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October 31, 2018

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID: DISTRIBUTED SYSTEM PLATFORM REV DEMONSTRATION PROJECT – Q3 2018 REPORT

Dear Secretary Burgess:

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") hereby submits for filing its quarterly update to the Distributed System Platform REV Demonstration Project Implementation Plan covering the period of July 1, 2018 to September 30, 2018 ("Q3 2018 Report") as required by the REV Demonstration Project Assessment Report filed by the New York State Department of Public Service Staff ("Staff") with the Commission on July 15, 2016 in Case 14-M-0101.

Please direct any questions regarding this filing to:

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National Grid looks forward to continuing to work collaboratively with Staff as it proceeds with the implementation of the Distributed System Platform REV Demonstration Project.

Respectfully submitted,

/s/ Karla M. Corpus

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Enc.

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Distributed System Platform
REV Demonstration Project
Buffalo, New York

Q3 2018 Report

October 31, 2018

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1.0 Executive Summary

Under the Commission's Reforming the Energy Vision ("REV") Proceeding, the Distributed System Platform ("DSP") Demonstration Project (the "Project") aims to develop, deploy, and test the first of its kind solution with the objective to create a new distribution-level energy market. The Project will identify the locational generation value of customer-owned distributed energy resources ("DER") and provide a platform that will allow these assets to participate and provide energy and/or ancillary services to the electric distribution system (*i.e.,* the "grid"). The Project was initially filed with the New York State Public Service Commission ("Commission") by Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") on July 1, 2015. A revised scope for the Project was filed with the Commission on June 15, 2016. The review of the revised scope for the Project was completed by the New York State Department of Public Service Staff ("DPS Staff") on June 22, 2016. DPS Staff subsequently filed an assessment report with the Commission on July 15, 2016 finding that the Project meets the Commission's REV policy objectives and demonstration project principles and complies with Ordering Clause 4 of the Commission's Track One Order.[1]

The Project will test a simple, small-scale DSP that will communicate with network-connected Points of Control ("POCs") associated with the Buffalo Niagara Medical Campus Inc. ("BNMC") DERs. Additionally, the project will evaluate and test the DSP in additional locations that may present different distribution-level constraints and DER types. The DSP is "an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs" where the "DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system."[2]

Image 1.1 – Part of the Buffalo Niagara Medical Campus

The Project team currently consists of National Grid, BNMC (*depicted in Image 1.1*), and Opus One Solutions ("Opus One"). Opus One provides contracted services to National Grid. Opus One is a software engineering company. Their role in the Project encompasses not only software development, but also thought leadership, planning, and execution.

[1] Case 14-M-0101 – *Proceeding On Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) ("Track One Order"), p. 132.
[2] *Id*., p. 31

The BNMC consists of thirteen (13) member institutions and close to one hundred (100) public and private companies that are a dynamic mix of health care, life sciences, medical education, and private enterprise; it is spurring significant growth in Western New York. As healthcare providers, most BNMC member institutions are required to have access to back-up or emergency power, which typically employ distributed generation (“DG”). However, even in an area that is affected by extreme weather such as Buffalo, these expensive DG assets sit idle most of the time. With the DSP, DER owners would have an option to extract more value from those DG assets by participating in the energy market through the DSP.

If successful, the DSP will create new revenue streams for both the DER owners and National Grid, and meet the other New York REV objectives as stated in the Track One Order. The DSP could then be extended across National Grid’s service territory.

Image 1.2 – Images of Kaleida Health (left) and the Roswell Park Cancer Institute (right), members of the BNMC

The Financial Model for DER Value Streams: LMP+D+E

In the near term, services transacted and purchased through the DSP will test the implementation of a “LMP+D+E” financial model approach for electric services. The value of “LMP+D+E” will be evaluated in the Project and is expected to generate sufficient financial incentives for existing DERs to participate in the DSP market. For LMP, the Project will consider New York Independent System Operator (“NYISO”) locational-based marginal prices (“LBMP”) for Day-Ahead (“DA”) and real-time market prices[3] and any additional capacity constraints and transmission losses that may be priced into the local area through the New York Installed Capacity Market (“ICAP”), if they can be determined.

