event was measured by the contractual (lowest hour of a multi-hour event) performance and by the average across multiple hours of an event. As shown in the event results below, BPA called events on two consecutive days three times, and on three consecutive days also three times. In one case from December 28th to December 30th 2015, BPA called events both morning and afternoon on three consecutive days. These multi-day events were designed to stress test the portfolio to see how it would hold up during the simulation of a cold weather event lasting several days. The events are shown in Table 2 and 3 below.

Table 2: Winter 2015/2016 Events

Event Date	12/7/2015	12/8/2015	12/16/2015	12/17/2015	12/28/2015	12/28/2015	12/29/2015	12/29/2015	12/30/2015	12/30/2015	1/29/2016
Total Nominated (kW)	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	9,000
Sum of Actual Load Reduction (kW)	16,714	15,201	58,495	38,253	46,245	64,030	65,110	59,597	80,135	63,020	29,219
Total Weighted Average Performance (kW)	16,714	15,201	19,498	12,751	15,415	21,343	22,197	19,866	26,712	21,007	19,479
Total Lowest (kW)	16,714	15,201	18,803	10,973	14,767	20,857	18,712	19,252	26,058	19,703	19,253
Average Hour Performance / Nominated	186%	169%	217%	142%	171%	237%	247%	221%	297%	234%	216%
Lowest Hour / Nominated Amount	186%	169%	209%	122%	164%	232%	208%	214%	290%	219%	214%
Event Date	4/18/2016	4/19/2016	4/20/2016	4/20/2016	4/27/2016	4/27/2016	4/28/2016	4/28/2016	4/29/2016	4/29/2016	Unweighted Average Performance
Total Nominated (kW)	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	
Sum of Actual Load Reduction (kW)	35,209	44,238	7,271	39,099	44,568	52,284	42,236	47,927	43,683	34,399	
Total Weighted Average Performance (kW)	11,736	14,746	2,424	19,549	17,827	17,428	14,079	15,976	14,561	15,289	
Total Lowest (kW)	11,303	13,509	2,207	19,173	17,642	16,777	14,007	15,839	14,405	13,926	
Average Hour Performance / Nominated	90%	113%	19%	150%	137%	134%	108%	123%	112%	118%	**164%**
Lowest Hour / Nominated Amount	87%	104%	17%	147%	136%	129%	108%	122%	111%	107%	**157%**

Table 3: Winter 2016/2017 Events

Event Date	12/8/2016	1/25/2017	2/28/2017	2/28/2017	3/2/2017	3/6/2017	3/6/2017	3/7/2017
Total Nominated (kW)	17,454	15,451	4,195	4,195	4,056	4,056	4,056	4,056
Sum of Actual Load Reduction (kW)	65,325	11,135	12,202	12,336	11,159	11,824	12,561	10,588
Total Weighted Average Performance (kW)	21,775	5,567	4,067	4,112	3,720	3,941	4,187	3,529
Total Lowest (kW)	21,240	5,541	4,026	3,938	3,542	3,909	3,873	3,319
Average Hour Performance / Nominated	125%	36%	97%	98%	92%	97%	103%	87%
Lowest Hour / Nominated Amount	122%	36%	96%	94%	87%	96%	95%	82%
Event Date	3/7/2017	3/7/2017	3/16/2017	3/16/2017	3/27/2017	3/28/2017	3/29/2017	Unweighted Average Performance
Total Nominated (kW)	4,056	4,056	3,995	3,995	3,995	3,995	3,995	
Sum of Actual Load Reduction (kW)	10,588	7,468	11,495	14,897	13,755	8,626	12,498	
Total Weighted Average Performance (kW)	3,529	3,734	4,180	4,966	4,585	4,313	4,166	
Total Lowest (kW)	3,319	3,726	3,795	4,708	4,349	4,256	3,852	
Average Hour Performance / Nominated	87%	92%	105%	124%	115%	108%	104%	**99%**
Lowest Hour / Nominated Amount	82%	92%	95%	118%	109%	107%	96%	**95%**

C. Performance Results

<u>Results – Contractual Performance ("Lowest Hour")</u>. As noted above, BPA evaluated performance in the contract of the lowest hour of kW in an event against the nominated kW. For example, if the aggregated portfolio achieved 7, 6, and 4 MWs of curtailment in hours one, two and three of an event respectively, the performance would be evaluated against the 4 MWs, the lowest performing hour. In the first season, the portfolio performed at greater than 90% of the lowest hour 90% of the time, while in the second season the portfolio performed greater than 90% of the lowest hour 79% of the time. The reduced performance is partly explained by a single large load leaving the portfolio in year 2; this industrial load had consistently contributed much more than 100% of its commitment. In total, 86% of events exceeded 90% performance.

