Karla M. Corpus
Senior Counsel
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January 31, 2017

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 – Q4 2016 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 Plans covering the period of October 1, 2016 to December 31, 2016 ("Q4 2016 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

Karla M. Corpus
Senior Counsel

Enc.

cc:
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Distributed System Platform

REV Demonstration Project

Buffalo, New York

Q4 2016 Report

January 31, 2017

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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 services based on a local, small-scale, but centralized DSP that will communicate with network-connected Points of Control ("POCs") associated with the Buffalo Niagara Medical Campus Inc. ("BNMC") DERs. DSP is defined as "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]

The Project team consists of National Grid, BNMC, and Opus One Solutions ("Opus One"). Opus One will provide contracted services to National Grid. Opus One is a software engineering company which shares the vision for the Project to develop and deploy one platform that can accommodate a complete range of business models. Their role in the Project will encompass not only software development, but also thought leadership, planning and execution.

Image 1.1 – Part of the Buffalo Niagara Medical Campus

[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 (*depicted in Image 1.1*), consisting 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, 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 the University at Buffalo, New York State Center of Excellence in Bioinformatics and Life Sciences (left) and the Roswell Park Cancer Institute (right), both members of the BNMC

The Model: LMP+D

In the near term, services transacted and purchased by the DSP will test the implementation of a "LMP+D+E" financial model approach for electric services. The value of "LMP+D" will be evaluated in the Project and is expected to generate sufficient financial incentives for DERs to participate in the DSP market. For LMP, the Project will consider New York Independent System Operator ("NYISO") location-based marginal prices ("LBMP") Zone-A West for day-ahead 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. Energy supply, volt-ampere reactive ("VAR") support, voltage management, peak load modifications, and dynamic load management are some of the services that will be evaluated in the Project to test what drives new market opportunities. 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. The value of D takes into consideration potential issues along the grid such as substation and feeder constraints.

"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 Project does not intend to evaluate a specific value of E.

2.0 Highlights since Previous Quarter

National Grid and the key partners in the Project have made substantial progress in the fourth quarter of 2016. The National Grid Project Team has worked closely with Opus One and the BNMC to advance the Financial Model, developing the different elements that are used to calculate the value of D (*i.e.,* locational value of generation on the distribution system). Initial results were obtained by running the model using the specific feeder information of the BNMC area, historical data, and the Day Ahead Clearing Prices for 2016 obtained from the NYISO.

All Project team members are evaluating the initial results of the Financial Model, with all parties continuing to push to deliver the expected outcomes laid out in the Project Implementation Plan.[4] For a reference timeline emphasizing the major milestones and accomplishments, see Figure 2.1 below. Changes and additions are highlighted in yellow and are further described in Section 2.2.

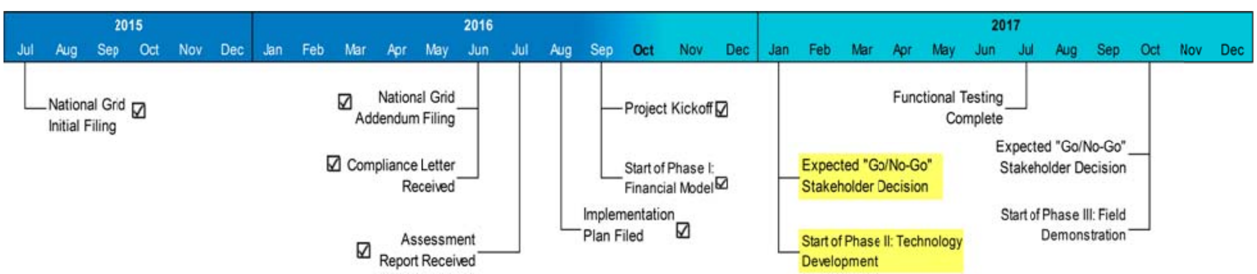

Figure 2.1 – Achievements and Milestones Timeline

2.1 Major Task Activities

1. **Financial Model Development**
   The major activity for Q4 of 2016 was development of the LMP+D Financial Model. Most of the effort was focused on identifying and quantifying the different elements to calculate the value of D (*i.e.*, locational value of generation on the distribution system). The National Grid Project team, in conjunction with the BNMC and Opus One, held a series of workshops with