“D” refers to distribution delivery value, which is the value that DERs can provide to the electric distribution system, such as load relief to help alleviate substation or feeder constraints. This evaluation effort will analyze potential issues with capacity provision by considering average demand, peak demand, forecasts of demand growth, day-ahead load forecast, and historical demand at the feeder and substation levels. After analyzing these issues, values can be

[3] NYISO LBMP and real-time pricing information, *available at*: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp.

assigned to each of these items. The value of D will be evaluated in the Project and is expected to generate sufficient financial incentives for DERs to participate in the DSP market.

"E" refers to external or societal value (*e.g.*, low carbon, renewable or domestic fuel source) that may be provided by DERs that are not captured in in LMP or D. The value of E will most likely be attributable to those renewable generation, or current Net Energy Metered ("NEM") resources eligible to participate in the Value of DER Phase One NEM or Value Stack compensation as set out in the Commission's Value of DER ("VDER") Order[4] (*i.e.*, solar PV, farm waste, micro-CHP, fuel cell, and micro-hydro DG). While this component was initially omitted from the DSP Implementation Plan,[5] the Project Team has developed a first component in order to incentivize the use of renewable energy.

2.0 Highlights Since Previous Quarter

The project continued to have positive progress during the Q3 of 2018. One key focus area was on enabling the DSP platform to be deployed in different NYISO areas and manage multiple distribution-level markets at once. Meanwhile, the team worked closely with the BNMC and worked around the metering issues installing a direct communication link between the DERs and the DSP.

For a reference timeline emphasizing the major milestones and accomplishments, see Figure 2.1 below.

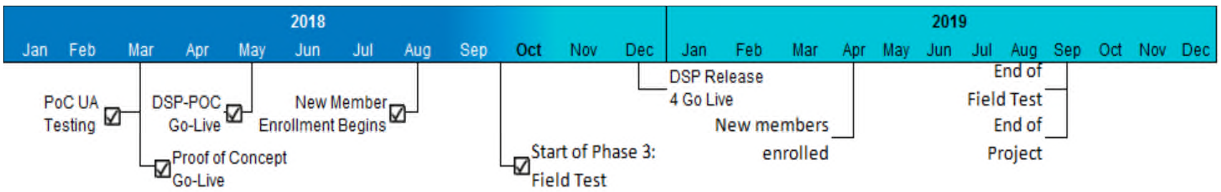

Figure 2.1 – Achievements and Milestones Timeline

2.1 Major Task Activities

1. DSP Sprint Releases

National Grid and Opus One maintained focus on the technology development of the DSP platform and POC features in this quarter, continuing to work with agile methodologies. The agile method is an approach to project management that is used in software development. This approach assists teams in responding to the unpredictability of constructing software. It uses incremental, iterative work sequences that are commonly known as sprints.

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[4] Case 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources* ("VDER Proceeding") *et al.*, *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* (issued March 9, 2017).
[5] REV Proceeding, National Grid: Distributed System Platform REV Demonstration Project-Implementation Plan (filed August 15, 2016) ("DSP Implementation Plan").

Opus One continued to develop and add features to the DSP platform, focusing on improving the user experience in the customer portal, refining the forecasting capabilities, and expanding the DSP's DER catalog.

However, with the proposed Project expansion to new locations (other than the BNMC), the Project team worked diligently to reprioritize certain features, such as Role-Based Access Control and improvements in reporting capabilities, to enable the DSP to be deployed in different NYISO zones, manage multiple markets, and meet different customer needs. As a result, the team agreed to push Release 3 to Q4 of 2018.

2. Customer M&V Equipment Installation

After encountering additional roadblocks (mainly, high upfront costs to accommodate additional switchgear, equipment and cabling) to the installation of the Itron meters to perform the necessary Measurement and Verification ("M&V") for DSP settlement, the Project team was able to find a work around to extract data directly from the customer's control system to the DSP.

