Division 22-5

Request:

Please refer to the Company's response to DIV 9-2, Attachment DIV 9-2-1, and provide all the "Sanction" and "Resanction Request" documentation for the following projects:

a. DMS/OMS Replacement, pages 1-8;

b. IN 1043 NE EMS Replacement, pages 9-16 ;

c. INVP 1172 – AMAG Upgrades, pages 79-84 ; and

d. IN 2330 ETRM Replacement Nucleus-Gas Benefit, pages 85-101.

Response:

a. Please see Attachment DIV 22-5-1 for all of the sanction and re-sanction documentation regarding the DMS/OMS Replacement.

b. Please see Attachment DIV 22-5-2 for all of the sanction and re-sanction documentation regarding the IN 1043 NE EMS Replacement.

c. Please see Attachment DIV 22-5-3 for all of the sanction and re-sanction documentation regarding the INVP 1172- AMAG Upgrades.

d. Please see Attachment DIV 22-5-4 for all of the sanction and re-sanction documentation regarding the IN 2330 ETRM Replacement Nucleus-Gas Benefit.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty

CAPEX IS Investment Proposal – Summary
EDO – OMS/DMS Platform Standardization & Enhancement Project
Electric Distribution & Generation, EDG, Project No. B07269/K233CS & X09966/K02940

Project sanction paper by Bob Rowe, executive sponsor Chris Root – 6/25/2009

Description

This paper seeks the approval of $29.97M to replace the 2 regional Distribution Outage Management Systems (OMS) Upstate NY and NE and implement a new Distribution Management System (DMS) with 2 new, integrated DMS/OMS installations from ABB. The sanction amount includes a risk margin of $2.5M for the Design, Development and Implementation phases.

Upon approval of this sanction paper, Delegation of Authority (DOA) will be sought for funds to finalize the Statement of Work (SOW), contract documents, software development, hardware purchases, testing and implementation of the new OMS/DMS software and hardware for National Grid USA.

The DMS/OMS Project is tightly integrated with the EMS Project and is being overseen by one Program Manager to ensure the projects remain on schedule, on budget and meet the intended scope. Implementations of the systems are needed due to the following:

- There is an existing business need to update the current upstate New York/New England OMS to a vendor supported version
- There is a business integration need to select a platform for growth to support additional automation on the Distribution Network, Smart Grid and future Mergers.
- The need for integrated OMS/DMS to improve Control Center efficiency by automating manual processes, eliminating paper maps and reducing the duplication of effort required to model the network in disparate systems.

Implementation of the new systems will result in a single view of the Distribution Network, incorporating all DMS/OMS information (ex; Customer Calls, Real Time Device Status/SCADA Integration, integrated Switch Order Writing and Tracking, Switching and Load Applications, Training Simulator) improving system operators' situational awareness, safety, reliability, and the customer experience. The systems are in direct support of realizing the Operate the Network Transformation goal of consolidating Control Centers and providing tools to allow inter-regional backup and support. Additionally, the systems will provide the Control Centers with a platform to support Smart Grid initiatives:

- Measure reduction in load and associated cost, improvement in power quality and reliability
- Implement technologies that provide timely energy usage information and automation to encourage and enable customers to reduce load or otherwise alter their consumption patterns.
- Demonstrate how electric distribution grid operating efficiency can be improved measurably by improved monitoring and control.
- Support reductions in critical peak loads with the combination of technology and rate mechanisms. These lower critical peak loads reduce the overall stress on the system. Stress degrades equipment and causes reliability challenges.
- Improve feeder reliability through the implementation of improved monitoring and control of the distribution grid and the integration of automated meter outage detection and restoration into the existing outage management systems and processes.
- Improve customer satisfaction by providing timely consumption and conservation options, automated load control and improved monitoring and control of the distribution grid.

Category: NPV (Strategic)

Risk score: 49, proposed investment is essential for the systems related FTE savings of Control Center Consolidation and EDO Transformation.

Project Classification: High   Region: US

Finance

Sanction Cost $29.97M for Full project sanction (includes $2.5M in risk margin)

Probability that project cost will exceed tolerance: A $2.5M risk margin was used to determine the sanction amount and is expected to be sufficient.

The Project was previously sanctioned for Analysis in July 2008 and Requirements in December 2008 for a total of $1.39M with a forecasted spend of $1.32M. The project is seeking additional funds of $28.65M for Design, Development and Implementation for a total Project Cost of $29.97M.

Project included in approved Business Plan INVP1185. The initial estimate of the Project Costs were articulated in INVP1185 and cover most of the FY10 and FY11 costs of the project but do not cover the cost for FY12 – FY13. The original estimate did not include Training, full Business Costs and accurate RTB costs. The revised estimate is based on:

- A more detailed review of the internal efforts required to implement the new systems, including development, delivery and receipt of training,
- A revised estimate from the vendor resulting from a focused effort to provide more detail to the Statement of Work,
- A detailed review of anticipated RTB impact, including additional resources to support the new systems,
- Addition of appropriate Risk dollars to the Project

Project cost relative to approved Business Plan: The Project Cost exceeds the current Business Plan by $14.45M Capex and $.6M Opex.

If cost > approved B Plan how will this be funded? Funding/Relief for the gap in FY10 and FY11 is determined to be manageable (52k Capex in FY10, 120k Capex in FY11). The Business Plan for FYF12 – FY13 will be modified accordingly to reflect the defined project costs. Additionally, the Project is seeking to offset project costs through alignment with Smart Grid funding.

Potential to include DMS/OMS Project Costs into Department of Energy (DOE) Smart Grid Funding

- June Regulatory re-filing to include DMS/OMS Project Costs
- July DOE Filing; Approval anticipated in December 2009
- If approved, DOE will fund up to 50% of Project
- Money to be spent inside of 2 years from DOE award date, payable upon achieved milestones

Other financial issues: None

$'000s	Current planning horizon								
	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	925	6,051	7,920	8,385	6,690		**29,971**		

Resources

Availability of internal resources to deliver project: Amber. Due to duration of Project, commitment to support the project is achieved, but named Resources for outer years will not be realized.

Availability of external resources to deliver project: Green. Vendor has committed to provide the resources required to meet the project schedule that was jointly developed between National Grid and the Vendor.

Operational impact on network system: N/A

Key issues

- Availability of internal IS and Business resources to support the Project Schedule due to duration of the project and competing projects (ex; GIS, ERP, Mobile)
- Procurement Resources to support the project will be new and will not have the experience of the EMS contract to apply to the DMS/OMS negotiations.
- Coordination of schedule around Facility consolidation/upgrades may impact deployment options and training plans.
- Coordination of schedule around EMS Project may impact deployment schedule and integration to SCADA. The Projects are being overseen by a Program Manager and are working closely to minimize this risk.
- Timing of global application decisions may impact interface development and implementation.
- Coordination with GIS Upgrade Project is required to manage impact of developing the Network Model extractor, ensuring minimal code rewrite and achievement of extraction milestones.
- Coordination with Mobile Project to ensure available resources to test and verify the interface and manage any Mobile direction change in concurrence with the Project Schedule.

Key milestones

- Initial Analysis Sanction – Jul 2008
- OMS/DMS Vendor selected – Oct 2008
- Strategic SCADA Architecture Decision – Nov 2008
- Requirements Sanction – Dec 2008
- Full Project Sanction – June 2009
- Detail Design & Development Kickoff - July 2009
- New England Production Implementation(DMS/OMS no SCADA) - September 2011
- New York Production Implementation (DMS/OMS w/ SCADA) – April 2012
- New England DMS integration to SCADA – November 2012

Climate change

Contribution to National Grid's 2050 80% emissions reduction target:	Neutral
Impact on adaptability of network for future climate change:	Neutral
Are financial incentives (e.g. carbon credits) available?	No

Prior sanctioning history:

July 2008 – IS PRM (Analysis)

July 2008 – ED&G IS Sanctioning Committee (Analysis)

December 2008 – IS PRM (Requirements)

December 2008 – ED&G IS Sanctioning Committee (Requirements)

June 2009 – IS GTG

June 2009 – IS PRM (Design, Development & Implementation)

July 2009 - ED&G IS Sanctioning Committee (Design, Development & Implementation)

March 2013 – Project Closure

Recommendations

The Sanctioning Authority is invited to:

(a) APPROVE the investment of $29.97m including risk margin of $2.5M by June 25, 2009

(b) NOTE that Chris Root is the Project Sponsor

(c) NOTE that Bob Rowe is the Project Manager and has the approved financial delegation to deliver the project

Signature…………………………………….. Date……………..

Chris Root, Executive VP Customer Operations

IS Finance

I hereby confirm that the financial data supports the business case outlined in this paper.

Signature…………………………………….. Date……………..

Duncan Brown, Head of IS Finance, Global IS

Electric Distribution & Generation Finance

I hereby confirm that this project has been included in the Electric Distribution and Generation Business Plan

Signature…………………………………….. Date……………..

Linda Ryan, Director of Finance, Electric Distribution and Generation

Information Services

I hereby support the recommendations made in this paper.

Signature…………………………………….. Date……………..

Doug Chapman, IS Head of Electricity Distribution and Generation

Decision of the Sanctioning Authority

I hereby approve the recommendations made in this paper.

Signature…………………………………….. Date……………..

Tom King, Chair, Electric Distribution & Generation IS Sanctioning Committee

CAPEX IS Investment Proposal – Summary

EDO – OMS/DMS Platform Standardization & Enhancement Project

Electric Distribution & Generation, EDG, Project No. B07269/K233CS & X09966/K02940

Project sanction paper by Bob Rowe, executive sponsor Chris Root – 6/25/2009

1. Background

This project is seeking funding to implement a tightly integrated OMS (Outage Management System) and DMS (Distribution Management System).The key project drivers include the following:

- There is an existing business need to update the current upstate New York/New England OMS to a vendor supported version
- There is a business integration need to select a platform for growth to support additional automation on the Distribution Network, Smart Grid and future Mergers.
- The need for integrated OMS/DMS to improve Control Center efficiency by automating manual processes, eliminating paper maps and reducing the duplication of effort required to model the network in disparate systems.

2. Driver

Business drivers for the investment include the following:

- Move to a vendor supported OMS platform across the Upstate NY and NE electric service territory.
- Allow for real time view of distribution network that will result in increased system awareness, faster trouble resolution, improved job safety awareness, and improved information back to the customer.
- Allow standardized training and operator development on one OMS/DMS, which will allow for mutual aid between control centers.
- Streamlined processes and procedures will be realized. This includes, but is not limited to automating manual processes, eliminating paper maps and reducing the duplication of effort required to model the network in disparate systems.
- New Systems are required to help Control Centers improve on *Power Quality and Reliability* Fourth Quartile Customer Service ranking from JD Powers.
- Implementation of the DMS is required to position National Grid to support Smart Grid

3. Project Description

The goal of this investment is to implement a tightly integrated OMS (outage management system) and DMS (distribution management system) that will be used by System Operations to respond to unplanned events, monitor & control the distribution network in real time, and respond to customer reliability issues. The project has completed the Requirements phase of the project that has resulted in:

- a comprehensive Statement of Work with the preferred vendor,
- documentation of the interface requirements with corporate systems,
- development of a detailed project plan,
- cost and resource schedules to develop, train and implement the systems

A tightly integrated OMS/DMS platform is required for the company to complete the Electric Distribution Operations Transformation initiative. Upstate NY and NE are utilizing a vendor OMS package (GE's PowerOn product) that is several versions behind the latest version and is no longer fully supported by the vendor. There is a significant upgrade effort and cost associated with bringing the application up to the latest version – upgrading the application will result in a supported OMS with no DMS functionality.

Implementation of DMS functionality will maximize control room expertise and efficiency with regards to safety, reliability and productivity. It will also allow for mutual aid between Control Centers, in addition to supporting standardized training and operator development and realizing streamlined processes and procedures. This includes minimizing/eliminating the use of paper maps, reducing legacy/manual processes, eliminating the duplication of effort, and creating one, current view of the Network Model that is available to all necessary resources.

Many of the interface points for OMS/DMS are slated for replacement as part of global transformation. Currently there are initiatives related to providing global GIS, Mobile, Work Management, and Customer systems. The selected OMS/DMS will have the ability to integrate with all of these systems regardless of vendor. Given the anticipated time frames for future systems, this project seeks to develop interfaces to existing legacy systems. Development of interfaces to future systems will be considered in scope for each of the distinct future project implementations. All interface work done in the scope of this project will be developed with a goal of reusability for future system integration.

An additional critical interface point for OMS/DMS is EMS (Energy Management System). Traditionally EMS and OMS have been separate discrete applications. The addition of DMS has resulted in the need to revisit the relationship between these applications and associated system architecture. The project has selected a suite of products from a single preferred vendor in an effort to reduce the complexity of communication between the systems, minimize potential off-site testing issues and create a consistent look and feel across all applications. The suite of products makes use of a common SCADA database that will reduce the potential Run the Business costs associated with disparate SCADA platforms.

The Project was previously sanctioned for Analysis in July 2008 and Requirements in December 2008 for a total of $1.39M with a forecasted spend of $1.32M. The project is seeking additional funds of $28.65M for Design, Development and Implementation for a total Project Cost of $29.97M (includes risk margin $2.5M).

A core project team comprised of seven internal business resources and two internal IS resources will work with the IS resources detailed in Appendix A on the following:

- Delivery of core OMS and DMS functionality from vendor
- Detail design, and development of required application functionality enhancements from vendor
- Detail design, development, and implementation of interfaces between OMS-DMS and corporate systems
- Delivery of required hardware by vendor
- DMS/OMS production implementation in New England by 11/2011; New York implementation by May 2012.
- DMS integration with SCADA for both regions by Q4 2012

4. Business Issues

The cost to implement an OMS/DMS is partially captured in the following Investment Plan:

INVP 1185 – Distribution Management System (DMS)

The initial estimate of the Project Costs were articulated in INVP1185 and cover most of the FY10 and FY11 costs of the project but do not cover the cost for FY12 – FY13. The original estimate did not include Training and full Business costs. The revised estimate is based on:

- A more detailed review of the internal efforts required to implement the new systems, including development, delivery and receipt of training,
- A revised estimate from the vendor resulting from a focused effort to provide more detail to the Statement of Work,
- Addition of appropriate Risk dollars to the Project

Additionally the RTB costs were not fully understood - a detailed review of anticipated RTB impact, including additional resources to support the new systems, has been considered and documented in the TCO Log.

The project is actively seeking ways to reduce the budget gap. This includes working with IS Finance to determine if there is any potential relief with the outlying years of the Investment Plan. The project is also working with the business and their respective Finance Groups to consider reprioritization of Capital Projects to secure additional funding

5. Options Analysis

Option	Recommendation	Rationale
Implement tightly integrated OMS/DMS platform	Recommended	Allow system operator to have all real time distribution network info in one view. Reduce duplication of effort in managing Network Model. Improve ability for cross-regional support. Provide control centers a platform for smart grid initiative.
Do Nothing:	Rejected	All regions maintain outdated or unsupported legacy platforms. This fails to meet the EDO Transformation recommendations for Control Center Consolidation and the ability for Control Centers to provide site backup and keeps Operations running an unsupported Outage Management System.
Defer project:	Rejected	Doesn't meet the recommended schedule developed by EDO transformation or allow for realization of transformation costs to achieve. There is unmitigated risk associated with running unsupported legacy vendor system.
Pursue separate OMS and DMS systems as stand alone applications	Rejected	There would be excessive internal costs to meet EDO Transformation requirements. Operators would be forced to maintain two separate network models, resulting in significantly fewer efficiency gains. Integration with Smart Grid applications would additionally be more complex.

6. Milestones

Key Milestones	Date	Responsible person…
Initial Sanction	Jul 2008	EDG IS Sanction Cmt
OMS/DMS Vendor selected	Oct 2008	OTN Systems Team
Requirements Sanction	Dec 2008	EDG IS Sanction Cmt
Full Project Sanction	Jun 2009	EDG IS Sanction Cmt
Design Phase begins	Jul 2009	
Development Phase begins	Jun 2010	
NE Production Implementation of DMS/OMS (w/o SCADA	Sep 2011	
NY Production Implementation of DMS/OMS (w/ SCADA)	Apr 2012	
NE Integration with SCADA	Nov 2012	
Project Completion	Mar 2013	

7. Safety, Environmental and Planning Issues

It is expected that this effort will result in a positive safety impact. OMS/DMS will allow for improved operational awareness and response to system events.

Investment Recovery

8. Investment Classification

This project is classified as NPV (Strategic)

9. Regulatory Implications

It is expected that new systems will allow for greater accuracy with regard to outage data, reliability data and reporting, and improved storm management information.

10. Customer Impact

Completion of the project will result in a better toolset for the system operators. This will result in improved outage response time, more timely and accurate outage restoration estimates, and better outage information back to the customer representative. The systems are required to help Control Centers improve on Power Quality and Reliability Fourth Quartile Customer Service ranking from JD Powers.

Financial Impact

11. Cost Summary

This investment proposal seeks funds the full projects, as shown in the table below. This includes funds already sanctioned for the Requirements and Design stages. A further breakdown of these costs is provided in Appendix B. The costs for this project will be allocated to EDO 100%

$'000s		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6 +	Total	Lower Range P20	Upper Range P20
Project Cost	Opex	925	499			800		2,224		
	Capex		5,552	7,920	8,385	5,890		27,747		
IS Investment Plan	Opex	925	500	200				1,625		
	Capex		5,500	7,800				13,300		
Variance to plan	Opex		1	200		(800)		(599)		
	Capex		(52)	(120)	(8,385)	(5,890)		(14,447)		

This project will increase IS ongoing support costs, as detailed in the following table.

RTB costs $'000s	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total
Current Annual RTB costs	885	885	885	885	885	4,425
New Annual RTB costs	885	885	1,140	1,831	1,914	6,655
Impact on RTB costs (new minus existing)			**255**	**946**	**1,029**	**2,230**
Variance to Plan			**255**	**746**	**829**	**1,830**

Project also recognizes an increase in Business Support of two FTEs.

12. Cost Assumptions

- Year 7+ - Annual Maintenance with ABB is initiated.
- Increased FTE support is due to new system (DMS), additional OMS Interfaces and increased frequency of Network Model increments.
- Increased Infrastructure to support High Availability, new system (DMS) and improved Interface Architecture (JCAPS) relates to increase in RTB.

13. Benefits Summary

- Proposed investment is essential for the realization of systems related FTE savings for Control Center Consolidation and EDO Transformation.
- New systems will allow for:
  - Increase Situational Awareness of the Distribution Network (S)
  - Reduce Switching Errors (S)
  - Improved Operator Training (S)
  - Remove reliance on paper maps (E)
  - Load Balancing / Reduce System Losses (E)
  - Allow for mutual aid and backup support between regions for large scale events (E)
  - Allow for realization of FTE reductions associated with Control Center Consolidation (E)
  - Crew Proximity – Efficient dispatching; Broader view of working crews (S, R, C)
  - Quicker Restoration Plan (S, R, C)
  - Asset Management/Optimization with Device Operating History (R)
  - Provide Control Centers with platform to support Smart Grid initiatives – Create the Future
  - New Systems are Key Enablers in achieving Operating Model changes for Operate the Network Transformation

(S) – Safety (R) – Reliability (C) - Customer Service (E) - Efficiency

14. NPV

N/A

15. Additional Impacts

N/A

16. Execution Risk Appraisal

No	There is a risk that …..	Countermeasure or Action	Risk Range	Monitored by ….
1	A separate SCADA will be required for Distribution	Early System Stress tests will verify current Infrastructure Plans.	$500K	Project Management Team
2	Proposed architecture may not be able to support the security requirements	Detail Design with the Vendor and Security Will verify current design.	$200K	Project Management Team

No	There is a risk that …..	Countermeasure or Action	Risk Range	Monitored by ….
	around applications and interfaces			
3	Project will be unable to sign a contract with preferred vendor	Work closely with Procurement and vendor to ensure all issues are understood	$500K	IS Procurement, Project Manager

Appendices

A. Resources
Stage 1:

Role	IS FTE	LoB FTE	Contractor	Systems Integrator	ODC	Other
Project Lead		.5				
Project Managers	1	1				
Business Analysts	1	5	1			
Enterprise Architects	.5					
IS Systems Integrators	4.1					
Developers	1.74					
Testers		1				

Stage 2:

External Resource Engagement:

KEMA or other SME - Provide additional labor / resources to supplement NG staff in completing project deliverables (supported in existing budget).

Stage 3: *Note that resources are confirmed through Design phase. Resourcing will be revisited prior to Development and Implementation*

Name	Role	FTE	Start	End	Availability*
Chris Murphy	PL	.5	Jul 09	May 10	Confirmed
Bob Rowe	PM	1	Jul 09	May 10	Confirmed
Tony Vota	BA	1	Jul 09	May 10	Confirmed
Steve Rebello	BA	1	Jul 09	May 10	Confirmed
Judi Brown	BA	1	Jul 09	May 10	Confirmed
Tom Towne	PM	1	July 09	May 10	Confirmed
Eric Vandewater	BA	1	July 09	May 10	Confirmed
Rob Modugno	SI	.5	Jul 09	May 10	Confirmed
CTO Support		**4.61**	**July 09**	**May 10**	
Enterprise Architecture (T. Radigan)	EA	.50	July 09	May 10	Confirmed
Database Admin (M. LaFrance)	SI	.07	July 09	May 10	Confirmed
Network Architecture (A. Shishonok. K. Walsh)	SI	.11	July 09	May 10	Confirmed

Network Data Mgmt (Contractor)	SI	.17	July 09	May 10	TBC
Enterprise Integration: Peter Heggie (US) Jagjit Singh (UK) Jerry Lerman (US) Santosh Karike (US) Shiva Murthy (UK)	SI	2.81	July 09	May 10	Confirmed
IS Security (C. Peluso)	SI	.10	July 09	May 10	Confirmed
Computing – Software Support (Y. Wu)	SI	.71	July 09	May 10	Confirmed
CNI – Data Support	SI	.13	July 09	May 10	TBC
Data Warehouse	SI	.01	July 09	May 10	TBC
Application Support (integration)		**1.24**	**July 09**	**May 10**	
GIS (S. Plante, S Cifelli)	D	.16	July 09	May 10	Confirmed
CSS (A. Tadevossian)	D	.12	July 09	May 10	Confirmed
IDS (R. Tanna)	D	.35	July 09	May 10	Confirmed
MWork (M. Lawless)	D	.05	July 09	May 10	Confirmed
STORMS/IScheduler	D	.55	July 09	May 10	TBC
AVLS (B Robinson)	D	.01	July 09	May 10	Confirmed

B. TCO Log

TOTAL COST LOG OF IS INVESTMENT - FINANCIAL SUMMARY

Investment Name: ' **1185 OMS-DMS Standardization**

Project Name: **OMS-DMS Standardization**

nvestment Plan No: ıent Plan No: **1185** Investment Start (Financial Year): **08/09**

Currency used: **US $**

	08/09 $'000s	09/10 $'000s	10/11 $'000s	11/12 $'000s	12/13 $'000s	13/14 $'000s	14/15 $'000s	Total $'000s
INVESTMENT PLAN DETAILS:								
OPEX	925	500	200					1,625
CAPEX		5,500	7,800					13,300
Net RTB Impact				200	200	200		600
INVESTMENT COST SUMMARY								
Start-Up - Opex	495							495
Start-Up - Capex								
Start-Up - Risk Margin								
Start-Up - Subtotal	495							495
Requirements and Design - Opex	430	499						929
Requirements and Design - Capex		3,775						3,775
Requirements and Design - Risk Margin								
Requirements and Design - Subtotal	430	4,274						4,704
Development and Implementation - Opex								
People					800			800
Software								
Hardware								
Telecommunications								
Service Contracts								
Other								
Risk Margin								
Development and Implementation - Capex								
People		751	6,920	7,065	4,890			19,626
Software		77	100	220				397
Hardware		449						449
Telecommunications								
Service Contracts								
Other		200	300	300	200			1,000
Risk Margin		300	600	800	800			2,500
Development and Implementation - Subtotal		1,777	7,920	8,385	6,690			24,772
Total Investment Costs - Opex	925	499			800			2,224
Total Investment Costs - Capex		5,552	7,920	8,385	5,890			27,747
Total Investment Costs	925	6,051	7,920	8,385	6,690			29,971
Non-Regulated Project - Uplift								
Non-Regulated Project - Total	925	6,051	7,920	8,385	6,690			29,971
Future Investments								
VARIANCES TO INVESTMENT PLAN:								
OPEX		1	200		(800)			(599)
CAPEX		(52)	(120)	(8,385)	(5,890)			(14,447)
RTB								
Current Annual RTB Expenditure	885	885	885	885	885			4,425
New Annual RTB Expenditure	885	885	1,140	1,831	1,914	1,601	2,296	10,552
Net RTB Impact			255	946	1,029	1,601	2,296	6,127
Variance to Investment Plan			255	746	829	1,401	2,296	5,527
BENEFITS ANALYSIS:								
Investment Benefits								

NPV/NPC SUMMARY INFORMATION

Discount Rate: 15% **NPV:** (23713) **IRR:** **VCR:** 0.41

Payback Period: 5 Years Months

US Sanction Paper

Title:	OMS/DMS Platform Standardization & Enhancement Project	**Sanction Paper #:**	USSC-12-249 (INVP1185)
Project #:	NGUS Capex - S00544	**Sanction Type:**	Re-sanction
Operating Company:	Service Company	**Date of Request:**	23 May 2012
Author:	Susan Stallard / Suzanne Rodriques	**Sponsor:**	John Spink, Vice President Control Centers Operations
Utility Service:	Electricity T&D		

1 *Executive Summary*

1.1 *Sanctioning Summary:*

This paper requests the re-sanction of INVP-1185 OMS/DMS Platform Standardization & Enhancement in the amount of **$49.2M** including a tolerance of +/- 10%.

This sanction amount is $49.2M broken down into:
$47.6M Capex
$1.6M Opex

NOTE: The original sanctioned amount was $30.0M, approved August 2009. Under governance requirements in effect today, this estimate would be considered a Conceptual Estimate. Additional funds of $19.2M are requested to cover the increased investment from detailed design / final engineering, changes in scope and costs not included in the original estimate. RTB costs will increase by $3.0M (by year 4), this will be an increase of $1M above the current plan.

1.2 *Brief Description:*

The re-sanction requests approval to complete the replacement of the 2 regional Distribution Outage Management Systems (OMS) in Upstate NY and NE with applications built by Asea Brown Boveri (ABB). Also, the project will build the application to allow a level of integrated functionality with the Energy Management System/Supervisory Control and Data Acquisition (EMS/SCADA) system. There is an existing business need to update the current NY/NE OMS to a vendor supported version. The integrated OMS will be used by Distribution Control Center Operations to respond to unplanned events and monitor & control the distribution network in real time. It will provide increased system awareness, improved ability to effectively manage the distribution system, and will reduce the duplication of effort required to model the network using multiple systems which exists currently. Implementation of the system will provide a platform to support future advanced distribution analysis applications and additional automation on the distribution networks.

The project closure date in the original Investment Proposal was March 2013. In 2010, National Grid and ABB re-evaluated the implementation options keeping in mind the required complex process to replace the current systems and coordinate the integration with the EMS for the control rooms. This additional engineering design resulted in a more thorough understanding of the complexity to implement an integrated system once the EMS portion has already been placed into service. It more clearly defined the level of effort and schedule required to build and implement a system that could be properly tested prior to implementation, as well as the network design necessary to support the integrated system. In addition, this type of project would be charged Allowance for Funds Used During Construction (AFUDC); however, the original sanction excluded AFUDC. These elements contribute to the variance from the original sanction amount.

The final design recommends a phased integration approach to lower costs for the project. ABB estimates significant additional costs to support full integration as described in the original sanction paper. The phased integration approach allows for the individual EMS and OMS implementations to replace the existing systems without a dependency on the timing of the integration. It provides staged integration capability so that the benefits of integration, including common tagging, can begin to be realized, and extends the project schedule through early 2014.

Implementation of advanced DMS application functionality and integration related to switch order functionality will be evaluated for future use. During the re-evaluation by National Grid and ABB, this functionality was identified as best being moved to the future, for reasons noted above. National Grid and ABB are currently involved in contract negotiations to determine the commercial implications of this approach.

The requirements for additional total funds of $19.2M net are summarized in the table below.

Description	Cost	Reasoning
Labor	2.5M	Primarily due to schedule extensions and increased resource requirements post identified in final engineering design
Wide Area and Local Area Network	5.0M	Additional support and hardware needs identified in final engineering design from due to increased network design complexity and revalidated capacity assumptions
Application	8.0M	Final Engineering identified the need for license and maintenance contracts for Oracle and JCAPS applications associated with the project. Also, additional security tools and reporting hardware were identified as well.
Other	4.3M	Primarily driven by AFUDC allocations, in addition of a factory maintenance system
OPEX Underspend	(0.6M)	Under run of OPEX funds previously sanctioned
Total	**19.2M**	

1.3 Summary of Projects:

Project Number	Project Title	Estimate Amount ($)
INVP 1185	**OMS/DMS Platform Standardization & Enhancement Project**	**$49.2M**
	Total	**$49.2M**

1.4 Associated Projects:

Project Number	Project Title	Company	Estimate Amount ($)
INVP 1041	**US EMS replacement project (NY)**	**Upstate NY**	**$20.1M**
INVP 1043	**US EMS replacement project (NE)**	**New England**	**$14.6M**
		Total	**$34.7M**

1.5 Prior Sanctioning History (including relevant approved Strategies):

Date	Governance	Sanctioned	Paper Title	Sanction Type

	Body	Amount		
July 2009	ED&G IS Sanctioning	$29.97M	EDO – OMS/DMS Platform Standardization & Enhancement Project	Design, Development and Implementation

Over / Under Expenditure Analysis

Summary Analysis	Capex	Opex	Removal	Total
Latest Approval	$27.8M	$2.2M	$0	$30.0M
Actual spend (to-date)	$20.5M	$1.1M	$0	$21.6M
Estimate to Complete	$27.1M	$0.5M	$0.02M	$27.6M
Change	$19.8M	($0.6)M	$0.02M	$19.2M
Re-Sanction Amount	**$47.6M**	**$1.6M**	**$0.02M**	**$49.2M**

1.6 Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
N/A	

1.7 Category:

Category	Reference to Mandate, Policy, or NPV Assumptions
☐ Mandatory ☒ Policy-Driven ☐ Justified NPV	Drivers for this investment are to replace the existing OMS system that is not supported by the original vendor or third party. Replacement ensures the Company can meet our regulatory and operational obligations of running a safe and reliable distribution system.

1.8 Asset Management Risk Score

Asset Management Risk Score: 49

Primary Risk Score Driver: (Policy Driven Projects Only)

☒ Reliability ☐ Environment ☐ Health & Safety

1.9 Complexity Level: (if applicable)

Not required for IS projects.

☐ High Complexity ☐ Medium Complexity ☐ Low Complexity

Complexity Score: ______

1.10 Business Plan:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
BP12 (FY2012-13) IS Business Plan	☒ Yes ☐ No	☒ Over ☐ Under	$6.147M CAPEX
BP12 (FY2013-14) IS Business Plan	☒ Yes ☐ No	☐ Over ☒ Under	$4.915M CAPEX
BP12 (FY2013-14) IS Business Plan	☒ Yes ☐ No	☒ Over ☐ Under	$0.407M OPEX
BP12 (FY2014-15) IS Business Plan	☒ Yes ☐ No	☐ Over ☒ Under	$2.426M CAPEX
BP12 (FY2014-15) IS Business Plan	☒ Yes ☐ No	☒ Over ☐ Under	$0.223M OPEX

1.11 If cost > approved Business Plan how will this be funded?

Funds for investment will be re-allocated within the US Operations portfolio of projects. This will be managed by Resource Planning.

1.12 Current Planning Horizon:

Company Name	Current planning horizon							
$0.0M	**Prior YR'S**	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6 +**	***Total***
		12/13	**13/14**	**14/15**	**15/16**	**16/17**		
Proposed Capex Investment	$20.5	$17.4	$6.0	$3.7				$47.6
Proposed Opex Investment	$1.1		$0.3	$0.2				$1.6
Proposed Removal Investment								$0.0
CIAC / Reimbursement								$0.0
Total	$21.6	$17.4	$6.3	$3.9	$0.0	$0.0	$0.0	$49.2

* - Current contract negotiations with the vendor may result in some Yr 3 funding being moved to a future year

1.13 Resources:

Resource Sourcing			
Engineering & Design Resources to be provided	☐ Internal		☐ Contractor
Construction/Implementation Resources to be provided	☒ Internal		☒ Contractor
Resource Delivery			
Availability of internal resources to deliver project:	☐ Red	☒ Amber	☐ Green
Availability of external resources to deliver project:	☐ Red	☒ Amber	☐ Green
Operational Impact			
Outage impact on network system:	☐ Red	☐ Amber	☒ Green
Procurement impact on network system:	☐ Red	☐ Amber	☒ Green

1.14 Key Issues (include mitigation of Red or Amber Resources):

1	Internal resources from CNI, Operations, and Network Architecture are required throughout the project. Availability of resources is recognized as a potential impact to the project. Mitigating actions include complementing CNI staff with resources from multiple companies that can support the required skills.

1.15 Key Milestones:

Milestone	Target Date: (Month/Year)
Sanctioning by USSC Sanctioning Authority	23 May 2012
OMS Implementation in NY	June 2013
OMS Implementation in NE	December 2013
OMS/EMS Integration complete	February 2014
Project Closure	May 2014

1.16 Climate Change:

Are financial incentives (e.g. carbon credits) available?		☐ Yes	☒ No
Contribution to National Grid's 2050 80% emissions reduction target:	☒ Neutral	☐ Positive	☐ Negative
Impact on adaptability of network for future climate change:	☒ Neutral	☐ Positive	☐ Negative

1.17 List References:

1	EDO – OMS/DMS Platform Standardization & Enhancement Project – Original July 2009 Sanctioning Investment Proposal http://spedg/sites/edotp/otnps/Shared%20Documents/Project%20Mgmt%20Documents%20and%20Reports/Sanction%20Information/Design,%20Development,%20and%20Implement%20Phases/EDO%20-%20OMS-DMS%20Platform%20Standardization%20-%20Design%20Sanction.doc

2 Recommendations:

The **Sanctioning Authority** USSC is invited to:

(a) APPROVE the investment of $49.2M and a tolerance of +/- 6.5% for the reasons stated above.

(b) APPROVE the RTB Impact of $0.18M for the first year, increasing to $3.0M per annum by year 4

(c) NOTE John Spink is the project sponsor

(d) NOTE that Jane Becker is the Project Manager and has the approved financial delegation.

Signature………………………………………. Date………………

John Spink, Vice President Control Centers Operations

3 Decisions

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on 23 May 2012.

Signature……………………………………………..Date………………

Lee S. Eckert
US Chief Financial Officer
Chairman, US Sanctioning Committee

4 Sanction Paper Detail

Title:	OMS/DMS Platform Standardization & Enhancement Project	**Sanction Paper #:**	INVP1185
Project #:	NGUS Capex - S00544	**Sanction Type:**	Re-sanction
Operating Company:	Service Company	**Date of Request:**	23 May 2012
Author:	Susan Stallard / Suzanne Rodriques	**Sponsor:**	John Spink, Vice President Control Centers Operations
Utility Service:	Electricity T&D		

4.1 Background

This Investment will replace the Upstate NY and NE OMS's, implementing new regional OMS systems with staged integration capability to the new EMS (Energy Management System)/SCADA systems.

This project was sanctioned in 2009 for $29.97M including a $2.5M tolerance. Under current governance requirements for project sanction, this estimate would be considered conceptual, not final. At that time, the project proposed a tightly integrated OMS/DMS platform for the company to fully deliver the Electric Distribution Operations Transformation initiative. Upstate NY and NE continue to utilize a vendor OMS package (GE's PowerOn product) that is several versions behind the vendor's most recent version and is no longer fully supported by the vendor. There would be a significant upgrade effort and cost associated with bringing the application up to the latest version without the benefit of integration with EMS or DMS functionality..

In 2009, National Grid and ABB began a detailed assessment regarding scope, efficiency of delivery, level of integration with EMS and timing of replacement of existing systems. This review extended the implementation date through early 2014, while minimizing implementation risks.

4.2 Drivers

Business drivers for the investment as identified for original sanctioning are:

- Move to a vendor supported OMS platform across the Upstate NY and NE electric service territory;
- Minimize operational risk of the current version that is not supported by the vendor;
- Improve Control Center situational awareness and ability to effectively manage the distribution system
- Improve Control Center efficiency through streamlined processes and procedures by automating manual processes and reducing the duplication of effort required to model the network with multiple systems;
- The integrated OMS will be used by Distribution Control Center Operations to respond to unplanned events and monitor & control the distribution network in real time
- Position National Grid to support grid modernization, future advanced distribution analysis applications and additional automation on the distribution networks
- Post sanctioning system performance has been a challenge impacting efficient modeling of restorations during major outages;

The following table indicates the key variations that account for the difference between the original Sanction Amount of $30.0M (Including a tolerance of $2.5M) and the requested Re-Sanction amount of $49.2M (Including a tolerance of $3.0M).

Detail Analysis (M's)	**Over/Under Expenditure?**	***Amount***
Original Sanction (Excl. Tolerance)		$27.5M

Labor (Internal & External)	☒ Over ☐ Under	$2.5M
Network	☒ Over ☐ Under	$5.0
Application	☒ Over ☐ Under	$8.0M
Other (Primarily AFUDC)	☒ Over ☐ Under	$3,8M
OPEX Underspend	☐ Over ☒ Under	$0.6M
Re-Sanction Risk (risk tolerance increased by $.5M from original sanctioning)		$3.0M
Re-Sanction Amount (Including Tolerance)		**$49.2M**

The reasons for re-sanctioning include:

- Labor (Internal & External) – Final engineering determined that a phased integration approach was necessary to replace the current systems as soon as is reasonable while also coordinating the system integration with the EMS for the control rooms. The result of final engineering schedules the in service date for early 2014. The expanded schedule requires use of labor resources over a longer period of time.

- Network – increased hardware costs
Final engineering determined greater system bandwidth requirements than assumed in the original conceptual estimate. In addition, security requirements have increased since the original estimate. Policy change for projects to pay maintenance costs during development resulted in increased maintenance charges

- Application – increased software costs
The variance in software is driven primarily by increased software needs. Final engineering identified a need for JCAPs licensing along with additional Oracle Licensing to support application messaging software and associated database usage. Policy change to have projects pay Oracle Maintenance while in development resulted in increased charges. .

- AFUDC & Other
in the original conceptual estimate did not account for Allowance for Funds Used During Construction (AFUDC) charges to the project. This project sanction estimate includes AFUDC charged to the project and forecast through the in-service date.
The Factory Maintenance System, which was planned as a separate project, was included in this project to reflect the total cost of the new systems.

- Opex Credit
  Opex underspend in the early phase of the project and some training budgeted in Opex was moved to Capex

Lessons Learned on the project to date include:

- Comprehensive network impact assessment across related projects/programs by internal and external subject matter experts during the Requirements Phase.

- Verify screen designs with proto-types developed during the Requirements Phase.

- The timing of procurement and delivery of hardware and software needs to balance budgetary concerns as well as maintenance and finance charges.

- Develop system requirements while reviewing the functionality of the vendor's system to verify what is truly baseline versus what may be a required enhancement or business process change.

4.3 Project Description

The goal of this investment is to implement an integrated OMS that will be used by Distribution Control Center Operations to respond to unplanned events and monitor and control the distribution network in real time.

The current OMS systems are no longer fully supported by the vendor and are running with the risk of being incompatible with newer hardware, operating systems, and operating system patches. System performance has been a challenge impacting efficient modeling of restorations during major outages. This project will implement a new OMS designed and configured to perform at acceptable levels even with the volume of outages experienced in the damaging storms of 2011. The systems will be implemented on a current platform with vendor supported releases, allowing for planned implementation of patches, new functionality and other enhancements.

The OMS system will interface with National Grid's Customer system (CIS) as a source for customer outage calls as well as to provide information on outages back to the customer. It will interface with our Automated Vehicle Locating system (AVL) to obtain real-time crew locations, and it will provide reliability information via an interface with our Interruption and Disturbance system (IDS). Additionally, an interface will be created between the OMS and EMS systems (integration with EMS) which is critical to improving Distribution Operator situational awareness and reducing the duplication of effort required to model the network with multiple systems. This interface will allow future use of advanced DMS applications like unbalanced load flow and fault isolation / system restoration, which improves Control Center operations.

Requirements, design, development have been completed for the ABB OMS system functionality, and the system is currently being tested in the factory. Implementation of OMS functionality is scheduled to be complete for both NY and NE in 2014 (following a coordinated approach with each EMS implementation).

The project is planning a staged implementation through early 2014. The first release of functionality will be in NY, in June 2013, and will consist of OMS functionality only. The next release will be in NE, in December 2013, and will consist of OMS functionality along with the capability for integration (hardware configuration and software functionality). This will be followed immediately by an upgrade to the NY system, providing the capability for integration. The project is scheduled for closure in May of 2014. Enabling of common points between EMS and OMS will take place in 2014 in an incremental fashion, as O&M work. This incremental approach limits the risks of implementing the actual integration functionality, allowing for growing experience with the functionality as more and more of the common points are defined.

4.4 Benefits Summary

A number of key non-financial benefits as outlined in the original sanctioned project will be realized as part of the revised project. Some will not be fully realized until common points are defined. Others will not be realized until advanced DMS application functionality is added at a future date, and are not reflected here. Of the benefits listed below, all are a direct result of the integration with EMS with the exception of Crew Dispatch. Under the revised project, the new systems will allow for:

(S) – Safety *(R) – Reliability* *(C) - Customer Service* *(E) - Efficiency*

- Customer Impact (C)
  - Integrated SCADA status reflects outages in real time in OMS network model
  - Benefits to outage response especially during nighttime hours and periods of high activity
- Crew Dispatch – real-time crew locations reflected on distribution system model; more efficient crew dispatch (S, R, C)
- Potential to improve safety by reducing switching errors (S)
- A single user interface for Distribution Operators, providing increased system awareness and improved ability to effectively manage the distribution system (S, E)

- Reducing manual processes and duplication of effort in multiple systems (E)
  - Interface to EMS SCADA providing real time updating of the OMS network model, maintaining real time system configuration
  - Common tagging provides a consistent network model across control rooms and desks
- Interface to EMS SCADA, providing real-time values for use by Control Room Operators as they operate and manage the distribution system (E)

There are no financial benefits achieved with the implementation of this project.

4.5 Business Issues

- The current OMS (PowerOn) continues to be taxed during severe storms, as evidenced during two major events in 2011. The performance of the system has affected timely reflection of outages and restorations in the system, thereby effecting downstream reporting to our customers and regulators.
- Due to integration with EMS/SCADA, the project is tightly dependent on the EMS project schedule – delays in EMS may delay the delivery of the OMS hardware due to requirements for the hardware to be set up in an integrated fashion at the factory and shipped together. (Section 4.8, Risk # 2)
- EMS defect resolution issues have not been effectively managed/resolved by ABB; project issues from EMS could spill over and affect the resources supporting the OMS project
- Business and IS Organizational changes have impacted the resources directly involved in the project as key resources have been assigned other roles within their organizations,
- Integration testing may result in discovery of functionality that does not work as anticipated or desired, impacting either or both systems (OMS, EMS). This could result in the integration between the systems no longer being the recommended solution, and EMS and OMS would be implemented independently in both regions. (Section 4.8, Risk #3)

4.6 Options Analysis

An options analysis conducted prior to re-sanction concludes that the original strategic intent to implement integrated electric systems in NE and NY are valid and the project should proceed to implement the chosen systems

Recommended Option: Proceed with phased integration approach

Rationale:

- Maintains the original strategic intent of integrated systems
- Delivers improved ability to effectively manage the distribution system
- Reduces manual processes and duplication of effort in multiple systems
- Provides benefits to outage response especially during nighttime hours and periods of high activity
- Provides foundation and extensibility for DMS advanced functionality in the future
- Maintains focus of the vendor on providing an integrated solution
- Requires additional funding and schedule extension, but less than that required for full integration

Rejected Alternative 1: Implement OMS only; consider Integration in the future

Rationale:

- Simplifies project but still requires additional funding for OMS only implementation
- Does not provide near-term benefits of integration

Creates risk of losing the vendor's focus on providing an integrated solution

Rejected Alternative 2: Proceed with full Integration

Rationale:

- Requires significant additional funding, beyond that of the Recommended Option
- Requires significant schedule extension, beyond that of the Recommended Option and puts additional risk on the current unsupported OMS
- Increases risk of the vendor delivering a fully integrated system; support of the additional functionality and extended schedule not desirable to the vendor

Options to do nothing or implement another OMS system are not relevant as they add significant cost write-offs & risk to the project

4.7 Safety, Environmental and Project Planning Issues

<u>Safety</u>

- In the data centers and control rooms, equipment will be installed on raised floors. During the installation, personnel will have to take appropriate measures such as making sure to avoid tripping hazards and open floor tiles to avoid accidents. Appropriate insulated tools and personal protective equipment shall be worn as necessary when working on energized equipment. All applicable work procedures and practices will be reviewed prior to installation.

Environmental

- This OMS equipment will reside in existing data centers located at the various control centers in the operating regions. This work will generally be exempted from environmental permitting.

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4.8 Execution Risk Appraisal

Number	Status (Active, Dormant, Retired)	Category	Detailed Description of Risk / Opportunity	Cause/Trigger	Probability	Impact		Score		Strategy	Risk Owner	Comments/Actions
						Cost	Schedule	Cost	Schedule			
1	Active		There is risk that program will experience issues with the Network during testing, deployment and commissioning.	Testing (including SAT) with the systems may result in poor network performance and functionality issues due to the complexity and implementation of new Network design	3	2	2	6	6	Mitigate	IS PM	Perform Network Performance/Load testing prior to the Systems arriving from the Factory, verifying Network Connectivity and Performance. The project is continuing to vet the SAT schedule to ensure it accounts for the appropriate testing, including coordination with the EMS SAT Schedule
2	Active		There is a risk that a delay in Go Live for EMS will affect the Go Live dates for OMS.	Due to sharing of network Infrastructure and OMS following the EMS implementations.	2	2	2	4	4	Mitigate	Operations PM	Project is currently planning for an expected delay.
3	Active		There is a risk that the planned Integration Testing will not identify all issues.	Due to lack of a fully integrated system in the factory to support Integration Testing.	2	2	2	4	4	Avoid	Operations PM	Project has defined various supplemental testing strategies to flush out potential Integration issues.
4	Active		There is a risk that there will be security issues identified during SAT that requires time to resolve or a network design change.	Due to bringing the OMS application into the ESP and undiscovered issues during factory testing	3	2	2	6	6	Mitigate	IS PM	Project has solicited design reviews from outside consultants and DR&S to ensure the design will support system and NERC-CIP requirements
5	Active		There is a risk that the Integrated system may result in a significant impact on network performance or EMS performance/availability	Due to unanticipated issues with the DAIS Interface	2	2	2	4	4	Avoid	Operations PM	Project has defined various testing strategies to verify the DAIS interface.
6	Active		There is a risk that the Terms and Conditions negotiation will affect the project in cost	ABB and National Grid being unable to come to terms on the cost impact of the Terms and Conditions.	2	2	2	4	4	Avoid	Business PM	Tom Morgan (Procurment) is working with ABB with the intention of no cost, or forecast impact to National Grid.
7	Active		There is a risk that the Maintenance and Support contract with ABB will exceed the forecasted RTB budget.	Due to ABB exceeding their previously stated estimate for Maintenance and Support during Contract Negotiations or due to National Grid changing the requirements of the Maintenance and Support contract.	2	2	1	4	2	Avoid	Business PM	Tom Morgan (Procurment) is working with ABB with the intention of resolving the Maintenance and Support contract consistent with what was recently proposed by ABB.
8	Active		There is a risk that National Grid could decide to delay the project beyond the contracted dates agreed to with ABB and ABB could use this as an opportunity to claim additional costs to	Re-sequence the implementation or delay due to competing priorities.	2	2	1	4	2	Mitigate	Business PM	Include this possibility as part of our contract negotiation discussions
								-	-			

4.9 Permitting

Not Applicable

4.10 Investment Recovery

4.10.1 Investment Recovery and Regulatory Implications

The project costs have been incorporated into the cost of service requirements in the Niagara Mohawk and Narragansett Electric rate cases being filed on April 27, 2012. Niagara Mohawk and Narragansett Electric will be allocated their shares of the capital costs in the form of a rent expense. The recovery in other jurisdictions will be dependent on the timing of their next rate cases.