[4] REV Proceeding, National Grid: Distributed System Platform REV Demonstration Project-Implementation Plan (filed August 15, 2016) ("DSP Implementation Plan").

the different subject matter experts to brainstorm ideas and debate the elements of "D". Some of the National Grid groups engaged in this process were:

- New Energy Solutions;
- Advanced Data Analytics;
- Transmission Planning;
- Electric Forecasting and Analysis;
- Wholesale Electric Supply;
- Electric Pricing;
- Regulatory Compliance;
- Retail Regulatory Strategy;
- Electric Operations;
- Retail Connections Engineering; and
- Customer Energy Integration Asset.

Additionally, as part of this effort the Project team utilized the framework developed in National Grid's Initial Distributed System Platform Implementation Plan ("DSIP")[5], and National Grid's Benefit Cost Analysis ("BCA") Handbook contained within the Company's DSIP filing, and the Joint Utilities' Supplemental DSIP.[6]

The resulting methodology developed can be illustrated as:

$$LMP + D \text{ } where \text{ } D = d_1 + d_2 + d_3 + d_4 + d_5$$

In particular:

- "LMP"= Locational Marginal Price from NYISO Zone A West Day Ahead Clearing Prices;
- "D"=Locational value of generation on the distribution system, and is the sum of
  - d1: Avoided Distribution Capacity Infrastructure Costs;
  - d2: Avoided O&M Costs;
  - d3: Avoided Distribution Losses;
  - d4: Avoided Restoration Costs; and
  - d5: Avoided Outage Costs.

A detailed explanation of the different components of each of the elements that constitute "D" can be found in attached Appendix A.

2. Financial Model Simulation

As the Project team began to collect the data needed to simulate the Financial Model, additional safety measures required by National Grid's Digital Risk and Security ("DR&S") group needed to be addressed in order to share Personal Identifying Information ("PII") and Critical Energy Infrastructure Information ("CEII") with Opus One.

Comprehensive individual Non-Disclosure Agreements were drafted and executed by National Grid and all Opus One employees who would be working with the aforementioned types of information. Information sharing between both parties was possible only after this effort was completed on December 16, 2016, which resulted in significant delays for the completion of the Financial Model Simulation *(See Part 2.2)*.

[5] REV Proceeding, National Grid Initial Distributed System Implementation Plan (filed June 30, 2016) and National Grid Errata Filing of Initial Distributed System Implementation Plan (filed July 1, 2016).
[6] Case 16-M-0411- *In the Matter of Distributed System Implementation Plans*, Joint Utilities Supplemental Distributed System Implementation Plan (filed November 1, 2016).

Opus One began to run simulations on the Financial Model in mid-December. National Grid anticipates its review of those simulations will occur in January 2017.

3. **BNMC Stakeholder Meeting**
An important element for the success of the DSP REV Demonstration Project is the participation of the BNMC members. For this reason the Project team has taken steps to engage often and early with the main participants to insure they are familiar with Project concepts, benefits, and future requirements. More importantly, the meetings are being used to develop a customer-centric solution by addressing any concerns voiced by BNMC members during the design phase.

A meeting presenting the DSP concept was held with the BNMC members on November 4, 2016 at the BNMC Innovation Center in Buffalo. As set forth in the DSP Implementation Plan, the Project will measure and calculate the locational value of generation at a specific point in the distribution network, and communicate events (*i.e.*, MW + Time + Price $/kWh) with the BNMC through a Point of Control ("POC"). Once a participant accepts an event, they will be logged into the DSP to generate the agreed amount of energy at the specific time required and receive revenue for it (See Figure 2.2 below for the DSP Functionality Infographic).

The concept received positive feedback from the meeting attendees, with all ideas and concerns addressed and incorporated into the conceptual design.