The Project team worked with Kaleida Health facilities management and the Cummins manufacturer's technical support team to install an interim monitoring solution that will be used to verify participation in DSP events and evaluate metering requirements going forward. The solution pulls Modbus register readings (a common communication protocol in industrial electronic devices) from the existing DER Digital Control System and relays the kWh readings to the DSP. These readings will be used to verify that the assets have participated in a committed event and will inform the settlement process until the full metering solution has been installed.

3. Enrollment of New DSP Participants

The Project team started to target potential new DSP participants, focusing on customers that could provide the most interesting case studies based on existing distribution needs, after considering their location and DER technology.

One of the most promising locations is in Utica, where there is a good mix of DER assets and distribution-level needs. The Project team has been working closely with a few potential customers that have shown strong interest in participating in the Project by adding the feeders' CYME models and modeling the customer's Combined Heat and Power ("CHP") assets.

However, there are some challenges that the Project team is working to overcome. Originally, the DSP was developed to meet the needs of a specific customer (the BNMC). As the team starts to work with different types of customers and asset types, there are new requirements related to communication protocols and automation needs not required by the BNMC.

Additionally, the majority of customers who have existing DER assets have long-term contracts *(i.e.,* Power Purchase Agreements or "PPA") that they may need to exit in order to participate in the Project. Moreover, while most customers targeted are interested in the DSP, there are concerns regarding the longevity of the Project, making it a difficult decision to exit a long term PPA for a short term REV demonstration project.

The Project team will continue to focus on enrolling new participants to the platform in Q4 of 2018 and beyond.

2.2 Challenges, Changes, and Lessons Learned this Quarter

2018	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q3	The high nameplate voltage on the BNMC's DERs, limitations at the facility, and funding concerns, have caused the BMNC to postpone the investment required to install the M&V equipment.	M&V Equipment Installation will be postponed. In the meantime, the DSP will have direct access to data from the customer's controller.	The Project team worked with Kaleida Health to install a direct secured link between the controller and the DSP.	The team has embraced the flexible and agile nature of REV demonstrations to be able to pivot, and find easier or faster alternatives as long as the main goal is met.
Q3	With the proposed Project expansion to new geographic areas, and the potential to add up to five (5) new participants, the Project's budget has increased to reflect the estimated impact on costs.	The Project budget has increased by $700,000 (~15%).	The Project has reallocated the remaining budget and reduced the budget totals in certain areas to mitigate the impact to the overall budget increase.	None.
Q3	Existing DER usually have long-term contracts (*e.g.,* PPA) or more lucrative alternatives (*e.g.,* NEM) that inhibit them from participating in the DSP.	As the pool of available DERs in the targeted geographic locations is reduced, there fewer potential candidates for the DSP.	The Project team is targeting customers that have PPAs with National Grid and is working with them to address any issues and concerns.	While alternatives like NEM are still available to DER owners, it will be more difficult to enroll them in the DSP.
Q3	The DSP was originally designed and built to meet the needs of the BNMC. As it is now being expanded, there are added software needs and additional time is required to address unplanned requirements.	The deliverable schedule was modified. Connect the new DERs to the DSP is expecting to be an ongoing effort through Q1 and Q2 of 2019.	After meeting with potential customers and identifying gaps, the Project team reprioritized and rescheduled the deliverable schedule.	The lack of standardization between DER providers in communication protocols and automation capabilities is a barrier to expanding the Project.

3.0 Next Quarter Forecast

During the 4th Quarter of 2018 the Project team will continue to work on the technology development of the DSP software. The result will be two (2) releases in the last quarter of 2018, scheduled for October and November.

At the same time, the Field Demonstration phase will officially start with the BNMC. The Project team will train Kaleida Health in the use of the Customer Portal, with the first events to occur in October.

