Division 2-1 (Electric)
System Capacity and Reliability

Request:

Discuss and provide additional information for the following budget line items. For distribution projects, provide the engineering justification, miles of line, conductor size, peak loading, capacity, and economic justification.

a.	C23012	63F6 Ext 2 PH down Ten Rod Rd	$200,000
b.	C24221	Load Relief to 9J3 -Brown Street	$400,000
c.	C27245	Relocate 23kV 2227 & 22230	$350,000
d.	C28851	Recon. 38F5 and 2227 Greenville Ave	$300,000
e.	C28884	Install Johnston 18F10 Feeder	$100,000
f.	C28900	Recond. 2228 Johnston sub -Randall	$750,000
g.	C28932	Recon. 0.5 Miles Segment of 2232	$700,000
h.	C32450	03492 Nasonville 127W43	$600,000
i.	C36397	04403 Clarkson - new 13F10 feeder (line)	$200,000
j.	PPM 11646	11646 38K23 Line Upgrade	$300,000
k.	PPM 12728	12728 Harrison Feeder Upgrades	$400,000

Response:

Please refer to Attachment DIV 2-1 (Electric) System Capacity for Company's response.

Prepared by or under the supervision of: Jennifer L. Grimsley

ELECTRIC ISR FILING
SUBMITTED TO THE
DIVISION OF PUBLIC UTILITIES AND CARRIERS
DATA REQUEST 2

28-Nov-2011

Table - SCR1

Project Identification							
Funding Number	Project Type	Project Name	Engineering Justification	Peak Load % (Loading /Capacity) Prior to Solution	Conductor Distance (mi)	Conductor Size	Project Scope
C23012	Distribution Line	63F6 Ext 2 PH down Ten Rod Road	Low voltage due to significant load development (approximately 2.5MVA) at the end of a 3-mile, 1/0 Al single phase line. (Lower cost alternatives, including load shifts have been compeleted in previous years.)	48%	3.0	1/0 Al	Extend two additional phases down Ten Rod Rd in Exeter, from Nooseneck Hill Rd to Escoeag Hill Rd. This will require approximately 10,000 Ft of overhead construction.
C24221	Distribution Line	Load Relief to 9J3 -Brown Street	Area wide equipment overloads during peak conditions. (Load transfers investigated and are not possible.)	9J3 - 93% 77J2 100% 37J4 - 87% 2J1 - 90%	0.1	477 Al	Extend the 79F2 along Brown Street and convert approximately 60A of 4 kV load to 12 kV system. Rearrange 4 kV to alleviate feeder loading in area after conversion.
C27245	Sub-Transmission	Relocate 23kV 2227 & 2230	The 2227 and 2230 sub-transmission lines must be relocated to accommodate the reconstruction of two existing 115kV lines (S171 & T172) and the construction of a new 345kV Line (Line 359). The construction of a new 345kV line and the reconstruction of the two 115kV lines is part of a comprehensive regional plan to improve transmission reliability in the New England area. This Ne England East-West Solution (NEEWS) project is currently in construction.	N/A	N/A	N/A	The S171 and T172 115 kV transmission lines will be rebuilt for a distance of approximately 20.2 miles each in order to create space on the existing right-of-way corridor to allow for the construction of the new 359 Line. To allow for this construction, the 2227 & 2230 23kV supply lines need to be relocated along this corridor.
C28851	Distribution Line & Sub-Transmission	Recon. 38F5 and 2227 Greenville Ave	Equipment overload during peak and emergency conditions. (Load transfers investigated and are not possible.) The 2227 is overbuilt construction on the 38F5 pole line.	38F5 - 100%	1.5	795 Al / 477 Al	Reconductor the 2227 with 795 kcmil Al and the 38F5 feeder with 477 kcmil Al between P187 Greenville Ave and P.9396 and 38F5 between P9396 Greenville and P.171 Putnam Pike.
C28884	Distribution Line	Install Johnston 18F10 Feeder	Area wide equipment overloads during peak conditions. (Load transfers investigated and are not possible.)	18F1 - 111% 18F3 - 90% 18F7 - 100% 21F2 - 94%	0.8	Various	Install a new feeder getaway at Johnston, construct approximately 4,200 ft of mainline and rearrange the area distribution.
C28900	Sub-Transmission	Recond. 2228 Johnston sub -Randall	Equipment overload during peak and emergency conditions. (Load transfers investigated and are not possible.)	2228 - 100%	2.4	795 Al	Install 795 kcmil Al on the 2228 line from Johnston substation to Randall St.
C28932	Sub-Transmission	Reconductor 0.5 Miles Segment of 2232 Line	Equipment overload during peak and emergency conditions. (Load transfers investigated and are not possible.)	2232 - 124%	0.5	795 ACSR	Replace the 2/0 Al conductor on the 2232 line from P9214 Centerville Road to P9199 Inskip Way with 795 ACSR conductor.
C32450	Distribution Line	Nasonville 127W43	Equipment overload during peak conditions. (Load transfers investigated and are not possible - load controlled by municipal electric company.)	127W43 - 100%	2.0	477 Al	To upgrade the capacity of the Nasonville 127W43 built two miles of new circuit parallel to the existing 127W43.
C36397	Distribution Line	Clarkson - new 13F10 feeder	Equipment overload during peak conditions and unserved load during emergency conditions. (Load transfers investigated and are not possible.)	13F2 - 100% 13F3 - 92% 13F4 - 89% 13F8 - 90%	0.3	1000 XLPE CU	New 13F10 feeder. Install new UG getaway from Sub to P12 Whipple St (1500' in existing MH&D).
CD0410 / PPM 11646	Sub-Transmission	38K23 Line Upgrade	Equipment overload during peak conditions and unserved load during emergency conditions. (Load transfers investigated and are not possible.)	38K23 - 105%	0.4	350 Cu EPR	Upgrade limiting section on 38K23 supply line to increase capacity. From Riser Pole P1 2nd St to MH 245, replace the existing 250 CU P&L cable with 3-1/C 350 CU EPR CN 25kV cable. Utilize cable with compact stranding and flat strap neutra to fit into
PPM 12728	Distribution Line	Harrison Feeder Upgrades	Equipment overload during peak conditions. (Load transfers investigated and are not possible.)	32J12 - 100%	0.6	Various	**32J2 Feeder:** Replace the 3-1/C 750 Cu cable installed 1 per duct with 3-1/C 500 Cu EPR CN 15kV cable installed in a single duct. **32J12 Feeder:** From MH228 to MH229 install a 2nd set of 3-1/C 500 Cu EPR CN 15kV cable. Operate both sets o cable in paral

Division 2-1 (Electric)
System Capacity and Reliability

Request:

Discuss and provide additional information for the following budget line items. For distribution projects, provide the engineering justification, miles of line, conductor size, peak loading, capacity, and economic justification.

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j.	PPM 11646	11646 38K23 Line Upgrade	$300,000
k.	PPM 12728	12728 Harrison Feeder Upgrades	$400,000

Response:

Please refer to Attachment DIV 2-1 (Electric) System Capacity for Company's response.

Prepared by or under the supervision of: Jennifer L. Grimsley

ELECTRIC ISR FILING
SUBMITTED TO THE
DIVISION OF PUBLIC UTILITIES AND CARRIERS
DATA REQUEST 2

28-Nov-2011

Table - SCR1

Project Identification							
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Division 2-2 (Electric)
System Capacity and Reliability

Request:

For the station projects given below, provide the existing and proposed station capacity, peak loading, contingency loading, and forecasted loading for all substation projects. Discuss any distribution alternatives that were explored in lieu of the station upgrades.

a. West Warwick
b. Hopkinton
c. Coventry
d. Newport
e. Johnston
f. Kilvert
g. Highland Drive

Response:

The table below provides the existing and proposed substation capacities for the substations referenced above. Also included are the estimated peak substation loading for the first year of expected operation and the forecasted loading for the fiscal year 2025. For single transformer stations, contingency loading is not applicable since station load will be manually transferred to adjacent stations to the extent that feeder ties allow. For substations with two transformers, load will be automatically transferred to the remaining transformer, i.e. contingency load is equal to station load.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-2 (Electric), p2
System Capacity and Reliability

Substation	Number of Distribution Transformers per Station	Existing Station Capacity	Proposed Station Capacity	Peak Station Loading	Forecasted Station Loading (2025)	N-1 Contingency Capacity
West Warwick	1	New Station	55 MW	30 MW	38 MW	N/A
Hopkinton	2	New Station	110 MW	55 MW	69 MW	60MW
Coventry	1	New Station	14 MW	11 MW	13 MW	N/A
Newport	2	New Station	110 MW	35 MW	41 MW	60MW
Johnston	2	121MW	N/A(One Transformer Replacement)	72MW	98MW	65MW
Kilvert Install 2nd Transformer	2	67 MW	134 MW	32 MW	39MW	84MW
Highland Drive	2	New Station	110 MW	43MW	45MW	60MW

Alternatives – Except for the two projects described below for which scopes are still being developed, alternatives are described in the attached sanction documents.

- West Warwick – Attachment 1 DIV 2-2 (Electric) System Capacity
- Hopkinton – Attachment 2 DIV 2-2 (Electric) System Capacity
- Coventry – Attachment 3 DIV 2-2 (Electric) System Capacity
- Newport – Attachment 4 (Electric) System Capacity
- Johnston – Attachment 5 (Electric) System Capacity

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-2 (Electric), p3
System Capacity and Reliability

These sanction documents are used in the justification of the work beginning at the conceptual level. As a project progresses through engineering and into construction the papers will be reviewed again for approval against new estimates. By way of example, the West Warwick substation project has encountered challenges regarding its location and the project team is currently evaluating alternative locations. As those issues are resolved, a revision to the sanction paper will be considered for approval.

Kilvert Street - The plan for Kilvert Street is still being developed. Alternatives will be developed during the plan development phase. Additional project details are described in the response to System Capacity & Reliability Question 2-3 (Electric).

Highland Drive Sub – This proposed 115 kV/13.8 kV two-transformer substation will address a number of area capacity issues as well as significant commercial growth. The Riverside and Staples substations have 290 and 593 MWHrs at risk exceeding distribution planning criteria. Commercial growth includes a CVS Caremark facility of 3.5 MVA located in Cumberland, RI. In addition CVS will be requesting guaranteed second feeder service (SFS) for this new 3.5 MVA of load as well as their existing load (4.5MVA) at their data center located in Woonsocket, RI. This substation will provide much needed relief to the Riverside and Staples substations and satisfy customer needs for normal and reserve capacity in this rapidly developing area. The substation will be located in the Highland Corporate Industrial Park with an estimated load of 33 MVA in 2014 (including guaranteed SFS reserved capacity). (Any CVS-related CIAC will be determined following a study of their service interconnection requirements which is expected to be completed in March 2012).

Prepared by or under the supervision of: Jennifer L. Grimsley

Capital/Revenue Investment Proposal – Summary

Project Title: West Warwick Substation - Install Metal Clad Switchgear withFour Distribution Feeders and Rebuild the 3310 and 3311 Sub-transmission Lines

Line of Business:Distribution

Regulatory Entity:Narragansett Electric

Projects #:C28920, C28921, C30161 and C30162

A **Sanction** by **Author/Sponsor: Chris Worme/Rob Sheridan**

Date: 10/01/2008

Description

A new 115/12.47 kV substation with four distributions feeders is being constructed to add distribution capacity in an area that is heavily loaded. This new capacity will relieve transformers, supply lines and distribution feeders that are projected to exceed their ratings by 2012.

C28920 – Approve preliminary engineering for the design a new 115/12.47 kV metal clad substation.

C28921 – Approve preliminary engineering for the design of feeder getaways from new substation.

C30161 – Approve preliminary engineering for design of 3310 line reconductoring.

C30162 – Approve preliminary engineering for design of 3311 line upgrades

Category: ☐**Mandatory**
☒**Policy-driven**
☐**Pure NPV**

BIT score: **39**

Primary Driver: ☐ **Health and Safety** ☐ **Mandatory** ☐ **NPV**
☐ **Transmission** ☐**Committed**
☐ **Environment** ☒**Reliability**

Finance

Sanction Cost **$0.365M**

Probability that project cost will exceed 25% tolerance: **NA**

Project included in approved Business Plan? ☒**Yes** ☐ **No**

Project cost relative to approved Business Plan **+/-$0.365M**

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

Other financial issues: ☒None If some please explain:

$M	Current planning horizon								
	Prior YR'S	**Yr 1 08/9**	**Yr 2 09/10**	**Yr 3 10/11**	**Yr 4 11/12**	**Yr 5 12/13**	**Yr 6+**	***Total***	
Proposed investment			0.320	2.120	1.065			3.505	

Resources

Availability of internal resources to deliver project: ☐**Red** ☐**Amber** ☒**Green**

Availability of external resources to deliver project: ☐**Red** ☐**Amber** ☒**Green**

Operational impact on network system: ☐**Red** ☐**Amber** ☒**Green**

Key issues (Highlight any significant issues associated with the project)

- A System Impact Study is presently ongoing within the Transmission Planning group. The results of this study will more fully define the scope of any associated Transmission projects. Should the results of this study have a material impact on the costs or schedule of the distribution projects covered by this paper, a revised paper will be brought to the DCIG for review. Upon completion of the System Impact Study, associated Transmission projects will be brought to the AMIC for Strategy review.

Key milestones

- Preliminary Engineering - 08/2009
- Full Spend Sanction Request - 01/2010
- Commissioning – 06/2011
- Completion – 08/2011
- Project Closure - 10/2011

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**

Are financial incentives (e.g. carbon credits) available? ☐**Yes** ☒**No**

Prior sanctioning history including relevant approved Strategies – None

Associated Projects

Project Number	Project Description	Projected Type	Sanction Amount
TBD	**Install West Warwick Substation - Transmission**	**Transmission**	**$2.800M**
TBD	**Install 115 kV Transmission Tap**	**Transmission**	**TBD**

Recommendations

The ☒ **DCIG** ☐**DEC** is invited to:

(a) APPROVE the investment of **$ 0.365 M** for preliminary engineering**.**

(b) NOTE that **Rob Sheridan** is the Project Sponsor

(c) NOTE that **Sergey Goldgaber** is the Project Manager.

(d) NOTE: It is expected that the project will be brought before DCIG for further sanction upon completion of preliminary engineering.

Decision of the Sanctioning Authority

I hereby approve the recommendations made in this paper.

Signature Date

[Name and title of sanctioning authority]

Capital/Revenue Investment Proposal – Summary

Project Title: West Warwick substation - Install Metal Clad Switchgear with Four Distribution Feeders and Rebuild the 3310 and 3311 Sub-transmission Lines

Line of Business: Distribution

Regulatory Entity: Narragansett Electric

Projects #:C28920, C28921, C30161 and C30162

A **Sanction** paper by **Author/Sponsor: Chris Worme/Rob Sheridan**

Date: 10/01/2008

1. Background

The Central Rhode Island West study area encompasses the Towns of Coventry, West Greenwich, and West Warwick and sections of the Cities of Cranston and Warwick, and Towns of East Greenwich, Exeter, and Scituate. The area load is projected to be 344 MVA in 2011 with approximately 47,000 customers served. The study area and existing area substations are shown in Figure 1.

Study of this area identified a number of transformers, feeders, and supply lines that are projected to be overloaded within the next five years. A new substation on Tiogue Avenue in Coventry RI was recommended and previously sanctioned to address projected feeder overloads in the western part of the study area through 2010. Load transfers were utilized to reduce feeder loads below the ratings of the feeders in other parts of the study area.

After all the possible load transfers have been utilized, six feeders are projected at or over 100% of rating in 2011 with another three feeders projected at 99% of rating. Further capacity additions are required to address these projected feeder overloads together with the projected transformer and supply line overloads.

2. Driver

The primary driver is projected thermal overloads of transformers, distribution feeders, and supply lines during periods of system peak loading. There have been a number of large developments in the area such as The Centre of New England and the Royal Mills complex that continue to add load to an area with heavily loaded feeders and supply lines. Load transfers have been utilized to prevent thermal overloads as a result of the new load additions and a total of nine feeders are projected at or near 100% by 2011.

The tables below show the facilities in the study area that are projected to exceed 100% of their rating by 2012 during either normal operation or during contingencies where load is automatically picked up by the remaining facilities. Table 1 below shows feeders in the area with loads projected to exceed 100% of their normal rating after the new MITS substation has been placed in service; Table 2 shows transformers with loads projected to exceed 100% of their normal rating; and Table 3 shows the supply lines that are overloaded during contingencies. Projected loads are based on actual 2007 loads and the 2008 PSA forecast for this area. Actual 2008 loads have been compared to projected loads and adjustments made where appropriate.

		2009		2010		2011		2012	
Station	Feeder	(A)	% SN	(A)	% SN	(A)	% SN	(A)	% SN
Anthony	64F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coventry	54F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Drumrock	14F4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hope	15F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kent County	22F3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kent County	22F4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natick	29F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natick	29F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
West Cranston	21F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 1 – Projected Loads through 2012 for Feeders with Loads Greater Than 100%

Note: The table assumes the new Tiogue Avenue substation is in service prior to June 1, 2010

		2009		2010		2011		2012	
Station	Transformer	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN
Anthony	T2	7.6	98	7.8	100	8.0	102	8.2	105

Table 2 – Projected Loads through 2012 for Transformers with Loads Greater Than 100%

	Segment		2009		2010		2011		2012	
Supply Line	From	To	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN
2230	Drumrock	Natick Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	Natick Tap	Arctic Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	Arctic Tap	Anthony Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	W. Mall Tap	Natick Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2232	Drumrock	V.Hydro Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2232	Arctic Tap	Anthony Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3310	K County Sub	Major Potter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3310	Major Potter	Hopkins H. Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3311	K County Sub	Hopkins H. Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3311	Hopkins H. Tap	Hopkins H. Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3 – Projected Contingency Loads through 2012 for Supply Line Segments with Loads Greater Than 100%

3. Project Description

A new 115/12.47 kV metal clad substation with a 24/32/40 MVA LTC transformer with an ultimate capacity of five feeder positions, is proposed for New London Ave., West Warwick. The station will be located adjacent to the transmission corridor between West Cranston and Drumrock substations and supplied by a 115 kV tap from an existing transmission line. A transmission impact study is underway to determine whether the supply will be from the S-171S or T-172S line. The proposed location of the new substation is shown in Figure 2 and a proposed one line is shown in Figure 3.

Initially, four 12.47 kV feeders will be installed and the distribution system will be rearranged to offload existing transformers, supply lines and distribution feeders. Approximately 300 kVA of 4 kV load in the area will be converted to 12.47 kV to accommodate the feeder getaways at the new station. The layout of the 12.47 kV distribution feeders, after installation of the station, is shown in Figure 4.

Table 4 below shows projected feeder loads after the new substation has been placed in service; Table 5 shows transformer loads; and Table 6 shows the supply line loads and Table 7 shows the supply line loading after upgrades of the lines.

		2009		2010		2011		2012	
Station	Feeder	(A)	% SN	(A)	% SN	(A)	% SN	(A)	% SN
Anthony	64F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coventry	54F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Drumrock	14F4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hope	15F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kent County	22F3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kent County	22F4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natick	29F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natick	29F2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
West Cranston	21F1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4 – Projected Feeder Loads through 2012 with West Warwick in Service

Note: This table assumes the new Tiogue Avenue substation is in service prior to June 1, 2010

		2009		2010		2011		2012	
Station	Transformer	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN
Anthony	T2	7.6	98	7.8	100	4.0	51	4.1	52

Table 5 – Projected Transformer Loads through 2012 with West Warwick in Service

	Segment		2009		2010		2011		2012	
Supply Line	From	To	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN
2230	Drumrock	Natick Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	Natick Tap	Arctic Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	Arctic Tap	Anthony Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2230	W. Mall Tap	Natick Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2232	Drumrock	V.Hydro Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2232	Arctic Tap	Anthony Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3310	K County Sub	Major Potter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3310	Major Potter	Hopkins H. Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3311	K County Sub	Hopkins H. Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3311	Hopkins H. Tap	Hopkins H. Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6 – Projected Supply Line Contingency Loads through 2012 with West Warwick in Service

There are two sections of the 3310 and 3311 supply lines that are projected to be overloaded on contingency after the new station is in service in 2011. These lines are classified on the books as transmission assets. The estimated cost of reconductoring approximately 5,000 ft of the 3310 line to eliminate the overloads is estimated at $380,000 and the cost of upgrading the 3311 for 120°C operation is $55,000. The alternative to the reconductoring and upgrade is to remotely drop a feeder at Hopkins Hill substation on a supply line contingency. It is recommended that these two circuits be upgraded. There is an amount of $45,000 included in this paper to cover the cost of preliminary engineering for these two projects.

The projected loading of these circuits when the upgrades are completed is shown below.

	Segment		2009		2010		2011		2012	
Supply Line	From	To	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN	(MVA)	% SN
3310	K County Sub	Major Potter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3311	K County Sub	Hopkins H. Tap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 7 – Projected Supply Line Contingency Loads through 2012 after Reconductoring and Upgrade of Lines

4. Business Issues

There is a total of $3,070,000 estimated for the distribution component of the project in the FY09/10, FY10/11 and FY11/12 capital plans. Of this total there is $310,000 capital, $15,000 O&M and $5,000 removal included in the FY09/10 distribution substation and line budgets.

There will be associated transmission costs that are necessary to support this project. The estimate for the supply line reconductoring and upgrades is $435,000 and the estimate for the transmission component of the substation construction is $2,500,000.

In addition to the transmission substation component and supply line costs, it will be necessary to tap a 115 kV transmission line and add sectionalizing devices to the main line. The review of this transmission component has not yet been completed but is expected to range from $500,000 to $2,800,000 depending on the recommendations of the impact study to provide the desired level of reliability.

5. Options Analysis

The no build option will result in thermal overloads to the distribution equipment and ultimately lead to equipment failure unless service is interrupted to customers on these feeders during high load conditions. Operating the system by interrupting load to customers will have a negative impact on system reliability and possibly lead to increased regulatory oversight and penalties.

There are several build alternatives that were considered. One alternative involved the expansion of existing 115/12.47 kV substations at West Cranston and Kent County together with expansion of the 23 and 35 kV supply systems at Drumrock and Kent County substations. The supply lines would have to be rebuilt for a larger capacity to accommodate two new modular stations in West Warwick and Coventry. It will be necessary to procure sites with the appropriate zoning for each station. The distribution system will be modified to accommodate the new stations. The estimated distribution cost of this option is $11,300,000. There will be an additional $3,800,000 in associated transmission costs. This option exceeded the cost of the preferred option; there are no additional benefits; and the uncertainty of finding appropriate lots make this option unattractive at this time.

A second alternative considered was the development of a new 115/12.47 kV metal clad station on a site in Cranston near Phenix Avenue. The transmission costs are similar to the preferred plan however the distribution costs to extend feeders from this site to relieve the overloaded feeders and supply lines would be significantly more due to the limited routes available and the distance from the overloaded facilities. The details of this option were not fully developed as the estimated distribution costs far exceeded those of the preferred alternative which was near the stations with loading issues. This option is also not recommended at this time.

6. Milestones

- Preliminary Engineering – 08/2009
- Full Spend Sanction Request – 01/2010

- Project commissioning – 06/2011
- Project completion – 08/2011
- Project closure – 10/2011

The transmission lines on the r-o-w, adjacent to the substation site, will be relocated as part of the NEEWS project. Approval is necessary to proceed with preliminary engineering in the first quarter of FY09/10 so that the station layout may be coordinated with the transmission project.

7. Safety, Environmental and Planning Issues

The site on New London Avenue is part of a parcel purchased for the transmission r-o-w but is not included as part of the 250 ft corridor. There are wetlands in other locations on the property; however, the proposed substation site is on an elevated section of the lot. An environmental assessment will be made prior to proceeding with final design.

There are several wet sections along the r-o-w containing the 3310 and 3311 lines. Permits may be required to replace the poles however this is not expected to have any impact on the project schedule.

8. Investment Recovery

8.1 Investment Classification

The investment is classified as policy driven. Without this project the company will not be unable to provide a reliable electric service to the customers in the study area.

8.2 Regulatory Implications

The Company franchise to distribute electricity obligates the Company to have the necessary facilities to provide a reliable electric service. The no build option will lead to a reduced level of reliability and possible regulatory penalties.

8.3 Customer Impact

No immediate impact. The costs will ultimately be included in rate base.

9. Financial Impact

9.1 Cost Summary

			Current Planning Horizon $000's							
Project #	**Project Description**	**$M 000's**	**Prior YR Spending**	**YR1 08/09**	**YR2 09/10**	**YR3 10/11**	**YR4 11/12**	**YR5 12/13**	**YR6 +**	**Total**
C28920	**Install Distr. Sub – West Warwick**	**Capex**			0.200	1.100	0.500			1.800
		Opex			0.005	0.010	0.005			0.020
		Removal								-
		Total			0.205	1.110	0.505		-	1.820
C28921	**Install 4 Dist. Fdrs West Warwick**	**Capex**			0.100	0.800	0.200			1.100
		Opex			0.010	0.080	0.010			0.100
		Removal			0.005	0.040	0.005			0.050
		Total		-	0.115	0.920	0.215	-	-	1.250
C30161	**Install 795 Al cond. on 3310 Line**	**Capex**				0.035	0.300			0.335
		Opex					0.015			0.015
		Removal					0.030			0.030
		Total		-		0.035	0.345	-	-	0.380
C30162	**Upgrade the 3311 Line for 120C Oper.**	**Capex**				0.040				0.040
		Opex				0.005				0.005
		Removal				0.010				0.010
		Total		-		0.055		-	-	0.055
	Total Proposed Sanction	**Capex**		-	0.300	1.975	1.000	-	-	3.275
		Opex		-	0.015	0.095	0.030	-	-	0.140
		Removal		-	0.005	0.050	0.035	-	-	0.090
		Total		-	0.320	2.120	1.065	-	-	3.505

This Project was budgeted for **$0M** Capex in the current fiscal Year (FY2009).

9.2 Cost Assumptions

Standard material procurement process to be followed, and there are no expected delivery delays.

The overall distribution substation project (C28920) estimate is a conceptual estimate (+/- 25%) from substation design template.

The overall distribution line project (C28921) estimate is a conceptual estimate (+/- 25%) using the distribution design cost estimate guideline. A breakdown of the costs by labour and materials is not available at this time but will be prepared as part of the preliminary engineering scope.

The overall transmission line project (C30161) estimate is a conceptual estimate (+/- 25%) using the distribution design cost estimate guideline. A breakdown of the costs by labour and materials is not available at this time but will be prepared as part of the preliminary engineering scope.

The overall transmission line project (C30162) estimate is a conceptual estimate (+/- 25%) using the distribution design cost estimate guideline. A breakdown of the costs by labour and materials is not available at this time but will be prepared as part of the preliminary engineering scope.

Engineering & design resources to be provided: ☒ **Internal** ☐ **Contractor**

Construction to be provided: **N/A;** will be identified on completion of preliminary engineering and finalized at project sanction

9.3 Benefits Summary

There are no direct financial benefits arising from this project

9.4 NPV

N/A

9.5 Additional Impacts

None

10. Execution Risk Appraisal

The substation site is adjacent to the r-o-w on which the transmission lines are being reconfigured as part of the NEEWS transmission project. Transmission has been made aware of the need to install additional distribution capacity and tap the transmission line. An attempt will be made to incorporate the tap to the substation in the design of the new transmission structures. The transmission design has not yet been completed, but it is expected that there will be adequate room on the r-o-w to tap the line.

A zoning variance will be necessary for the substation construction. Although the site abuts a residential complex obtaining a variance is not expected to be a problem; however additional screening of the substation may be required.

The r-o-w with the 3310 and 3311 lines has a section of wetlands that will require permitting. This could impact the schedule of projects C30161 and C30162 if there is a delay in obtaining these permits

11. Statements of Support

N/A

12. Recommendation

The ☒**DCIG** ☐**DEC** is invited to:

(a) APPROVE the investment of $ 0.365 M for preliminary engineering.

