nationalgrid

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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 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 July 1, 2017 to September 30, 2017 ("Q3 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

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Enc.

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Distributed System Platform

REV Demonstration Project

Buffalo, New York

Q3 2017 Report

October 31, 2017

Table of Content

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

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[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 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" 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") 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

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[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 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

National Grid and the key partners in the Project completed the detailed design of the DSP. Once finalized, the Project team was able to develop a detailed release plan and schedule, as well as an estimated budget for the remaining duration of the Project, which is detailed in Section 4.0 below. The DSP will be delivered in three (3) major releases, with each release adding additional functionalities to the platform. The first release is expected to go live in Q4 2017.

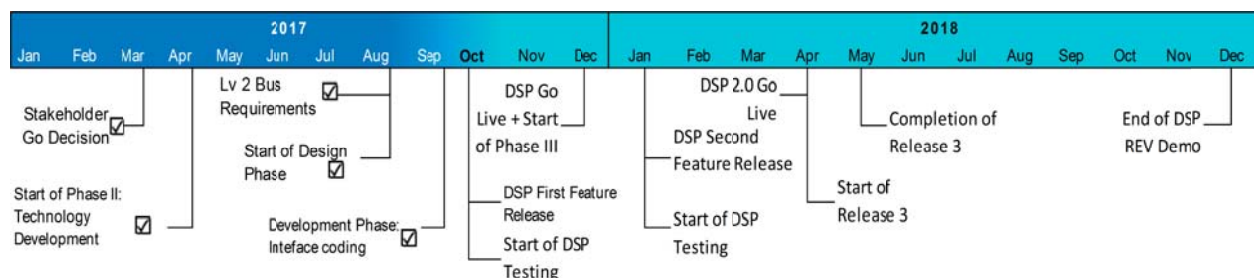For a reference timeline emphasizing the major milestones and accomplishments, see Figure 2.1 below.

Figure 2.1 – Achievements and Milestones Timeline

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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").

2.1 Major Task Activities

1. DSP Release Planning

Given the delayed start of the Solution Development phase, the Project Team devised a plan to test the DSP technology and marketplace for at least twelve (12) months. The team adopted an agile approach and redefined the DSP, as it would now be delivered via three (3) major releases, with each release adding an extra layer of functionality.

For the first release, the DSP will be operated as a Minimum Viable Product ("MVP") with only the core functionality needed to calculate events and start the field demonstration in Q4 2017. Additional automation and enhancements to the data feeds and User Interface ("UI") will be added in Q2 2018.

Under the aforementioned release plan, Phases 2 and 3 of the DSP Implementation Plan will effectively overlap, as Field Demonstration (Phase 3) will start once the DSP goes live in in Q4 2017, while the Technology Development (Phase 2) will continue to update and upgrade the software.

The main features of each release can be found in the following table.

Rel #	Release Functionality	Release Date
1	• Software as a Service ("SaaS") DSP hosted on Opus One's Amazon Web Services ("AWS") cloud; one (1) automated integration feed for Plant Information ("PI") data via batch process • MVP release will have email notifications and manually uploaded metering data for settlement • Weather and two (2) NYISO feeds will be sourced to the external AWS hosted environment • Hosted "AuthO" authentication services	Q4 2017
2	• Automation of meter data feed • Update of PI data feed to Automated Programming Interface ("API") / JavaScript Object Notation ("JSON") format • Integration of National Grid's Oracle Identity Access Manager ("IAM") solution • Development of discrete Point of Control (POC) software	Q3 2017
3	• Possible DSP migration to National Grid's hosted Azure cloud environment • Redesign of National Grid's Comprehensive Integration Services ("CIS") integration for PI and meter data feeds • Additional CIS Integration of two (2) NYISO feeds, weather data feed, DSP to POC communication	Q3 2017

Table 2.1 – Release Functionality Description

2. DSP Detailed Solution Design

Working with Opus One and National Grid Information Services ("IS"), the Project team developed a design of the DSP - POC software, and integrated feeds in support of generating market events and forecasting tools.