Table 4: Contractual Performance

2016				
Contract Performance Bands			Performance For Each Event	
Max	Min	Penalty	Total	Total
	100%	0	19	90%
100%	90%	1%	0	0%
90%	80%	6.50%	1	5%
80%		13%	1	5%

2017				
Contract Performance Bands			Performance For Each Event	
Max	Min	Penalty	Total	Total
	100%	0	4	29%
100%	90%	1%	7	50%
90%	80%	6.50%	2	14%
80%		13%	1	7%

Total - Both Seasons				
Contract Performance Bands			Performance For Each Event	
Max	Min	Penalty	Total	Total
	100%	0	23	66%
100%	90%	1%	7	20%
90%	80%	6.50%	3	9%
80%		13%	2	6%

The graphs below show contractual performance by event. While performance was stronger in the first year, in the second year, we saw more performance consistency starting with the third event in 2016/2017 after the large industrial load left the portfolio in 2017. After this point, there was less performance variation and a more balance in the portfolio.

Figure 5: Contractual Performance Event Performance – Winter 2015/2016

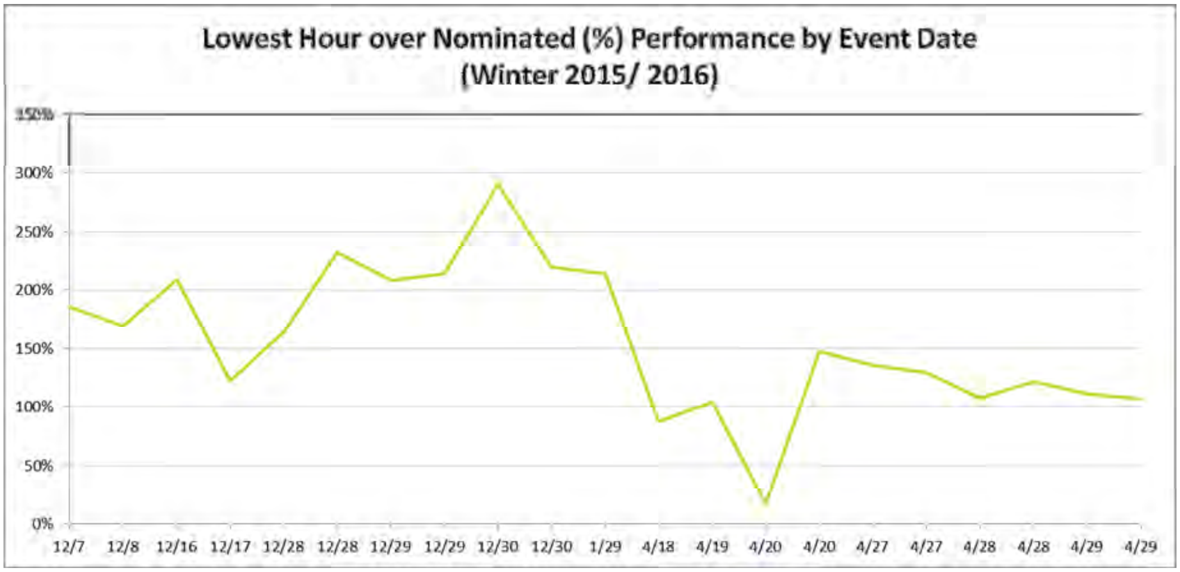
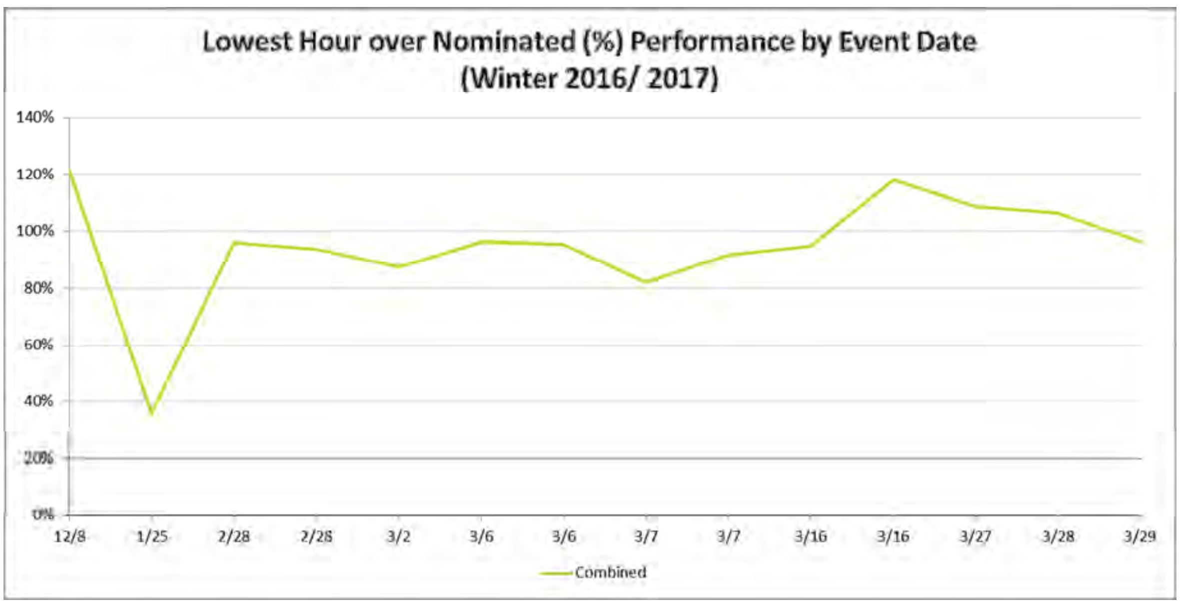