(b) NOTE that Rob Sheridan is the Project Sponsor

(c) NOTE that Sergey Goldgaber is the Project Manager.

(d) NOTE: It is expected that the project will be brought before DCIG for further sanction upon completion of preliminary engineering.

Supporting signatures (not required if DCIG minutes reflect approval of paper)

Investment planning

Signed Date
Christian Brouillard, Director, Investment Management

On behalf of Regulation by

Signed Date
Peter Zschokke, Director US Regulatory Strategy & Research

On behalf of Procurement by

Signed Date
Jeffrey Way, VP Procurement

Sponsor's Signature

(Required)
Signed Date
Patrick Hogan, Sr. VP Network Strategy

Decision of the DCIG Sanctioning Authority
(Required)

I hereby approve the recommendations made in this paper

Signed Date
Executive VP Electricity Distribution, National Grid

13. Appendices

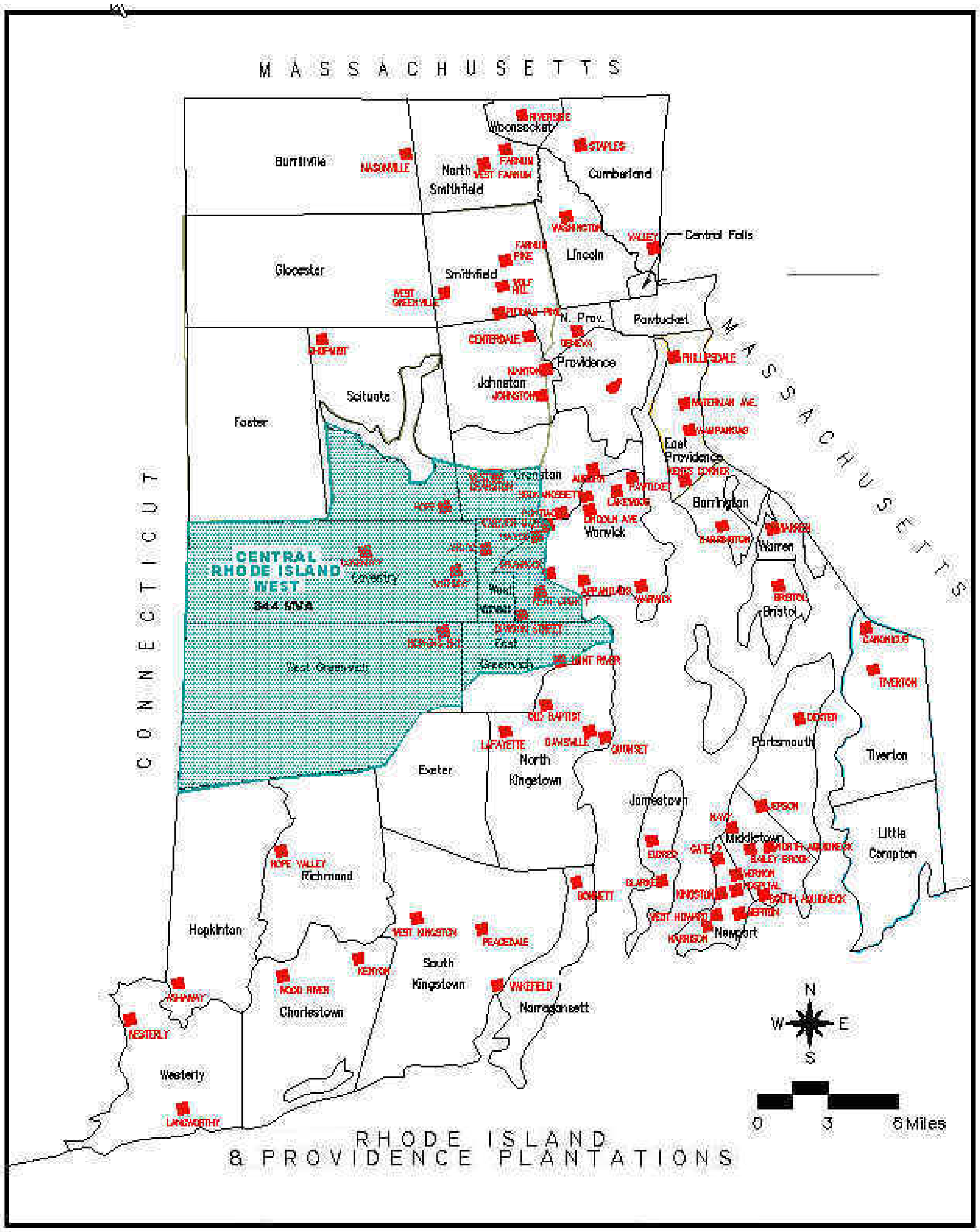


Figure 1 Central Rhode Island West Study Area

This document has been redacted for Critical Energy Infrastructure Information (CEII).

Figure 2 Proposed Location of West Warwick Substation

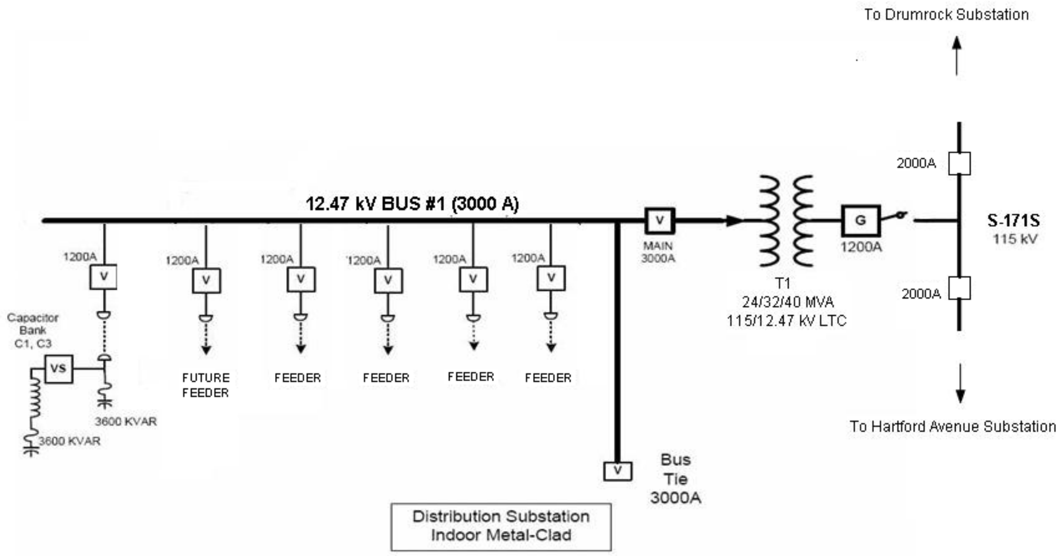


Figure 3 Proposed One-line: New West Warwick Substation

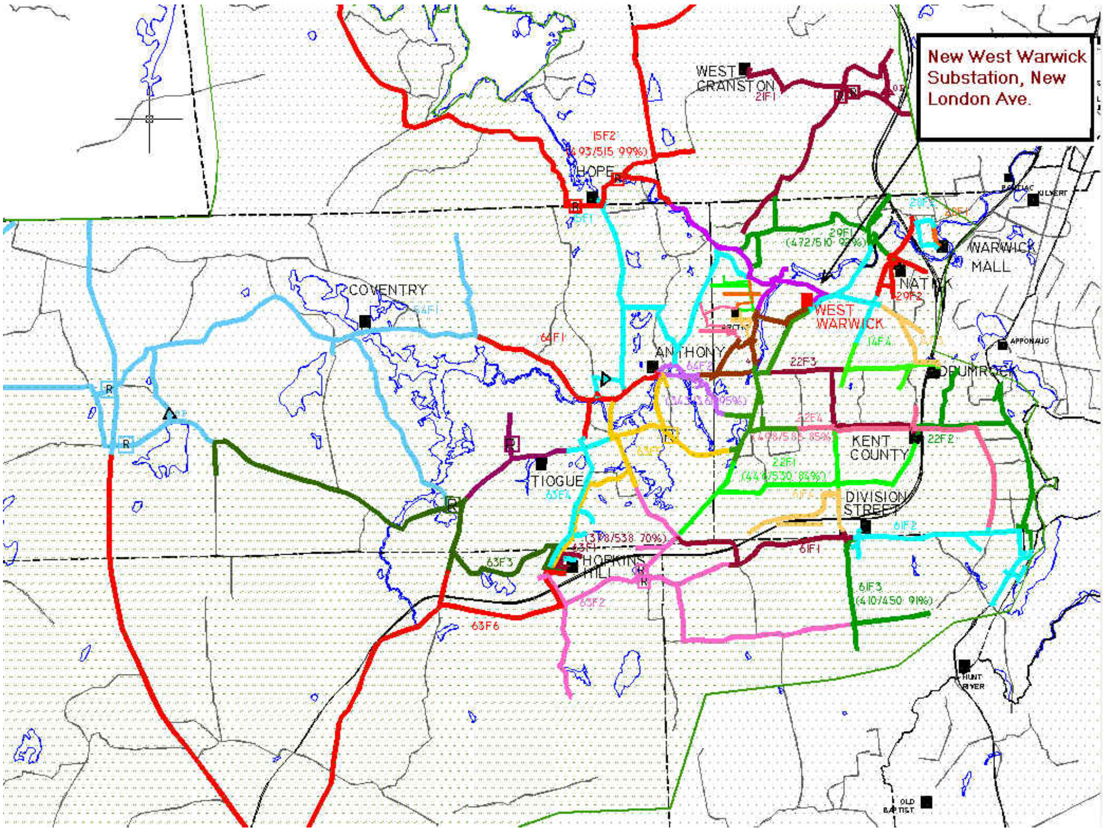


Figure 4 Proposed Layout of Feeders After Installation of New West Warwick Substation

Strategy Paper

Sanctioning Authority	DCIG
For DCIG approval Sanction or re-sanction	Sanction
Strategy, project, program	Projects
Title of the Paper	Hopkinton New Substation Installation
Operating Company	Narragansett Electric
Scheme / project Number(s)	Funding Projects C24175, C24176
Author(s)	Jack P. Vaz
Project Classification	Capital – multiple projects
Meeting Date	April 2, 2008
Total sanction value	$250,000
Completion date of project	June 1, 2010
Specific materials or labour requirements	None

Duty Holders	**Scheme Sponsor**	Robert Sheridan
	Project Manager	Sergey Goldgaber

1. Executive Summary

a) This paper proposes preliminary engineering expenditures of $250,000 to develop project grade estimates to establish a new substation in the town of Hopkinton that will serve the South Western Rhode Island (SWRI) area.

b) This project is needed for load relief. The 2007 Annual Plan identified a number of concerns in the SWRI area. The concerns identified are as follows:

- In 2010, loading on 3 - feeders is projected to exceed Summer Normal (SN) ratings.
- In 2010, loading on 1 - transformer is projected to exceed SN ratings and contingency loading on 3 - transformers is projected to exceed Summer Emergency (SE) ratings.
- In 2010, loading on 1 - supply line is projected to exceed SN ratings and contingency loading on 2 – supply lines is projected to exceed SE ratings.

c) To provide relief to area facilities, the following work is recommended:

- Tap the existing 115kV line (1870S). Install 2 - sets of breaker disconnects and 2 - load break switches (Transmission).
- Install a 24/32/40 MVA, 115/13.2kV LTC transformer and circuit switcher on an NGRID owned site adjacent to the 115kV right-of-way (Transmission).
- Install metal clad switchgear with 3 – feeder positions and a 7.2 MVAR 2 – stage capacitor bank (Distribution).
- Upgrade and reconfigure existing area distribution system (Distribution).

d) The Associated Projects are:

- Distribution Substation Project – C24176
- Distribution Line project – C24175
- Transmission Line Project – TBD
- Transmission Substation Project - TBD

2. Background

a) The SWRI area encompasses the towns of Charlestown, Hopkinton, Richmond, Westerly, and a section of South Kingstown. This area has 27,000 customers and about 115MW of load.

b) Six substations supply the SWRI area. Combined, these stations supply 12 - 12kV feeders and 3 - 35kV lines. The 115kV system supplies a 35kV station and a 12kV station while the 35kV system supplies 4 - 12kV stations.

c) The 2007 Annual Plan identified a number of concerns in SWRI area. These concerns consist projected loading on a number of feeders, transformers, and distribution supply lines to be in excess of either summer normal or summer emergency capability. Facilities in the SWRI area are forecasted to grow at an average annual growth rate of 2.9% from 2008 to 2011.

d) Assuming no new capacity is added, the table below shows projected loading on the area feeders:

Projected Feeder Loading			2010		2011	
Substation	Feeder	SN Limit	Peak (A)	Peak (%)	Peak (A)	Peak (%)
ASHAWAY	43F1	388	407	105%	419	108%
HOPE VALLEY	41F1	338	265	78%	272	80%
KENYON	68F1	512	537	105%	552	108%
KENYON	68F2	511	419	82%	431	84%
KENYON	68F3	512	515	101%	530	103%
KENYON	68F4	514	356	69%	366	71%
KENYON	68F5	612	362	59%	372	61%
LANGWORTHY	86F1	382	343	90%	353	92%
WESTERLY	16F1	515	465	90%	478	93%
WESTERLY	16F2	515	486	94%	500	97%
WESTERLY	16F3	515	421	82%	433	84%
WESTERLY	16F4	645	392	61%	403	62%

e) Assuming no new capacity is added, the table below shows projected loading on the area transformers:

Substation	Xfrm ID	Rating (MVA)		Projected Loading			
				2010	2011	2010	2011
		SN	SE	% SN	% SN	% SE	% SE
ASHAWAY	1	8.4	9.1	105%	108%	96%	99%
HOPE VALLEY	1	7.3	9.3	79%	81%	62%	63%
KENYON	1	49.7	53.7	60%	62%	87%	89%
KENYON	2	49.7	53.7	34%	35%	87%	89%
LANGWORTHY	1	8.2	9.3	90%	93%	80%	82%
WESTERLY	2	25.6	26.7	75%	77%	140%	144%
WESTERLY	4	25.6	26.7	74%	76%	140%	144%
WOOD RIVER	10	48.2	52.4	99%	102%	140%	144%
WOOD RIVER	20	91.2	106.6	30%	31%	69%	71%

f) Assuming no new capacity is added, the table below shows projected loading on the 35kV supply lines:

Projected Loading		Rating (MVA)		2010	2011	2010	2011
Circuit	Voltage (kV)	SN	SE	% SN	% SN	% SE	% SE
85T1	34.5	35.8	38.5	30%	31%	82%	84%
85T2	34.5	35.8	38.5	78%	80%	115%	118%
	34.5	30.7	43.9	91%	94%	101%	104%
85T3	34.5	53.9	58.3	74%	75%	97%	100%
	34.5	30.7	43.9	128%	132%	129%	133%
	34.5	53.2	53.2	74%	76%	106%	109%

3. Project Description

a) Project C24176, Distribution Substation

This project is to purchase and install metal-clad switchgear for three new feeder positions and a 7.2 MVAR station capacitor bank. Scope to include the installation of all required foundations and structures to support this equipment.

b) Project C24175, Distribution Line

This project is to install an underground infrastructure system to allow for the installation of 1000 KCMIL Cu cable getaways from the proposed metal-clad switchgear. It is also to upgrade and to reconfigure the existing area distribution system due to the new feeders.

c) Related Transmission Project # TBD, Transmission Line

This project will be initiated by the transmission organization. Project scope will be to install foundations, structures and equipment required to tap the existing 115kV line (1870S) to supply the proposed substation.

d) Related Transmission Project # TBD, Transmission Substation

This project will be initiated by the transmission organization. Project scope will be to purchase and install one 24/32/40MVA, 115/13.2kV LTC transformer and one 115kV circuit switcher. Scope will also include the installation of all required foundations and structures to support this equipment.

e) Assuming 3 – new feeders are installed at Hopkinton substation, the table below shows projected loading on the area feeders:

Projected Feeder Loading			2010		2011	
Substation	Feeder	SN Limit	Peak (A)	Peak (%)	Peak (A)	Peak (%)
HOPE VALLEY	41F1	550	288	52%	295	54%
KENYON	68F1	512	413	81%	423	83%
KENYON	68F2	511	412	81%	422	83%
KENYON	68F3	512	455	89%	466	91%
KENYON	68F4	514	389	76%	398	78%
KENYON	68F5	612	441	72%	452	74%
LANGWORTHY	86F1	382	335	88%	343	90%
WESTERLY	16F1	515	435	84%	445	86%
WESTERLY	16F2	515	366	71%	375	73%
WESTERLY	16F3	515	419	81%	429	83%
WESTERLY	16F4	515	143	28%	146	28%
HOPKINTON	F1	530	297	56%	304	57%
HOPKINTON	F3	515	304	59%	311	60%
HOPKINTON	F5	515	370	72%	379	74%

e) Assuming 3 – new feeders are installed at Hopkinton substation, the table below shows projected loading on the area transformers:

Substation	Xfrm ID	Rating (MVA)		Projected Loading			
				2010	2011	2010	2011
		SN	SE	% SN	% SN	% SE	% SE
ASHAWAY	1	8.4	9.1	0%	0%	0%	0%
HOPE VALLEY	1	7.3	9.3	86%	88%	67%	68%
KENYON	1	49.7	53.7	54%	55%	81%	83%
KENYON	2	49.7	53.7	34%	35%	81%	83%
LANGWORTHY	1	8.2	9.3	88%	90%	78%	80%
WESTERLY	2	25.6	26.7	70%	72%	**102%***	**105%***
WESTERLY	4	25.6	26.7	42%	43%	**102%***	**105%***
WOOD RIVER	10	48.2	52.4	69%	70%	96%	99%
WOOD RIVER	20	91.2	106.6	19%	20%	47%	49%
HOPKINTON	**1**	**45.0**	**60.0**	**44%**	**45%**	**33%**	**34%**

* Projected contingency load on the Westerly transformers has been significantly reduced. To address the remaining exposure, block transfer on one bay will be required only during peak loading conditions.

g) Assuming 3 – new feeders are installed at Hopkinton substation, the table below shows projected loading on the area 35kV supply lines:

Projected Loading		Rating (MVA)		2010	2011	2010	2011
Circuit	Voltage (kV)	SN	SE	% SN	% SN	% SE	% SE
85T1	34.5	35.8	38.5	30%	31%	72%	73%
85T2	34.5	35.8	38.5	50%	51%	72%	74%
	34.5	53.0	76.0	34%	35%	37%	37%
85T3	34.5	53.9	58.3	51%	52%	76%	77%
	34.5	53.0	76.0	52%	53%	58%	59%
	34.5	53.2	53.2	52%	53%	83%	84%

4. CAPEX Classification

a) Project C24176 (Distribution Substation) – Capital - Substation Addition

b) Project C24175 (Distribution Line) - Capital – Line Addition

c) Project TBD (Transmission Substation) – Capital - Substation Addition

b) Project TBD (Transmission Line) - Capital – Line Addition

5. Options Summary

a) Option1 – (Not Recommended)

In 2005, an area study titled "Westerly Area Supply and Distribution Study" was issued to address loading concerns in the SWRI area. The study recommended reinforcements and expansion of the 34.5kV supply and 12.47kV distribution system. It recommended replacement of both Westerly transformers; replacement of both Wood River Supply transformers; development of the Westerly 16F4, 16F5 and 16F6 feeders; and upgrades to the Wood River supply lines. The estimated cost of this alternate plan is $11 Million.

b) The total cost for the two plans is as follows:

	Preferred Plan (study grade)	Option 1 (study grade)
Total Cost	$5,900,000	$11,000,000

c) The preferred plan is recommended because it is lower in cost and provides more distribution capacity than option 1.

6. Execution Risk Appraisal

Hopkinton substation is proposed to be constructed on an NGRID owned site adjacent to the 115kV right-of-way. Although an environmental assessment needs to be performed, there are no known environmental issues that would rule out the installation of a substation at this site.

7. Financial Impact

A. Distribution Expenditures – Authorization Requested

a) Estimates are study grade with a level of accuracy of (+/- 25%). The estimated distribution expenditures by project are as follows:

Co #	Company	Project #	Capital	O&M	Removal	Total
00049	Distribution	C24175	1,650,000	25,000	25,000	1,700,000
00049	Distribution	C24176	1,200,000	0	0	1,200,000
		Total	2,850,000	25,000	25,000	2,900,000

B. Related Transmission Expenditures – for information

b) Estimates are study grade with a level of accuracy of (+/- 25%). The estimated transmission expenditures by project are as follows:

Co #	Company	Project #	Capital	O&M	Removal	Total
00049	Transmission	T-Line	500,000	0	0	500,000
00049	Transmission	T-Sub	2,500,000	0	0	2,500,000
		Total	3,000,000	0	0	3,000,000

8. Commercial Issues

a) None.

9. Justification

a) A new substation is recommended to relieve forecasted loading concerns in the SWRI area and to provide capacity for future load growth. The addition of this proposed substation is the least cost solution.

10. Recommendation

The Distribution Capital Investment Group is invited to:

a) APPROVE the expenditure of $250,000 to cover the preliminary engineering charges to develop project grade estimates for the distribution projects associated with the above recommendations and Robert Sheridan as the Scheme Sponsor.

Supporting signatures (not required if DCIG minutes reflect approval of paper)

Investment planning

Signed Date
Christian Brouillard, Director, Investment Management

On behalf of Regulation by

Signed Date
Peter Zschokke, VP US Regulatory Strategy & Research

On behalf of Procurement by

Signed Date
Jeffrey Way, VP Procurement

Sponsor's Signature

(Required)

Signed Date
Patrick Hogan, Sr. VP Network Strategy

4/10/08

Decision of the DCIG Sanctioning Authority
(Required)

I hereby approve the recommendations made in this paper

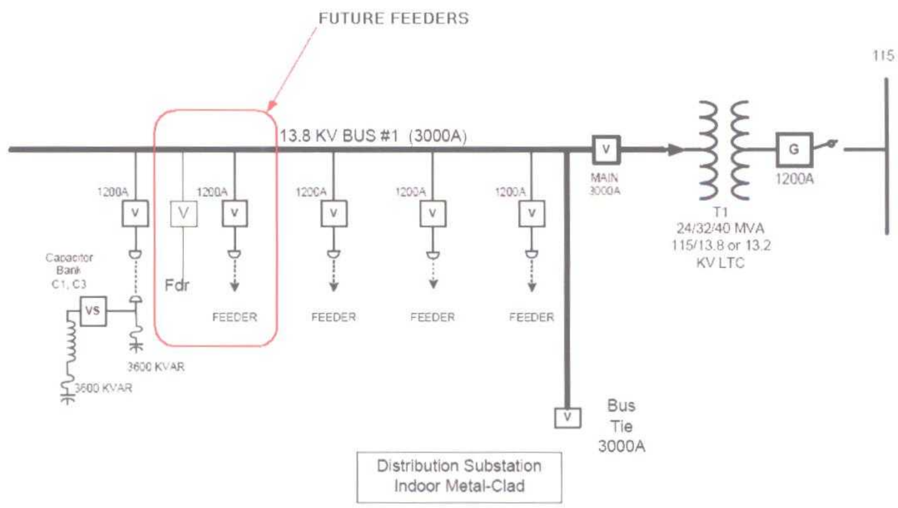
Signed Date
Executive VP Electricity Distribution, National Grid

Appendix

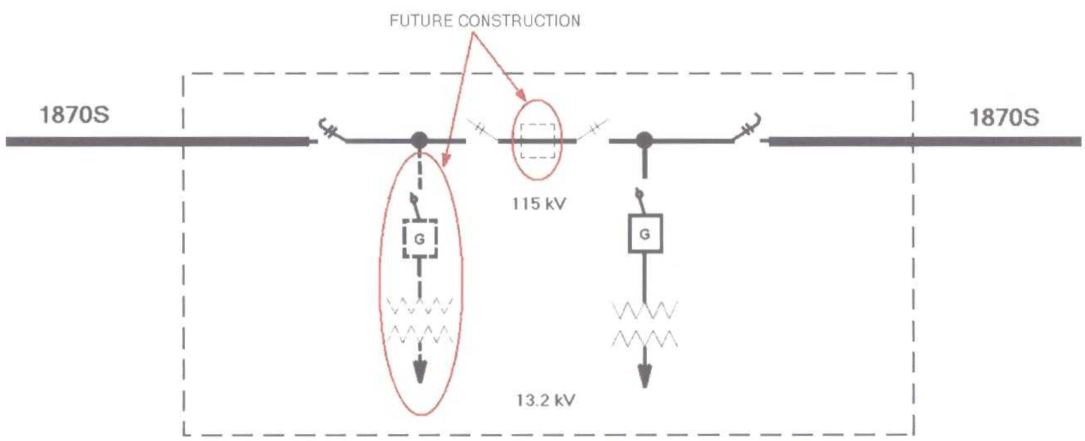
Attachment A – Proposed Hopkinton Substation
Attachment B –South Western Rhode Island Study Area
Attachment C – Geographic Limits of SWRI Study Area

This document has been reviewed for Critical Energy Infrastructure Information (CEII).
This document does not contain CEII.