Finally, the Project team will continue to engage potential DSP participants, working to address any new requirements in order to meet the customer's needs.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	DSP Sprint Releases	1/10/17 – 10/31/18	1/10/17 – 11/31/18	
2	DSP Release 3 and 4 UAT & Go Live	7/31/18 – 10/28/18	10/15/18 – 12/10/18	
5	Enroll new DSP participants	7/1/18 – 10/25/18	7/1/18 –4/1/19	

Key

- On-Track
- Delayed start, at risk of missing on-time completion, or over-budget
- Terminated/abandoned checkpoint

1. DSP Sprint Releases

Status: [ ]
Start Date: 1/10/17
End Date: 11/31/18

National Grid and Opus One will continue using an agile process, having continuous two (2) weeks sprint development cadence, adding additional features, functionalities and customization abilities to the DSP and Customer Portal.

The Project team will continue to work directly with Opus One's development team in multi-week sessions, looking at mockups and using quick prototyping to quickly gather customer and end-user feedback.

2. DSP Release 3 and 4 UAT & Go Live
Status: [🟡]
Start Date: 10/15/18
End Date: 12/10/18

During the final quarter of 2019, the team will continue to improve the DSP-POC functionalities, focusing on:

- Improved User Experience ("UX") for both the market participant and the DSP operator;
- Incorporated short-term weather-adjusted load forecast;
- Improved management and coordination of multiple markets;
- Expansion in DSP operator notifications; and
- General bug fixes.

After UAT is complete, and with National Grid approval, Opus One will have the green light to proceed with the push to the production environment of the Release 3 and 4 software.

3. Enrollment of New DSP Participants
Status: [🟡]
Start Date: 7/1/18
End Date: 4/1/19

The Project team will continue to address some of the gaps found after the initial conversations with potential new participants. Mainly, most of the development will be focused in allowing for a deeper integration with more automated and smart controllers. Additionally, the DSP will be working with a key customer in Utica that is deploying the Pacific Northwest National Laboratory's ("PNNL") VOLTTRON protocol to customize the DSP's Application Program Interfaces ("APIs") to communicate with that system.

At the same time, the Project team will continue to target to add two (2) to five (5) potential new participants that were given the highest priority ranking during the analysis phase. For a complete enrollment into the DSP, for each new participant will require:

- CYME feeder models from National Grid's Advanced Data & Analytics group;
- PI historians tags and feeds for each feeder from National Grid's Energy Management Systems ("EMS") group; and
- Metering from National Grid's Distribution Critical Network Infrastructure ("CNI") group.

Subsequently, the information will be imported and integrated into the DSP, and each participant will be provided their POC log-in information.

4.0 Work Plan & Budget Review

4.1 Updated Work Plan

An updated version of the Gantt chart found in the DSP Project Implementation Plan is set out below.

Task Name	Start	Finish
Phase 0	**Mon 8/15/16**	**Mon 8/29/16**
Project Kickoff	Thu 9/8/16	Thu 9/8/16
Phase 1 - Financial Model	**Thu 9/8/16**	**Wed 3/29/17**
Phase 2 - Technology Development	**Mon 4/17/17**	**Wed 11/28/18**
Phase 2 Kickoff	Mon 4/17/17	Mon 4/17/17
DSP & POC	**Tue 4/18/17**	**Wed 11/28/18**
Requirements definition	**Tue 4/18/17**	**Mon 8/7/17**
Solution Design	**Tue 8/8/17**	**Mon 10/16/17**
Solution Development	**Tue 10/10/17**	**Wed 11/28/18**
Software Development	Tue 10/10/17	Mon 6/4/18
PoC UAT	Wed 3/21/18	Tue 3/27/18
PoC Go Live	Wed 3/28/18	Fri 3/30/18
DSP-POC UAT	Thu 5/17/18	Wed 5/30/18
DSP-POC Go Live	Thu 5/31/18	Fri 6/1/18
Go/No Go Decision	Mon 6/4/18	Tue 6/5/18
Release 3 Go Live	Mon 6/4/18	Wed 11/28/18
Release 4 Go Live	Mon 7/30/18	Wed 11/28/18
Phase 3 - Field demonstration	**Wed 3/21/18**	**Fri 10/25/19**
Phase 3 Kickoff	Fri 3/30/18	Fri 3/30/18
M&V Equipment Installation	Sun 4/1/18	Tue 8/21/18
Evaluate New Customer Enrollment	Wed 3/21/18	Thu 6/28/18
Enroll New Customers	Fri 6/29/18	Mon 4/1/19
DSP, POC and Market Monitoring and Measurement	**Mon 4/2/18**	**Fri 10/25/19**
Evaluate new revenue streams	Mon 4/2/18	Fri 5/24/19
Scenario and Sensitivity Testing and Analysis	Mon 4/2/18	Fri 5/24/19
Continuous Improvement and Updates	Mon 4/2/18	Fri 9/27/19
Project Clousure (Reporting, etc)	Mon 9/30/19	Fri 10/25/19