Figure 6: Contractual Performance Event Performance – Winter 2016/2017



<u>Results – Average Performance.</u> On an average hourly basis, the portfolio delivered 136% of the nominated over both seasons. In year one, we saw performance of 164% of the nomination; this was primarily due to a single large asset whose business operation entailed turning off pulp refining motors and whose load reduction greatly exceed their individual MW nomination. In the second season, the portfolio delivered 99% on average of the nomination.

Figure 7: Average Hour Event Performance – Winter 2015/2016

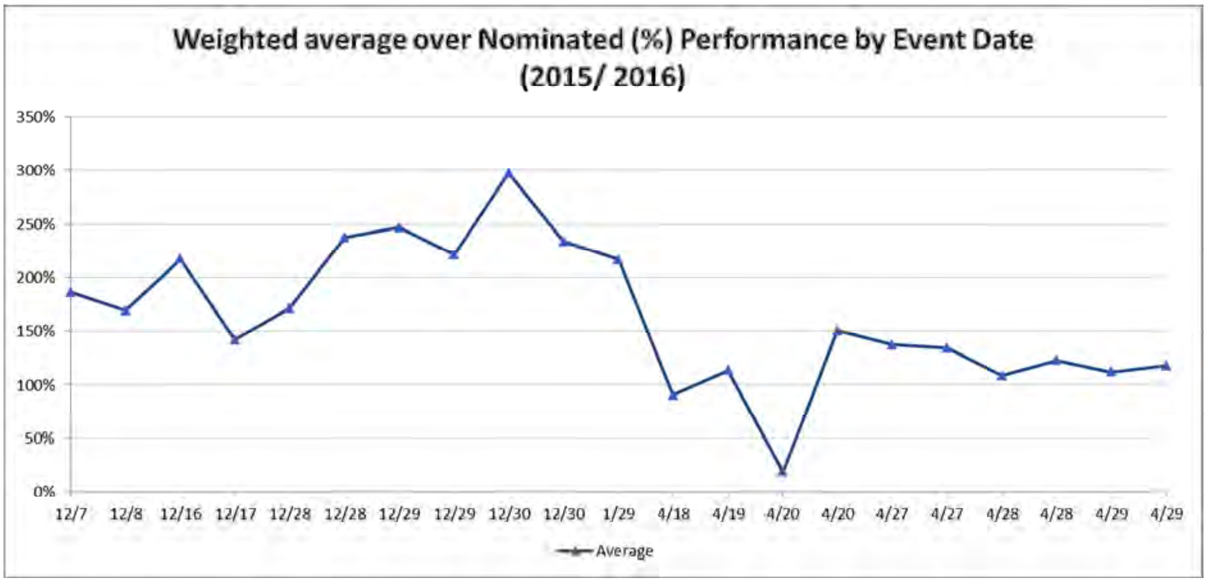


Figure 8: Average Hour Event Performance – Winter 2016/2017

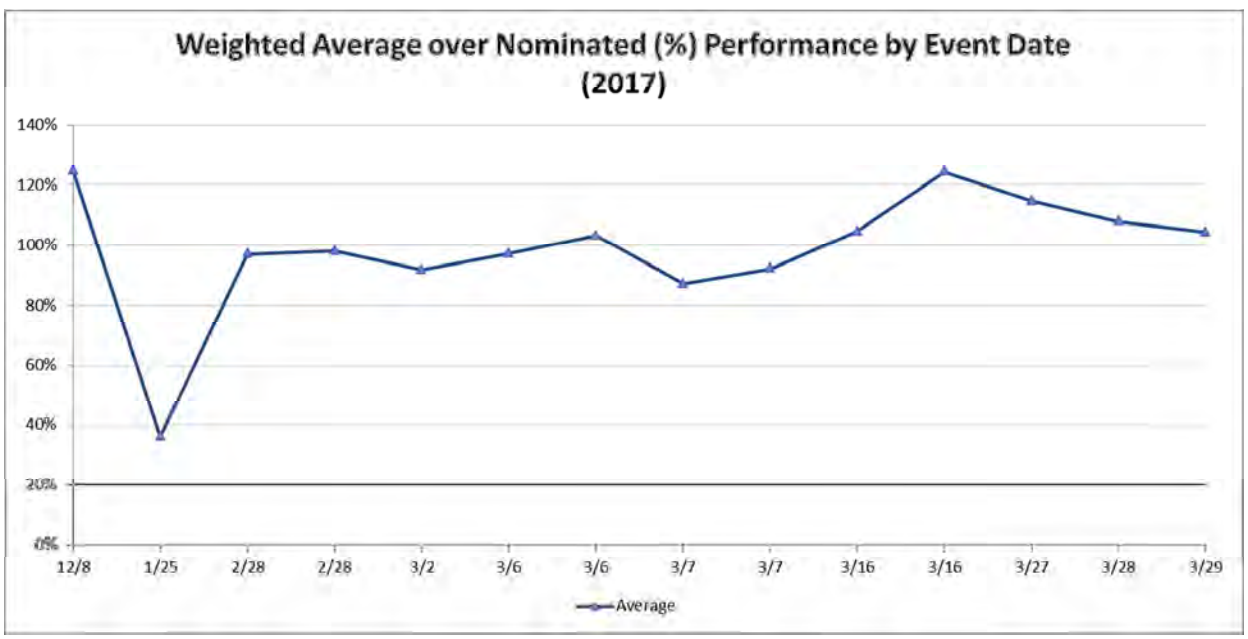