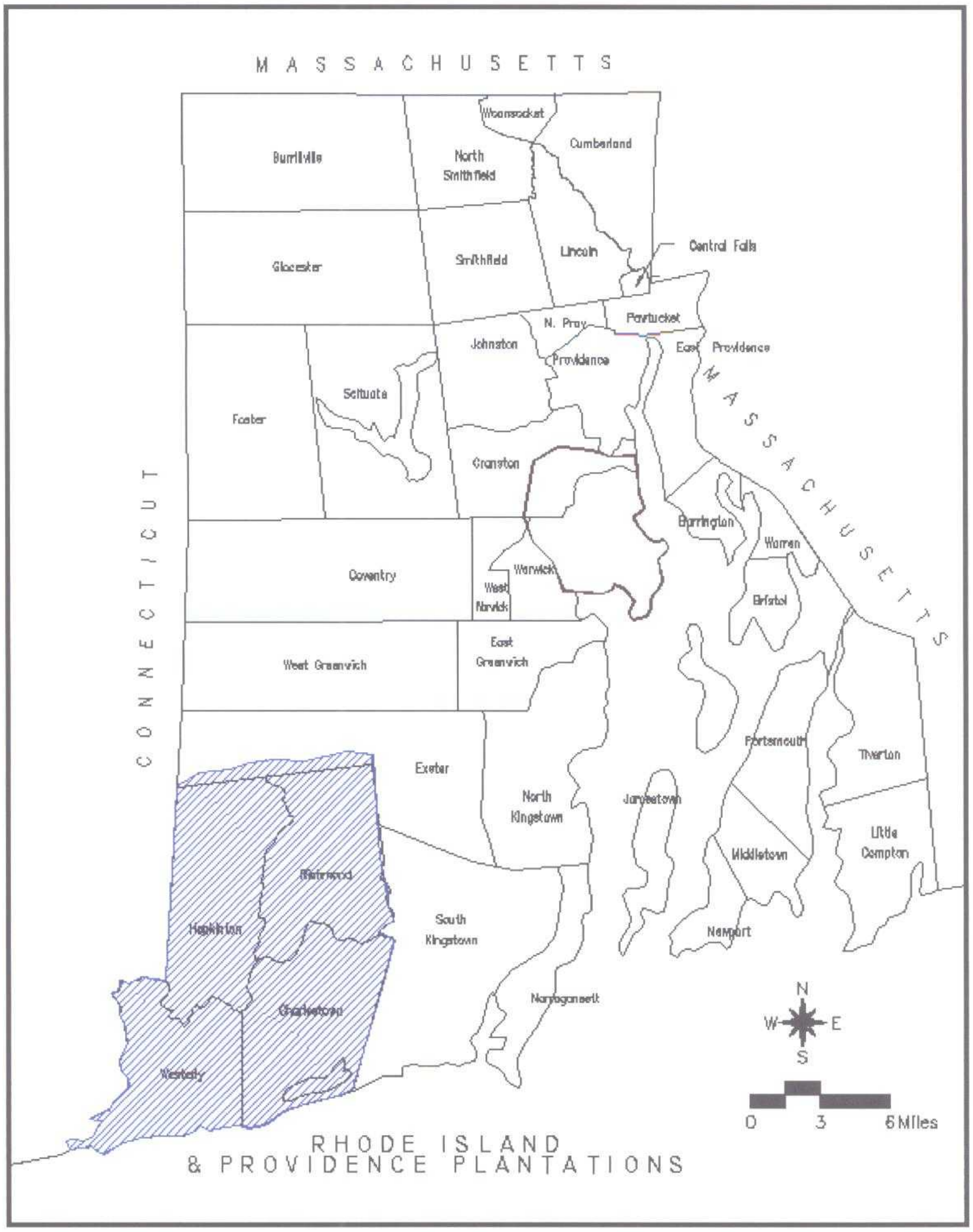
Highly Confidential DCIG0408P36



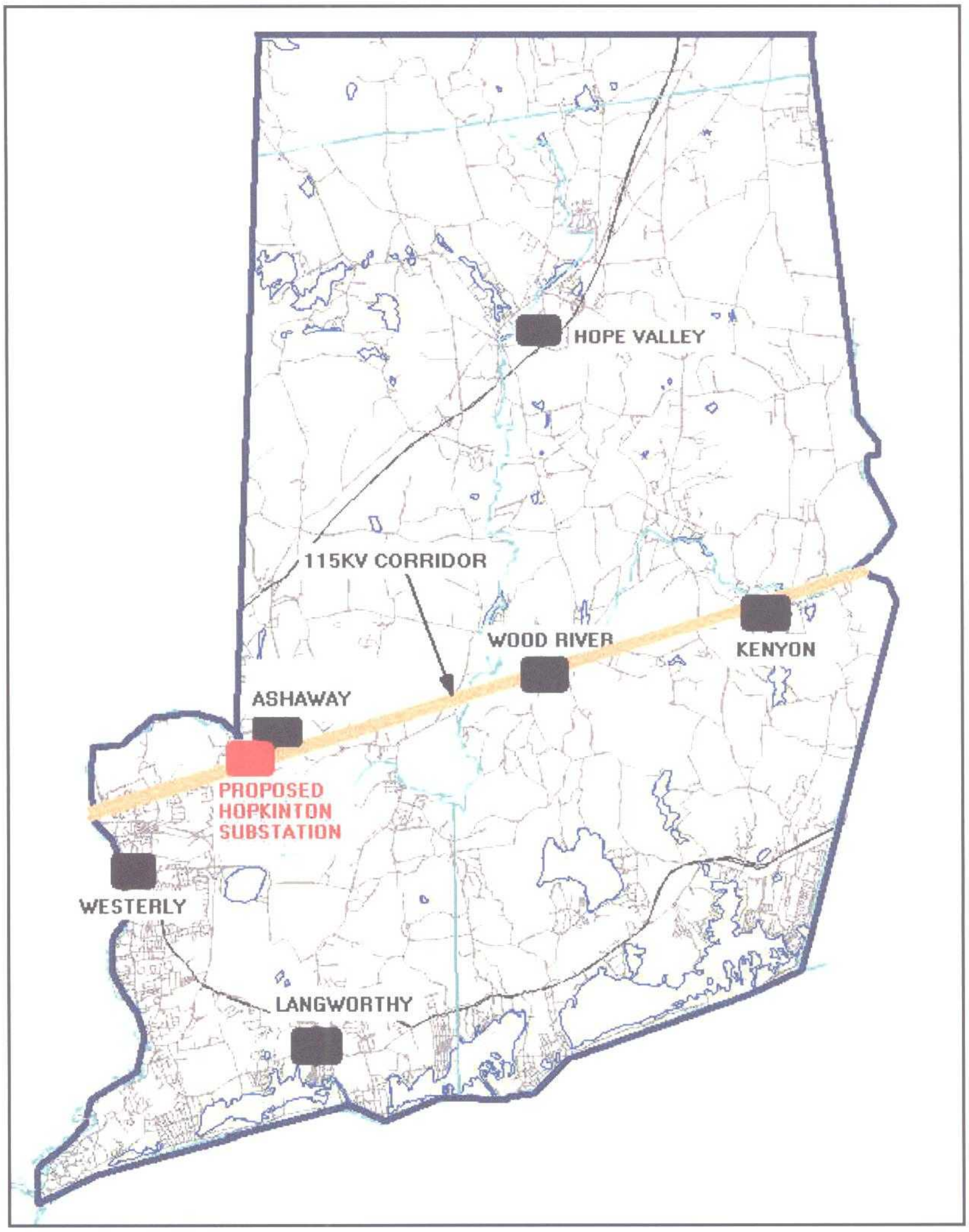
PROPOSED ONE-LINE: NEW HOPKINTON SUBSTATION



Attachment A – Proposed Hopkinton Substation



Attachment B –South Western Rhode Island Study Area



Attachment C – Geographic Limits of SWRI Study Area

This document has been redacted for Critical Energy Infrastructure Information (CEII).

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Capital/Revenue Investment Proposal – Summary
Project Title: New Tiogue Avenue MITS Substation and Distribution feeder
Line of Business: Distribution
Regulatory Entity: Narragansett Electric
Project #: C24179 and C24180
(A **Sanction** paper by **Author/Sponsor:** Chris Worme/Rob Sheridan **Date: 7/2/2008)**

Description

C24179 – Purchase a parcel of land in Coventry, RI and perform preliminary engineering for installation of a new MITS substation.

C24180 – Extend a 34.5 kV distribution supply line to new substation site and rearrange 12.47 kV distribution system to accommodate new station.

Category: ☐ **Mandatory**
☒ **Policy-driven**
☐ **Pure NPV**

BIT score: **41** Primary Driver: ☐ **Health and Safety** ☐ **Mandatory** ☐ **NPV**
☐ **Transmission** ☐ **Committed**
☐ **Environment** ☒ **Reliability**

Finance

Sanction Cost **$0.650M**

Probability that project cost will exceed tolerance: **NA**

Project included in approved Business Plan? **Yes**

Project cost relative to approved Business Plan **$.100 Under Budget**

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

Other financial issues: Purchase price of land for substation is based on the preferred site which has lowest asking price of three available lots. The preferred site will also require the shortest extension of the 34.5 kV supply line. If this site becomes unavailable, it will increase the cost of the overall project and impact the milestones. It is therefore recommended that immediate action be taken to purchase the preferred site.

	Current planning horizon								
$M	**Prior YR'S**	**Yr 1 08/9**	**Yr 2 09/10**	**Yr 3 10/11**	**Yr 4 11/12**	**Yr 5 12/13**	**Yr 6+**	***Total***	
Proposed investment		0.650	1.505	0.280				2.435	

Resources

Availability of internal resources to deliver project: ☐ **Red** ☐ **Amber** ☒ **Green**

Availability of external resources to deliver project: ☐ **Red** ☐ **Amber** ☒ **Green**

Operational impact on network system: ☐ **Red** ☐ **Amber** ☒ **Green**

This document has been redacted for Critical Energy Infrastructure Information (CEII).

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- **Key issues** (Highlight any significant issues associated with the project)
- A property with appropriate zoning needs to be acquired for the substation.

Key milestones (Please provide date in grey boxes)
- Identify substation site and begin purchasing process – **08/2008**
- Purchase substation site – **11/2008**
- Preliminary Engineering – **02/2009**
- Full Sanction Approval – **04/2009**
- Commissioning (In Service) – **06/2010**
- Completion – **09/2010**
- Project Closure - **12/2009**

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**
Are financial incentives (e.g. carbon credits) available? ☐**Yes** ☒**No**

Prior sanctioning history including relevant approved Strategies 0- N/A

Date	Governance Body	Sanctioned Amount	Paper Title

Associated Projects - None

Recommendations
The ☒**DCIG** ☐**DEC** is invited to:
(a) APPROVE the investment of **$0.650M** for preliminary engineering.
(b) NOTE: That **Rob Sheridan** is the Project Sponsor.
(c) NOTE: That **Sergey Goldgaber** is the Project Manager.
(d) NOTE: It is expected that the project will be brought before the DCIG for further sanction upon completion of preliminary engineering.

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

Signature Date
[Name and title of sanctioning authority]

This document has been redacted for Critical Energy Infrastructure Information (CEII).

Confidential DCIG0408P37

Capital/Revenue Investment Proposal – Summary
Project Title: New Tiogue Avenue MITS Substation and Distribution feeder
Line of Business: Distribution
Regulatory Entity: Narragansett Electric
Project #: C24179 and C24180
A **Sanction** paper by **Author/Sponsor:** Chris Worme/Rob Sheridan **Date:**

1. Background

The Central Rhode Island West study area encompasses the Towns of Coventry, West Greenwich, and West Warwick and sections of the Cities of Cranston and Warwick, and Towns of East Greenwich, Exeter, and Scituate. The area load is projected at 344 MVA in 2008 with approximately 47,000 customers served.

The projected summer loading on the distribution feeders in the study area is heavy and there is difficulty in serving new customers in some areas. There are twenty seven 12.47 kV distribution feeders and four 4.16 kV supplying the area load. Of these thirty one feeders, ten 12.47 kV (37%) and one 4.16 kV (25%) are projected to exceed their summer normal ratings by 2012. There are another six 12.47 kV feeders (22%) that are projected at over 95%.

In addition to the projected feeder overloads, there are a combined total of five 23 kV and 34.5 kV supply lines with projected 2008 contingency summer overloads. In order to prevent operating the lines above a safe load level, it will be necessary to use a combination of blocking load transfers at several stations and dropping load in some locations when contingencies occur.

The study area and substations are shown in Figure 1 and the distribution feeders are shown in Figure 2 with the proposed new substation on Tiogue Avenue, Coventry.

A combination of load transfers to adjacent feeders, a new 12.47 kV feeder in Coventry, and use of the load bonus feature on station regulators is recommended to resolve the thermal overloads in summer 2009 and 2010. This strategy, in addition to installing a new 115/12.47 kV metal clad station in West Warwick in 2011, will address all the projected normal feeder overloads and contingency supply line overloads through the planning horizon. The investments proposed with in service date of June 2011 will be included in the FY10, FY11 and FY12 budgets and will be documented in a separate sanction paper.

2. Driver

The primary driver is summer thermal overloads projected on the distribution feeders. After a slow start to the development of the Centre of New England project, there has been an increase in activity in the past year with completion of a large number of new commercial and residential units. Table 1 below shows all feeders in the area with loads projected to exceed 100% of their normal rating by 2012. Projected loads are based on actual 2007 loads and the 2008 PSA forecast for this area.

This document has been redacted for Critical Energy Infrastructure Information (CEII).

		2009		2010		2011		2012	
Station	Feeder	(A)	% SN	(A)	% SN	(A)	% SN	(A)	% SN
Anthony	64F1	[redacted]							
Anthony	64F2								
Coventry	54F1								
Drumrock	14F4								
Hope	15F1								
Hope	15F2								
Hopkins Hill	63F3								
Kent County	22F4								
Natick	29F1								
Natick	29F2								
Arctic	49J1								

Note: Items in table highlighted in red indicate load at summer normal rating or above.

Table 1 – Feeder Loads and Percent of Summer Normal Rating

3. Project Description

The project scope includes the procurement and development of a substation site on Tiogue Ave., Coventry RI. A modular feeder position is recommended for this location due to the limited supply infrastructure and the rural location of the station in the west central part of the state. A new Mobile Integrated Transportable Substation (MITS), the preferred design for a modular feeder position due to lower cost and labour requirements, will be purchased and installed at this site to provide a new 12.47 kV feeder. Figure 3 shows a MITS substation taken from the manufacturer's brochure and Figure 4 shows a typical one line for a modular substation.

The 34.5 kV supply line, 3309, will be extended approximately 0.4 miles on Tiogue Ave. from Hopkins Hill Rd to substation site. A feeder getaway will be installed and the distribution feeders in the area reconfigured to create a new 12.47 kV feeder.

4. Business Issues

There is a total of $250,000 included in the FY08/09 business plan to cover the cost of preliminary engineering and procurement costs of a site. Preliminary investigation has revealed a number of potential sites in the area with the lowest cost site on the market for $400,000. It will be necessary to walk additional money into the budget to procure a site in FY09.

5. Options Analysis

There is no viable option to the recommended plan to relieve the overloaded feeders by 2010 due to the time frame required to implement alternatives. Failure to implement the recommended plan will result in conductors sagging in excess of design limits on several of the feeders limited by overhead conductor.

6. Milestones

- Identify substation site and begin purchasing process – 08/2008.
- Purchase substation site – 11/2008
- Preliminary Engineering – 02/2009.

This document has been redacted for Critical Energy Infrastructure Information (CEII).

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- Full Spend Sanction Request – 04/2009.
- Project commissioning – 06/2010.
- Project completion – 09/2010
- Project closure – 12/2010.

7. Safety, Environmental and Planning Issues

The available sites on Tiogue Avenue will be evaluated for any environmental issues prior to purchase.

8. Investment Recovery

8.1 Investment Classification

- Distribution Substation Capital
- Distribution Line Capital

8.2 Regulatory Implications

The Company franchise to distribute electricity obligates the Company to have the necessary facilities to provide electric service.

8.3 Customer Impact

No immediate impact. The costs will ultimately be included in rate base.

9. Financial Impact

9.1 Cost Summary

Distribution Line estimates are study grade estimates (+/-25%).

			Current Planning Horizon $000's							
Project #	Project Description	$M 000's	Prior YR Spending	YR1 08/09	YR2 09/10	YR3 10/11	YR4 11/12	YR5 12/13	YR6 +	Total
C24179	Install a New MITS substation, Tiogue Avenue	Capex		0.600	1.200	0.200				2.000
		Opex		0.000	0.000	0.000				0.000
		Removal		0.000	0.000	0.000				0.000
		Total		0.600	1.200	0.200	-	-	-	2.000
C24180	Extend the 3309 Supply Line to Site and Rearrange Distribution.	Capex		0.050	0.280	0.060				0.390
		Opex		0.000	0.020	0.015				0.035
		Removal		0.000	0.005	0.005				0.010
		Total		0.050	0.305	0.080	-	-	-	0.435
	Total Proposed Sanction	Capex		0.650	1.480	0.260	-	-	-	2.390
		Opex		0.000	0.020	0.015	-	-	-	0.035
		Removal		0.000	0.005	0.005	-	-	-	0.010
		Total		0.650	1.505	0.280	-	-	-	2.435

This Project was budgeted for **$0.950M** Capex in the current fiscal Year (FY2009).

9.2 Cost Assumptions

Standard material procurement process to be followed, and there are no expected delivery delays. The FY09 preliminary engineering estimate is calculated to be 7.5% of total project expenditure.

The overall distribution substation project (C24179) estimate is a conceptual estimate (+/- 25%) from substation design.

The overall distribution line project (C24180) estimate is a conceptual estimate (+/- 25%) using the distribution design cost estimate guideline.

Engineering & design resources to be provided: **Internal**

Construction to be provided: **N/A; will be identified on completion of preliminary engineering and finalized at project sanction**

9.2 Benefits Summary

This project will help to relieve the area overloads until a new substation can be built in West Warwick. Table 2 shows the feeder loads after the new feeder and other area 2009 distribution rearrangements.

		2009		2010		2011		2012	
Station	Feeder	(A)	% SN	(A)	% SN	(A)	% SN	(A)	% SN
Anthony	[redacted]								
Anthony									
Coventry									
Drumrock									
Hope									
Hope									
Hopkins Hill									
Kent County									
Kent County									
Natick									
Natick									
West Cranston									
Arctic*									

* This feeder was limited by the regulators and the load bonus feature is utilized to eliminate the regulators as the limiting item.

Items in table highlighted in red indicate load at summer normal rating or above.

9.3 NPV

N/A

This document has been redacted for Critical Energy Infrastructure Information (CEII).

9.5 Additional Impacts

None

10. Execution Risk Appraisal

The execution of the projects assumes the successful acquisition of a site and that there are no environmental issues with the site. There are two other sites on Tiogue Avenue that are on the market with higher asking prices that would have to be evaluated for zoning environmental issues if the preferred site was no longer available. Both alternate sites will also require a longer extension of the 34.5 kV supply line.

11. Statements of Support

12. Recommendation

The ☒**DCIG** ☐**DEC** is invited to:

(a) APPROVE the investment of $0.650M for preliminary engineering.

(b) NOTE: That Rob Sheridan is the Project Sponsor.

(c) NOTE: That Sergey Goldgaber is the Project Manager.

(d) NOTE: It is expected that the project will be brought before the DCIG for further sanction upon completion of preliminary engineering.

This document has been redacted for Critical Energy Infrastructure Information (CEII).

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Supporting signatures (not required if DCIG minutes reflect approval of paper)

Investment planning

Signed Date
Christian Brouillard, Director, Investment Management

On behalf of Regulation by

Signed Date
Peter Zschokke, VP US Regulatory Strategy & Research

On behalf of Procurement by

Signed Date
Jeffrey Way, VP Procurement

Sponsor's Signature

(Required)
Signed Date
Patrick Hogan, Sr. VP Network Strategy

7/24/08

Decision of the DCIG Sanctioning Authority
(Required)

I hereby approve the recommendations made in this paper

Signed Date 7/28/08
Executive VP Electricity Distribution, National Grid

This document has been redacted for Critical Energy Infrastructure Information (CEII).

13. Appendices

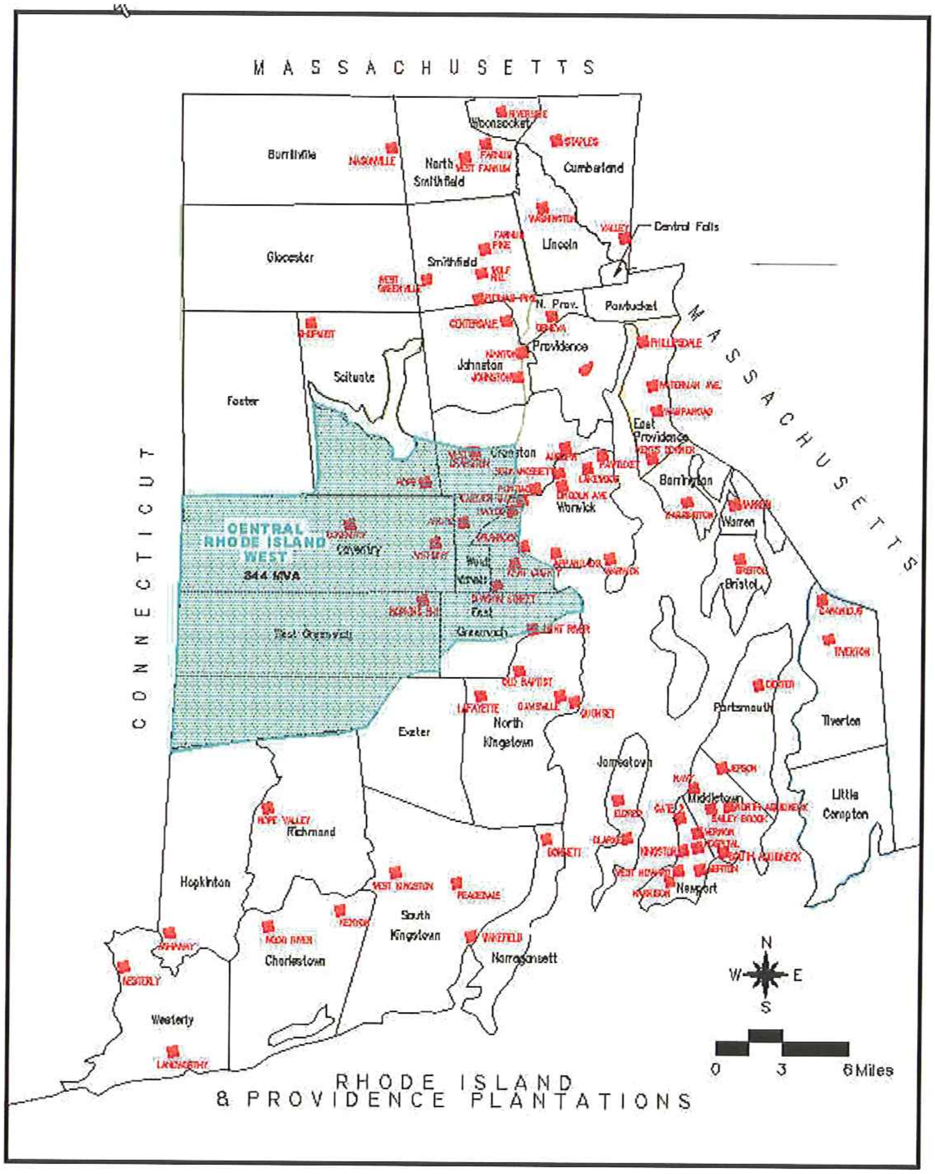

Figure 1 Central Rhode Island West Study Area

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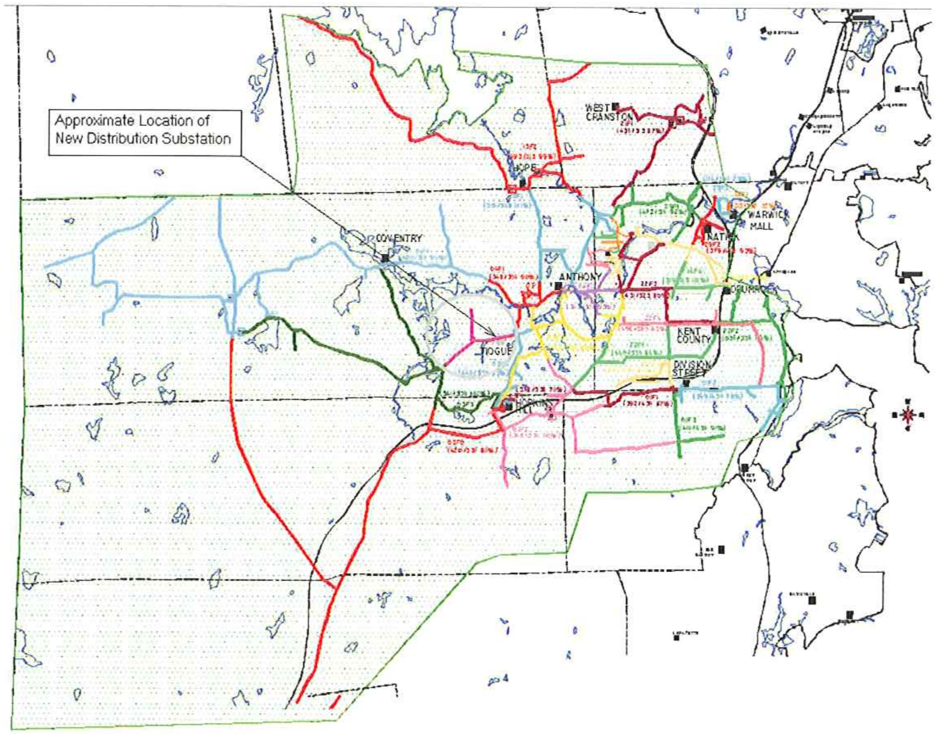

Figure 2 Proposed Layout of Feeders After Installation of New Tiogue Avenue Substation

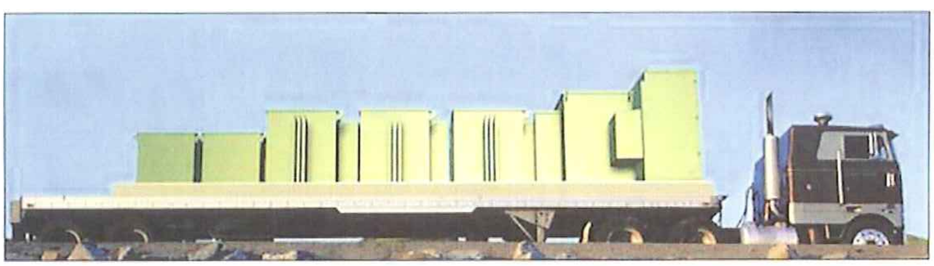

Figure 3 Picture of MITS from manufacture's brochure

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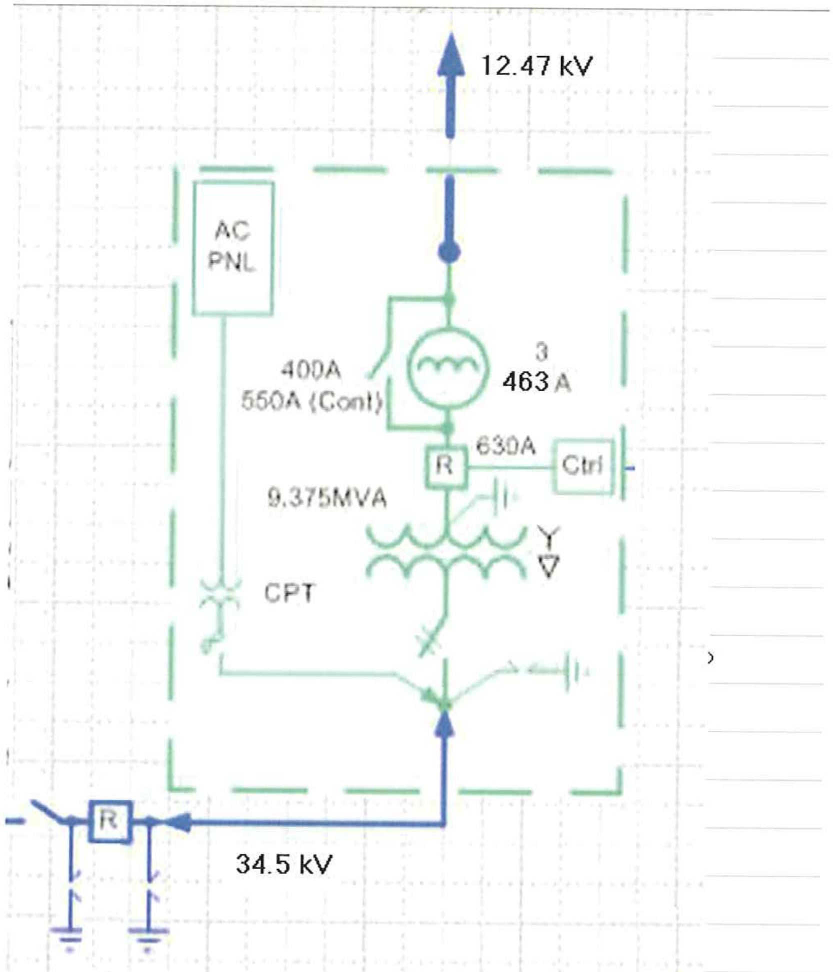

Figure 4. Typical One Line for Modular MITS Station

This document has been reviewed for Critical Energy Infrastructure Information (CEII) as it stands now – cannot say for any added info.

nationalgrid

US Sanction Paper

Title:	Aquidneck Island	**Sanction Paper #:**	USSC0408PS34
Project #:	See Section 1.3 Below	**Sanction Type:**	Partial Sanction
Operating Company:	The Narragansett Electric Company	**Date of Request:**	Nov 9, 2011
Author:	Jack Vaz	**Sponsor:**	Chris Root
Utility Service:	Electricity T&D		

1 <u>Executive Summary</u>

Sanctioning Summary:

This paper requests partial sanction in the amount of $15.000M and a tolerance of ±25%. This sanction amount will cover the cost of work performed to date, the purchase of a parcel of land to house a new substation, provide preliminary engineering funding necessary to develop Planning Grade estimates, and provide funding to initiate the permitting and licensing process.