4.10.2 Customer Impact

There may be some minimal impact to customers during cutover, but the benefits outweigh the risks. Cutover will be performed during a time of minimal outage activity. Business Continuity plans may be utilized during actual cutover. The timing of the cutovers will be closely coordinated during the commissioning process.

4.10.3 CIAC / Reimbursement

Not Applicable

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4.11 Financial Impact to National Grid

4.11.1 Cost Summary Table

				Current Planning Horizon								
Project #	Project Description	Project Estimate level	$M	Prior YR Spending	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
INVP-1185	OMS/DMS		Capex	20.468	17.447	5.975	3.674					47.564
INVP-1185	OMS/DMS		Opex	1.115		0.297	0.223					1.635
			Removal			0.020						0.020
		3%	Total	21.583	17.447	6.292	3.897	0.000	0.000	0.000	0.000	49.219
Project #	Description											
			Capex									0.000
			Opex									0.000
			Removal									0.000
			Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Proposed Sanction												
			Capex	20.468	17.447	5.975	3.674	0.000	0.000	0.000	0.000	47.564
			Opex	1.115	0.000	0.297	0.223	0.000	0.000	0.000	0.000	1.635
			Removal	0.000	0.000	0.020	0.000	0.000	0.000	0.000	0.000	0.020
			Total	21.583	17.447	6.292	3.897	0.000	0.000	0.000	0.000	49.219
				$21.583	$17.447	$6.292	$3.897	$0.000	$0.000	$0.000	$0.000	$49.219

Total Project Current Year and Future Years Cost = $49.219 M

4.11.2 Project Budget Summary Table

Total Project Current Year and Future Years Cost = $49.219 M

Project Budget Summary Table										
Project Costs per Business Plan		Prior Year Spending*	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
	Capex	21.605	11.300	10.800	6.100	0.000	0.000	0.000	0.000	49.805
	Opex	1.625	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.625
	Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Total Cost in B Plan	23.230	11.300	10.800	6.100	0.000	0.000	0.000	0.000	$51.430
	* P/Y Actuals									
Variance		Prior Year Spending	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
	Capex	1.137	(6.147)	4.825	2.426	0.000	0.000	0.000	0.000	2.241
	Opex	0.510	0.000	(0.297)	(0.223)	0.000	0.000	0.000	0.000	(0.010)
	Removal	0.000	0.000	(0.020)	0.000	0.000	0.000	0.000	0.000	(0.020)
	Total Variance	1.647	(6.147)	4.508	2.203	0.000	0.000	0.000	0.000	$2.211

4.11.3 Cost Assumptions

This estimate was based on the original budget developed in 2009, and verified against the current Project Schedule that was co-developed with ABB.

- Integration will create separate project accounting from OMS implementations following original cost allocations
- AFUDC charges will cease once the project is in service
- Network and Oracle Maintenance costs will transition from the project to Service Delivery with EMS Implementations
- No additional sourcing impacts (IS and Business organizational changes)
- No additional Network or Facility impacts

4.11.4 Net Present Value / Cost Benefit Analysis

Not Applicable - Not Financially Driven

4.11.5 Additional Impacts

Not Applicable

4.12 Statements of Support

4.12.1 Supporters

Role	Name	Responsibilities
IS Business Relationship Mgmt	Matthew Guarini	Endorses the project aligns with jurisdictional objectives
EVP Chief Operations Officer	Ellen Smith	Endorses the project aligns with US Operational objectives
IS Finance	Duncan Brown	Confirms that the financial data supports the business case outlined in the paper
Program Sponsor; Vice President of Control Center Operations	John Spink	Endorses the project aligns with US Operational objectives

4.12.2 Reviewers

See section 5.2.2 for reviewers.

5 Appendices

5.1 Project Cost Breakdown

Below is the Financial Summary for the project

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TOTAL COST LOG OF IS INVESTMENT - FINANCIAL SUMMARY

Investment Name: **INVP 1185 OMS-DMS Standardization**

Project Name: **OMS-DMS Standardization**

Investment Plan No: **1185** Investment Start (Financial Year): **08/09**

Currency used: **US $**

	08/09 $'000s	09/10 $'000s	10/11 $'000s	11/12 $'000s	12/13 $'000s	13/14 $'000s	14/15 $'000s	15/16 $'000s	Total $'000s
INVESTMENT PLAN DETAILS:									
OPEX	925	500	200						**1,625**
CAPEX		5,500	7,800	8,305	11,300	10,800	6,100		49,805
Net RTB Impact					603	1,343	2,071	2,071	**6,088**
INVESTMENT COST SUMMARY									
Start-Up - Opex									
Start-Up - Capex									
Start-Up - Risk Margin									
Start-Up - Subtotal									
Requirements and Design - Opex	*586*	*529*							**1,115**
Requirements and Design - Capex									
Requirements and Design - Risk Margin									
Requirements and Design - Subtotal	*586*	*529*							**1,115**
Development and Implementation - Opex									
People						*297*	*223*		**520**
Hardware/Software									
Telecommunications									
Service Contracts									
Other						*20*			**20**
Risk Margin									
Development and Implementation - Capex									
People		*1,907*	*2,780*	*2,880*	*10,744*	*4,163*	*530*		**23,005**
Hardware/Software		*3,432*	*3,563*	*4,111*	*4,580*	*857*	*54*		**16,597**
Telecommunications									
Service Contracts									
Other		*281*	*379*	*1,136*	*2,123*	*955*	*90*		**4,962**
Risk Margin							*3,000*		**3,000**
Development and Implementation - Subtotal		*5,620*	*6,721*	*8,127*	*17,447*	*6,292*	*3,897*		**48,104**
Total Investment Costs - Opex	*586*	*529*				*317*	*223*		**1,655**
Total Investment Costs - Capex		*5,620*	*6,721*	*8,127*	*17,447*	*5,975*	*3,674*		**47,564**
Total Investment Costs	*586*	*6,149*	*6,721*	*8,127*	*17,447*	*6,292*	*3,897*		**49,219**
Non-Regulated Project - Uplift									
Non-Regulated Project - Total	*586*	*6,149*	*6,721*	*8,127*	*17,447*	*6,292*	*3,897*		**49,219**
Future Investments									
VARIANCES TO INVESTMENT PLAN:									
OPEX	339	(29)	200			(317)	(223)		**(30)**
CAPEX		(120)	1,079	178	(6,147)	4,825	2,426		**2,241**
RTB									
Current Annual RTB Expenditure	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**480**
New Annual RTB Expenditure	60	60	60	60	244	1,736	2,705	3,055	**7,980**
Net RTB Impact					184	1,676	2,645	2,995	**7,500**
Variance to Investment Plan					(419)	333	574	924	**1,412**
BENEFITS ANALYSIS:									
Investment Benefits									

NPV/NPC SUMMARY INFORMATION

Discount Rate:	**15%**	**NPV:**	**(30401)**	**IRR:**		**VCR:**	**0.44**
Payback Period:		**5**	Years	Months			

DMS-OMS - Total Cost of Ownership LC

Below is the RTB table for the project

RTB costs $'000s	Yr 4 11/12	Yr 5 12/13	Yr 6 13/14	Yr 7 14/15	Yr 8 15/16	Total
Current Annual RTB costs	60	60	60	60	60	300
New Annual RTB costs	60	244	1,736	2,705	3,055	7,800
Impact on RTB costs (new minus existing)		**184**	**1,676**	**2,645**	**2,995**	**7,500**
Variance to Plan		**(419)**	**333**	**574**	**924**	**1,412**

RTB costs include labor and hardware & software costs to maintain the existing NY and NE systems. The increase in RTB costs (Variance to Plan) are due to:

- Increased hardware and software maintenance costs as the new maintenance costs are initiated after project completion
- An increase of (2) Process and Systems FTE's required to support the new application suite. This increase is required to support an incremental model build for each region (NY and NE) of two times per week as well as increased support required to assist the business in understanding the Focal Point expanded data model that will be available for reporting

Once in-service, cost will be allocated to the operating companies using the following bill pool.

Pool	Company	Name		Allocation
00231	00004	Nantucket Electric Company	DIST	0.239
00231	00005	Massachusetts Electric	DIST	34.611
00231	00036	Niagara Mohawk Power Corp	DIST	53.984
00231	00041	Granite State Electric Company	DIST	0.604
00231	00049	Narragansett Electric Company	DIST	10.562
00231 Total				**100.000**

5.2 Other Appendices

5.2.1 Resource Plan

Name of Resource	Project Role*	Source for Resource	Start	End	Average Monthly Allocation	Availability Confirmed? ***
Jane Becker	Project Manager	Operations	05/25/12	05/25/14	100%	Yes
Tom Towne	IS Project Manager	IS	05/25/12	05/31/14	100%	Yes
Bill Myles	IS Program Manager	IS	05/25/12	05/31/14	50%	Yes
Eric Vandewater	IS Project Lead	IS	05/25/12	05/31/14	100%	Yes
Steve Rebello	OMS Lead	Operations	05/25/12	05/31/14	100%	Yes
Jeff Pires	Data Mgmt Lead	Operations	05/25/12	05/31/14	50%	TBC
Judi Brown	Training Lead	Operations	05/25/12	05/31/14	100%	Yes
Christyl Tremblay	Training & OMS SME	Operations	05/25/12	05/31/14	40%	Yes (1)
Zuozhe Zhang	IS SME	IS	05/25/12	09/31/13	100%	Yes
Steve Plante	IS GIS SME	Ext (IBM)	05/25/12	05/31/14	50%	Yes
Infrastructure Mgr	IS Lead	TBD	TBD	12/31/2013	50%	No
Infrastructure Analyst – NE	IS Analyst	TBD	TBD	12/31/2013	50%	No
Infrastructure Analyst – NY	IS Analyst	TBD	TBD	12/31/2013	50%	No
CNI Support	Analyst	TBD	TBD	12/31/2013	10%	TBC
Service Manager Support	Analyst	TBD	TBD	12/31/2013	10%	No
Lauren Liberati	IS OMS SME	IS	05/25/12	12/31/13	100%	Yes
John Franklin	OMS SME	Operations	05/25/12	05/31/14	100%	Yes
Brian Craig	OMS SME	Operations	05/25/12	05/31/14	100%	Yes
Mark Baustert	OMS Consultant	Ext (KEMA)	05/25/12	05/31/14	40%	Yes
Mary Lafrance	DBA	Ext (IBM)	05/25/12	05/31/14	10%	Yes
Diana Simkin	Security	DR&S	05/25/12	05/31/14	20%	Yes
Basavaraj Urs	Solution Architect	Ext (IBM)	05/25/12	05/31/14	5%	Yes
Susan Stallard	BA	Ext (IBM)	03/15/12	08/31/12	30%	Yes
Carla Cogiltore	Lead BA	IS	03/15/12	08/31/12	10%	Yes
IS OMS Analyst		IS	05/25/12	05/31/14	100%	TBC
OMS SME	OMS SME	Operations	05/25/12	12/31/13	100%	TBC

(1) - Firm involvement confirmed through summer, 2012; continued involvement to be coordinated

* Role: Use role abbreviations identified within Stage 1.

** Source: IS=National Grid IS FTE; Bus=National Grid Business FTE; Ext=External FTE

*** Only enter Confirmed if approved by the relevant Portfolio Lead, otherwise enter TBC (to be confirmed)

5.2.2 IS Stakeholders

The following Stakeholders have read this paper for content / language and recommends edits if necessary.

Confirmation that….		Stakeholder	Stage	Confirmed
	The Business Sponsor supports the proposal and has agreed to the costs and benefits	RM	ALL	Sheena Anand 05/11/2012
	Dependencies with other projects have been identified and addressed	RM	ALL	Sheena Anand 05/11/2012
Solutions Delivery	Scope is defined and the timescale is accurately reflected in the Production Plan	PDM	ALL	Gary Sidoti 05/08/2012
	Delivery impact has been checked with other projects/programmes across the portfolio	PDM	ALL	Gary Sidoti 05/08/2012
	The necessary project resources are named and available.	PDM	ALL	Gary Sidoti 05/08/2012
	Cost estimates seem reasonable. If applicable, third party confirmation of estimates (i.e. benchmarking) has been performed	PDM	ALL	Gary Sidoti 05/08/2012
IS Finance	The project is budgeted for / included within the relevant Business Plan, or appropriate funding by substitution is proposed.	Regional Finance Manager	ALL	Duncan Brown 05/11/2012
	The costs and benefits in the business case have been calculated correctly.	Regional Finance Manager	ALL	Duncan Brown 05/12/2012
	Ongoing support costs are in line with budgeted values (as per the Investment Plan)	Regional Finance Manager	D&I	NA
	The financial value indicators are based on an approved Discounted Cash Flow conforming to company standards	Regional Finance Manager	D&I	NA
	A Total Cost of Ownership Log has been completed (where appropriate).	Regional Finance Manager	D&I	NA
Architecture	The Investment Proposal aligns with National Grid IS Strategy	IS Strategy Manager	R&D	NA
	The Investment Proposal conforms to the National Grid Enterprise Architecture or has been granted an exception	Enterprise Architect	ALL	Ronald Krantz 05/01/2012
Service Delivery	Impacts to new (i.e. Transformation) and existing commercial agreements are understood. If applicable, agreements are updated	IS Investment Manager	ALL	Rick Sheer 05/11/2012
	SLA impacts are understood and addressed	IS Service Manager	D&I	Rick Sheer 05/11/2013

	Impacts to new (i.e. Transformation) and existing commercial agreements are understood. If applicable, agreements are updated	IS Investment Manager	ALL	William Mays 05/11/2012
	SLA impacts are understood and addressed	IS Investment Manager	D&I	William Mays 05/11/2012
Digital Risk & Security	Service definition (including security checklist) has been completed and level of DR&S engagement agreed to	DR&S Consultant	ALL	Diana Simkin 05/01/2012
IS Regulatory	The proposal clearly articulates the: reason for the investment, customer benefits and the mechanism for cost recovery	IS Regulatory Manager	ALL	Tom Gill 05/16/2012

5.3 NPV Summary (if applicable)

Not Applicable

5.4 Customer Outreach Plan (if applicable)

Not Applicable

Resanction Request

Title:	OMS/DMS Platform Standardization & Enhancement Project	**Sanction Paper #:**	USSC-12-249
Project #:	INVP 1185 / S00544 / XG380008082	**Sanction Type:**	Resanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	September 25, 2013
Author / NG Representative:	Susan Stallard / Duane Bloomfield	**Sponsor:**	John Spink, Vice President Control Centers Operations
Utility Service:	IT	**Project Manager:**	Gary Sidoti

1 Sanctioning Summary

This paper requests the re-sanction of INVP 1185 in the amount $65.181M with a tolerance of +/- 10% for the purposes of Development and Implementation.

This sanction amount is $65.181M broken down into:

$55.897M CapEx
$ 9.264M OpEx
$ 0.020M Removal

Note the previously sanctioned amount of $49.200M.

2 Re-sanction Details

2.1 Brief Summary:

This resanction regards the planned implementation of the Distribution Outage Management Systems (OMS) in the Upstate New York and New England regions, which includes a level of integrated functionality with the Energy Management System (EMS) Supervisory Control and Data Acquisition (SCADA) system.

The project's Go Live will move from May 2013 to December 2014 due to application and network issues associated with the complex CNI system. There were also additional changes required to support the successful system implementation. Examples include: Bandwidth required for increased use (i.e. Storms), establish segregated networks for the Quality Assurance System and Operator Training System. Additional hardware purchases were required to mitigate potential downtime to the CNI network.

2.2 Summary of Projects:

Project Number	Project Title	Estimate Amount ($M)
INVP 1185	OMS / DMS Platform Standardization	$ 65.181
	Total	$ 65.181

2.3 Prior Sanctioning History

Previously approved sanctions are attached.

Date	Governance Body	Sanctioned Amount	Paper Title	Sanction Type	Paper Reference Number
Jun 25, 2009	ED&G IS Sanctioning	$29.970M	OMS/DMS Platform Standardization & Enhancement Project	Design, Development and Implementation	USSC-12-249
May 23, 2012	USSC	$49.200M	OMS DMS Standardization and Enhancement Project 23-May-2012 D-I Resanction	Development and Implementation	USSC-12-249

Over / Under Expenditure Analysis

Summary Analysis (M's)	Capex	Opex	Removal	Total
Latest approval	$47.6M	$1.6M	$0.020M	$49.2M
Resanction Amount	$55.9M	$9.2M	$0.020M	$65.1M
Change*	$8.3M	$7.6M	$0.000M	$15.9M

Change = (Latest Approval – Resanction Amount)

Revised Planning Horizon

		Revised Planning Horizon							
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
($M)	Prior Yrs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Total
CapEx	$ 33.748	$ 11.414	$ 10.735	$ -	$ -	$ -	$ -	$ 55.897
OpEx	$ 1.621	$ 3.999	$ 3.384	$ 0.260	$ -	$ -	$ -	$ 9.264
Removal	$ -	$ -	$ -	$ 0.020	$ -	$ -	$ -	$ 0.020
CIAC/Reimbursement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 35.369	$ 15.414	$ 14.118	$ 0.280	$ -	$ -	$ -	$ 65.181

2.4 Drivers

2.4.1 *Detailed Analysis Table*

The following table indicates the major key variations that account for the difference between the previous re-sanction amount and the requested re-sanction amount. Appendix 1 contains greater detail on the source and reason for the variance increase.

Detail Analysis (M's)	**Over/Under Expenditure?**	***Amount***
Labor	☒ Over ☐ Under	$10.4M
Hardware	☐ Over ☒ Under	$0.4M
Software	☒ Over ☐ Under	$2.2M
AFUDC (Allowance for Funds Used During Construction) Allocation	☒ Over ☐ Under	$2.3M
Other Expenses	☒ Over ☐ Under	$1.4M

2.4.2 Explanation of Key Variations

- The implementation and testing of the complex, cyber secure Local and Wide Area Networks exposed additional issues and changes which increased labor costs. These included:
    - Implementation of additional bandwidth.
    - Segregated networks for quality Assurance System and the operator Training System.
    - LAN stabilization activity to implement proper routing, switching, firewall configuration.

- The prior sanction assumed that the current middleware infrastructure would need to be replaced. After further review, it was determined that this was not necessary, resulting in the hardware underspend. This underspend helped to offset additional hardware purchases.

- Increase in software and labor costs associated with the additional time to complete development and implementation of the integrated Asea Brown Boveri (ABB) EMS product, and subsequent implementation of OMS.
  - During integration and testing of the ABB applications with the dedicated Local and Wide Area Networks, a number of application development issues were identified that require resolution prior to commissioning. The resolution of these issues has caused a requirement for additional resource time to resolve issues found in testing, complete additional testing and commissioning.

- Implementation of lessons learned from other key programs which identified additional opportunities to ensure application and business readiness for go-live.
  - Labor costs have been impacted by the addition of further end-to-end testing and mock go live drills, as well as expansion of business readiness plans.

- Increase in AFUDC from higher overall costs and a longer time to implement.

2.5 Business Plan:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
IS Investment Plan FY2013-14	◉ Yes ○ No	◉ Over ○ Under ○ N/A	$12.911M

2.6 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the IS Relationship Manager with the Planning Analyst assistance to meet jurisdictional budgetary, statutory and regulatory requirements.

2.7 Key Milestones:

Milestone	Target Date: (Month/Year)
Start Up	Apr 2009
Begin Requirements and Design	Aug 2009
Begin Development and Implementation	May 2010
Move to Production – New York	Jun 2014
Move to Production – New England	Dec 2014
Project Complete	Feb 2015
Project Closure	May 2015

2.8 Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
May 2015	Project Closure

3 *Statements of Support*

3.1 Supporters

Role	Name	Responsibilities
IS Finance	Chip Benson	Endorses the project aligns with jurisdictional objectives
IS Business Relationship Management	Aman Aneja	Endorses the project aligns with jurisdictional objectives
US Business Supporter	John Spink	Endorses the project aligns with jurisdictional objectives

3.2 Reviewers

Reviewer List	Area	Name
Finance	All	Chip Benson
Regulatory	All	Gideon Katsh
Jurisdictional Delegates	New England- Electric	Jennifer L. Grimsley
	New York- Electric	Allen C. Chieco
	FERC	Nabil E. Hitti
Procurement	All	Art Curran

4 Decisions:

The US Sanctioning Committee (USSC) at a meeting held on September 25, 2013:

(a) APPROVE this paper and the investment of $65.181M and a tolerance of +/- 10% for Development and Implementation.

(b) APPROVE the RTB Impact of $23.098M total for 5 years.

(b) NOTED that Gary Sidoti is the Project Manager and has the approved financial delegation.

Signature………………………………………………..Date………………

Lee S. Eckert
US Chief Financial Officer
Chairman, US Sanctioning Committee

Resanction Request

5.1 Combined EMS / OMS Program Summary

Program Capital Cost Summary

	Actuals through July FY '14	Forecast through Go Live	Projected actuals	Previous Resanction	Variance	Variance Explanation
Payroll (Burdened)	15.4	7.6	23.0	17.7	(5.3)	**Schedule Extensions -** Internal and external labor to support project, as well as increased resource requirements. **Key Drivers:** Verizon resources, CNI Resources
Contractors	19.6	13.9	33.6	19.2	(14.3)	
Hardware	9.2	0.6	9.8	11.2	1.4	**Key Drivers:** Light Speed WAN Upgrade,JCAPs being significantly discounted from original cost projection. **Policy Change -** Shift of HW/SW Support & Maintenance to OpEx, Shift of WAN Leased Lines to OpEx
Software	8.0	(0.2)	7.8	10.1	2.4	
ABB Pmts	17.6	4.6	22.2	21.8	(0.4)	**Key Drivers:** Change orders(PCU Relocation NE, Focal Point changes), Additional engineering hours, Contract Change credit not going to receive.
AFUDC	7.9	5.5	13.4	9.1	(4.4)	**Schedule Extensions -** AFUDC increases and builds, along with travel, employee expenses and misc expenses as schedule delays.
Other	3.8	1.5	5.4	2.6	(2.8)	
Risk		7.2	7.2	6.6	(0.6)	
Total	81.7	40.6	122.3	98.2	(24.1)	

Program Operating Cost Summary

	Actuals to Date (July FY '14)	Forecast through Go Live	Projected actuals	Previous Resanction	Variance	Variance Explanation
Labor (internal & contractors)	2.1	5.7	7.8	2.6	(5.2)	**Schedule Extensions -** increased resources, includes "beddown," training costs.
Hardware/Software	0.0	5.0	5.0	-	(5.0)	**Policy Change:** The recording of the Leased Lines as well as HW/SW Support and Maintenance shifted from CapEx to OpEx
Other	0.1	0.1	0.3	-	(0.3)	**Schedule Extensions -** increased resources and training
Risk		0.6	0.6	-	(0.6)	
Totals	2.3	11.4	13.6	2.6	(11.0)	

Resanction Request

nationalgrid

Title:	OMS/DMS Platform Standardization & Enhancement Project	**Sanction Paper #:**	USSC-12-249 v3
Project #:	INVP 1185 / S00544 / XG380008082	**Sanction Type:**	Resanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	May 13, 2015
Author / NG Representative:	Diane Beard / Mike Gerolamo	**Sponsor:**	John Spink, Vice President Control Center Operations
Utility Service:	IT	**Project Manager:**	Jane Becker

1 *Executive Summary*

This paper requests the resanction of INVP 1185 in the amount $79.738M with a tolerance of +/- 10% for the purposes of Development & Implementation.

This sanction amount is $79.738M broken down into:

$67.157M	Capex
$12.561M	Opex
$ 0.020M	Removal

Note the previously requested sanction amount of $65.181M.

2 *Resanction Details*

2.1 Project Summary

This resanction is in regard to the planned replacement of the two regional existing Outage Management Systems (OMS), in New England (NE) and Upstate New York (NY).

In March 2014 National Grid commissioned a review of the Energy Management System (EMS) / OMS program, to better understand potential risks of the solution design with respect to the utility industry's maturing understanding of cyber security. Significant cyber security risks were identified, primarily due to the linkage between the EMS and the OMS.. Specifically, there was a potential cyber security threat of a larger user population, associated with OMS, gaining access to a critical EMS application. While the probability of these risks being realized is low, the impact is high. EMS is a mission critical system and the efficient operation of the system is dependent on its secure performance. To mitigate the security risks, a decision was reached to decouple the two systems.

As a result of decoupling EMS and OMS, the project go live dates will move to October 15, 2015 for NY-OMS, and December 15, 2015 for NE-OMS. Additional time is needed to update requirements and design documentation, procure required hardware and build a new private network for OMS that is separate from EMS, test the new network, perform security audits, conduct testing and remediate any outstanding issues, and complete training.

The EMS and OMS projects will replace the Company's outdated systems and ensure these systems can be fully supported by vendors in the future. The Company anticipates the upgrade and replacement of these systems will provide certain benefits vital to successful operation of the electric system, including, but not limited to: improved informational security; increased functionality and situational awareness; more accurate and reliable data and reporting; and improved storm management. The projects will bring the systems in line with current industry standards, provide a platform to support future smart grid initiatives and facilitate compliance with NERC Critical Infrastructure Protection ("CIP") Security Standards.

After re-sanction in September 2013, the Company projected an in-service date for EMS in March 2014 and OMS in June 2014. However, the Company discovered several issues during project development and integration not originally anticipated during the planning process. Concerns developed regarding potential cybersecurity risks associated with EMS and the Company was concerned these risks would affect data integrity. Additionally, during project development, the Company participated in industry cybersecurity groups and was subject to NERC audits, which alerted the Company to upcoming changes in NERC CIP standards and compliance requirements. These changes created uncertainties and risk in implementation and compliance that the Company would be required to remediate prior to go-live. Software defects were also discovered and, while the vendor, ABB, made progress in correcting these defects, the defects created additional risk and schedule uncertainty. Based on these concerns, the Company determined it could not proceed with EMS/OMS integration without further analysis.

The Company performed an options assessment of the projects in April 2014 to analyze the issues discovered during development. After vetting its options, the Company decided, as indicated earlier, to decouple and separately implement the EMS and OMS systems. The Company determined that decoupling the systems was the best course of action to mitigate potential cybersecurity penetration risks and ensure that OMS operated in a secure perimeter, as required by NERC standards and rules. Decoupling was also the least cost solution to mitigate the issues discovered during project development.

2.2 Summary of Projects

Project Number	Project Title	Estimate Amount ($M)
INVP 1185	OMS/DMS Platform Standardization & Enhancement Project	79.738
	Total	79.738

2.3 Prior Sanctioning History

Previously approved sanctions are attached and listed below (Newest to Oldest)

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Paper Title	Sanction Type	Paper Reference Number	Tolerance
Sep 25, 2013	USSC	$65.181M	$65.181M	OMS/DMS Platform Standardization & Enhancement Project	Resanction	USSC-12-249	10%
May 23, 2012	USSC	$49.200M	$49.200M	OMS/DMS Platform Standardization & Enhancement Project	Development and Implementation	USSC-12-249	10%
Jun 25, 2009	ED&G IS Sanctioning	$29.970M	$29.970M	OMS DMS Standardization and Enhancement Project 23-May-2012 D-I Resanction	Design, Development and Implementation	USSC-12-249	10%

Over / Under Expenditure Analysis

Summary Analysis ($M)	Capex	Opex	Removal	Total
Resanction Amount	67.157	12.561	0.020	79.738
Latest Approval	55.897	9.264	0.020	65.181
Change*	11.260	3.297	0.000	14.557

Change = (Re-sanction – Amount Latest Approval)

Resanction Request

2.4 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Current Planning Horizon Yr. 1 2014/15	Yr. 2 2015/16	Yr. 3 2016/17	Yr. 4 2017/18	Yr. 5 2018/19	Yr. 6 + 2019/20	Total
INVP 1185	OMS/DMS Platform Standardization & Enhancement Project	+/- 10%	CapEx	44.715	7.800	14.642	0.000				67.157
			OpEx	4.192	2.184	6.172	0.013				12.561
			Removal	0.000	0.000	0.020	0.000				0.020
			Total	48.907	9.984	20.834	0.013				79.738
Total Project Sanction			CapEx	44.715	7.800	14.642	0.000				67.157
			OpEx	4.192	2.184	6.172	0.013				12.561
			Removal	0.000	0.000	0.020	0.000				0.020
			Total	48.907	9.984	20.834	0.013				79.738

2.5 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
IS Investment Plan FY2014-15 CapEx	◉ Yes ○ No	○ Over ◉ Under ○ NA	2.936
IS Investment Plan FY2014-15 OpEx	◉ Yes ○ No	○ Over ◉ Under ○ NA	1.200
IS Investment Plan FY2015-16 CapEx	◉ Yes ○ No	○ Over ◉ Under ○ NA	0.258
IS Investment Plan FY2015-16 OpEx	◉ Yes ○ No	○ Over ◉ Under ○ NA	0.008
IS Investment Plan FY2016-17 OpEx	○ Yes ◉ No	◉ Over ○ Under ○ N/A	0.013

2.6 Drivers

2.6.1 Detailed Analysis Table

The following table indicates the major key variations that account for the difference between the last sanction amount and the requested resanction amount.

Detail Analysis (M's)	Over/Under Expenditure?	Amount
1. Labor	☒ Over ☐ Under	$16.10M
2. Hardware/Software	☒ Over ☐ Under	$1.170M
3. AFUDC (Allowance for Funds Used During Construction) Allocation	☐ Over ☒ Under	$1.010M
4. Risk	☐ Over ☒ Under	$1.930M
5. Others	☒ Over ☐ Under	$0.410M

2.6.2 Explanation of Key Variations

As a result of the decision to decouple the EMS and OMS, additional work is needed to update requirements and design documentation, segregate OMS from the EMS hardware, reconfigure network firewalls that had been associated with the OMS and perform regression testing.

1. Extended Labor and Timeline ($16.100M)
   - Requirements and design documentation will be updated to reflect a decoupled OMS system. This includes a significant number of updates to the business requirements, technical requirements, detailed application design documents, and test plans.
   - Labor for the design and implementation of the new private networks to support the New York and New England OMS applications.
   - Labor costs associated with data center construction and reconfiguration to support additional network and server infrastructure.
   - Testing of the application and network will be required once the new OMS network is complete to ensure proper operation of the standalone OMS.
   - Labor by ABB to support the decoupling of EMS and OMS and set up the OMS application on the new OMS network.
   - Increase in labor due to expanded training program; Field feedback resulted in increased number of trainees,full cost of training now being borne by the project.
   - Total labor costs are somewhat offset by the transfer of labor costs associated with dedicating the network to EMS. The original planned network was shared between the OMS and EMS applications. Since the original network will be dedicated to EMS going forward, the portion of the labor costs charged to OMS to date for establishing that network will be transferred to the EMS project.
2. Increased Hardware/Software costs are associated with the physical creation of new private networks to support both the New York and New England OMS applications as well as the extension of the schedule. Costs include purchase of over 70 switches and firewalls, 40 servers, and 140 workstations as well as increased support and maintenance costs due to schedule extension. Total

increased costs are somewhat offset by the transfer of Hardware/Software costs related to dedication of the original network to EMS. ($1.170M)
3. Decrease in AFUDC due to decrease in rates from 2013 resanction forecast ($-1.010M)
4. Reduced project risk margin from 3 months to 1 month (-$1.930M)
5. Other costs include overheads and travel ($0.410M)

2.7 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the IS Relationship Manager with the Planning Analyst assistance to meet jurisdictional budgetary, statutory and regulatory requirements.

2.8 Key Milestones

Milestone	Target Date: (Month/Year)
Start Up	Oct 2009
Begin Requirements and Design	Dec 2009
Begin Development and Implementation	May 2010
Move to Production - NY	Oct 2015
Move to Production - NE	Dec 2015
Project Complete	Dec 2015
Project Closure	May 2016

2.9 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
May 2016	Closure

3 ***<u>Statements of Support</u>***

3.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities	Title
IS Business Relationship Mgmt	Aman Aneja	1. Review & Endorse IS Investment Proposals 2. Ensure IS Stakeholders approvals are obtained	IS Portfolio Relationship Manager
IS Finance	Chip Benson	Finance Director	Finance Director
IS Regulatory	Wayne Watkins	Regulatory Director	Regulatory Director
US Business Sponsor	John Spink	VP of the business area	Vice President Control Center Operations

3.2 Reviewers

The reviewers have provided feedback on the content/language of the paper

Function	Individual	Area
Finance	Chip Benson	All
Regulatory	Peter Zschokke	All
Jurisdictional Delegate(s)	Jim Patterson	New England – Electric
	Mark Harbaugh	New York- Electric
	Carol A. Sedewitz	FERC
Procurement	Art Curran	All

4 ***Decisions***

The US Sanctioning Committee (USSC) at a meeting held on May 13, 2015. (a) APPROVED this paper and the investment of $79.738M and a tolerance of +/- 10%. (b) APPROVED the RTB Impact of $34.917M total for 5 years for combined NY and NE. (c) NOTED that Jane Becker is the Project Manager and has the approved financial delegation. Signature……………………………………………..Date……………… Margaret Smyth US Chief Financial Officer Chair, US Sanctioning Committee

Capital IS Investment Proposal – Summary

Sanction to Design & Implement Two Energy Management Systems in New England and Upstate New York T&D

A sanction paper by THE EMS TEAM

Sponsored by Nabil Hitti & Chris Root

February 27, 2009

Description

This paper seeks the approval of $34.7m to upgrade/replace the two (2) existing regional Energy Management Systems in New England & Upstate NY with new regional EMS installations from ABB. The sanction amount includes approximately 12% risk margin of $3.7m.

The EMS replacement project is a combined T&D project since the EMS in each region is a single asset used for monitoring, control and operation of the T&D electrical systems.

Upon approval of this sanction paper DOA will be sought for funds to finalize the Statement of Work (SOW), contract documents, software development, hardware purchases, testing and implementation of the new EMS software and hardware for National Grid USA.

The cost for the replacement of the LI EMS, consistent with the National Grid US strategy, has been included as an option in the proposal from ABB. The approval for the LI system will be obtained under a separate sanction paper. This paper assumes that National Grid is not funding the LI project

Category: **Policy-driven: Asset Replacement**

Risk score: **49**

***Finance**

Aggregate Cost & Range **$31.0m, to 34.7m Total T&D Cost**

NE Strategy Cost & Range:	**$13.0m to $14.6m Total T&D Cost**
NE-T	**$5.5m to $6.2m**
NE-D	**$7.5m to $8.4m**
NY Strategy Cost & Range	**$18.0m to $20.1m Total T&D Cost**
NY-T	**$11.7m to $13.1m**
NY-D	**$6.3m to $7.1m**

*Costs and ranges above are rounded to the nearest 1/10th of a million.

Probability that project cost will exceed tolerance: A 12% risk margin was used to determine the sanction amount and is expected to be sufficient.

Project included in approved IS Business Plan? Project costs based on the initial RFP have been included in the draft FY09/10-FY13/14 IS business plans. The funds in the business plan assumed a project start date of January 2009. A delayed project start and updated costs based on finalized requirements will require the project costs to be re-phased over the project plan period and necessary adjustments made in the outlying years.

If cost is greater than the approved Business Plan how will this be funded? The Business Plan will be updated according to approved project costs and funds will be substituted from existing IS or business projects.

Other financial issues: None

	Current planning horizon								
$m	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	0.5	10.1	9.3	7.7	3.4		31.0	N/A	N/A

Note: Above figures do not include risk margin.

Resources

Availability of internal resources to deliver project: Amber

Availability of external resources to deliver project: Green

Operational impact on network system: Amber/Green

Key issues

- This sanction paper proposes the expenditure of $34.7m to upgrade/replace the 2 regional T&D EMS's in NE and Upstate NY with 2 new T&D EMS installations from ABB.
- The implementation plan is to replace the Upstate NY EMS first and the NE system second as the NY system carries a higher risk.
- The investment modernizes the Energy Management Systems to mitigate reliability risks associated with the loss of system control and situational awareness of the T&D electrical systems, minimizes the possibility of disrupting the ISO markets, and eliminates the issues associated with lack of vendor support for the existing NY EMS.
- The current age of the Upstate NY EMS is 23 yrs; the NE EMS's age is 7 yrs. The current systems have been maintained with hardware refresh and in-house support staff and, where appropriate, with EMS vendor maintenance contracts. The proposed investment will enable the US EMS's to follow a 4-6yr system refresh cycle that is in line with current industry practices.
- The project provides a common vendor and system for process & real-time control systems in NY and NE.
- The common platform enables EMS support staff to develop a common knowledge base and standardize roles and responsibilities among CNI and business staff, resulting in a potential for lower support cost for EMS.
- The costs for the EDO Transformation control center consolidation are not contained within this investment proposal. The ability to support proposed map board designs however, are covered within this scope of work.
- The spend plans reflect the decision of National Grid not to fund the LI EMS.

Key milestones

- Contract and Statement of Work (SOW): – March 2009
- Development and Implementation (D&I) – May 2012
- D&I – NY: – Dec 2011
- D&I – NE: – May 2012
- Completion – May 2012
- Project Closure – Dec 2012

Climate change

Contribution to National Grid's 2050 80% emissions reduction target:	Neutral
Impact on adaptability of network for future climate change:	Neutral
Are financial incentives (e.g. carbon credits) available?	No

Recommendations

The Transmission Asset Investment Committee and the ED&G ISSG Committee is invited to:

(a) SUPPORT this Sanction paper for the investment of $34.7m to replace/upgrade the EMS system in Upstate NY & NE. The cost by region and LOB are outlined in the Finance section attached.

(b) NOTE that Nabil Hitti and Christopher Root are the Project Sponsors

(c) NOTE that Chris Murphy is the Program Lead

(d) NOTE that Joe Farella is the Business Project Manager.

(e) NOTE that Dan Hasenwinkel is the IS Project Manager.

Signature…………………………………….. Date……………… for Transmission

Paul Renaud, Vice President Transmission Asset Management

Signature…………………………………….. Date……………… for Distribution

John Pettigrew, Executive Vice President, Electricity Distribution

IS Finance

I hereby confirm that the financial data supports the business case outlined in this paper.

Signature…………………………………….. Date………………

Duncan Brown, Head of IS Finance, Global IS

Transmission/Distribution Finance

I hereby confirm that this project will be funded in the FY 10-14 US Business Plan. FY09, costs project are included in the Gross IT Forecast.

Signature……………………………………. Date………………

Pam Viapiano, VP US Transmission Finance

Signature…………………………………….. Date………………

Dave Campbell, VP US Electric Distribution Finance

Information Services

I hereby support the recommendations made in this paper.

Signature……………………………………….. Date………………

Madalyn Hanley Vice President IS Transmission

Signature……………………………………….. Date………………

Douglas Chapman, Vice President IS Electricity Distribution and Generation

Business Sponsor

I hereby support the recommendations made in this paper.

Signature……………………………………….. Date………………

Nabil Hitti, VP Transmission Network Operations, US Transmission

Signature……………………………………….. Date………………

Chris Root, Senior Vice President Customer Operations

Decision of the Sanctioning Authority

We hereby approve the recommendations made in this paper.

Signature……………………………………….. Date……………… for Transmission

Nick Winser, on behalf of the Transmission Investment Committee

Signature……………………………………….. Date……………… for Distribution

Thomas B. King, on behalf of the Distribution and Generation Executive Committee

Capital/Revenue IS Investment Proposal – Summary

Sanction to Design and Implement Two Energy Management Systems in New England and Upstate New York

A supplement to the project sanction paper by the EMS TEAM

February 27, 2009

Summary

In keeping with the overall strategy to upgrade/replace the two (2) regional existing Energy Management Systems in New England and Upstate and NY with 2 new EMS installations from ABB, this paper seeks the approval of $34.7m. The approval for the LI system will be obtained under a separate sanction paper. This paper assumes that National Grid is not funding the LI project.

This request for sanction is in line with the approved strategy for the replacement of the three EMS systems and was developed using the details from the Statement Of Work (SOW) and the RFP from ABB.

1. Background

The strategy for the US control room systems is to implement a single EMS/DMS/OMS for both Transmission and Electric Distribution & Generation on an integrated platform from a single vendor. ABB Network Manager was selected as the US vendor to provide the EMS/DMS/OMS application suite and two project teams: one for EMS and the second for DMS/OMS were formed to deliver these systems to the Transmission & Distribution business.

The EMS replacement strategy is a single proposal for the US Transmission and Distribution electric business units. The new systems will monitor, operate and control the electric assets of the T&D system as well as exchange data and information with the regional Independent Systems Operators (ISO's) and Transmission Owners (TO's) in New York (NY) and New England (NE)

In parallel with this effort the ED&G team will undertake a separate project and develop the strategy and proposal for a DMS/OMS Platform Standardization & Enhancement which will be sanctioned under separate cover, but will interface tightly with the EMS and requires an integrated high level implementation plan.

The scope of the EMS replacement project is to upgrade/replace the three (3) regional existing Energy Management Systems in New England, Upstate and Downstate NY with 3 new regional EMS installations from ABB. To ensure an acceptable rate of recovery, the cost to replace the LI EMS system has been priced as an option specifically to allow for a cost recovery strategy to be developed and pursued with LIPA. It is important to note that approval for the LI EMS replacement must be obtained by 9/30/2009 to leverage any commercial benefits from a three system implementation.

Upgrade or replacement of the existing EMS systems is being undertaken as asset replacement to mitigate reliability risks associated with the loss of system control and situational awareness of the T&D electrical systems, minimize the possibility of disrupting the ISO markets, and to eliminate the lack of vendor support for the existing NY EMS.

National Grid USA is responsible for the reliable operation, monitoring and control of the Transmission and Distribution (T&D) systems in New England (NE), upstate New York (NY) and on behalf of the Long Island Power Authority (LIPA) for downstate NY under a managed service agreement (MSA). Additionally, system information is provided to the NE and NY ISO's to facilitate the markets and to provide a wide area overview for control area reliability. The primary systems used for this purpose are process real-time control systems known as

Energy Management Systems (EMS). Currently National Grid USA operates three primary EMS systems serving the NE, Upstate and Downstate NY T&D operations.

The NY upstate EMS vendor, Stagg Systems, is no longer in business. The existing system is 23+ years old and vendor support & upgrades are no longer available. The industry average age of EMS systems is just under 6 years.

The NE EMS is an ABB SPIDER system installed and commissioned in 1997 and upgraded in 2001. The NE EMS was planned for an upgrade in 2005 but was put on hold so that a common EMS strategy could be developed for both NY and NE.

The LI EMS is a GE XA/21 system installed and commissioned in 1997 and partially upgraded in 2003. Some of the existing hardware is over 12 years old and cannot be replaced without a software upgrade. Keyspan was considering an upgrade of the system prior to the merger, and the work to encompass the Downstate NY requirements was included in the National Grid US Request for Proposal (RFP).

The current age, hardware obsolescence, and lack of adequate support for the EMS systems creates potential risk for loss of system control and situational awareness. The current suite has been maintained with hardware refresh and in-house support staff and, where appropriate, with EMS vendor maintenance contracts. Industry benchmarking indicates a common practice of upgrading or replacing EMS systems on a 4 to 6 year basis.

An EMS Strategy Analysis Team was formed comprising of Transmission, Distribution and IS personnel. KEMA Consulting was retained to support this effort. The Analysis Team recommendation was accepted and a project team was formed to develop a Request for Information (RFI) document and issue it to prospective EMS vendors for proposed system solutions.

An RFP was developed and resent to the short listed vendors with the additional downstate NY requirements as well as deferred options for Distribution Management System (DMS) and Outage Management System (OMS) functions.

A staggered implementation process is proposed with the NY EMS being commissioned in the second quarter of FY12. New England will follow with commissioning occurring in the last quarter of FY12. The ABB proposal provides an option for LI EMS. A milestone for a decision on whether to exercise the option has been established with a date of 9/30/2009.

An evaluation was performed to determine if the NY transmission mapboard should be replaced while replacing the EMS. It was determined that there is no benefit at this time to replacing the mapboard or changing the existing technology. There is no asset replacement requirement, no NPV benefit, and no regulatory requirement warranting replacement. The current NY Distribution mapboards will remain in their current configuration. If the Regional Control Centers consolidate, the requirements for a new mapboard will be evaluated at that time and the costs will be included in the respective investment proposal. The NE T & D mapboards will be replaced as part of the Northborough relocation project. The hardware and software to drive the mapboard displays is included in this project scope.

2. Business Drivers

Reliability is the primary driver in determining the overall risk score for the proposed investment. The table below illustrates the risk score by region.

Primary Driver	**Safety**	**Environmental**	**Reliability**
Impact Level – NY	5	0	7

Likelihood Level - NY	5	0	7
Overall Risk Score - NY	38	0	47
Impact Level – NE	5	0	7
Likelihood Level - NE	2	0	2
Overall Risk Score - NE	22	0	32

The risk score of 49 using the capital risk prioritization tool is based on the project being in-flight. The regional risk scores outlined above determine the priority of the staggered system implementation by region.

The business drivers outlined in the SG106 Strategy Paper are still valid at the time of this sanction request and have not been repeated.

3. Project Description

ABB will provide the hardware and software for the solution in a turnkey type delivery. National Grid resources will be utilized in providing data and displays necessary for system operation as well as being involved in commissioning, testing and integration at the supplier facilities and when the systems are delivered and installed at National Grid's Control Centers.

Project time line is estimated to be 36 months in length from contract signing. Once the systems are delivered on site, a parallel operation will occur between the old EMS system and the new EMS system in order to minimize impact on Control Center Operations during the transition and cutover process.

The systems being procured and delivered are Process Real-Time Control systems and will operate on their existing independent network. Any interface to the corporate network will be through firewalls and DMZ's. The systems are being designed to meet the NERC Critical Infrastructure Protection Standards which are mandatory and enforceable for compliance purposes.

4. Business Issues

The following items need to be noted in addition to the business issues identified in the strategy paper.

- Approximately $36M has been included in the business plan for FY10-14 which includes the investment for replacement of the LI EMS. The options for LI should be exercised by the date in the SOW to leverage the commercial terms of the contract and implement the platform necessary for EDO control center consolidation and backup control center strategy. Adjustments to the business plan will be made in FY10 by substituting IS & business projects.

