Karla M. Corpus
Senior Counsel
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July 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 – Q2 2017 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 April 1, 2017 to June 30, 2017 ("Q2 2017 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

Q2 2017 Report

July 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 Kaleida Health (left) and the Roswell Park Cancer Institute (right), members of the BNMC

The Model: LMP+D

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" 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") locational-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 assigned to each of these items. Energy supply, volt-ampere reactive ("VAR") support, voltage

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

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 value of E will most likely be attributable for renewable generation, or current Net Energy Metered ("NEM") resources as defined 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

National Grid and the key partners in the Project have made progress in the initial stages of Phase II, working on a fast-paced schedule to catch up from the three (3) month delay encountered in Phase I. The National Grid Project Team worked closely with Opus One and the BNMC to collect and document the business requirements that will serve as a guideline for the technology development, and define the basics of the DSP architecture. To collect these requirements, the Project Team held a series of workshops with the different DSP stakeholders.

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. Phase II Kickoff Meeting

[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").

The Phase II Kickoff meeting was held on 4/18 with participation of the major project partners and National Grid's group leadership (Figure 2.2 presents the DSP Infographic used during the meeting). The meeting focused on giving a brief overview of the Financial Model, the Project schedule and the workshop plan. The National Grid groups involved in the meeting were:

- New Energy Solutions;
- Regulatory Compliance;
- Electric Operations;
- Network Strategy;
- Distribution Control and Integration ("C&I");
- Distribution Planning;
- Wholesale Electric Supply;
- New York Electric Pricing;
- Digital Risk & Security
- Retail Connections Engineering, NY;
- Meter Data Services;
- Regional Control Room;
- Information Services ("IS"); and
- Advanced Data and Analytics ("ADA").

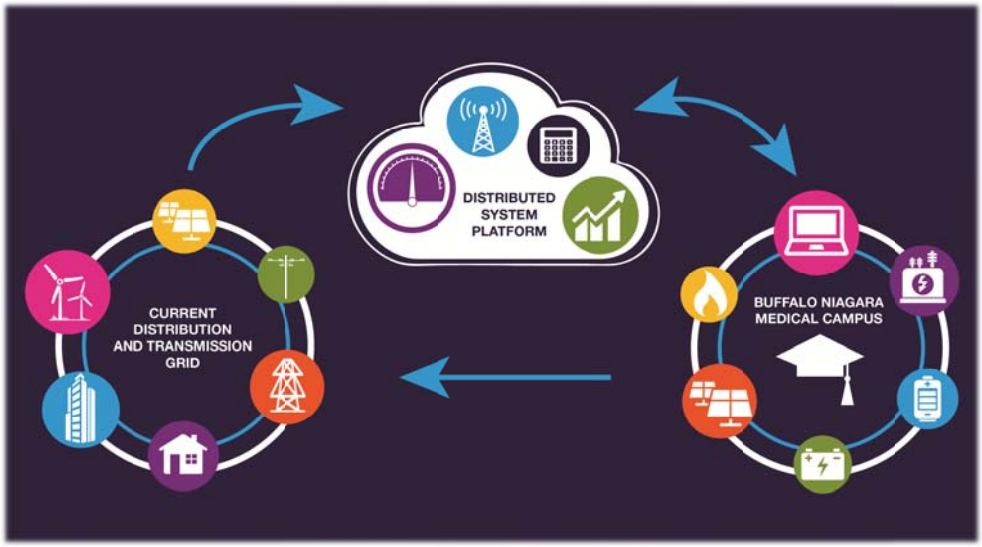

Figure 2.2 – DSP Infographic

2. Business Requirement Workshops

The Business Requirements collect the basic functionalities and specifications that need to be built into the DSP. This includes the development of detailed business requirements (both functional and non-functional requirements) that will lead to a technology solution that is consistent and viable with the needs of the Project.

To accomplish this, the Project Team performed a series of cross-functional workshops with different internal and external stakeholders in order to quantify and qualify the requirements. In these three (3) to four (4) hour guided sessions the participants delved into specifics of the DSP-POC solution, brainstormed functionalities, identified dependencies and risks, and classified requirements in terms of essential versus non-essential for DSP operation and scalability.

From mid-April to late-June, multiple workshops and follow-up meetings were held to dig deeper into:

- DSP operations;
- DSP event creation;
- Event coordination;
- Market operation and coordination; and
- DSP communications and network.