The sanction amount of $15.000M is broken down into:

$13.900M		Capex
$	0.800M	Opex
$	0.300M	Removal

NOTE the potential investment of $42.000M and a tolerance of -25% to +50%, contingent upon submittal and approval of a Project Sanction paper following completion of preliminary engineering activities.

Brief Description:

This project is required to address reliability concerns on Aquidneck Island and follow up on commitments made to the Rhode Island Public Utility Commission. These concerns and commitments are as follows:

- The southern portion of Aquidneck Island is supplied by a highly utilized supply and distribution system. It is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport. The Jepson 13.8kV system has been utilized to provide relief to the 23kV supply system, the 4.16kV distribution system, and to supply large spot loads. However, this 13.8kV system has been extended to its limits.
- For loss of the Dexter 115/13.8kV transformer on peak up to 13MW of load on Aquidneck Island would remain un-served until the transformer is replaced or a mobile is installed resulting in an exposure of approximately 350MWh.
- For loss of the Jepson 69/13.8kV transformer on peak up to 17MW of load on Aquidneck Island would remain un-served until the transformer is replaced or a mobile is installed resulting in an exposure of approximately 460MWh.
- For loss of the 69kV line section between Jepson and the Navy substation on peak up to 18MW of load on Aquidneck Island would remain un-served resulting in an exposure of approximately 500MWh.

- In the summer of 2003, interruptions to the electrical system in Newport resulted in significant customer outages. One of the action items proposed by the Company to the Rhode Island Public Utility Commission was to conduct a planning study to identify and resolve electrical related issues in the area.

To address the concerns identified above, the recommended plan for this area is as follows:

- Construct a second 69kV overhead supply line into the City of Newport, from Jepson to Gate 2 substation.
- Build a new substation in Newport consisting of two (2) transformers supplying metal-clad switchgear. Install five (5) 13.8kV feeders and reconfigure the area distribution system.
- Install a new 69/23kV transformer at Gate 2 substation and retire the existing Gate 2 4.16kV substation to provide routes for the new 13.8kV feeders from Newport substation.
- Retire the existing 23/4.16kV substation at Jepson to address asset condition concerns and provide routes for new 13.8kV feeders.
- Retire Bailey Brook and Vernon substations to provide routes for new 13.8kV feeders from Newport substation and eliminate environmental concerns at Bailey Brook and asset concerns at Vernon.

Summary of Projects:

Project Number	Project Title	Estimate Amount ($M)
03533/C11578	Newport Sub Land Purchase (D-Sub)	$3.000
03529/C15158	Newport Substation (D-Sub)	$9.500
03527/C15409	Newport Phase 1 (D-Line)	$7.590
03531/C24159	Newport 69kV Line 63 (D-Line)	$0.520
03528/C28628	Newport Phase 2 (D-Line)	$8.800
16880/TBD	Bailey Brook Retirement (D-Sub)	$0.430
16882/TBD	Vernon Retirement (D-Sub)	$0.300
17045/TBD	Jepson Substation (D-Sub)	$0.500
17046/TBD	Gate 2 Substation (D-Sub)	$2.900
C41185	Newport Substation (T-Sub)	$0.350
C41184	Newport Substation (T-Line)	$6.490
C41183	Jepson Substation (T-Sub)	$1.500
C41186	Gate 2 Substation (T-Sub)	$0.120
	TOTAL	**$42.000**

Associated Projects:

N/A

Prior Sanctioning History (including relevant approved Strategies):

Date	Governance Body	Sanctioned Amount	Paper Title	Sanction Type
12/03/2008	DCIG	$15.500M	Substation Installation Project	Sanction
04/02/2008	DCIG	$3.500M	Newport Substation Installation	Partial
10/11/2005	Power Plant Approval per DOA Requirements	$1.000M	Newport Land Purchase	Partial

Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
May 2012	Planning Sanction

Category:

Category	Reference to Mandate, Policy, or NPV Assumptions
☐ Mandatory ☒ Policy-Driven ☐ Justified NPV	National Grid USA EO Internal Strategy Document Distribution Planning Criteria Strategy Issue 1 – February 2011

Asset Management Risk Score

Asset Management Risk Score: **41**

Primary Risk Score Driver: (Policy Driven Projects Only)

☒ Reliability ☐ Environment ☐ Health & Safety

Complexity Level: (if applicable)

☒ High Complexity ☐ Medium Complexity ☐ Low Complexity

Complexity Score: **33**

US Sanction Paper

Business Plan:

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
Dist- Current 5 year Spending Plan FY12-16 Budget	☒ Yes ☐ No	☒ Over ☐ Under	$13.434M
Trans- Current 5 year Spending Plan FY12-16 Budget	☐ Yes ☒ No	☒ Over ☐ Under	$8.460M

The FY 13-17 Budget has been updated to reflect the expected spend listed in 4.11.1 for this project

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

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

Current Planning Horizon:

Company Name	Current planning horizon							
$M	Prior YR'S	Yr 1 11/12	Yr 2 12/13	Yr 3 13/14	Yr 4 14/15	Yr 5 15/16	Yr 6 +	*Total*
Proposed Capex Investment	7.450	2.770	0.770	3.650	11.780	6.820	2.500	35.740
Proposed Opex Investment	0.900	0.000	0.000	0.000	1.600	0.720	0.000	3.220
Proposed Removal Investment	0.350	0.000	0.000	0.000	0.900	1.790	0.000	3.040
CIAC / Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000		0.000
Total	$8.700	$2.770	$0.770	$3.650	$14.280	$9.330	$2.500	$42.000

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	

Key Issues:

1	Energy Facility Siting Board (EFSB) Filing will be required for the proposed 69kV line
2	Rhode Island Department of Environmental Management (RI DEM) Filing will be required for 69kV line work and substation work
3	State and local permits will most likely be required
4	Wetlands will most likely be encountered in portions of this work

Key Milestones:

Milestone	**Target Date: (Month/Year)**
• Preliminary Engineering	April 2012
• Planning Sanction	May 2012
• Final Engineering	January 2013
• Project Sanction	February 2013
• Construction Start	April 2013
• Construction Finish	March 2016
• Project Closure	August 2016

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

List References:

1	Distribution Planning Criteria Strategy, Issue 1, February 2011
2	Conceptual Engineering Report, Newport Mall Substation, 7/20/11
3	Conceptual Engineering Report, Gate 2 Substation, 7/21/11
4	Conceptual Engineering Report, Jepson Substation, 7/22/11
5	Conceptual Engineering Report, Bailey Brook Substation, 7/25/11
6	Conceptual Engineering Report, Vernon Substation, 7/25/11
7	Newport Area Supply and Distribution Study, May 2007
8	Jepson Equipment Condition Assessment, February 2005

2 Recommendations:

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

(a) APPROVE up to the investment of $15.000M and a tolerance of +/- 25% for the cost of work performed to date, the purchase of a parcel of land to house a new substation, provide preliminary engineering funding necessary to develop Planning Grade estimates, and provide funding to initiate the permitting and licensing process for the reasons stated above.

(b) NOTE the potential investment of $42.000M and a tolerance of -25% to +50%, contingent upon submittal and approval of a Project Sanction paper following completion of final engineering and design.

(c) NOTE that Ayo Osimboni is the Project Manager and has the approved financial delegation to undertake the activities stated in (a).

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

Project Sponsor: Christopher E. Root, Senior Vice President Network Strategy

3 Decisions

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on November 09, 2011

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

Lee S. Eckert

US Chief Financial Officer

Chairman, US Sanctioning Committee

4 Sanction Paper Detail

Title:	Aquidneck Island	**Sanction Paper #:**	USSC0408PS34
Project #:	See Section 1.3	**Sanction Type:**	Partial Sanction
Operating Company:	The Narragansett Electric Company	**Date of Request:**	Nov 9, 2011
Author:	Jack Vaz	**Sponsor:**	Chris Root
Utility Service:	Electricity T&D		

Background

The Newport Study Area encompasses the City of Newport and the towns of Portsmouth, Middletown, Jamestown and Prudence Island. Figure 1 shows a geographic map of the study area. The area has approximately 34,000 customers with a projected peak demand of approximately 146MW. Aquidneck Island has most of the load and peaks at approximately 135MW, while Jamestown peaks at approximately 10MW and Prudence Island at 1MW.

The study area is supplied by two (2) 115kV lines (L14 & M13) which terminate on the northern half of Aquidneck Island at Dexter substation. From Dexter substation, two (2) 69 kV lines (Lines 61 & 62) continue south to supply Jepson substation. From Jepson substation, a single 69kV line (Line 63) continues south to supply the US Naval Base (Navy 1 substation) and Gate 2 Substation. Figure 2 shows a one-line of the existing transmission system.

A single 115/13.8kV transformer at Dexter supplies the distribution load on the northern section of Aquidneck Island and a single 69/13.8kV transformer at Jepson supplies the middle section of the Island. The remainder of the load is supplied by five (5) 23kV sub-transmission lines sourced from Jepson and Gate 2 substations which supply a 4.16kV distribution system with approximately 70MW of load. Twelve 23/4.16kV substations, ten located in the southern half of Aquidneck Island and two located in Jamestown, supply this 4.16kV system. Figure 3 shows a one-line of the existing sub-transmission system and Figure 4 shows the approximate geographic areas supplied by the distribution system.

Interruptions to the Newport electrical system resulting in significant customer outages occurred in the summer of 2003. One of the action items proposed by the Company to the Rhode Island Public Utility Commission (RI PUC) was to conduct a planning study to identify and resolve electrical related issues in the area.

This area study was published in May 2007 and titled "The Newport Area Supply and Distribution Study". The Study identified an immediate need to build a new substation in the City of Newport to address both normal and contingency overloads. The study recommended construction of a new substation consisting of a single transformer supplying four (4) feeder positions. The new station was to be sourced from Line 63, a radial 69kV supply line that supplies the US Navy and Gate 2 substations.

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Construction of a new substation was contingent on the company acquiring a parcel of land in the City of Newport for this substation. The Company has encountered significant challenges in locating and acquiring a parcel of land which has impacted the projected in-service date of this substation. To address the most critical loading concerns in the City of Newport, the 2008 Annual Plan recommended accelerating some of the distribution construction identified in the 2007 study. The Annual Plan also recommended reinforcing existing infrastructure, redistributing the area load on both the supply and distribution systems to maximize all available capacity, and the addition of a new feeder at Harrison substation.

All short-term recommendations made in the 2008 Annual Plan have been implemented. The existing infrastructure has been reinforced and expanded and area load has been redistributed on both the supply and distribution systems. This investment has addressed the most critical normal overloads. Recently, the Company has identified a potential site for the new substation. A purchase and sale agreement has been signed and the Company has begun the due diligence process to insure this site is suitable for a new substation.

The 2007 study covered a 10-year horizon period (2006 – 2016). In 2016, the study projected a peak area load of 159MW. This compares with a current projection of 160.5MW for the same year utilizing the latest load growth forecast. The plan recommended in the 2007 study discussed the risk of sourcing a new substation from a single highly utilized radial 69kV line. In the year 2016, the study projected an un-served load of 24MW for loss of this supply line. The 2007 study cautioned that load growth higher than forecasted to a point of taking unacceptable risk with a single supply, a second 69kV supply line into the City of Newport would be required.

During the 2011 Annual Planning process, a review was performed of this area. The 2011 Annual Plan covered a horizon period thru 2027. For this review, the most recent Distribution Planning Criteria was utilized. The 2011 Annual Plan, using the most recently published load growth forecast, is projecting the area load to peak at 168MW at the end of the horizon year 2027. Based on this review, it is recommended that the original plan for this area be modified and a second transmission line be installed into the City of Newport. The modifications to this plan are in-line with the long-term recommendations made in the 2007 study.

Drivers

The southern portion of Aquidneck Island is supplied by a highly utilized supply and distribution system. This 23kV supply system and 4.16kV distribution system has limited capacity to supply load growth and new spot loads. It is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport.

The Jepson 13.8kV system has been utilized to provide relief to the 23kV supply system, the 4.16kV distribution system, and to supply large spot loads. However, this 13.8kV system has been extended to its limits. For loss of the Jepson 13.8kV system, the 13.8kV supplied load in the City of Newport will be out until Jepson is placed back in service.

In 2011, for loss of the Dexter 115/13.8kV transformer on peak up to 13MW of load on Aquidneck Island (primarily in Portsmouth) would remain un-served until the transformer is replaced or a mobile is installed. This results in an exposure of approximately 350MWh.

In 2011, for loss of the Jepson 69/13.8kV transformer on peak up to 17MW of load on Aquidneck Island (primarily Middletown and the City of Newport) would remain un-served until the transformer is replaced or a mobile is installed. This results in an exposure of approximately 460MWh.

In 2011, for loss of the 69kV line section between Jepson and the Navy substation on peak up to 18MW of load would remain un-served. Either Navy load would be un-served or a large portion of the City of Newport load would be un-served. This results in an exposure of approximately 500MWh.

Equipment concerns exist at the Jepson 4.16kV substation. A condition evaluation of these assets was completed in 2005 by O&M services. This evaluation identified concerns with the 4.16kV station regulators and the 37J4 recloser. Regulators do not meet clearance requirements and are located before the breakers. This configuration results in a regulator failure causing a two feeder outage. In addition, both feeders need to be removed from service to perform any regulator maintenance making operating the 4.16kV station challenging. O&M services recommends either the station equipment be reconfigured or the station be retired.

Project Description

Construct a second 69kV overhead supply line into the City of Newport. At Jepson substation, install a 69kV circuit breaker. From Jepson to Gate 2 substation, upgrade the existing 37K33 supply line from 23kV to 69kV and upgrade the under-built 4.16kV distribution circuit to 13.8kV. Remove 13.8kV infrastructure from the east side of West Main Road to the newly under-built 13.8kV circuit. Figure 5 shows the scope of work on the 37K33 line upgrade. Figure 6 shows the proposed 69kV supply system one-line.

Build a new 69/13.8kV substation in Newport consisting of two (2) 40MVA LTC transformers supplying metal-clad switchgear each with four (4) feeders and a two-stage 7.2MVAR capacitor bank. Figure 7 shows the proposed one-line for the new station in Newport.

Install a new 69/23kV 40MVA transformer at Gate 2 substation. Retire the existing Gate 2 4.16kV substation to provide routes for the new 13.8kV feeders from Newport substation and to allow for the use of the existing infrastructure. Remove all 4.16kV equipment at Gate 2 substation. Figure 8 shows the proposed one-line of the Gate 2 substation.

Retire the existing 23/4.16kV substation at Jepson to address asset condition concerns, provide routes for new 13.8kV feeders, and improve area aesthetics. Remove all related 23/4.16kV station equipment at Jepson. Modify the sub-transmission system as shown in Figure 9 and retire the 37K22 breaker position. Figure 10 shows a proposed one-line for Jepson substation.

Retire Bailey Brook & Vernon 23/4.16kV substations and remove all substation equipment. This retirement will provide routes for the new 13.8kV feeders from Newport substation and allow for the use of the existing infrastructure. Refer to Figure 11 & 12 for the substation one-lines.

Install five 13.8kV feeders at the proposed Newport Substation and reconfigure the area distribution system. Figure 13 shows the existing feeder mainline routes and Figure 14 shows the proposed feeder mainline routes. Figure 15 shows the location of the proposed substation, road modification being proposed for the Newport area, and the proposed land to be redeveloped.

Benefits Summary

The recommended plan is in-line with the recommendations made in the 2007 study and the commitments made by the Company to state regulators. The plan introduces the most capacity in the City of Newport, is the least sensitive to load growth, and is the most reliable. The plan offers the following benefits:

- Plan introduces approximately 60MW of new 13.8kV capacity in the heart of the existing Newport 4.16kV system sourced from the 69kV supply system. No load will be lost for loss of a transformer or supply line at the new station, resulting in a very reliable supply to the City of Newport and southern Middletown.
- Plan provides capacity to supply load growth on Aquidneck Island well beyond the study horizon period at relatively low cost. Spare capacity will exist at Dexter, Jepson and the Newport substation to supply future load growth.
- Plan eliminates substation equipment that has been identified as needing replacement or upgrading and provides capacity to address other 4.16kV assets via a conversion, if conversion proves to be the most economical option.
- Plan consolidates overhead facilities installed on both sides of West Main Road in Middletown to just one side of the road which has a positive impact on the aesthetics of this area and removes the significant congestion that currently exists.
- Plan retires Bailey Brook substation located within local wetlands and adjacent to a running brook that is a source of the water supply for the island. The retirement of Bailey Brook will eliminate the potential of an oil spill into the brook and the islands water supply, the potential of the substation being damaged due to flooding, and improve the overall aesthetics of the area. Retirement of this station eliminates the need to maintain a SPCC system that requires routine maintenance of its sump pumps. The highly congested overhead system in this area will be reduced with the retirement of this station by removing the double circuiting that currently exists.
- Plan retires Vernon substation located in the middle of a highly congested residential area and with numerous asset condition concerns. The Vernon metal-clad switchgear was installed in 1949 along with the TR231 transformer. The TR232 transformer was installed in 1963. The retirement of Vernon substation removes unreliable equipment from service and eliminates the need for asset replacement work at this station. All the station breakers have been identified for asset replacement along with the TR231 transformer. This transformer is highly loaded and has operational concerns. Because there is no adequately sized spare for this transformer and the highly utilized area assets, this transformer has been placed on the New England Watch List and has been targeted for replacement.
- Plan provides capacity to fully back-up the Navy Base and Gate 2 substation thus eliminating the load at risk that currently exists and eliminates the risk of a prolonged outage to the Navy Base and Gate 2 substation.

Business Issues

The proposed project is in the approved capital plan. A Planning Sanction paper will be presented once Preliminary Engineering has been completed.

The proposed project follows up on the action items proposed by the Company to the Rhode Island Public Utility Commission to identify and resolve electrical related issues in the area as a result of interruptions to the Newport electrical system resulting in significant customer outages that occurred in the summer of 2003. Failure to execute this project may impact commitment made by the Company to state regulators.

The proposed project requires the construction of an approximately four (4) mile long 69kV transmission line with much of it to be installed along a public roadway. A filing with the Energy Facility Sitting Board is required to permit this line.

Options Analysis

Recommended Option ($42.000M): The Plan, as outlined in the Project Description section of this paper, is the recommended plan. These recommendations are in-line with the recommendations made in the 2007 study. The plan introduces the most capacity in the City of Newport, is the least sensitive to load growth, and is the most reliable.

Alternative 1 ($56.000M): This plan proposes similar investments to the recommended plan and offers similar benefits. The main difference being this alternative assumes the second 69kV supply line into Newport would be installed underground. The estimated cost of this alternative is $56M due to the increased cost to build the underground 69kV line. This plan maintains the overhead facilities installed on both sides of West Main Road in Middletown and would not reduce the congestion that currently exists in the area. This plan is not recommended due to the incremental cost to install an underground transmission line and because it offers no reliability improvement over the recommended plan.

Alternative 2 ($42.000M*):* This plan recommends construction of two new substations. The first is a new 69/13.8kV station in the City of Newport consisting of a single 40MVA transformer supplying four (4) feeders sourced from the existing 69kV line. The second is a new 69/13.8kV station in the existing Jepson substation yard consisting of a single 40MVA transformer supplying four (4) feeders and sourced from the existing 69kV system. This plan recommends upgrades to the 37K33 supply line from Jepson to Gate 2 substations to increase back-up capacity for loss of the overhead 69kV line to the US Navy, Gate 2 substation, or the new substation in Newport. This plan is not recommended because:

- The estimated cost of this alternative is $42.000M, or approximately equivalent in cost to the recommended plan. However this plan is less reliable, more sensitive to load growth, and less flexible.

- Plan adds approximately 25MW of additional load to the radial 69kV supply line (Line 63). The load on this radial line would increase to 81MW. For loss of Line 63 all new station and Navy load would be out (approximately 46MW). The new station load needs to be manually picked up from Jepson feeders. This would require substantial reinforcements and expansion of the existing 13.8kV distribution system. These reinforcements would occur on highly congested roads and would add to the congestion of the area. Navy load would have to be manually picked up through the 23kV supply line into Gate 2.
- Plan requires reinforcement and expansion of triple circuited assets installed on highly congested roads. Reinforcements would be required on both sub-transmission and distribution assets. Permitting this type of construction could be challenging due to the high area congestion already existing. Plan would not eliminate the overhead assets installed on both sides of West Main Road in Middletown. Rather it would require reinforcement and upgrades to these assets.
- Plan assumes that sufficient upgrades can be performed to establish strong ties between Jepson substation and the new substation in Newport to address the load at risk for loss of the supply line to the new station or loss of the station transformer. If these upgrades are not possible, there could be enough un-served load at the new station to initially be non-compliant with the Distribution Planning Criteria.
- Plan assumes load growth will occur uniformly on Aquidneck Island. This may not be the case since the City of Newport has plans to open up land for development and the Navy is still considering a base expansion. If higher than forecasted load growth occurs in Newport or the Navy expands, it will be increasingly challenging to back-up this load from Jepson substation. This will result in Newport load being out until the Newport substation is placed back in-service and Navy load being out until repairs are made to the 69kV supply line. This will accelerate the need to extend the second 69kV line into Newport and the expansion of Newport substation.

Alternative 3 ($31.000M): This plan recommends construction of a single modular feeder in the City of Newport and a new 69/13.8kV station in the existing Jepson substation yard consisting of a single 40MVA transformer supplying four (4) feeders. This Plan recommends upgrades to the 37K33 supply line from Jepson to Gate 2 substations to increase back-up capacity for loss of the overhead 69kV line to the US Navy and Gate 2 substation. This plan is not recommended because it does not address the long-term needs of the area or the asset concerns at Vernon substation and the environmental concerns at Bailey Brook substation:

- Plan provides little new capacity in the City of Newport, where capacity is needed the most. A modular feeder only adds 12.6MW of new capacity in the heart of the Newport 4.16kV system. Initial loading would be 9.2MW leaving only 3.4MW of capacity to supply future load growth in the City.
- Plan is extremely sensitive to load growth. The City of Newport is pursuing the development of the area in the vicinity of the proposed modular feeder as shown on Figure 15. If load growth exceeds forecasted values, a major new investment would be required in the City of Newport. This investment would likely be a new substation in the City of Newport and the second 69kV supply line.

- Plan does not introduce sufficient capacity to retire Bailey Brook substation. This station is located within local wetlands and adjacent to a running brook that is a source of the water supply for the island.
- Plan does not introduce sufficient capacity to retire Vernon substation. The Vernon metal-clad switchgear was installed in 1949 along with the TR231 transformer. The station breakers have been identified for asset replacement along with the TR231 transformer. The recommended plan eliminates the need for asset replacement at this station by retiring these assets.
- Plan adds an additional 12.6MW of load to an already highly utilized sub-transmission system which would have a negative impact on the areas reliability.
- Plan requires reinforcement and expansion of triple circuited assets installed on highly congested roads. Reinforcements would be required on both sub-transmission and distribution assets. Permitting and construction may be challenging due to the high congestion already existing. Plan would not eliminate the overhead assets installed on both sides of West Main Road in Middletown. Rather it would require reinforcement and upgrades to these assets.
- Plan assumes that sufficient upgrades can be performed to establish strong ties between Jepson substation and the new modular feeder to address the load at risk for loss of the modular feeder. If higher than forecasted load growth occurs in Newport, it will be increasingly challenging to back-up this load from Jepson substation. This will result in Newport load being out until the modular feeder is placed back in-service.
- Plan assumes load growth occurs uniformly on Aquidneck Island. This may not be the case since the City of Newport has plans to open up land for development and the Navy is still considering a base expansion. If load growth occurs in Newport or the Navy expands, it will be challenging to supply Newport load and to back-up Navy load. This would accelerate the need to extend the second 69kV line into Newport and the construction of Newport substation.
- The cost of this plan is estimated at $31.000M. However, the plan only defers the need for a major investment in the City of Newport. The plan would defer but not eliminate the need to eventually install the second 69kV line into the City of Newport and construct a new substation in Newport to supply load growth on the southern part of Aquidneck Island. This plan offers the least reliability improvements and is the most sensitive to load growth.

Alternative 4*:* This Plan would do nothing or defer the investment. Neither of these options addresses the previously identified concerns.

Safety, Environmental and Project Planning Issues

A filing to the Rhode Island Energy Facility Siting Board ("EFSB") is required to permit the proposed 69kV transmission line. This filing will require the company to engage a consultant to assist in preparing the siting board application. A major public outreach effort is required to site the new transmission line and the new substation.

An Environmental Report is required to support the application to the EFSB for construction of jurisdictional facilities. The Environmental Report must be prepared in accordance with the EFSB Rules to provide information on the potential environmental impacts of the electric transmission system improvements proposed by the applicant.

Voltage conversions will be required to upgrade portions of the City of Newport from 4.16kV to 13.8kV. Outages will be required to energize the converted areas at 13.8kV. The outages may have to occur during off hours or during winter months to avoid conflicts with the City of Newport's busy tourist season.

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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	Property Rights	Land acquisition for Newport Substation.	Unable to secure substation site.	3	5	5	15	15	Mitigate	Ayo Osimboni	
2	Active	Permitting	EFSB Filing for new transmission line.	Public oposition to OH 69kV line	5	5	5	25	25	Mitigate	Ayo Osimboni	
3	Active	Permitting	City of Newport Permit for new substation (Zoning).	Public oposition to substation	5	5	5	25	25	Mitigate	Ayo Osimboni	
4	Active	Permitting	Political oposition	City of Newport has historicaly resisted upgrades	5	5	5	25	25	Mitigate	Ayo Osimboni	
5	Active	Stakeholders/ Outreach/Partnerships	Public outreach plan is required for permiting.	Public oposition is expected	5	5	5	25	25	Mitigate	Ayo Osimboni	
6	Active	Construction	Construction/outage availability in the summer months is limited due to high level of tourism in the area	City does not allow summer construction activities	4	5	5	20	20	Mitigate	Ayo Osimboni	

Permitting

Permit Name	Probability Required (Certain/ Likely/ Unlikely)	Duration	Status (Complete/ In Progress Not Applied For)	Estimated Completion Date
EFSB Filing	Certain			
RI DEM Filing	Certain			
Newport Planning Commission	Likely			
RI Public Utility Commission Filing	Likely			

Investment Recovery

4.1.1 Investment Recovery and Regulatory Implications

N.A

4.1.2 Customer Impact

This project will improve the reliability to customers on Aquidneck Island. The costs will ultimately be included in the rate base.