- The project is an asset replacement project which will provide increased functionality and support to the regional transmission and distribution control centers with the existing number of support staff. The number of applications being supported will increase from 13 to 24, and the number of environments will increase from 13 to 20 across the three regions.

5. Options Analysis

The following is a table extracted from the approved strategy paper recommending replacement of the 3 regional Energy Management Systems:

Option	Recommendation	Rationale

Option	Recommendation	Rationale
Do Nothing:	Rejected	• NY system is obsolete, has no vendor support, in-house staff is ageing (VERO) and limited • Not sustainable in NE or LI • Current contemporary practices recommend an upgrade or replacement of EMS systems on a 4 to 6 year basis. Current fleet age: NY-23 yrs, NE-7 yrs, LI-5 yrs (other parts of LI system are older)
Defer project:	Rejected	• Systems are aging and at or near end of use full life • Lack of spare parts for long term sustained operation • Significant Life Extension dollars would have to be spent on re-engineering applications to execute on unsupported hardware
Upgrade/Replace the NE, Upstate & Downstate NY EMS Systems with 3 Installations from a Common EMS Vendor	**Recommended as per approved Strategy**	• Strategy recommended by EMS Project Team and EMS Steering Committee • Based on the Technical, Commercial & Cost evaluation, proceed with the upgrade/replacement with ABB as the selected EMS vendor

6. Milestones

Key Milestones are shown below. These milestones are taken from the Project Schedules submitted by ABB and will be contingent upon the signing of the contract in April 2009.

- Receive Sanction approval– 3/30/2009
- Establish Project Team – 6/1/2009
- Contract award – 4/24/2009
- Phase I – Upstate NY –12/2011
- Phase II – NE – 5/2012
- NY system delivery and site acceptance –12/2011
- NE system delivery and site acceptance –5/2012
- NY system in service – 12/2011
- NE system in service – 5/2012
- Project closure – 3/2013

7. Safety, Environmental and Planning Issues

Safety

- In the data centers and control rooms, equipment will be installed on raised floors. During the installation, personnel will have to take appropriate measures such as making sure to avoid tripping hazards and open floor tiles to avoid accidents. Appropriate insulated tools and personal protective equipment shall be worn as necessary when working on energized equipment. All applicable work procedures and practices will be reviewed prior to installation.

Environmental

- This EMS equipment will reside in existing data centers located at the various control centers in the three operating regions. This work will generally be exempted from environmental permitting.
- Excepting unforeseen issues, there are no other external approvals or conditions expected.

8. Investment Recovery

The regulatory recovery strategy developed for the strategy paper is still applicable for Upstate NY and NE and is attached as Attachment 1.

The strategy to recover costs for the LI EMS is under discussion with the Long Island Power Authority (LIPA). A separate agreement will need to be negotiated once the funding and recovery approach has been agreed.

8.1 Investment Classification

The investment classification of asset replacement for this strategy is based on the age of existing systems and the current recommended practice to upgrade/replace systems on a 4 to 6 year cycle.

9. Regulatory Implications

There are no regulatory requirements to replace the EMS's. However, this project is an asset replacement project for critical systems that are past end-of-life and there would be significant damage to the National Grid reputation should a significant event occur as a result of our aging fleet of EMS systems

10. Customer Impact

There may be some minimal impact to customers. The impact centers around the temporary loss of telemetry as Remote Terminal Units (RTU's) are cut over from the old EMS to the new EMS. Some revenue meter information is collected via the pulse accumulator functionality within an RTU. The timing of the cutovers will be closely coordinated during the commissioning and Site Acceptance Testing (SAT) phases of the project.

11. Financial Impact

Cost Summary

The following tables show the breakdown of the aggregate cost estimate of $31m for the project as well as the allocation of cost estimates by region and lines of business.

Table 1 illustrates the proposed total aggregate cost for the project. The initial DOA for preliminary work, up to $1,000k was requested via a Preliminary Works Sanction Paper which includes IS requirements and design.

NY and NE allocations are based on the system development costs for each region. The cost allocation between T&D in each region is based on the methodology developed in the previously presented strategy paper (RTU counts by business segment). Ongoing RTB costs will be recalculated annually based on T&D RTU counts.

Note: The following tables do not include the 12% risk margin.

Table 1: Aggregate Project Cost Estimate by region

$m	NE	NY	Total
Trans	5.5	11.7	17.2
Dist	7.5	6.3	13.8
Total	13.0	18.0	31.0

Tables 2-9 illustrate the aggregate cost per region and then cost per LOB in each region. Comparison to costs in the IS FY09-13 Business Plan are also outlined.

Note - All numbers are rounded to the nearest 1/10 of a million.

Table 2: Aggregate Project Cost Estimate:

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
Project Cost	OPEX	0.5	0.0	0.0	0.0	0.0	0.5	N/A	N/A
	CAPEX	0.0	10.2	9.3	7.6	3.4	30.5	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	5.6	15.7	12.3	6.6	1.4	41.6		
Variance to plan	OPEX	0.5	0.0	0.0	0.0	0.0	0.5		
	CAPEX	5.6	5.5	3.0	(1.0)	(1.9)	10.2		

Table 3: New England Aggregate Project Cost Estimate:

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NE Aggregate Project Cost	OPEX	0.2	0.0	0.0	0.0	0.0	0.2	N/A	N/A
	CAPEX	0.0	3.7	4.2	3.4	1.5	12.8	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	2.4	2.2	1.8	0.2	6.5		
Variance to plan	OPEX	0.2	0.0	0.0	0.0	0.0	0.2		

	CAPEX	0.0	(1.3)	(2.0)	(1.7)	(1.3)	(6.3)		

Table 4: New England Transmission Project Cost Estimate:

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NE Trans Project Costs	OPEX	0.1	0.0	0.0	0.0	0.0	0.1	N/A	N/A
	CAPEX	0.0	1.6	1.8	1.4	0.6	5.4	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	1.0	0.9	0.7	0.1	2.7		
Variance to plan	OPEX	0.1	0.0	0.0	0.0	0.0	0.1		
	CAPEX	0.0	(0.6)	(0.9)	(0.7)	(0.5)	(2.7)		

Table 5: New England Distribution Project Cost Estimate:

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NE Dist Project Costs	OPEX	0.1	0.0	0.0	0.0	0.0	0.1	N/A	N/A
	CAPEX	0.0	2.2	2.4	2.0	0.9	7.5	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	1.4	1.2	1.0	0.1	3.7		
Variance to plan	OPEX	0.1	0.0	0.0	0.0	0.0	0.1		
	CAPEX	0.0	(0.8)	(1.2)	(1.0)	(0.8)	(3.8)		

Table 6: New York Aggregate Project Cost Estimate:

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NY Aggregate Project Cost	OPEX	0.3	0.0	0.0	0.0	0.0	0.3	N/A	N/A
	CAPEX	0.0	6.5	5.1	4.2	1.9	17.7	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	5.6	8.0	6.0	1.3	0.0	20.9		
Variance to plan	OPEX	0.3	0.0	0.0	0.0	0.0	0.3		
	CAPEX	5.6	1.5	0.9	(2.9)	(1.9)	3.2		

Table 7: New York Transmission Project Cost Estimate: Note this does not include the cost range

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NY Trans Project Cost	OPEX	0.2	0.0	0.0	0.0	0.0	0.2	N/A	N/A
	CAPEX	0.0	4.2	3.3	2.7	1.2	11.5	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	5.6	5.2	3.9	0.8	0.0	15.6		
Variance to plan	OPEX	0.2	0.0	0.0	0.0	0.0	0.2		
	CAPEX	5.6	1.0	0.6	(1.9)	(1.2)	4.1		

Table 8: New York Distribution Project Cost Estimate: Note this does not include the cost range

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NY Dist Project Cost	OPEX	0.1	0.0	0.0	0.0	0.0	0.1	N/A	N/A
	CAPEX	0.0	2.3	1.8	1.5	0.7	6.2	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	2.8	2.1	0.4	0.0	5.3		
Variance to plan	OPEX	0.1	0.0	0.0	0.0	0.0	0.1		
	CAPEX	0.0	0.5	0.3	(1.0)	(0.7)	(0.9)		

Table 9: Long Island Distribution Project Cost Estimate
Note: Since National Grid is not funding the LI system at this time the Project Cost is zero and the funds will be re-allocated to reduce the variance for the NY & NE systems.

$m		Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total	Lower Range P20	Upper Range P80
NY Dist Project Cost	OPEX	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
	CAPEX	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
IS Investment Plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	5.3	4.2	3.6	1.2	14.3		
Variance to plan	OPEX	0.0	0.0	0.0	0.0	0.0	0.0		
	CAPEX	0.0	5.3	4.2	3.6	1.2	14.3		

The costs for this project will be tracked and allocated by region and then by Lines of Business (LOB) within each region.

The cost allocation per region, and LOB within each region are as follows:

- NE
  - NE Transmission 42%
  - NE Distribution 58%

- Upstate NY
  - Upstate NY Transmission 65%

- o Upstate NY Distribution 35%

This project will decrease IS ongoing support costs, as detailed in the following table.

Support (RTB) Costs ($k)	**Yr 1** 08/09	**Yr 2** 09/10	**Yr 3** 10/11	**Yr 4** 11/12	**Yr 5** 12/13	**Total**
Existing Support Costs	$5,148	$4,397	$4,319	$4,174	$4,147	$22,185
New support costs	$5,148	$4,397	$4,319	$4,174	$3,421	$21,459
Impact on RTB costs (new minus existing)	-	-	-	-	-$726	-$726
Variance to Plan						

RTB costs include labour and hardware & software costs to maintain the existing NY and NE systems. The new & existing costs remain unchanged over the project period as the existing systems will require to be supported in parallel with the new system development and deployment. The decrease in RTB costs in year 5 is due to lower hardware and software maintenance costs as the new maintenance costs are initiated after project completion.

Note: Initial analysis indicates that there is a potential for additional reduction in RTB costs through the improvement and alignment of processes to configure and maintain the Network Model, RTU configurations, etc. across regions. The project team will coordinate further analysis with relevant business areas to quantify the potential savings.

12. Cost Assumptions

Estimates of cost and time required for development & implementation have been determined by finalizing the SOW and are on a not to exceed basis. Final pricing will be determined at the end of contract negotiations with ABB.

This cost estimate is Sanction Grade (+/- 12%).

13. Benefits Summary

There is no cost benefit associated with this project since it is an asset replacement of aging EMS installations. Qualitative benefits are shown below.

- Provide operators with the best tools & situational awareness
- Provide a platform that can integrate distribution system operational and analytical tools
- Provide a single, modern, and scalable system with multiple installations
- Minimize operating and reputation risk
- Provide full Operator Training Simulator (OTS) capability
- Addition of Operator Training Simulator in NY
- Addition of PI in NY

14. NPV

This strategy is not financially driven; therefore the NPV is not applicable.

15. Additional Impacts

The Disaster Recovery procedures will be updated to reflect the new hardware, software and system put in place as part of this strategy.

IS Security will be improved by this project and applicable NERC CIP standards will be incorporated.

Commissioning of the upgraded/replaced installations in the 2 regions will be closely coordinated and planned with T&D Operations in order to minimize operational impacts to the T&D systems and the ISO Markets.

16. Execution Risk Appraisal

	RISK	MITIGATION	Probability	MARGIN $
1	Project scope changes	Follow the detailed Statement of Work (SOW) contract document which includes a detailed specification of requirements and agreed to functionality. Follow strict change control process at the Steering Committee level.	Low	1,089k
2	Schedule slippage if adequate in-house labor resources are not allocated or those resources do not have the necessary skill sets	Ensure with the businesses and IS that sufficient personnel are assigned to the project. Backfill with contractors if applicable.	Medium	1,000k
3	Insufficient support from Protection and Telecom Operating (PTO) group for RTU commissioning.	Ensure PTO group are aware of the project. Schedule and resource requirements for commissioning.	High	300k
4	The system does not meet requirements as specified.	Review with ABB the deficient requirements and develop a mitigation strategy. Delay shipment of the system from the factory until requirements have been satisfied.	Low	0
5	ABB is late in delivering the project.	Monitor the project progress and schedule. Escalate issues to Steering Committee and Program Board. Coordinate with Procurement on liquidated damages.	Medium	300k
6	ABB is late in delivering the project which causes National Grid to vacate the Westborough Complex later than planned.	Procure EMS kit (hardware and software) to install existing release in Northborough prior to new system being delivered.	Low	0
7	Current plan to relocate facilities fails to be implemented, falls behind schedule or strategy changes.	Facilities will continue to provide updates on a monthly basis. If delays develop or plans change negotiate with facilities and businesses to remedy impact.	Medium	1,000k

Note: The 12% risk margin will be managed across the entire project and will only be released through change control documents approved by the Project Steering Committee

17. Supporters

Author of this paper assure that in accordance with TGP 11, the supporters listed below have been consulted and that each states they support the paper.

- Senior Vice President, Customer Operations -*Chris Root*
- Vice President, Transmission Network Operations- *Nabil Hitti*
- Vice President ,Transmission Asset Strategy – *Paul Renaud*
- Senior Vice President, Electricity Distribution, Network Strategy – *Pat Hogan*
- Director, Dispatch and Control – NE & Upstate NY – *John Spink*
- Director, Systems Operations LI – *Theodore Pappas*
- Director, Transmission Finance, Reporting & Forecasting – *Andrew Forth*
- Manager, Transmission Finance-Rates- *Linda Doering*
- Manager, Transmission Commercial Services- Bill Malee
- Director, Project Management- Peter Kohnstam
- Manager, ED Finance Decision Support – *Diane Sharron*
- Manager, Transmission Asset Strategy – *Alan Roe*
- Director, NE & NY Control Centers – *Will Houston, Michael Schiavone*
- Director, Manager, Network Operational Planning and Review – *Julian Cox*
- Director, Protection & Telecom Operations Management – *Leonard Fiume*
- Manager, Energy Management Systems - *Vasilios Tsolias*
- Director, Global CNI Systems Support - *MaryAnne Douville*
- Director, Transmission Planning – *Carol Sedewitz*
- Director, Electricity Distribution, Network Asset Planning - *Rob Sheridan*
- Manager, Electricity Distribution, Capacity Planning - *Al Labarre*

A. Resources

Stage 1 has been completed with the exception of final sanctioning.

The following resources are NOT included in the project costs:
- Supply Chain Resources

Stage 2:

External Resource Engagement:

ABB Contractors - Work with vendor (ABB) and get them on board to implement some of the work. We have followed this route before in previous implementations with much success.

KEMA or other SME- Provide additional labor / resources to supplement NG staff in completing project deliverables.

Stage 3:

Name	Role	FTE	Start	End	Availability
Chris Murphy	PL	.5	Jan. 09	Sep 13	Confirmed
TBA	PMO / Business Analyst	2.0	April 09	Sep 13	TBD
Joe Farella	PM	1.0	Dec. 08	Sep 13	Confirmed
Art Vierling	NY Network	1.0	Feb 09	Mar 12	Confirmed

Name	Role	FTE	Start	End	Availability
	Operator 1				
TBA	NY Network Operator 2	1.0	May 09	Mar 12	TBD
TBA	NE Network Operator	1.0	May 09	May 12	TBD
TBA	NY Display and Database	5.0	June 09	June 10	TBD
TBA	NE Display and Database	2.0	June 09	June 10	TBD
TBA	NY Dispatch Operator	1.0	April 09	Mar 12	TBD
TBA	NE Dispatch Operator	1.0	April 09	May 12	TBD
Dan Hasenwinkel	IS PM	1.0	Dec. 08	Sep 13	Confirmed
Ryan Lee 50% Kristen LeBouf 50% Brian Finn 50% Dexter Freivald 50% Sam Sankaran 50% Rich Kent 50%	NE EMS IS	3.0	May 09	Aug 12	Confirmed
Doug Howe 50% Jim Gonzalez* 50% Nate Purdy 50% Deb Wood 50% Ed Dumas 50% TBA 50% * Needs to be backfilled after VERO October 1, 2010	NY EMS IS	3.0	May 09	Mar 12	Confirmed
TBA	CTO – Network Comms. & Plng Support - NY	.75	4/09	4/10	External Assumed
TBA	CTO – Network Comms. & Plng Support - NE	.33	4/10	4/11	External Assumed
TBA	NE CIP	.33	4/11	3/12	TBD
TBA	NY CIP	.33	4/11	3/12	TBD
TBA	NY Field Commissioning	5	4/10	3/12	TBD
TBA	NE Field Commissioning	5	4/10	3/12	TBD

Additional resources will be brought in as contractors to backfill for support team to allow them to work on the project.

IS resource from Enterprise Architecture, Security, Computing and Data Centre Services will be consulted as needed.

B. Financial Impact – breakdown

The Total Project costs shown in the table below are indicative at this stage.

Project Costs $k	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Total
Requirements & Design - OPEX	460					
Requirements & Design - CAPEX						
Requirements & Design – risk margin	56					
R&D SUBTOTAL	**460**					**460**
Development & Implementation – OPEX						
Internal resource – IS	0					
Internal resource – business	0					
External resource	0	0	0	0	0	0
Hardware	0	0	0	0	0	0
Software	0	0	0	0	0	0
Other	0	0	0	0	0	0
Development & Implementation – CAPEX						
Internal resource – IS	0	1050	1050	1150	450	3700
Internal resource – business	0	1875	2625	2624	1125	8249
External resource	0	500	400	300	0	1200
Hardware	0	780	580	0	0	1360
Software	0	0	0	0	0	0
Expenses	0	450	575	525	0	1550
Project Support		160	160	160	0	480
Legal		100	0	0	0	100
AFUDC 5% all regions		246	270	238	79	833
Sales Tax (NY)		268	226	204	65	763
ABB	0	4,741	3,418	$2,425	1,666	12,250
Subtotal		10,169	9,303	7,626	3,385	30,483
Risk Margin						3,689
TOTAL PROJECT COSTS						**$34,632**

C. TCO log

Date Last updated: 16 February 2009 | Year 0 is financial year: 08/09

TOTAL COST LOG FOR IS INVESTMENTS

Enter system name:

ABB TCO: EMS Replacement: NE/NY

Enter Scheme No: (e.g. ISREVxxxx or ISCAPxxxx)

INVP1041, INVP1043, INVP1566

LIFECYCLE COST SUMMARY

	Previous Cumulative $'000s	Year 0 $'000s	Year 1 $'000s	Year 2 $'000s	Year 3 $'000s	Year 4 $'000s	Year 5 $'000s	Year 6 $'000s	Total $'000s	
									-	+
Current Annual Support Costs		5,148	4,397	4,319	4,174	4,147	4,118	4,091	**30,394**	+
Previous Investments									-	+
This investment OPEX		*426*	-	-	-	-	-		***426***	
This investment CAPEX		-	*7,083*	*5,542*	*4,017*	*2,259*	-		***18,902***	
This Investment TOTAL		426	7,083	5,542	4,017	2,259	-		**19,328**	+
Future Investments			-	-	-	-	-	-	-	+
TOTAL COST	-	**5,574**	**11,480**	**9,861**	**8,191**	**6,406**	**4,118**	**4,091**	**49,722**	=

INCREMENTAL SUPPORT COST OF THIS INVESTMENT

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Net Incremental Support Costs	-	-	-	-	- 726	- 768	- 805	- 2,299

D. Attachment 1: Regulatory and Finance Analysis of Proposed Energy Management Systems (EMS) Replacement Project

US Sanction Paper

Title:	Design & Implement Two Energy Management Systems in New England and Upstate New York T&D	**Sanction Paper #:**	(USSC-12-248) INVP1041 - UNY INVP1043 - NE
Project #:	EMS NE S00281 EMS NY C40766	**Sanction Type:**	Re-Sanction
Operating Company:	Allocated	**Date of Request:**	May 23, 2012
Author:	Yelena Belousova / Joseph Kruczlnicki	**Sponsor:**	John Spink, Vice President Control Center Operations
Utility Service:	NY & NE Electric Operations		

1 Executive Summary

1.1 Sanctioning Summary:

This paper requests the re-sanction of 'EMS NE S00281' and 'EMS NY C40766' projects in the amount of $51.6M including a tolerance of +/- 10%.

This sanction amount is $51.6M broken down into:
$50.6M Capex
$1.0M Opex

Note the originally requested sanctioned amount was $34.7M. Under governance requirements in effect today, this estimate would be considered a Conceptual Estimate. Additional funds of $16.9M are requested to cover the increased investment from final engineering, schedule extension, changes in scope, and costs not included in the original estimate.

1.2 Brief Description:

In keeping with the overall approved strategy the project's scope includes the upgrade/ replacement of the two (2) regional existing Energy Management Systems (EMS) in New England (upgrade) and Upstate NY (replace) with 2 new EMS installations from the vendor Ventyx, an ABB company (ABB).

The re-sanction assumes a 54 month project schedule, an increase of 18 months from the original contact duration of 36 months. Once the systems are delivered on site, a period of parallel operation will occur with the old and new EMS systems in order to minimize the impact on Control Center Operations during the transition and cutover process.

The primary drivers for re-sanctioning include the costs associated with extending resources through the schedule delays caused by ABB's development of baseline code, and the additional funding for hardware and software to meet design requirements that were better defined throughout the project design phase.

The requirements for additional funds of $16.9M are summarized in the table below:

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Description	Cost	Reasoning
Labor	$4.7M	Primarily due to schedule extensions and increased resource requirements post conceptual design
Wide Area and local Area Network	$4.1M	Additional support and hardware needs identified in final engineering and design from increased network design functionality and revised capacity requirements
Application	$4.2M	Increased clarity of hardware and software needs
Other	$3.9M	Primarily driven by AFUDC (Allowance for Funds Used During Construction) allocations and the addition of a factory maintenance system
Total	**$16.9M**	

1.3 Summary of Projects:

Project Number	Project Title	Estimate Amount ($)
EMS NY C40766 INVP1041	US EMS Replacement (NY)	$30.0M
EMS NE S00281 INVP1043	US EMS Replacement (NE)	$21.6M
	Total	**$51.6M**

1.4 Associated Projects:

Project Number	Project Title	Company	Estimate Amount ($)
S00544 INVP1185	OMS-DMS Platform Standardization and Enhancement	National Grid US	$30.0M
		Total	**$30.0M**

1.5 Prior Sanctioning History (including relevant approved Strategies):

Date	Governance Body	Sanctioned Amount	Paper Title	Type of Approval (Sanction)
March 2009	TIC, ED&G Executive Committee, IS PRM	$34.7M	Design & Implement Two EMS in New England & New York T&D	Sanction

Over / Under Expenditure Analysis

Summary Analysis (M's)	Capex	Opex	Removal	Total
Latest approval	$34.2M	$0.5M	$0	$34.7M
Re-Sanction Amount	$50.6M	$0.9M	$0.1	$51.6M
Change*	$16.4M	$0.4M	$0.1	$16.9M

1.6 Next Planned Sanction Review:

Not applicable

1.7 Category:

Category	Reference to Mandate, Policy, or NPV Assumptions
☐ Mandatory ☒ Policy-Driven ☐ Justified NPV	There are no regulatory requirements to replace the EMS's. However, this project is an asset replacement project for critical systems that are past end-of-life and there would be significant damage to National Grid reputation should a significant event occur as a result of our aging fleet of EMS systems

1.8 Asset Management Risk Score

Asset Management Risk Score: 49 (**in flight project**)

Primary Risk Score Driver

☒ Reliability ☐ Environment ☐ Health & Safety

1.9 Complexity Level: (if applicable)

Not required for IS projects.

1.10 Business Plan/Capital Tracker:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
BP12 (FY2012-13) IS Business Plan	☒ Yes ☐ No	☒ Over ☐ Under	$8.1M CAPEX in FY13
BP12 (FY2013-14) IS Business Plan	☒ Yes ☐ No	☒ Over ☐ Under	$7.0M CAPEX in FY14

1.11 If cost > approved Business Plan how will this be funded?

Business plan overspend by IS supported by a re-allocation of funds within the US Operations portfolio will be managed by Resource Planning.
.

1.12 Current Planning Horizon:

NE EMS Project

	Current planning horizon								
$'000s	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	204	3,612	3,769	3,078	5,968	4,985	**21,617**		

Upstate NY EMS Project

$'000s	Current planning horizon								
	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	259	6,667	5,766	4,423	9,768	3,127	30,009		

1.13 Resources:

Resource Sourcing			
Engineering & Design Resources to be provided	☒ Internal		☒ Contractor
Construction/Implementation Resources to be provided	☒ Internal		☒ Contractor
Resource Delivery			
Availability of internal resources to deliver project:	☐ Red	☒ Amber	☐ Green
Availability of external resources to deliver project:	☐ Red	☒ Amber	☐ Green
Operational Impact			
Outage impact on network system:	☐ Red	☐ Amber	☒ Green
Procurement impact on network system:	☐ Red	☐ Amber	☒ Green

1.14 Key Issues (include mitigation of Red or Amber Resources):

1	Internal resources from CNI, Operations, and Network Architecture are required throughout the project. Availability of resources is recognized as a potential impact to the project. Mitigating actions include complementing CNI staff with resources from multiple companies that can support the required skills.
2	There is a large demand for experienced EMS contractors in the current workplace. DOE (Department of Energy) monies have created a surge in EMS type infrastructure activities. The majority of required contract resources have been placed under contract with National Grid and relationships with current vendors are being maintained.

1.15 Key Milestones:

Milestone	Target Date: (Month/Year)
USSC Sanctioning Meeting	May 23, 2012
NY Cutover	March 2013
NY Closure	June 2013
NE Cutover	September 2013
NE Closure	December 2013

1.16 Climate Change:

Are financial incentives (e.g. carbon credits) available?		☐ Yes	☒ No
Contribution to National Grid's 2050 80% emissions reduction target:	☒ Neutral	☐ Positive	☐ Negative
Impact on adaptability of network for future climate change:	☒ Neutral	☐ Positive	☐ Negative

1.17 List References:

1	AMIC 0911-Original Sanction
2	TIC 0906-Original Sanction
3	SG106 Strategy Paper
4	EMS NY - Stagg Asset Analysis
5.	EMS NE - ABB Spider Asset Analysis
6.	Regulatory and Finance Analysis of Proposed Energy Management Systems (EMS) Replacement Project (as of November 20, 2008)

2 Recommendations:

The **Sanctioning Authority** USSC is invited to:

(a) APPROVE the investment of $51.6M including a tolerance of +/- 6.9% [$3.55M]

(b) NOTE that Joe Farella is the Project Manager and has the approved financial delegation.

(c) APPROVE the RTB Impact of $139K (per annum) for Energy Management Systems (EMS) in New England.

(d) APPROVE the RTB Impact of $377K (per annum) for Energy Management Systems (EMS) in Upstate NY.

Signature……………………………………….. Date………………

John Spink, Vice President Control Center Operations

3 Decisions

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on May 23, 2012

Signature……………………………………………..Date………………

Lee S. Eckert
US Chief Financial Officer
Chairman, US Sanctioning Committee

4 Sanction Paper Detail

Title:	Design & Implement Two Energy Management Systems in New England and Upstate New York T&D	**Sanction Paper #:**	INVP1041 - UNY INVP1043 - NE
Project #:	EMS NE S00281 EMS NY C40766	**Sanction Type:**	Re-Sanction
Operating Company:	Allocated	**Date of Request:**	May 23, 2012
Author:	Yelena Belousova	**Sponsor:**	John Spink, Vice President Control Center Operations
Utility Service:	NY & NE Electric Operations		

4.1 Background

Currently National Grid USA operates three primary EMS systems serving the New England (NE), Upstate New York (UNY), and Downstate NY Transmission and Distribution (T&D) operations for LIPA.

National Grid USA is responsible for the reliable operation, monitoring and control of the T&D systems in New England and Upstate New York. Additionally, system information is provided to the NE and NY ISO's (Independent Systems Operators) to facilitate the markets and to provide a wide area overview for control area reliability. The primary systems used for this purpose are process real-time control systems known as Energy Management Systems (EMS).

At this time, current EMS applications face the following challenges:

- The upstate NY EMS vendor, Stagg Systems, is no longer in business. The existing UNY system is over 26 years old, and vendor support and upgrades are no longer available. The industry average age of EMS systems is just under six years.
- The existing NE EMS is an ABB SPIDER system installed and commissioned in 1997 and upgraded in 2001. The NE EMS was planned for an upgrade in 2005, but was put on hold so that a common EMS strategy could be developed for both NY and NE.

The current suite has been maintained with hardware refresh and in-house support staff and, where appropriate, with EMS vendor maintenance contracts. The current age of the systems, hardware obsolescence, and lack of a level of support for enduring operations for the EMS systems increases the risks associated with the loss of system control and situational awareness of the Transmission and Distribution (T&D) electrical systems.

Industry benchmarking indicates a common practice of upgrading or replacing EMS systems on a four to six year basis. The proposed investment will enable the Upstate NY and NE EMS's to be under full lifecycle management with vendor support, and will allow for a planned system refresh cycle.

An EMS Strategy Analysis Team was formed comprising of Transmission, Distribution and IS personnel. KEMA Consulting was retained to support this effort. The Analysis Team recommendation was accepted and a project team was formed to develop a Request for Information (RFI) document and issue it to prospective EMS vendors for proposed system solutions.

The strategy for the US control room systems is to implement a single EMS/DMS (Distribution Management System) /OMS (Outage Management System) for Electric Transmission and Distribution on an integrated platform from a single vendor. The vendor, Ventyx, an ABB company, was selected as the vendor to provide the US EMS/DMS/OMS application suite. Two project teams, one for EMS, and the second for DMS/OMS, were formed to deliver these systems to the Transmission & Distribution (T&D) business.

To resolve the EMS applications' challenges, and in keeping with the overall approved strategy, the replacement of the existing EMS systems is being undertaken as an asset replacement project. The replacement minimizes the possibility of disrupting the regional wholesale markets, will eliminate the lack of vendor support for the existing NY EMS, and will mitigate reliability risks associated with the loss of system control and situational awareness of the T&D electrical systems.

The EMS replacement strategy is a single proposal for the US T&D electric business. The new systems will monitor, operate, and control the electric assets of the T&D system, as well as exchange data and information with the regional Independent System Operators (ISO's) and other Transmission Owners (TO's) in New York and New England.

In parallel with this effort the ED&G team undertook a separate project to develop the strategy and proposal for a DMS/OMS Platform Standardization & Enhancement which was sanctioned separately. It will interface with the EMS and requires an integrated high level implementation plan.

An evaluation was performed to determine if the NY transmission mapboard should be replaced while replacing the EMS. It was determined that there is no benefit at this time to replacing the mapboard or changing the existing technology. There is no asset replacement requirement, no NPV benefit, and no regulatory requirement warranting replacement. The current NY Distribution mapboards will remain in their current configuration. If the Regional Control Centers consolidate, the requirements for a new mapboard will be evaluated at that time and the costs will be included in the respective investment proposal. The NE T&D mapboards have been replaced as part of the Northborough relocation project. The hardware and software to drive the mapboard displays is included in this project scope.

4.2 Drivers

The following table indicates the key variations that account for the difference between the original Sanction Amount $34.7M (Incl. tolerance of $3.7M) and the requested Re-Sanction amount $51.6M (Incl. tolerance of $3.55M).

Detail Analysis (M's)	**Over/Under Expenditure?**	***Amount***
Original Sanction (Excl. Tolerance)		$31M
Labor (Internal & External)	☒ Over ☐ Under	$6.3M
Hardware	☒ Over ☐ Under	$3.3M
Software	☒ Over ☐ Under	$3.6M
AFUDC (Allowance for Funds Used During Construction) Allocation	☒ Over ☐ Under	$4.5M
Expenses	☐ Over ☒ Under	$0.8M
Sales Tax	☐ Over ☒ Under	$0.2M
ABB Payments	☒ Over ☐ Under	$0.3M
Re-Sanction Tolerance		$3.55M
Re-Sanction Amount (Incl. Tolerance)		**$51.6M**

The reasons for re-sanctioning include:

- Increased hardware & labor costs due to a clarification of requirements around LAN & WAN design as well as resiliency requirements.
- Increased Network Maintenance charges to the project due to policy change and the clarity of requirements/assumptions on the Network Design.
- The variance in software costs is driven by clarity of requirements/assumptions (increased hardware needs; increased software licenses for Oracle and PI, a modern data historian).
- Scope changes (security requirements for network monitoring; hardware to support maintenance system in the ABB factory)
- The variance in AFUDC (Allowance for Funds Used During Construction) charges is due to an inaccurate forecast at the project start and the extended project timeline
- Schedule delays due to ABB product development and the extension of the associated resources to complete the project.
- Scope changes (Revised Automatic Generation Control functionality for the NY Operator Training Simulator, updated ABB bandwidth requirements, DR (Disaster Recovery), Resiliency for Lincoln / Northborough sites).

- Incomplete LOD (List of Deliverables) from ABB including Common Tagging Servers and additional consoles for OTS (Operator Training Simulator) due to network security requirements.

Lessons Learned on the project to date include:

- Comprehensive network impact assessment across related projects/programs by internal and external subject matter experts during the requirements phases.
- Projects implementing new software products should incorporate higher tolerances due to unpredictability of product development schedule.
- Understand financial implications around timing of procurement and delivery of hardware and software.
- Insure large projects have a checkpoint after R&D (Requirements and Design) phase to validate original estimates and assumptions.

4.3 Project Description

The scope of the EMS replacement project is to upgrade/replace the two (2) regional existing Energy Management Systems in New England (upgrade) and Upstate NY (replace) with two new regional EMS installations from Ventyx, an ABB company. ABB will provide the hardware and software for the EMS Applications in a turnkey type delivery.

The systems being procured and delivered are Process Real-Time Control systems and will operate on independent networks. Any interface to the corporate network will be through firewalls and DMZ's. (DMZ stands for "demilitarized zone" - a physical or logical sub-network that contains and exposes an organization's external services to a larger untrusted network, such as the corporate network or the Internet). The systems are being designed to meet the NERC Critical Infrastructure Protection Standards which are mandatory and enforceable for compliance purposes.

National Grid resources will be utilized in providing data and displays necessary for system operation, as well as support during commissioning, testing and integration at the supplier facilities and on site when the systems are delivered and installed at National Grid's Control centers.

A staggered implementation process is proposed with the NY EMS being commissioned in the last quarter of FY13. New England will follow with commissioning occurring in the second quarter of FY14.

The following applications will be decommissioned as the result of the project:

- Energy Management Systems in New England (EMS NE - ABB Spider) Unique ID 961.001
- Energy Management Systems in Upstate NY (EMS NY – Stagg) Unique ID 961.002

The Decommission Plan includes the following:

- Invoke change request procedures
    - Shutdown of EMS
    - Shutdown Operator Desktops
    - Remove retired desktop cabling
    - Shutdown legacy EMS front end processors
    - Remove data center cabling
- Retire ICCP links
- Retire legacy displays
- Retire modem monitoring system
- Retire legacy network and monitoring equipment
- Retire legacy time signal hardware
- Disconnect WAN circuits
- Decommission hardware following NERC CIP compliant procedures
    - Complete disposal travelers
    - Wipe and/or destroy hard drives
    - Update Active Monitoring Plan
- Storage of backup tapes
- Update PowerPlant Asset Database

4.4 Benefits Summary

There is no cost benefit associated with this project since it is an asset replacement of aging EMS installations. Qualitative benefits are shown below.

- Provide operators with the modern tools & situational awareness.
- Provide a platform that can integrate distribution system operational and analytical tools.
- Provide a common, modern, and scalable system for NE and Upstate NY.
- Provide a common vendor and system for process & real-time control systems in Upstate NY and NE.
- The common platform enables EMS support staff to develop a common knowledge base and standardize roles and responsibilities among CNI and business staff, resulting in a potential for lower support cost for EMS.
- The investment modernizes the Energy Management Systems to mitigate reliability risks associated with the loss of system control and situational awareness of the T&D electrical systems, minimizes the possibility of disrupting the ISO markets, and eliminates the issues associated with lack of vendor support for the existing UNY EMS.
- Minimize operating and reputation risk.
- Provide full Operator Training Simulator (OTS) capability in NE.
- Addition of Operator Training Simulator in NY.
- Addition of a modern data historian (PI) to the NY system, to provide standard data historian systems in US Electric CNI.

4.5 Business Issues

The following items are noted in addition to the business issues identified in the SG106 Strategy Paper:

The project is an asset replacement project which will provide increased functionality and support to the regional transmission and distribution control centers. Application support will be provided by the US IS CNI staff. Remote Telemetry Unit (RTU) and Telemetry support will remain unchanged.

The project's fund committed to date is $27.8M. A portion of the additional funds requested are in the IS BP12 Business Plan. Additional substitution will be needed. The systems are being implemented in data centers that are in line with the US CNI Data Center and Property Strategies.

IS Procurement is leading a vendor strategy with ABB to ensure adequate commercial arrangements are in place.

The recommendation is for Network Operations to pursue the deployment of the ABB Network Manager NM 5.5.

4.6 Options Analysis

An options analysis conducted prior to re-sanction concludes that the original decision to replace NY and NE EMS is still valid and the project should proceed to implement the selected systems.

Recommended Option: Continue to pursue the deployment of the ABB Network Manager NM 5.5.

Rationale:

- Executive level focus is in place to ensure system delivery.
- Provides the shortest time frame to replace existing aged systems.
- Maintains ABB focus on the current solution.
- Procurement to renegotiate project contract to minimize contractual and commercial issues compared to other alternatives.

Rejected Alternative 1: Place the project on hold pending ABB future releases

Rationale:

- Increases risk of existing system failure due to extended in-service time of existing systems.
- ABB may redeploy project team, leading to loss of staff knowledge of the National Grid system and requirements.
- National Grid may redeploy EMS Development project team, leading to loss of staff knowledge of the National Grid system and requirements.
- Product may not be adopted by other customers, leading to National Grid owning a bespoke system, rather than using a product with a large customer base.

Rejected Alternative 2: Abandon the contract and pursue other options.

Rationale:

- Delays EMS replacement of bespoke system
- Degrades ABB focus on product development
- Impacts contracted EMS Development workforce.
- Likely to create commercial and legal issues requiring time and money to resolve.
- Likely to cause other utilities to seek alternative solution impacting future support of ABB NM.

Rejected Alternative 3: Take a mature ABB Ranger EMS until Network Manager matures.

Rationale:

- Delays EMS replacement of bespoke system
- Degrades ABB focus on product development
- Likely to cause other utilities to seek alternative solution impacting future support of ABB NM.

4.7 Safety, Environmental and Project Planning Issues

Safety

- In the data centers and control rooms, equipment will be installed on raised floors. During the installation, personnel will have to take appropriate measures such as making sure to avoid tripping hazards and open floor tiles. Appropriate insulated tools and personal protective equipment shall be worn as necessary when working on energized equipment. All applicable work procedures and practices will be reviewed prior to installation.

Environmental

- This EMS equipment will reside in existing data centers located at the various control centers in the operating regions. This work will generally be exempted from environmental permitting.
- Excepting unforeseen issues, there are no other external approvals or conditions expected.

Regulatory

- Old hardware will be disposed of as required by the NERC CIP Regulations.

4.8 Execution Risk Appraisal

Number	Status (Active, Dormant, Retired)	Category	Detailed Description of Risk / Opportunity	Cause/Trigger	Probability	Impact		Score		Strategy	Risk Owner	Comments/Actions
						Cost	Schedule	Cost	Schedule			
1	Active		There is a risk that the program will experience issues with the network during testing, deployment and commissioning	Testing (including Site Acceptance Testing - SAT) with the systems may result in poor network performance and functionality issues due to the complexity and implementation of the new network design.	3	2	2	6	6	Mitigate	IS PM	The Program is planning the appropriate Network performance/Load testing prior to the systems arriving from the Factory, verifying Network Connectivity and Performance. The project is continuing to vet the final SAT schedule to ensure it accounts for the appropriate testing.
2	Active		There is a risk that some functionality will not work as designed because ABB will not resolve all required SPRs (System Problem Reports)	ABB will resolve some defects between FAT Re-Test and SAT. This is due to the number of open SPR's categorized as Critical, Major and Medium.	2	1	1	2	2	Accept / Mitigate	Business PM	ABB and NG are working together to establish the best possible solution for maintaining schedule while ensuring that the NY regression testing, either in Sugarland or on-site, mitigates all risk of this testing approach. The team will use the NE test environment at the factory and the NY SAT to thoroughly test all changes made after FAT retest.

			prior to the start of FAT (Factory Acceptance Testing) Re-Test.									
3	Active		There is a risk that there will be security issues identified during FAT (Factory Acceptance Testing) & SAT (Site Acceptance Testing) that requires time to resolve or a Network design change.	Due to issues undiscovered during Factory Testing.	3	2	2	6	6	Mitigate	IS PM	Project has solicited design reviews from outside consultants and DR&S to ensure the design will support system and NERC-CIP requirements.

4	Active		There is a risk that the Integrated system may result in a significant impact on network performance or EMS performance/ availability	Due to unanticipated issues with the DAIS (Data Acquisition for Industrial Systems) and Common Tagging Interface	2	2	2	4	4	Avoid	Business PM	Project has defined various testing strategies to verify the DAIS and tagging interfaces.
5	Active		There is a risk that some functionality will not work as designed because ABB will be delivering new code with the NY SAT release.	Due to ABB's inability to address lock/unlock functionality for tagging in time to test at FAT.	2	1	1	2	2	Mitigate	Business PM	Perform testing using Beta versions of functionality and the NE test environment prior to delivery and final acceptance. This functionality will be thoroughly tested during NY SAT.
6	Active		There is a risk that the Maintenance and Support contract with ABB will exceed the forecasted RTB budget.	Due to ABB exceeding their previously stated estimate for Maintenance and Support during Contract Negotiations or due to National Grid changing the requirements of the Maintenance and Support contract.	2	2	1	4	2	Avoid	Business PM	Tom Morgan (Procurement) is working with ABB with the intention of resolving the Maintenance and Support contract consistent with what was recently proposed by ABB.

7	Active		There is a risk that National Grid could decide to delay the project beyond the contracted dates agreed to with ABB and ABB could use this as an opportunity to claim additional costs to support the extended timeline and we have no costs forecasted for this.	Re-sequence the implementation or delay due to competing priorities.	2	1	1	2	2	Mitigate	Business PM	Include this possibility as part of our contract negotiation discussions.

4.9 Permitting

Not applicable

4.10 Investment Recovery

The regulatory and finance analysis conducted during the original sanction in 2008 is still applicable. Based on the revised timing of the project expenditures and the timing of anticipated rate filings, it can be expected that new revenue streams will be in place to recover a substantial portion of this new investment.

The amount of the recovery of the NY EMS will be dependent on two key factors: outcome of the 2012 rate filing and the depreciable life of the system. The capital investment for the NY EMS was included in 2012 rate filing.

It is anticipated that a majority of the investment in NE EMS will be recovered through transmission and distribution rates charged to customers as the NE distribution companies implement new rate plans. Cost for NE EMS were included in 2012 RI rate filing.

4.10.1 Investment Recovery and Regulatory Implications

The investment classification of asset replacement for this strategy is based on the age of existing systems and the current recommended practice to upgrade/replace systems on a four to six year cycle.

There are no regulatory requirements to replace the EMS's. However, this project is an asset replacement project for critical systems that are past end-of-life and there would be significant damage to the National Grid reputation should a significant event occur as a result of our aging fleet of EMS systems.

4.10.2 Customer Impact

There may be some minimal impact to customers during system cutover. The impact centers around the temporary loss of telemetry as Remote Terminal Units (RTU's) are cut over from the old EMS to the new EMS. Some revenue meter information is collected via the pulse accumulator functionality within an RTU. The timing of the cutovers will be closely coordinated during the commissioning and Site Acceptance Testing (SAT) phases of the project.

The benefits of the having new vendor supported EMS systems mitigate the reliability risks of the existing systems and outweigh the system cutover risks for the customer.

4.10.3 CIAC / Reimbursement

Not Applicable

4.11 Financial Impact to National Grid

4.11.1 Cost Summary Table

				Current Planning Horizon								
Project #	Project Description	Project Estimate level	$M	Prior YR Spending	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
INVP1043	EMS NE		Capex	10.460	5.823	4.853						21.136
			Opex	0.204	0.070	0.132						0.406
			Removal		0.075							0.075
			Total	10.664	5.968	4.985	0.000	0.000	0.000	0.000	0.000	21.617
INVP1041	EMS NY											
			Capex	16.856	9.638	3.015						29.509
			Opex	0.259		0.166						0.425
			Removal		0.075							0.075
			Total	17.115	9.713	3.181	0.000	0.000	0.000	0.000	0.000	30.009
Total Proposed Sanction												
			Capex	27.316	15.461	7.868	0.000	0.000	0.000	0.000	0.000	50.645
			Opex	0.463	0.070	0.298	0.000	0.000	0.000	0.000	0.000	0.831
			Removal	0.000	0.150	0.000	0.000	0.000	0.000	0.000	0.000	0.150
			Total	27.779	15.681	8.166	0.000	0.000	0.000	0.000	0.000	51.626

Total Project Current Year and Future Years Cost = $51.6 M

4.11.2 Project Budget Summary Table

NE EMS project:

Project Budget Summary Table

Project Costs per Business Plan		Prior Year Spending*	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
	Capex	11.300	3.300	0.500	0.000	0.000	0.000	0.000	0.000	15.100
	Opex	0.200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.200
	Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Total Cost in B Plan	11.500	3.300	0.500	0.000	0.000	0.000	0.000	0.000	$15.300

* P/Y Actuals

Variance		Prior Year Spending	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
	Capex	0.840	(2.523)	(4.353)	0.000	0.000	0.000	0.000	0.000	(6.036)
	Opex	(0.004)	(0.070)	(0.132)	0.000	0.000	0.000	0.000	0.000	(0.206)
	Removal	0.000	(0.075)	0.000	0.000	0.000	0.000	0.000	0.000	(0.075)
	Total Variance	0.836	(2.668)	(4.485)	0.000	0.000	0.000	0.000	0.000	($6.317)

Upstate NY EMS project:

Project Budget Summary Table

Project Costs per Business Plan	Prior Year Spending*	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
Capex	15.800	4.100	0.600	0.000	0.000	0.000	0.000	0.000	20.500
Opex	0.300	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.300
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in B Plan	16.100	4.100	0.600	0.000	0.000	0.000	0.000	0.000	$20.800

* P/Y Actuals

Variance	Prior Year Spending	YR 1 12/13	YR 2 13/14	YR 3 14/15	YR 4 15/16	YR 5 16/17	YR 6 17/18	YR7+	Total
Capex	(1.056)	(5.538)	(2.415)	0.000	0.000	0.000	0.000	0.000	(9.009)
Opex	0.041	0.000	(0.166)	0.000	0.000	0.000	0.000	0.000	(0.125)
Removal	0.000	(0.075)	0.000	0.000	0.000	0.000	0.000	0.000	(0.075)
Total Variance	(1.015)	(5.613)	(2.581)	0.000	0.000	0.000	0.000	0.000	($9.209)

4.11.3 Cost Assumptions

This estimate was developed in 2012 using the standard IS estimating methodology and a detailed Bottom-Up approach.