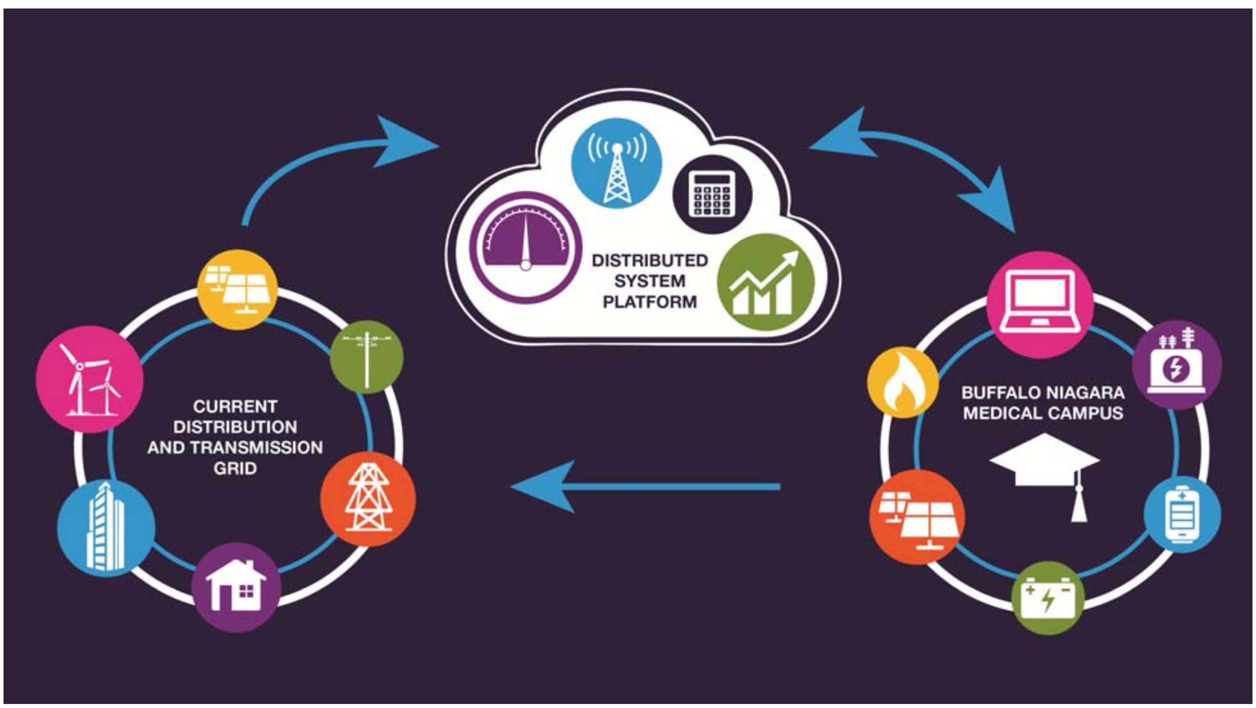

Figure 2.2 – DSP Functionality Infographic

2.2 Challenges, Changes, and Lessons Learned

Qtr 2016	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q3	Daniel Payares Luzio was named Project Manager and Dennis Elsenbeck appointed as Executive Sponsor for National Grid.	None	None	Involvement of the Executive Sponsor and Project Manager in the early planning phase of the Project is beneficial for a better understanding of the business case and improve planning and implementation.
Q3	Contract negotiations with vendor (Opus One) were delayed.	The Project timeline will be slightly impacted by delays in concluding contract negotiations.	Both parties proceeded with Project development in good faith in anticipation of contract finalization in order to avoid additional adverse Project impacts. Additional re-scheduling of tasks will be necessary to avoid further delays.	The Project team should always allocate sufficient time for contract negotiations.
Q3	Some or all of the BNMC's DERs may not be NYISO Tier 4 compliant.	A DER that is not NYISO Tier 4 compliant cannot operate in non-emergency situations (*e.g.*, cannot participate in NYISO markets).	Additional investment may be needed in order to comply with regulations or to acquire other types of DG.	
Q4	Unplanned requirement of personal NDAs prevented data sharing between Project partners, delaying the use of historical data to run and test the Financial Model Simulation.	The project stakeholders were not able to proceed with the Go/NoGo decision as no simulation was available, requiring this checkpoint to be re-scheduled to the end of January 2017.	National Grid and Opus One worked diligently with their legal teams to reach an agreement on the terms and conditions.	Whenever PII or CEII data is required, individual NDAs should be prepared and executed early in the contracting process.