4.1.3 CIAC / Reimbursement

N.A

Financial Impact to National Grid

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4.11.1 Cost Summary Table

				Current Planning Horizon							
Project #	Project Description	Project Estimate level	$M	Prior YR Spending	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6 16/17	Total
Project #	**Description**	**-25/+50%**	**Capex**	0.700 2	.300						**3.000**
03533	Newport Sub Land		**Opex**								**0.000**
C11578	Purchase (D-Sub)		**Removal**								**0.000**
			Total	**0.700**	**2.300**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**3.000**
Project #	**Description**	**-25/+50%**	**Capex**	0.100 0	.030	0.250	1.500	4.320	2.000	1.100	**9.300**
03529	Newport Substation		**Opex**					0.150	0.050		**0.200**
C15158	(D-Sub)		**Removal**								**0.000**
			Total	**0.100**	**0.030**	**0.250**	**1.500**	**4.470**	**2.050**	**1.100**	**9.500**
Project #	**Description**	**+/-10%**	**Capex**	5.900 0	.440						**6.340**
03527	Newport Phase 1		**Opex**	0.900							**0.900**
C15409	(D-Line)		**Removal**	0.350							**0.350**
			Total	**7.150**	**0.440**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**7.590**
Project #	**Description**	**-25/+50%**	**Capex**	0.370 0.	050		0.050	0.050			**0.520**
03531	Newport 69kV Line		**Opex**								**0.000**
C24159	63 (D-Line)		**Removal**								**0.000**
			Total	**0.370**	**0.000**	**0.050**	**0.050**	**0.050**	**0.000**	**0.000**	**0.520**
Project #	**Description**	**-50/+200%**	**Capex**	0.300 0.	100		0.500	2.600	2.600	0.900	**7.000**
03528	Newport Phase 2 (D		**Opex**					0.450	0.450		**0.900**
C28628	Line)		**Removal**					0.450	0.450		**0.900**
			Total	**0.300**	**0.000**	**0.100**	**0.500**	**3.500**	**3.500**	**0.900**	**8.800**
Project #	**Description**	**-25/+50%**	**Capex**								**0.000**
16880	Bailey Brook		**Opex**								**0.000**
	Retirement (D-Sub)		**Removal**					0.030	0.400		**0.430**
			Total	**0.000**	**0.000**	**0.000**	**0.000**	**0.030**	**0.400**	**0.000**	**0.430**
Project #	**Description**	**-25/+50%**	**Capex**								**0.000**
16882	Vernon Retirement		**Opex**								**0.000**
	(D-Sub)		**Removal**					0.020 0	.280		**0.300**
			Total	**0.000**	**0.000**	**0.000**	**0.000**	**0.020**	**0.280**	**0.000**	**0.300**
Project #	**Description**	**-25/+50%**	**Capex**					0.100			**0.100**
17045	Jepson Substation		**Opex**								**0.000**
	(D-Sub)		**Removal**					0.100 0	.300		**0.400**
			Total	**0.000**	**0.000**	**0.000**	**0.000**	**0.200**	**0.300**	**0.000**	**0.500**
Project #	**Description**	**-25/+50%**	**Capex**			0.100 0	.30 0	1.060	0.900		**2.360**
17046	Gate 2 Substation		**Opex**					0.170 0	.020		**0.190**
	(D-Sub)		**Removal**					0.100 0	.250		**0.350**
			Total	**0.000**	**0.000**	**0.100**	**0.300**	**1.330**	**1.170**	**0.000**	**2.900**
Project #	**Description**	**-25/+50%**	**Capex**	0.050 0.	05	0	0.200	0.050			**0.350**
C41185	Newport Substation		**Opex**								**0.000**
	(T-Sub)		**Removal**								**0.000**
			Total	**0.050**	**0.000**	**0.050**	**0.200**	**0.050**	**0.000**	**0.000**	**0.350**
Project #	**Description**	**-25/+50%**	**Capex**	0.030		0.100 0	.50 0	3.000	1.150 0	.500	**5.280**
C41184	Newport Substation		**Opex**					0.700 0	.20 0		**0.900**
	(T-Line)		**Removal**					0.200 0	.11 0		**0.310**
			Total	**0.030**	**0.000**	**0.100**	**0.500**	**3.900**	**1.460**	**0.500**	**6.490**
Project #	**Description**	**-25/+50%**	**Capex**			0.100 0	.50 0	0.600	0.170		**1.370**
C41183	Jepson Substation		**Opex**					0.130			**0.130**
	(T-Sub)		**Removal**								**0.000**
			Total	**0.000**	**0.000**	**0.100**	**0.500**	**0.730**	**0.170**	**0.000**	**1.500**
Project #	**Description**	**-25/+50%**	**Capex**			0.020	0.100				**0.120**
C41186	Gate 2 Substation		**Opex**								**0.000**
	(T-Sub)		**Removal**								**0.000**
			Total	**0.000**	**0.000**	**0.020**	**0.100**	**0.000**	**0.000**	**0.000**	**0.120**
Total Proposed Sanction			**Capex**	7.450	2.770 0	.77 0 3	.65 0	11.780	6.820 2	.500	**35.740**
			Opex	0.900	0.000 0	.00 0 0	.00 0	1.600	0.720 0	.000	**3.220**
			Removal	0.350	0.000 0	.00 0 0	.00 0	0.900	1.790 0	.000	**3.040**
			Total	**8.700**	**2.770**	**0.770**	**3.650**	**14.280**	**9.330**	**2.500**	**42.000**

4.11.2 Project Budget Summary Table

Project Costs per Business Plan	Prior Year Spending*	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6 16/17	YR 7 17/18	Total
Capex	7.450	0.620	6.606	2.450	0.650	0.000 0	.000 0	.000	17.776
Opex	0.900	0.023	0.259	0.162	0.042	0.000 0	.000 0	.000	1.386
Removal	0.350	0.020	0.247	0.261	0.066	0.000 0	.000 0	.000	0.944
Total Cost in B Plan	8.700	0.663	7.112	2.873	0.758	0.000	0.000	0.000	$20.106

* P/Y Actuals

Variance (Business Plan-Project Estimate)	Prior Year Spending	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6 16/17	YR 7 17/18	Total
Capex	0.000	(2.150)	5.836	(1.200)	(11.130)	(6.820)	(2.500)	0.000	(17.964)
Opex	0.000 0	.023	0.259	0.162	(1.558)	(0.720)	0.000 0.	000	(1.834)
Removal	0.000 0	.020	0.247	0.261	(0.834)	(1.790)	0.000 0.	000	(2.096)
Total Variance	0.000	(2.107)	6.342	(0.777)	(13.522)	(9.330)	(2.500)	0.000	($21.894)

4.11.3 Cost Assumptions

Substation estimates were obtained from Conceptual Engineering Reports prepared by substation engineering. Conceptual Grade Estimates have been developed with only the conceptual understanding of the project. The estimates have been prepared using historical cost data or data from similar projects. The accuracy of these estimates is in the range of -25% to +50%.

The estimate for the 69kV transmission line was obtained from the Conceptual Engineering Report prepared by transmission line engineering. This Conceptual Grade Estimate has been developed with only the conceptual understanding of the project. The estimates have been prepared using historical cost data or data from similar projects. The accuracy of the estimate is in the range of -25% to +50%.

The distribution line work estimate for Phase 2 Distribution Line construction was developed utilizing generic construction costs. No field work has been performed to assess the actual condition of the assets in the field, the feasibility of the routes selected, or the number of poles and transformers needing replacement associated with the conversion from 4kV to 13kV. This is an Investment Grade Estimate with a level of accuracy ranging from -50% to +200%.

The distribution line work associated with Phase 1 Distribution Line construction is mostly complete. This work was necessary to address the most critical normal loading concerns in the City of Newport because of delays in securing a site for the new substation and its impact on the in-service date of the substation.

4.11.4 Net Present Value / Cost Benefit Analysis

Not financially driven.

4.11.5 Additional Impacts

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4.12 Statements of Support

4.12.1 Supporters

Role	Name	Responsibilities
Investment Planning	Ray Morey	Endorses relative to 5-year business plan or emergent work
Project Manager		Endorses cost, scope, schedule, and quality and support of all stakeholders
Resource Planning	Mark Phillips	Resource Planning Transmission/Substations
	Jim Patterson	Resource Planning Distribution Line - NE
Engineering/Design	Carol Sedewitz	Transmission Planning
	Mark Browne	Transmission Line Engineering
	Robert Sheridan	Distribution Asset Owner
	John Gavin	Substation Engineering & Design
	Len Swanson	Protection & Telecom
Construction	Fred Raymond	In-House construction
	Jeff Faber	Outsourced construction
	Diedre Matthews	Major Permits
	Dan Glenning	Project Management
	Sonny Anand	Project Management

4.12.2 Reviewers

Reviewer List	Name
Finance	Stephen Nigloschy
Regulatory	Peter Zschokke
Procurement	Art Curran
Jurisdictional Delegates	Jennifer Grimsley

5 Appendices

US Sanction Paper

FIG 1 – GEOGRAPHIC AREA MAP

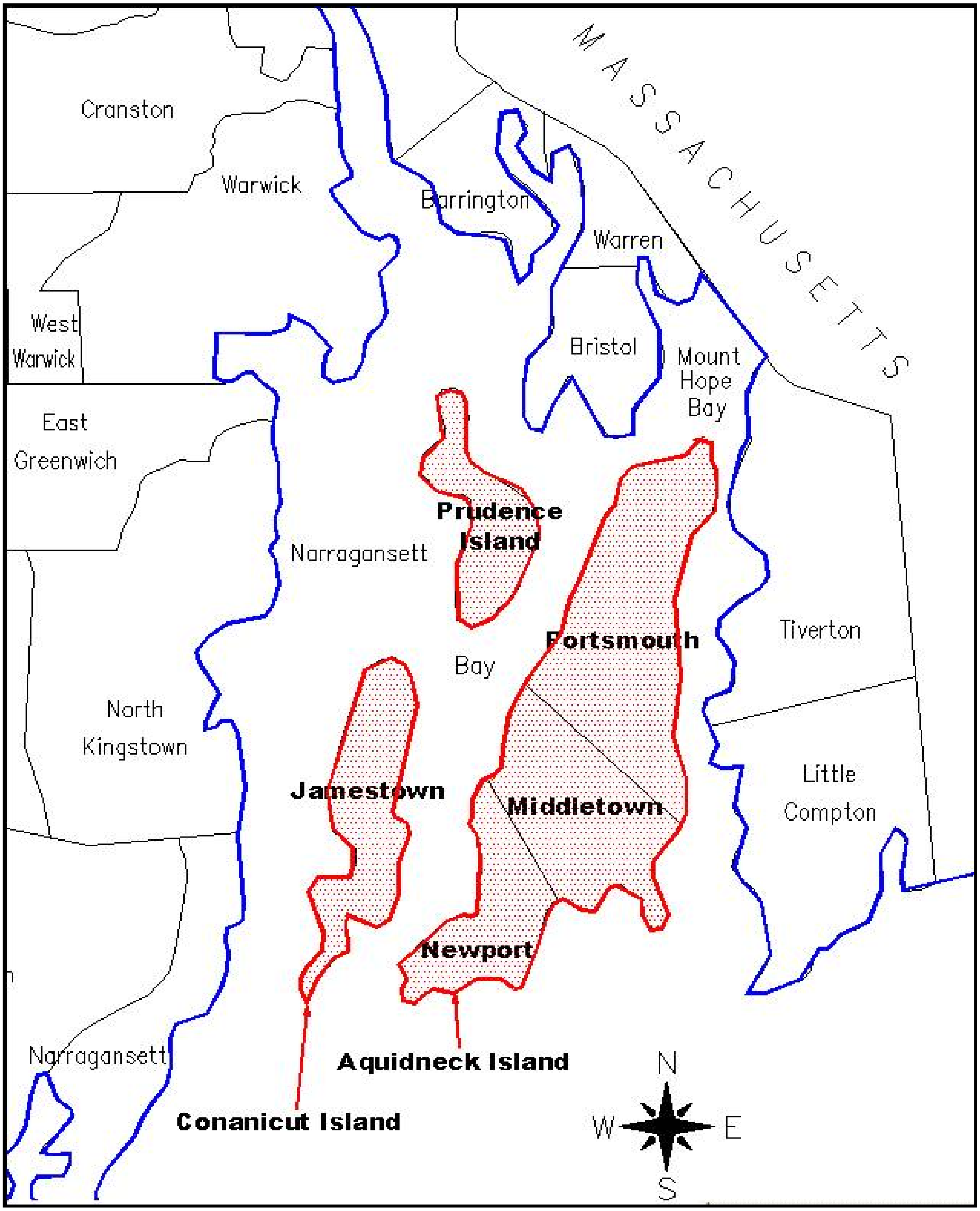

FIG 2 – EXISTING TRANSMISSION ONE-LINE DIAGRAM

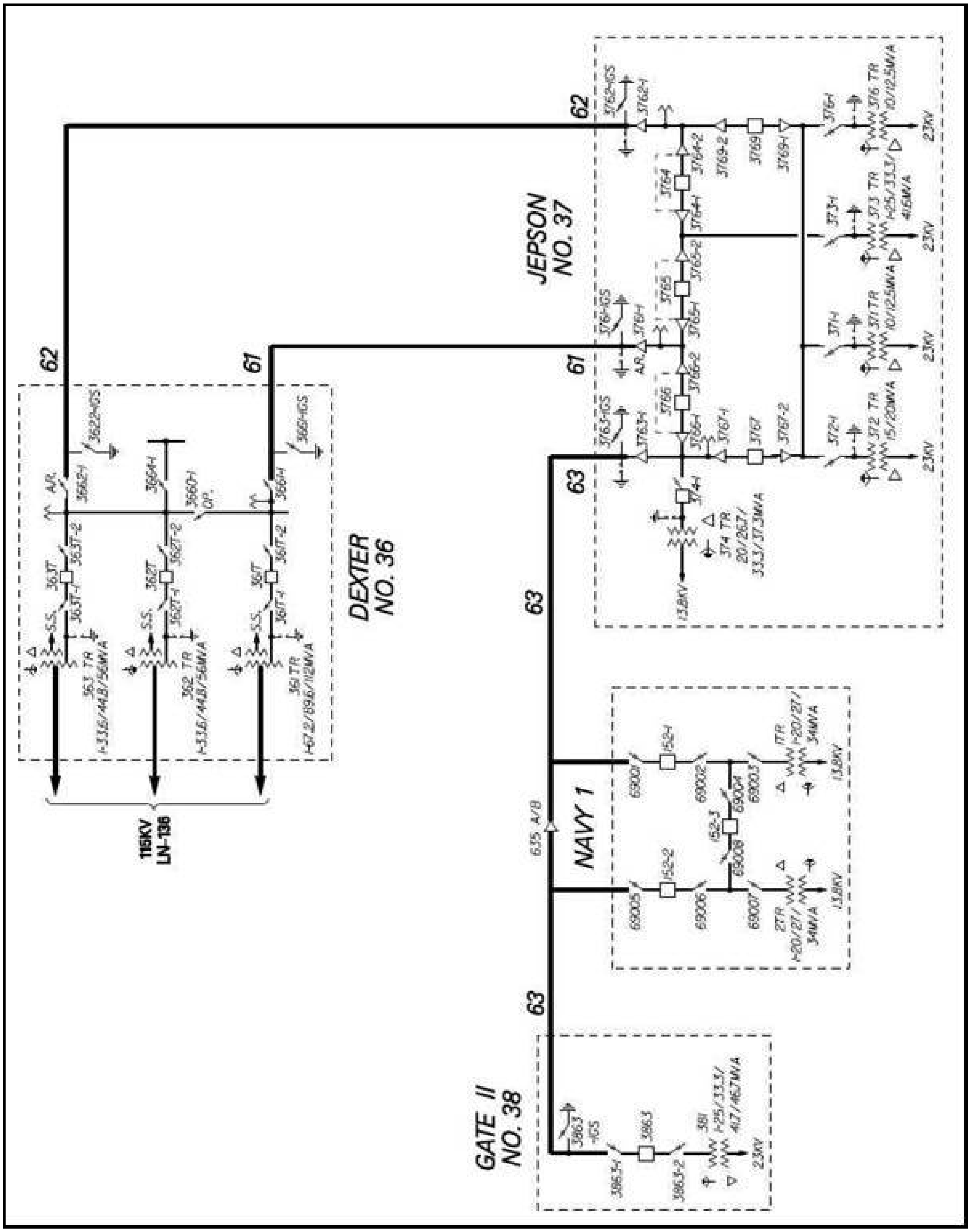

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FIG 3 – EXISTING SUB-TRANSMISSION ONE-LINE DIAGRAM

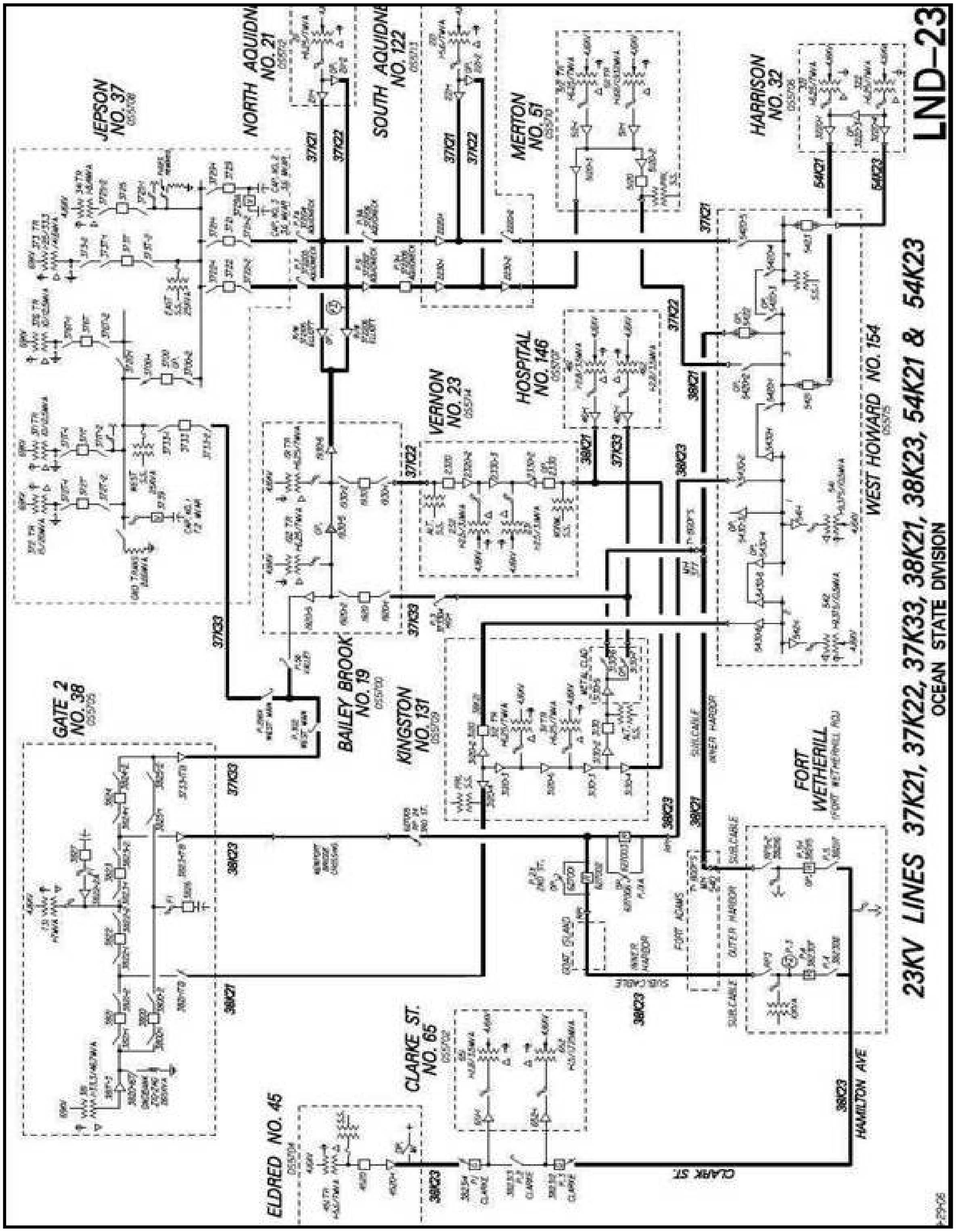

FIG 4 – GEOGRAPHIC MAP OF EXISTING DISTRIBUTION

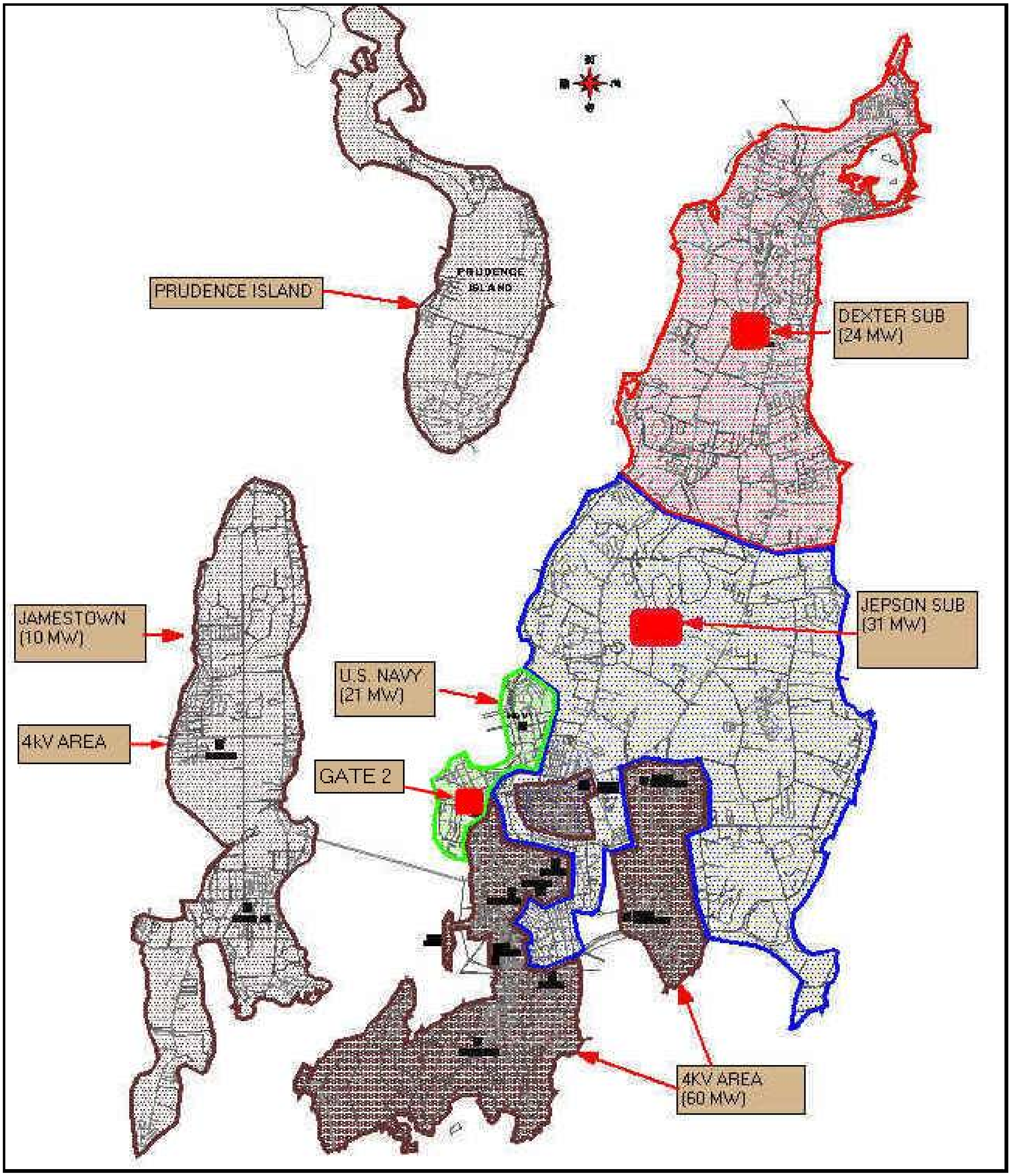

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FIG 5 – PROPOSED 37K33 UPGRADES

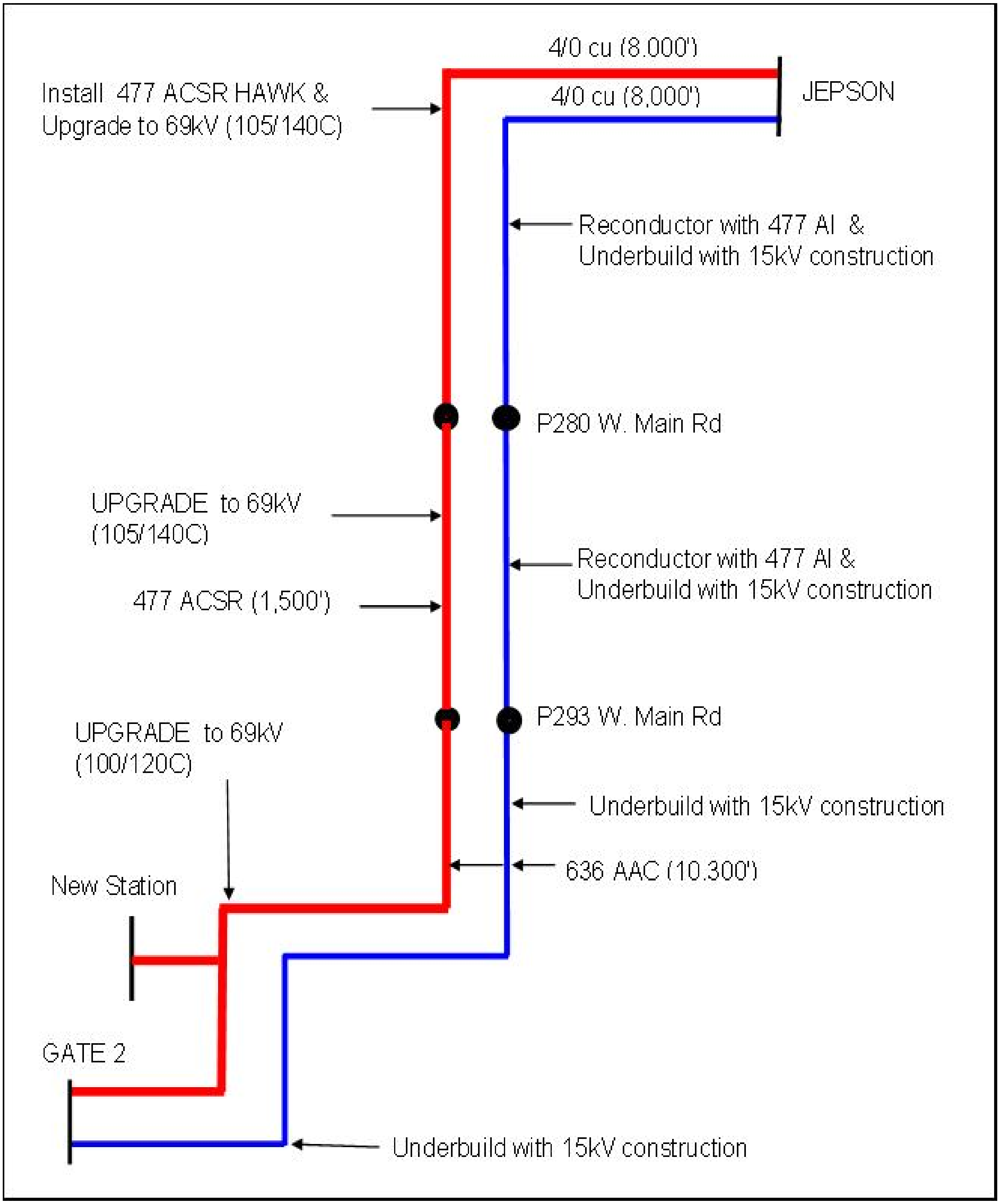

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FIG 6 – PROPOSED 69kV ONE-LINE