Figure 2.3 shows the initial Conceptual Technical Model ("CTM") developed by National Grid's Solutions Architect after collecting and analyzing the feedback and requirements from the DSP Workshops.

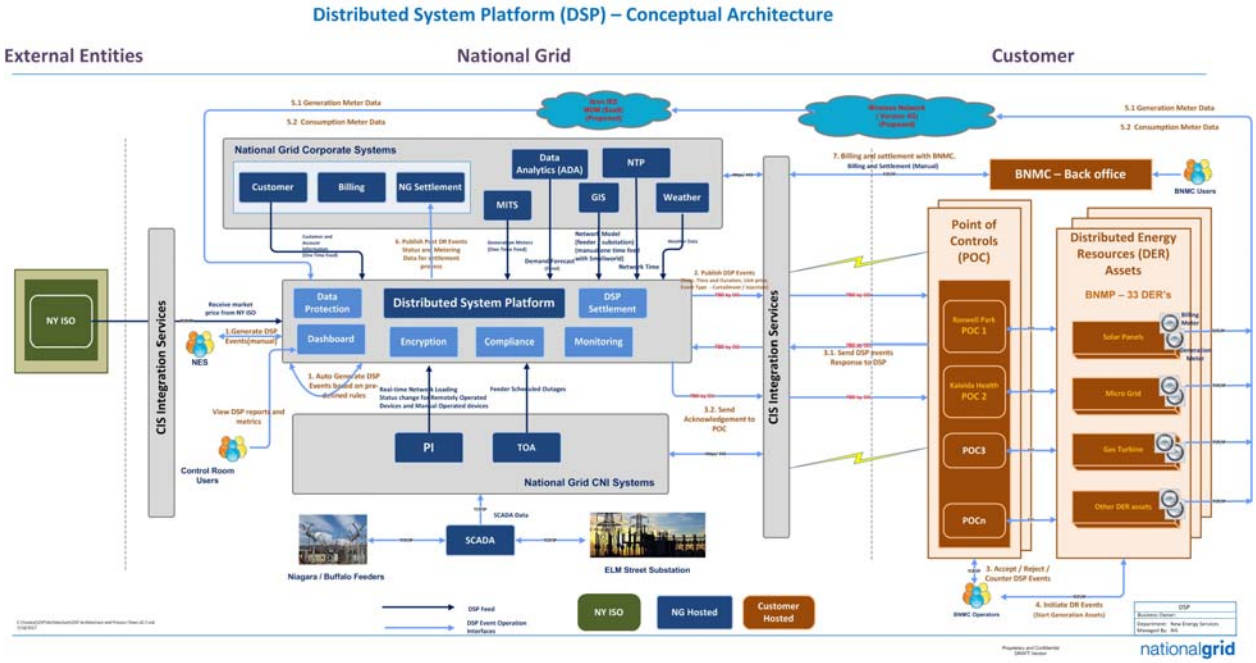

Figure 2.3 – DSP High-Level Process Flow

Additionally, on June 16th the Project Team met with representatives of Roswell Park Cancer Institute ("RPCI") and Kaleida Health ("KH"), two of the largest BNMC members that have agreed to be part of the DSP Project. During the meeting, the team collected the customers' POC requirements and presented with initial User Interfaces ("UI") to get feedback on the POC appearance, information, and accessibility.

3. Process Flow Development

The Project Team developed high-level process flows to determine the logic, communication protocols, and interfaces of the DSP-POC solutions with both internal and external systems. In summary, the event stages have been classified as:

- Event Creation: Calculation of Day Ahead ("DA") and Same Day ("SA") LMP+D+E prices;
- Event Dispatch: Communication of event prices to DSP participants through the POC;
- Event Response: Acceptance/Denial/Counter of DSP events by DSP participants;
- Event Initiation: Once accepted, start of the DSP event at the agreed time;

- Event Closure: Termination of the event;
- DSP Event Settlement: Collection of event data for verification; and
- National Grid (“NG”) Settlement: Final settlement process between NG and the DSP participant.

Figure 2.4 below represents a snapshot of the initial overarching event management process flow.