4.11.4 Net Present Value / Cost Benefit Analysis

Not applicable

4.11.5 Additional Impacts

Not applicable

4.12 Statements of Support

4.12.1 Supporters

Role	Name	Responsibilities
IS Business Relationship Mgmt	Matthew Guarini	Endorses the project aligns with jurisdictional objectives
IS Finance	Duncan Brown	Endorses the project aligns with jurisdictional objectives
Program Sponsor; Vice President of Control Center Operations	John Spink	Endorses the project aligns with US Operational objectives
EVP Chief Operations Officer	Ellen Smith	Endorses the project aligns with US Operational objectives

4.12.2 Reviewers

See section 5.2.2 IS Stakeholders Checklist

5 Appendices

5.1 Project Cost Breakdown

Financial Summary for NE EMS project:

US Sanction Paper

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TOTAL COST LOG OF IS INVESTMENT - FINANCIAL SUMMARY

Investment Name:	NE EMS Replacement Project		
Project Name:	NE EMS Replacement Project		
Investment Plan No:	1043	Investment Start (Financial Year):	08/09
		Currency used:	US $

	08/09 $'000s	09/10 $'000s	10/11 $'000s	11/12 $'000s	12/13 $'000s	13/14 $'000s	14/15 $'000s	Total $'000s
INVESTMENT PLAN DETAILS:								
OPEX	200							**200**
CAPEX		3,700	4,200	3,400	3,300	500		15,100
Net RTB Impact						113	175	**288**
INVESTMENT COST SUMMARY								
Start-Up - Opex								
Start-Up - Capex								
Start-Up - Risk Margin								
Start-Up - Subtotal								
Requirements and Design - Opex	*204*							**204**
Requirements and Design - Capex								
Requirements and Design - Risk Margin								
Requirements and Design - Subtotal	*204*							**204**
Development and Implementation - Opex								
People					*70*	*132*		**202**
Hardware/Software								
Telecommunications								
Service Contracts								
Other					*75*			**75**
Risk Margin								
Development and Implementation - Capex								
People		*1,629*	*1,967*	*2,526*	*3,423*	*2,474*		**12,019**
Hardware/Software		*1,947*	*1,361*	*125*	*1,554*	*175*		**5,161**
Telecommunications								
Service Contracts								
Other		*37*	*441*	*427*	*846*	*704*		**2,456**
Risk Margin						*1,500*		**1,500**
Development and Implementation - Subtotal		*3,612*	*3,769*	*3,078*	*5,968*	*4,985*		**21,413**
Total Investment Costs - Opex	*204*				*145*	*132*		**481**
Total Investment Costs - Capex		*3,612*	*3,769*	*3,078*	*5,823*	*4,853*		**21,136**
Total Investment Costs	*204*	*3,612*	*3,769*	*3,078*	*5,968*	*4,985*		**21,617**
Non-Regulated Project - Uplift								
Non-Regulated Project - Total	*204*	*3,612*	*3,769*	*3,078*	*5,968*	*4,985*		**21,617**
Future Investments								
VARIANCES TO INVESTMENT PLAN:								
OPEX	(4)				(145)	(132)		**(281)**
CAPEX		88	431	322	(2,523)	(4,353)		**(6,036)**
RTB								
Current Annual RTB Expenditure	**628**	**628**	**628**	**628**	**628**	**628**	**628**	**4,398**
New Annual RTB Expenditure	628	628	628	628	697	735	767	**4,713**
Net RTB Impact					68	107	139	**314**
Variance to Investment Plan					68	(6)	(36)	**26**
BENEFITS ANALYSIS:								
Investment Benefits								

NPV/NPC SUMMARY INFORMATION

Discount Rate:	**15%**	**NPV:**	**(14202)**	**IRR:**		**VCR:**	**0.46**
Payback Period:		**5**	Years	Months			

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US Sanction Paper

Financial Summary for NY EMS project:

TOTAL COST LOG OF IS INVESTMENT - FINANCIAL SUMMARY

Investment Name:	**NY EMS Replacement Project**		
Project Name:	**NY EMS Replacement Project**		
Investment Plan No:	**1041**	Investment Start (Financial Year):	**08/09**
		Currency used:	**US $**

	08/09 $'000s	09/10 $'000s	10/11 $'000s	11/12 $'000s	12/13 $'000s	13/14 $'000s	14/15 $'000s	Total $'000s
INVESTMENT PLAN DETAILS:								
OPEX	300							**300**
CAPEX		6,500	5,100	4,200	4,100	600		20,500
Net RTB Impact					189	191	410	**790**
INVESTMENT COST SUMMARY								
Start-Up - Opex								
Start-Up - Capex								
Start-Up - Risk Margin								
Start-Up - Subtotal								
Requirements and Design - Opex	*259*							**259**
Requirements and Design - Capex								
Requirements and Design - Risk Margin								
Requirements and Design - Subtotal	*259*							**259**
Development and Implementation - Opex								
People						*166*		**166**
Software								
Telecommunications								
Service Contracts								
Other					*75*			**75**
Risk Margin								
Development and Implementation - Capex								
People		*2,672*	*4,321*	*2,131*	*5,900*	*484*		**15,508**
Software		*3,801*	*1,128*	*613*	*2,190*			**7,732**
Telecommunications								
Service Contracts								
Other		*194*	*317*	*1,679*	*1,547*	*482*		**4,219**
Risk Margin						*2,050*		**2,050**
Development and Implementation - Subtotal		*6,667*	*5,766*	*4,423*	*9,713*	*3,181*		**29,750**
Total Investment Costs - Opex	*259*				*75*	*166*		**500**
Total Investment Costs - Capex		*6,667*	*5,766*	*4,423*	*9,638*	*3,015*		**29,509**
Total Investment Costs	*259*	*6,667*	*5,766*	*4,423*	*9,713*	*3,181*		**30,009**
Non-Regulated Project - Uplift								
Non-Regulated Project - Total	*259*	*6,667*	*5,766*	*4,423*	*9,713*	*3,181*		**30,009**
Future Investments								
VARIANCES TO INVESTMENT PLAN:								
OPEX	41				(75)	(166)		**(200)**
CAPEX		(167)	(666)	(223)	(5,538)	(2,415)		**(9,009)**
RTB								
Current Annual RTB Expenditure	**600**	**600**	**600**	**600**	**600**	**600**	**600**	**4,201**
New Annual RTB Expenditure	600	600	600	600	856	876	977	**5,109**
Net RTB Impact	0	0	0	0	256	276	377	**909**
Variance to Investment Plan	0	0	0	0	67	85	(33)	**119**
BENEFITS ANALYSIS:								
Investment Benefits								

NPV/NPC SUMMARY INFORMATION

Discount Rate:	**15%**	**NPV:**	**(20743)**	**IRR:**		**VCR:**	**0.41**
Payback Period:		**5**	Years	Months			

Project Cost Breakdown		
Cost Category	**Company Name ($ Amount)**	**Description of Cost Category**
Internal Labor	NGRID ($7.7m)	
External Labor	Various ($12.7m)	Bridge, UDS, TRC
Hardware/Software	Various ($8.4m)	Multiple Vendors (LAN, WAN, etc)
ABB Payments	ABB ($12.5m)	ABB Payments for Project Milestones
AFUDC (Allowance for Funds Used During Construction) Allocation	NGRID ($5.3m)	
Other	NGRID ($1.4m)	Incl. Expenses, Sales Tax, etc.
Tolerance	($3.6m)	
Total:	**$51.6M**	

The following tables show the breakdown of the aggregate cost estimate of $51.6M for the project as well as the allocation of cost estimates by region and business segment.

Table 1 illustrates the proposed total aggregate cost for the project. The initial DOA (Delegation of Authority) for preliminary work, up to $1,000K was requested via a Preliminary Works Sanction Paper which includes IS requirements and design.

NY and NE allocations are based on the system development costs for each region. The cost allocation between T&D in each region is based on the methodology developed in the previously presented strategy paper (RTU counts by business segment). Ongoing RTB costs will be recalculated annually based on T&D RTU (Remote Telemetry Unit) counts.

Note: All numbers are rounded to the nearest 1/10 of a million.

Table 1: New York & New England Aggregate Project Cost Estimate

		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	463				220	298	981
	Capex		10,279	9,535	7,502	15,461	7,868	50,645
IS Investment Plan	Opex	500						500
	Capex		10,200	9,300	7,600	7,400	1,100	35,600
Variance to plan	Opex	37				(220)	(298)	(481)
	Capex		(79)	(235)	98	(8,061)	(6,768)	(15,045)

Tables 2 through 9 illustrate the aggregate cost per region as compared to the IS BP12 Business Plan.

Table 2: New England Aggregate Project Cost

		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	204				145	132	481
	Capex		3,612	3,769	3,078	5,823	4,853	21,136
IS Investment Plan	Opex	200						200
	Capex		3,700	4,200	3,400	3,300	500	15,100
Variance to plan	Opex	(4)				(145)	(132)	(281)
	Capex		88	431	322	(2,523)	(4,353)	(6,036)

Table 3: New England Transmission Project Cost Estimate:

Variance to plan		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	86				61	55	202
	Capex		1,517	1,583	1,293	2,446	2,038	8,877
IS Investment Plan	Opex	84						84
	Capex		1,554	1,764	1,428	1,386	210	6,342
Variance to plan	Opex	(2)				(61)	(55)	(118)
	Capex		37	181	135	(1,060)	(1,828)	(2,535)

Table 4: New England Distribution Project Cost Estimate:

Variance to plan		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	118				84	77	279
	Capex		2,095	2,186	1,785	3,377	2,815	12,259
IS Investment Plan	Opex	116						116
	Capex		2,146	2,436	1,972	1,914	290	8,758
Variance to plan	Opex	(2)				(84)	(77)	(163)
	Capex		51	250	187	(1,463)	(2,525)	(3,501)

Table 5: New York Aggregate Project Cost

		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	259				75	166	**500**
	Capex		6,667	5,766	4,423	9,638	3,015	**29,509**
IS Investment Plan	Opex	300						**300**
	Capex		6,500	5,100	4,200	4,100	600	**20,500**
Variance to plan	Opex	41				(75)	(166)	**(200)**
	Capex		(167)	(666)	(223)	(5,538)	(2,415)	**(9,009)**

Table 6: New York Transmission Project Cost Estimate:

Variance to plan		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	168				49	108	**325**
	Capex		4,333	3,748	2,875	6,265	1,960	**19,181**
IS Investment Plan	Opex	195						**195**
	Capex		4,225	3,315	2,730	2,665	390	**13,325**
Variance to plan	Opex	27				(49)	(108)	**(130)**
	Capex		(108)	(433)	(145)	(3,600)	(1,570)	**(5,856)**

Table 7: New York Distribution Project Cost Estimate:

Variance to plan		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	Total
Project Cost	Opex	91				26	58	**175**
	Capex		2,333	2,018	1,548	3,373	1,055	**10,328**
IS Investment Plan	Opex	105						**105**
	Capex		2,275	1,785	1,470	1,435	210	**7,175**
Variance to plan	Opex	14				(26)	(58)	**(70)**
	Capex		(58)	(233)	(78)	(1,938)	(845)	**(3,153)**

This project will increase IS ongoing support costs, as detailed in the following tables.

RTB table for NE EMS project:

RTB costs $'000s	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6 13/14	Yr 7 14/15	Total
Current Annual RTB costs	628	628	628	628	628	628	628	4,398
New Annual RTB costs	628	628	628	628	697	735	767	4,713
Impact on RTB costs (new minus existing)					**68**	**107**	**139**	**314**
Variance to Plan					**68**	**(6)**	**(36)**	**26**

RTB table for NY EMS project:

RTB costs $'000s	Yr 1 08/09	Yr 2 09/10	Yr 3 10/11	Yr 4 11/12	Yr 5 12/13	Yr 6 13/14	Yr 7 14/15	Total
Current Annual RTB costs	600	600	600	600	600	600	600	4,201
New Annual RTB costs	600	600	600	600	856	876	977	5,109
Impact on RTB costs (new minus existing)	**0**	**0**	**0**	**0**	**256**	**276**	**377**	**909**
Variance to Plan	**0**	**0**	**0**	**0**	**67**	**85**	**(33)**	**119**

RTB costs include labor, hardware and software costs to maintain the existing NY and NE systems. The new and existing costs occur simultaneously during the project period because the existing systems will be supported in parallel with the new system development and deployment until the legacy systems are decommissioned. The increase in RTB costs in year 5 is due to increased hardware and software maintenance costs with the new system, and need for two additional FTEs on a sustaining basis for NY CNI.

Standardization of support processes was discussed with the business and IS teams and the following recommendations were accepted:

- Standardize RTU (Remote Telemetry Unit) configuration and testing tasks within the PTO (Protection and Telecommunication Operations) organization.
- Standardize telemetry and RTU support in the CNI teams. The process used today is similar in both regions and any organizational moves will be deferred to a later stage.
- Standardize Network Model, Display and Database maintenance tasks within the CNI organization.

The additional two FTE's on sustaining basis will be required by CNI NY to standardize practices across the NY and NE CNI organizations for Network Model, Display and Database maintenance tasks. These additional FTEs will also provide support for the Operator Training Simulator System and the new Network Model and EMS databases being implemented for the upstate NY EMS.

Project Company Allocations

The cost allocation between T&D in each region is based on the methodology developed in the previously presented strategy paper (RTU counts by business segment).

INVP 1043 – NY EMS Replacement

NY EMS Replacement is charged to Company 36 (Niagara Mohawk) Project C40766 at 100%. Once in-service, the depreciation expense is charged 100% to Co. 36, split 65% to Transmission and 35% to Distribution.

INVP 1041 – NE EMS Replacement

NE EMS Replacement is charged to Company 99 (Service Company) Project S00281 at 100%. Once in-service, cost will be allocated to the operating companies using the following bill pools.

42% of the Expense will be allocated to **NE Transmission** by Bill Pool 00234:

Bill Pool 00234 Allocations		**NE Transmission**		
00234	00005	Massachusetts Electric	TRAN	3.719
00234	00010	New England Power Company	TRAN	85.998
00234	00049	Narragansett Electric Company	TRAN	10.283
00234 Total				**100.000**

58% of the Expense will be allocated to **NE Distribution** by Bill Pool 00232:

Bill Pool 00232 Allocations		**NE Distribution**		
00232	00004	Nantucket Electric Company	DIST	0.520
00232	00005	Massachusetts Electric	DIST	75.215
00232	00041	Granite State Electric Company	DIST	1.313
00232	00049	Narragansett Electric Company	DIST	22.952
00232 Total				**100.000**

5.2 Other Appendices

5.2.1 Project Resources Breakdown

Name of Resource	Project Role*	Source for Resource	Start	End	Average Monthly Allocation	Availability Confirmed? ***
Bill Myles	Program Manager	Internal	Present	Dec 31, 2013	50%	Yes
Joseph Farella	Business PM	Internal	Present	Dec 31, 2013	100%	Yes
Gerry Abad	IS PM	Bridge	Present	Dec 31, 2013	100%	Yes
Andrew Aylward	BA	Internal	Present	Dec 31, 2013	100%	Yes
Brian Schiavone	BA	Internal	Present	Dec 31, 2013	20%	Yes
John Carlson	Operator	Internal	Present	Sept 31, 2013	15%	Yes
Matthew Antonio	Operator	Internal	Present	March 31,2013	15%	Yes
Parvis Sigari	Proj Supp	UDS	Present	October, 2013	100%	Yes
Art Vierling	Proj Supp	UDS	Present	October, 2013	100%	Yes
Gerard Ayotte	CNI Supp	Bridge	Present	Sept 31, 2013	85%	Yes
NE CNI Staff	CNI Supp	IS	Present	Sept 31, 2013	100%	Yes
NE CNI Staff	CNI Supp	IS	Present	Sept 31, 2013	100%	Yes
William Higgins	Developer	Bridge	Present	March, 2013	100%	Yes
Paul Johnson	Developer	Bridge	Present	March, 2013	100%	Yes
Kolby Lavallee`	Developer	Bridge	Present	March, 2013	100%	Yes
NY CNI Staff	CNI Supp	IS	Present	March 31,2012	100%	Yes
Robert Hickman	CNI Supp	Bridge	Present	March 31,2012	40%	Yes
Jim Gonzales	CNI Supp	Bridge	Present	March 31,2012	50%	Yes
NY CNI Staff	CNI Supp	IS	Present	March 31,2012	50%	Yes
Giri Valmikam	Net Supp	Bridge	Present	June, 2013	100%	Yes
Bill Paterson	Developer	TRC	Present	March, 2013	100%	Yes
Michael Reals	Developer	TRC	Present	March, 2013	100%	Yes
Cheryl Gieger	Developer	TRC	Present	March, 2013	100%	Yes
Yelena Belousava	Lead-BA	Internal	Present	Dec 31, 2013	5%	Yes
Basavaraj Urs	Lead-SA	Internal	Present	Dec 31, 2013	5%	Yes
Joe Dudiak	Infrastructure PM	KEMA	Present	April 2014	50%	Yes
Infrastructure Analyst – NE	IS Analyst	TBD	TBD	Dec 31, 2013	50%	No
Infrastructure Analyst – NY	IS Analyst	TBD	TBD	Dec 31, 2013	50%	No
Diane Simkin	DR&S	Internal	Present	Dec 31, 2013	20%	Yes
Kristen Lemire	IS Lead	IS - CNI	Present	Dec 31, 2013	100%	Yes
Joanne E. Austin	Business Continuity	Internal	Jan 2013	Jan 2013	2.5%	Yes

5.2.2 IS Stakeholder Checklist

	Confirmation that....	Stakeholder	Stage	Confirmed
BRM	The Business Sponsor supports the proposal and has agreed to the costs and benefits	RM	ALL	Sheena Anand **05/09/2012**
	Dependencies with other projects have been identified and addressed	RM	ALL	Sheena Anand **05/09/2012**
Solutions Delivery	Scope is defined and the timescale is accurately reflected in the Production Plan	PDM	ALL	Gary Sidoti **05/07/2012**
	Delivery impact has been checked with other projects/programmes across the portfolio	PDM	ALL	Gary Sidoti **05/07/2012**
	The necessary project resources are named and available.	PDM	ALL	Gary Sidoti **05/07/2012**
	Cost estimates seem reasonable. If applicable, third party confirmation of estimates (i.e. benchmarking) has been performed	PDM	ALL	Gary Sidoti **05/07/2012**
IS Finance	The project is budgeted for / included within the relevant Business Plan, or appropriate funding by substitution is proposed.	Regional Finance Manager	ALL	Duncan Brown **05/11/2012**
	The costs and benefits in the business case have been calculated correctly.	Regional Finance Manager	ALL	Duncan Brown **05/11/2012**
	Ongoing support costs are in line with budgeted values (as per the Investment Plan)	Regional Finance Manager	D&I	Duncan Brown **05/11/2012**
	The financial value indicators are based on an approved Discounted Cash Flow conforming to company standards	Regional Finance Manager	D&I	Duncan Brown **05/11/2012**
	A Total Cost of Ownership Log has been completed (where appropriate).	Regional Finance Manager	D&I	Duncan Brown **05/11/2012**
Strategy & Architecture	The Investment Proposal aligns with National Grid IS Strategy	IS Strategy Manager	R&D	**N/A**
	The Investment Proposal conforms to the National Grid Enterprise Architecture or has been granted an exception	Enterprise Architect	ALL	Ron Krantz **05/01/2012**
Service Delivery	Impacts to new (i.e. Transformation) and existing commercial agreements are understood. If applicable, agreements are updated	IS Investment Manager	ALL	Carmine Mileo **05/08/2012**
	SLA impacts are understood and addressed	IS Service Manager	D&I	Bill Mays (CNI) **05/11/2012**

				Rick Sheer **05/11/2012**
Digital Risk & Security	Service definition (including security checklist) has been completed and level of DR&S engagement agreed to	DR&S Consultant	ALL	Mike Andreozzi **04/27/2012**
IS Regulatory	The proposal clearly articulates the: reason for the investment, customer benefits and the mechanism for cost recovery	IS Regulatory Manager	ALL	Tom Gill

5.3 Customer Outreach Plan (if applicable)

Not applicable

Title:	Design & Implement Two Energy Management Systems in New England and Upstate New York T&D	**Sanction Paper #:**	USSC-12-248
Project #:	INVP 1043: EMS NE S00281 INVP 1041: EMS NY C28802	**Sanction Type:**	Resanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	September 25, 2013
Author / NG Representative:	Travis Coleman / Duane Bloomfield	**Sponsor:**	John Spink, Vice President Control Center Operations
Utility Service:	IT	**Project Manager:**	Gary Sidoti

1 Sanctioning Summary

This paper requests the re-sanction of INVP 1041 & 1043 in the amount $70.785M with a tolerance of +/- 10% for the purposes of Development & Implementation.

This sanction amount is $70.785M broken down into:

$66.111M CapEx
$ 4.524M OpEx
$ 0.150M Removal

Note the previously requested sanction amount of $51.600M.

2 Re-sanction Details

2.1 Brief Summary:

This resanction is in regard to the planned replacement of the two (2) regional existing Energy Management Systems (EMS), in New England and Upstate NY, with 2 new vendor supported EMS systems, which include a level of integrated functionality with the Distribution Outage Management System (OMS).

The project's Go Live will move from May 2013 to December 2014 due to application and network issues associated with the complex CNI system. There were also additional changes required to support the successful system implementation. Examples include: Bandwidth required for increased use (i.e. Storms), establish segregated networks for the Quality Assurance System and Operator Training System. Additional hardware purchases were required to mitigate potential downtime to the CNI network.

2.2 Summary of Projects:

Project Number	Project Title	Estimate Amount ($M)
INVP 1041	NY EMS Replacement	$ 40.768
INVP 1043	NE EMS Replacement	$ 30.017
	Total	$ 70.785

2.3 Prior Sanctioning History

Previously approved sanctions are attached.

Date	Governance Body	Sanctioned Amount	Paper Title	Sanction Type	Paper Reference Number
March 2009	TIC, ED&G Executive Committee, IS PRM	$34.7M	Design & Implement Two EMS in New England & New York T&D	Sanction	USSC-12-248
May 2012	USSC	$51.6M	Design & Implement Two EMS in New England & New York T&D	Re-sanction	USSC-12-248

Over / Under Expenditure Analysis

Summary Analysis (M's)	CapEx	OpEx	Removal	Total
Latest approval	$50.6M	$0.9M	$0.1M	$51.6M
Resanction Amount	$66.2M	$4.5M	$0.2M	$70.8M
Change*	$15.6M	$3.6M	$0.1M	$19.2M

Change = (Latest Approval – Resanction Amount)

Revised Planning Horizon

($M)	Prior Yrs	Revised Planning Horizon Yr. 1 2013/14	Yr. 2 2014/15	Yr. 3 2015/16	Yr. 4 2016/17	Yr. 5 2017/18	Yr. 6 + 2018/19	Total
CapEx	$ 42.975	$ 15.558	$ 7.578	$ -	$ -	$ -	$ -	$ 66.111
OpEx	$ 0.532	$ 2.948	$ 1.044	$ -	$ -	$ -	$ -	$ 4.524
Removal	$ -	$ -	$ 0.150	$ -	$ -	$ -	$ -	$ 0.150
CIAC/Reimbursement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 43.507	$ 18.506	$ 8.772	$ -	$ -	$ -	$ -	$ 70.785

NOTE: Reference Appendix, Section 5.2, for a breakdown of the Revised Planning Horizon by Region.

2.4 Drivers

2.4.1 Detailed Analysis Table

The following table indicates the major key variations that account for the difference between the previous sanction amount and the requested re-sanction amount.

Detail Analysis (M's)	Over/Under Expenditure?	*Amount*
Labor	☒ Over ☐ Under	$10.9M
Hardware	☒ Over ☐ Under	$1.4M
Software	☒ Over ☐ Under	$2.6M
AFUDC (Allowance for Funds Used During Construction) Allocation	☒ Over ☐ Under	$2.1M
Risk	☒ Over ☐ Under	$1.0M
Others	☒ Over ☐ Under	$1.2M

NOTE: Appendix 1 contains greater detail on the source and reason for the variance increase. Reference Appendix, Section 5.3, for a breakdown of the Detailed Analysis Table by Region.

2.4.2 Explanation of Key Variations

- The implementation and testing of the complex, cyber secure Local and Wide Area Networks exposed additional issues and changes which increased hardware and labor costs. These included:
  - Implementation of additional bandwidth.

  - Segregated networks for the Quality Assurance System and the Operator Training System.
  - LAN stabilization activity to implement proper routing, switching, and firewall configuration.

- The prior sanction assumed that the current middleware infrastructure would need to be replaced. After further review, it was determined that this was not necessary, resulting in the hardware underspend. This underspend helped to offset additional hardware purchases.

- Increase in software and labor costs associated with the delay in development and implementation of the integrated ABB (vendor) EMS product.
  - During integration and testing of the ABB applications with the dedicated Local and Wide Area Networks, a number of application development issues were identified that require resolution prior to implementation. The resolution of these issues has caused a additional requirements for issue resolution, testing and implementation above the prior estimate.

- Increase in AFDUC from higher overall costs and a longer time to implement.

2.5 Business Plan:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
IS Investment Plan FY2013-14	⦿ Yes ○ No	⦿ Over ○ Under ○ N/A	$10.275M

2.6 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the IS Relationship Manager with the Planning Analyst assistance to meet jurisdictional budgetary, statutory and regulatory requirements.

2.7 Key Milestones:

Milestone	Target Date: (Month/Year)
Start Up	Oct 2009
Begin Requirements and Design	Dec 2009
Begin Development and Implementation	May 2010
Move to Production - NY	Mar 2014
Move to Production - NE	Sep 2014
Project Complete	Oct 2014
Project Closure	Dec 2014

2.8 Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
Dec 2014	Closure

3 Statements of Support

3.1 Supporters

Role	Name	Responsibilities
IS Finance	Chip Benson	Endorses the project aligns with jurisdictional objectives
IS Business Relationship Mgmt	Aman Aneja	Endorses the project aligns with jurisdictional objectives
US Business Supporter	John Spink	Endorses the project aligns with jurisdictional objectives

3.2 Reviewers

Function	Area	Individual
Finance	All	Chip Benson
Regulatory	All	Gideon Katsh
Jurisdictional Delegates	New England- Electric	Jennifer L. Grimsley
	New York- Electric	Allen C. Chieco
	FERC	Nabil E. Hitti
Procurement	All	Art Curran

4 Decisions:

The US Sanctioning Committee (USSC) at a meeting held on September 25, 2013:

(a) APPROVED this paper and the investment of $70.785M and a tolerance of +/- 10%.

(b) APPROVED the total RTB Impact of $17.666M for 5 years for both NY and NE.

(c) NOTED that Gary Sidoti is the Project Manager and has the approved financial delegation.

Signature……………………………………………..Date………………

Lee S. Eckert
US Chief Financial Officer
Chairman, US Sanctioning Committee

5 Appendices*:*

5.1 Project Funding Breakdown

N/A

5.2 Revised Planning Horizon by Region

Below is a detailed breakdown by region of the combined Revised Planning Horizon shown in Section 2.3 above.

		($M)		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +		Total Ex.
Number	Name	Spend	Prior Yrs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Total	CIAC
INVP 1041	NY EMS Replacement	CapEx	26.555	9.088	2.330					37.973	
		OpEx	0.325	1.764	0.631					2.720	
		Removal			0.075					0.075	40.768
		CIAC/Reimbursement								0.000	

				Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +		Total Ex.
Number	Name	Spend	Prior Yrs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Total	CIAC
INVP 1043	NE EMS Replacement	CapEx	16.420	6.470	5.248					28.138	
		OpEx	0.207	1.184	0.413					1.804	
		Removal			0.075					0.075	30.017
		CIAC/Reimbursement								0.000	

5.3 Detailed Analysis Table by Region

Below is a detailed breakdown by region of the combined Detailed Analysis Table shown in Section 2.4.1 above.

Detail Analysis by Region	NE	NY	TOTAL
Labor	$4.0M	$6.9M	$10.9M
Hardware	$0.8M	$0.6M	$1.4M
Software	$1.6M	$1.0M	$2.6M
AFUDC	$0.8M	$1.3M	$2.1M
Risk	$0.6M	$0.4M	$1.0M
Other	$0.4M	$0.8M	$1.2M

5.4 Combined EMS / OMS Program Summary

Program Capital Cost Summary

	Actuals through July FY '14	Forecast through Go Live	Projected actuals	Previous Resanction	Variance	Variance Explanation
Payroll (Burdened)	15.4	7.6	23.0	17.7	(5.3)	**Schedule Extensions -** Internal and external labor to support project, as well as increased resource requirements. **Key Drivers:** Verizon resources, CNI Resources
Contractors	19.6	13.9	33.6	19.2	(14.3)	
Hardware	9.2	0.6	9.8	11.2	1.4	**Key Drivers:** Light Speed WAN Upgrade,JCAPs being significantly discounted from original cost projection. **Policy Change -** Shift of HW/SW Support & Maintenance to OpEx, Shift of WAN Leased Lines to OpEx
Software	8.0	(0.2)	7.8	10.1	2.4	
ABB Pmts	17.6	4.6	22.2	21.8	(0.4)	**Key Drivers:** Change orders(PCU Relocation NE, Focal Point changes), Additional engineering hours, Contract Change credit not going to receive.
AFUDC	7.9	5.5	13.4	9.1	(4.4)	**Schedule Extensions -** AFUDC increases and builds, along with travel, employee expenses and misc expenses as schedule delays.
Other	3.8	1.5	5.4	2.6	(2.8)	
Risk		7.2	7.2	6.6	(0.6)	
Total	81.7	40.6	122.3	98.2	(24.1)	

Program Operating Cost Summary

	Actuals to Date (July FY '14)	Forecast through Go Live	Projected actuals	Previous Resanction	Variance	Variance Explanation
Labor (internal & contractors)	2.1	5.7	7.8	2.6	(5.2)	**Schedule Extensions -** increased resources, includes "beddown," training costs.
Hardware/Software	0.0	5.0	5.0	-	(5.0)	**Policy Change:** The recording of the Leased Lines as well as HW/SW Support and Maintenance shifted from CapEx to OpEx
Other	0.1	0.1	0.3	-	(0.3)	**Schedule Extensions -** increased resources and training
Risk		0.6	0.6	-	(0.6)	
Totals	2.3	11.4	13.6	2.6	(11.0)	

nationalgrid

Resanction Request

Title:	Design & Implement Two Energy Management Systems in New England and Upstate New York T&D	**Sanction Paper #:**	USSC-12-248 v4
Project #:	INVP 1043: EMS NE S00281 INVP 1041: EMS NY C28802	**Sanction Type:**	Resanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	December 10, 2014
Author / NG Representative:	Diane Beard / Mike Gerolamo	**Sponsor:**	John Spink, Vice President Control Center Operations
Utility Service:	IT	**Project Manager:**	Joseph Farella

1 ***Executive Summary***

This paper requests the resanction of INVP 1041 & 1043 in the amount $90.280M with a tolerance of +/- 10% for the purposes of Development & Implementation.

This sanction amount is $90.280M broken down into:

$83.306M Capex
$ 6.773M Opex
$ 0.201M Removal

Note the previously requested sanction amount of $70.785M.

2 ***Resanction Details***

2.1 Project Summary

This resanction is in regard to the planned replacement of the two regional existing Energy Management Systems (EMS), in New England (NE) and Upstate New York (NY).

In March 2014 National Grid commissioned a review of the EMS / Outage Management System (OMS) program, to better understand potential risks of the solution design with respect to the utility industry's maturing understanding of cyber security. Significant cyber security risks were identified. Specifically, there is a potential cyber security threat of a larger user population, associated with OMS, gaining access to a critical EMS application. While the probability of these risks being realized is low, the impact is high. EMS is a mission critical system and the efficient operation of the system is dependent on its secure performance.

Resanction Request

As a result of decoupling EMS and OMS and remediating Northeast Power Coordinating Council (NPCC) security recommendations, the project go live dates will move to April 1, 2015 for NY-EMS, and September 15, 2015 for NE-EMS. Additional time is needed to update requirements and design documentation, remove OMS configurations from the EMS hardware, reconfigure network firewalls that had been associated with the OMS, continue to perform regression testing and remediate any outstanding issues. The NE EMS cutover may be subject to further delay due to the restrictions on commissioning during peak summer months.

The EMS and OMS projects will replace the Company's outdated systems and ensure these systems can be fully supported by vendors in the future. The Company anticipates the upgrade and replacement of these systems will provide certain benefits vital to successful operation of the electric system, including, but not limited to: improved informational security; increased functionality and situational awareness; more accurate and reliable data and reporting; and improved storm management. The projects will bring the systems in line with current industry standards, provide a platform to support future smart grid initiatives and facilitate compliance with NERC Critical Infrastructure Protection ("CIP") Security Standards.

After re-sanction in September 2013, the Company projected an in-service date for EMS in March 2014 and OMS in June 2014. However, the Company discovered several issues during project development and integration not originally anticipated during the planning process. Concerns developed regarding potential cybersecurity risks associated with EMS and the Company was concerned these risks would affect data integrity. Additionally, during project development, the Company participated in industry cybersecurity groups and was subject to NERC audits, which alerted the Company to upcoming changes in NERC CIP standards and compliance requirements. These changes created uncertainties and risk in implementation and compliance that the Company would be required to remediate prior to go-live. Software defects were also discovered and, while the vendor, ABB, made progress in correcting these defects, the defects created additional risk and schedule uncertainty. Based on these concerns, the Company determined it could not proceed with EMS/OMS integration without further analysis.

The Company performed an options assessment of the projects in April 2014 to analyze the issues discovered during development. After vetting its options, the Company decided to decouple and separately implement the EMS and OMS systems. The Company determined that decoupling the systems was the best course of action to mitigate potential cybersecurity penetration risks and ensure that OMS operated in a secure perimeter, as required by NERC standards and rules. Decoupling was also the least cost solution to mitigate the issues discovered during project development.

Resanction Request

Decoupling will extend the timeline to go-live by approximately six to nine months, with implementation planned between December 2014 and August 2015 for EMS and OMS. At this time, it is estimated that decoupling will increase costs by approximately $16.7 million, which is inclusive of the labor, resources and hardware needed to decouple the system as well as the costs to hire a third-party consultant to assist with the projects. These additional costs also include approximately $5 million spent on a necessary network upgrade identified in late 2012/early 2013 needed to support the upgraded EMS and OMS systems.

At the time of the initial EMS/OMS sanction, the plan to simultaneously integrate the systems appeared extremely beneficial to the Company and its customers. However, as the project evolved, the various issues identified in the coupled platforms caused National Grid to reevaluate this plan and ultimately determine that decoupling was the best course of action. Decoupling will ensure a more successful implementation of the systems and achieve other operational efficiencies that will inure to the benefit of both the Company and its customers, such as: minimization of potential security, availability and reliability issues; isolation of system and performance issues, which, in turn, will allow the Company to address those issues more efficiently; and the capability for a routine NERC CCA certification for EMS.

2.2 Summary of Projects

Project Number	Project Type (Elect only)	Project Title	Estimate Amount ($M)
INVP 1041	Project type	NY EMS Replacement	50.171
INVP 1043	Project type	NE EMS Replacement	40.109
		Total	90.280

2.3 Prior Sanctioning History

Previously approved sanctions are attached and listed below (Newest to Oldest)

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Paper Title	Sanction Type	Paper Reference Number	Tolerance
Sep 2013	USSC	$70.785	$70.785	INVP 1041_1043 Design & Implement Two Energy Management Systems in New England and	Re-sanction	USSC-12-248	10%

				Upstate New York T&D			
May 2012	USSC	$51.6M	$51.6M	Same	Re-sanction	USSC-12-248	10%
Mar 2009	TIC, ED&G Executive Committee, IS PRM	$34.7M	$34.7M	Same	Sanction	USSC-12-248	10%

Over / Under Expenditure Analysis

Summary Analysis ($M)	Capex	Opex	Removal	Total
Resanction Amount	83.306	6.773	0.201	90.280
Latest Approval	66.111	4.524	0.150	70.785
Change*	17.195	2.249	0.051	19.495

2.4 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Current Planning Horizon Yr. 1 2014/15	Yr. 2 2015/16	Yr. 3 2016/17	Yr. 4 2017/18	Yr. 5 2018/19	Yr. 6 + 2019/20	Total
INVP 1041	NY EMS Replacement	+/- 10%	CapEx	35.711	9.869	1.232					46.812
			OpEx	1.671	0.875	0.687					3.233
			Removal			0.126					0.126
			Total	37.382	10.744	2.045					50.171
INVP 1043	NE EMS Replacement	+/- 10%	CapEx	21.852	9.469	5.173					36.494
			OpEx	1.426	1.067	1.047					3.540
			Removal			0.075					0.075
			Total	23.278	10.536	6.295					40.109
Total Project Sanction			CapEx	57.563	19.338	6.405					83.306
			OpEx	3.097	1.942	1.734					6.773
			Removal			0.201					0.201
			Total	60.660	21.280	8.340					90.280

2.5 Business Plan

IS Investment Plan FY2014-15

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)

IS Investment Plan FY2014-15 CapEx	◉ Yes ○ No	◉ Over ○ Under ○ NA	11.760
IS Investment Plan FY2014-15 OpEx	◉ Yes ○ No	◉ Over ○ Under ○ NA	0.442
IS Investment Plan FY2015-16 CapEx	○ Yes ◉ No	◉ Over ○ Under ○ NA	6.405
IS Investment Plan FY2015-16 OpEx	○ Yes ◉ No	◉ Over ○ Under ○ NA	1.935

2.6 Drivers

2.6.1 Detailed Analysis Table

The following table indicates the major key variations that account for the difference between the last sanction amount and the requested resanction amount.

Detail Analysis (M's)	Over/Under Expenditure?	Amount
1. Labor	☒ Over ☐ Under	$13.223M
2. Hardware/Software	☒ Over ☐ Under	$6.407M
3. AFUDC (Allowance for Funds Used During Construction) Allocation	☒ Over ☐ Under	$2.128M
4. Risk	☐ Over ☒ Under	$2.881M
5. Others	☒ Over ☐ Under	$0.618M

For a NY/NE breakdown reference Appendix 5.2 Detailed Analysis Table by Region.

2.6.2 Explanation of Key Variations

As a result of the decision to decouple the EMS and OMS, additional work is needed to update requirements and design documentation, segregate OMS from the EMS hardware, reconfigure network firewalls that had been associated with the OMS and perform regression testing.

1. Extended Labor and Timeline ($13.223M)
   - Requirements and design documentation will be updated to reflect a decoupled system. This includes a significant number of updates to the business requirements, technical requirements, detailed application design documents, and test plans.
   - Physical decoupling of OMS from EMS will include installing the Native Tagging function within the EMS as well as application security changes.
   - Network reconfiguration will include updates to the firewall rules, switches and routers to eliminate access to the EMS from the OMS application.

- Regression testing of the application and network will be required once the physical decoupling and network reconfiguration is complete to ensure proper operation of the standalone EMS.
- Transfer of labor costs associated with dedicating the network to EMS. The original planned network was shared between the OMS and EMS applications. Since the the network will be dedicated to EMS going forward, the portion of the labor costs charged to OMS to date for establishing the network will be transferred to the EMS project.
- Additional network configuration work was required to apply industry experience to firewall rules. This additional scope was a result of the NPCC recommendations provided to National Grid NY & NE on July 23, 2014 and August 6, 2014. The NPCC recommendations were to:
    i. Breakdown complex rules
    ii. Eliminate use of VLAN and subnet and replace with IP based rules
    iii. Eliminate unused rules and constrain existing rules as appropriate

2. Transfer of Hardware/Software costs related to dedication of the network to EMS, scope changes required additional equipment, EMS responsible for Network support and maintenance, ABB operating upgrade ($6.407M)
3. Increase in AFUDC due to increased overall costs and a longer implementation timeframe ($2.128M)
4. Reduced risk from 3 months to 1 month (-$2.881M)
5. Other costs include overheads and travel ($0.618M)

2.7 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the IS Relationship Manager with the Planning Analyst assistance to meet jurisdictional budgetary, statutory and regulatory requirements.

2.8 Key Milestones

Milestone	Target Date: (Month/Year)
Start Up	Oct 2009
Begin Requirements and Design	Dec 2009
Begin Development and Implementation	May 2010
Move to Production - NY	Apr 2015
Move to Production - NE	Sep 2015
Project Complete	Sep 2015
Project Closure	Dec 2015

2.9 Next Planned Sanction Review

Resanction Request

Date (Month/Year)	Purpose of Sanction Review
Dec 2015	Closure

3 ***Statements of Support***

3.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities	Title
IS Business Relationship Mgmt	Aman Aneja	1. Review & Endorse IS Investment Proposals 2. Ensure IS Stakeholders approvals are obtained	IS Portfolio Relationship Manager
IS Finance	Chip Benson	Finance Director	Finance Director
IS Regulatory	Wayne Watkins	Regulatory Director	Regulatory Director
US Business Sponsor	John Spink	VP of the business area	Vice President Control Center Operations

3.2 Reviewers

The reviewers have provided feedback on the content/language of the paper

Function	Individual	Area
Finance	Chip Benson	All
Regulatory	Peter Zschokke	All
Jurisdictional Delegate(s)	Jim Patterson	New England – Electric
	Mark Harbaugh	New York- Electric
	Carol A. Sedewitz	FERC
Procurement	Art Curran	All

4 *Decisions*

The US Sanctioning Committee (USSC) at a meeting held on December 10, 2014.

(a) APPROVED this paper and the investment of $90.256M and a tolerance of +/- 10%.

(b) APPROVED the RTB Impact of $30.673M total for 5 years for combined NY and NE.

(c) NOTED that Joseph Farella is the Project Manager and has the approved financial delegation.

Signature……………………………………………..Date………………
Margaret Smyth
US Chief Financial Officer
Chair, US Sanctioning Committee

5 *Appendices*

5.1 Project Funding Breakdown

N/A

5.2 Detailed Analysis Table by Region

Below is a detailed breakdown by region of the combined Detailed Analysis Table shown in Section 2.6.1 above.

Detail Analysis by Region	NE	NY	TOTAL ($M)
Labor	(8.973)	(4.250)	(13.223)
Hardware/Software	(2.565)	(3.842)	(6.407)
AFUDC	0.279	(2.407)	(2.128)
Risk	1.331	1.550	2.881
Other	(0.158)	(0.460)	(0.618)

US Sanction Paper

Title:	AMAG Upgrade	**Sanction Paper #:**	USSC - _____
Project #:	INVP 1172 XG020004604 (OpEx) 90000112731 (CapEx)	**Sanction Type:**	Sanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	October 22, 2014
Author:	Mayumi Okada / Paula Webb	**Sponsor:**	Warren Bamford, VP, Global Security
Utility Service:	IT	**Project Manager:**	Donald Stahlin

1 <u>Executive Summary</u>

1.1 Sanctioning Summary

This paper requests sanction of INVP 1172 in the amount $4.630M with a tolerance of +/- 10% for the purposes of Development and Implementation.

This sanction amount is $4.630M broken down into:

$4.478M CapEx
$0.152M OpEx
$0.000M Removal

1.2 Project Summary

This policy-driven project will replace our current version of AMAG physical access control system (Enterprise Edition 6.01) with the more current release (Enterprise Edition 8.01 SP1). The upgrade will include all new infrastructure being installed in parallel with the current production system and a phased migration over to the new system. The upgraded system will remain on National Grid property in CNI managed data centers.

This upgrade is to resolve performance issues with the current system due to aging infrastructure and vendor support issues caused by being several versions behind the current release. The upgrade is required for National Grid to complete its rollout of Windows 7 workstations as the currently installed version will not run on Windows 7. The upgrade will enhance National Grid's compliance with NERC/CIP (North American Electric Reliability Corp. / Critical Infrastructure Protection) regulations.

1.3 Summary of Projects

Project Number	Project Title	Estimate Amount ($M)
INVP 1172	AMAG Upgrade	4.630
	Total	4.630

1.4 Associated Projects

Project Number	Project Title	Estimate Amount ($M)
		0.000
	Total	0.000

1.5 Prior Sanctioning History

Date	Governance Body	Sanctioned Amount	Paper Title	Sanction Type
Apr 2011	US BRM	$0.156M	AMAG Upgrade: Requirements and Design	Partial Sanction

1.6 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
APR 2016	Closure

1.7 Category

Category	Reference to Mandate, Policy, or NPV Assumptions
○ Mandatory ⦿ Policy- Driven ○ Justified NPV	Access Control Policy (NSGP-4) of National Grid.

1.8 Asset Management Risk Score

Asset Management Risk Score: **49**

Primary Risk Score Driver: (Policy Driven Projects Only)

◉ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

1.9 Complexity Level

◉ High Complexity ○ Medium Complexity ○ Low Complexity ○ N/A

Complexity Score: **26**

1.10 Process Hazard Assessment

A Process Hazard Assessment (PHA) is required for this project:

○ Yes ◉ No

1.11 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
IS Investment Plan, FY-2014/15	◉ Yes ○ No	◉ Over ○ Under ○ NA	$1.389M

1.12 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the Business Support Manager to meet jurisdictional budgetary, statutory and regulatory requirements.

1.13 Current Planning Horizon

		Current Planning Horizon						
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Total
CapEx	0.000	0.625	1.789	2.044	0.020	0.000	0.000	4.478
OpEx	0.000	0.044	0.000	0.106	0.002	0.000	0.000	0.152
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.669	1.789	2.150	0.022	0.000	0.000	4.630

1.14 Key Milestones

Milestone	Target Date: (Month/Year)
Start Up	Feb 2011
Begin Requirements and Design	Apr 2011
Begin Development and Implementation	Nov 2014
Begin User Acceptance Testing	May 2015
Move to Production	Aug 2015
Project Complete	Jan 2016
Project Closure	Apr 2016

NOTE: Project was placed on hold Oct-2012, and re-activated in May-2013

1.15 Resources, Operations and Procurement

Resource Sourcing			
Engineering & Design Resources to be provided	☑ Internal	☑ Contractor	
Construction/Implementation Resources to be provided	☑ Internal	☑ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	○ Red	○ Amber	⦿ Green
Availability of external resources to deliver project:	○ Red	○ Amber	⦿ Green
Operational Impact			

Outage impact on network system:	○ Red	○ Amber	⦿ Green
Procurement Impact			
Procurement impact on network system:	○ Red	○ Amber	⦿ Green

1.16 Key Issues (include mitigation of Red or Amber Resources)

1	Funding for the AMAG and Verizon hardware and software is only available for this fiscal year (FY15). Thus, the orders must be placed and equipment received prior to year end. *MITIGATION*: Working with IS Procurement to start negotiations early in the process.
2	AMAG's currently installed client software will not run on Windows 7 workstations. This is delaying completion of corporate Windows 7 desktop rollout. *MITIGATION*: the AMAG Upgrade Project must coordinate with the Windows 7 workstation rollout to replace existing AMAG client workstations as the AMAG upgrade is being deployed.

1.17 Climate Change

Contribution to National Grid's 2050 80% emissions reduction target:	⦿ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	⦿ Neutral	○ Positive	○ Negative

1.18 List References

1	Cost Info => INVP 1172-TCO Log 22-Oct-2014 D-I v5a.xlsx

2 Decisions

The US Sanctioning Committee (USSC) at a meeting held on October 22, 2014:

(a) APPROVED this paper and the investment of $4.630M and a tolerance of +/- 10%.