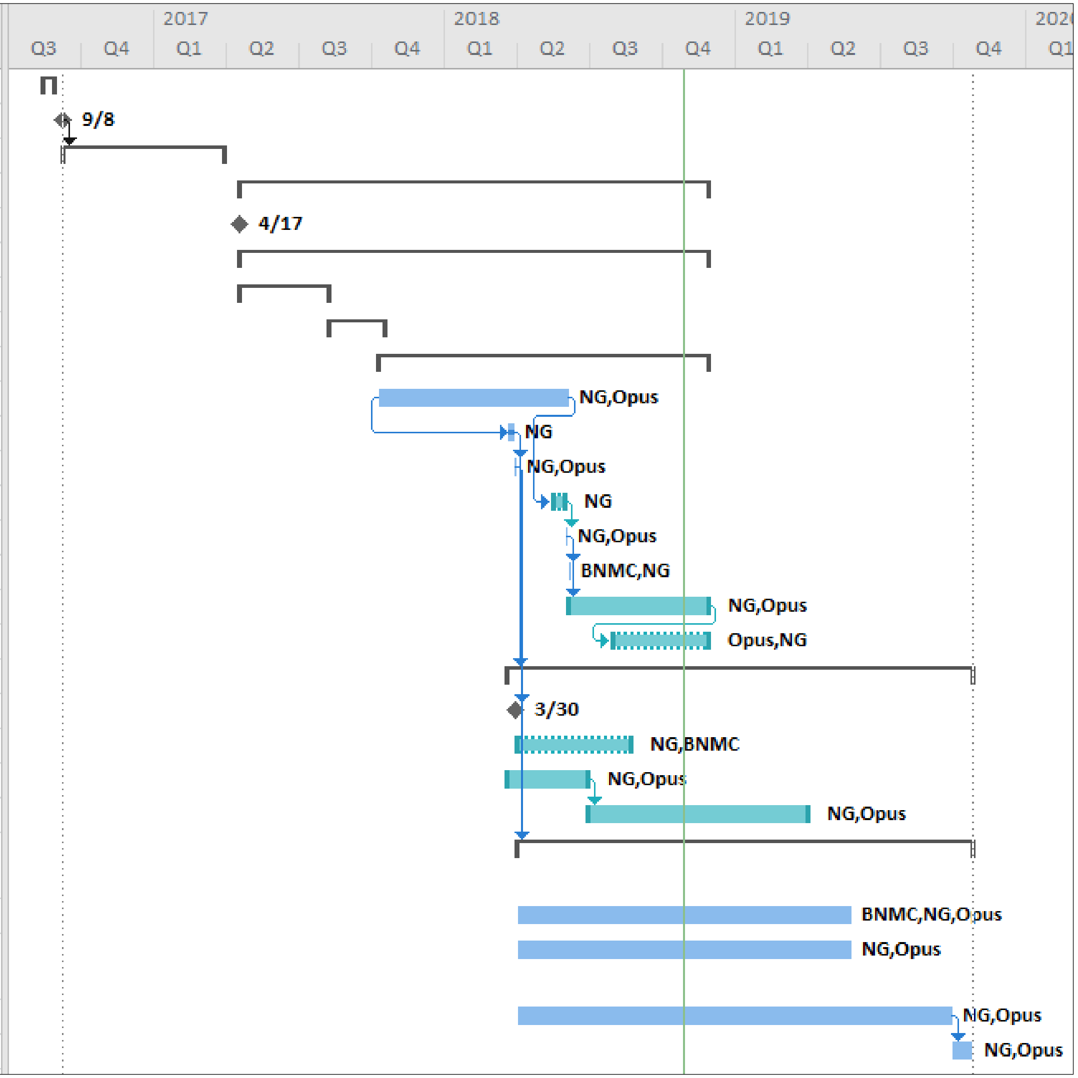

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

4.2 Updated Budget

There are updates to the estimated budget set forth in the filed DSP Implementation Plan. The updated budget information is displayed in the table below.

Project Task	3rd Quarter Actual Spend	Project Total Spend to Date	Project Budget[6]	Remaining Balance
CapEx				
	$ -	$ -	$ -	$ -
OpEx				
NG Resources	$ 25,492	$ 839,840	$ 915,000	$ 75,160
IT Integration Services	$ 131,909	$ 546,219	$ 586,000	$ 39,781
Program Management	$ 217,175	$ 1,327,082	$ 2,000,000	$ 672,918
Software License	$ -	$ 500,000	$ 1,000,000	$ 500,000
Software Development ($2M in kind)	$ -	$ -	$ -	$ -
DER Payments	$ -	$ -	$ 859,000	$ 859,000
Annual License Maintenance (est)	$ -	$ -	$ 150,000	$ 150,000
Total	**$ 375,576**	**$ 3,213,141**	**$ 5,510,000**	**$ 2,296,859**

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of September 30, 2018 total $1,347,030.31 Continued monitoring and reporting of incremental costs will be included in subsequent quarterly reports.

5.0 Tracking Metrics

The Project team continues to monitor prices at the BNMC location for both Day Ahead ("DA") and Same Day ("SD") events, and also monitor any peak events that may have occurred at the bulk or feeder level.