3.0 Next Quarter Forecast

During the 1st Quarter of 2017 the Project team will finalize the evaluation of the Financial Model Simulation results and continue to the Go/No-Go decision. At the same time, the Project team will continue gathering the technical requirements needed for the technology development of the DSP and its integration with National Grid's servers and operations. If a Go decision is reached by all interested parties, the Project will continue to Phase 2 – Technology Development of the DSP and POC.

To avoid further delays, the Project team is currently developing a fast-paced approach to the critical path tasks that are a pre-requisite to the timely commencement of Phase 3 – Field Demonstration.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	Phase 1 Stakeholder Go/No-Go Decision	12/30/16	1/31/17	● (yellow)
2	Phase 2: Technology Development	1/2/17 – 11/17/17	2/1/17– 11/17/17	● (yellow)

Key

- ● (green) On-Track
- ● (yellow) Delayed start, at risk of on-time completion, or over-budget
- ● (red) Terminated/abandoned checkpoint

1. Phase 1 Stakeholder Go/No-Go Decision

Status: [●]
Start Date: 1/31/2017
End Date: 1/31/2017

In order to have sufficient information to proceed with the Go/No-Go decision, the Project team is currently evaluating the preliminary results of the Financial Model simulation. Opus One conducted DSP Financial Model simulations with historical data, real-time data, and forecasted data for defined test scenarios in order to generate LMP+D values. The scenarios include:

- Different DER types combination;
- Scenarios for Blue-Sky Day (*e.g.*, no constrains in the system/area) operations and for Constrained-Day operations (*e.g.,* constrains in the system, with higher than average load requirements and LMP prices); and
- Locations within and surrounding the BNMC, and one (1) or two (2) other feeders from different NYISO zones in New York, up to a maximum of ten (10) distribution feeders.

See attached Appendix B for a more detailed explanation on the test case scenarios.

After the evaluation is complete, Phase 1 will end with a “Go/No-Go” decision from the major Project stakeholders (*i.e.,* BNMC and National Grid).

2. Start of Phase 2: Technology Development

Status: [●]
Start Date: 2/1/2017
End Date: 11/17/2017

If a “Go” decision is reached by all Project stakeholders at the end of Phase 1, the Project will continue to Phase 2 (Technology Development of the DSP and POCs). This phase will focus on designing, developing, testing and implementing the DSP and POC architecture and software. Phase 2 will require more involvement from the National Grid Information System (“IS”) group as they will work closely with Opus One to develop a solution that is compatible and compliant with National Grid Information Technology (“IT”) systems.

Specifically, in Q1 of 2017 National Grid and Opus One will focus their efforts on the development of the technology solution to meet the business and technical requirements for the DSP and POC. This will include the development of detailed business requirements, logical, physical and technical models, a detailed application design, test plans and training plans that will all lead to a technology solution that is consistent and viable with the needs of the Project.

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.