(b) APPROVED the RTB Impact of $3.671M over a 5 year period.

(c) NOTED that Donald Stahlin has the approved financial delegation.

Signature……………………………………………..Date………………

Margaret Smyth
US Chief Financial Officer
Chair, US Sanctioning Committee

3 Sanction Paper Detail

Title:	AMAG Upgrade	**Sanction Paper #:**	USSC - _____
Project #:	INVP 1172 XG020004604 (OpEx) 90000112731 (CapEx)	**Sanction Type:**	Sanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	October 22, 2014
Author:	Mayumi Okada / Paula Webb	**Sponsor:**	Warren Bamford, VP, Global Security
Utility Service:	IT	**Project Manager:**	Donald Stahlin

3.1 Background

AMAG is the Physical Access Control and Alarm Monitoring System currently used at all National Grid U.S. locations, excluding some Upstate NY locations. All US National Grid sites covered by NERC CIP regulations are monitored with the system.

The currently installed version of AMAG (6.01), which was installed in 2007 is experiencing performance issues. The number of clients, companies, alarm routes, readers, and card holders within the system has grown over time and is contributing to the slow performance. In an attempt to improve performance, National Grid has replaced a number of servers but this has resulted in only marginal improvement leaving National Grid at risk of major failure/issue such as:

- Delayed notification of alarm conditions due to slow system response
- Delayed execution of remote commands, such as to open/close a gate
- Inability to add new sites

After consultation with the AMAG software provider, it was recommended that National Grid upgrade the software to a current release (Enterprise Edition 8.01 SP1) which is more appropriate for a company of National Grid's size. The infrastructure on which the software runs will also need to be replaced, since the new version will not run on the older hardware.

Since AMAG is a business critical application with a 24x7 availability requirement, the upgrade will occur in parallel with the operation of the current production system and be phased into production. The system design also includes additional security and isolation from the corporate network in order to enhance compliance with NERC CIP regulations. Further, based on a recommendation from Digital Risk and Security, the upgraded system will remain on National Grid property and reside in a secure area within the existing National Grid CNI data centers.

3.2 Drivers

The primary drivers for this project are:

- The current system resides on aging infrastructure with a release of software significantly out of date which greatly limits our support capabilities.
- The current system can not operate on the Windows 7 platform which impacts a corporate technology upgrade initiative.
- To provide greater flexibility in the event that additional regulatory mandates are imposed by the NY PSC and/or NE DPU.

3.3 Project Description

This project scope will include:

- Upgrading AMAG from Enterprise Edition 6.01 to the current version, 8.01 SP1
- Installing new high availability hardware, in parallel with the current production system, and then a phased migration over to the new system
- Remaining on National Grid property in CNI managed data centers, as recommended by Digital Risk and Security
- Verifying that all system functions and reporting capability, including those used to support regulatory compliance are performing as expected
- Retiring existing version of application after archiving relevant data.

3.4 Benefits Summary

The following benefits gained by implementing this project are:

- Eliminates risk of aged infrastructure and out of date software
- Implementation of Windows 7 compliant platform in support of corporate technology upgrade initiative
- Enhanced NERC CIP compliance
- The newly developed near-CNI data center environment can potentially be used by future implementations with similar security requirements

3.5 Business and Customer Issues

There are no significant business issues beyond what has been described elsewhere.

3.6 Alternatives

Alternative 1: Do Nothing / Defer

This solution is not an enduring option due to the age of the system, performance issues, and the increasing risk of system failure. In the event of a system failure, the business would need to invoke manual processes to maintain compliance at an incremental cost to the company.

Alternative 2: Other Product Options

This option is not cost effective or as efficient, since this implementation would unify all of US National Grid under single system.

3.7 Safety, Environmental and Project Planning Issues

There are no significant issues beyond what has been described elsewhere.

3.8 Execution Risk Appraisal

Number	Detailed Description of Risk / Opportunity	Probability	Impact		Score		Strategy	Pre-Trigger Mitigation Plan	Residual Risk
			Cost	Schedule	Cost	Schedule			
1	The AMAG and Verizon hardware/software acquisition could be delayed beyond the end of the current fiscal year (FY15), where the budget has been allocated. The hardware and software must be received so it can be booked in time to utilize the budgeted dollars.	3	2	2	6	6	Mitigate	The PM will be working with IS Procurement to start negotiations early in the process. -	Would not would not increase cost; more of a budgeting issue - would underspend FY15 budget and overspend FY 16 budget.
2	The Windows 7 desktop rollout project could be completed prior to the timeframe the project intended for the AMAG client workstation replacements to occur. The currently installed AMAG client software will not run on Windows 7 workstations and the new workstation rollout funded by that project cannot occur unless coordinated with AMAG Upgrade project.	3	2	2	6	6	Mitigate	The client workstations will be upgraded to Windows 7 by the Windows 7 Rollout Team.	If that project is no longer active when we intend to replace the workstations then this project would have to fund and acquire the replacement workstations.
3	AMAG Upgrade Project schedule could be impacted by the work required to relocate the AMAG servers located in Melville. The current version of AMAG has some servers in Melville CAC data center and that data center is scheduled to close by the end of 2014, which is before this upgrade project will be completed.	3	1	3	3	9	Mitigate	The equipment will be moved to an interim location until the upgrade is completed and will be considered a separate effort outside of the scope of this project.	Moving equipment to an alternate location could potentially impact project resource availablility.

3.9 Permitting

Permit Name	Probability Required	Duration To Acquire	Status (Complete/	Estimated Completion

	(Certain/ Likely/ Unlikely)	Permit	In Progress Not Applied For)	Date

3.10 Investment Recovery

3.10.1 Investment Recovery and Regulatory Implications

Recovery will occur at the time of the next rate case for any operating company receiving allocations of these costs.

3.10.2 Customer Impact

3.10.3 CIAC / Reimbursement

$M	Prior Yrs	Yr. 1 2013/14	Yr. 2 2014/15	Yr. 3 2015/16	Yr. 4 2016/17	Yr. 5 2017/18	Yr. 6 + 2018/19	Total
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

3.11 Financial Impact to National Grid

3.11.1 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Current Planning Horizon Yr. 1 2013/14	Yr. 2 2014/15	Yr. 3 2015/16	Yr. 4 2016/17	Yr. 5 2017/18	Yr. 6 + 2018/19	Total
INVP 1172	AMAG Upgrade	+/- 10%	CapEx	0.000	0.625	1.789	2.044	0.020	0.000	0.000	4.478
			OpEx	0.000	0.044	0.000	0.106	0.002	0.000	0.000	0.152
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.669	1.789	2.150	0.022	0.000	0.000	4.630

3.11.2 Project Budget Summary Table

Project Costs per Business Plan

$M	Yrs (Actual)	Current Planning Horizon Yr. 1 2013/14	Yr. 2 2014/15	Yr. 3 2015/16	Yr. 4 2016/17	Yr. 5 2017/18	Yr. 6 + 2018/19	Total
CapEx	0.000	0.000	0.200	0.000	0.000	0.000	0.000	0.200
OpEx	0.000	0.000	0.200	0.000	0.000	0.000	0.000	0.200
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.400	0.000	0.000	0.000	0.000	0.400

Variance (Business Plan-Project Estimate)

$M	Yrs (Actual)	Current Planning Horizon Yr. 1 2013/14	Yr. 2 2014/15	Yr. 3 2015/16	Yr. 4 2016/17	Yr. 5 2017/18	Yr. 6 + 2018/19	Total
CapEx	0.000	(0.625)	(1.589)	(2.044)	(0.020)	0.000	0.000	(4.278)
OpEx	0.000	(0.044)	0.200	(0.106)	(0.002)	0.000	0.000	0.048
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	(0.669)	(1.389)	(2.150)	(0.022)	0.000	0.000	(4.230)

3.11.3 Cost Assumptions

This estimate was developed in 2014 using the standard IS estimating methodology. The accuracy level of estimate for each project is identified in table 3.11.1.

3.11.4 Net Present Value / Cost Benefit Analysis

This is not an NPV project.

3.11.4.1 NPV Summary Table

Economic measures		5yr	10yr	20yr	Comment
NPV	@ Discount rate				
IRR					
MIRR					
Simple Payback in Years					
Total O&M					
Total Capital Investment					
Total Savings					

3.11.4.2 NPV Assumptions and Calculations

3.11.5 Additional Impacts

None

3.12 Statements of Support

3.12.1 Supporters

Role	Name	Responsibilities
IS Finance	Chip Benson	Endorses the project aligns with jurisdictional objectives
IS Programme Delivery US Head	Trish Torizzo	Endorses the project aligns with jurisdictional objectives
IS Business Relationship Mgmt	Jeffrey Dailey	Endorses the project aligns with jurisdictional objectives
US Business Supporter	Warren Bamford	Endorses the project aligns with jurisdictional objectives

3.12.2 Reviewers

Function	Area	Individual
Finance	All	Chip Benson
Regulatory	All	Peter Zschokke
Jurisdictional Delegate(s)	New England- Electric	James Patterson
	New York- Electric	Allen C. Chieco
	FERC	Nabil E. Hitti
	Gas - NY	Laurie T. Brown
	Gas - NE	David Iseler
Procurement	All	Art Curran

4 Appendices

4.1 Other Appendices

4.1.1 Project Cost Breakdown

Project Cost Breakdown			
Cost Category	**sub-category**	**$ (millions)**	**Name of Firm(s) providing**
Personnel	NG Resources	0.836	
	SDC Time & Materials	0.251	IBM
	SDC Fixed-Price	-	
	All other personnel	1.364	Alliance, Verizon, Others
	TOTAL Personnel Costs	2.451	
Hardware	Purchase	0.762	Alliance, Verizon, CNI, CSC
	Lease	-	
Software		0.682	AMAG, Alliance, CNI
Risk Margin		0.312	
Other		0.423	
	TOTAL Costs	4.630	

4.1.2 Benefiting Operating Companies

This investment will benefit companies in New York and New England (including Rhode Island) as shown in the table below:

Benefiting Operating Companies Table:

Operating Company Name	Business Area	State
National Grid USA Parent	Parent	N/A
KeySpan Energy Corp.	Service Company	N/A
Niagara Mohawk Power Corp.- Electric Distr.	Electric Distribution	NY
Niagara Mohawk Power Corp. - Gas	Gas Distribution	NY
Niagara Mohawk Power Corp. - Transmission	Transmission	NY
KeySpan Energy Delivery New York	Gas Distribution	NY

KeySpan Energy Delivery Long Island	Gas Distribution	NY
Massachusetts Electric Company	Electric Distribution	MA
Massachusetts Electric Company - Transmission	Transmission	MA
Nantucket Electric Company	Electric Distribution	MA
Boston Gas Company	Gas Distribution	MA
Colonial Gas Company	Gas Distribution	MA
Narragansett Electric Company	Electric Distribution	RI
Narragansett Gas Company	Gas Distribution	RI
Narragansett Electric Company - Transmission	Transmission	RI
New England Power Company - Transmission	Transmission	MA
NE Hydro - Trans Electric Co.	FERC Interconnect	N/A
New England Hydro - Trans Electric Co.	FERC Interconnect	N/A
New England Electric Trans Electric Co.	FERC Interconnect	N/A
NG LNG LP Regulated Entity	FERC Gas Ops	N/A
KeySpan Generation LLC (PSA)	Generation	NY
KeySpan Glenwood Energy Center	Generation	NY
KeySpan Port Jefferson Energy Center	Generation	NY
KeySpan Energy Trading Services	Parents	N/A
Transgas, Inc.	Other Non-Regulated	MA
KeySpan Energy Development Corporation	Non-Regulated	NY
KeySpan Services Inc.	Other Non-Regulated	NY

4.1.3 IS Ongoing Operational Costs (RTB):

This project will increase IS on-going operations support costs as per the following table. These are also known as Run the Business (RTB) costs.

Summary Analysis of RTB Costs							
All figures in $ millions **Forecast of RTB Impact**	**Yr. 1 13/14**	**Yr. 2 14/15**	**Yr. 3 15/16**	**Yr. 4 16/17**	**Yr. 5 17/18**	**Yr. 6+**	**Total**
RTB if Status Quo Continues	-	-	0.013	0.030	0.046	0.149	**0.238**
RTB if Project is Implemented	-	-	0.345	0.849	0.886	2.871	**4.950**
Net change in RTB	-	-	0.332	0.819	0.840	2.722	**4.713**
RTB Variance Analysis (if Project is Implemented)							
Net Δ RTB funded by Plan(s)	-	-	-	-	-	-	**-**
Variance to Plan	-	-	0.332	0.819	0.840	2.722	**4.713**
Total RTB Costs - by Cost Type (if Project is Implemented)							
App.Sup. - SDC 1	-	-	0.013	0.030	0.030	0.097	**0.170**
App.Sup. - SDC 2	-	-	-	-	-	-	**-**
App.Sup. - other	-	-	-	-	-	-	**-**
SW maintenance	-	-	0.054	0.188	0.188	0.609	**1.039**
SaaS	-	-	-	-	-	-	**-**
HW support	-	-	0.268	0.547	0.584	1.892	**3.291**
Other: IS	-	-	0.010	0.084	0.084	0.272	**0.450**
All IS-related RTB (sub-Total)	-	-	0.345	0.849	0.886	2.871	**4.950**
Business Support (sub-Total)	-	-	-	-	-	-	**-**
Total RTB Costs	-	-	0.345	0.849	0.886	2.871	**4.950**

nationalgrid

Title:	AMAG Upgrade	**Sanction Paper #:**	USSC- 14-251
Project #:	INVP 1172 XG020004604 (OpEx) 90000112731 (CapEx)	**Sanction Type:**	Resanction
Operating Company:	National Grid USA Svc. Co.	**Date of Request:**	November 19, 2015
Author / NG Representative:	Susan Stallard / Fran Mangano	**Sponsor:**	Warren Bamford, VP, Global Security
Utility Service:	IT	**Project Manager:**	Donald Stahlin

1 *Executive Summary*

This paper requests the resanction of INVP 1172 in the amount $6.041M with a tolerance of +/- 10% for the purposes of Development and Implementation.

This sanction amount is $6.041M broken down into:
$5.806M Capex
$0.235M Opex
$0.000M Removal

Note the originally requested sanction amount of $4.630M for Development and Implementation in Oct 2014.

2 *Resanction Details*

2.1 Project Summary

This policy-driven project will replace our current version of AMAG physical access control system (Enterprise Edition 6.01) with the more current release (Enterprise Edition 8.01 SP1). The upgrade will include new infrastructure installed with the current production system in preparation for a phased migration to the new system. The upgraded system will remain on National Grid property in CNI managed data centers.

This upgrade is to resolve performance issues with the current system due to aging infrastructure and vendor support issues caused by being several versions behind the current release. The upgrade is required for National Grid to complete its rollout of Windows 7 workstations as the currently installed version will not run on Windows XP.

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The upgrade will enhance National Grid's compliance with NERC/CIP (North American Electric Reliability Corp. / Critical Infrastructure Protection) regulations.

2.2 Summary of Projects

Project Number	Project Title	Estimate Amount ($M)
INVP 1172	AMAG Upgrade	6.041
	Total	6.041

2.3 Prior Sanctioning History

Previously approved sanctions are listed below (Latest to Oldest).

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Paper Title	Sanction Type	Paper Reference Number	Tolerance
Oct 2014	USSC	$4.630M	$4.630M	AMAG Upgrade	Full Sanction	USCC-14-251	10%
Apr 2011	US BRM	$0.156M	$0.966M	AMAG Upgrade Requirements and Design	Partial Sanction	INVP 1172	25%

Over / Under Expenditure Analysis

Summary Analysis ($M)	Capex	Opex	Removal	Total
Resanction Amount	$5.806M	$0.235M	$0.000M	$6.041M
Latest Approval	$4.478M	$0.152M	$0.000M	$4.630M
Change*	$1.328M	$0.083M	$0.000M	$1.411M

Change = (Re-sanction – Amount Latest Approval)

2.4 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Yr. 1 2015/16	Yr. 2 2016/17	Yr. 3 2017/18	Yr. 4 2018/19	Yr. 5 2019/20	Yr. 6 + 2020/21	Total
INVP 1172	AMAG Upgrade	Est Lvl (e.g. +/- 10%)	CapEx	2.161	3.051	0.594	0.000	0.000	0.000	0.000	5.806
			OpEx	0.093	0.042	0.100	0.000	0.000	0.000	0.000	0.235
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	2.254	3.093	0.694	0.000	0.000	0.000	0.000	6.041

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2.5 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
Investment Plan FY15/16	⦿ Yes ○ No	⦿ Over ○ Under ○ N/A	$0.950M
Investment Plan FY16/17	⦿ Yes ○ No	○ Over ⦿ Under ○ N/A	$0.167M

2.6 Drivers

2.6.1 Detailed Analysis Table

The following table indicates the major key variations that account for the difference between the original sanction amount and the requested resanction amount.

Detail Analysis	Over/Under Expenditure?	Amount
Elongated timeframe	☒ Over ☐ Under	$0.435M
Detailed Design Discoveries	☒ Over ☐ Under	$1.057M
Necessary Scope Changes	☒ Over ☐ Under	$0.243M
Detailed Design Efficiencies	☐ Over ☒ Under	$0.324M

2.6.2 Explanation of Key Variations

The key driver for the resanction is to provide funding that was not included in the original budget with respect to:

1. Additional Hardware, Software and associated installation costs in areas where the original design was deficient.
   - Telecommunications equipment for the required connectivity
   - Increased storage capacity for long term data retention requirements
   - Effort to deploy 'mini' data center within the CNI data centers was more extensive than originally envisioned

- Inadequate versions of software quoted in original project costs

2. Additional scope was uncovered.
   - Compliance with a NERC-CIP requirement not previously identified
   - Telecommunications equipment for appropriate level of redundancy
   - Additional user licenses for AMAG SW
   - Compliance with NG's cyber security requirements not previously identified
   - AFUDC increased due to additional scope as well as AFUDC rate increase
3. Elongated timeframe for delivery.
   - Project duration extended 5 months due to above points 1and 2
   - Additional staff to supplement skills not originally anticipated
4. Detailed Design Efficiencies.
   - Eliminated some redundancies which were not critical to day to day operations and reasonable alternatives existed.

2.7 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by the Business Support Manager to meet jurisdictional budgetary, statutory and regulatory requirements.

2.8 Key Milestones

Milestone	Target Date: (Month/Year)
Start up	Feb 2011
Begin Requirements and Design	Apr 2011
D-I Sanction	Oct 2014
Begin Development and Implementation	Nov 2014
D-I Resantion	Nov 2015
Begin User Acceptance Testing	Apr 2016
Move to Production	Jun 2016
Project Complete	Sep 2016
Project Closure	Jan 2017

2.9 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
Jan 2017	Project Closure

3 Statements of Support

3.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Role	Individual's Name
Business Executive Sponsor	Warren Bamford
Head of BRM/Strategy	Jon Poor
Relationship Manager	Jeff Dailey
Head of PDM	Richard Wood obo Trish Torizzo
Program Delivery Manager	Don Stahlin
IS Finance Management	Chip Benson
IS Regulatory	Wayne Watkins
Digital Risk &Security	Diana Simkin
Service Transition	Brian Detota
Enterprise Architecture	Joe Clinchot

3.2 Reviewers

The reviewers have provided feedback on the content/language of the paper

Function	Area	Individual
Finance	All	Chip Benson
Regulatory	All	Peter Zschokke
Procurement	All	Art Curran
Jurisdictional Delegate(s)	Electric - NE	James Patterson
	Electric -NY	Mark Harbaugh
	FERC	Carol Sedewitz
	Gas – NY	Laurie Brown
	Gas - NE	David Iseler

4 ***Decisions***

The US Sanctioning Committee (USSC) at a meeting held on November 19, 2015:

(a) APPROVED this paper and the investment of $6.041M and a tolerance of +/- 10%.

(b) Approved the RTB impact of $0.891M per annum for 5 years.

(c) NOTED that Donald Stahlin is the Project Manager and has the approved financial delegation.

Signature………………………………………………..Date………………
Margaret Smyth
US Chief Financial Officer
Chair, US Sanctioning Committee

CAPEX IS Investment Proposal
ETRM Replacement: Requirements and Design
US (EDG / Shared), Project No. INVP 2330B

(A project sanction paper by Paula Webb and Aman Aneja
on behalf of Lorraine Lynch, VP Treasury US – 06Aug2010)

Description

This investment proposal seeks sanction of $3.538m (including $160k previously sanctioned for vendor evaluations and a risk margin of $240k) for the Requirements and Design phases of the ETRM (Nucleus) Replacement Project.

The approximate total cost of the replacement project is $5.668m (including risk margin of $481k). The full project cost will be confirmed during the R&D phase, and will be adjusted based on results of the R&D phase.

This paper is being resubmitted, post sanctioning by the US ISSC on 13 Sept 2010. The requested funding for R&D was updated from $1.8m to $3.5m. The additional $1.7m is needed for SW licensing costs. The vendor, Allegro, is requiring SW license costs at contract. This was discussed at the US ISSC meeting and the committee gave approval for the updated R&D costs and to move the project forward.

Nucleus is the current US ETRM (Energy Trading, Transaction and Risk Management) platform. ETRM solutions help to manage the front, middle, and back office aspects of an energy trading entity. Functionality includes capturing and managing energy market transactions from execution to settlement and invoicing, and the managing and reporting of market risk and credit exposures. National Grid US purchases $8 billion per year in Energy.

Risks associated with remaining on Nucleus include the following:

- Nucleus version R13 was implemented in 2003 and we are still on version R13. SunGard, the Nucleus vendor, is no longer providing updates or enhancements to R13. Despite annual maintenance costs of $300k, SunGard has displayed limited commitment and ability to provide an acceptable level of support. In 2009 SunGard announced plans to “sunset” R13 and provide support for only critical issues. Although SunGard later reversed this decision, the future of SunGard support is questionable.
- A Level 1 system failure that prevents an annual closing could have a maximum financial impact of $143m (sum value of all credit thresholds). If the failure continues for a prolonged period, we would be expected to transfer all of our over-the-counter positions to the NYMEX/CME platform. This would result in an incremental posting of approximately $236m (as of August 17, 2010).
- Impact to National Grid’s reputation; investor and bondholder loss of confidence.
- Loss of trust and confidence of our regulators/PSC/LIPA in NG operations in the event of an outside audit that highlights a mission critical system with limited support.
- Inability to keep up with changing business and regulatory requirements (RECs, Carbon, Metals, Green tags, etc)
- Current system is incapable of responding to new or expanded SOX reporting requirements, or reporting requirements to assist in UK financial closing.
- New system implementation can take up to 18 months. We are not likely to have that much notice in the event that SunGard, or 3rd party contractors, cannot provide adequate levels of support.
- Potential FERC liabilities and fines from a system failure.

Four vendors (SunGard, Allegro, OpenLink, and Triple Point) were evaluated in an RFP and Allegro was selected. The RFP responses, evaluations, and the final recommendation were presented to the Steering Committee and were approved on August 3, 2010.

The potential use of this solution for UK will be explored at a later date so that the risks associated with the US are addressed as quickly as possible. The project team will, at the highest level, consider the potential expanded use by the UK as it proceeds through Requirements and Design to ensure no steps are taken which would preclude a future expansion to the UK. The project team will not solicit the UK requirements nor explicitly design nor implement a solution for the UK as part of this initiative.

This proposal seeks funds to complete Requirements and Design for the selected vendor, Allegro.

Category: Policy
Risk score: 45 Primary Driver – Reliability
Project Classification: Medium Region: US

Finance

Sanction Cost $3.538m (including previously sanctioned amount of $160 for vendor evaluations and a risk margin of $240k)

Cost volatility: P20 cost: n/a P80 cost: n/a

Probability that project cost will exceed tolerance: n/a

Project included in approved Business Plan? Yes

Indicative Full Project cost relative to approved Business Plan 153%

If cost > approved B Plan how will this be funded?

OPEX – FY11

1) Substitution of $200k from INVP2200 Customer Self Service via Web - Customer Experience

2) Substitution of $200k from INVP2201 Customer Self Service via Web – Operational Improvements

CAPEX

FY11 – Substitution of $89k from INVP1656 Customer Systems Agent Desktop.

FY12 - The incremental FY12 CAPEX requirement of $1,416k is being submitted through the currently on-going business planning process.

Other financial issues:

Currently the Investment Plan for 2010/11 includes (CAPEX) $3.2m for FY11 and $0.5m for FY12.

$'000s	Current planning horizon: Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	52	3,700	1,916				5,668		

Resources

Availability of internal resources to deliver project: Green

Availability of external resources to deliver project: Green

Operational impact on network system: Green

Key issues

- SOX compliance mandates a code freeze from Jan – Mar. The Implementation timeline has to be planned accordingly.

Key milestones

Complete Req/RFP/Vendor Selection	Aug 2010
Submit R&D Investment Proposal	Aug 2010
Engage Vendor	Sept 2010
Start R&D Phase	Sept 2010
Complete Requirements and Design	Feb 2011
Complete Development and Implementation	July 2011
Complete UAT / extended Parallel Testing	Sept 2011
Go-live	Oct 2011
Final Sign-off	Nov 2011
Project Closure	Nov 2011

Climate change

Contribution to National Grid's 2050 80% emissions reduction target:	Neutral
Impact on adaptability of network for future climate change:	Neutral
Are financial incentives (e.g. carbon credits) available?	n/a

Prior sanctioning history:

November 2009 RFP/Vendor Selection

Recommendations

The Sanctioning Authority is invited to:

(a) APPROVE the investment of $3.538m including risk margin of $240k by February 28, 2011

(b) NOTE that Lorraine Lynch is the Project Sponsor

(c) NOTE that Aman Aneja is the Project Manager and has the approved financial delegation to deliver the project

Signature……………………………………….. Date………………

Lorraine Lynch, VP Treasury US

IS Finance

I hereby confirm that the financial data supports the business case outlined in this paper.

Signature……………………………………….. Date………………

Duncan Brown, Head of IS Finance, Global IS

Information Services

I hereby support the recommendations made in this paper.

Signature……………………………………….. Date………………
Madalyn Hanley, IS Head of Relationship FSSC

Decision of the Sanctioning Authority
I hereby approve the recommendations made in this paper.

Signature……………………………………….. Date………………
David Lister, Chair of US ISSC

CAPEX IS Investment Proposal
ETRM Replacement: Requirements and Design
US (EDG / Shared), Project No. INVP 2330B

1. Background

- Nucleus is the current US ETRM (Energy Trading, Transaction and Risk Management) platform. Functionality includes capturing and managing energy market transactions from execution to settlement and invoicing, and the managing and reporting of market risk and credit exposures.
- NationalGrid US purchases $8 billion/yr in Energy.
- Nucleus was implemented in 2003. We are still on the original version, R13. SunGard, the Nucleus vendor, is no longer providing updates or enhancements to R13. Despite annual maintenance costs of $300k, SunGard has displayed limited commitment and ability to provide an acceptable level of support.
- A detailed RFP, including demos and site visits, was recently completed and Allegro was selected as the vendor of choice.
- Four vendors, including SunGard, were evaluated on detailed criteria. The core evaluation team included IS project leads and key business personnel from the Front, Middle, and Back office of the EPM organization. Vendors were scored on
    - Functional fit
    - Technical fit
    - Product maturity
    - Strength, vision, and focus of company
- Implementation costs and timelines are estimates only and will be finalized during the R&D phase.
- This proposal seeks funds to complete the Requirements and Design stages of the project only.

2. Driver

The key business drivers identified for the project are:

Risk Mitigation

- Risk of current system and infrastructure failure was added to the ED&G and Treasury Risk Registers (ID#3318).
    - See Appendix C.
- Recent level 1 failure (namely business critical) demonstrated that SunGard is very thin in being able to support this product line with technical experts to restore Nucleus to operating condition.
- New system implementation can take up to 18 months. We are likely not to have that much notice in the event that SunGard cannot provide adequate levels of support for Nucleus R13
- Overall risk score of 45
- Finding (VI-12) of the Management Audit stated that “NG’s current risk management framework will not be adequate to handle procuring energy capacity and hedging instruments in future energy markets. “ The related recommendation (VI-3) included: “Define and restructure the risk management policies, procedures and functions to assure appropriate monitoring of risk factors as the transition and long-term supply procurement plans are implemented. The risk management tools should incorporate appropriate market monitoring to know when contingencies are needed.”

While the audit did not mention Nucleus/ETRM specifically, the ETRM Replacement project is addressing these concerns by implementing a state-of-the-art Risk Management solution which is regarded as one of the top solutions available, especially within the Public Utility sector. The selected vendor, Allegro, has a significant customer base (36%) in the utility sector. Approximately 36% of Allegro's customer base of about 110 clients is utility type organizations similar to National Grid. Allegro software allows capturing and monitoring risk for a wide range of traditional and new energy products including power (physical and financial), capacity, renewable credits, emissions and others. The software flexibility and configuration capabilities of Allegro will enable National Grid to adapt to future market changes quickly and to continue monitoring risk appropriately.

Functionality/Productivity

- National Grid US purchases $8 billion/yr in Energy .
- A robust toolset in support of Rate Case filings as opposed to the current use of manually entered data into spreadsheets which require substantial reviews and oversight to ensure accuracy
- Robust credit module will replace a regime that is currently completely spreadsheet based with significant manual input, oversight and review to run and maintain.
- Flexibility to adapt to changing regulatory requirements and increasing pool of products (REC's, Carbon Credits, Metals, etc).
- Provide ability to capture and report on LNG transactions, allowing full transparency of LNG purchases from execution to invoicing.
- FAS 157 & 161 support is currently all manual and subject to error
- Add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front, middle, and back offices, auditors, creditors and regulators.

3. Project Description

Requirements and Design will be performed in conjunction with the Allegro vendor. The Allegro methodology ("Foundations") includes two phases that map to our R&D – "Plan" and "Translate". The Allegro methodology is a data centric model which requires data mapping, conversion, and verification during the R&D (Translate) phase. In accordance with Allegro's Foundations methodology, two development instances will be configured during the R&D phase. The major tasks and deliverable are:

Plan

- **Work plan.**
    - Identify resources and availability
    - Identify detail tasks with accountable resource
    - Balance resources to create work plan
- **Resource plan**
    - Set expectations of time commitments of all participants
- **Communication plan**
    - Establish status reporting and change management policies and decision makers
- **Customer and Allegro verify that project plans match the Scope of Services**

Translate

- **Project Infrastructure.** Establish the project infrastructure
- **Data Source Definition.** Identify the source of data
- **Data Conversion.** Convert data from source to development environment.
- **Data Verification.** Verify the accuracy of converted data

- **Business Process Confirm.** Confirm processes with customer
- **Extension Definition.** Identify and define extensions:
  - **Data model.** New tables/columns, database views, triggers, stored procedures
  - **Visual model.** New views, panes, sets, icons
  - **Messaging.** Event-based alerts, notifications, and actions
  - **Connect.** Transformation of data between systems
  - **Reports.** External reports, generally developed with Crystal
  - **Web Services.** Existing WS invocation, new WS invocation, external assemblies
- **Translate Phase Approval.** Obtain phase approval

At the end of Requirements and Design we will:

- Confirm required level of funding for implementation project, including resources, HW, and SW.
- Develop Investment Proposal for Development and Implementation phases.

The current Nucleus system interfaces with Oracle AP and Great Plains AR. The replacement ETRM system will ultimately need to interface with SAP. Project timelines and schedules will be monitored and updated as necessary to ensure minimal impacts, rework and unnecessary costs.

The potential use of this solution for UK will be explored at a later date so that the risks associated with the US are addressed as quickly as possible. The project team will, at the highest level, consider the potential expanded use by the UK as it proceeds through Requirements and Design to ensure no steps are taken which would preclude a future expansion to the UK. The project team will not solicit the UK requirements nor explicitly design nor implement a solution for the UK as part of this initiative.

4. Business Issues

This project will mitigate the risks associated with staying on Nucleus R13:

- **A Level 1 system failure that prevents an annual closing could have a maximum financial impact of $143m (sum value of all credit thresholds). If the failure continues for a prolonged period, we would be expected to transfer all of our over-the-counter positions to the NYMEX/CME platform. This would result in an incremental posting of approximately $236m (as of August 17 2010).**
- Impact to National Grid's reputation (investor and bondholder loss of confidence).
- Loss of trust and confidence of our regulators/ PSC/LIPA in NG operations in the event of an outside audit that highlights a mission critical system with limited support .
- Auditors: possibility of qualified opinion regarding marginally supported system
- Inability to keep up with changing business and regulatory requirements (REC's Carbon, Metals, Green tags, etc).
- Current system is incapable of responding to support any new or expanded SOX reporting requirements or reporting requirements that could assist our UK financial closing
- Based on recent events, SunGard's long term plans may not include remaining in the Energy Sector. A new owner may find supporting Nucleus unprofitable, potentially leaving us with an unsupported Risk Management system
- New system implementation can take up to 18 months – we are likely not to have that much notice in the event that SunGard cannot provide adequate levels of support
- Potential FERC liabilities and fines from a system failure (Legal advisor opinion)

5. Options Analysis

Option	Recommendation	Rationale
Do Nothing:	Rejected	• Current Nucleus R13 version is at risk of a system failure resulting in a significant financial impact • SunGard has demonstrated an inability to provide timely resolution to critical and non-critical issues. In 2008 there were approximately 30 non-critical issues. • We no longer report issues to SunGard and have implemented various workarounds instead. However we still pay $300k maintenance annually. • Will not address items in the ED&G and Treasury Risk Registers (ID#3318).
Stay on Nucleus R13, purchase the source code, and get 3rd party support	Rejected	Approximate Cost of $1.1m one time and $150k annual. (Additional analysis would be needed to confirm costs). • $1.1m includes $600k to purchase SW and $500k to engage 3rd party (Adapt2) to modify SW to address functional gaps • $150k RTB for annual maintenance. Current Nucleus maintenance cost is $300k, will be reduced to approximately $250k based on retired modules This is contrary to current IS direction. • Adapt2 is not one of our prospective sourcing partners • Customization of package should be avoided • Option undesirable as the platform is built on outdated technologies, is complex and inflexible to changing business needs • Would be an interim short term solution – only 3-5 years. • Adapt2 is a small group of former SunGard programmers that have started a consulting firm. There is a risk that the company will not be long lived. • Will not address items in the ED&G and Treasury Risk Registers (ID#3318), due to uncertainty of Adapt2s future
Continue paying SunGard $300k	Rejected	Not an option. Would violate the

Option	Recommendation	Rationale
annually for level 1 support and hire a third party to maintain level 2 and 3 issues.		SunGard Contract.
Complete Requirements and Design stages and plan for Allegro implementation.	Recommended	• In addition to risk mitigation, new system will add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front and back offices, auditors, creditors and regulators.

6. Milestones

Key Milestones	Date	Responsible person…
Complete Requirements/RFP/Vendor Selection	Aug 2010	Project Manager(s)
Submit R&D Investment Proposal	Aug 2010	Project Manager(s)
Engage Vendor	Sep 2010	Project Manager(s)
Start R&D Phase	Sep 2010	Project Manager(s)
Complete Requirements and Design	Feb 2011	Project Manager(s)
Complete Development and Implementation	July 2011	Project Manager(s)
Complete UAT / extended Parallel Testing	Sept 2011	Project Manager(s)
Go-live	Oct 2011	Project Manager(s)
Final Sign-off	Nov 2011	Project Manager(s)
Project Closure	Nov 2011	Project Manager(s)

7. Safety, Environmental and Planning Issues

N/A

Investment Recovery

8. Investment Classification

- This project is Policy driven as asset replacement.

9. Regulatory Implications

N/A

10. Customer Impact

N/A

Financial Impact

11. Cost Summary

The following table show the full costs for the project, which are indicative at this stage. This investment proposal seeks sanction of funds for the Requirements and Design stages of the project only. This amounts to $3.538m including $240K risk range – a detailed breakdown is provided in Appendix B. The costs for this project will be allocated to US Gas and US Electric.

A significant driver for the cost variation from the original indicative cost (Pre RFI/RFP) to current indicative cost (Pre Requirements & Design) is attributed to the utilization of the vendor quotation from TriplePoint (vendor which was eliminated during RFP process). Had the project team utilized the Allegro (vendor which eventually was selected) quotation at that time, the indicative cost would have been $1,232,500 higher than what was originally submitted.

Other factors that contributed to the change in costs from the original indicative cost to current indicative cost are:

1) Additional scope (LNG) was discovered during RFI/RFP analysis
2) Travel Expenses for vendor were not included in the original
3) Inclusion of cost for 1 business backfill was not included in the original estimate

$'000s		Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6 +	Total	Lower Range P20	Upper Range P20
Project Cost	Opex	52	411	0	0	0	0	**463**		
	Capex	0	3,289	1,916	0	0	0	**5,205**		
IS Investment Plan	Opex	0	0	0	0	0	0	**0**		
	Capex	0	3,200	500	0	0	0	**3,700**		
Variance to plan	Opex	(52)	(411)	0	0	0	0	**(463)**		
	Capex	0	(89)	(1,416)	0	0	0	**(1,505)**		

1. This stage of the project is planned to be completed in FY10/11.
2. Currently the Investment Plan for 2011/12 is in the planning stage.
3. The total project cost (RFP + R&D + D&I) for implementation is $5.668m.
4. The Total Project costs are indicative only, as the project is at the Requirements and Design stage. There will be more accurate project costs after these stages are completed and the investment proposal for the D&I phase is written.
5. The project is expected to run into FY2011/12.

Funding Summary:

OPEX – FY11

1) Substitution of $200k from INVP2200 Customer Self Service via Web - Customer Experience

2) Substitution of $200k from INVP2201 Customer Self Service via Web – Operational Improvements

CAPEX

FY11 – Substitution of $89k from INVP1656 Customer Systems Agent Desktop.

FY12 - The incremental FY12 CAPEX requirement of $1,416k is being submitted through the currently on-going business planning process.

Other financial issues:

Currently the Investment Plan for 2010/11 includes (CAPEX) $3.2m for FY11 and $0.5m for FY12.

The costs for this project will be allocated to:

Gas (G5200 - all gas allocation code) 65% and
Electric (G1060 - all electric distribution code) 28% and
LIPA 7%

(This is based on transaction volume, the financial impact, and number of users.)

New Annual RTB estimates are preliminary only and will be confirmed during the R&D phase.

RTB costs $'000s	Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Total
Current Annual RTB costs	780	780	780	780	780	3,900
New Annual RTB costs	780	780	780	497	497	3,334
Impact on RTB costs (new minus existing)				(283)	(283)	(566)
Variance to Plan				(283)	(283)	(566)

The current RTB breakdown is estimated based on:

- Licences - $300k
- Servers and infrastructure - $150k
- Application support - $330k

12. Cost Assumptions

The costs and timelines for the D&I stages and the RTB are indicative only at this stage in the project. After the Requirements and Design stages are completed, the investment proposal for the D&I phase will be completed and will have more accurate information on the implementation and RTB costs and timelines.

13. Benefits Summary

- This project has no direct savings, aside from RTB savings noted above, at this time. However, the potential to utilize this solution for the UK will be explored at a later date and that could result in the retirement of two (2) bespoke systems which may translate into additional savings.
- A robust toolset in support of Rate Case filings, opposed to manual spreadsheets subject to error
- Robust credit module that will replace a regime that is currently completely spreadsheet based with significant manual input to run and maintain.
- Flexibility to adapt to changing regulatory requirements and increasing products (REC's, Carbon Credits, Metals, etc)
- Provide ability to capture and report on LNG transactions, allowing full transparency of LNG purchases from execution to invoicing.
- FAS 157 & 161 support (currently manual and subject to error)
- Add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front, middle and back offices, auditors, creditors and regulators.

14. NPV

While this initiative is not being driven by it's NPV, there is an RTB savings which will be achieved. The resulting NPV is $-4,230k.

15. Additional Impacts

N/A

16. Execution Risk Appraisal

No	There is a risk that …..	Countermeasure or Action	Risk Range	Monitored by ….
1	Internal resource constraints may arise due to the overlap with the SAP BO Project and the TMS project.	Build into Project Plan and monitor.	20%	IS Project Manager
2	Vendor may not be able to provide the required level of qualified resources	Requesting resumes and named resources prior to project kickoff.	20%	IS Project Manager
3	Internal resources may not be available due to holiday periods.	Build into Project Plan and monitor.	20%	IS Project Manager
4	Some design decisions, for example interfaces to the ERP, will have to be closely aligned with the SAP BO Project timeframes.	Regularly scheduled status meetings and ongoing communications.	NA	IS Project Manager

Note: Risk is largely being applied to Internal Labor as a fixed price contract with the vendor has been assumed in the current estimates and is consistent with the on-going vendor discussions/negotiations. However, since those contracts are not signed, some risk has been attributed to vendor services costs.

Appendices

A. Resources

Step 1:

Role	National Grid Resources (FTEs)		External Resources (FTEs)			
	IS	Business	Contractor	Systems Integrator	ODC	Other
Program Managers / BRM	TBD					Allegro
Project Managers (PM)		Tom Warmath	Aman Aneja			Allegro
Business Analysts (BA)		TBD / backfill one FTE	Gary Crespin			Allegro
Application Developer (AD)	TBD					Allegro
Solution Architects (SA)	Abraham Jose					
DBA	TBD					
ICOE	TBD					
Solution Delivery SMEs	TBD					
IS Procurement Lead	Nancy Curtin					

The following resources are NOT included in the project costs:
IS Procurement; Business resources (except for BA backfill)

Step 2:

External Resource Engagement:
PM / BA / SA Contractors: extend contracts
Other (Allegro) – vendor engagement

Step 3:

Name	Role*	Source**	FTE	Start	End	Availability***
TBD	PgM / BRM	IS	0.20	Aug 10	Feb 11	TBC
Aman Aneja	PM	IS	1	Aug 10	Feb 11	Confirmed
Tom Warmath	PM	Bus	0.25	Aug 10	Feb 11	Confirmed
Gary Crespin	BA	IS	0.50	Aug 10	Feb 11	TBC
TBD	BA	Bus	1	Aug 10	Feb 11	TBC
TBD	AD	IS	0.50	Aug 10	Feb 11	TBC
Abraham Jose	SA	IS	0.25	Aug 10	Feb 11	Confirmed
TBD	DBA	IS	0.10	Aug 10	Feb 11	Confirmed
TBD	ICOE	IS	0.05	Aug 10	Feb 11	Confirmed
Nancy Curtin	IS Proc	IS	0.10	Aug 10	Feb 11	Confirmed

- *Role: Use role abbreviations identified within Stage 1.*
  *** Source: IS=National Grid IS FTE; Bus=National Grid Business FTE; Ext=External FTE*
  **** Only enter Confirmed if approved by the relevant Portfolio Lead, otherwise enter TBC (to be confirmed)*

Step 4:

Resource Phasing related comments:

B. TCO Log

The Total Project costs shown in the table below are indicative only, as the project is at the Requirements, RFP, and Vendor Selection stage. There will be more accurate project costs after these steps are completed and the investment proposal for the D&I phase is written.

C. Risk Register

Risk of current system and infrastructure failure was added to the ED&G and Treasury Risk Registers.

CAPEX IS Investment Proposal – Summary

ETRM Replacement
US , Project No. INVP 2330

A project sanction paper by Fran Mangano and Amanprit Aneja for Lorraine Lynch – July 2011

Description

This investment proposal seeks sanction of funds for the Development & Implementation stages of the project. The projected cost of the replacement project is at $6.086m (including risk margin of $228k).

Nucleus is the current US ETRM (Energy Trading, Transaction and Risk Management) platform. ETRM solutions help to manage the front, middle, and back office aspects of an energy trading entity. Functionality includes capturing and managing energy market transactions from execution to settlement and invoicing, and the managing and reporting of market risk and credit exposures. National Grid US purchases $8 billion per year in Energy for the jurisdictions it serves.

The Niagara Mohawk audit by the New York Public Service Commission in December 2009 indicated that National Grid's current risk management framework will not be adequate to handle procuring energy capacity and hedging instruments in future energy markets. While not specifically mentioning the current US ETRM system, we believe that the Allegro system will enable National Grid to capture and monitor risks for a wide range of traditional and new energy products including, but not limited to, natural gas, power, capacity, renewable credits, emissions and others. Due to the flexibility and capabilities of the system, National Grid will have the ability to adapt to future market and regulatory changes quickly and monitor risk appropriately. With Allegro, National Grid will enter all transactions into one system which will provide a single source for confirmation, invoice verification, invoice generation, valuation and risk reporting. Because National Grid provides commodity procurement services across many state jurisdictions, it is important to keep each group of customer transactions separate and apart from one another. This system allows the company to prevent commingling of customer commodity costs across jurisdictions, while allowing for a common practice enterprise wide. The Allegro system also has the necessary security features that provide the ability to separate access by job functionality.

The Allegro transaction and risk management system will replace Nucleus (National Grid's existing transaction management system). National Grid was informed a few years ago that Sungard the company that owns Nucleus would no longer provide technical support of the product and at that time it embarked on finding its replacement. Both systems are databases that allow for a very efficient management of energy transactions from its execution to the invoicing. This system provides the necessary controls and industry best practices as recommended by the Committee of Chief Risk Officers (CCRO) and required by Sarbanes-Oxley regulations. In addition, the replacement of this system is currently identified in the Energy Procurement and Treasury Risk Registers (This item is classified as ID#3318).

In addition to the jurisdictional entity requirements, the ETRM system is utilized for the recording and accounting of energy transactions. Weakness in accounting for derivatives is one of the most frequent areas reported under Sarbanes-Oxley. Hence, the implementation of a rigorous process and controls to ensure the accuracy of the data further supports the ability to mitigate risk around recording of energy transactions and valuation of energy derivative transactions. A failure in controls could result in the incorrect disbursement of funds and incorrect accounting for transactions leading to the restatement of financial statements. Such failure could also lead to a material weakness being identified resulting in a significant financial burden to rectify.

To address the risks associated with the Nucleus system, a phased implementation approach has been adapted. The phased approach will reduce the risk associated with current system by transitioning all transactions currently performed in Nucleus to the new system in the early phases of implementation.

During the Business Process Confirmation activity, where the product is demonstrated process by process on an early delivery of converted data, a number of additional extensions to the core product have surfaced. Additionally, a number of enhancements to the core product which were thought to be needed have now been deemed as unnecessary as the core product delivers this as a standard core function.

Category:	Policy
Risk score:	45
Project Classification: Medium	Region: US

Finance

Sanction Cost $6.086m

Cost volatility: P20 cost: N/A P80 cost: N/A

Probability that project cost will exceed tolerance: Fixed Price Contract

Project included in approved Business Plan? INVP2330

Project cost relative to approved Business Plan -20%

$'000s	Current planning horizon Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6+	Total	Lower Range P20	Upper Range P80
Proposed Investment	160	3,059	2,867				6,086		

Resources

Availability of internal resources to deliver project: Green

Availability of external resources to deliver project: Green

Operational impact on network system: Green

Key issues

- SOX compliance mandates a code freeze for financial transactions between January and March. The implementation timeline has been adjusted to a phased implementation to address this.
- Phased implementation reduces risk associated with current system. Current system transactions will be transitioned to the new system in the early phases of implementation thereby addressing the Risk Register consequence.
- Delay in the US Foundation Project has caused the project to develop temporary interface from Great Plains, replacing the existing interfaces that exist today with Nucleus. The temporary interface is estimated to cost $35k.
- ETRM system is not dependant on US Foundations Project or Global Treasury Workstations Project. While interfaces will exist between the systems, there is system stability risk associated with delaying the ETRM system. From a pure cost perspective, a delay in implementing Allegro will result in software support of $300k with the current vendor (Sungard).