Table 5.1 presents the average and maximum DSP prices for DA and SD from April to September in $/MWh. Additionally, it estimates the number of events and revenue opportunity for a 1MW DER that has an estimated $100/MWh cost to operate[7]

[6] The Company updated the Project budget to reflect incremental costs, and to account for costs that may have originally been characterized as capital or operating expenses, but now, because of changed circumstances (*e.g.*, licensing instead of owning software), should be categorized differently.
[7] The analysis assumes that a DER would accept an event any time when the DSP price is above the cost to operate.

		Average DSP Price	Max DSP Price	Events Above $100/MWh	Revenue Potential (1MW @ $100/MWh marginal cost)
April	DA	$ 29.76	$ 68.88	0	$ -
	SD	$ 26.19	$ 189.33	14	$ 1,920
May	DA	$ 30.00	$ 210.55	29	$ 3,917
	SD	$ 37.82	$ 2,515.38	33	$ 15,326
June	DA	$ 31.90	$ 196.04	16	$ 2,199
	SD	$ 32.77	$ 2,959.36	20	$ 7,418
July	DA	$ 42.69	$ 519.89	26	$ 6,770
	SD	$ 38.34	$ 488.04	34	$ 7,328
August	DA	$ 61.59	$ 567.62	42	$ 21,446
	SD	$ 58.52	$ 593.98	51	$ 21,853
September	DA	$ 38.75	$ 574.28	10	$ 5,029
	SD	$ 37.46	$ 824.48	26	$ 7,654

Table 5.1 – DSP Price Comparison for Q2 and Q3 2018

As expected, the average prices for both DA and SD events peaked in August. On that month there were also the most opportunities to participate (for a DER with a cost to run of $100/MWh) and the biggest revenue potential for DERs (See Figure 5.1)