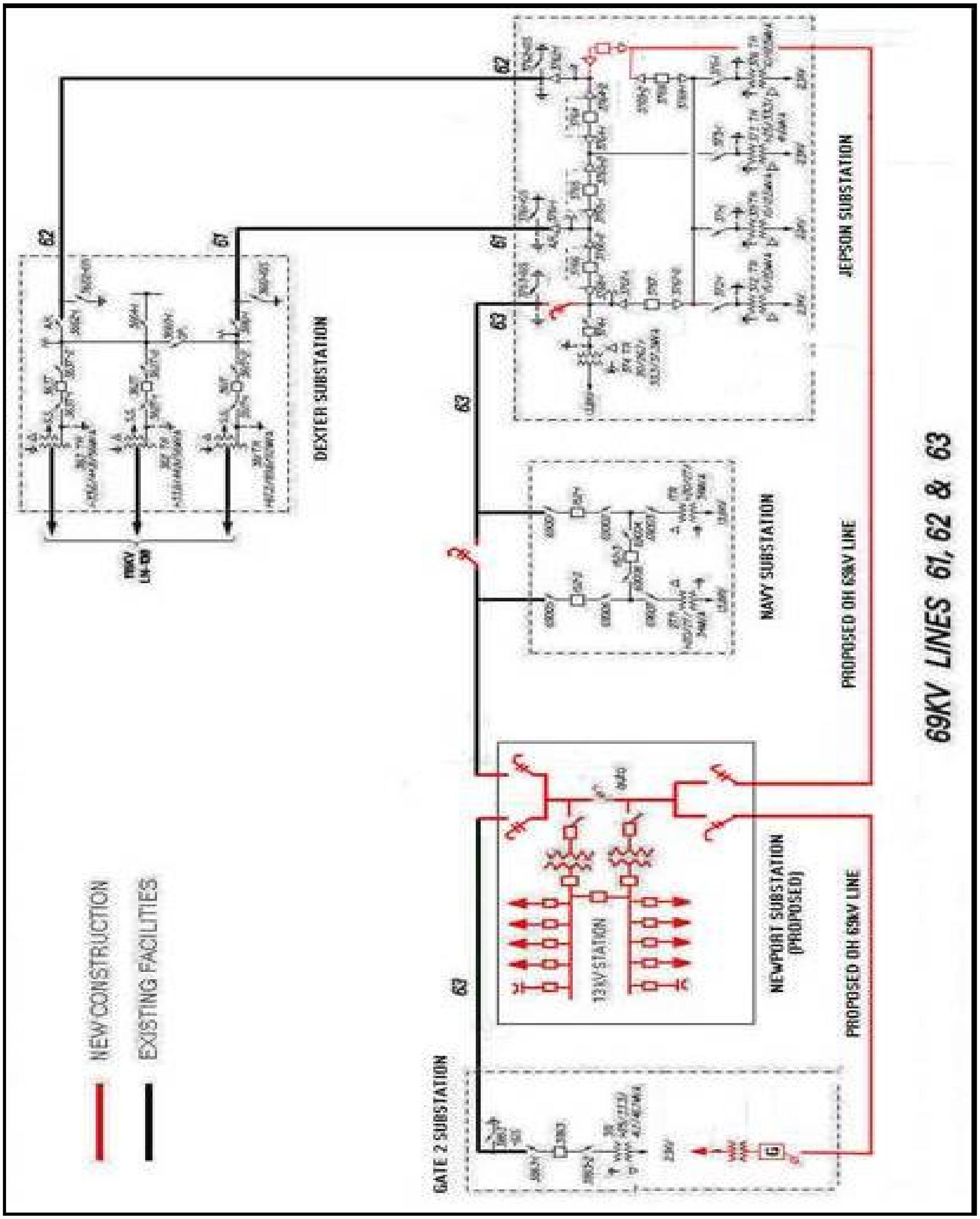

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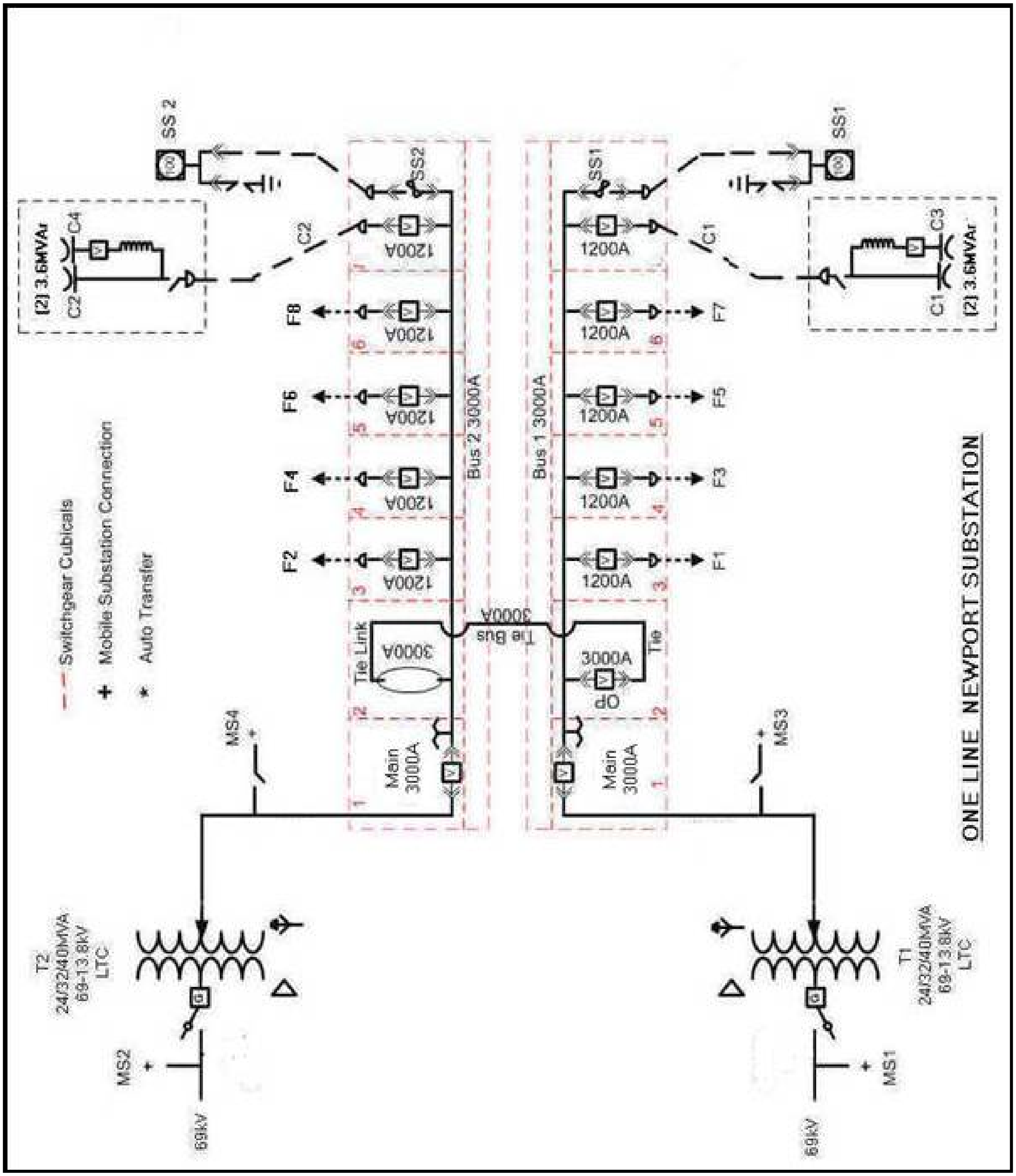
FIG 7 – NEWPORT SUBSTATION PROPOSED ONE-LINE



US Sanction Template Rev 1

FIG 8 – GATE 2 SUBSTATION PROPOSED ONE-LINE

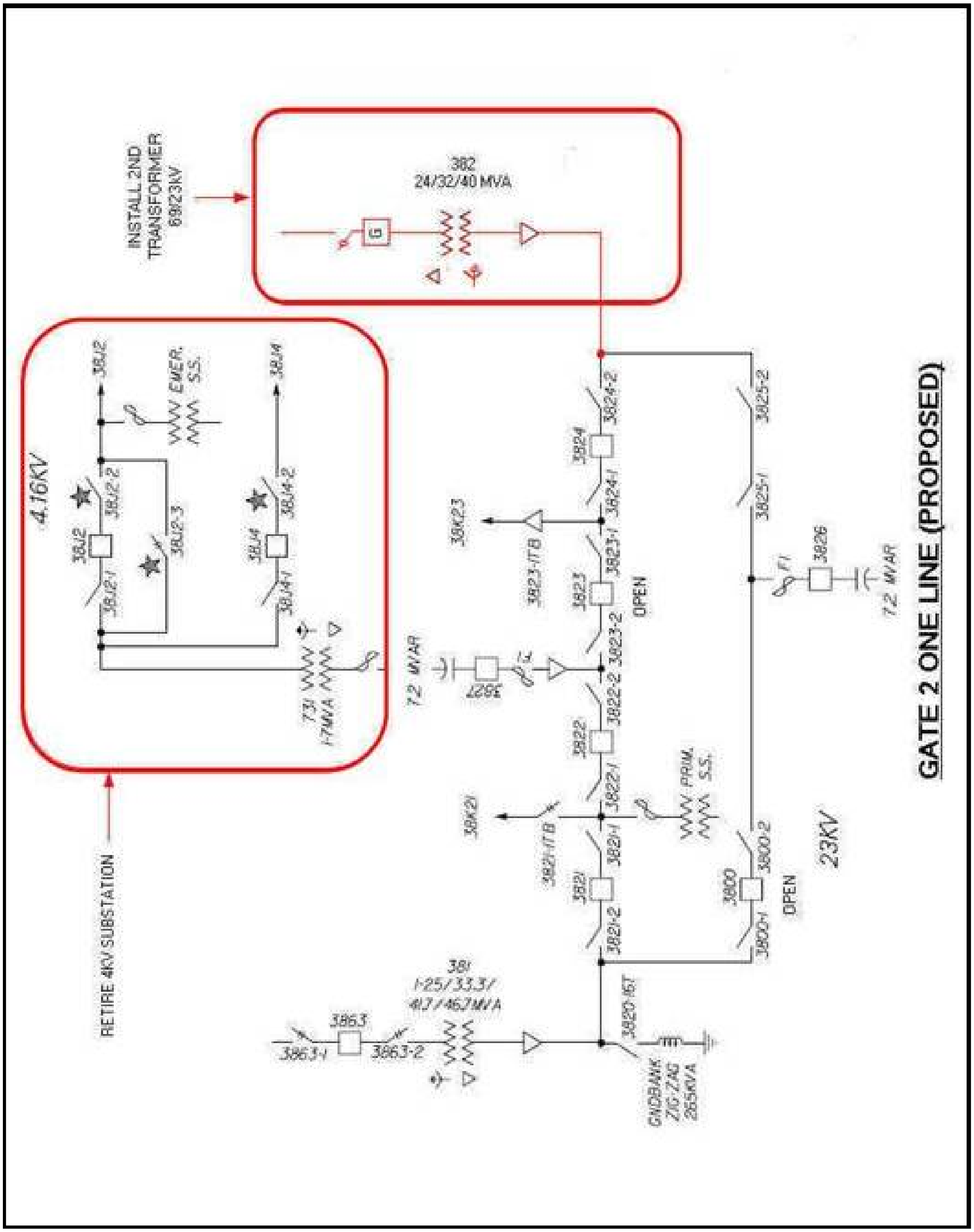


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FIG 9 – PROPOSED SUB-TRANSMISSION ONE-LINE

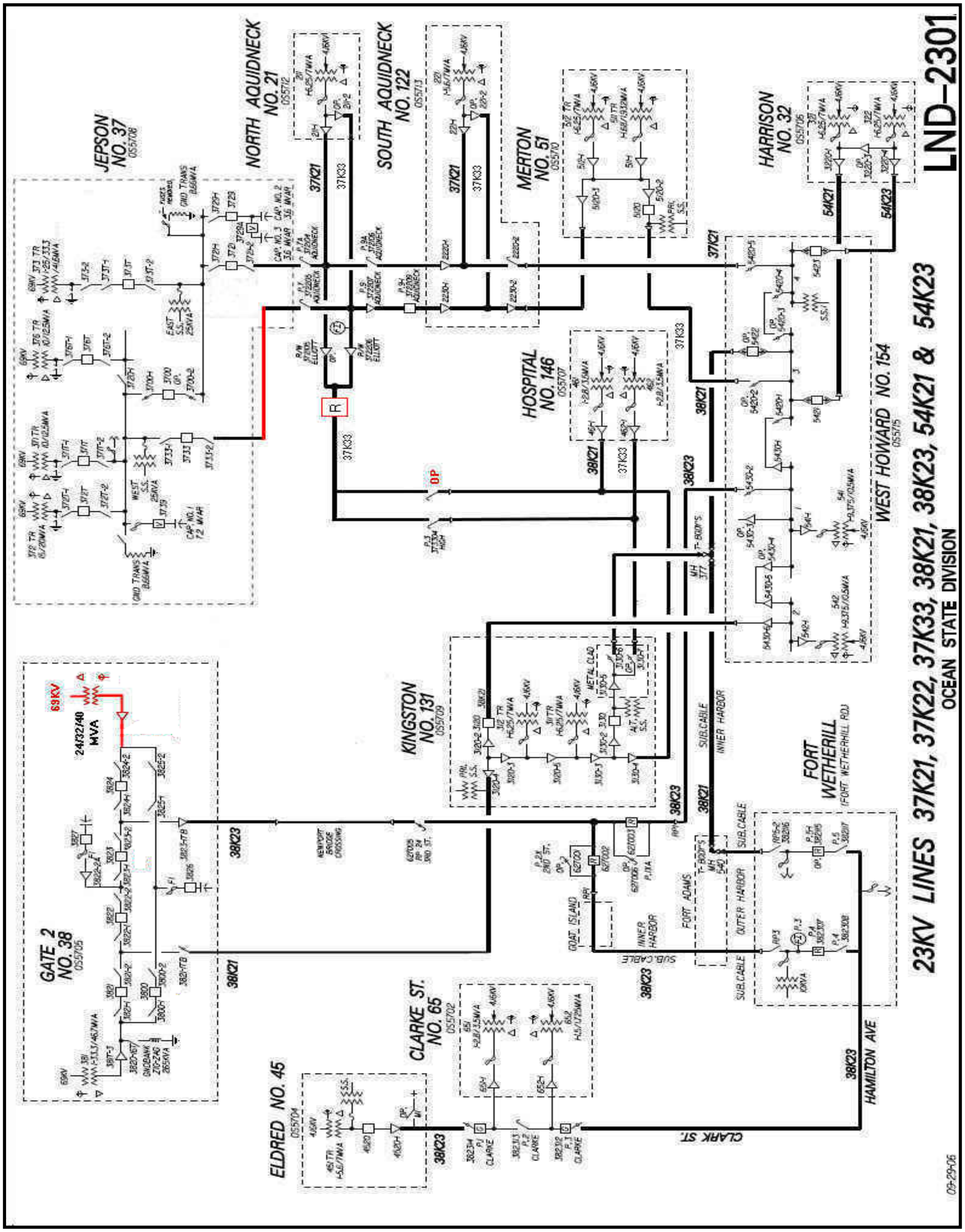

FIG 10 – PROPOSED JEPSON SUBSTATION ONE-LINE

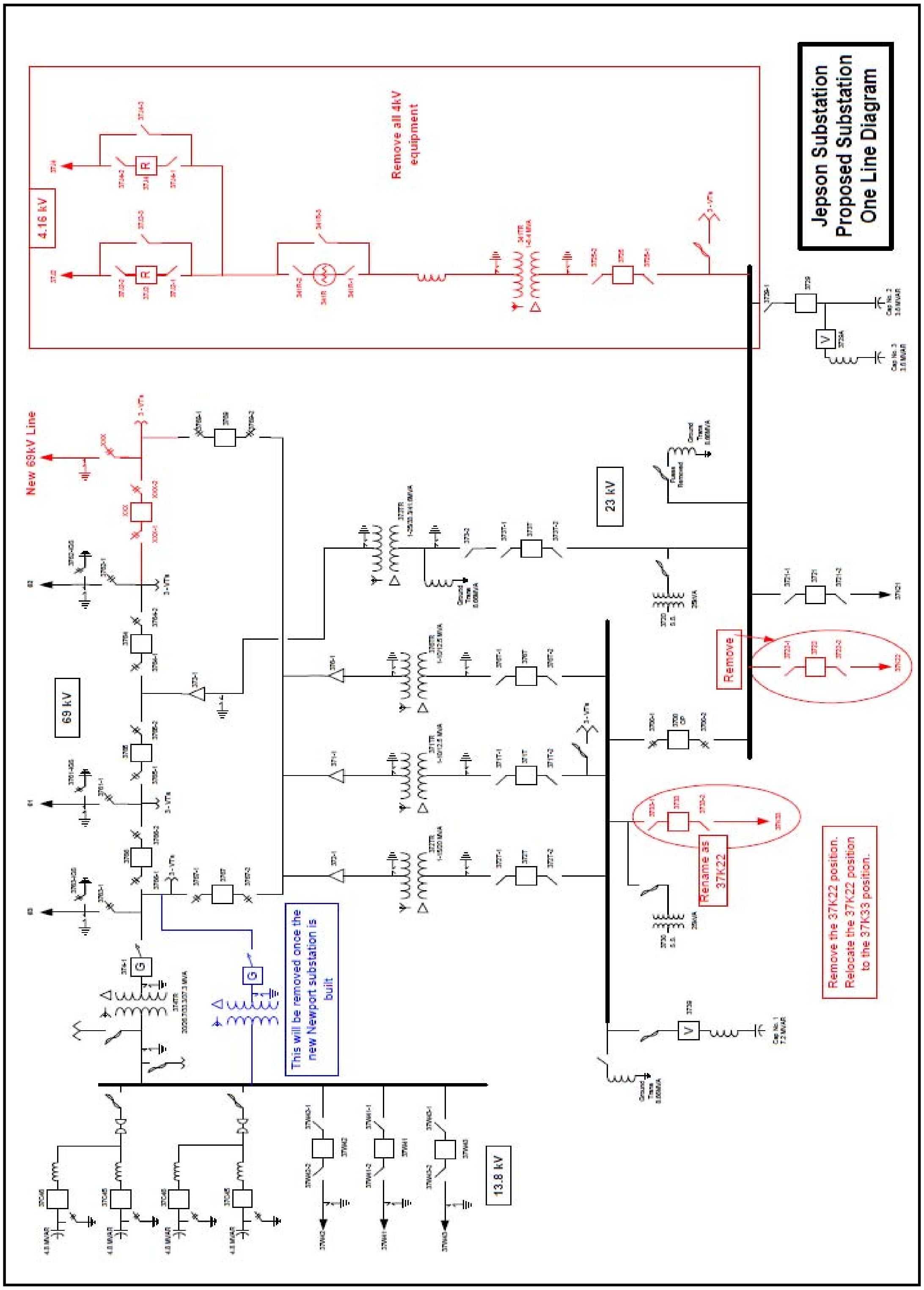

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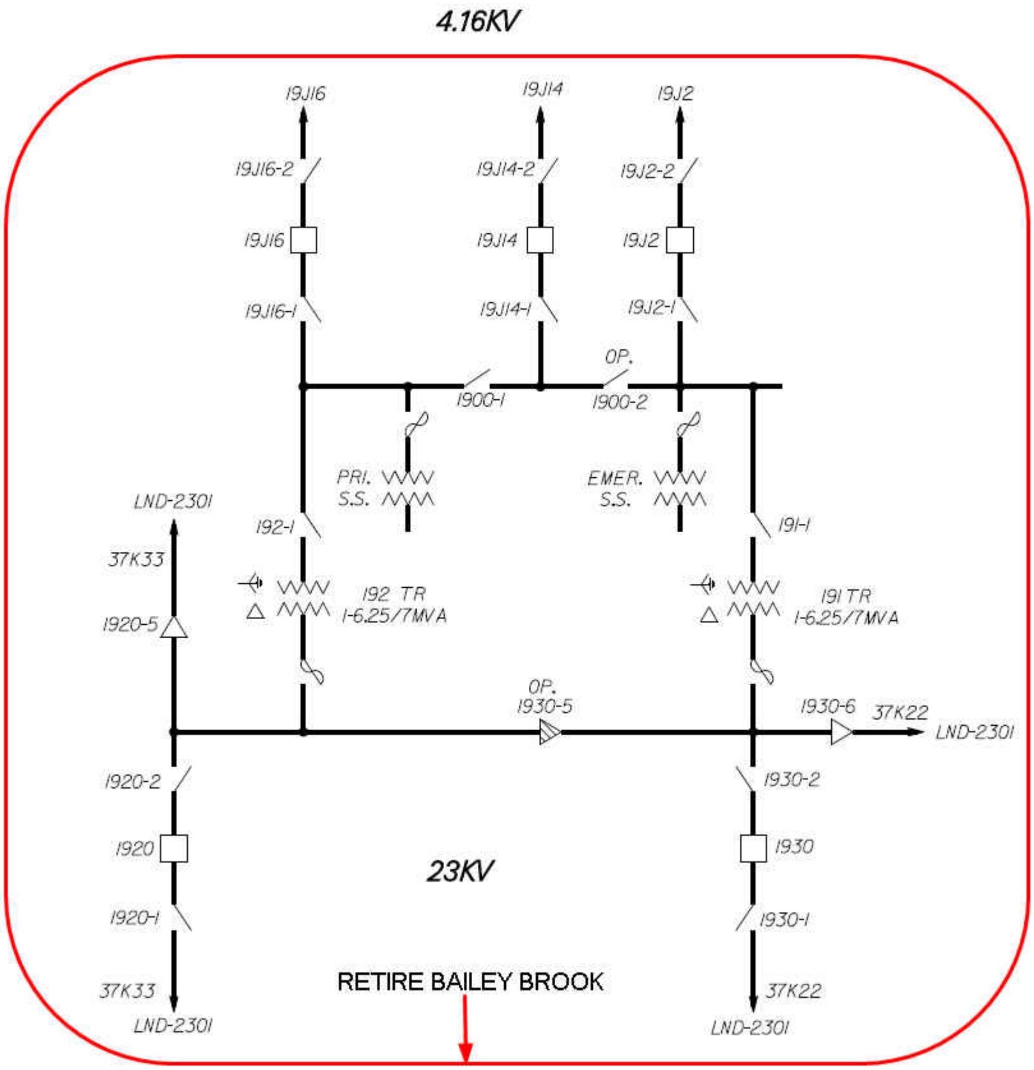
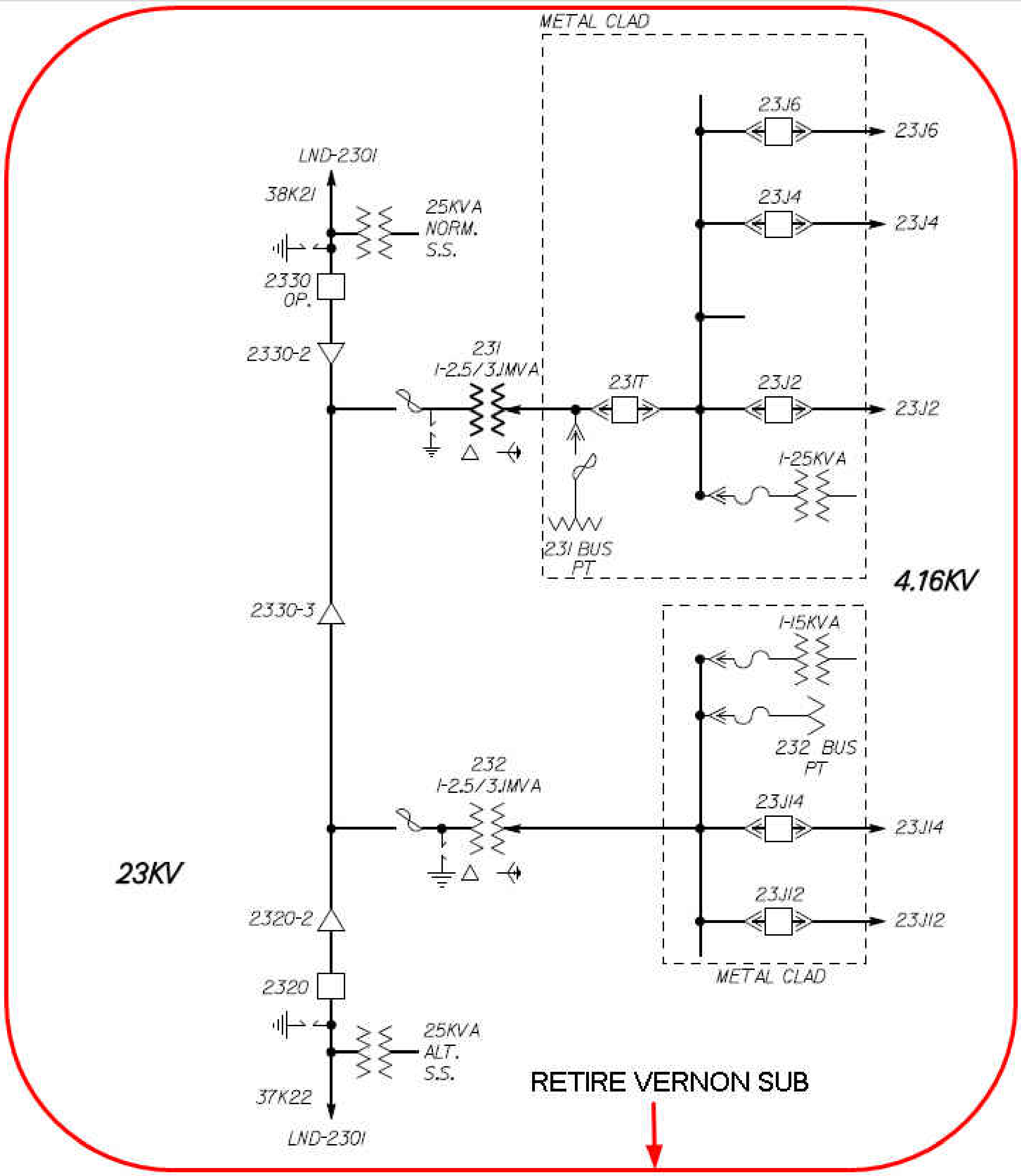
FIG 11 – PROPOSED BAILEY BROOK RETIREMENT



BAILEY BROOK SUBSTATION

FIG 12 – PROPOSED VERNON RETIREMENT



VERNON SUBSTATION

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FIG 13 – EXISTING MAINLINE DISTRIBUTION

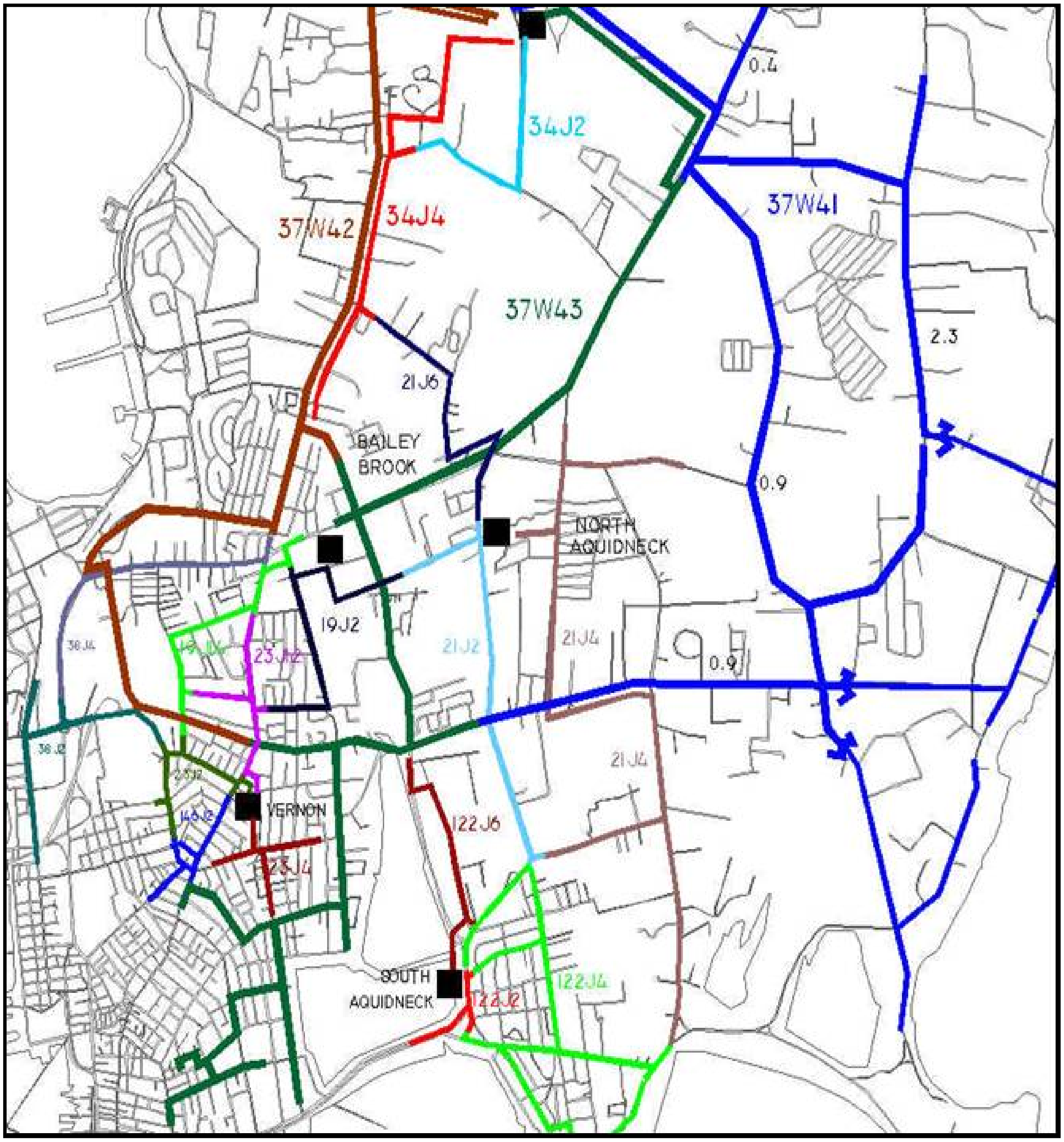

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FIG 14 – PROPOSED MAINLINE DISTRIBUTION