Key milestones

Complete Req/RFP/Vendor Selection	Aug 2010
Submit R&D Investment Proposal	Aug 2010
Engage Vendor	Sept 2010
Start R&D Phase	Sept 2010
Complete Requirements and Design	June 2011
Implement Phase 1 (Gas)	October 2011
Implement Phase 2 (Power & Emissions)	November 2011
Implement Phase 3 (Credit, ERP & Risk)	January 2012
Implement Phase 4 (Truck, LNG)	February 2012
Final Sign-off	Mar 2012
Project Closure	Mar 2012

Climate change	
Contribution to National Grid's 2050 80% emissions reduction target:	Neutral
Impact on adaptability of network for future climate change:	Neutral
Are financial incentives (e.g. carbon credits) available?	NA
Incorporated the cost of carbon into Investment Planning Decision?	NA

Prior sanctioning history:

- November 2009 – RFI/Vendor Selection
- August 2010 – R&D Sanction Submitted
- May 2011 – Re-Sanction R&D Submitted
- July 2011 – Sanction D&I Sanction Submitted

Recommendations

The **US Sanctioning Committee** is invited to:

(a) Approve the total investment of $6.086m for design and implementation.

(b) NOTE that **Lorraine Lynch** is the Project Sponsor.

(c) NOTE that **Amanprit Aneja** is the Project Manager and has the approved financial delegation to deliver the project and/or other operation management employees approving contracts and materials procurement related to this project, subject to the DOA limits and requirements posted to the Info net.

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Signature……………………………………….. Date………………

Lorraine Lynch, VP Treasury US

I hereby approve the recommendations made in this paper.

Signature……………………………………………..Date………………

Matthew Guarini, VP, IS Business Relationship Management

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on July 27, 2011.

Signature……………………………………………..Date………………

Lee S. Eckert, Chief Financial Officer, US Financial Services

US Sanction Committee, Chairman

CAPEX IS Investment Proposal – Summary
ETRM Replacement
US , Project No. INVP 2330
A project sanction paper by Fran Mangano and Amanprit Aneja for Lorraine Lynch – July 2011

1. Background

Allegro was one of the four vendors chosen during the RFI / RFP Stage as per the business requirements set along with the assistance of Procurement.

During the requirements and design phase, Allegro and National Grid met to confirm all requirements that were needed out of the base application were available to us. Due to various needs unique to National Grid enhancements to the base application were needed.

In order to reduce the risk associated with a multiple objective project deployment, the remainder of the National Grid core project will be broken into four agile phases. The four agile phases should allow National Grid to accelerate their return on investment by realizing benefits from the system earlier, minimizing potential disruption to the business and allowing faster acceptance and adoption of the Allegro solution.

Four agile projects will be created:
1. Nat Grid P1 Natural Gas
2. Nat Grid P2 Power Emissions
3. Nat Grid P3 Credit Risk Hedge
4. Nat Grid P4 Truck LNG

Tasks associated with the following categories and/or phases of the Nat Grid ETRM Core project will be descoped and re-allocated to one of four agile projects:
1. Extension Definition
2. Integrate Phase
3. Validate Phase
4. Deploy Phase
5. Operate Phase
6. Manage Phase

- Nucleus is the current US ETRM (Energy Trading, Transaction and Risk Management) platform. Functionality includes capturing and managing energy market transactions from execution to settlement and invoicing, and the managing and reporting of market risk and credit exposures.
- National Grid US purchases $8 billion/yr in Energy for the jurisdictions it serves.
- Nucleus was implemented in 2003. We are still on the original version, R13. SunGard, the Nucleus vendor, is no longer providing updates or enhancements to R13. Despite annual maintenance costs of $300k, SunGard has displayed limited commitment and ability to provide an acceptable level of support. MAKE MORE FACTUAL.
- A detailed RFI and RFP over a nine-month period, including demos and site visits, was recently completed and Allegro was selected as the vendor of choice.
- Four vendors, including SunGard, were evaluated on detailed criteria. The core evaluation team included IS project leads and key business personnel from the Front, Middle, and Back office of the EPM organization. Vendors were scored on
    - Functional fit
    - Technical fit
    - Product maturity
    - Strength, vision, and focus of company

- The evaluation also included the systems ability to reduce and/or eliminate current manual processes or spreadsheets, the ability to adapt to changing regulatory requirements and the ability to increase efficiency in support of auditors, creditors and regulators.

2. Driver

- Nucleus was implemented in 2003. We are still on the original version, R13. SunGard, the Nucleus vendor, is no longer providing updates or enhancements to R13. National Grid currently pays a support contract of $300k, which entitles National Grid to Sev 1 incidents only due to limited staff that can support Sev 2 and beyond incidents.
- Vendor uncertainty posed risk to the jurisdictional entities for which we procure commodity.
- Current system risks could result in our inability to: separate customer commodity costs across jurisdictions; adequately segregate job functions; accurately account for and record energy transactions; and accurately value energy derivative transactions. Such deficiencies could result in a material weakness being identified and therefore requiring a significant level of effort and cost to address.

3. Project Description

Plan

- **Work plan.**
  - Identify resources and availability
  - Identify detail tasks with accountable resource
  - Balance resources to create work plan
- **Resource plan**
  - Set expectations of time commitments of all participants
- **Communication plan**
  - Establish status reporting and change management policies and decision makers
- Customer and Allegro verify that project plans match the Scope of Services

Translate

- **Project Infrastructure.** Establish the project infrastructure
- **Data Source Definition.** Identify the source of data
- **Data Conversion.** Convert data from source to development environment.
- **Data Verification.** Verify the accuracy of converted data
- **Business Process Confirm.** Confirm processes with customer
- **Extension Definition.** Identify and define extensions:
  - **Data model.** New tables/columns, database views, triggers, stored procedures
  - **Visual model.** New views, panes, sets, icons
  - **Messaging.** Event-based alerts, notifications, and actions
  - **Connect.** Transformation of data between systems
  - **Reports.** External reports, generally developed with Crystal
  - **Web Services.** Existing WS invocation, new WS invocation, external assemblies
- **Translate Phase Approval.** Obtain phase approval
- **Confirmed required level of funding for implementation project, including resources, HW, and SW.**

The current Nucleus system interfaces with Oracle AP and Great Plains AR. The replacement ETRM system will have temporary interfaces to Great Plains and will be interfaced to SAP once US Foundation goes live. The cost associated with development of the temporary interfaces is estimated to be $35k. Based on the risks identified, it is not beneficial to delay the ETRM system by approximately 9 months so that it aligns with the US Foundations project. Also the delay will pose resource availability by the vendor. Such a delay would also result in an additional financial burden of $300k to this system implementation. This is due to support from Sungard that National Grid would have to receive since the existing system would be up and running.

The following four interfaces are required from the ETRM system and SAP.

AR Import Interface
AR Export Interface
AP Import Interface
AP Export Interface

4. Business Issues

This project will mitigate the risks associated with staying on Nucleus R13:

- Impact to National Grid's reputation (investor and bondholder loss of confidence).
- Loss of trust and confidence by our jurisdiction regulators and LIPA in the event of an outside audit that highlights a mission critical system with limited support.
- Auditors: weakness in accounting for derivatives is one of the most frequent areas reported under Sarbanes-Oxley. Hence, the level of rigor around processes and controls to ensure data integrity further supports the ability to mitigate risk and possibility of receiving a qualified opinion regarding a marginally supported system.
- Inability to accurately segregate and separate commodity costs and procurement transactions by jurisdiction, resulting in regulatory scrutiny and uncertainty around regulatory cost recovery.
- Inability to keep up with changing business and regulatory requirements (REC's Carbon, Metals, Green tags, etc). While not specifically mentioning the Nucleus system, the Niagara Mohawk PSC audit has already indicated that our current risk management framework will not be adequate to handle procuring energy capacity and hedging instruments in future energy markets.
- Current system is incapable of responding to support any new or expanded SOX reporting requirements or reporting requirements that could assist our UK financial closing
- Based on recent events, SunGard's long term plans may not include remaining in the Energy Sector. A new owner may find supporting Nucleus unprofitable, potentially leaving us with an unsupported Risk Management system
- New system implementation can take up to 18 months – we are likely not to have that much notice in the event that SunGard cannot provide adequate levels of support
- Potential FERC liabilities and fines from a system failure (Legal advisor opinion)

5. Options Analysis

Option	Recommendation	Rationale
Do Nothing:	Rejected	• Current Nucleus R13 version is at risk of a system failure resulting in a significant financial impact • Will not address items in the Treasury Risk Register This item is classified as ID#3318
Stay on Nucleus R13, purchase the source code, and get 3rd party support	Rejected	Approximate Cost of $1.1m one time and $150k annual. (Additional analysis would be needed to confirm costs). • $1.1m includes $600k to purchase SW and $500k to engage 3rd party (Adapt2) to modify SW to address functional gaps • $150k RTB for annual maintenance. Current Nucleus maintenance cost is $300k, will be reduced to approximately $250k based on retired modules • Option undesirable as the platform is built on outdated technologies, is complex and inflexible to changing business needs • Would be an interim short term solution – only 3-5 years. • Adapt2 is a small group of former SunGard programmers that have started a consulting firm. There is a risk that Adapt2 may not be able to deliver a long term project due to financial and resource constraints. • Will not address items in the Treasury Risk Register (ID#3318), due to uncertainty of Adapt2s future
Continue paying SunGard $300k annually for level 1 support and hire a third party to maintain level 2 and 3 issues.	Rejected	Not an option. Would violate the SunGard Contract.
Complete Allegro implementation.	Recommended	• In addition to risk mitigation, new system will add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front and back offices, auditors, creditors and regulators. • Allow for utilization of a single system to manage transactions and valuations in order to mitigate the risks of manual

Option	Recommendation	Rationale
		processes and spreadsheet errors. • Mitigate material weakness being identified due to a poorly supported system

6. Application Decommissioning

Application will be in read only state for limited users In order to be able to accommodate future data requests from state regulators and/or FERC.

Application will be online for 1 year after which an underlying database will be retained for minimum of 6 years.

7. Milestones

Revised Key Milestones	Date	Responsible person…
Complete Requirements/RFP/Vendor Selection	Aug 2010	Project Manager
Submit R&D Investment Proposal	Aug 2010	Project Manager
Engage Vendor	Sep 2010	Project Manager
Start R&D Phase	Sep 2010	Project Manager
Complete Requirements and Design	June 2011	Project Manager
Complete Development and Implementation	February 2012	Project Manager
Project Closure	March 2012	Project Manager

8. Safety, Environmental and Planning Issues

N/A

Investment Recovery

9. Investment Classification

This project is Policy driven as asset replacement.

10. Regulatory Implications

This solution enables fulfilment of our regulatory obligation to procure and deliver energy to our customers. The Nucleus system will enable us to continue to manage energy procurement costs in a cost effective and reliable manner.

11. Customer Impact

Because National Grid provides commodity procurement services across many state jurisdictions, it is important to keep each group of customer transactions separate and apart from one another. This system allows the company to prevent commingling of customer commodity costs across jurisdictions, while allowing for a common practice enterprise wide. The Allegro system also has the necessary security features that provide the ability to separate access by job functionality.

Financial Impact

12. Cost Summary

This investment proposal seeks funds the full projects, as shown in the table below. This includes funds already sanctioned for the Requirements and Design stages. A further breakdown of these costs is provided in Appendix B.

$'000s		Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6 +	Total	Lower Range P20	Upper Range P20
Project Cost	Opex	160	168	35				363		
	Capex		2,891	2,832				5,723		
IS Investment Plan	Opex									
	Capex		3,200	4,449				7,649		
Variance to plan	Opex	(160)	(168)	(35)				(363)		
	Capex		309	1,617				1,926		

The costs for this project will be allocated to:

Gas (G5200 - all gas allocation code) 65% and
Electric (G1060 - all electric distribution code) 28% and
LIPA 7%

The costs for this project will be allocated to US Gas, US Electric and LIPA. The method for the allocated charge will be based on actual transaction history therefore resulting in an allocation to jurisdictional entities based on usage. This method, reviewed by LIPA Finance, Regulation and Pricing and Accounting Services, is consistent with the recent Liberty audit recommendation to charge costs to jurisdictional entities when able. This methodology will be modified if necessary because of the audit finding.

RTB costs $'000s	Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Total
Current Annual RTB costs	780	780	780	780	780	3,900
New Annual RTB costs	780	780	780	497	497	3,334
Impact on RTB costs (new minus existing)				(283)	(283)	(566)
Variance to Plan				(283)	(283)	(566)

RTB will drop in 12/13 as we will not be paying for support from Sungard.

13. Cost Assumptions

Based on Requirements and Design phase completed.

14. Benefits Summary

- This project has no direct savings, aside from RTB savings noted above, at this time. However, the potential to utilize this solution for the UK will be explored at a later date and that could result in the retirement of two (2) bespoke systems which may translate into additional savings.
- A robust toolset in support of Rate Case filings, opposed to manual spreadsheets subject to error
- Robust credit module that will replace a regime that is currently completely spreadsheet based with significant manual input to run and maintain.
- Robust system that will improve our ability to estimate market and credit risk exposures thereby enabling more informed risk mitigation decisions related to exposures.
- Flexibility to adapt to changing regulatory requirements and increasing products (REC's, Carbon Credits, Metals, etc)

- Provide ability to capture and report on LNG transactions, allowing full transparency of LNG purchases from execution to invoicing.
- FAS 157 & 161 reporting is currently a manual process. The Allegro system provides flexibility that appears to provide enhancements over the current process, however it will not completely automate the FAS 157 and 161 reports.
- Add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front, middle and back offices, auditors, creditors and regulators.

NPV

N/A

15. Additional Impacts

N/A

16. Execution Risk Appraisal

No	There is a risk that …..	Countermeasure or Action	Risk Range	Monitored by ….
1	That US Foundation team will not have the data values established in time to allow for a more flexible deployment	Set deadline and if the values are not met, alter direction to use existing values for interfaces with Oracle and Great Plains.	20%	IS Project Manager
2	Business will continue to surface requirements, even after scope is signed off.	Monitor closely and 'cap' scope relegating business to trade off if new requirements surface after sanctioning, with very few exceptions.	20%	Business Project Manager

Appendices

A. Resources

Step 1:

Role	National Grid Resources (FTEs)		External Resources (FTEs)			
	IS	**Business**	**Contractor**	**Systems Integrator**	**ODC**	**Other**
Program Managers (PgM)	Fran Mangano					Allegro
Project Managers (PM)		TBD	TBD			Allegro
Business Analysts (BA)		Eboni Troupe	TBD (existing BA recently resigned)			Allegro
Application Developer (AD)						Allegro
Enterprise Architects (EA)	Steve Gates					
Database Administrator (DBA)	Paul Fleisher					
Digital Risk & Security (DR&S) Consulting	Marc Mandel					

The following resources are NOT included in the project costs: IS Procurement; Business resources (except for BA backfill)

Step 2:

External Resource Engagement:

Other (Allegro) – Vendor fixed priced engagement on original scope; Time and Materials on incremental scope

Step 3:

Name of Resource	Project Role*	Source for Resource**	FTE	Start	End	Availability Confirmed?***
Fran Mangano	Pgm Mgr	IS	0.20	Aug 10	Mar 12	Confirmed
TBD	PM	IS	1	Aug 10	Mar 12	Confirmed
TBD	PM	Bus	0.25	Aug 10	Mar 12	Confirmed
TBD	BA	IS	0.50	Aug 10	Mar 12	TBC
TBD	BA	Bus	1	Aug 10	Mar 12	TBC
TBD	AD	IS	0.50	Aug 10	Mar 12	TBC
Steve Gates	SA	IS	0.25	Aug 10	Mar 12	Confirmed
TBD	DBA	IS	0.10	Aug 10	Mar 12	Confirmed
TBD	ICOE	IS	0.05	Aug 10	Mar 12	Confirmed

B. TCO Log

nationalgrid

US Sanction Paper

Title:	Nucleus ETRM Replacement	**Sanction Paper #:**	USSC-12-363 v2 (INVP 2330)
Project #:		**Sanction Type:**	Re-sanction
Operating Company:	Allocated	**Date of Request:**	25 JUL 2012
Author:	Mayumi Okada / Joseph Kruczlnicki	**Sponsor:**	Lorraine Lynch, VP of Treasury
Utility Service:	IS - FSS&C		

1 Executive Summary

1.1 Sanctioning Summary:

This paper requests the re-sanction of INVP-2330 in the amount $8.008M**,** including a tolerance of +/- 10% for the purposes of D&I Re-sanction of the replacement of the Energy Trading, Transaction and Risk Management (ETRM) platform called Nucleus.

This sanction amount is $8.008M broken down into:
- $0.388M OPEX
- $7.620M CAPEX

Note the originally requested sanction amount of $6.086M. Additional funds of $1.922M are requested to complete the work. Reference Section 4.2, Drivers, for a breakdown of the additional funds requested.

1.2 Brief Description:

This policy-driven, reliability-based project will replace National Grid's retired & unsupported Nucleus system with the Allegro Transaction and Risk Management System. Nucleus is the current US ETRM (Energy Trading, Transaction and Risk Management) platform. ETRM solutions help to manage the front, middle, and back office aspects of an energy trading entity. Functionality includes capturing and managing energy market transactions from execution to settlement and invoicing, and the managing and reporting of market risk and credit exposures. National Grid US purchases $8B per year in Energy for the jurisdictions it serves.

This sanction proposal is a D&I Re-sanction to:

- Acquire the funding necessary to complete the project goals.

1.3 Summary of Projects:

Project Number	Project Title	Estimate Amount ($)
INVP-2330	ETRM Replacement	$8.008M
	Total	$8.008M

1.4 Associated Projects:

Project Number	Project Title	Company	Estimate Amount ($)
		Total	$

1.5 Prior Sanctioning History (including relevant approved Strategies):

Date	Governance Body	Sanctioned Amount	Paper Title	Sanction Type
AUG 2010	USSC	$3.538M	ETRM Replacement	R&D Sanction
MAY 2011	USCCS	$3.572M	ETRM Replacement	R&D Re-sanction
JUL 2011	USSC	$6.086M	ETRM Replacement	D&I Sanction

Over / Under Expenditure Analysis

Summary Analysis (M's)	Capex	Opex	Removal	Total
Latest approval	$5.723	$0.363	$	$6.086
Re-Sanction Amount	$7.620	$0.388	$	$8.008
Change*	$1.897	$0.025	$	$1.922

Change = (Latest Approval – Re-Sanction Amount)

1.6 Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
APR / 2013	Project Closure

nationalgrid

US Sanction Paper

1.7 Category:

Category	Reference to Mandate, Policy, or NPV Assumptions
☐ Mandatory ☒ Policy-Driven ☐ Justified NPV	In response to the findings of the Management Audit of [VI-12] that stated: "NG's current risk management framework will not be adequate to handle procuring energy capacity and hedging instruments in future energy markets." The related recommendation [VI-3] included: "Define and restructure the risk management policies, procedures and functions to assure appropriate monitoring of risk factors as the transition and long-term supply procurement plans are implemented. The risk management tools should incorporate appropriate market monitoring to know when contingencies are needed."

1.8 Asset Management Risk Score

Asset Management Risk Score: 45

Primary Risk Score Driver: (Policy Driven Projects Only)

☒ Reliability ☐ Environment ☐ Health & Safety

1.9 Complexity Level: (if applicable)

☐ High Complexity ☐ Medium Complexity ☐ Low Complexity

Complexity Score: ______

1.10 Business Plan:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
INVP-2330, FY 09/10	☐ Yes ☒ No	☒ Over ☐ Under	$0.160M
INVP-2330, FY 10/11	☒ Yes ☐ No	☐ Over ☒ Under	$0.141M
INVP-2330, FY 11/12	☒ Yes ☐ No	☒ Over ☐ Under	$1.582M
INVP-2330, FY 12/13	☐ Yes ☒ No	☒ Over ☐ Under	$3.118M

1.11 If cost > approved Business Plan how will this be funded?

The following is how this re-sanctioning will be funded.

- The $2.896M CAPEX shortage will be funded via a substitution from $0.774M CAPEX from INVP2861 and a substitution of $2.122M CAPEX from INVP2864

1.12 Current Planning Horizon:

$'000s	Current planning horizon						
	Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6+	Total
Proposed Investment	160	2,891	1,839	3,118			8,008

1.13 Resources:

Resource Sourcing			
Engineering & Design Resources to be provided	☐ Internal	☒ Contractor	
Construction/Implementation Resources to be provided	☒ Internal	☒ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	☐ Red	☐ Amber	☒ Green
Availability of external resources to deliver project:	☐ Red	☐ Amber	☒ Green
Operational Impact			
Outage impact on network system:	☐ Red	☐ Amber	☒ Green
Procurement impact on network system:	☐ Red	☐ Amber	☒ Green

1.14 Key Issues (include mitigation of Red or Amber Resources):

1	If we don't complete the interface with USFP & Allegro then manual entry of Receivables and Payables will be required.
2	Difficulties in acquiring needed internal business resources. Mitigation recommendation will be to get essential internal business resources reassigned to the project 100% by the business, backfill as needed and commitment of additional hours by team during testing period.

1.15 Key Milestones:

Milestone	Target Date: (Month/Year)
R&D Sanction	AUG / 2010
Start R&D	SEP / 2010
Complete R&D	JUN / 2011
D&I Sanction	JUL / 2011
D&I Re-sanction	JUL / 2012
Implementation Release 1	AUG / 2012
Implementation Release 2	NOV / 2012
Implementation Release 3	DEC / 2012
Project Complete	FEB / 2013
Project Closure	APR / 2013

1.16 Climate Change:

Are financial incentives (e.g. carbon credits) available?		☐ Yes	☒ No
Contribution to National Grid's 2050 80% emissions reduction target:	☒ Neutral	☐ Positive	☐ Negative
Impact on adaptability of network for future climate change:	☒ Neutral	☐ Positive	☐ Negative

1.17 List References:

1	Last sanctioning Investment Proposal, from July 2011.

2 Decisions

The **Sanctioning Authority**, USSC / NGUSA Board, etc is invited to:

(a) APPROVE the investment of $8.008M, including a tolerance of +/- 10%.

(b) APPROVE the RTB Impact of -$236K (per annum) for 4 years.

(c) NOTE that Lorraine Lynch is the Project Sponsor.

(d) NOTE that Anantha Mantrala is the Project Manager and has the approved financial delegation to deliver the project.

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on 25 JUL 2012

Signature……………………………………………..Date………………

Lee S. Eckert
US Chief Financial Officer
Chairman, US Sanctioning Committee

3 Sanction Paper Detail

Title:	Nucleus ETRM Replacement	**Sanction Paper #:**	INVP 2330
Project #:		**Sanction Type:**	Re-sanction
Operating Company:	Allocated	**Date of Request:**	25 JUL 2012
Author:	Mayumi Okada / Joseph Kruczlnicki	**Sponsor:**	Lorraine Lynch, VP of Treasury
Utility Service:	IS - FSS&C		

3.1 Background

In December 2009, the Niagara Mohawk audit by the New York Public Service Commission indicated that National Grid's current risk management framework will not be adequate to handle procuring energy capacity and hedging instruments in future energy markets.

While not specifically mentioning the current US ETRM system, we believe that the Allegro system will enable National Grid to capture and monitor risks for a wide range of traditional and new energy products including, but not limited to, natural gas, power, capacity, renewable credits, emissions and others. Due to the flexibility and capabilities of the system, National Grid will have the ability to adapt to future market and regulatory changes quickly and monitor risk appropriately. With Allegro, National Grid will enter all transactions into one system which will provide a single source for confirmation, invoice verification, invoice generation, valuation and risk reporting. Because National Grid provides commodity procurement services across many state jurisdictions, it is important to keep each group of customer transactions separate and apart from one another. This system allows the company to prevent commingling of customer commodity costs across jurisdictions, while allowing for a common practice enterprise wide. The Allegro system also has the necessary security features that provide the ability to separate access by job functionality.

The Allegro transaction and risk management system will replace Nucleus (National Grid's existing transaction management system). National Grid was informed a few years ago that SunGard the company that owns Nucleus would no longer provide technical support of the product and at that time it embarked on finding its replacement. Both systems are databases that allow for a very efficient management of energy transactions from its execution to the invoicing. This system provides the necessary controls and industry best practices as recommended by the Committee of Chief Risk Officers (CCRO) and required by Sarbanes-Oxley regulations. In addition, the replacement of this system is currently identified in the Energy Procurement and Treasury Risk Registers (This item is classified as ID#3318).

In addition to the jurisdictional entity requirements, the ETRM system is utilized for the recording and accounting of energy transactions. Weakness in accounting for derivatives is one of the most frequent areas reported under Sarbanes-Oxley. Hence, the implementation of a rigorous process and controls to ensure the accuracy of the data further supports the ability to mitigate risk around recording of energy transactions and valuation of energy derivative transactions. A failure in controls could result in the incorrect disbursement of funds and incorrect accounting for transactions leading to the restatement of financial statements. Such failure could also lead to a material weakness being identified resulting in a significant financial burden to rectify.

To address the risks associated with the Nucleus system, a phased implementation approach has been adapted. The phased approach will reduce the risk associated with current system by transitioning all transactions currently performed in Nucleus to the new system in the early phases of implementation.

During the Business Process Confirmation activity, where the product is demonstrated process by process on an early delivery of converted data, a number of additional extensions to the core product have surfaced. Additionally, a number of enhancements to the core product which were thought to be needed have now been deemed as unnecessary as the core product delivers this as a standard core function.

Application Decommissioning

- Application will be in read only state for limited users In order to be able to accommodate future data requests from state regulators and/or FERC.
- Application will be online for 1 year after which an underlying database will be retained for minimum of 6 years.
- Nucleus will be in read-only state for 1 year.

3.2 Drivers

Below are the drivers for this project:

- Nucleus was implemented in 2003. We are still on the original version, R13. SunGard, the Nucleus vendor, is no longer providing updates or enhancements to R13. National Grid currently pays a support contract of $300k, which entitles National Grid to Sev 1 incidents only due to limited staff that can support Sev 2 and beyond incidents.
- Vendor uncertainty posed risk to the jurisdictional entities for which we procure commodity.
- Current system risks could result in our inability to: separate customer commodity costs across jurisdictions; adequately segregate job functions; accurately account for and record energy transactions; and accurately value energy derivative transactions. Such deficiencies could result in a material weakness being identified and therefore requiring a significant level of effort and cost to address.
- Recent level 1 failure (namely business critical) demonstrated that SunGard is very thin in being able to support this product line with technical experts to restore Nucleus to operating condition.
    - National Grid US purchases $8 billion/yr in Energy, so has a vested interest in managing this process efficiently, with a robust toolset in support of Rate Case filings.

The following table indicates the key variations that account for the difference between the original Sanction Amount $6.086M and the requested Re-Sanction amount $8.008M:

DETAIL ANALYSIS (M's)	OVER / UNDER EXPENDITURES?	AMOUNT
Latest Approval	>>>	$6.086M
Addition of 3rd party resources w/ETRM implementation experience	☑ OVER ☐ UNDER	$0.866M
Out of Scope Extensions	☑ OVER ☐ UNDER	$0.615M
Additional Business Labor	☑ OVER ☐ UNDER	$0.068M
Additional IS Labor	☑ OVER ☐ UNDER	$0.123M
Risk Margin (re-stated)	☑ OVER ☐ UNDER	$0.250M
	SUBTOTAL	$1.922M

3.3 Project Description

PLAN

- **Work plan**
  - Identify resources and availability
  - Identify detail tasks with accountable resource
  - Balance resources to create work plan
- **Resource plan**
  - Set expectations of time commitments of all participants
- **Communication plan**
  - Establish status reporting and change management policies and decision makers
- **Customer and Allegro verify that project plans match the Scope of Services**

TRANSLATE

- **Project Infrastructure.** Establish the project infrastructure
- **Data Source Definition.** Identify the source of data
- **Data Conversion.** Convert data from source to development environment.
- **Data Verification.** Verify the accuracy of converted data
- **Business Process Confirm.** Confirm processes with customer
- **Extension Definition.** Identify and define extensions:
  - **Data model.** New tables/columns, database views, triggers, stored procedures
  - **Visual model.** New views, panes, sets, icons
  - **Messaging.** Event-based alerts, notifications, and actions
  - **Connect.** Transformation of data between systems
  - **Reports.** External reports, generally developed with Crystal
  - **Web Services.** Existing WS invocation, new WS invocation, external assemblies
- **Translate Phase Approval.** Obtain phase approval
- **Confirmed required level of funding for implementation project, including resources, HW, and SW.**

3.4 Benefits Summary

Below is an overview of the benefits for this project:

- This project has no direct savings, aside from RTB savings noted above, at this time. However, the potential to utilize this solution for the UK will be explored at a later date and that could result in the retirement of two (2) bespoke systems which may translate into additional savings.

- A robust toolset in support of Rate Case filings, opposed to manual spreadsheets subject to error
- Robust credit module that will replace a regime that is currently completely spreadsheet based with significant manual input to run and maintain.
- Robust system that will improve our ability to estimate market and credit risk exposures thereby enabling more informed risk mitigation decisions related to exposures.
- Flexibility to adapt to changing regulatory requirements and increasing products (REC's, Carbon Credits, Metals, etc)
- Provide ability to capture and report on LNG transactions, allowing full transparency of LNG purchases from execution to invoicing.
- The Allegro system provides flexibility to provide enhancements over the current process and will automate wherever possible.
- Add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front, middle and back offices, auditors, creditors and regulators.

3.5 Business Issues

This project will mitigate the risks associated with staying on Nucleus R13:

- Impact to National Grid's reputation (investor and bondholder loss of confidence).
- Loss of trust and confidence by our jurisdiction regulators and LIPA in the event of an outside audit that highlights a mission critical system with limited support.
- Auditors: weakness in accounting for derivatives is one of the most frequent areas reported under Sarbanes-Oxley. Hence, the level of rigor around processes and controls to ensure data integrity further supports the ability to mitigate risk and possibility of receiving a qualified opinion regarding a marginally supported system.
- Better efficiency gained automating the segregate and separate commodity costs and procurement transactions by jurisdiction as well any attendant risk of error from manual methods.
- By proactively positioning the company for the changing business and regulatory requirements (REC's Carbon, Metals, Green tags, etc).
- Current system is incapable of responding to support any new or expanded SOX reporting requirements or reporting requirements that could assist our UK financial closing
- Based on recent events, SunGard's long term plans may not include remaining in the Energy Sector. A new owner may find supporting Nucleus unprofitable, potentially leaving us with an unsupported Risk Management system

- New system implementation can take up to 18 months – we are likely not to have that much notice in the event that SunGard cannot provide adequate levels of support
- An extended system outage of a limited supported technology which could result in FERC liabilities and fines (Legal advisor opinion)

A noteworthy issue is the:

- Impact to National Grid's reputation (investor and bondholder loss of confidence).

3.6 Options Analysis

Recommended Option: Complete Allegro implementation

Rationale:

- In addition to risk mitigation, new system will add new scope and increase efficiency in ability to monitor, manage and report risk, in support of the front and back offices, auditors, creditors and regulators.
- Allow for utilization of a single system to manage transactions and valuations in order to mitigate the risks of manual.

Alternative 1: Continue paying SunGard $300k annually for level 1 support and hire a third party to maintain level 2 and 3 issues.

Rejected Rationale:

- Not an option. Would violate the SunGard Contract.

Alternative 2: Stay on Nucleus R13, purchase the source code and get a 3rd party vendor to support it.

Rejected Rationale:

Approximate Cost of $1.1m one time and $150k annual. (Additional analysis would be needed to confirm costs).

- $1.1m includes $600k to purchase SW and $500k to engage 3rd party (Adapt2) to modify SW to address functional gaps
- $150k RTB for annual maintenance. Current Nucleus maintenance cost is $300k, will be reduced to approximately $250k based on retired modules
- Option undesirable as the platform is built on outdated technologies, is complex and inflexible to changing business needs
- Would be an interim short term solution – only 3-5 years.
- Adapt2 is a small group of former SunGard programmers that have started a consulting firm. There is a risk that Adapt2 may not be able to deliver a long term project due to financial and resource constraints.

- Will not address items in the Treasury Risk Register (ID#3318), due to uncertainty of Adapt2s future

Alternative 3: Do Nothing

Rejected Rationale:

- Current Nucleus R13 version is at risk of a system failure resulting in a significant financial impact
- Will not address items in the Treasury Risk Register This item is classified as ID#3318

3.7 Safety, Environmental and Project Planning Issues

Not applicable.

3.8 Execution Risk Appraisal

Number	Status (Active, Dormant, Retired)	Cat	Detailed Description of Risk / Opportunity	Cause/Trigger	Probability	Impact		Score		Strategy	Risk Owner
						Cost	Schedule	Cost	Schedule		
1	Active		USFP Interfaces	I/F not complete in time	4	1	1	4	4	Mitigate	Business
2	Active		Availability of internal business resources	Internal business resources are still performing day to day funcitons	2	2	2	4	4	Accept	Business

3.9 Permitting

Permit Name	Probability Required (Certain/ Likely/ Unlikely)	Duration	Status (Complete/ In Progress Not Applied For)	Estimated Completion Date

3.10 Investment Recovery

3.10.1 Investment Recovery and Regulatory Implications

This solution enables fulfilment of our regulatory obligation to procure and deliver energy to our customers. The Nucleus system will enable us to continue to manage energy procurement costs in a cost effective and reliable manner.

3.10.2 Customer Impact

Because National Grid provides commodity procurement services across many state jurisdictions, it is important to keep each group of customer transactions separate and apart from one another. This system allows the company to prevent commingling of customer commodity costs across jurisdictions, while allowing for a common practice enterprise wide. The Allegro system also has the necessary security features that provide the ability to separate access by job functionality.

3.10.3 CIAC / Reimbursement

	CIAC/Reimbursement							
$M	**Prior YR'S**	**Yr 1 12/13**	**Yr 2 13/14**	**Yr 3 14/15**	**Yr 4 15/16**	**Yr 5 16/17**	**Yr 6 17/18**	***Total***
CIAC / Reimbursement								

3.11 Financial Impact to National Grid

3.11.1 Cost Summary Table

				Current Planning Horizon								
Project #	Project Description	Proj Est level	$M	Prior YR Spending	YR 1 09/10	YR 2 10/11	YR 3 11/12	YR 4 12/13	YR 5 13/14	YR 6 14/15	YR7+	Total
Project #	Description		Capex			2.891	1.832	2.667				7.390
INVP 2330	Project		Opex		0.160	0.000	0.007	0.201				0.368
			Removal									0.000
			Total	0.000	0.160	2.891	1.839	2.868	0.000	0.000	0.000	7.758
Project #	Description											
INVP 2330	Risk Margin		Capex					0.230				0.230
			Opex					0.020				0.020
			Removal									0.000
			Total	0.000	0.000	0.000	0.000	0.250	0.000	0.000	0.000	0.250
Total Proposed Sanction												
			Capex	0.000	0.000	2.891	1.832	2.897	0.000	0.000	0.000	7.620
			Opex	0.000	0.160	0.000	0.007	0.221	0.000	0.000	0.000	0.388
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.160	2.891	1.839	3.118	0.000	0.000	0.000	8.008
				$0.000	$0.160	$2.891	$1.839	$3.118	$0.000	$0.000	$0.000	$8.008

3.11.2 Project Budget Summary Table

$'000s		Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Yr 6 +	Total
Project Cost	Opex	160		7	221			388
	Capex		2,891	1,832	2,897			7,620
IS Investment Plan	Opex	160	168	35	391			754
	Capex		2,891	2,832				5,723
Variance to plan	Opex		168	28	170			366
	Capex			1,000	(2,897)			(1,897)

3.11.3 Cost Assumptions

3.11.4 Net Present Value / Cost Benefit Analysis

3.11.5 Additional Impacts

3.12 Statements of Support

3.12.1 Supporters

Role	Name	Responsibilities
IS Business Relationship Management	Matthew Guarini	Endorses the project aligns with jurisdictional objectives
IS Finance	Duncan Brown	Endorses the project aligns with jurisdictional objectives

3.12.2 Reviewers

Reviewer List	Name
Finance	Duncan Brown
Regulatory	Katsh, Gideon
Jurisdictional Delegates	Grimsley, Jennifer L. (New England – Electric)
Jurisdictional Delegates	Chieco, Allen C. (New York – Electric)

4 Appendices

4.1 Project Cost

4.1.1 Project Cost Breakdown -

The entire TCO Log is available upon request.

Project Cost Breakdown		
Cost Category	**Company Name ($ Amount)**	**Description of Cost Category**
Labor	($1.364M)	Labor, including Internal Overhead
Materials	($6.644M)	Software Licenses, H/W, Service Contracts
Risk Margin	($0.250M)	OPEX/CAPEX Risk Margin
Total:	$8.008M	

BILL POOL PERCENT ALLOCATION: The costs for this project will be allocated in the following manner:

- 65% Gas G5200 – all gas allocation code
- 28% Electric G1060 – all electric distribution code
- 7% LIPA

The costs for this project will be allocated to US Gas, US Electric and LIPA. The method for the allocated charge will be based on actual transaction history therefore resulting in an allocation to jurisdictional entities based on usage. This method, reviewed by LIPA Finance, Regulation and Pricing and Accounting Services, is consistent with the recent Liberty audit recommendation to charge costs to jurisdictional entities when able. This methodology will be modified if necessary because of the audit finding.

RTB COSTS: The project will decrease the RTB costs over time as shown in detail below:

RTB costs $'000s	Yr 1 09/10	Yr 2 10/11	Yr 3 11/12	Yr 4 12/13	Yr 5 13/14	Total
Current Annual RTB costs	780	780	780	780	780	3,900
New Annual RTB costs	780	780	780	544	544	3,428
Impact on RTB costs (new minus existing)				**(236)**	**(236)**	**(472)**
Variance to Plan				**(236)**	**(236)**	**(472)**

4.2 Project Resources

4.3 NPV Summary (if applicable)

4.4 Customer Outreach Plan (if applicable)

Division 22-6

Request:

Please refer to the Company's response to DIV 9-2, Attachment DIV 9-2-1, INVP 4172 – Cross Company, pages 17-31, and respond to the following:

a. Refer to Section 1.7 Category on page 18, and please respond to the following:

   i. For the three categories shown, what are the internal capital budget definitions that define each category and prompt the selection of one category over the others?

b. Refer to Section 1.8 Asset Management Risk Score on page 18, and please respond the following:

   i. Explain the risk score scale and determination process used by the Company to risk assets or projects.

   ii. Explain the Company personnel who are involved in determining the scores.

   iii. Does the Company complete a risk score for every project or asset? If not, please explain what types of projects or assets are given a risk score.

   iv. What does an asset management risk score of 37 mean?

c. Refer to Section 1.9 Complexity Level on page 19, and please respond the following:

   i. Explain the complexity level scale and determination process used by the Company to assign complexity to assets or projects.

   ii. Explain the Company personnel who are involved in determining the complexity score.

   iii. Does the Company assign a complexity level for every project or asset? If not, please explain what types of projects or assets are assigned a complexity level.

   iv. What does a complexity score of 19 mean?

d. Refer to Section 1.12, "If cost > approved Business Plan how will this be funded?", on page 19, and please respond the following:

   i. Define portfolio.

   ii. Explain how funds can be re-allocated within a portfolio and how this re-allocation is specifically impacted due to Rhode Island budgetary, statutory, and regulatory requirements.

   iii. Explain and provide documents that detail the Rhode Island jurisdictional budgetary, statutory, and regulatory requirements.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty

e. Refer to Section 3.8 Execution Risk Appraisal on page 26, and please respond the following:

   i. Define probability, impact (cost and schedule), and score (cost and schedule).

   ii. Explain the risk appraisal score scale and determination process used by the Company to assign a score for each probability, impact (cost and schedule), and score (cost and schedule).

   iii. Explain if there is a combined score that indicates the overall risk for each project. If yes, then how is it determined?

   iv. Explain the Company personnel who are involved in determining the risk appraisal.

   v. Does the Company complete a risk appraisal for every project or asset? If not, please explain what types of projects or assets are risk appraised.

   vi. What does the red coloring of Score – Schedule in Number 2 indicate?

f. Refer to Section 3.11.3 Cost Assumptions on page 27, and please respond the following:

   i. Explain and provide documentation that details the Company's standard IS estimating methodology.

   ii. Has the Company's standard IS estimating methodology changed since the last base rate case? If so, please provide additional documentation that details the previous or most current standard IS estimating methodology.

g. Refer to Section 3.11.4 Net Present Value / Cost Benefit Analysis on page 27, and please respond the following:

   i. Explain why this is not an NPV project.

   ii. What types of projects are considered NPV projects?

   iii. Explain the cost-benefit analysis process the Company would use to determine an NPV.

   iv. Provide documentation that details the cost-benefit analysis process.

   v. Explain the Company personnel who are involved in determining the NPV of a project.

h. Refer to Section 4.2.1 Project Cost Breakdown on page 30, and please respond to the following:

   i. Explain why the Company does not provide this itemized level of project cost breakdown on projects that require "Resanction Request" forms.

   ii. Define the cost items associated with each of the following cost categories and sub-categories: All other personnel, Risk Margin, and Other.

i. Refer to Section 4.2.3 IS Ongoing Operational Costs (RTB) on page 31, and please explain how "Run the Business" costs are treated for accounting purposes and where are they in the revenue requirement for the Rate Year and the Data Years 1 and 2.

Response:

a. The investment categories define the type of work being undertaken and are subsequently used to provide an overall risk score for the project. The definition of each category, as defined in US Sanction Paper instructions are:

- Mandatory: There is an explicit external obligation to do this specific project immediately. There is no discretion on the need for the expenditure with statutory, regulatory, or damage failure type work.

- Policy-driven: The driver for these projects will be either a general external guideline, including statutory and regulatory obligations, or an internal policy. In either situation, Information Services (IS) will usually have choices regarding how and when to make such investments (i.e. there is some discretion regarding scope and timing for work involving system capacity and performance, asset condition, and non-infrastructure-related work).

  Justified NPV: Projects undertaken at National Grid's discretion to deliver positive financial returns/benefits for the benefit of the US operations. These projects are not driven by external obligations or internal policies and do not mitigate any network risk.

b. i. National Grid uses a standard risk scoring methodology that is based on a scale of 0-49. Please see Attachment DIV 22-6-1 for the methodology.

- Mandatory: By default, mandatory projects have an assigned risk score of 49 because there is an explicit external obligation that must often be addressed immediately.

- Policy-driven: The risk scoring methodology is used to calculate the risk score for policy driven projects. Pursuant to the methodology, each policy driven investment is scored across three specific dimensions—safety, reliability, and environment—with each receiving a risk score based on the potential impact and the likelihood of occurrence. The maximum score of the three dimensions is considered the asset management risk score for the project.

- Justified NPV: Value-driven projects do not have a risk score – risk score is left blank.

ii. Senior personnel in the IS Business Relationship Management (BRM) and IS Project Management teams work with the business project sponsor to review and assess the project risk and agree on the overall score.

iii. Mandatory projects receive a score of 49 by default because of the explicit external obligations to undertake the project and NPV are not scored; therefore, it is primarily the investments defined as policy driven that are scored.

iv. Utilizing the risk scoring methodology, National Grid determined that reliability was the primary risk score driver on the Cross Company project (INVP 4172). The risk score of 37 was based on an impact level of 4 and likelihood of occurrence level of 7, which are defined on pages 13 and 15 of the methodology.

c. i. Please see Attachment DIV 22-6-2 for the Complexity Score guidelines. The Complexity level score provides a means to consistently identify the size and scale, and intricacies of the solution being implemented. The score provides the sanction paper reviewers and approvers with a method to compare and contrast differing investments and potentially recommend changes to reduce the overall project complexity level.

ii. Senior personnel in the IS BRM and Project Management teams perform the complexity assessment, which is reviewed and approved as part of the sanction process.

iii. All projects preparing for sanction require a complexity score, which is reviewed and determined based on the project complexity scoring guidelines.

iv. The overall score of 19 indicates a project of medium complexity as shown on the excerpt below from the guidelines. The score assists in the determination of the level of oversight required around the delivery of the project.

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Project Complexity Implications

Project Complexity Score	Project Sponsor	Steering Committee	PM Certification	Quarterly Checkpoint	Project Board
>= 25	>= VP	Required Monthly	Required	Required	Required
>= 19, < 25	>=VP	Required Quarterly	Required	Not Required	Required
<19	>= Director	Not Required	Not Required	Not Required	Required

d. i. The "Portfolio" refers to the group of projects in the annual IS Investment Plan.

ii. Re-allocation of funds for these National Grid USA Service Company, Inc. projects are reviewed by a committee and documented through the Budget Exception process. After the IS Investment

Plan is set for the year, any projects that represent emerging demand must be evaluated and decisions made on whether to fund the project via substitution from a lower priority project or the addition of funding to the Plan. In the event there was a significant impact to Rhode Island, the changes would be reviewed and approved by Rhode Island Jurisdictional leadership prior to adoption.

iii. As part of the process to build the annual IS Investment Plan, all potential investments are assessed from a business function, jurisdictional, and IS perspective. To the extent that a project was required to comply with a regulatory mandate from Rhode Island, it would be prioritized within the overall Plan.

e. i./ii. The Execution Risk Appraisal identifies those risks that could potentially impact the "delivery" of a project from a cost and schedule perspective. A scale of 1-5 (very low, low, medium, high, and very high) is used to score the probability of the risk occurrence and the impact to the costs and schedule if the risk materialized. A total "score" for both cost and schedule is then calculated by multiplying the probability by each of the impacts.

iii. Please see the project Risk Score, referenced in the response to question b. above, and section 1.8 Asset Risk Management Risk Score of the Investment Proposal.

iv. The IS BRM and Project Management teams work with the business project sponsor to review and assess the project risk and agree on the subsequent score.

v. All projects preparing for sanction require a review of execution risks; however, not all projects may identify associated risks.

vi. The color is a visual differentiator for ranges of scores as depicted in the chart below:

Score	
High	15-25
Medium	5-14
Low	1-4

f. i. IS Project Mangers utilize the Financial Workbook/Total Cost of Ownership (TCO) Log to capture project cost estimates. The estimates are prepared under the guidance of a senior Project Manager or Business Relationship Manager, who have experience in delivering projects of similar size, scale and complexity.

ii. No, the IS estimating methodology has not materially changed since the last general rate case (Docket No. 4323).

g. i. The primary reasons that the Cross Company project was undertaken were to upgrade an unsupported platform (Windows XP), replacement of a legacy interface, and other similar work; therefore, the project is considered policy driven under the US Sanction Paper and Investment Planning guidelines.

ii. NPV projects are projects undertaken at National Grid's discretion to deliver positive financial returns/benefits for the benefit of the US operation. These are not driven by external obligations or internal policies and not mitigating any network risk.

iii. A detailed assessment and calculation workbook supports all NPV projects. The summary of project financials generates a ten year NPV, IRR, and simple payback calculation.

iv. Please see Attachment DIV 22-6-3 for the NPV workbook.

v. The IS BRM and Project Management teams work closely with the IS Finance team to complete the NPV analysis.

h. i. IS utilizes the standard National Grid template for projects that require "Re-Sanction". The intent of the Re-sanction is to focus on those variables that are causing a cost or schedule change. Since the itemized detail noted in Section 4.2.1 were previously reviewed and approved, there was no need to re-include the information in the Re-Sanction document.

ii. The cost items included in the TCO Log are as follows:

- All Other Personnel: These are external vendor costs for vendors other than the two Solution Delivery Centers partners, IBM and Wipro. The $2.085 million in costs were for Ernst &Young – Change Management services ($1.879 million) and Computer Sciences Corporation (CSC) – Datacenter services ($.206 million).