Figure 9: Average Hour Event Performance by Megawatt - Winter 2015/2016

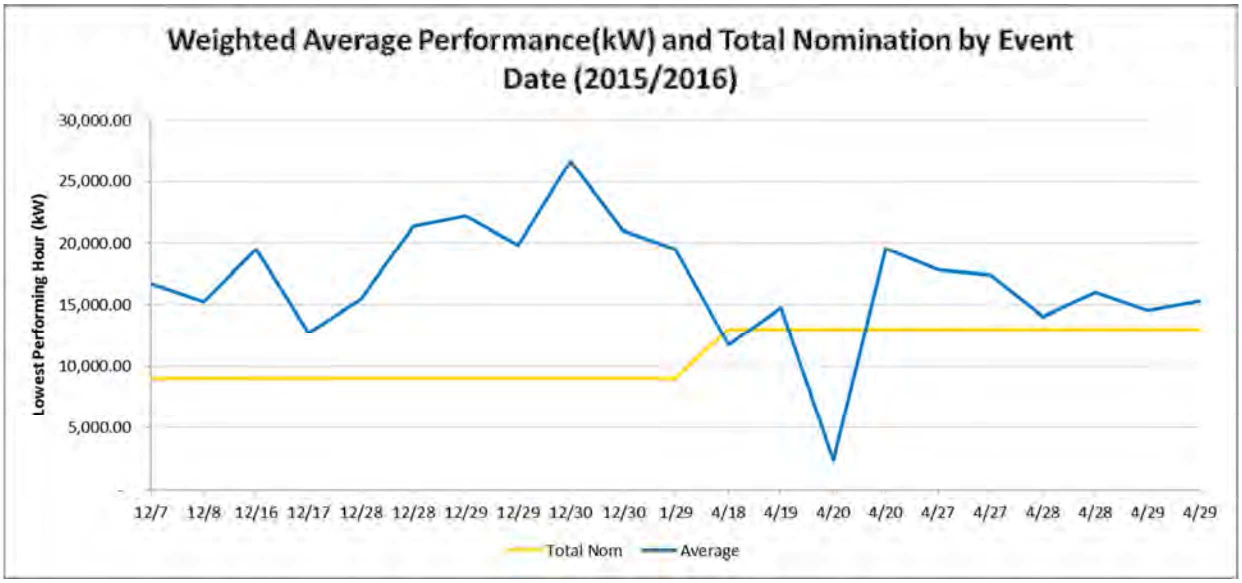
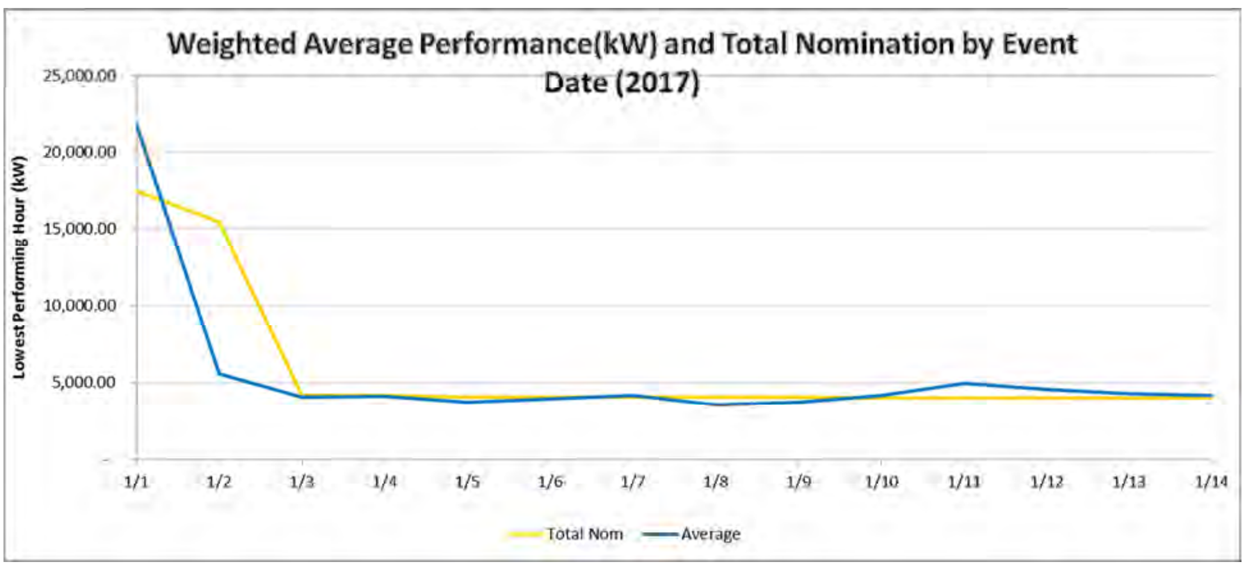


Figure 10: Average Hour Event Performance by Megawatt - Winter 2016/2017



Portfolio Fatigue. For the events that occurred on two and three consecutive days, we did not see strong evidence that by the final day portfolio performance fell. There was some trending, but not enough to draw a statistical conclusion that there was some fatigue after January 2017 when the last single asset, the paper mill, was no longer in the Demonstration. See table 5 below.

Table 5: Average Hour Event Performance for Consecutive Day Events

Two Consecutive Days Events	Events Per Day	Event 1	Event 2	Event 3	Event 4	Event 5	Event 6
12/7 - 12/8/2015	1	186%	169%				
12/16 - 12/17/2015	**1**	209%	122%				
3/6 - 3/7/2017	**2**	97%	103%	87%	92%		
Three Consecutive Days Events							
12/28 - 12/30/2015	2	164%	232%	208%	214%	290%	219%
4/18 - 4/20/2016	1*	87%	104%	17%	147%		
4/27 - 4/28/2016	2	136%	129%	108%	122%	111%	107%
3/27 - 3/29/2017	**1**	115%	108%	104%			
** This event had two events on the last day (morning and afternoon).*							

VII. Lessons Learned

BPA identified the following lessons learned from the demonstration as a result of speaking with customer utilities, participating loads, and BPA's Power internal operations, contracting, metering and Distributed Energy Resources teams.