nationalgrid

	Task Name	Start	Finish
1	Phase 0	Mon 8/15/16	Thu 9/8/16
2	Implementation Plan Filed	Mon 8/15/16	Mon 8/15/16
3	Contracts executed, project charter developed	Wed 9/7/16	Wed 9/7/16
4	Project Kickoff	Thu 9/8/16	Thu 9/8/16
5	Phase 1 - Financial Model	Fri 9/30/16	Fri 12/30/16
6	Design and development	Fri 9/30/16	Thu 11/10/16
7	LMP+D	Fri 9/30/16	Thu 11/10/16
14	Settlement - wholesale	Fri 9/30/16	Tue 10/25/16
17	Settlement - financial	Fri 10/14/16	Thu 10/27/16
20	New Revenue streams	Fri 10/14/16	Tue 11/8/16
24	Customer Service Process Development	Fri 10/14/16	Thu 10/27/16
25	Initial model stakeholder GO/NOGO	Thu 11/10/16	Thu 11/10/16
26	Startup - infrastructure definition	Fri 10/14/16	Thu 11/10/16
32	Financial Model Simulation	Fri 11/11/16	Thu 12/8/16
36	Phase 1 Stakeholder GO/NOGO	Tue 1/31/17	Tue 1/31/17
37	Phase 2 - Technology Development	Wed 2/1/17	Tue 12/19/17
38	DSP & POC	Wed 2/1/17	Tue 12/19/17
39	Requirements definition	Wed 2/1/17	Tue 2/14/17
42	Solution Design	Wed 2/15/17	Tue 3/14/17
45	Solution Development	Wed 3/15/17	Tue 8/29/17
52	Solution Testing	Wed 8/30/17	Tue 12/5/17
59	Implemention	Wed 12/6/17	Tue 12/19/17
63	Phase 2 stakeholder GO/NOGO	Tue 12/19/17	Tue 12/19/17
64	Phase 3 - Field demonstration	Tue 9/26/17	Mon 10/8/18
65	Phase 3 Kick off	Tue 9/26/17	Tue 9/26/17
66	Market Structure and Economics	Tue 9/26/17	Mon 10/9/17
67	Market Deployment	Tue 9/26/17	Mon 10/9/17
68	Market Deployment complete	Mon 10/9/17	Mon 10/9/17
69	Market Integration into DSP and POC Build Environment	Tue 9/26/17	Mon 10/23/17
70	Testing and Op Demonstration	Tue 10/24/17	Mon 11/6/17
71	DSP, POC and Market Monitoring and Measurement	Tue 11/7/17	Mon 10/8/18