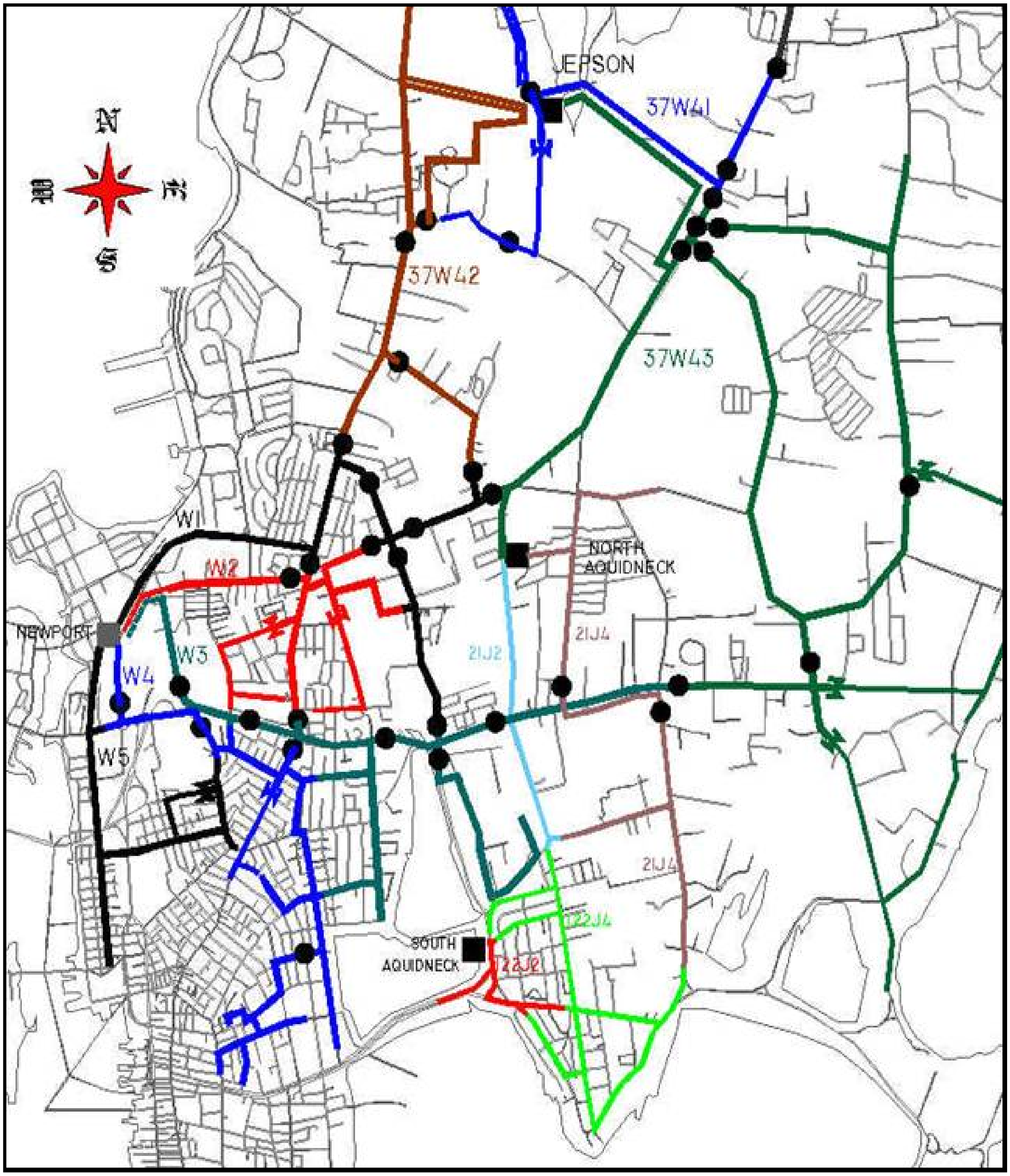

FIG 15 – PROPOSED SUBSTATION SITE

This paper contains no Critical Energy Infrastructure Information (CEII). As it reads now.

US Sanction Paper

Title:	Johnston #18 Substation Expansion	**Sanction Paper #:**	USSC0110PS259 PWS11005
Project #:	See Below – Summary of Projects	**Sanction Type:**	Partial Sanction
Operating Company:	Narragansett Electric	**Date of Request:**	September 14, 2011
Author:	Soma Soko	**Sponsor:**	Cheri Warren
Utility Service:	Electricity T&D		

1 Executive Summary

1.1 Sanctioning Summary

This paper requests partial sanction of **C33535, C34002, C28884, and C36072** in the amount of **$0.695M** and a tolerance of **-25% and +50%** for the purposes of **preliminary engineering.**

This sanction amount is **$0.695M** is broken down into
Capex **$0.695M**
Opex **$0.000**
Removal **$0.000**

NOTE the partial investment of $0.695M and a tolerance of -25% and +50%, contingent upon submittal and approval of a Project Sanction paper following completion of **preliminary engineering.**

NOTE the total project is **$7.350M** and a tolerance of **-25% and +50%.**

The total project cost is broken down into
Capex **$6.600M**
Opex **$0.400M**
Removal **$0.300M**

1.2 Brief Description:

This project is being undertaken due to load growth in the area and an asset condition in the substation. Transformer T3, which is projected to violate the 240 MWHr distribution planning criteria under a single contingency, will be replaced with a 55 MVA unit.

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Four 12.47 kV feeders will be transferred from the old yard to the new yard, and one new 12.47 kV feeder will be built. All the 12.47 kV equipment in the old yard will be removed.

1.3 Summary of Projects:

Project Number	Project Title	Estimate Amount ($)
C33535	Expand new 12.47 kV switchyard	$0.495
C34002	New underground getaway cables for new 12.47 kV feeder	
C28884	Installation of new 12.47 kV feeder	
C36072	Upgrade Transformer No. 3	$0.200
	Total	$0.695

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
March 2010	DCIG	$0.495M	Johnston Sub 12.47 kV – New Yard Expansion (DCIG011P259)	

1.6 Next Planned Sanction Review:

Date (Month/Year)	Purpose of Sanction Review
None	None

US Sanction Paper

1.7 Category:

Category	Reference to Mandate, Policy, or NPV Assumptions
☐ Mandatory ☒ Policy-Driven ☐ Justified NPV	Distribution Planning Guide

1.8 Asset Management Risk Score

Asset Management Risk Score: 35

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: 23

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 ($)
C33535	☒ Yes ☐ No	☒ Over ☐ Under	**$0.483M**
C34002	☒ Yes ☐ No	☒ Over ☐ Under	
C28884	☒ Yes ☐ No	☒ Over ☐ Under	
C36072	☒ Yes ☐ No	☒ Over ☐ Under	**$0.930M**

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

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

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1.12 Current Planning Horizon:

C33535	Current planning horizon							
$M	Prior YR'S	Yr 1 11/12	Yr 2 12/13	Yr 3 13/14	Yr 4 14/15	Yr 5 15/16	Yr 6 16/17	*Total*
Proposed Capex Investment	0.020	0.200	0.240	1.400	2.040			3.900
Proposed Opex Investment			0.039	0.050	0.102			0.191
Proposed Removal Investment					0.100			0.100
CIAC / Reimbursement								0.000
Total	$0.020	$0.200	$0.279	$1.450	$2.242	$0.000	$0.000	$4.191

C34002	Current planning horizon							
$M	Prior YR'S	Yr 1 11/12	Yr 2 12/13	Yr 3 13/14	Yr 4 14/15	Yr 5 15/16	Yr 6 16/17	*Total*
Proposed Capex Investment		0.022	0.040	0.063	0.125			0.250
Proposed Opex Investment				0.013	0.013			0.026
Proposed Removal Investment								0.000
CIAC / Reimbursement								0.000
Total	$0.000	$0.022	$0.040	$0.076	$0.138	$0.000	$0.000	$0.276

C28884	Current planning horizon							
$M	Prior YR'S	Yr 1 11/12	Yr 2 12/13	Yr 3 13/14	Yr 4 14/15	Yr 5 15/16	Yr 6 16/17	*Total*
Proposed Capex Investment		0.065	0.100	0.225	0.054			0.444
Proposed Opex Investment				0.018	0.002			0.020
Proposed Removal Investment				0.014	0.006			0.020
CIAC / Reimbursement								0.000
Total	$0.000	$0.065	$0.100	$0.257	$0.062	$0.000	$0.000	$0.484

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C36072	Current planning horizon						
$M	Prior YR'S	Yr 1 11/12	Yr 2 12/13	Yr 3 13/14	Yr 4 14/15	Yr 5 15/16	Yr 6 16/17	*Total*
Proposed Capex Investment		0.200	0.300	0.750	0.750			2.000
Proposed Opex Investment				0.100	0.100			0.200
Proposed Removal Investment					0.200			0.200
CIAC / Reimbursement								0.000
Total	$0.000	$0.200	$0.300	$0.850	$1.050	$0.000	$0.000	$2.400

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	All substation work will be within the existing fence.
2	Work must be properly staged to transfer circuits to the new switchgear so that old switchgear can be removed for the 5th bay and capacitors.
3	There is a Distribution strategy paper (DCIG011P259) that was approved for $0.495M for preliminary engineering on C33535 in March 2010. Since it has been more than one year since the DCIG paper was written and the original milestones dates were approved, it was decided to move forward the combined paper and new milestone dates at this stage.

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1.15 Key Milestones:

Milestone	**Target Date: (Month/Year)**
Start Preliminary Engineering	October 2011
Planning Sanction	December 2012
Engineering Design Complete - EDC	July 2013
Project Sanction	September 2013
Construction Start	October 2013
Construction Complete – CC	October 2014
Submit Facility Rating to ISO	April 2014
Ready for Load – RFL	October 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	Distribution strategy paper (DCIG011P259) – Johnston Sub 12.47 kV New Yard Expansion – March 2010
2	System Impact Study – Johnston #18 Substation Expansion – December 2010

US Sanction Paper

2 __Recommendations:__

The **Sanctioning Authority** i.e. USSC / NGUSA Board, etc is invited to:

(a) APPROVE up to the investment of **$0.695M** and a tolerance of **-25% and +50%** for Preliminary Engineering for the reasons stated above.

(b) NOTE the potential investment $7.350M to and a tolerance of -25% and +50%, contingent upon submittal and approval of a Project Sanction paper following completion of final engineering and design.

(c) NOTE that Sonny Anand is the Project Manager and has the approved financial delegation to undertake the activities stated in (a).

Signature……………………………………….. Date………………

Project Sponsor: Cheri Warren VP Asset Management

I hereby approve the recommendations made in this paper.

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

Christopher E. Root, Senior Vice President Network Strategy

3 __Decisions__

The US Sanctioning Committee (USSC) approved this paper at a USSC meeting held on September 14, 2011

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

Lee S. Eckert

US Chief Financial Officer

Chairman, US Sanctioning Committee

US Sanction Paper

4 Sanction Paper Detail

Title:	Johnston #18 Substation Expansion	**Sanction Paper #:**	USSC0110PS259 PWS11005
Project #:		**Date of Request:**	September 14, 2011
Company Name:	Narragansett Electric	**Sponsor:**	Cheri Warren
		Author:	Soma Soko

4.1 Background

The 115/23/12.47kV 3-winding No.2 transformer at Johnston Substation failed in March 2009. Prior to the failure there were four transformers of this type and voltage on the system, two at Drumrock substation and two at Johnston substation. This is the fourth transformer failure that has occurred in these two stations since 1984. The remaining three winding transformer at Johnston is a rewound transformer that previously failed in that location in 1992. The No.2 Johnston transformer has been replaced with a spare 2-winding 115/23kV transformer.

The No. 2 transformer along with the No.1 transformer previously supplied a 2-bay, 4-feeder breaker and a half outdoor 12.47kV distribution substation that has been in service since the 1960's. The 12.47kV substation includes obsolete GE VIR circuit reclosers which also limit the total load that the feeders in each bay can carry. A new 12.47kV station was installed in 2001 to provide the growing electrical demand of the area. Two new 115/12.47kV transformers, No.3 and No.4, were added to the substation along with a second 12.47kV outdoor breaker and a half substation supporting five feeders. Station one lines, prior to the transformer failure, are shown in Figure 1 and Figure 2. The ultimate design of the new yard was to eventually replace the older distribution equipment. A partial future site layout plan of Johnston substation is shown in Figure 3.

The loss of one of the 12.47kV supplies to the old yard as a result of the installation of the two winding transformer in the No. 2 position leaves the old 12.47kV substation with a single source. As an interim measure, a temporary bus tie has been constructed from the new substation to the old to provide switching flexibility for loss of the No.1 transformer.

In addition to the reliability and asset condition issues discussed above, there is a capacity related need for expansion of the new 12.47kV yard. A new industrial park was established in 2007 adjacent to interstate I-295, west of Johnston substation. Several new tenants have located there in the last two years and there are additional lots available for further development.
The area west of Johnston substation is supplied by three feeders from the Johnston substation (18F1, 18F3 and 18F7) and two from the West Cranston substation (21F2 and

21F4). Two of the feeders are projected to be in excess of 100% of their normal summer rating by 2014 and one feeder is projected to be equal to or in excess of 94% of its rating. Projected loadings on the Johnston and West Cranston feeders based on the 2011 forecast are shown in Figure 4. These projections and the need for this project were initially based on the 2009 load forecast. The need was re-evaluated using the 2011 load and the need to upgrade transformer No. 3 was verified.

Due to the heavy loading of the feeders in this area and the limitations of the feeders in the old yard, switching is not a viable option to reduce loading on the feeders that are above their normal rating. Also new capacity is required in the area. It is proposed that a new feeder be developed out of Johnston Substation, to be completed by summer 2014. A plan showing the new feeder layout is shown in Figure 5.

The addition of substation capacitors for transformer reactive loss compensation is also recommended at this time.

Along with the expansion of the new 12.47 kV switchgear it is recommended that the 40 MVA T3 transformer (DxT Asset) be replaced with a 55 MVA unit in order to satisfy the planning design criteria for a contingency for loss of a transformer. The worst contingency is the loss of T4 which could lead to a 266 MWHr outage in 2013. The proposed one line is shown in Figure 6.

4.2 Drivers

This project is being driven by the failure of the three-winding No. 2 transformer at Johnston substation and the need for additional feeder capacity in the area. Projected feeder loads after installation of the new feeder is shown in Figure 7.

4.3 Project Description

The DxD portion of the project consists of the following:

- Complete the 3rd bay by adding the second feeder position consisting of a feeder breaker, regulators, switches, relays, control and other associated equipment.
- Add a 4th and 5th bay consisting of a tie breaker and two feeder positions each consisting of a feeder breaker, regulators, switches, relays, controls and other associated equipment.
- Add 2 – 2 stage 3.6/7.2 MVAr substation capacitor banks including breakers and stage switches for transformer reactive loss compensation.
- Retire and remove all equipment in the old 12.47 kV substation.
- Install underground ducts and cables to connecting circuits to the new feeder positions.

US Sanction Paper

The DxT portion of the project consists of the following:

- Replace the existing 24/32/40 MVA transformer No. 3 with a unit rated 33/44/55 MVA.

4.4 Benefits Summary

The recommended solution will increase the capacity of the new 12.47 kV switchyard, and will allow the 12.47 kV feeders from the old switchyard to be transferred. One new 12.47 kV feeder will also be built. The old 12.47 kV switchyard can be retired, and obsolete equipment, including 6-VIR type circuit reclosers, can be removed. An additional benefit of the project will be the replacement of assets in the original 12.47 kV yard.

4.5 Business Issues

The need for new feeder was planned in previous business plans, however additional scope was developed after the transformer failure in March 2009. Costs for the full project will be included in future budgets. This project does not affect any commercial agreements. This project does have a linkage to the Circuit Breaker and Recloser replacement strategy.

A Distribution strategy paper (DCIG011P259) was approved for $0.495M for preliminary engineering in March 2010.

4.6 Options Analysis

Option 0 **(Not Recommended)**	***<u>Do Nothing</u>***
	Doing nothing will not solve the problem of the overloaded 12.47kV feeders because it won't increase the capacity at the substation. During certain single contingencies, the 240 MWHr distribution planning criteria would not be met and customers could have an extended outage.
Option 1 **Recommended**	**Replace transformer No. 3 with 55 MVA unit, transfer all 12.47kV load to transformers No. 3 and No. 4, remove 12.47kV winding from transformer No. 1**
	This option includes building five 12.47kV feeders. Four of the feeders will be transferred from the old switchyard, and one feeder will be brand new. The old 12.47kV switchyard will be retired, and all the equipment (including the 6-VIR type circuit reclosers) will be removed. Two substation capacitor banks will also have to be installed. This option will increase the capacity of the new 12.47kV switchgear and will

US Sanction Paper

	make it possible to remove the old 12.47kV equipment from the remaining 3-winding transformer, including the 6-VIR type circuit reclosers which are now obsolete. (Total Cost: $7.35M)
Option 2 **(Not Recommended)**	**Replace transformer No. 3 with 55 MVA unit, but continue using transformer No. 1 as is**
	This option involves building only one additional 12.47kV feeder at the new switchyard which is necessary to relieve the overloaded 18F1 and 18F7 feeders. Transformer No. 1 will continue to serve the 12kV load it is currently serving. The 6-VIR type circuit reclosers in the old 12 kV switchyard will need to be replaced due to obsolescence. Replacements are presently being budgeted and scheduled under the *Circuit Breaker and Recloser Strategy*. Other upgrades will also be necessary in the old yard to remove loading limitations in the bays during contingencies. This will permit full utilization of the available feeder capacity in the old yard. The 12.47kV connection to the new yard will have to be made permanent or the No. 2 transformer will have to be replaced with another three winding transformer. A separate 115/12.47kV transformer to supply the No. 2 12.47kV bus is not feasible due to space limitations in the yard. Delay in eliminating the old yard will make eventual elimination of the yard more difficult and costly. This is due to the old yard having to be removed prior to expanding the new yard and a larger station load having to be maintained during construction. This will require construction to be carried out in multiple phases in periods of light load condition, adding to the complexity, risk to load and mobilizing and demobilizing costs each time. The recommended plan can be executed in a staged sequence that minimizes reliability risk and project cost. The installation of capacitors for transformer reactive compensation would either have to be delayed or performed in an unconventional manner since installing capacitors in their typical location on the bus ends would hinder future expansion of the new 12.47kV yard to accommodate additional feeders. Although this option may defer equipment costs, it could lead to higher construction costs. It also increases reliability risk as aging equipment is kept in service.. (Total Cost: $8.2M – this includes the deferred costs)

4.7 Safety, Environmental and Project Planning Issues

- All substation work will be within the existing fence.

- Due to a previous catastrophic transformer failure that led to a major oil release into the soil and underlying groundwater, the Johnston Substation is an active remediation site. Based on the aforementioned and the need for the Site to remain energized, a land deed restriction is currently being prepared for the property. It is unclear at this time if said restriction will impact the proposed Project.

- Dewatering will be necessary at the site. Any and all groundwater removed from the subsurface will require containerization, at least, prior to either off-Site removal and/or on-Site permitted discharge. Previous projects have indicated that the groundwater level is high at the Johnston substation, but it is not known whether the water is still contaminated with oil due to a previous oil spill. During the excavation when construction starts, Environmental will investigate if the water is still contaminated with oil. If oil contamination is found, then additional funds will be needed to de-contaminate the water.

- A soil Erosion Sediment Control (SESC) Permit would need to be secured with the Town of Johnston for soil excavation activities. See Section 9.1.6 for Permitting Schedule.

- Some of the proposed work will be conducted within the buffer zone to fresh water wetlands and would therefore require permitting under the RI DEM freshwater wetlands program. A minimum of six to nine months would be expected for the preparation, submittal and issuance of this permit.

- A Storm water pollution prevention plan (SWPPP) is not anticipated to be required due to the relatively small scale of this project (ie. Less than one acre of disturbance is anticipated). However, elements of a SWPPP would be incorporated into an Environmental Field Issue (EFI) to direct crews on where to place erosion controls to protect wetlands and to dictate the frequency of site inspections by an environmental monitor.

- Because the entire project is within the limits of the existing developed substation yard, cultural/historical resources and endangered species are not anticipated to be an issue.

- Project sequencing will be critical to maintain reliability as feeders are transferred between switchgear and equipment is removed to make way for new construction.

4.8 Execution Risk Appraisal

Numb	Status (Active, Dormant, Retired)	Category	Detailed Description of Risk / Opportunity	Cause/Trigger	Probabi	Cost	Schedule	Cost	Schedule	Strategy	Risk Owner	Comments/Actions
1	Dormant	Outage Planning and Availability	There is a project planned to rebuild the S-171S and T-172S lines, as part of the NEEWS Rhode Island Reliability Project (RIRP). Once the rebuild project starts, the S-171S will be radial, and unable to come out of service for testing the new transformer under oil Although most of this work should be complete before the Johnston transformer will be replaced, there is a low possibility for some scheduling conflicts.	If the project to rebuild the S-175S and T-172S lines gets delayed, it could lead to this risk.	1	1	1	1	1	Accept	Sonny Anand	
2	Dormant	Permitting	Some non-environmental permitting, including a Special Use Permit, Dimensional Variance and a Floodplain Development Permit may be required for this project. **Mitigation steps**: The need for these permits will be investigated during preliminary engineering, and will be included in the sanction paper. If these permits are required, it could delay the project.	A Special Use Permit will be needed if the substation fence needs to be expanded. A Dimensional Variance will be needed if any of the new structures are over 35 feet, or if over 20% of the lot is covered by "buildings". A Floodplain Development Permit is needed if the substation is in a floodplain.	2	1	5	2	10	Mitigate	Lauren Peloquin	
3	Active	Construction	The old 12kV yard is physically located where the new 12kV yard expansion is going to be, but it can't be removed completely to make room because it is still carrying load. There needs to be a plan to de-energize the old 12kV yard so the construction in the new 12kV yard can be accommodated. **Mitigation steps:** The construction can be done in phases so that load can be transferred before the old equipment is removed.		5	5	5	25	25	Mitigate	Sonny Anand	
4	Active	Engineering / Design	The current LPS98 design at Johnston substation is designed for a maximum of three-bays with cap banks installed at the end of each bus. The LPS98 design utilizes a programmable logic controller (PLC) for control, annunciation, and SCADA. Expanding the current three bay build to accommodate the proposed five bays will involve major programming changes to the PLC and associated equipment which will require significant engineering effort. As part of this reprogramming there is a risk of encountering hardware and software limits that could result in a major reengineering of the substation control and integration network, and replacement of the associated equipment. Additionally, this design poses the risk of undesired operations during commissioning and it will require significant engineering commissioning effort during construction. If a major reengineering of the substation is required it could add a significant cost to the estimate, and could also impact the schedule of the project. **Mitigation steps:** Still being determined at this time.	Once Preliminary Engineering starts, the protection engineers will determine how much re-engineering in the sub is needed.	5	5	5	25	25	Mitigate	Bill Panas	
								-	-			

4.9 Permitting

Permit Name	Probability Required (Certain/ Likely/ Unlikely)	Duration	Status (Complete/ In Progress Not Applied)	Estimated Completion Date
State Environmental (RI DEM Freshwater Wetlands)	Certain	12 months		October 2012
Other State (RIPDES discharge permit and operation of groundwater treatment system for groundwater)	Certain	Open permit		October 2013
Local Planning Commissions	Certain	6 months		October 2012
Environmental Field Issue	Certain	1 month		October 2012

4.10 Investment Recovery

4.10.1 Investment Recovery and Regulatory Implications

Non-PTF Plant (radial facilities <= 115kV serving local network)

Capital Projects of Narragansett Electric are recovered through a capital recovery mechanism established by Rhode Island General Laws. Inclusion of this project in the capital plan approved by the Rhode Island Public Utilities Commission will provide the opportunity for recovery of these prudently incurred costs through the capital recovery mechanisms.

The Transmission portion of the project, which is owned by Narragansett Electric, would be remunerated under the transmission, local network service (LNS) rates.

The Distribution portion of the project, which includes the 115/12.47 kV transformer, would be remunerated under the retail rates.

Narragansett Electric's transmission capital investment costs are recoverable through the FERC-approved Integrated Facilities Arrangement (IFA) in place between Narragansett Electric and NEP under NEP's FERC Electric Tariff First Revised Volume No. 1, Schedule III-B. Recovery begins in the month following the "in-service" date under the formula-rate structure.

NEP recovers charges received under the IFA through the Regional Network Services rate or the Local Network Services rate, dependent upon whether the facilities are Pool Transmission Facilities (PTF) or Non-PTF, as approved by FERC, under Section II of ISO-NE's Transmission, Markets and Services Tariff (ISO-NE Tariff).

Actual performance on a project may be subject to review and approval by the Federal Energy Regulatory Commission to determine whether the costs of the project are just and reasonable in the provision of transmission service.

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4.10.2 .*Customer Impact*

Risks to reliability and provision of service to new loads are mitigated.