Impacts of Contracting Complexity. This demonstration had multiple layers of contracts - between BPA and the aggregator, between the aggregator and the serving utility, and between the aggregator and the end-load. This complexity led to a drawn out time period to get started with the operational/testing phase of the demonstration and to bring new facilities into the portfolio. In many cases, redundant talks were happening with each utility. In retrospect, it may have made more sense to go through the contractual parameters as a group – BPA, aggregator and utilities - rather than with a one-off approach.

Recruitment.

The serving utility is the lynchpin to making the program a success. In recognition that the public distribution (retail) utilities have relationships with customers, this demonstration required the retail utility to "opt in" before EnerNOC could sign up loads. In all cases, it was critical for the utility to see a clear business proposition for their customers, to see the value in dedicating time – to answer customer questions and to cover their costs. We observed that if the utility – management and account executives – were on board to help vet potential accounts and give their explicit support recruitment was more successful.

This said, it was also observed that having an EnerNOC representative with the utility at early meetings with candidate loads was important so the aggregator could explain the program. Further, it is BPA's belief that a regional "kick-off" meeting hosted by BPA would have been helpful before having one-on-one meetings to introduce the program.

Not all distribution utilities approached chose to participate. Public utilities in only prescribed locations were eligible for the summer transmission congestion test, while all public utilities in the BPA balancing authority were eligible for the winter peak shaving test. BPA notified all these utilities about the demonstration. To meet timelines and focus resources, EnerNOC contacted 20 utilities. Of these, 10 utilities had qualified loads and wanted to participate, and in the end seven of the utilities had loads that signed up.

Utilities had a variety of reactions when approached to become part of the demonstration. Some wanted to engage to learn about demand response themselves and offer a service and financial opportunity to their customers. Some utilities were wary of an outside commercial entity operating in their territory and declined to participate, while smaller utilities often cited lack of staff and/or time to work on a new program.

Expect a "waterfall" of load participation. EnerNOC had advised and it was borne out that there is a standard "waterfall of participation" that should be expected. For every hundred loads screened, only a certain percentage will qualify, and of these only a certain percentage will consider signing up, and of these only a certain percentage will enroll. For this demonstration, hundreds of loads were vetted. EnerNOC ended up meeting with 64 entities, and ultimately signed up 16 to participate. As such, the lesson is that a large volume of candidates is needed to reach participant and megawatt goals. Because several of the largest utilities in the prescribed zone for the South of Allston summer product did not participate, the pool of potential candidates to start with was limited.

The diversity of the commercial, industrial and municipal customer loads meant a diversity of reasons for non-participation of potential loads. As EnerNOC met with prospects, they documented the reasons participants declined to enroll. The single largest factor was the minimum load size, which was 65kW for summer and winter participants, 110 kW for winter only participants, and 165 kW for summer only participants. Additionally, prospects cited many other reasons, for not enrolling including:

- Operations shut down by mid-afternoon, which did not allow load reduction for event calls that could go until 8:00 pm in the evening.
- The demonstration length at two years was too short to go through the effort and expense of having control vendors make changes to energy management systems, of having to build a work-around process for curtailment days, and determining curtailment strategies.
- Notification time was inadequate. The demonstration originally used a 10 minute advance notification for summer participants, and 20 minute notification for winter loads to respond to a request to curtail their load. BPA then, after consulting its internal operators, relaxed this notification time to 60 minutes in an attempt to increase the number of eligible potential participants. Even with this alteration, some entities said they would need more time to react, e.g. a day ahead.
- Some facilities had no ability to curtail without causing too much operational disruption.
- Facilities that had unpredictable operational schedules (not the same energy consumption day-to-day during the week) could not guarantee availability on days when curtailment requests would be made.
- The duration of the event calls at up to three hours was too long without causing harm to the product, e.g. at cold storage warehouses. Additionally, the up to three consecutive days was a challenging requirement for irrigators.

- The incentive payment was not high enough to induce enrollment for some candidates.

Metering

Equipment was seen as effective; however, there were some concerns about its installation and disposition. Multiple facilities said they liked the aggregator site server (“box”) that was used to gather meter pulses and report 1 minute interval data to BPA. Reports were that it was easy to install (less than 30 minutes) and there were no reports of malfunction.

In some cases, utilities noted that they preferred to install the box themselves, or at minimum have their meter technicians accompany the aggregator contractor to ensure quality and to meet safety requirements. Multiple utilities and sites also expressed that they would have liked clearer communication on who owned the equipment and what would happen to the site server after the close of the Demonstration. The equipment was left on-site, in line with the contract, and the site/utility were free to disable and remove if they chose.