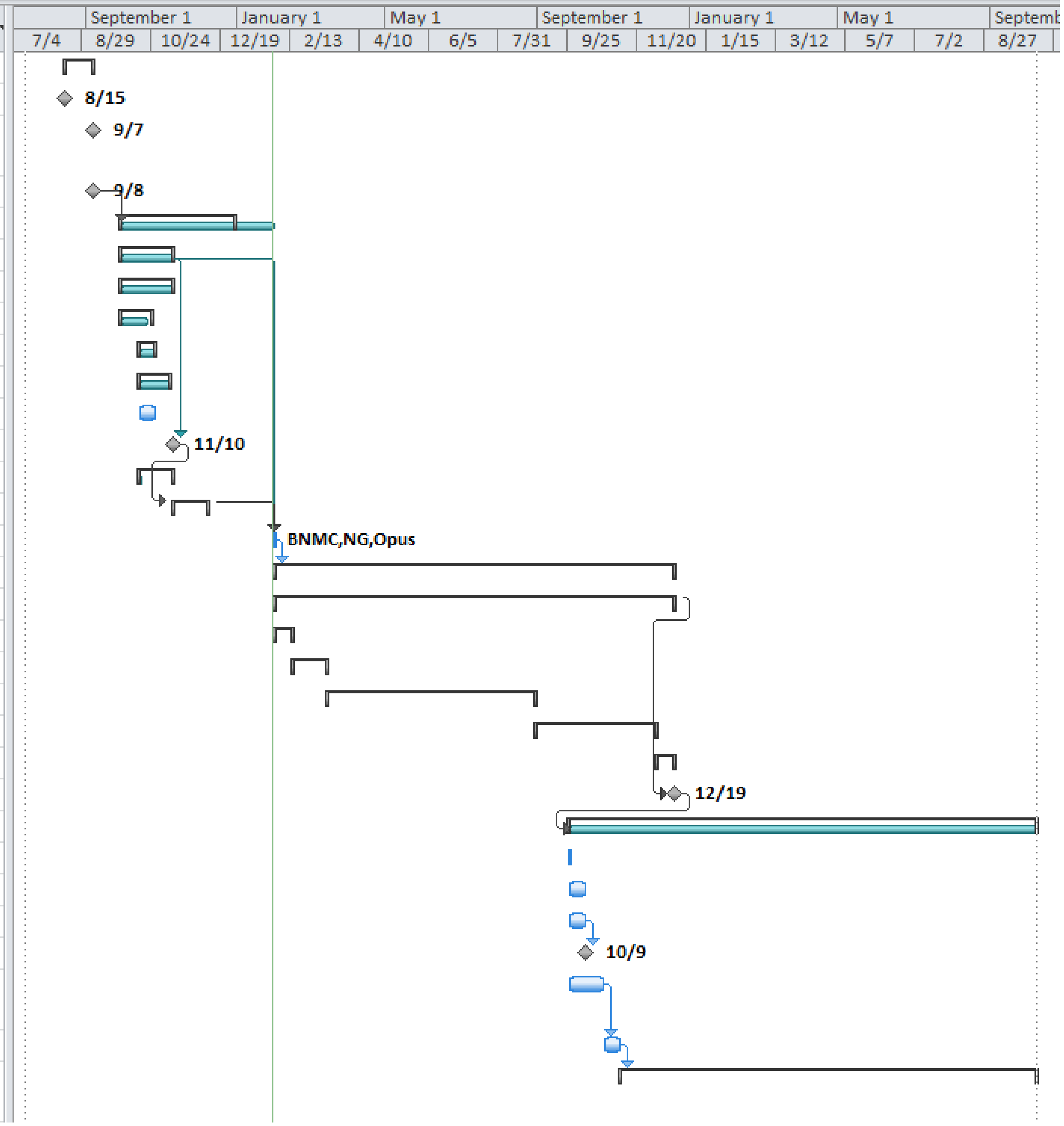

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

4.2 Updated Budget

There are no changes to date for the forecasted budget set forth in the filed DSP Implementation Plan.

Project Budget Requirement		**Phase 1**		**Phase 2**		**Phase 3**		**Total Project**	
		CAPEX	**OPEX**	**CAPEX**	**OPEX**	**CAPEX**	**OPEX**	**CAPEX**	**OPEX**
Opus One	Software License - 50% start of phase 2			$500,000				$500,000	
	Software License - 50% start of phase 3					$500,000		$500,000	
	Program management	$250,000		$750,000		$1,000,000		$2,000,000	
	Software development			$2,000,000				$2,000,000	
National Grid	Resources	$250,000		$750,000		$125,000	$125,000	$1,125,000	$125,000
	IT Integration Services			$200,000				$200,000	
	IT Hardware/Software			$25,000				$25,000	
	IT Network and communications			$75,000				$75,000	
	Subtotal	**$500,000**	**$0**	**$4,300,000**	**$0**	**$1,625,000**	**$125,000**	**$6,425,000**	**$125,000**
	Cost Share (in-kind software development)			$2,000,000				$2,000,000	$0
	Annual operational costs				$30,000		$230,000	$0	$260,000
	Total Funding Request	**$500,000**	**$0**	**$2,300,000**	**$30,000**	**$1,625,000**	**$355,000**	**$4,425,000**	**$385,000**

Ongoing Annual Operational Costs		**Year 1**		**Year 2**	
		CAPEX	**OPEX**	**CAPEX**	**OPEX**
Opus One	Annual license maintenance 20%		$0		$200,000
National Grid	Integration Services		$20,000		$20,000
	Hardware 10%		$2,500		$2,500
	Network and communications 10%		$7,500		$7,500
	Total Annual Operational Costs	**$0**	**$30,000**	**$0**	**$230,000**

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of December 31, 2016 total $6,375. Continued monitoring and reporting of incremental costs will be included in subsequent quarterly reports.

5.0 Progress Metrics

Key Progress Metrics have not yet been determined, but will be developed at the end of Stage 1 based on the Check Points identified in pages 15 and 16 of the DSP Implementation Plan.