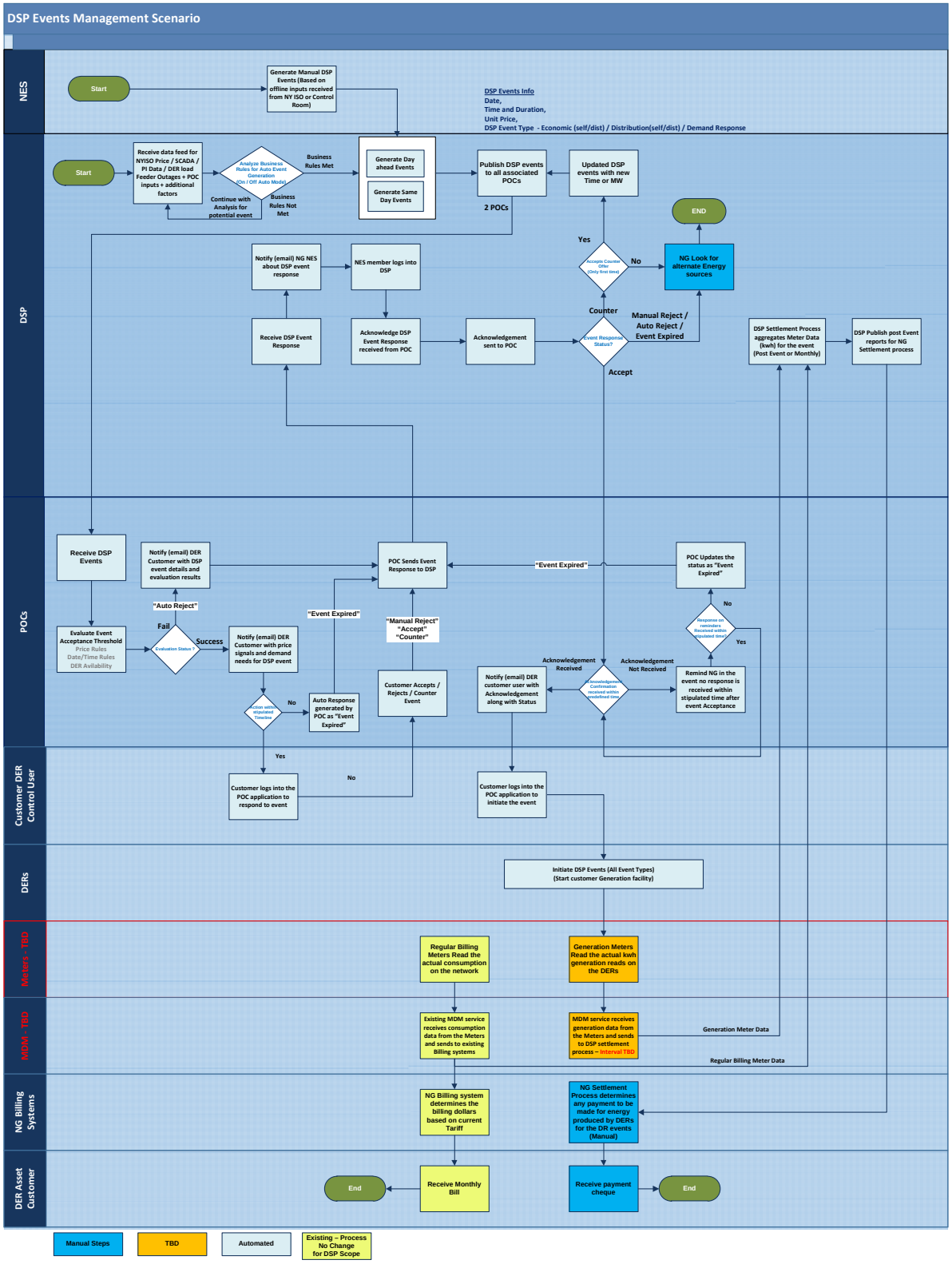

Figure 2.4 – DSP High-Level Overall Event Management Process Flow

2.2 Challenges, Changes, and Lessons Learned this Quarter

2017	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q2	Delays in the development of the Financial Model caused a shortened timeline to develop the DSP technology.	With approximately 30% less time to devote on Phase II, the Project Team will need to re-define certain aspects of the DSP-POC to comply with the proposed timelines.	The Project Team has adopted an agile approach to define a Minimal Viable Product ("MVP") to develop for Day 1 of the DSP, with additional functionalities being added in subsequent updates.	While an agile approach can be a good solution to develop the DSP-POC, it also increases risks in other areas of the Project.
Q2	The delivery of the advanced feeder modeling and forecast of the BNMC feeders by National Grid's internal teams does not align with the Project's timeline.	The Project may need to use other alternatives for feeder modeling and forecasting that are not as accurate as the one being developed by NG. Otherwise, the Project will need to wait for the modeling to be completed.	The Project Team is currently evaluating alternatives to model the BNMC feeders, while assessing any trade-offs that may exist for each approach.	There is an added complexity in modeling feeders in a mesh configuration over radial feeders. The BNMC is being fed by underground meshed feeders. [6]
Q2	Domenick Freda named National Grid's Information Systems Project Manager	None.	None.	None.