The main feeds and applications in the DSP are:
- PI Data to DSP: Feeder level data that will be used in a continuous power flow analysis in order to optimize the feeder load;
- DER Meter Reads: Meters will be placed at the output of every participating DER in order to validate participation and proceed to settlement;
- Weather Data: Weather information will be used in the DSP to forecast peak demand at the feeder level;
- NYISO Pricing: Day-Ahead and Real-Time pricing information will be pulled from the NYISO website to calculate the LMP+D+E price signals for Day-Ahead and Same-Day DSP events; and
- DSP to POC / POC to DSP Communication Protocols: Externally hosted POC software, acting as the primary client UI, will require two-way communication with the DSP to alert client of market events, provide event status, and maintain an inventory of assets.

The DSP will use ninety-three (93) PI tag feeds of the BNMC feeders downstream of the Elm Street substation to determine (in near real-time) the network load, perform power flow analyses, and estimate load forecasts at the feeder level. The data will be sent every fifteen (15) minutes, providing five (5) minute average values. For the first release, this Critical Network Infrastructure ("CNI") data will be transferred using National Grid's CIS protocols and pushed to Opus One's Amazon Web Services ("AWS") cloud environment.

Special attention has been given to Cybersecurity and data governance procedures. The Project team designed strict Security Protocols for the DSP – POC software, including Identity Management and Firewall Setup.

The design of the DSP solution focused on providing a secure, scalable solution that will meet the demonstration needs of the Project, as well as provide a foundation for future customer adoption and growth of the DSP.

The detail design was captured in National Grid's standard Solution Delivery Framework ("SDF") templates (Conceptual Technical Model ("CTM"), Logical Technical Model ("LTM"), Business Requirements Document, etc.) and reviewed by National Grid's Architecture Governance Board and Digital Risk and Security ("DR&S") team.

3. DSP Solution Development

In Q3 2017, Opus One began the development of the DSP software in a hosted environment, utilizing AWS. As part of the development, Opus One configured segregated environments for Development, Testing, and Production. National Grid will be responsible for validation of the end-to-end solution in the Q4 2017.

At the same time, National Grid started the development of integration solutions for non-public data, such as PI and Meter Data, while Opus One focused in externally sourced information, such as the weather data and NYISO pricing feeds.

4. DSP Business Rules Development

The Project Team defined the key characteristics of the DSP and developed the basic rules and conditions for participating in the DSP marketplace. The key elements of the DSP are set out below.

A. Events:

An event is defined as a generation opportunity. Events will be calculated for both Day Ahead and Same Day NYISO markets. The key components for all events are:
- o Time;
- o Duration;
- o Size; and
- o Price.

POC users will have the ability to configure thresholds through the POC and set up filters to avoid getting event notifications that are not of interest. These thresholds will allow them to filter events by price, time of day, duration, and size.

There are two (2) types of events:
- o Day Ahead ("DA") Events: Every day at noon, each DER owner will receive twenty-four (24) events for each hour of the next day (unless the event does not meet the threshold requirements). DA Events will be automatically rejected if there are no customer responses by the end of the day (exact time to be determined).
- o Same Day ("SD") Events: POC users will receive a one (1) hour SD Event with a one (1) hour lead time. Once accepted, every thirty (30) minutes the POC user will receive a price signal for the subsequent thirty (30) minute period. This will allow DER owners to decide if they want to keep their assets running for the next hour.

Depending on the DER owner response, events will be logged in the DSP as:
- o Accepted;
- o Rejected;
- o Automatically Rejected;
- o Threshold Rejected;
- o Cancelled; or
- o Countered.

While DER owners will be able to cancel an accepted DA event, it will automatically exclude them to accept a SD event for the same time period as the cancelled DA event.

B. Settlement:

Settlement will occur in a monthly basis. After each event, the DSP will match meter data with accepted events to verify performance. Subsequently, a report will be pulled by the DSP Administrator and verified by National Grid before proceeding to payment.

C. Penalties:

At this moment, no penalties for non-performance will be applied to market participants while technology and marketplace are being tested and refined. However, the Project team foresees eventually implementing a penalty for nonperformance similar to the current NYISO penalty policy.

2.2   Challenges, Changes, and Lessons Learned this Quarter

2017	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q3	Delays in the development of the Financial Model (Phase 1) impacted the start of the DSP technology development phase.	Instead of one (1) major release, the DSP will go live in three (3) releases. The first version, with basic DSP functionality, is expected to commence in Q4 2017.	The Project team has adopted an agile approach to define an MVP to develop for Day One 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.