6.0 Appendices

Appendix A: Elements of +D calculation

Following the framework of the BCA Handbook included in National Grid's initial DSIP filing, the different elements that comprise the LMP+D calculation are:

$$LMP + D \text{ where } D = d_1 + d_2 + d_3 + d_4 + d_5$$

In particular:

- "LMP"= Locational Marginal Price from NYISO Zone A West Day Ahead Clearing Prices;
- "D"=Locational value of generation on the distribution system, and is the sum of
  - d1: Avoided Distribution Capacity Infrastructure Costs;
  - d2: Avoided O&M Costs;
  - d3: Avoided Distribution Losses;
  - d4: Avoided Restoration Costs; and
  - d5: Avoided Outage Costs.

The Project team is using the following formulas from the BCA Handbook to calculate each element:

- Avoided Distribution Capacity Infrastructure Costs:

$$d_1 = \sum_{V}\sum_{C} \frac{\Delta PeakLoad_{Y,r}}{1 - Loss\%_{Y,b\rightarrow r}} * DistCoincidentFactor_{C,V,Y} * DeratingFactor_{Y} * MarginalDistCost_{C,V,Y,b}$$

Where:

Variable	Definition
ΔPeakLoad	(MW) is the nameplate demand reduction of the project at the retail delivery or connection point.
Loss%	(%) is the variable loss percent between the bulk system ("b") and the retail delivery point.
DistCoincidentFactor	Captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction.
DeratingFactor	Is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours.
MarginalDistCost	($/MW-yr) is the marginal cost of the distribution equipment from which the load is being relieved.

Table A.1 – Definitions for Avoided Distribution Capacity Cost equation

- Avoided O&M Expenses:

$$d_2 = \sum_{AT} \Delta Expenses_{AT,Y}$$

Where:

Variable	Definition
ΔExpenses	($/yr) Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs.

Table A.2 – Definition for Avoided O&M Cost equation

- Avoided Distribution Losses:

$$d_3 = \sum_{Z} \begin{matrix} SystemEnergy_{Z,Y+1,b} * LBMP_{Z,Y+1,b} * \Delta Loss\%_{Z,Y+1,i\to r} \\ + \ SystemDemand_{Z,Y,b} * AGCC_{Z,Y,b} * \Delta Loss\%_{Z,Y,i\to r} \end{matrix}$$

$$with \ \ \Delta Loss\%_{Z,Y,i\to r} = Loss\%_{Z,Y,i\to rbaseline} - Loss\%_{Z,Y,i\to r,post}$$

Where:

Variable	Definition
SystemEnergy	(MWh) is the system energy purchased in the relevant area of the distribution system (*i.e.*, the portion of the system where losses were impacted by the project) at the retail location by zone.
LBMP	($/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level.
ΔLoss%	(Δ%) is the change in fixed and variable loss percent in the interface between the T&D systems (“i”) and the retail delivery point (“r”) resulting from a project that changes the topology of the distribution system.
SystemDemand	(MW) is the system peak demand for the portion of the retail location on the distribution system(s) (*i.e.*, the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone (Zone A West).
AGCC	($/MW-yr) Avoided Generation Capacity Cost represents the annual AGCCs at the bulk system level (“b”) based on forecast of capacity prices for the wholesale market provided by DPS Staff.
Loss% Post	(%) is the post-project fixed and variable loss percent between the interface of the T&D systems (“i”) and the retail delivery point (“r”).
Loss% Baseline	(%) is the baseline fixed and variable loss percent between the interface of the T&D systems (“i”) and the retail delivery point (“r”).