Baseline proved to be highly complex, not easily understood, and perhaps not the best fit for participating load types. The “5 of 10” baseline with the day-of adjustment proved to be a challenge for many parties to understand. As multi-step calculations were required, participants were not easily able to determine if their curtailment met their target. One load had difficulty in setting its target because of the complexity and consistently over-delivered by a factor of two. Further, there were questions about why the five highest previous days would be chosen (as opposed as all ten) for non-thermal loads that tended to behave independently of weather patterns where a baseline would be desired for previous hot or cold days most like those during a curtailment day.

Software systems.

Aggregator software provided added benefit to utilities and participating loads. Positive comments were received – particularly from load participants – that the aggregator software gave them much better visibility to their energy usage with a more refined time resolution than from traditional metering. A few went so far as to say that this was a major benefit of participating.

Software Customizations of the Demand Response Optimization System (DROMS). BPA limited customizations and AutoGrid was able to integrate a majority of our requirements that were new for them into their base product. No code was being maintained especially for BPA.

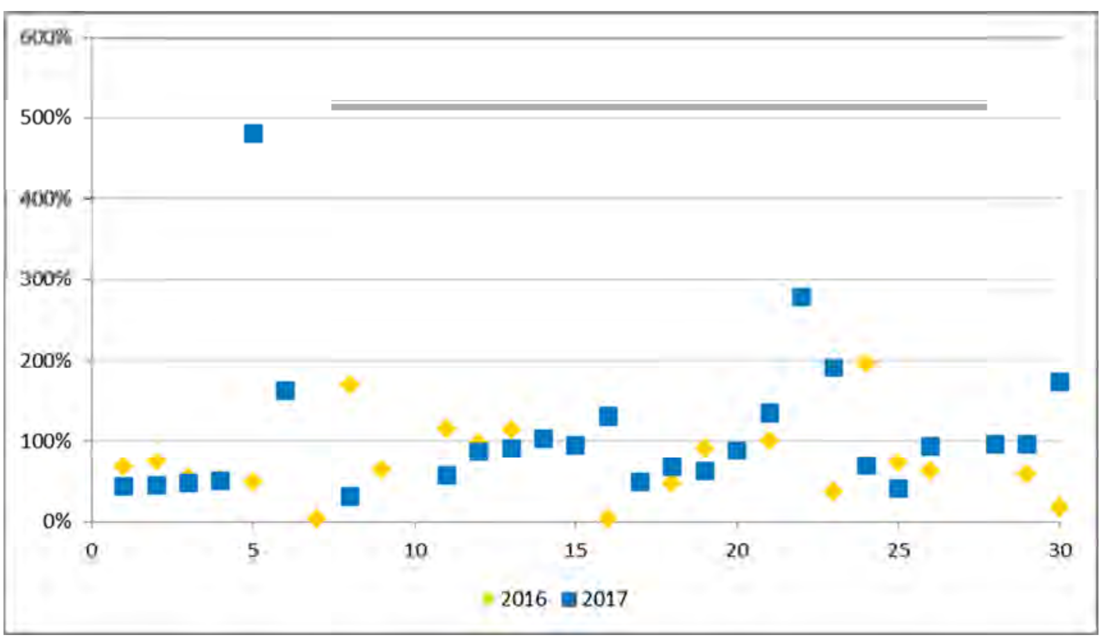
Vendor Collaboration for the DROMS. Vendor collaboration was a key element in system implementation and integration successes. Even though both teams were remote they built a rapport that allowed them to work through issues as they arose.

OpenADR Is Not Plug and Play. BPA found that while two vendors may use OpenADR they may not be able to shake hands without one or both vendors having to make modifications to their code. OpenADR was developed to be flexible and with that flexibility there have been many flavors of OpenADR implemented and the different flavors can't always communicate with each other.

Inclusion of non-traditional DER assets expanded the range of learnings. The demonstration was open not only to DR but also to energy storage and qualifying distributed generation. One battery, a lithium ion storage system, was enrolled, by Snohomish PUD. The utility was able to develop software programming such that the battery was consistently available and meeting its nomination amount. It also showed that "all sources" procurements will broaden the available asset pool for curtailment programs. At the same time, the demonstration was not able to enroll distributed generation that met the permitting requirements of the state and local jurisdictions, and it was found that this process was time consuming (to review eligibility of distributed generation for non-emergency purposes).