- Risk Margin: This is a contingency amount to account for project uncertainties and risk which was set at four percent ($.460 million) for this project.

- Other: This category captures miscellaneous expenses of Travel ($.083 killion), AFUDC ($.598 million), and Vendor Management Fees shared across projects ($.326 million).

j. The IS On-going Operational Costs, known as run the business (RTB) costs, are treated as an expense from an accounting standpoint and commence once the project is complete and moved into service. RTB costs are shown in the revenue requirement as operating expenses in the line items that reflect the nature of the expense, such as labor, benefits, or other operating and maintenance expense. The RTB costs and project operating expenses forecast for the rate year were comparable to the test year; therefore, the Company did not seek any incremental RTB costs within the rate proceeding. The Company previously provided the analysis in part d. of its response to Division 3-28, which is provided as Attachment DIV 22-6-4. New project-related RTB costs are included in the Investment Plan line on page 1 of Attachment DIV 3-28-1. The supporting project details for the Investment Plan amount are shown on Attachment DIV 3-28-2 within the same response.

Investment Planning Review

Risk Scoring Guide

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Final V2.0 June 2008

Risk scoring methodology

Contents

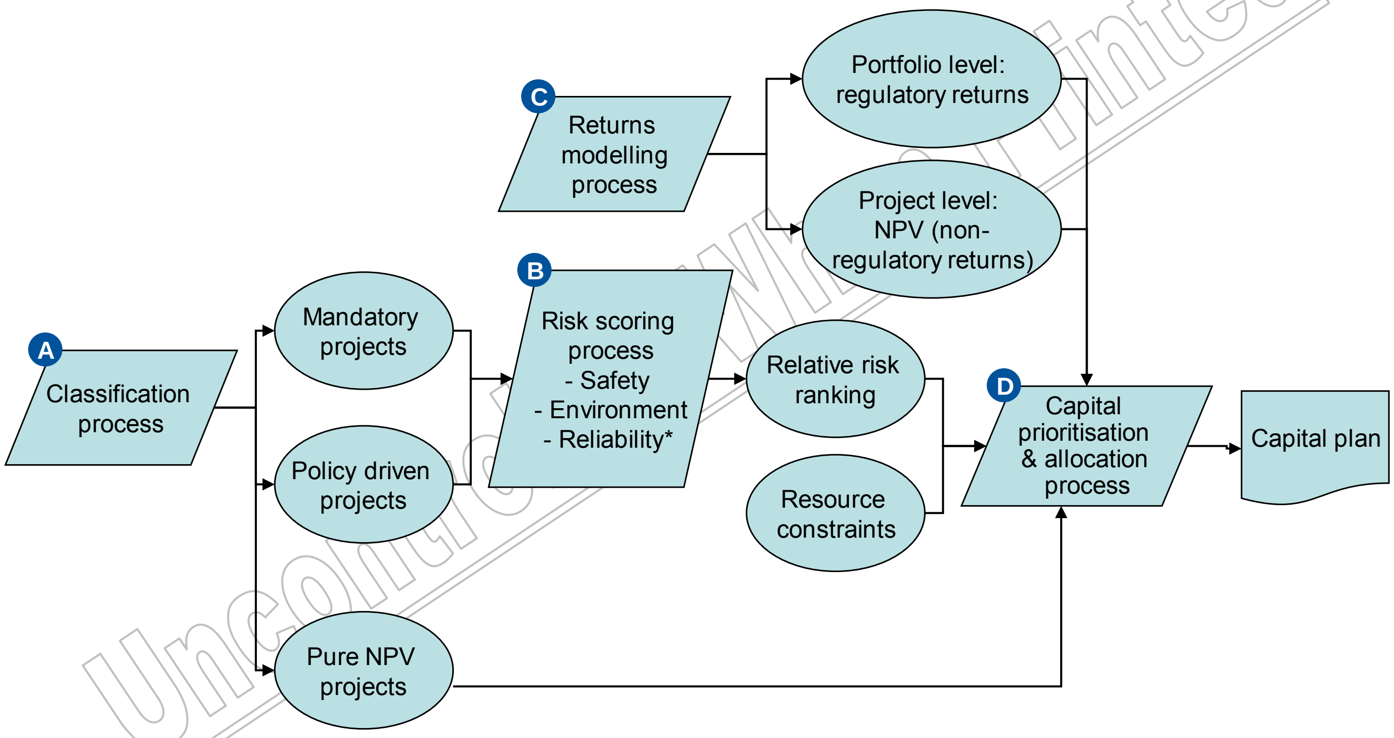
- **What is the end-to-end risk scoring process and why do we need it?**

- Risk scoring methodology process steps
  – How does Project Classification work?
  – How does Risk Scoring work?
  – How does Prioritisation work?

Risk scoring methodology – What is it and why do we need it?

Purpose	• Create a **single risk score** which can be used to compare the safety, reliability and environmental risks addressed in the capital plan for each of our businesses
How will it be used	• Provide **transparency** within the Lines of Business and to the Executive on the amount of risk being mitigated in each business relative to the capital plan • **Link the return** on investment to the risk eliminated by investing into the business
Relevance	• Previously **no common method** to assess risk across the business • Opportunity for you to **shape**, going forward, the standardised way this should be done • Opportunity to **inform regulatory dialogue** and debate
What this concept is not	• Is not a technical measure of **residual** system risk, i.e. the risk remaining to be mitigated once the proposed projects have been completed

Risk scoring and capital prioritisation process (1/2)



Final V2.0 June 2008

* Includes avoided penalties and incentives relating to reliability

Risk scoring and capital prioritisation process (2/2)

A Classification process

- Categorise projects into
  - Mandatory
  - Policy driven
  - Pure NPV
- Where necessary, bundle projects into programmes, for ease of risk scoring and sanctioning

B Risk scoring process

Mandatory
- Default to highest risk score

Policy driven
- Compute risk score on following criteria
  - Safety
  - Environment
  - Reliability (including avoided penalties)

C Returns modelling process

Mandatory and Policy driven
- Calculate portfolio returns
- Calculate incremental returns for projects with opex savings

Pure NPV
- Compute NPV

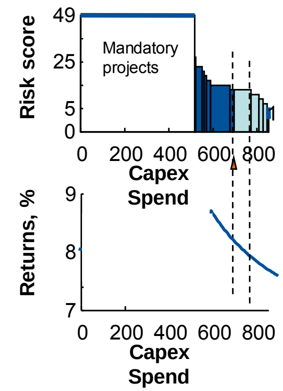
D Capital prioritisation & allocation process

Prioritisation

- Unconstrained prioritisation based on:
  - Risk score
- Constrained prioritisation based on
  - Operational and timing constraints
  - Incremental financial benefits
- Strong governance for projects the LOB wants to justify on:
  - Incremental financial benefits
  - 'Strategic' rationale

Risk-return trade-off

Mandatory and policy driven



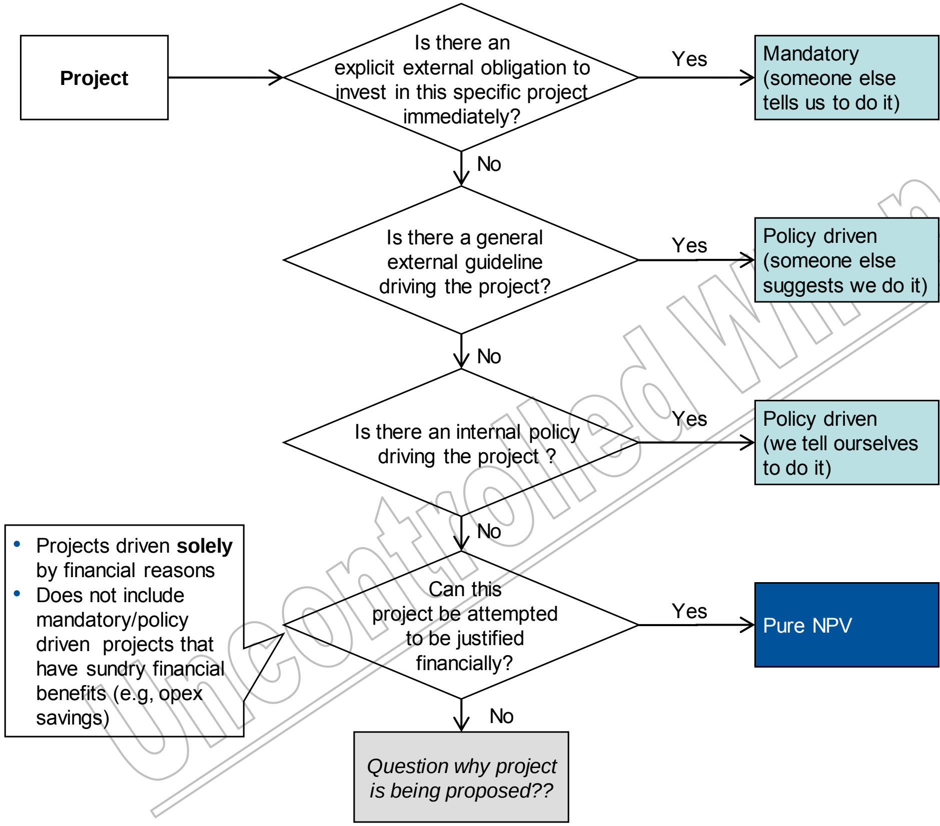
- Trade-off level of investment in terms of risk and return

Pure NPV
- Do all positive NPV projects

Risk scoring methodology

Contents

A Projects will be classified as mandatory, policy driven and pure NPV, using the following decision tree



Definitions

- Projects done to fulfil an explicit, deterministic statutory/regulatory obligation, where there is absolutely no discretion on timing or options and there is an immediate and palpable risk of regulatory or legal breach
- Projects undertaken to fulfil a statutory/regulatory obligation, where there is some discretion* on timing or options
- Projects necessary to meet internal policies**
- Projects undertaken to deliver financial benefits at complete discretion of NG, not driven by external or internal policies
- Residual projects that should be questioned/ policies to be reviewed

* Decision on project elements (i.e., timing, which option, etc.) reflect corporate risk appetite

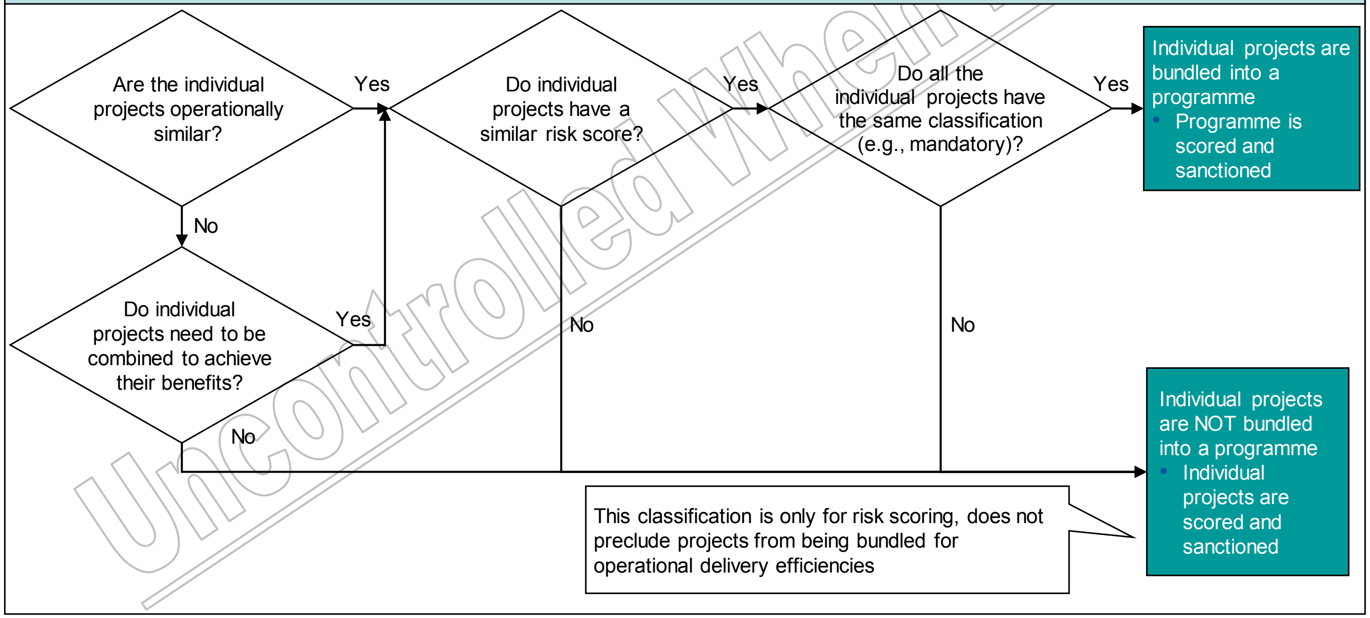
** Internal policies reflect corporate risk appetite

A A portfolio of projects will be bundled into a programme for risk scoring and sanctioning

Definition of programme

- A portfolio of individual projects, that are can be scored and sanctioned together, which are:
  - Either operationally similar or required to be combined in order to achieve benefits
  - Have similar risk scores and same classification (mandatory, policy driven, etc.)

Decision tree for bundling individual projects into a programme



A How project classification will be done in practice

Goals

- To ensure consistent classification by all LOBs into mandatory, policy-driven, pure NPV
- To provide guidance on interpretation of above definitions
- To ensure sufficient transparency on bundling of projects into programmes
- To update definitions and checklists if required

	How will governance work?	What will this entail?
Guidance notes	• Customised checklist will be provided to LOBs to assist them in classifying projects into mandatory, policy-driven, etc. as well as to bundle projects into programmes	• A checklist will be developed (in conjunction with LOBs) to classify projects
Guidance meetings	• Investment Planning project team/Investment Decision Support* (IDS) team member to interact periodically with LOB investment planners on risk scoring	• Project team/IDS member to review classification of projects to ensure consistency and provide guidance

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* IDS = Investment Decision Support: explained in detail later in document

Risk scoring methodology

Contents

- What is the end-to-end risk scoring process and why do we need it?
- Risk scoring methodology process steps
  - How does Project Classification work?
  - **How does Risk Scoring work?**
  - How does Prioritisation work?

B Risk scoring process will use following principles

1 Determine Impact and likelihood levels

Step 1 – Score project on **impact** in each of the following criteria

Impact	**Safety**	**Reliability**	**Envi-ronment**
Very low	1	1	1
Low	2	2	2
Moderately low	3	3	
Moderate	4	4	
Moderately high	5	5	
High	6	6	
Very high	7	7	

Any impact of penalties for reliability/ health and environment to be considered when scoring project on impact

Step 2 – Score project on **likelihood** of occurrence in each of the following criteria

Likelihood	**Safety**	**Reliability**	**Envi-ronment**
Very low	1	1	1
Low	2	2	2
Moderately low	3	3	3
Moderate	4	4	4
Moderately high	5	5	5
High	6	6	6
Very high	7	7	7

2 Obtain blended risk score* for each criterion

Safety score

Impact \ Likelihood	1	2	3	4	5	6	7
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13

Reliability score*

Impact \ Likelihood	1	2	3	4	5	6	7
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13

Scores are ranked based on the expected monetary value of each outcome

Environmental score*

Impact \ Likelihood	1	2	3	4	5	6	7
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13

3 Obtain overall risk score

- Overall score is maximum of
  - Safety (7)
  - Environment (11)
  - Reliability (28)
- Maximum score method was selected because:
  - Impact levels are assessed on an exponential scale, hence the highest score outweighs other lower scores (e.g.,Level 7 has a monetary impact > £20Mn and Level 1 has a a monetary impact of <£5k)
  - Aggregating different scores into a simple score is mathematically inaccurate
  - Maximum score ensures that projects with a high score on a single criteria are not ignored
  - Most projects are expected to have a single driver that dominates

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* Scores are grouped and colour coded for ease of viewing (40 and above - red, 16-39 - yellow and 15 and below - green)

B1 Health & Safety and Environmental impact descriptions…

Score	Financial Impact	Health and Safety	Environment
1	• < £5k • < $10k	• Minor injury requiring first aid with a quick and complete recovery (£100-200/$200-400) • Minor illness with up to one –week absence. No permanent health consequences (£500/$1000)	• Non-significant Environmental Incident without agency oversight (eg minor spillage (eg < 5 litres) that does not enter drain or watercourse, small quantities of hazardous waste left on site, temporary impact to the environment) (£1k- 2k/$2k-4k) or a minor regulatory compliance issue.
2	• £5k-50k • $10k-100k	• Illness with over one week absence but no permanent health consequences (£5k/$10k)	• Significant Environmental Incident usually without agency oversight (eg spillage that does not enter drain or watercourse, fly-tipping on National Grid land or site, a release of methane gas under 200 tonnes) (£5k-50k/$10k-100k) or regulatory non-compliance issues which may result in minimal fines.
3	• £50k-250k • $100k-500k	• Injury to member of public requiring medical treatment but no permanent consequences (£50k/$100k)	• Significant Environmental Incident with agency oversight (eg minor silt run-off to reservoir, discolouration noted around edges, mitigation measures required and some clean up required, a release of more than 200kg of sulphur hexafluoride gas) (£50k-250k/$100k-500k) or a non-compliance issue which results in significant fines and/or actions taken by regulatory authorities (eg permit limits for air emissions exceeded).
4	• £250k-1m • $500k-2m	• Permanently incapacitating injury or illness to employees (moderate to severe pain for 1 – 4 weeks with possible recurrence of pain for certain activities and some permanent restrictions to leisure or work) (£500k/$1000k) • Injury to member of public requiring extended medical treatment but no permanent consequences	• Significant Environmental Incident with agency oversight (eg uncontained release of liquid (eg silty water or bentonite drilling fluid, petroleum) to a drain or watercourse that has the potential for enforcement action and which may cause fish or aquatic plants to die) (£250k-1m/$500k-2m) non-compliance issue which results in significant fines and/or actions taken by regulatory authorities (eg permit limits for air emissions exceeded, noise abatement order issued).
5	• £1m-5m • $2m-10m	• Permanent incapacitating injury to a member of public or fatality of an employee (£4.5m/$9m)	• Significant Environmental Incident (eg several full drums of oil spill on to ground and significant quantity enters high quality watercourse leading to >500 fish killed and damage to river bed requiring remediation and leading to prosecution, damage to environmentally sensitive sites, listed buildings or damage to a Site of Special Scientific Interest) (£1m-5m/$2m-10m) or non-compliance issue which results in significant fines and actions taken by regulatory authorities.
6	• £5m-20m • $10m-40m	• Fatality of a single member of public/multiple fatalities of employees (<4 people) (£20m/$40m)	• Catastrophic Environmental Incident (eg contamination of a ground water source leading to prosecution, enforced clean-up and provision of alternative water supply) (£5m-20m/$10m–40m) or a non-compliance issue that results in fines and actions taken by regulatory authorities and presents a risk of affecting future business operations.
7	• £20m + • $40m +	• Multiple public fatalities or multiple fatality of 5 or more employees (£50 m/$100m)	

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B1 Reliability impact descriptions (1 of 2)…

Score	Financial Impact	Reliability – ETx	Reliability – GTx	Reliability – GDx	Reliability – EDx
1	• < £5k • < $10k				
2	• £5k-50k • $10k-100k	• Disruption to outage & maintenance/ construction programmes (£50k/$100k)	• Failure resulting in minor disruption to network – replan maintance (e.g. auxiliary buildings or access roadways) (£50k/$100k)	• Local failure resulting in minor disruption to network. Loss of up to 50 customers. • Minor maintenance required to replace/repair	• Loss to less than 500 customers • Less than <50K CMI • Loss of 0.5 (13KV) feeder • Loading: 95-100% • Voltage (P.U.): 0.93-0.95
3	• £50k-250k • $100k-500k	• Major disruption to outage & maintenance/ construction programmes (£250k/$500k)	• Minor disruption to network– replan commissioning/ 3rd party loss (eg to replace passing valve) (£250k/$500k) • Loss of a standby compressor	• Failure resulting in low pressure and minor loss of customers (< 500). • Local action is required to be taken to restore system stability	• Loss to 500-5,000 customers • 50K to 500K CMI • Loss of 0.5-1 (13KV) feeder • Loading: 100-105% • Voltage (P.U.): 0.92-0.93
4	• £250k-1m • $500k-2m	• Significant increase in transmission constraint costs (£500k/$1m) • Loss of supply upto 50 MWs	• Loss of off-take to single industrial load or loss of single compressor unit resulting in minimal buy-back	• Failure resulting in low pressure and loss of one large and/or local loss residential customers (approx 3k). • System stability restored in < 1 week	• Loss to 5,000-10,000 customers • 500K to 1M CMI • Loss of 1-3 (13 KV) feeder • Loading: 105-110% • Voltage (P.U.): 0.90-0.92
5	• £1m-5m • $2m-10m	• Significant increase in transmission constraint costs (£2.5m/$5m) • Loss of supply between 50 - 250MWs	• Major disruption to the National Transmission System requiring support from local distribution zones (such as interruptible load) and LNG storage support	• Failure resulting in low pressure and loss of more than one large and/or local loss of residential customers (approx. 10k). • System stability restored in <2 weeks with in-house regional resources • Emergency Plan is implemented	• Loss to 10,000-25,000 customers • 1M to 5M CMI • Loss of 3-6 (13KV) feeder • Loading: 110-115% • Voltage (P.U.): 0.87-0.90
6	• £5m-20m • $10m-40m	• Significant increase in transmission constraint costs (£7.5m/$15m) • Loss of supply between 250 – 1,000MWs	• Insufficient base-line capacity results in intermittent locational buy-back	• Failure resulting in significant loss of residential and commercial customers (greater than 30k). • The use of external resources is required to restore system stability • Recovery is completed in > 2 week and < 1 month. • Emergency plan is implemented	• Loss to 25,000-50,000 customers • 5M to 20M CMI • Loss of 6-10 (13KV) feeder • Loading: 115-120% • Voltage (P.U.): 0.85-0.87
7	• £20m + • $40m +	• Loss of supply greater than 1,000 MWs (£20m+/$40m+)	• Insufficient base-line capacity results in continuous locational buy-back (upto £30m/60m) • Loss of a single off-take, feeder, multi-junction or compressor station resulting in buy-back or disruption to the National Transmission System network & one or more DN – 5-20% firm load (£200m/$400m)	• Failure causing major disruption to the GDx network and widespread loss of customers (greater than 100k). • Major recovery action is required to be taken to restore system stability with the use of external resources • Recovery time >1 month • Emergency plan is implemented	• Loss to 50,000 customers • More than 20M CMI • Loss of more than 10 (13KV) feeders • Loading: 120% • Voltage (P.U.): less than 0.85

Assumed exchange rate: £1=$2

B1 Impact Matrix – Reliability (2 of 2)

Score	Financial Impact	Reliability – Global IS and shared services	Reliability – LNG
1	• < £5K • < $10k	• -	• -
2	• £5K-50K • $10K-100K	• Local failure of infrastructure or business systems affecting <100 employees for a day	• Localised failure of control equipment, instrumentation or civils/structural plant (e.g. minor auxiliary equipment failure requiring isolation) but with no impact on plant import or export capability. • Reduction in plant security and/or reduction to personnel or vehicle access with no impact to import or export capability
3	• £50K-250K • $100K-500K	• Local failure of infrastructure or business system affecting <100 employees for <1 week	• Plant or auxiliary equipment failure leading to limited (<3 days) loss of liquefaction capability • Loss of non critical building or structure which has minor (< 3 days) impact on export capability
4	• £250K-1Mn • $500K-2Mn	• Failure of infrastructure or business system at a major business location (>300 employees) for a day. Potential impact into more critical IS systems	• Failure of significant plant, equipment, buildings or structure (e.g. moderate bunding/dyke) that results loss of liquefaction capability for between 4 and 14 days • As above but leading to loss of site export capability for up to 1 day at time of winter peak
5	• £1Mn-5Mn • $2Mn-10Mn	• Enterprise wide or multiple major location failure of infrastructure or business systems for <24 hours. More critical IS systems impacted	• Major failure of plant, equipment or structure (e.g. major bunding/dyke repairs) that leads to loss of liquefaction capability for between 15 and 50 days • As above but leading to loss of site export capability for between 1 and 5 days at time of winter peak
6	• £5Mn-20Mn • $10Mn-40Mn	• Enterprise wide or multiple major location of infrastructure or business systems for >24 hours. More critical IS systems seriously impacted	• Major failure of plant, equipment or structures (e.g. cold box failure requiring replacement) that results in loss of liquefaction capability for between 50 and 150 days • As above but leading to loss of export capability of more than 5 days under peak condition
7	• £20Mn + • $40Mn +	• Extended enterprise failure or infrastructure or business systems that impact national Grid's ability to function as a commercial business. More critical IS systems highly impacted	• As for 6 above but where the disruption to the site would last for more than 1 season or where the adverse economic impact is >£20Mn/$40Mn-

B1 Likelihood Matrix 1 of 5 – Guide to use the likelihood tables

• **Safety projects caused by a single event (e.g., installation of handrails)**	3 of 5	
Asset failure	**No coincident event needed for impact**	**Coincident event needed for impact**
• Time to failure known and earliest asset of failure has not been reached	2 of 5	4 of 5
• Time to failure known and earliest asset of failure has already been reached	3 of 5	5 of 5
• Time to failure not known, but history of similar failures is available	3 of 5	5 of 5

B1 Using a ‘time to failure’ approach

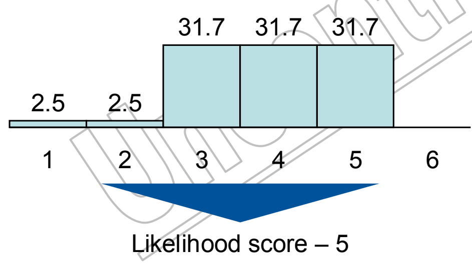
Likelihood scores after considering time to failure

Time to failure (in years)	Likelihood level
>1 years	7
1 to 3 years	6
3 to 5 years	5
5 to 10 years	4
10 to 20 years	3
20 to 100 years	2
>100 years	1

Example

An asset is not expected to fail in the next 2 years, but it is expected to fail in 3 to 5 years

Probability of failure, %



Using this table

- Step 1 – Establish the earliest and latest time to failure for an asset
- Step 2 – Determine the likelihood score by scrolling across the table, e.g. if an asset is not expected to fail in the next 3 years, but it is expected to fail in 3 to 5 years, the likelihood score is 5

B1 'Time to certain event' or 'probability' approach

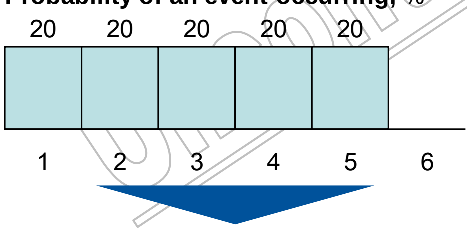
Likelihood scores after considering the time to a certain impact or the probability of an impact happening next year (assuming a uniform distribution)

Years to certain impact	Likelihood level	Probability of certain impact happening next year
1	7	100%
2	7	50%
3	6	33%
5	6	20%
6	5	17%
10	5	10%
20	4	5%
100	4	1%
200	3	0.5%
500	2	0.2%
1000	2	0.1%
2000	1	0.05%

NB. Health & Safety and Environmental risks assessed using this approach

Example
An event will happen in the next 5 years (on the probability of the event happening next year is 20%)

Probability of an event occurring, %



Likelihood score – 6

Using this table

- Step 1 – Establish the time to a certain impact or the probability of a certain impact happening next year
- Step 2 – Identify the likelihood score from the coloured central column by scrolling across the table above, e.g. if an event will happen in the next 5 years (or the probability of the event happening next year is 20%), the likelihood score is 6

B1 ‘Time to failure’ approach and ‘coincident event'

Likelihood scores after considering time to asset failure and coincident event required for the impact

Time to failure	Time to coincident event →	1	2	3	4	5	10	20	33	100	1000
	>1 years	7	7	6	6	6	5	4	4	4	2
	1 to 3 years	6	6	6	6	5	5	4	4	4	2
	3 to 5 years	5	5	5	5	5	4	4	4	3	1
	5 to 10 years	4	4	4	4	3	3	2	2	1	1
	10 to 20 years	3	3	3	3	3	2	2	1	1	1
	20 to 100 years	2	2	2	2	2	2	1	1	1	1
	>100 years	1	1	1	1	1	1	1	1	1	1
	Likelihood of coincident event	100%	50%	33%	25%	20%	10%	5%	3%	1%	0.1%

Using this table

- Step 1 – Establish the earliest and latest time to failure for an asset
- Step 2 – Establish the likelihood of coincident event required to result in the impact (say failure of another asset required to result in the impact of loss of supply). If no coincident event is required, assume 100%
- Step 3 – Determine the likelihood score by scrolling across the table, e.g. 3–5 years to failure and coincident event likelihood of 25% (will happen in the next years) results in a likelihood score of 5

B1 ‘Probability’ approach and ‘coincident event’

Likelihood scores after considering likelihood of primary and coincident event required for the impact

Years to certain impact (assuming uniform likelihood)	Time to coincident event: 1	2	3	4	5	10	20	33	100	1000	Probability of certain impact happening in the next year
1	7	7	6	6	6	5	4	4	4	2	100%
2	7	6	6	6	6	5	4	4	4	2	50%
3	6	6	6	6	5	5	4	4	4	2	33%
4	6	6	6	6	5	5	4	4	4	2	25%
5	6	6	5	5	5	5	4	4	3	2	20%
6	5	5	5	5	5	4	4	4	3	1	17%
7	5	5	5	5	5	4	4	4	3	1	14%
8	5	5	5	5	5	4	4	4	3	1	13%
9	5	5	5	5	5	4	4	4	3	1	11%
10	5	5	5	5	5	4	4	4	3	1	10%
20	4	4	4	4	4	4	4	3	2	1	5%
50	4	4	4	4	4	3	3	2	2	1	2%
100	4	4	4	4	3	3	2	2	1	1	1%
200	3	3	3	3	3	2	2	1	1	1	0.5%
500	2	2	2	2	2	2	1	1	1	1	0.2%
1,000	2	2	2	2	2	1	1	1	1	1	0.1%
2,000	1	1	1	1	1	1	1	1	1	1	0.05%
Likelihood of coincident event	100%	50%	33%	25%	20%	10%	5%	3%	1%	0.1%	

Using this table

- Step 1 – Establish the likelihood (or time to event) of the primary event
- Step 2 – Establish the likelihood (or time to event) of coincident event required to result in the impact
- Step 3 – Determine the likelihood score by scrolling across the table, e.g. probability of primary event happening next year is 50% (or a maximum of 2 years to a certain event) and coincident event likelihood of 25% (or maximum of 4 years to a coincident event) results in a likelihood score of 6

B2 Risk scores reflect 'expected monetary values' and are 'non-linear'

Risk scores*

Impact \ Likelihood	1	2	3	4	5	6	7
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13

- The expected monetary value (EMV) for a given outcome is the product of the average monetary impact and the average likelihood probability.
- The risk score matrix is populated with 49 unique scores by reference to the underlying EMVs.
- We are not indifferent between events where there is
  - an impact of 7 and likelihood of 1,
  - an impact of 1 and a likelihood of 7
- The EMV attributable to a risk score of 40 is more than 100 times that of a score of 20

Expected monetary value, £

Impact	*Average monetary impact, £*	1	2	3	4	5	6	7
7	*35,000,000*	35,000	210,000	612,500	3,937,500	13,125,000	25,375,000	33,250,000
6	*12,500,000*	12,500	75,000	218,750	1,406,250	4,687,500	9,062,500	11,875,000
5	*3,000,000*	3,000	18,000	52,500	337,500	1,125,000	2,175,000	2,850,000
4	*625,000*	625	3,750	10,938	70,313	234,375	453,125	593,750
3	*150,000*	150	900	2,625	16,875	56,250	108,750	142,500
2	*27,500*	28	165	481	3,094	10,313	19,938	26,125
1	*2,500*	3	15	44	281	938	1,813	2,375
	Average cumulative probability over next 5 years	*0.10%*	*0.60%*	*1.8%*	*11%*	*38%*	*73%*	*95%*

Likelihood

* Traffic light colours indicative only

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How to . . .

Classify

Risk score

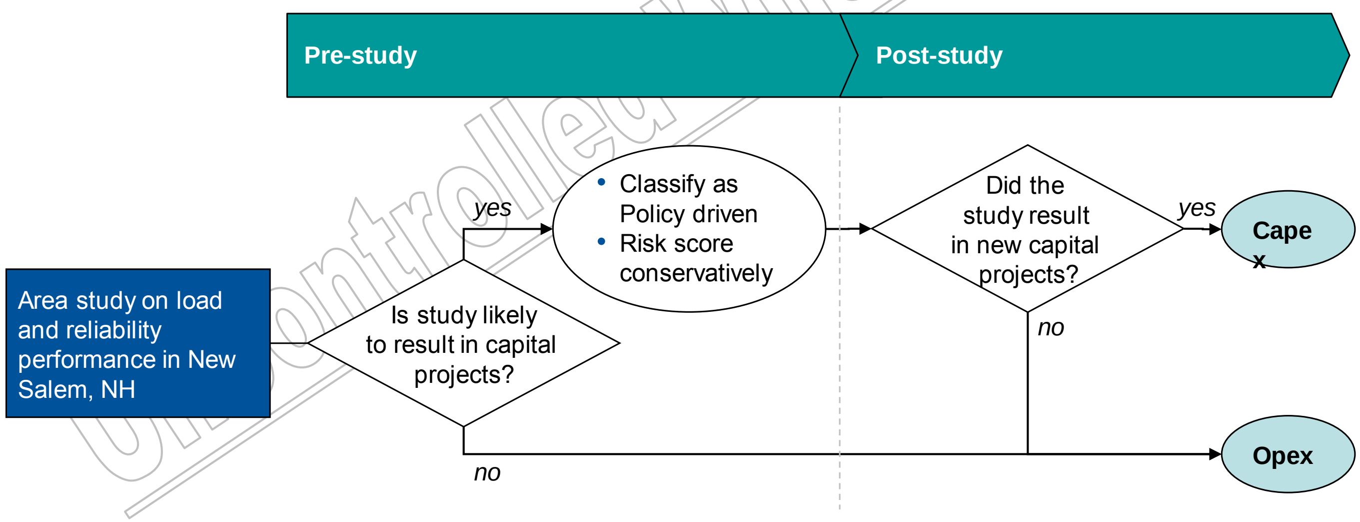
1. Diagnostic studies
2. Projects to comply with targets set by the regulator
3. Blankets
4. Projects whose impact requires a coincident event
5. Asset failure projects for assets that have reached the earliest onset of failure
6. Projects with mitigation alternatives
7. Programs that are bundles of similar projects
8. Projects on interdependent assets

Source: Team analysis

1 How to classify diagnostic studies

- A study should be considered **opex** unless it is likely to result in a capital project
- Capex studies should be classified as **policy driven and scored conservatively** (i.e., worst possible consequence that the study may uncover)
- Studies that were considered capex and do not result in capital investments should be expensed and written off the capital plan

Example



2 How to classify projects to comply with targets set by the regulator

- **Policy driven** if the targets are on reliability, safety or environmental parameters, as there is **discretion on projects needed** to achieve these targets
- **Mandatory** if the targets are on capex (or capex equivalent) spent on **specific project/programmes immediately**

Examples

Project	Classification	Rationale
1 Transformer replacement to maintain reliability targets/ standards	• Policy driven	• Discretion on specific projects needed to achieve targets
2 Replacement of specified length of gas mains (e.g. KED LI regulatory target – 60 mile **per year**)	• Policy driven	• Obligation to achieve target immediately, but there is discretion on which mains to replace, and the mix will affect the capex required
3 Replacement of specific length of miles of gas mains (regulatory target – 300 miles in **5 years**)	• Policy driven	• Capex-equivalent target on specific program, but there is discretion on timing of the replacement

Source: Risk scoring pilots; team analysis

3 How to classify blankets

- Blankets (or provisions) are capital allocations for unspecified expenditures during capital plan period – e.g., new connections, load relief
- Blankets should be classified in the same way as one of its expenditures (i.e. mandatory or policy driven)
- If policy driven, they should be scored according to the risk/likelihood of a single expenditure

Examples

Project	Classification	Rationale
1 **New connections** blanket providing capital for expected new connections	• Mandatory	• New connections will be required by regulator immediately
2 Blanket for **load relief** work	• Policy driven	• Load relief projects occur at the discretion of an LOB
3 Damage and failure	• Mandatory	• Repairs will be required by regulator immediately

4 How to risk score projects whose impact requires a coincident event

- Estimate the time to failure for the asset or the probability of the asset failing. This is the **primary event**
- Estimate the probability of the **coincident event**, making sure that you **correct for exposure**
- Look up the likelihood score in pages 4/5 or 5/5

Example

Replacement of a circuit breaker. There is a risk of catastrophic failure and subsequent injury to an employee. The breaker is expected to fail in 5–10 years

Primary event	Coincident event	Likelihood score
Time to failure: 5–10 years	An employee spends 8 hours a day on site Monday–Friday and is near the breaker for 50% of the time he spends on site	• Time to failure: 5–10 years • Probability of coincident event: 12% • Likelihood page 4/5

% of time spent on site: $\frac{8\text{ h} \times 5}{24\text{ h} \times 7} = 24\%$

×

% of time near breaker: 50%

=

Probability of coincident event: **12%**

Likelihood score is 3

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Source: Risk scoring pilots; team analysis

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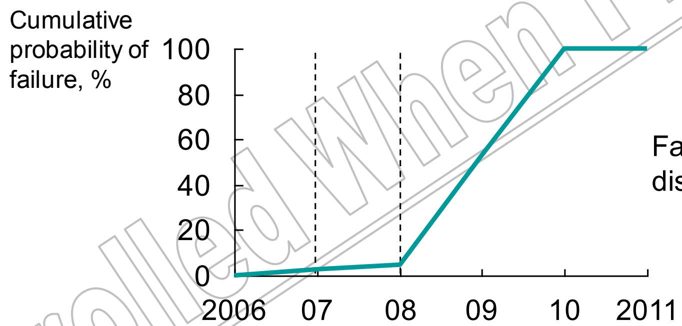
5 How to risk score asset failure projects for assets that have reached their earliest onset of failure

- Estimate the time to failure in years and use likelihood page 3/5 if asset has reached its earliest onset of failure

Example

Replacement of a disconnector



Failure curve for one disconnector

Impact may be caused by disconnector failure. What is the likelihood score?

	Likelihood page	Years to failure	Likelihood score
Before earliest onset of failure (2007)	2/5	• 1–3 (earliest asset in 2008 and failure expected by 2010)	6
After earliest onset of failure (2008)	3/5	• 2 (failure expected anytime before 2010)	7

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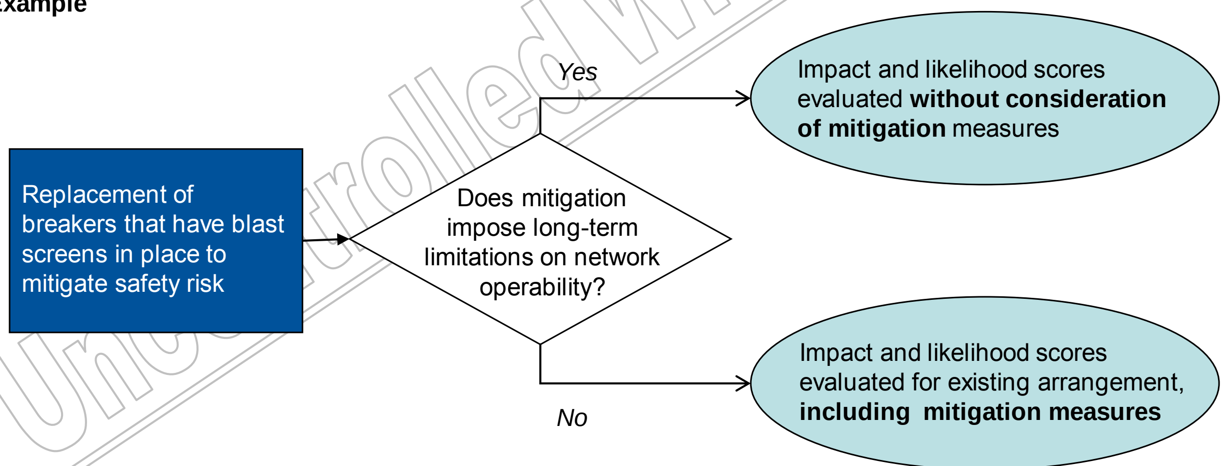
Source: Risk scoring pilots; team analysis

6 How to risk score projects with mitigation alternatives

- Risk mitigation measures are sometimes available as alternatives to asset replacement or permanent repair
- In cases where alternative mitigation measures may be undertaken, the scoring approach is driven by the long-term liability of the mitigation:
  - If mitigation can remain **stable** with little/no impact on network operability in the long term, projects should be considered **post-mitigation**
  - If mitigations are **temporary** in nature or impose limitations on network operability (unacceptable long-term), risk scores should be evaluated **pre-mitigation**

Example



7 How to risk score programmes made up of several similar projects

- Similar projects bundled into a single programme of work should be scored according to the risk/likelihood appropriate for **one** such project.
- If bundled projects vary in impact and/or likelihood (i.e., equipment of varying ages or with different levels of connectivity), programme should be disaggregated and risk scores evaluated for each component project

Example Programme 1

A replacement programme to upgrade 60 governor stations with similar risk profiles:

Project	Impact	Likelihood	Risk score
Each of the 60 governor stations	5	6	41
Total programme	**5**	**6**	**41**

Project scored to evaluate impact / likelihood of a single failure, not the combined total impact

Example Programme 2

A replacement programme to upgrade 60 governor stations with different risk profiles:

Project	Impact	Likelihood	Risk score
15 governor stations	5	5	39
45 governor stations	5	6	41

This program should be disaggregated to appropriately reflect the different risk profiles

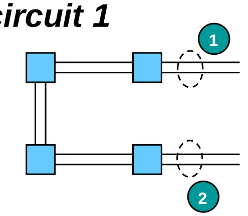
8 How to risk score projects on interdependent assets

- Risk score the project considering the failure of the individual asset
- Risk score the project considering coincident failures (e.g., within the same electrical zone) of the **interdependent assets within the network**
- **The higher of the two scores is used for prioritisation**

Example

Electricity transmission – overhead line work

The project is to refurbish double-circuit 1



Double-circuit (DC) 1 is expected to fail within 5 years

	Impact	Likelihood	Risk
Individual failure	**2** Disruption and mainte-nance costs	**6** Expected to fail within 5 years	**23**
Coincident failure	**6** Loss of both lines would cause supply loss between 250–1,000 MW	**3** Probability of coincident failure of DC 2 is 1%	**33**

Risk of the project is 33

Source: Risk scoring pilots; team analysis

IS Project Complexity

August 2013

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THE POWER OF ACTION

Project Complexity Scoring

- Provides clarity and objectivity in Complexity Scoring.
- Creates Complexity Scoring consistency across IS and Business projects, to the extent possible.
  - Table-driven scores for as many factors as possible.
  - Explanations for both table-driven and more subjective factors to guide scoring.

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THE POWER OF ACTION

Complexity Scoring Table

Factor	Weight	Score: 3	Score: 2	Score: 1
Project Cost	**2**	**>= $5M**	**>= $1M, <$5M**	**<$1M**
Project Duration	**1**	**> 2 yrs**	**<2 yrs, >= 1 yr**	**<1 yr**
Delivery Complexity	**2**	**High**	**Medium**	**Low**
Business Process Impact	**2**	**High**	**Medium**	**Low**
External Impact	**2**	**High**	**Medium**	**Low**
Dependencies	**1**	**>3**	**<3, >=1**	**<1**
Innovation	**1**	**High**	**Medium**	**Low**

The USSC may, at its discretion, raise or lower the Complexity Score based on its perception of the overall project and the scoring of the individual factors.

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Complexity Factor Descriptions

Complexity Factor	Description
Project Cost	**This is the total estimated cost of the entire project. If the project is actually a program with multiple component projects, this is the sum of the estimated costs for those component projects. If the confidence level in the estimated total cost of the project is low, this category should receive a score of 3. If each of the component projects can stand on its own merit, they should be submitted separately with notes indicating that each is part of a larger program.**
Project Duration	**This is the total estimated duration of the entire project. If the project is actually a program with multiple component projects, this is the sum of the estimated duration for those component projects. If the confidence level in the project duration is low, this category should receive a score of 3. If each of the component projects can stand on its own merit, they should be submitted separately with notes indicating that each is part of a larger program.**
Delivery Complexity	**This is the overall complexity and risk associated with delivery of the project. It considers sub-factors such as the degree of internal coordination required for the project, the maturity level (extent of use, reputation) of available software packages, whether or not the base application platform is changing, the availability of fixed pricing, and the reputation, reliability and financial stability of available vendors, and the availability, level, and diversity of skills needed by the project team. Delivery complexity also includes the amount of planning and preparation necessary to ensure smooth transition of the application into steady state mode. In order to achieve a score of 1 in this area, assessments in each of the sub-factors must be high confidence. Questionable confidence in any one area reduces the score to at least 2, and in more than one area, to 3.**

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Complexity Factor Descriptions

Complexity Factor	Description
Business Process Impact	This is a measure of the complexity involved in coordinating the project with existing departments, jurisdictions, operating companies, and business processes. A larger number of departments, jurisdictions, operating companies, and business processes impacted by the project, and/or a higher level of regulatory complexity results in a higher complexity score. A score of 1 would be applied to projects that impact one or two organizational entities or business processes, and that have little or no regulatory complexity. A score of 2 would be applied to projects that impact three to five organizational entities or business processes and/or that have a moderate level of regulatory complexity. A score of 3 would be applied to projects impacting more than five organizational entities or business processes and/or that have a high level of regulatory complexity.
External Impact	This is a measure of the importance or impact of the project to external parties such as customers, regulators, vendors, or other legal entities. A sore of 1 would indicate little impact or importance to external stakeholders. A score of 2 or 3 would reflect gradually higher levels of concern that the project would impact external stakeholders, and that the project should be managed to avoid those impacts.
Dependencies	This measures the total number of projects and activities that interrelate with the project in either a dependent or supportive manner. These projects and activities can be other IS projects, business projects, or business initiatives that have any sort of substantive bearing on the project.
Innovation	This measures the level of new and innovative technology, or project approach, within the project, and can include the base project software/hardware, new delivery methodology, use of a hosted service, or tools to be used in the project delivery effort. To achieve a score of 1, the project must use proven technology and delivery methodologies that have a record of successful implementation and use. Scores of 2 or 3 would be assigned to projects that use higher levels of innovation and that have shorter records of successful implementation and use.