Table A.3 – Definitions for Avoided Distribution Losses Cost equation

- Avoided Restoration Costs:

$$d_4 = \Delta CrewTime_Y * CrewCost_Y + \Delta Expenses_Y \quad with$$

$$\Delta CrewTime_Y = \#Interruptions_{base,Y} * \left(CAIDI_{base,Y} - CAIDI_{post,Y} * (1 - \%ChangeSAIFI_Y)\right)$$

$$and \quad \%ChangeSAIFI_Y = \frac{SAIFI_{base,Y} - SAIFI_{post,Y}}{SAIFI_{base,Y}}$$

Where:

Variable	Definition
ΔCrewTime	(Δhours/yr) is the change in crew time to restore outages based on an impact on frequency and duration of outages.
CrewCost	($/hr) is the average hourly outage restoration crew cost for activities associated with the project under consideration.
ΔExpenses	(Δ$) are the average expenses (*e.g.,* equipment replacement) associated with outage restoration.
#Interruptions	(int/yr) are the baseline (*i.e*., pre-project) number of sustained interruptions per year, excluding major storms.
CAIDI Base	(hr/int) is the baseline (*i.e*., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms.
CAIDI Post	(hr/int) is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms.
%ChangeSAIFI	(Δ%) is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.
SAIFI Base	(int/cust/yr) is the baseline (*i.e*., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms.
SAIFI Post	(int/cust/yr) is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario.

Table A.4 – Definitions for Avoided Restoration Cost equation

- Avoided Outage Costs:

$$d_5 = \sum_{C} ValueOfService_{C,Y,r} * AverageDemand_{C,Y,r} * \Delta SAIDI_Y \qquad with$$

$$\Delta SAIDI_Y = SAIFI_{base,Y} * CAIDI_{base,Y} - SAIFI_{post,Y} * CAIDI_{post,Y}$$

Where:

Variable	Definition
ValueOfService	($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point.
AverageDemand	(kW) is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure.
ΔSAIDI	(Δhr/cust/yr): is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.
SAIFI Base	(int/cust/yr) is the baseline (*i.e.,* pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms.
CAIDI Base	(hr/int) is the baseline (*i.e.*, pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms.
CAIDI Post	(hr/int) is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case.
SAIFI Post	(int/cust/yr) is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case.

Table A.5 – Definitions for Avoided Outage Cost equation

Appendix B: Financial Model Simulation – Test Case Scenarios

Opus One ran simulations on the Financial Model using different assumptions for un-constrained (*e.g.*, Blue Sky) and constrained situations of the feeders. See further details on the assumptions for each scenario on the following Table B.1:

#	Condition	Description
1	Blue Sky	•Normal load profile at BNMC •Normal LMP price profile at Zone A West •All BNMC DERs are available to generate power
2	Blue Sky	•Normal load profile at BNMC •High LMP price profile at Zone A West •All BNMC DERs are available to generate power
3	Blue Sky	•Normal load profile at BNMC •High LMP price profile at Zone A West •All BNMC DERs are available to generate power •VVO Price – 8¢/kWh
4	Blue Sky	•Normal load profile at BNMC •High LMP price profile at Zone A West •All BNMC DERs are available to generate power •VVO Price – 15¢/kWh
5	Constrained	•High load profile (120% normal load profile) at BNMC •High LMP price profile at Zone A West •All BNMC DERs are available to generate power •12% of DR is also available at National Grid's CSRP tariff – 20¢/kWh
6	Constrained	•High load profile (120% normal load profile) at BNMC •High LMP price profile at Zone A West •N-1 Contingency: Feeder 11E open at Elm Street Substation •All of BNMC DERs are available to generate power •12% of DR is also available at National Grid's CSRP tariff – 20¢/kWh
7	Constrained	•High load profile (120% normal load profile) at BNMC •High LMP price profile at Zone A West •All of BNMC DERs are available to generate power •12% of DR is also available at National Grid's CSRP tariff – 20¢/kWh •VVO Price – 12¢/kWh
8	Constrained	•High load profile (120% normal load profile) at BNMC •High LMP price profile at Zone A West •N-1 Contingency: Feeder 11E open at Elm Street Substation •All of BNMC DERs are available to generate power •12% of DR is also available at National Grid's CSRP tariff – 20¢/kWh •VVO Price – 12¢/kWh

Table B.1 – Scenarios tested for the Financial Model Simulation