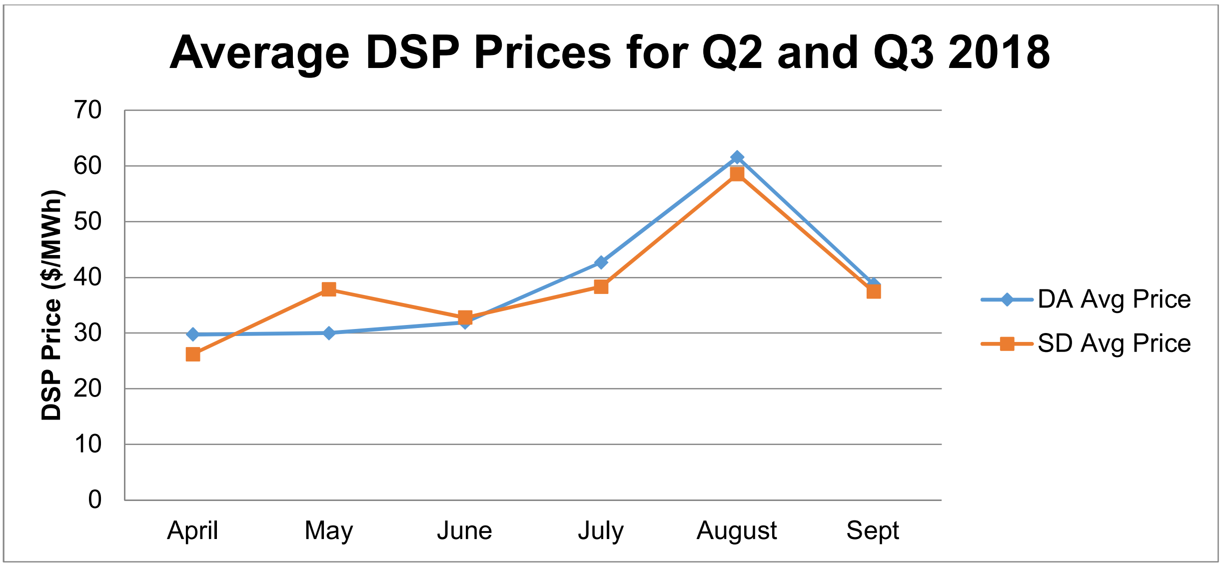

Figure 5.1 – Average DA and SD DSP Prices for Q2 and Q3 of 2018

Additionally, Q2 of 2018 saw the firsts B1 events. B1 prices are triggered whenever the forecasted NYISO load is above 85% of the forecasted peak. The main goal is to incentivize DER generation in order to lower National Grid's load in those peak hours, therefore reducing the Company's 2019 ICAP requirement. Table 5.3 below reflects the amount of hours where B1 pricing would have been awarded to DSP participants, the potential revenue for a 1MWh production of energy, and the impact that participating in those peak hours can have over the total revenue potential.

Month	NYISO Peak Events	B1 Revenue Potential (1MW)	Total Revenue Potential (SD)	B1 Revenue Contribution
July	15	$ 1,872.60	$ 7,328.21	26%
August	42	$ 9,071.71	$ 21,853.45	42%
September	9	$ 1,943.94	$ 7,653.62	25%

Table 5.2 – B1 tracking and Impact Analysis

The graphs in Figure 5.2 display the price variation trend for DA and SD events in Q3 of 2018.