3.0 Next Quarter Forecast

During the 3rd Quarter of 2017 the Project team will continue to work on the technology development of the DSP and POC software. The team will focus on the detailed business

[6] One of the proposed DSP features is to continuously run Power Flow analysis to optimize the feeder load by strategically deploying DERs. An advanced feeder model is required to perform this analysis.

requirements, building system architecture, creating logical, physical and technical models, and development of detailed application design, test plans and training plans for the DSP and POC. The team will then commence the development of the DSP and POC software.

At the same time, the Project Team will work closely with the BNMC to develop the DSP rules and membership agreements. This effort will result in a comprehensive manual containing clarification of all event rules, rewards, penalties, safety procedures, and qualifying criteria for the DSP.

While the Project Team is working in a fast-paced, agile and aggressive approach in order to compensate for the timeline delays in Phase I and to finalize the Technology Development Phase within the timeline set forth in the Implementation Plan, the Team also recognizes that there is a significant risk of not being able to reach that milestone in the allotted time.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	Detailed Business Requirements Completed	5/1/17	8/3/17	🟡
2	Solution Design	5/2/17 – 5/29/17	8/4/17 – 9/6/17	🟡
3	Solution Development	5/30/17 – 8/14/17	8/24/17 – 11/29/17	🟡

Key

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

1. Detailed Business Requirements Completed

Status: [🟡]
End Date: 8/3/17

After obtaining the high level business requirements during Q2 of 2017, the Project Team will need to develop additional details and functionalities for each requirement. The effort will result in the documentation of all the specific features and characteristics that will be built in the DSP and POC.

2. Solution Design

Status: [🟡]
Start Date: 8/4/17
End Date: 9/6/17

During the Solution Design, National Grid's IS team will work closely with Opus One and BNMC to translate all the business requirements into a detailed solution design that complies with the requests of the major Project stakeholders. This design will then be used as the blueprint for the development of the DSP and POC software and integration points.

The final design will then be reviewed and approved by the major Project stakeholders, including the BNMC, NG Team Leads, and Opus One.

3. Solution Development

Status: [🟡]
Start Date: 8/24/17
End Date: 11/29/17

During this stage, a development operations environment will be utilized by the development team to create the DSP and POC software where all unit testing will take place. Both a test and production operations environments will be set up. The environments will be set up identically to reduce impact at launch. This effort could also provide the ability to use the test environment as a disaster recovery environment. All functional, integration, and end-to-end testing will happen in the test environment.

The elaboration of the DSP and POC software will take place in a series of iterative and incremental software development huddles, or scrums. After each scrum, the Project Team will review the progress, adjust if necessary and continue to the next one.

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.

ID	Task Name	Start	Finish
1	**Phase 0**	**Mon 8/15/16**	**Thu 9/8/16**
5	**Phase 1 - Financial Model**	**Fri 9/30/16**	**Fri 3/31/17**
6	**Design and development**	**Fri 9/30/16**	**Thu 11/10/16**
7	**LMP+D**	**Fri 9/30/16**	**Mon 3/13/17**
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	Initial model stakeholder GO/NOG	Thu 3/30/17	Thu 3/30/17
25	**Financial Model Simulation**	**Fri 11/11/16**	**Thu 12/8/16**
26	Test case development	Fri 11/11/16	Thu 11/17/16
27	model simulation	Fri 11/18/16	Thu 12/8/16
28	analysis	Fri 11/18/16	Thu 12/8/16
29	Phase 1 Stakeholder GO/NOGO	Fri 12/30/16	Fri 12/30/16
30	**Phase 2 - Technology Development**	**Tue 4/18/17**	**Fri 12/8/17**
31	**DSP & POC**	**Tue 4/18/17**	**Fri 12/8/17**
32	**Requirements definition**	**Tue 4/18/17**	**Thu 8/3/17**
35	**Solution Design**	**Fri 8/4/17**	**Wed 9/6/17**
38	**Solution Development**	**Thu 8/24/17**	**Wed 11/29/1**
45	**Solution Testing**	**Mon 10/16/1**	**Thu 11/30/17**
52	**Implemention**	**Mon 11/27/1**	**Fri 12/8/17**
56	Phase 2 stakeholder GO/NOGO	Thu 11/30/17	Thu 11/30/17
57	**Phase 3 - Field demonstration**	**Thu 11/30/17**	**Wed 12/12/18**