3.0   Next Quarter Forecast

During the 4th Quarter of 2017 the Project team will continue to work on the technology development of the DSP software. The majority of the effort will be devoted in coding, releasing, and testing the features of the DSP. The major milestone will be the go-live of version 1.0 of the DSP.

At the same time, the Project team will work closely with the BNMC to finalize the DSP 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.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	DSP First Feature Release	10/27/17 – 10/30/17	10/27/17 – 10/30/17	🟢
2	DSP End-to-End Testing	10/16/17 – 11/30/17	11/21/17 – 12/15/17	🟡
3	DSP 1.0 Go Live	10/24/2017 – 11/7/2017	12/15/17 - 12/18/17	🟡

Key

🟢 On-Track

🟡 Delayed start, at risk of missing on-time completion, or over-budget

🔴 Terminated/abandoned checkpoint

1. DSP First Feature Release
Status: [🟢]
Start Date: 10/27/17
End Date: 10/27/17

Opus One will release the first set of features of the DSP software to the testing environment. In detail, this release will feature:
- A deployable but simple DSP with visual representation of National Grid's feeder model and Event Creation capability; with code existing on a separate virtual machine within a development environment in the AWS cloud with LMP+D+E Calculation;
- Display of Day-Ahead and Real-Time pricing from NYSIO graphically in the DSP User Interface ("UI");
- Minimal functionality to support a manual settlement process;
- Secure login of DSP users through cloud-based user authentication;
- Ability to manually generate a DSP event (Pricing Event) through the DSP;
- Ability to see currently supported states of the Event Lifecycle (Accepted, Rejected, Threshold Rejected, Countered, or Cancelled) reflected in the DSP UI; and
- Simplistic feeder forecasting based on historical data.

Testing of these features will begin once this major milestone is completed.

2. DSP End-to-End Testing
Status: [🟡]
Start Date: 11/21/17
End Date: 12/15/17

National Grid IS will be responsible for oversight of the end-to-end testing and for all phases of development and acceptance testing. Opus One will be responsible for documentation of the test strategy and all unit and system integration testing of the DSP. National Grid will be responsible for testing of data transmission from National Grid systems (outside of the DSP), and will coordinate end-to-end testing efforts with Opus One to confirm transmission of required feeds into the DSP. The National Grid IS team will also be responsible for validation that all

testing scenarios have been documented, verified (through either IS testing or Opus One testing efforts), and passed business acceptance criteria, in accordance with the Business Requirements and Requirements Traceability Matrix.

3. DSP 1.0 Go Live
Status: [🟠]
Start Date: 12/15/17
End Date: 12/18/17

The DSP will go live once end-to-end testing is completed and there is user acceptance from National Grid's Project team. This version of the DSP will be able to calculate the distribution value of generation for both Day-Ahead and Same-Day markets.

This version of the DSP will effectively start the Project's demonstration phase. Initially, DSP users will be required to communicate all events to the BNMC via email, while the POC and other communication functionalities are developed for Release 2.