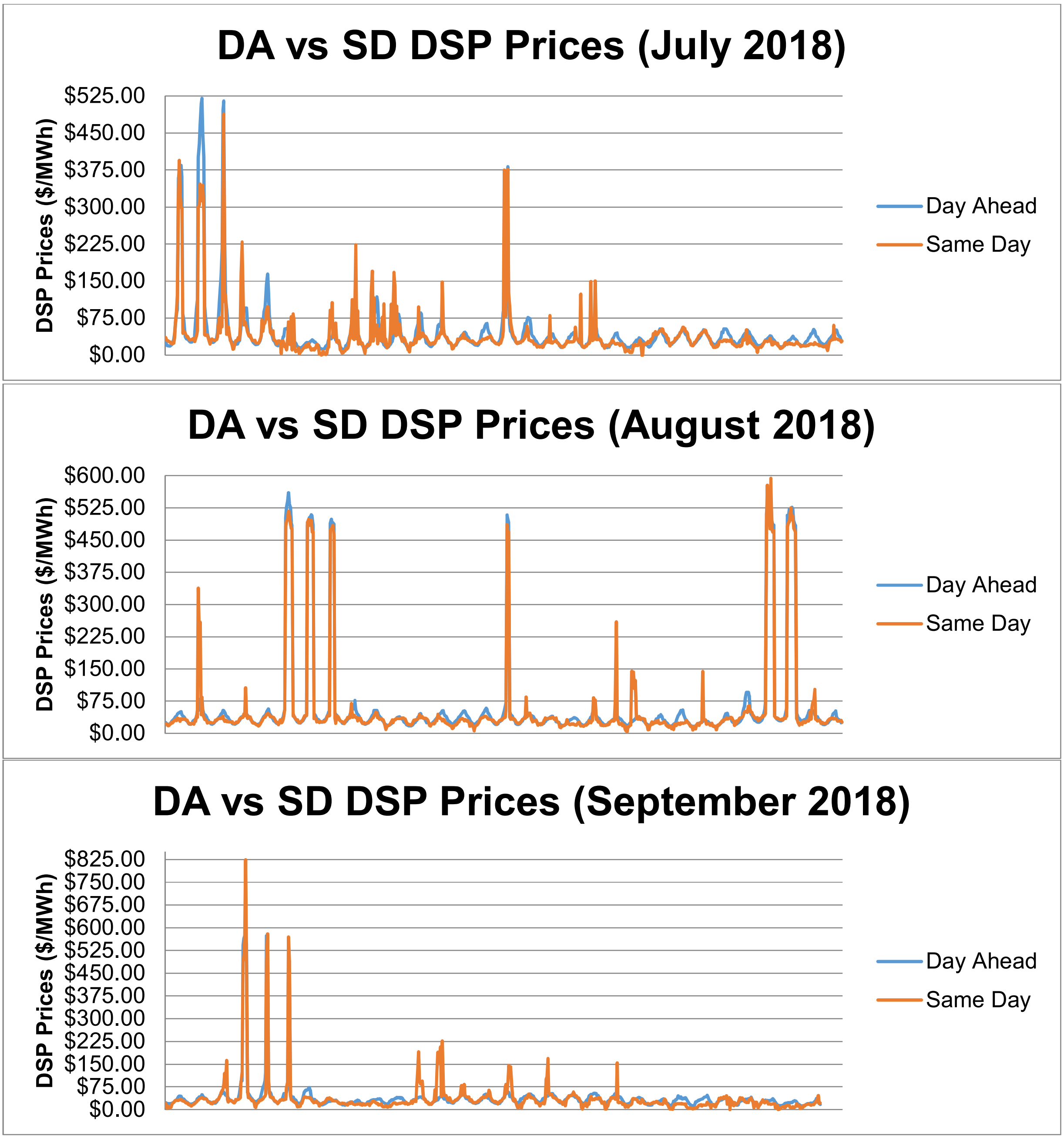

Figure 5.2 – DA vs SD DSP Price trends for July, August, and September of 2018

The Project team will continue to gather and monitor several data points on the DSP (*see Table 5.3*), to measure and evaluate a set Key Performance Indicators ("KPI") that will serve to inform all stakeholders on the potential and feasibility for Distributed System Platforms.

Focus Area	Objectives and KPIs
LMP+D Prices	• Monitor LMP+D prices (avg, max) for both DA and SD markets. • Monitor values for each component of LMP+D price signal (avg, max) for both DA and SD markets.
Event Tracking	• Track the market participant's responses towards events (number of events generated, accepted, rejected, etc.) for both DA and SD markets.
DER Participation	• Total amount of capacity (in MW) enrolled in the DSP. • Number of customers enrolled.
DSP-POC Communication	• Measurement of roundtrip communications for price signals and responses. • Average participant's event response time.
DSP Operations	• Monitor DSP operations (total hours of DER operation, total MW delivered vs MW committed, Number of peak events generated vs accepted vs delivered).
DER Operations	• Monitor and track the participation and effectiveness of different types of DER technology to respond to DSP events.

Table 5.4 – Key Project Metrics