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Project Complexity Implications

Project Complexity Score	Project Sponsor	Steering Committee	PM Certification	Quarterly Checkpoint	Project Board
>= 25	>= VP	Required Monthly	Required	Required	Required
>= 19, < 25	>=VP	Required Quarterly	Required	Not Required	Required
<19	>= Director	Not Required	Not Required	Not Required	Required

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Sample Project Scores

➢ US Foundation	30
➢ OMS/EMS	27
➢ Gas GIS Consolidation	27
➢ Rate Case System Modifications	24
➢ PeopleHub	23
➢ AMAG Upgrade	19
➢ Legal Hold / Clearwell Implementation	16
➢ Earned Value Management	16
➢ Computapole Upgrade	14
➢ IDS Improvements	13
➢ Cascade Server Replacement	11

US Sanctioning Committee - Standardized Project Summary

Business Case	
Project #	
Sanction Paper#	
Project title	
Jurisdiction	
Operating Company	
Sponsor	
Author	

Economic measures			5yr	10yr	Comment
NPV	@ Discount rate	6.0%	0	0	
IRR			#NUM!	#NUM!	
Simple Payback in Years			11	11	
Total O&M			$0	$0	
Total Capital Investment			$0	$0	
Total Savings			$0	$0	

Income Statement

Fiscal	YR 1	YR 2	YR 3	YR 4	YR 5	YR 6	YR 7	YR 8	YR 9	YR 10
Savings/Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Expense:										
Project O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EBT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Current Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Earnings after Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cash Flow

Fiscal	YR 1	YR 2	YR 3	YR 4	YR 5	YR 6	YR 7	YR 8	YR 9	YR 10
Period	1	2	3	4	5	6	7	8	9	10
Savings/Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Costs/Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Cash Flow	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Profitability Ratios

N/A for this analysis

Fiscal	YR 1	YR 2	YR 3	YR 4	YR 5	YR 6	YR 7	YR 8	YR 9	YR 10
Operating Profit Margin										
Net Profit Margin										
ROA										
ROE										
ROIC										

Assumptions Summary

Category	Descriprion summary	Source
Investment	Renovation and relocation	Facilities Mgmt Estimate
Facilities O&M Savings	Savings due to consolidation of facility space	Facilities Mgmt Estimate
Property Tax savings	Savings from leasing out gas facility offset by new investment	Estimate calculated based on current & Malden tax rate x Renovation cost
Avoided Capex	Annual facility cost is avoided for first few years after renovations	Facilities Mgmt Estimate
Other…		

NPV Sensitivity

	Discount Rate		
Years	5.0%	6.0%	8.0%
5	-	-	-
10	-	-	-
15			
20			

Version 0.0 (test sample)
Last Modified July 12, 2011

Division 3-28

Request:

Referring to the testimony of Bhargava, DeMauro, and Rapivaty, p. 7, lines 14-15:

a. Please identify each of the "external partners" utilized in the delivery model.
b. Describe the role of each such partner during the test year.
c. State how much was paid to each of the partners during the test year.
d. Please provide an estimate of how much will be paid to each external partner during the Rate Year.
e. Please provide an estimate of how much will be paid to each external partner during the Rate Year solely in connection with implementation of the Technology Modernization Program.

Response:

a. Please see below for a list of the primary external partners utilized in the information services delivery model and the role each partner played during the test year.

External Partner	Services Provided During Test Year
IBM Corp.	Application Maintenance - day to day support of existing applications
WIPRO Ltd.	Application Maintenance - day to day support of existing applications
IBM Corp. / WIPRO Ltd.	Internet, Collaboration, and Email - function provides email, web conferencing, instant messaging and collaboration tools, such as SharePoint, operated on vendor-owned and hosted infrastructure.
Verizon	Networks and Communication- manage the company's networks and telecommunication services.
DXC (Computer Sciences Corp.)	Data Centers - provides data center services (e.g., servers, data storage); management of hardware, software and storage and provides security, back-up capability, and disaster recovery services.
DXC (Computer Sciences Corp.)	End User Devices - proviside and support end user devices (e.g., laptops) and deployment and maintenance of the operating systems and applications that run on those devices.
Xerox	Managed Print - manage the support services for a refreshed and standardized fleet of print devices, enabling increased security for printing, copying, faxing, and scanning.

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b. Please see the Company's response to part a. above.

c. Below is a list of payments to the external partners during the rate year.

External Partner	Service	Test Year Actual ($M's)
IBM Corp.	Application Maintenance	$ 7.4
WIPRO Ltd.	Application Maintenance	$ 8.4
IBM Corp. / WIPRO Ltd.	Internet, Collaboration and Email	$ 4.2
Verizon	Networks & Telecom	$ 32.9
DXC (Computer Sciences Corp.)	Data Centers	$ 13.1
DXC (Computer Sciences Corp.)	End User Devices	$ 7.6
Xerox	Managed Print	$ 3.1

d. Please see Attachment DIV 3-28-1 for a breakdown of the operating expenses for Information Services (IS) in the historic Test Year and Rate Year. National Grid IS is forecasting no incremental operating expenses in the Rate Year, and no operating expenses have been included in this rate case proceeding.

Please note that IS forecasts its operating expenses by functional group (*i.e.* Commercial Management), not by external partner. The expenses for each of the external partners are embedded in the functional groups because they are responsible for managing these costs. In addition, there are operating expenses related to the investment plan. These operating expenses represent expenses that cannot be capitalized according to accounting standards. The maintenance and support expenses will be absorbed into the functional groups once the investment goes into service. Please see Attachment DIV 3-28-2 for the operating expense details related to each IS capital investment. If an investment generates savings, the savings are included on the list and used to offset other expenses.

e. As noted in part d. of this response, IS does not prepare its project estimates on an external partner basis because the level of partner involvement is often not known until the project begins in earnest; therefore, the cost estimates are done at the project level. Regarding the rate case proceeding, the operating expenses estimates for Technology

Modernization are included in the Investment Plan line on Attachment DIV 3-28-1, and the projects details are included on Attachment DIV 3-28-2. The capital cost estimates are included in Schedule ISP-1. As noted above, IS' overall operating expenses are in line with historic Test Year levels, so no incremental funding for operating expense were included in the rate proceeding for the Technology Modernization program.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty

Narragansett Electric & Gas d/b/a National Grid
Total Information Services
Incremental Operating Expenses Excluding Labor & Burdens($Millions)

Operational Cost	**HTY** Ending June 30, 2017	**Rate Year** Ending Aug. 31, 2019	Comments
Commercial Management	17.7	18.7	The operating costs for Commercial Management are forecasted to be higher in the Rate Year compared to the HTY due primarily to the purchase of additional software licenses (SAP Hanna, Concur and Microsoft Azure).
Cyber Security	5.4	5.6	Increase due to inflation factor of 3%.
Physical Security	6.1	6.8	Incremental costs in the Rate Year compared to the HTY (+0.5M) due to forecasted higher break/fix costs for security equipment plus a 3% inflation factor. A milder than usual winter in the HTY kept break/fix costs lower than usual.
Apps Maintenance	14.9	16.6	Addition of SAP Max Attention at the end of the HTY has increased cost by $1.2M annually in addition to a 3% inflation factor.
CNI Ops	18.9	19.5	Increase due to inflation factor of 3%.
Data Centers	30.1	31.0	Increase due to inflation factor of 3%.
Networks & Telecom (Excludes CNI network costs that are included in CNI Ops)	32.7	33.2	Rate Year increase driven by network upgrades (+$1.0M) plus a 3% inflation factor. The circuit assessment initiative will reduce costs from the HTY (-$1.5M).
Email & Xerox	7.2	7.4	Increase due to 3% inflation factor.
Enterprise Service Delivery	7.8	8.0	Increase due to inflation factor of 3%.
Administration	7.7	8.0	Increase due to inflation factor of 3%.
Subtotal Operational Cost	$148.6	$154.8	
IS Investment Plan - Including Labor & Burdens (1)	38.0	32.1	see Attachment DIV 3-28-2
Investment Plan	$38.0	$32.1	
Total IS Opex	$186.6	$186.9	
Total Incremental IS Opex Costs from HTY	N/A	$0.3	

(1) Excludes Gas Business Enablement (GBE)

Naragansett Electric Company d/b/a National Grid
IS Investment Plan Operating Expenses

Investment Name	Programs	INVP #	Bill Pool	In Service Date	Amortization Period	FY19 OPEX	FY19 RTB	FY20 OPEX	FY20 RTB	9/01/18- 8/31/19 Rate Year OpEx	9/01/18- 8/31/19 Rate Year RTB
INVP 3614D1 Ent Network Security	Cyber Security 1	3614D1	G020	1/31/18	84		3,841,685		3,841,685	-	3,841,685
IT/OT Discovery and Implementation Phase 1	Cyber Security 2	3683X11	G020	10/1/20	84	500,000	-	500,000	83,340	500,000.00	34,725
Identity & Access Management: Privileged Access Management	Cyber Security 2	3683X5	G020	3/1/18	84	640,000	104,699		104,699	373,333.33	104,699
Identity & Access Management: Shared Area Access Management	Cyber Security 2	3683X5	G020	3/1/21	84					-	-
US CNI Security Enhancements Phase 1	Cyber Security 2	3683X6	G020	3/1/19	84	350,000	40,000		60,000	204,166.67	48,333
Big Data Security Analytics Phase 1	Cyber Security 2	3683X7	G020	3/1/21	84			150,000		62,500.00	-
Domain Based Security Phase 1	Cyber Security 2	3683X13	G020	3/1/19	84	200,000	-		350,000	116,666.67	145,833
US CNI Intrusion Detection/Prevention Phase 1 (CNI IDS Refresh)	Cyber Security 2	3683X1	G020	12/1/18	84	180,000	-		25,096	105,000.00	10,457
US CNI Intrusion Detection/Prevention Phase 2 (CNI IDS Refresh)	Cyber Security 2	3683X1	G020	12/1/21	84					-	-
Enhanced DLP Gateway and Endpoint	Cyber Security 2	3683X8	G020	3/1/21	84					-	-
Identity & Access Management :Role Base Access Management (RBAC)	Cyber Security 2	3683X5	G020	3/1/20	84			150,000	185,896	62,500.00	77,457
Identity & Access Management: Fine Grain Access Management (Unified Platform)	Cyber Security 2	3683X5	G020	3/1/18	84	150,000	100,432		100,432	87,500.00	100,432
Threat Behavior Modeling	Cyber Security 2	3683X15	G020	3/1/20	84			100,000	17,875	41,666.67	7,448
vStig Scaling Upgrades	Cyber Security 2	3683X12	G020	3/1/19	84	100,000	-		400,000	58,333.33	166,667
Big Data Security Analytics - Phase 2	Cyber Security 2	3683X7	G020	3/1/21	84					-	-
Data Visualization	Cyber Security 2	3683X16	G020	3/1/20	84					-	-
Cloud Security (Cloud Access Security Broker)	Cyber Security 2	3683B	G020	12/1/17	60		60,500		60,500	-	60,500
Security Research Lab	Cyber Security 2	3683X14	G020	3/1/20	84			50,000		20,833.33	-
Risk Based Authentication - 2FA token alternative (Multi Factor Authentication)	Cyber Security 2	3683X2	G020	3/1/18	84		15,530		15,530	-	15,530
Security Incident Event Management Phase 4	Cyber Security 2	3683X4	G020	3/1/21	84			12,500		5,208.33	-
Enhanced Phishing Protection	Cyber Security 2	3683X3	G020	12/1/18	84	140,000	120,000		120,000	81,666.67	120,000
Situation Intelligence & Cyber Intelligence: Phase 2	Cyber Security 2	3683	G020	10/1/20	84					-	-
Situation Intelligence & Cyber Intelligence: Phase 1	Cyber Security 2	3683	G020	10/1/18	84	120,000	2,857		5,714	70,000.00	4,048
Security Incident Event Management Phase 5	Cyber Security 2	3683X4	G020	12/1/20	84					-	-
Domain Based Security Phase 2 (Network Segregation)	Cyber Security 2	3683X13	G020	3/1/21	84					-	-
Perimeter Enhancements	Cyber Security 2		G020	10/1/18	84					-	-
Internal PKI (Public Key) Infrastructure	Cyber Security 2		G020	10/1/18	84					-	-
Enterprise Centralized Patch Management	Cyber Security 2		G020	12/1/18	84					-	-
Firewall Rule Clean up	Cyber Security 2		G020	12/1/18	84	125,000				72,916.67	-
Sustainable Red-Team Service Model	Cyber Security 2		G020	10/1/18	84	208,000				121,333.33	-
Removable Media Control Pilot	Cyber Security 2		G020	10/1/18	84	175,000				102,083.33	-
Application Security As a Service	Cyber Security 2		G020	9/1/19	84			100,000		41,666.67	-
Continuous review of Reference Security Architecture	Cyber Security 2		G020	8/1/19	84					-	-
GPS Project	Cyber Security 2		G020	3/31/21	84					-	-
INVP 4401 SAP/PowerPlan/Front Office Maintenance of Business (MOB) - FY1	FY18 Plan	4401	G020	3/31/18	84	-	-	-	-	-	-
INVP 3932 Call Center Customer Contact Center/SDC Technology Upgrade Imp	FY18 Plan	3932	C175	9/1/18	84	547,000	642,000	-	642,000	319,083.33	642,000
INVP 4481 US MDS-Energy Accounting System (EAS) migration to Wholesale	FY18 Plan	4481	G186	10/1/18	84	265,000	275,000	-	275,000	154,583.33	275,000
INVP 3737 US CNI GMS SCADA Upgrade &	FY18 Plan	3737	C210	12/31/19	84	317,000	174,000	236,000	611,000	283,250.00	356,083
INVP 4348 US SAP: Infrastructure Landscape	FY18 Plan	4348	G020	3/31/18	60	-	936,000	-	936,000	-	936,000
INVP 4408 Doc Mgmt Systems Replacement Delivery	FY18 Plan	4408	G149	6/22/18	84	19,380	440,000	-	1,351,000	11,305.00	819,583
INVP 4568 US CNI-EMS Lifecycle Hardware and Software Upgrade	FY18 Plan	4568	U186	3/31/18	84	100,000	(2,000)	-	(2,000)	58,333.33	(2,000)
INVP 4662 - Concur Licenses	FY18 Plan	4662	G020	1/31/18	84					-	-
INVP 3976 IDS Next Generation 2.0	FY18 Plan	3976	G186	3/31/18	84	-	-	-	-	-	-
INVP 4399 FSSC&HR Systems (Non-SAP) Operational	FY18 Plan	4399	G020	3/31/18	84	-	-	-	-	-	-
INVP 3718 New Medical System	FY18 Plan	3718	G020	3/31/18	84	-	105,000	-	105,000	-	105,000
INVP 4403Annual Ariba upgrades - FY18	FY18 Plan	4403	G020	3/31/18	84	-	-	-	-	-	-
INVP 3924 Host Transition	FY18 Plan	3924	G020	3/31/18	84	-	-	-	-	-	-
INVP 3982 Substation Monitoring-DobleARMS	FY18 Plan	3982	G381	1/1/18	84	5,000	80,000	-	80,000	2,916.67	80,000
INVP 4466 Gas Capital Investment Planning Tool	FY18 Plan	4466	G210	1/17/18	84	5,000	112,000	-	112,000	2,916.67	112,000
INVP 4480 US Control-Gas System Operating Procedure (SOP) Upgrade	FY18 Plan	4480	G210	10/2/17	84	-	36,000	-	36,000	-	36,000
INVP 4554 Nightcrawler Asset Update	FY18 Plan	4554	G210	3/31/18	84	-	2,000	-	2,000	-	2,000
INVP 4697-HP Exstream upgra to v9.5	FY18 Plan	4697	G020		84					-	-
INVP 4402 US SAP Regulatory Requirements, Reporting & Rate Case support -	FY18 Plan	4402	G020	3/31/18	84	-	-	-	-	-	-
INVP 4188 Aging System Stabilize	FY18 Plan	4188	G148	3/31/18	84					-	-
INVP 4398 Storms/ISched Upgrade	FY18 Plan	4398	G160	4/23/18	84	72,000	294,000	-	294,000	42,000.00	294,000
INVP 4487 Changes to ACIS for PMCC Civil Vendor Billing	FY18 Plan	4487	G186	7/31/18	84	-	29,000	-	29,000	-	29,000
INVP 3986 Cascade Electric Application Upgrade Project	FY18 Plan	3986	G198	10/31/17	84	-	15,000	-	15,000	-	15,000
INVP 4681 Zscaler	FY18 Plan	4681	G020	10/2/17	84					-	-
INVP 3486 US MDS-Itron Enterprise Edition (IEE)	FY18 Plan	3486	G186	3/31/18	84	-	27,000	-	27,000	-	27,000
INVP 4484 Payment Processing for CRIS	FY18 Plan	4484	C173	3/31/18	84	-	-	-	-	-	-
INVP 4390 Plastic Fusion II	FY18 Plan	4390	G207	3/31/18	84	-	264,000	-	264,000	-	264,000
INVP 4651 Operation Telecommunication Optimization	FY18 Plan	4651	G327	3/31/18	84	-	-	-	-	-	-
INVP 4669 US SAP: Max attention	FY18 Plan	4669	G020		84					-	-
INVP 4692 - Experian NetConnect Upgrade	FY18 Plan	4692	G020		84					-	-

Naragansett Electric Company d/b/a National Grid
IS Investment Plan Operating Expenses

										9/01/18- 8/31/19 Rate Year	
Investment Name	**Programs**	**INVP #**	**Bill Pool**	**In Service Date**	**Amortization Period**	**FY19 OPEX**	**FY19 RTB**	**FY20 OPEX**	**FY20 RTB**	**OpEx**	**RTB**
INVP 4395 US Mobile Device Refresh	FY18 Plan	4395	G020	3/31/18	60	-	300,000	-	300,000	-	300,000
INPV 4462 Computapole Enhancements to Support Inspection Types	FY18 Plan	4462	G186	3/1/18	84	-	50,000	-	50,000	-	50,000
INVP 4394 NE Gas Leak Recheck (next Phase)	FY18 Plan	4394	G310	8/31/18	84	-	75,000	-	75,000	-	75,000
INVP 4469 Informatica Upgrade/Microstrategy Replacement Program	FY18 Plan	4469	G020	5/1/18	84	15,000	443,000	-	443,000	8,750.00	443,000
INVP 3956 WIFI for Fleet Services Diagnostic Laptops	FY18 Plan	3956	G352	11/1/17	84	-	40,000	-	40,000	-	40,000
INVP 4464 Data Visualization	FY18 Plan	4464	G020	9/30/17	84	-	506,000	-	506,000	-	506,000
INVP 4420 US CNI OMSFocalPoint Infrastructure Upgrade	FY18 Plan	4420	G198	5/23/17	84	-	90,000	-	90,000	-	90,000
INVP 4214 FERC Wholesale Customer System	FY18 Plan	4214	G220	3/31/18	84	-	142,000	-	142,000	-	142,000
INVP 4570 US CNI Tech Services-Network Equipment Lifecycle Replacements	FY18 Plan	4570	G186	3/31/19	84	-	30,000	-	30,000	-	30,000
INVP 4914 US CNI-EMS Lifecycle Hardware and Software Upgrade	FY18 Plan	4914	U186	**8/1/19**	84	1,302,155				759,590.42	-
INVP 4704Q Customer Bill Redesign	FY18 Plan	4704Q	H173	3/31/19	84	27,000		190,000	-	94,916.67	-
INVP 4144 HRIS Simplification Programme	FY18 Plan	4144	G020	5/2/19	84		2,400,000		2,400,000	-	2,400,000
INVP 4144 HRIS Simplification Programme (Customer Benefits)	FY18 Plan	4144	G020	5/2/19	84		(1,164,360)		(1,164,360)	-	(1,164,360)
INVP 4397 Ariba TLS and CI Update	FY18 Plan	4397	G020	8/28/17	120	-	-	-	-	-	-
INVP 4750 Customer Experience Transformation Tech Program	Growth Play Book-Finance	4750	C175	8/31/19	84		477,000		477,000	-	477,000
INVP 4217 US SAP: Business Planning	Growth Play Book-Finance	4217	G020	3/31/19	84			-	-	-	-
INVP 4222 Governance Risk & Compliance (GRC) Optimization/Upgrade	Growth Play Book-Finance	4222	G020	3/1/19	84					-	-
INVP 4563 US SAP: FERC on Hana (FOH)	Growth Play Book-Finance	4563	G020	3/31/19	84	724,000			-	422,333.33	-
Regulatory Mandates - FY19	Mandate		G020	3/31/19	84	5,864,000		-	-	3,420,666.67	-
Regulatory Mandates - FY20	Mandate		G020	3/31/20	84	-		6,000,000	-	2,500,000.00	-
Regulatory Mandates - FY21	Mandate		G020	3/31/21	84	-		-	-	-	-
Regulatory Mandates - FY22	Mandate		G020	3/31/22	84	-		-	-	-	-
INVP 4479 US Control-Gas Electronic Bulletin Board (EBB) Upgrade	Mandate	4479	G210	5/1/18	84	193,000	779,000	-	779,000	112,583.33	779,000
Regulatory Mandates - FY18	Mandate		G020	3/31/18	84	-		-	-	-	-
INVP 4124 Auto Remote Net Meter	Mandate	4124	C198	11/30/17	84	-	-	-	-	-	-
INVP 4411AB Distributed Generation Portal	Mandate	4411A+B	C198	11/30/17	84	-	-	-	-	-	-
INVP 4400 Annual HR & Payroll Mandatory Service Pack Upgrade (HRSP) - FY	Mandate	4400	G020	8/14/17	84	-	-	-	-	-	-
INVP 4411D New Gas Connections	Mandate	4411D	C210	10/31/18	84	136,000	-	-	-	79,333.33	-
INVP 4421 - New Arrearage Forgiveness Plan	Mandate	4421	G316	10/31/17	84					-	-
INVP 4555 RI Renewable Energy Program changes	Mandate	4555	5360E	2/28/18	84					-	-
INVP 4391 - Operations MW	Minor Works	4391	G148		84	-	-	-	-	-	-
INVP 4477-Customer FY18 Minor Works (former Customer & Digital)	Minor Works	4477	C175		84	-	-	-	-	-	-
INVP 4741-US Control Center Operations Minor Works-FY18	Minor Works	4741	G148		84	-	-	-	-	-	-
INVP 4742-Network Strategy FY18 Minor Works	Minor Works	4742	G186		84	-	-	-	-	-	-
INVP 4354-US FSSC Minor Works	Minor Works	4354	G020		84					-	-
INVP 4740-Customer Systems Regulatory and Operational Requirements and Up	Other - Mandate	4740	C175		84					-	-
RI Electric Only Physical Security Replacements - FY18	Physical Security	N/A	5360E	3/31/18	84					-	-
RI Gas Only Physical Security Replacements - FY18	Physical Security	N/A	5360G	3/31/18	84					-	-
All Companies Physical Security Replacements - FY18	Physical Security	N/A	G020	3/31/18	84					-	-
New England Companies Physical Security Replacements - FY18	Physical Security	N/A	G285	3/31/18	84					-	-
RI Electric Only Physical Security Replacements - FY19	Physical Security	N/A	5360E	3/31/19	84					-	-
RI Gas Only Physical Security Replacements - FY19	Physical Security	N/A	5360G	3/31/19	84					-	-
All Companies Physical Security Replacements - FY19	Physical Security	N/A	G020	3/31/19	84					-	-
New England Companies Physical Security Replacements - FY19	Physical Security	N/A	G285	3/31/19	84					-	-
RI Electric Only Physical Security Replacements - FY20	Physical Security	N/A	5360E	3/31/20	84					-	-
RI Gas Only Physical Security Replacements - FY20	Physical Security	N/A	5360G	3/31/20	84					-	-
All Companies Physical Security Replacements - FY20	Physical Security	N/A	G020	3/31/20	84					-	-
New England Companies Physical Security Replacements - FY20	Physical Security	N/A	G285	3/31/20	84					-	-
RI Electric Only Physical Security Replacements - FY21	Physical Security	N/A	5360E	3/31/21	84					-	-
RI Gas Only Physical Security Replacements - FY21	Physical Security	N/A	5360G	3/31/21	84					-	-
All Companies Physical Security Replacements - FY21	Physical Security	N/A	G020	3/31/21	84					-	-
New England Companies Physical Security Replacements - FY21	Physical Security	N/A	G285	3/31/21	84					-	-
INVP 4761 US Foundation Hosting Renewal	Tech. Modernization	4761	G020	3/31/18	84	-	(2,261,000)	-	(2,559,000)	-	(2,385,167)
INVP 4564 US SAP: Enhancement Pack 9 Upgrade	Tech. Modernization	4564	G020	3/31/20	84	2,427,000	-	592,000	-	1,662,416.67	-
INVP 4377 Data Center Decommission Melville	Tech. Modernization	4377	G020	3/31/19	84	-	-	-	-	-	-
INVP 4489 Active Directory Improvements	Tech. Modernization	4489	G020	12/31/18	84	500,000	-	-	-	291,666.67	-
INVP 4362 Legacy DMZ migration to vSTIG	Tech. Modernization	4362	G020	12/31/18	84	300,000	-	-	-	175,000.00	-
INVP 4529 Service Now Deployment - Release 2	Tech. Modernization	4529	G020	3/31/18	84	-	-	-	-	-	-
INVP 4491 ICE Replacement	Tech. Modernization	4491	G020	12/31/18	60	400,000	(1,297,000)	-	(1,516,000)	233,333.33	(1,388,250)
INVP 4490 Application Performance Management (APM)	Tech. Modernization	4490	G020	12/31/18	84	350,000	100,000	320,000	100,000	337,500.00	100,000
INVP 4706 1327 Interfaces - 523 FTS, 340 RDX, 245 MQSI, 253 JCAPS, 44 PM4D, 7 VB	Tech. Modernization	4706	G020	6/30/19	84	400,000	125,000	150,000	125,000	295,833.33	125,000
INVP 4710 Data Security	Tech. Modernization	4710	G020	3/31/20	84	300,000	-	300,000	-	300,000.00	-
INVP 4562 US SAP: Business Warehouse (BW) Consolidation to HANA Enterp	Tech. Modernization	4562	G020	3/31/19	84	810,000	11,000	-	43,000	472,500.00	24,333
INVP 4493 Monitoring and Alerting	Tech. Modernization	4493	G020	3/31/20	84	300,000	120,000	260,000	120,000	283,333.33	120,000
INVP 4758 Critical App Resiliency Remediation	Tech. Modernization	4758	G020	3/31/18	84	-	-	-	-	-	-

Naragansett Electric Company d/b/a National Grid
IS Investment Plan Operating Expenses

Investment Name	Programs	INVP #	Bill Pool	In Service Date	Amortization Period	FY19 OPEX	FY19 RTB	FY20 OPEX	FY20 RTB	9/01/18- 8/31/19 Rate Year OpEx	RTB
Move to public and private managed cloud	Tech. Modernization	4831	G020	3/31/20	84	150,000	-	300,000	-	212,500.00	-
INVP 4727 Virtual Desktop - DaaS	Tech. Modernization	4727	G020	12/31/19	60	300,000	100,000	300,000	100,000	300,000.00	100,000
Contract Re-bid Enterprise Services	Tech. Modernization	3427	G020	3/31/19	84	600,000	-	-	-	350,000.00	-
Contract Re-bid Networks	Tech. Modernization	3426	G020	3/31/19	84	600,000	-	-	-	350,000.00	-
Policy Based/Trust based Network Access	Tech. Modernization	TBD	G020	3/31/20	84	200,000	40,000	200,000	40,000	200,000.00	40,000
INVP4756-IS Sourcing Renewal	Tech. Modernization	4756	G020	3/31/18	84					-	-
Legacy Email Infrastructure	Tech. Modernization	4268	G020	12/31/19	84	250,000	-	250,000	-	250,000.00	-
Migration of Oracle to Linux	Tech. Modernization	4830	G020	12/31/20	84	100,000	-	150,000	-	120,833.33	-
DR Remediation F&A	Tech. Modernization	4712	G020	3/31/18	84	-	-	-	-	-	-
INVP 4778 - Dev Test to Cloud	Tech. Modernization	4778	G020	9/30/18	84	250,000	-	-	-	145,833.33	-
INVP 4560 US SAP: Dynamic Storage Tiering	Tech. Modernization	4560	G020	7/5/18	84	464,000	177,000	-	236,000	270,666.67	201,583
Network Management Capability - Next Generation	Tech. Modernization	4833	G020	12/31/20	84	150,000	15,000	150,000	45,000	150,000.00	27,500
Unified Communications (From Accenture Study)	Tech. Modernization	4576	G020	12/31/19	84	200,000	-	200,000	-	200,000.00	-
INVP 4497US Video Conference Programme	Tech. Modernization	4497	G020	6/1/19	84	150,000	(300,000)	-	(300,000)	87,500.00	(300,000)
DR Priority 2 Apps Remediation	Tech. Modernization	4824	G020	12/31/19	84	100,000	-	100,000	-	100,000.00	-
DR Priority 3 Apps Remediation	Tech. Modernization	4825	G020	12/31/20	84	-	-	100,000	-	41,666.67	-
Network Automation - DNA Center	Tech. Modernization	TBD	G020	3/31/20	84	-	-	200,000	40,000	83,333.33	16,667
SharePoint 2007 Decommission	Tech. Modernization	3667	G020	12/31/19	84	100,000	-	100,000	60,000	100,000.00	25,000
Cloud Based Secure Internet Access - Zscaler	Tech. Modernization	4822	G020	3/31/19	84	200,000	600,000	-	800,000	116,666.67	683,333
Cloud Orchestration, Self service and Broker	Tech. Modernization	TBD	G020	3/31/19	84	100,000	-	100,000	-	100,000.00	-
INVP 4279 Citrix Infrstructure Upgrade (Xenapp and NetScaler)	Tech. Modernization	4279	G020	3/31/18	60	-	-	-	-	-	-
INVP 3899 Cloud Broker - Hybrid Enablement	Tech. Modernization	3899	G020	12/31/17	84	-	-	-	-	-	-
INVP 4606 Data Visualisation Expansion	Tech. Modernization	4606	G020	6/30/19	84	-	253,000	-	337,000	-	288,000
INVP 4709 Data Center Consolidation efforts	Tech. Modernization	4709	G020	3/31/19	84	100,000	-	-	-	58,333.33	-
Hicksville Fiber	Tech. Modernization	4828	G020	3/31/19	84	100,000	-	-	-	58,333.33	-
SD-WAN Core, automation, orchestration tools and pilot sites	Tech. Modernization	4837	G020	3/31/19	84	100,000	100,000	-	100,000	58,333.33	100,000
Virtualized Branches	Tech. Modernization	4843	G020	3/31/20	84	100,000	(250,000)	-	(750,000)	58,333.33	(458,333)
INVP 4261 Service Now - Release 3	Tech. Modernization	4261	G020	3/31/18	84	-	-	-	-	-	-
INVP 4759 MTC and Syracuse Boardrooms & Auditoriums	Tech. Modernization	4759	G020	3/31/18	60	-	50,000	-	50,000	-	50,000
Network Transformation Continuation-Substations	Tech. Modernization	4835	G020	12/31/20	84	20,000	10,000	20,000	20,000	20,000.00	14,167
INVP 4676 Hix D/C Improvement Server Refresh	Tech. Modernization	4676	G020	3/31/18	60	-	-	-	-	-	-
INVP 4461 Unix51 Interface Migration	Tech. Modernization	4461	G020	9/30/18	84	50,000	-	-	-	29,166.67	-
Wireless LAN Management Tools	Tech. Modernization	4284	G020	3/31/19	84	50,000	60,000	-	50,000	29,166.67	55,833
INVP 4392 PPMI	Tech. Modernization	4392	G020	12/31/17	84	-	-	-	-	-	-
INVP 4386 Verizon Audio to Webex	Tech. Modernization	4386	G020	3/31/18	84	-	-	-	-	-	-
Network Transformation Continuation-Risk Avoidance	Tech. Modernization	4834	G020	3/31/20	84	20,000	15,000	20,000	45,000	20,000.00	27,500
INVP 3901-Virtual Desktop Offshore	Tech. Modernization	3901	G020	3/31/18	84	-	-	-	-	-	-
INVP 4687 Network Tx-NB/MTC	Tech. Modernization	4687	G020	12/31/17	60	-	-	-	-	-	-
INVP 4274 VSTIG Hardware Refresh	Tech. Modernization	4274	G020	3/31/18	60	-	-	-	-	-	-
INVP 4725 MWORK and Netmotion Risk Avoidance	Tech. Modernization	4725	G020	12/31/18	84	20,000	-	-	-	11,666.67	-
INVP 4714-EMM Phase2	Tech. Modernization	4714	G020	3/31/18	60	-	225,000	-	225,000	-	225,000
INVP 4760 Mainframe DR Machine	Tech. Modernization	4760	G020	3/31/18	60	-	-	-	-	-	-
Network Transformation Continuation-Substations and Security Sites	Tech. Modernization	4836	G020	12/31/20	84	20,000	30,000	-	60,000	11,666.67	42,500
VC - MetroTech Auditorium VC	Tech. Modernization	4840	G020	9/30/18	84	20,000	10,000	-	10,000	11,666.67	10,000
VC - Syracuse A39/40	Tech. Modernization	4841	G020	6/30/19	84	10,000	10,000	10,000	20,000	10,000.00	14,167
INVP 4269 RAS/VPN Re-Platform/Mobile	Tech. Modernization	4269	G020	3/31/18	60	-	-	-	-	-	-
INVP 4575 Software Defined Networking	Tech. Modernization	4575	G020	6/30/17	60	-	-	-	-	-	-
INVP 4270 RSA Re-platform	Tech. Modernization	4270	G020	3/31/18	84	-	-	-	-	-	-
INVP 4288 AD Data Cleanse	Tech. Modernization	4288	G020	12/31/17	84	-	-	-	-	-	-
INVP 4267 - WAN Bandwidth Upgrades	Tech. Modernization	4267	G020	3/31/18	84	-	180,000	-	180,000	-	180,000
INVP 4680 WAP Density deployment	Tech. Modernization	4680	G020	3/31/18	60	-	180,000	-	180,000	-	180,000
INVP 4631 Box Enablement	Tech. Modernization	4631	G020	12/31/17	84	-	-	-	-	-	-
INVP 4677 Application monitoring, Network/IDS, Operations monitoring	Tech. Modernization	4677	G020	6/30/17	84	-	-	-	-	-	-
INVP 4693 Enterprise Labs	Tech. Modernization	4693	G020	12/31/17	84	-	-	-	-	-	-
INVP 4679 Cisco Prime	Tech. Modernization	4679	G020	9/30/18	84	-	100,000	-	100,000	-	100,000
INVP 4726 Orchestration and Self Service	Tech. Modernization	4726	G020	3/31/18	84	-	-	-	-	-	-
Legacy Migration of Web Access Portal User to VZ RSA Service	Tech. Modernization	4724	G020	3/31/18	84	-	-	-	-	-	-
INVP 4707 Business Innovation Projects 1	Tech. Modernization	4707	G020	3/31/19	84	794,647	-	-	-	463,544.20	-
INVP 4715 EUC, network, and data center strategy	Tech. Modernization	4715	G020	12/31/17	84	771,429	-	-	-	450,000.00	-
INVP 4716 FY19 Data Center Projects	Tech. Modernization	4716	G020	3/31/19	84	250,000	100,000	-	-	145,833.33	58,333
INVP 4720 FY20 Edge Projects	Tech. Modernization	4720	G020	3/31/20	84	-	-	1,000,000	-	416,666.67	-
INVP 4713 EMM Licenses	Tech. Modernization	4713	G020	12/31/18	84	-	-	-	132,000	-	55,000
INVP 4719 FY20 Data Center Projects	Tech. Modernization	4719	G020	3/31/20	84	-	-	500,000	200,000	208,333.33	83,333
INVP 4582 Enterprise Data Management Platform	Tech. Modernization	4582	G020	6/1/20	84	450,000	-	450,000	-	450,000.00	-
INVP 4708 Business Innovation Projects 2	Tech. Modernization	4708	G020	3/31/21	84	673,723	-	794,647	-	724,107.87	-
INVP 4728 Business Innovation Projects 3	Tech. Modernization	4728	G020	3/31/21	84	673,723	-	794,647	-	724,107.87	-
INVP 4577 Call Manager Upgrade	Tech. Modernization	4577	G020	12/31/17	60	-	(1,100,000)	-	(1,100,000)	-	(1,100,000)

Naragansett Electric Company d/b/a National Grid
IS Investment Plan Operating Expenses

Investment Name	Programs	INVP #	Bill Pool	In Service Date	Amortization Period	FY19 OPEX	FY19 RTB	FY20 OPEX	FY20 RTB	9/01/18- 8/31/19 Rate Year OpEx	RTB
INVP 4749 VSTIG Hardware Refresh - IDS Card Replacement	Tech. Modernization	4749	G020	3/31/18	60	-	240,000	-	240,000	-	240,000
Network Data Center Cleanup	Tech. Modernization	4832	G020	3/31/20	84	-	50,000	-	50,000	-	50,000
Log Logic (from VSTIG Programme) (INVP 4664)	Tech. Modernization	4674	G020	3/31/18	84	-	(100,000)	-	(100,000)	-	(100,000)
Legacy DMZ Firewalls (from VSTIG Programme) (INVP 4665)	Tech. Modernization	4688	G020	3/31/18	84	-	40,000	-	-	-	23,333
EMM Single Sign on	Tech. Modernization	4826	G020	12/31/18	84	-	100,000	-	100,000	-	100,000
	Total					**26,404,056**	**9,615,342**	**14,849,794**	**11,798,407**	**21,589,780**	**10,524,953**
	Total OPEX & RTB									*32,114,733*	

Division 22-7

Request:

Please refer to the Company's response to DIV 9-2, Attachment DIV 9-2-1, INVP2495H US CNI Frame Relay Replacements, page 73, and explain what the green coloring of Score – Schedule in Number 5 indicates.

Response:

Risk # 5 in the Execution Risk Appraisal section of the Investment Sanction paper 2495H pertains to the risk of schedule delays that may be caused by finalizing the maintenance and support contract with the vendor. The green color in the risk #5 of the Section 3.8 Execution Risk Appraisal represents "very low impact if any/less than 1 week" impact on the project schedule, in case the risk became an issue. National Grid's IS Department uses a red/amber/green color scheme to denote high/medium/low risk impact.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty

Division 22-8

Request:

Please refer to the Company's response to DIV 9-2, Attachment DIV 9-2-2, Allocated Cost Breakdowns, page 27, and explain if the allocated costs for the USFP changed from what is shown in Appendix A during its implementation. If so, please explain why and provide a table showing the allocation changes by date changed.

Response:

Yes, the allocated costs for the USFP changed from what is shown in Appendix A in two ways. First, National Grid USA Service Company, Inc.'s cost allocation rates are updated annually based on the underlying allocation factors upon which the rates are based. The all company General Allocator is the cost allocation methodology used by National Grid USA Service Company, Inc. to allocate the cost of the USFP-related assets to all US companies. Second, the implementation of the USFP systems included a change in the calculation of the General Allocation rates. At the time of implementation of USFP the Company consolidated two existing service companies into the current service company (i.e., National Grid USA Service Company, Inc.). Each service company had its own legacy allocation method, and National Grid could only use one method in the combined service company. Therefore, the three point allocation method was chosen as this method minimized customer impact. The change was approved in the Company's last general rate case (Docket No. 4323). The General Allocator rates for each participating company are currently based on the three point average of Net Plant, Net Operating & Maintenance Expense, and Net Margin of each National Grid company that derives a benefit from USFP-related assets. The sanction paper included the previous general allocation rates that were based on Net Operating & Maintenance Expense only. The Company's response to Division 3-32, which is provided as Attachment DIV 22-8 for ease of reference, includes the table representing the G020 General Allocator, 3-Point Formula for Fiscal Year 2018 that is used to allocate USFP-related costs.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty

Division 3-32

Request:

With respect to each of the Technology Modernization Program projects identified in Schedule ISP-1, please provide the allocator used to estimate the cost to Narragansett Electric's distribution businesses for each of the projects. Please also explain why the chosen allocator is reasonable for each.

Response:

The purpose of the Technology Modernization Program is to modernize obsolete Information Systems (IS) technology and services that inhibit employee performance and affect service to customers. The Technology Modernization Program directly impacts the Company's ability to deliver core operational capabilities applicable to each jurisdiction by fixing the foundational assets upon which IS operates. These enhancements will be experienced through improved reliability, use ability, speed, and efficiency across all functions while reducing the risk of system failure. The IS infrastructure assets, applications, and services that the Technology Modernization Program intends to address are National Grid USA Service Company, Inc. (Service Company) assets that transcend the business. Therefore, each benefitting company is allocated its share of the expenditures using a FERC-approved G-020 Cost Allocation Method.

The FERC-approved G-020 Cost Allocation Method used to allocate Service Company costs associated with the investments in the Technology Modernization Program is based on the 3-Point Formula (Net Plant, Net Margin, Net O&M), as depicted in Attachment DIV 3-32.

Prepared by or under the supervision of: John Gilburt, Daniel DeMauro, and Mukund Ravipaty

G - General Allocator, 3-Point Formula

G-020

Description:

The purpose of this sheet is to provide a listing of the companies that make up the G-020 FERC approved allocator used to allocate Service Company charges based on the 3-Point Formula (Net Plant, Net Margin, Net O&M).

Description	Alloc. Code	SAP Co./Seg.	SAP Co. Code	SAP Segment	Company Description	3 Pt. Allocation %	3 Pt. Allocation %	Net Margin	Net Plant	Net O&M
All KeySpan and NG Companies	**G-020**	5020R	5020	PARENT	National Grid USA Parent	0.09%	0.09%	$ -	$ -	$ 10,678,534
	G-020	5040R	5040	PARENT	KeySpan Energy Corp.	0.01%	0.01%	$ -	$ -	$ 669,841
	G-020	5210E	5210	NYELEC	Niagara Mohawk Power Corp.- Electric Distr.	15.72%	15.72%	$ 1,198,921,609	$ 4,264,491,304	$ 619,066,340
	G-020	5210G	5210	NYGASD	Niagara Mohawk Power Corp. - Gas	4.75%	4.75%	$ 346,680,591	$ 1,491,438,437	$ 165,095,195
	G-020	5210T	5210	NYTRAN	Niagara Mohawk Power Corp. - Transmission	5.59%	5.59%	$ 385,690,791	$ 2,415,788,723	$ 106,731,443
	G-020	5220G	5220	NYGASD	KeySpan Energy Delivery New York	12.38%	12.38%	$ 993,070,386	$ 3,676,541,909	$ 416,418,656
	G-020	5230G	5230	NYGASD	KeySpan Energy Delivery Long Island	8.51%	8.51%	$ 668,892,495	$ 2,981,821,126	$ 225,375,331
	G-020	5310E	5310	MAELEC	Massachusetts Electric Company	20.02%	20.02%	$ 1,598,840,493	$ 2,680,685,854	$ 1,159,865,088
	G-020	5310T	5310	FRTRAN	Massachusetts Electric Company - Transmission	0.17%	0.17%	$ 17,339,390	$ 52,007,344	$ 4,203,096
	G-020	5320E	5320	MAELEC	Nantucket Electric Company	0.27%	0.27%	$ 22,878,224	$ 68,758,022	$ 10,060,149
	G-020	5330G	5330	MAGASD	Boston Gas Company	9.03%	9.03%	$ 716,665,901	$ 2,406,613,994	$ 347,617,727
	G-020	5340G	5340	MAGASD	Colonial Gas Company	2.04%	2.04%	$ 161,327,519	$ 581,444,275	$ 73,390,098
	G-020	5360E	5360	RIELEC	Narragansett Electric Company	6.60%	6.60%	$ 574,052,546	$ 926,658,890	$ 353,600,201
	G-020	5360G	5360	RIGASD	Narragansett Gas Company	2.85%	2.85%	$ 231,782,063	$ 761,289,647	$ 106,868,890
	G-020	5360T	5360	FRTRAN	Narragansett Electric Company - Transmission	1.77%	1.77%	$ 133,930,510	$ 862,645,421	$ 13,013,773
	G-020	5410T	5410	FRTRAN	New England Power Company - Transmission	5.00%	5.00%	$ 378,086,156	$ 2,221,166,435	$ 69,879,050
	G-020	5411F	5411	FRELEC	NE Hydro - Trans Electric Co.	0.17%	0.17%	$ 16,753,717	$ 31,800,443	$ 7,178,838
	G-020	5412F	5412	FRELEC	New England Hydro - Trans Corp.	0.11%	0.11%	$ 11,910,006	$ 4,272,818	$ 6,000,534
	G-020	5413F	5413	FRELEC	New England Electric Trans Corp	0.01%	0.01%	$ 1,374,412	$ 0	$ 204,770
	G-020	5420G	5420	FRGASO	NG LNG LP Regulated Entity	0.17%	0.17%	$ 8,230,443	$ 82,150,480	$ 3,828,666
	G-020	5430P	5430	FRPGEN	KeySpan Generation LLC (PSA)	4.04%	4.04%	$ 464,650,405	$ 594,113,557	$ 156,428,992
	G-020	5431P	5431	FRPGEN	KeySpan Glenwood Energy Center	0.13%	0.13%	$ 11,845,255	$ 38,062,111	$ 4,152,842
	G-020	5432P	5432	FRPGEN	KeySpan Port Jefferson Energy Center	0.15%	0.15%	$ 13,342,875	$ 45,737,978	$ 4,298,071
	G-020	5820R	5820	PARENT	Keyspan Energy Trading Services	0.00%	0.00%	$ -	$ 308,494	$ 158,770
	G-020	5825N	5825	NONREG	Transgas Inc	0.08%	0.08%	$ 3,982,586	$ 7,837,743	$ 6,208,446
	G-020	5840N	5840	NONREG	KeySpan Energy Development Corporation	0.18%	0.18%	$ -	$ 74,017,254	$ 10,567,625
	G-020	5850N	5850	NONREG	KeySpan Services Inc.	0.16%	0.16%	$ 14,478,322	$ 6,613,711	$ 11,009,061
					Total	100.00%	100.00%	7,974,726,692	26,276,265,968	3,892,570,026

Division 22-9

Request:

Please refer to the Company's response to DIV 9-4, Attachment DIV 9-4, and please explain why the NECO G Allocation of 2.85% and Distribution Allocation of 8.37% changed in Rate Year 3 to 2.72% and 8.47%, respectively.

Response:

The Company's response to Division 9-4 pertained to USFP-Projects in Workpaper MAL-6a through Workpaper MAL-6c Service Company Rents, IS Existing Projects.

The Narragansett Gas allocation changed in Data Year 2 because the referenced allocation table used was incorrect. Data Year 2 Service Company Rents were calculated in Workpaper MAL-6c. The allocation percentages used for Data Year 2 should have been identical to the rates used in Data Year 1. The Company will make this correction in the next submission of the cost of service.

This error affected USFP Projects as well as certain other projects listed on Workpaper MAL-6c. The impact of the correction for all affected projects in Workpaper MAL-6c will be an increase of $60,208 to the Narragansett Gas revenue requirement and a decrease of $49,098 to the Narragansett Electric revenue requirement for Data Year 2.

Prepared by or under the supervision of: John Gilbert, Daniel DeMauro, and Mukund Ravipaty