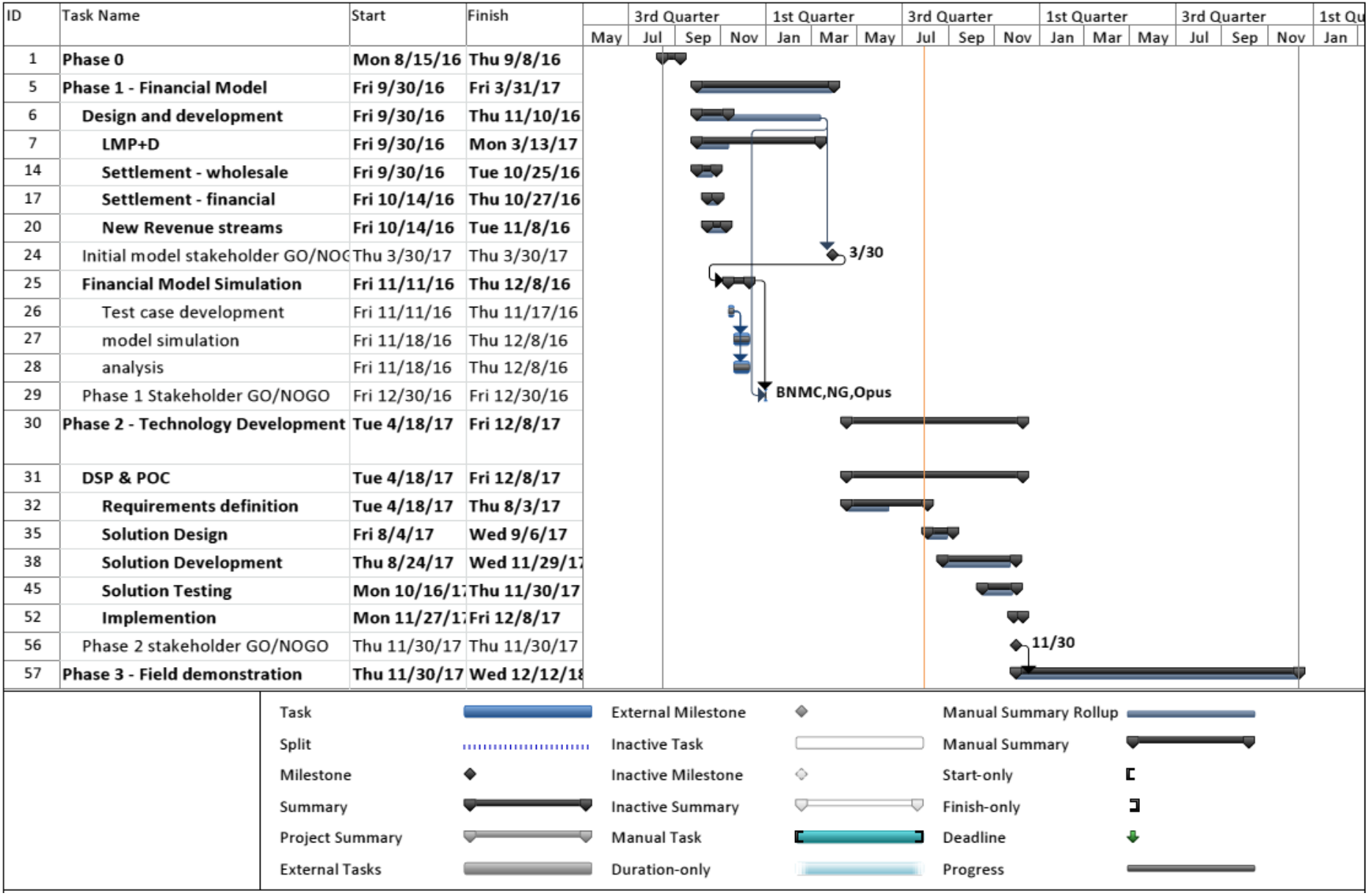

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

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 June 30, 2017 total $685,305. 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 during Phase II based on the Check Points identified in pages 15 and 16 of the DSP Implementation Plan.