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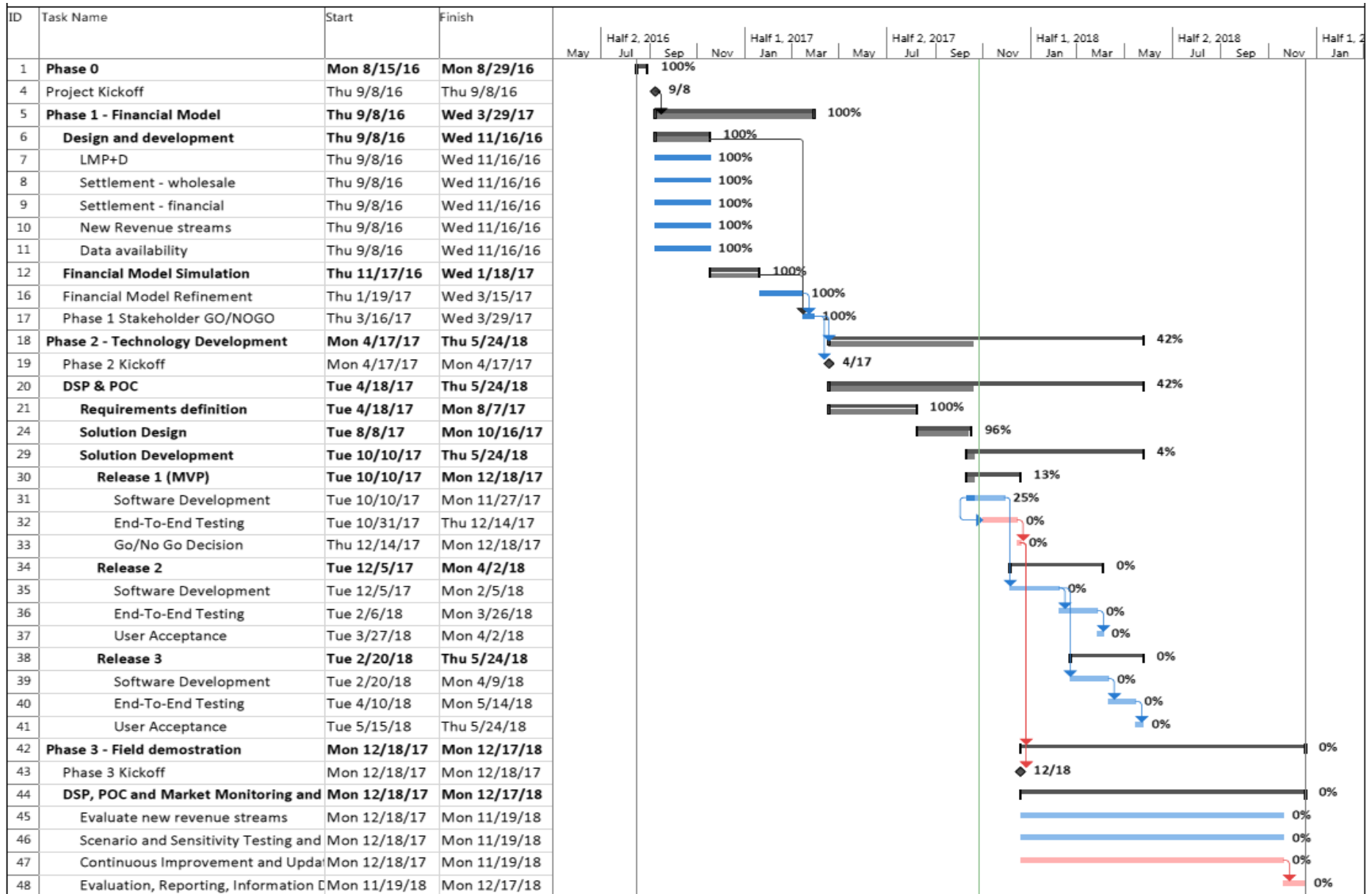
Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

4.2   Updated Budget

There are updates to the estimated budget set forth in the filed DSP Implementation Plan. The main drivers for the changes are:
- Capital overhead expenses were not included in the original budget.
- The delay and challenges in the financial model development required National Grid to engage more internal resources than originally planned.
- The Project Team was finally able to develop a more accurate budget forecast for the internal integration costs after defining the detailed business requirements and design specifications during the first part of Phase 2.

The updated budget information is displayed in the table below.

Project Budget Requirement		Phase 1		Phase 2		Phase 3		Total Project	
		CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
Opus One	Software License			$ 500,000		$ 500,000		$ 1,000,000	
	Program Management	$ 250,000		$ 1,000,000		$ 750,000		$ 2,000,000	
	Software Development (in kind)			$ 2,000,000				$ 2,000,000	
	Annual License Maintenance						$ 200,000		$ 200,000
National Grid	Resources	$ 150,000	$ 220,000	$ 360,000	$ 60,000	$ 160,000	$ 72,000	$ 670,000	$ 352,000
	IT Integration Services			$ 1,250,000			$ 60,000	$ 1,250,000	$ 60,000
Subtotal		$ 400,000	$ 220,000	$ 5,110,000	$ 60,000	$ 1,410,000	$ 332,000	$ 6,920,000	$ 612,000
	Cost Share (in-kind)			$ (2,000,000)				$ (2,000,000)	$ -
	Capital Overhead	$ 87,500		$ 962,500		$ 437,500		$ 1,487,500	
Total Estimated Budget		$ 487,500	$ 220,000	$ 4,072,500	$ 60,000	$ 1,847,500	$ 332,000	$ 6,407,500	$ 612,000

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of September 30, 2017 total $1,101,831. 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 finalized, but will continue to be developed during Phase 2 based on the Check Points identified in pages 15 and 16 of the DSP Implementation Plan.