Aggregation Performance –Advantages of Load Diversity. The demonstration saw three loads drop out (two for business reasons, and one for operational disruption) and four loads join in the second season. Aggregate load performed at greater than 90% of nomination (actual as a % of expected) 86% of the time against the lowest hour, and on an average hour basis at 136%. Because of several large outliers, a weighted average was not used in our evaluation. In the scatter chart of Figure 11, each marker represented a metered site (the x axis). On the y axis, the sum of the weighted average performance over the sum of the nominated amount is presented. The graph shows that while the overall portfolio performs well there is a wide range of individual performance – many sites below or above 100% of their needed contribution and others well below or above. This highlights the value of diversity.

Figure 11: Average Hour Event Performance by Metered Site



Lessons Learned from Aggregator. EnerNOC, as aggregator, also provided their observations on lessons learned from the pilot. These lessons are:

- Serving utility support is critical to being able to reach MW targets:
    - If key serving utilities do not want to participate, then not able to access end loads needed to reach 25MW.
    - Key serving utilities participating, but limiting participants approached, also will lead to challenges in reaching targets.
- Serving utility and participant recruitment can be expected to be slow, and best to allocate more time to participant recruitment
    - Average timeframe between initial pilot introduction to utility and first meeting with a participant: 59 days.
    - Average Timeframe between first conversation with participant and participant signing up: 74 days.
        - Standard EnerNOC timeframe from first conversation to contract signing is 90 days.
- There were limited large loads to approach for summer/transmission congestion goals in the designated geography.
    - Finding ways to encourage key summer utilities and more smaller utilities to participate, and participation fully was critical to be able to enroll a 5+MW.
- There were limited large loads that can participate in a program with 60 hours of dispatch over a season
- Water and wastewater participants are a good fit for high dispatch program
    - 6/16 participants and 60% of April, 2017 nomination were from water and wastewater participants.
- Generators will likely take longer time to recruit than other participants
    - Detailed regulations within OR and WA could add time to beginning of process, then will have time needed to recruit the generators themselves, plus time needed to make expected equipment upgrades necessary for participation.
- Participants are able to respond to multiple events per day and multiple days in a row
    - Winter 2015/2016 had dispatches in mornings and evenings on 4/27, 4/28 and 4/29 with average performance of 130%.
    - Winter 2016/2017 had dispatches in mornings and evenings on 3/6 and 3/17 with average performance of 95%.

Recommendations from EnerNOC for future demand response efforts:

1. Partner with serving utilities to enroll participants:
    - Create stakeholder committee with utilities to work together on program rules and gain buy-in from initial design.
    - Set program start gate of key utilities or critical mass of utilities signed up to participate or might not make sense to move forward with program depending upon program goals.
    - Best for BPA to lead discussion with utility, with aggregator providing support, as utility likely trusts BPA more than aggregator.
    - For greatest success, BPA to provide utility incentives for participant enrollment or coach aggregator on designing meaningful incentives.
    - Work with each utility to set enrollment target and provide bonus if able to achieve enrollment target within schedule.
    - Give utility option to either fill target MW on their own, partner with aggregator, or let aggregator work directly with participants and vary incentive levels accordingly.
2. Identify key, large loads before program and discuss program rules with them that would allow them to participate:
    - Larger loads will favorably respond to being consulted early in process and can tailor program rules to be most successful; could meet with individually or create stakeholder participant group.
3. Create program with options to allow for greatest amount of participants to fit with rules, prioritizing needs of key loads:
    - Could offer options that limit number of dispatches per month, longer or shorter dispatch hours, longer or shorter lead times, longer or shorter event lengths, and potentially different baselines to allow most participants to find rules that work for them.
    - Will lead to greater amount of management oversight, but will result in highest MW enrollment.
4. Offer longer term contracts so participants are more likely to join, especially for generators
    - Participants more likely to join program in which they have multiple years to earn back any perceived losses.
    - Aggregator can work with generators to upgrade to EPA standards if have longer period of time to recoup costs.

VIII. Conclusion

While the demonstration did not achieve the levels of participation BPA wanted in the summer seasons, it did achieve significant advancements that will help public power execute DR in the Pacific Northwest.

The demonstration set a high bar – and achieved aggressive goals - in many ways: (1) Loads were required to respond with 60 minutes and had to be available for three consecutive days for up to three hours at a time, (2) loads were given a high number of event dispatches, (3) BPA's DERMS was integrated with EnerNOC's communications and control system with OpenADR to provide real-time one minute data, (4) a cascading contract structure was conceived that involved three parties many for the first time with demand response, and (5) multiple asset types were allowed including batteries which do not have a long history participating in DER portfolios.