4.11 Financial Impact to National Grid

4.11.1 *Cost Summary Table*

Project #	Project Description	$M	Prior YR Spending	YR1 11/12	YR2 12/13	YR3 13/14	YR4 14/15	YR5 15/16	YR6+	Total
			Current Planning Horizon							
C33535	Johnston Sub	**Capex**	0.100	0.200	0.200	1.360	2.040			**3.900**
	12.47kV Expansion	**Opex**			0.039	0.050	0.102			**0.191**
	D-Sub	**Removal**					0.100			**0.100**
		Total	**0.100**	**0.200**	**0.239**	**1.410**	**2.242**	**0.000**	**0.000**	**4.191**
Project #	**Description**									
C34002	Johnston Sub	**Capex**		0.022	0.040	0.063	0.125			**0.250**
	12.47kV Expansion	**Opex**				0.013	0.013			**0.026**
	D-Line	**Removal**								**0.000**
		Total	**0.000**	**0.022**	**0.040**	**0.076**	**0.138**	**0.000**	**0.000**	**0.276**
Project #	**Description**									
C28884	Install Johnston	**Capex**		0.065	0.100	0.225	0.054			**0.444**
	18F10 Feeder	**Opex**				0.018	0.002			**0.020**
	D-Line	**Removal**				0.014	0.006			**0.020**
		Total	**0.000**	**0.065**	**0.100**	**0.257**	**0.062**	**0.000**	**0.000**	**0.484**
Total Proposed Sanction										
		Capex	0.100 0.	287	0.340	1.648	2.219	0.000	0.000	**4.594**
		Opex	0.000 0.	000	0.039	0.081	0.117	0.000	0.000	**0.237**
		Removal	0.000 0.	000	0.000	0.014	0.106	0.000	0.000	**0.120**
		Total	**0.100**	**0.287**	**0.379**	**1.743**	**2.442**	**0.000**	**0.000**	**4.951**
			$0.100	**$0.287**	**$0.379**	**$1.743**	**$2.442**	**$0.000**	**$0.000**	**$4.951**

4.11.2 Project Budget Summary Table

Project Costs per Business Plan		Prior Year Spending*	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6+	Total
	Capex	0.100 0.	585	2.342	0.975	0.195	0.000	0.000	**4.197**
	Opex	0.000 0.	018	0.078	0.029	0.006	0.000	0.000	**0.131**
	Removal	0.000 0.	018	0.087	0.029	0.006	0.000	0.000	**0.140**
	Total Cost in B Plan	**0.100**	**0.621**	**2.507**	**1.033**	**0.207**	**0.000**	**0.000**	**$4.468**
	* P/Y Actuals								

Variance (Business Plan-Project Estimate)		Prior Year Spending	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6+	Total
	Capex	0.000 0.	298	2.002	(0.673)	(2.024)	0.000 0.	000	**(0.397)**
	Opex	0.000 0.	018	0.039	(0.052)	(0.111)	0.000 0.	000	**(0.106)**
	Removal	0.000 0.	018	0.087	0.015	(0.100)	0.000 0.	000	**0.020**
	Total Variance	**0.000**	**0.334**	**2.128**	**(0.710)**	**(2.235)**	**0.000**	**0.000**	**($0.483)**

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US Sanction Paper

Associated Project(s) Cost Summary Table

			Current Planning Horizon							
Project #	Project Description	$M	Prior YR Spending	YR1 11/12	YR2 12/13	YR3 13/14	YR4 14/15	YR5 15/16	YR6+	Total
C36072	Johnston #18 Sub	Capex	0.050	0.200	1.650	0.100				**2.000**
		Opex	0.000	0.100	0.100	0.000				**0.200**
		Removal	0.000	0.000	0.200	0.000				**0.200**
		Total	**0.050**	**0.300**	**1.950**	**0.100**	**0.000**	**0.000**	**0.000**	**2.400**
Total Proposed Sanction										
		Capex	0.050 0.	200	1.650	0.100	0.000	0.000	0.000	**2.000**
		Opex	0.000 0.	100	0.100	0.000	0.000	0.000	0.000	**0.200**
		Removal	0.000 0.	000	0.200	0.000	0.000	0.000	0.000	**0.200**
		Total	**0.050**	**0.300**	**1.950**	**0.100**	**0.000**	**0.000**	**0.000**	**2.400**
			$0.050	**$0.300**	**$1.950**	**$0.100**	**$0.000**	**$0.000**	**$0.000**	**$2.400**

Total Project Current Year and Future Years Cost = $2.350 M

Project Budget Summary Table

Project Costs per Business Plan

		Prior Year Spending*	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6+	Total
	Capex	0.050 0.	260	1.160	0.000	0.000	0.000	0.000	**1.470**
	Opex	0.000 0.	000	0.000	0.000	0.000	0.000	0.000	**0.000**
	Removal	0.000 0.	000	0.000	0.000	0.000	0.000	0.000	**0.000**
	Total Cost in B Plan	**0.050**	**0.260**	**1.160**	**0.000**	**0.000**	**0.000**	**0.000**	**$1.470**

* P/Y Actuals

Variance (Business Plan-Project Estimate)

		Prior Year Spending	YR 1 11/12	YR 2 12/13	YR 3 13/14	YR 4 14/15	YR 5 15/16	YR 6+	Total
	Capex	0.000 0.	060	(0.490)	(0.100)	0.000 0.	000	0.000	**(0.530)**
	Opex	0.000	(0.100)	(0.100)	0.000 0.	000	0.000	0.000	**(0.200)**
	Removal	0.000 0.	000	(0.200)	0.000 0.	000	0.000	0.000	**(0.200)**
	Total Variance	**0.000**	**(0.040)**	**(0.790)**	**(0.100)**	**0.000**	**0.000**	**0.000**	**($0.930)**

4.11.3 Cost Assumptions

These cost estimates are conceptual grade (-25% to +50%). They were developed by internal estimating tools in 2010, and are for multi-year projects. $0. 200M is the cost for transmission preliminary engineering, and is included in the capital expenditure for FY11/12. $0.495M is the cost for distribution preliminary engineering and is included in the capital expenditure for FY11/12.

4.11.4 Net Present Value / Cost Benefit Analysis

This project is not financially driven, so NPV is not applicable.

4.11.5 Additional Impacts

N/A

4.12 Statements of Support

Authors of this paper assure that in accordance with TGP 11 the supporters listed below have been consulted and that each function listed below supports this paper.

4.12.1 *Supporters*

Role	Name	Responsibilities
Sponsor/ Asset Manager/ Asset Owner/ Process Owner		Endorses the project aligns with jurisdictional objectives
Investment Planning	Ray Morey	Endorses relative to 5-year business plan or emergent work
Engineering/Design (Director, Electric Transmission Planning)	Carol Sedewitz	Transmission Planning
Engineering/Design (Manager – Transmission Asset Owner)	Peter Altenburger	Asset Management Transmission
Project Management	Dan Glenning	Endorses Cost, Scope, Schedule, and Quality and support of all stakeholders
Engineering/Design (Director – Substation Engineering and Design)	John Gavin	Substations
Engineering/Design (Director – Protection and Telecommunications)	Len Swanson	Protection and Communications
Construction (Manager – Siting and Permitting)	Diedre Matthews	Major Permits
Engineering/Design (Director – Distribution Asset Owner)	Rob Sheridan	Distribution Asset Management
Construction	Fred Raymond	In house construction
Control Center - Director – Transmission Control Center , NE	Will Houston	New England Control Center
Resource Planning	Mark Phillips	

4.12.2 *Reviewers*

Reads paper for content / language. Recommends edits if necessary

Reviewer List	Name
Finance	Steve Bern
Regulatory	Peter Zschokke
Procurement	A Curran, T Morgan
Jurisdictional Delegates	Jennifer Grimsley

5 *Appendices*

5.1 Project Cost Breakdown

Project Cost Breakdown		
Cost Category	**Company Name ($ Amount)**	**Description of Cost Category**
Total:		

5.2 Other Appendices

US Sanction Paper

Figure 1 - Johnston 115/ 23kV One Line (Prior to Transformer Failure)

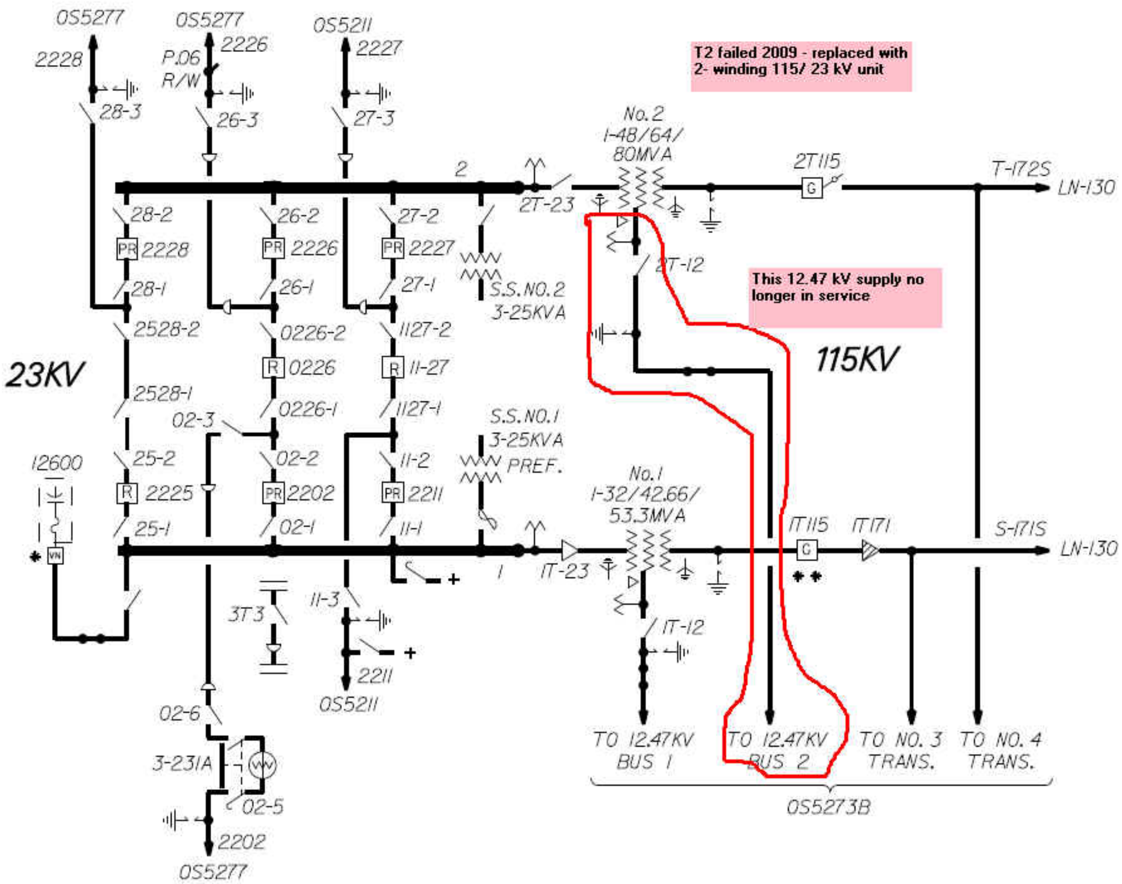


Figure 2 - Johnston 12.47kV One Line (Prior to Transformer Failure)

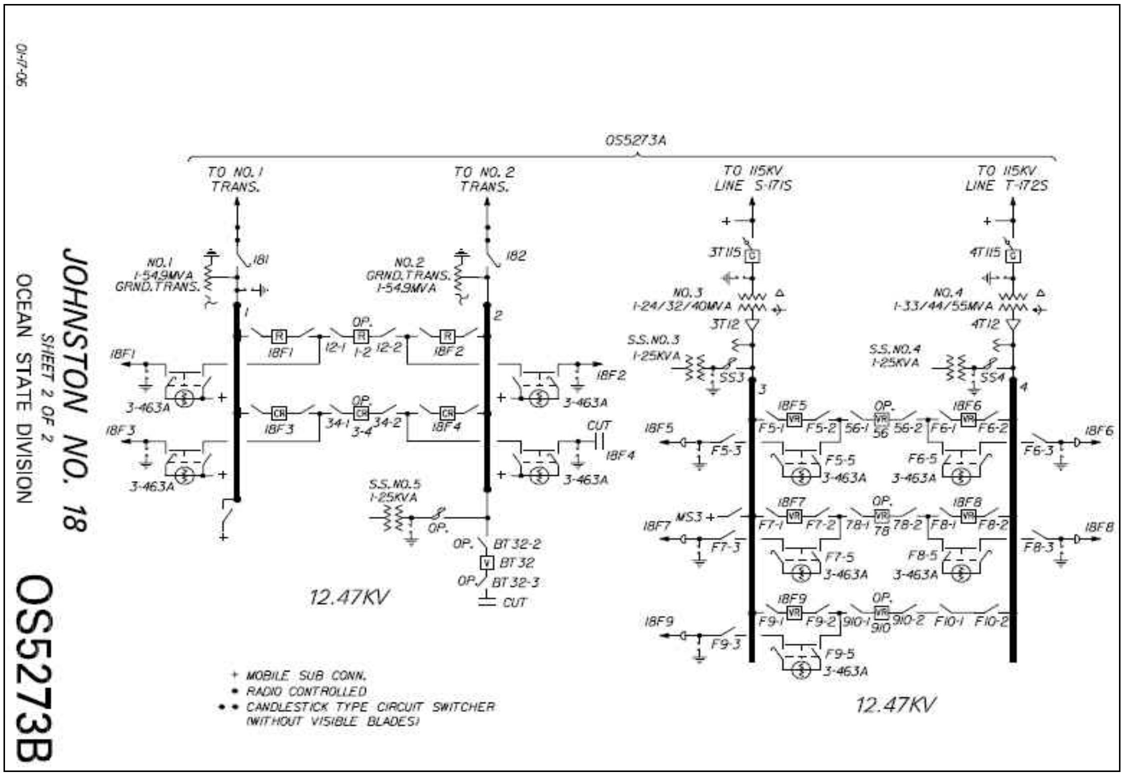
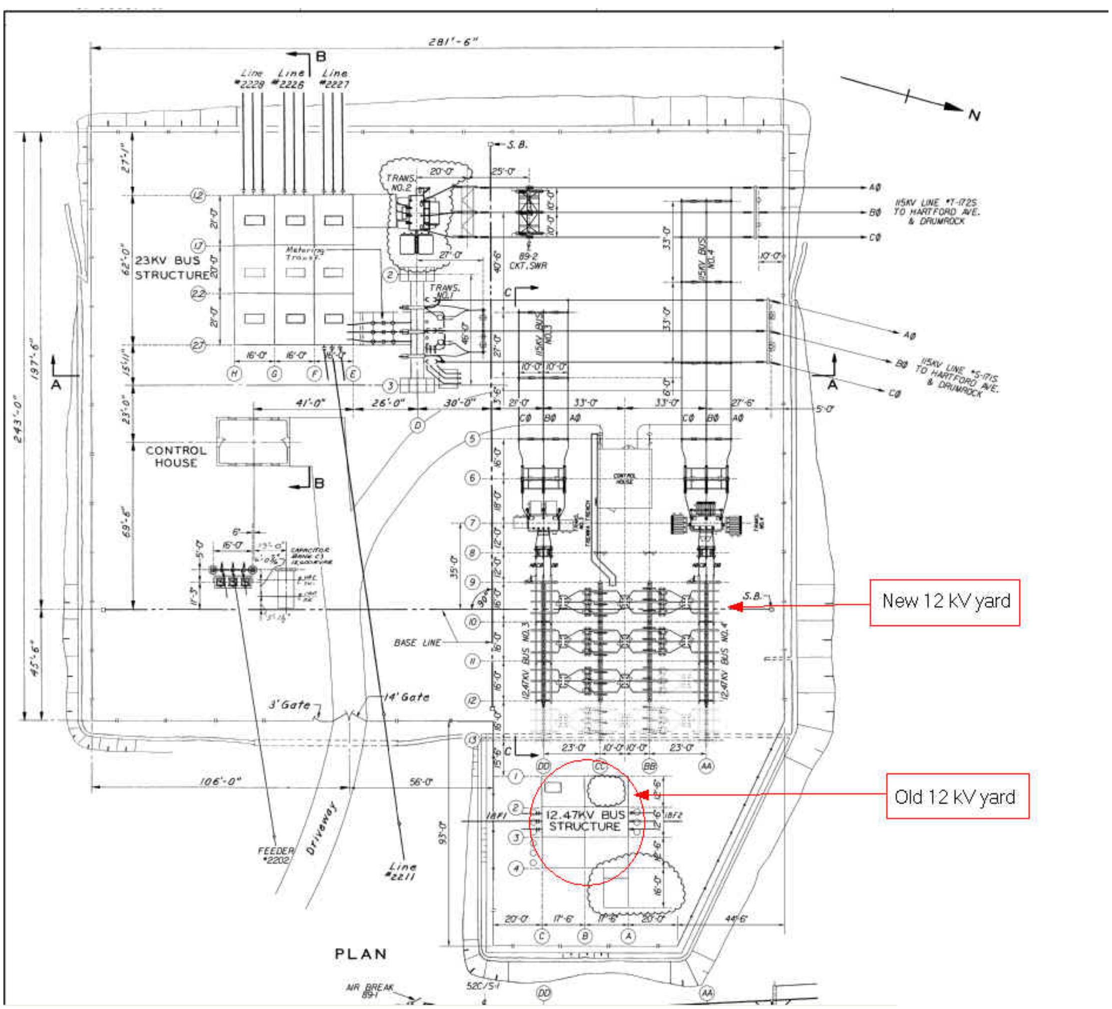


Figure 3 - Johnston 18 Layout of Existing Yard



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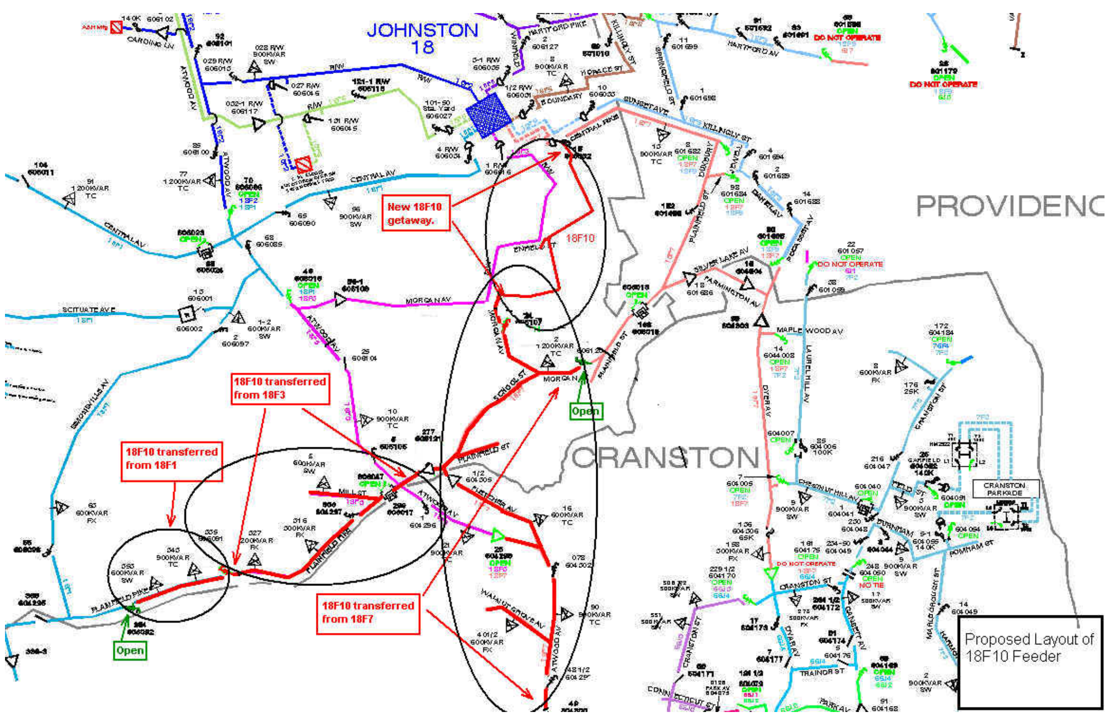
US Sanction Paper

Figure 4 – Projected Loading of Area 12.47kV Feeders

Johnston and West Cranston Feeders - Projected Loadings										
		Amps		% SN Rating						
Substation	Feeder	SN Rating	SE Rating	2011	2012	2013	2014	2015	2016	2017
Johnston 18	18F1	526	372	71%	85%	88%	72%	74%	76%	78%
Johnston 18	18F2	452	312	69%	61%	63%	65%	67%	69%	71%
Johnston 18	18F3	515	476	92%	96%	100%	103%	106%	108%	111%
Johnston 18	18F4	530	179	34%	35%	36%	38%	39%	39%	40%
Johnston 18	18F5	530	487	92%	76%	79%	82%	84%	86%	88%
Johnston 18	18F6	515	414	80%	88%	92%	95%	97%	99%	102%
Johnston 18	18F7	530	492	93%	81%	84%	87%	89%	91%	94%
Johnston 18	18F8	530	244	46%	56%	58%	60%	61%	63%	65%
Johnston 18	18F9	530	275	52%	72%	75%	77%	79%	81%	83%
West Cranston 21	21F2	515	515	90%	95%	98%	102%	105%	108%	110%
West Cranston 21	21F4	515	515	78%	82%	85%	88%	91%	93%	95%

Figure 5 – Plan showing Layout of New Johnston 18F10 Feeder



US Sanction Paper

Figure 6 - Proposed Expansion of Johnston 12.47kV Station

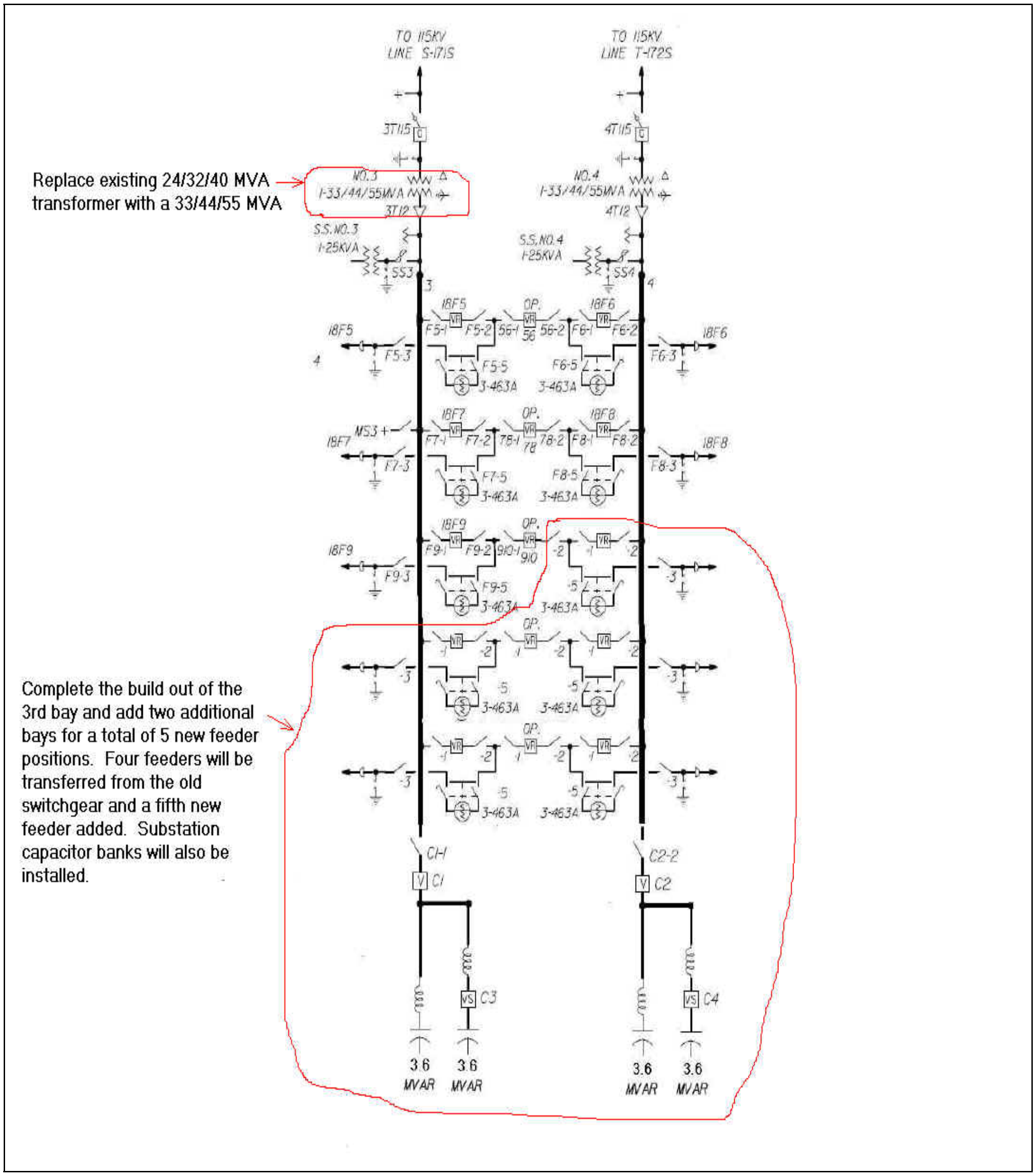


Figure 7 - Proposed Loading of Feeders after Installation of New Feeder

Johnston Feeders - Projected Loadings after New Feeder Installation									
		Amps		% SN Rating					
Substation	Feeder	SN Rating	SE Rating	2011	2012	2013	2014	2015	2016
Johnston 18	18F1	526	372	74%	77%	80%	64%	65%	80%
Johnston 18	18F2	452	312	73%	75%	78%	80%	82%	84%
Johnston 18	18F3	515	476	97%	98%	102%	70%	71%	73%
Johnston 18	18F4	530	179	49%	51%	53%	55%	56%	57%
Johnston 18	18F5	530	487	82%	85%	89%	91%	94%	96%
Johnston 18	18F6	515	414	85%	88%	92%	95%	97%	99%
Johnston 18	18F7	530	492	87%	90%	93%	58%	60%	75%
Johnston 18	18F8	530	244	49%	51%	53%	75%	77%	79%
Johnston 18	18F9	530	275	78%	81%	84%	86%	89%	91%
Johnston 18	18F10	530	612	0%	0%	0%	85%	88%	90%

Division 2-3 (Electric)
System Capacity and Reliability

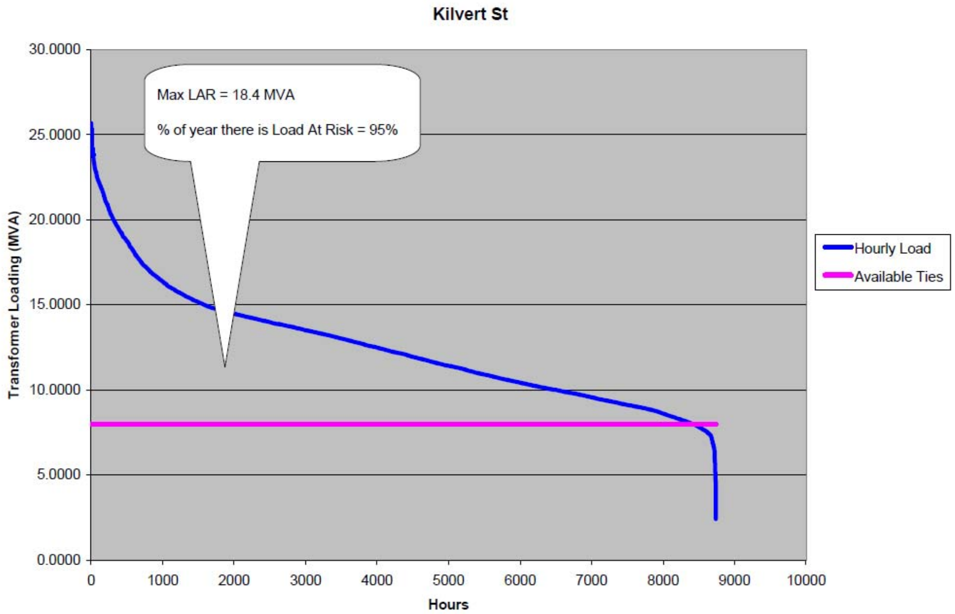
Request:

The Kilvert substation is planned for a significant upgrade and capacity increase through the addition of a second transformer. Has the company completed a risk assessment and contingency study which identified the maximum number of MW hours at risk of outage? We presume the peak load of 26.4 MVA and the 18.4 MVA of load at risk of a 24 hour outage due to a transformer failure is based on the failure occurring on peak and for that peak load to be sustained until a mobile is connected. Is that how it is represented in the report? How many hours of the year if the transformer fails could adjacent substations serve all or most of the load? Also, fully explain why it will take 24 hours to transport and install a mobile into the substation in order to pickup the load? Additionally, how much non residential and "critical" load is served form this substation that could not be served from adjacent substations during an outage?

Response:

As part of its annual planning process the Company completed a risk assessment for loss of the single transformer at Kilvert Street substation. After transfers of Kilvert Street load to adjacent stations, it was estimated that approximately 18.4 MVA (or approximately 440 MWh on a peak day) of customer load could remain un-served for loss of the Kilvert Street transformer. The load at risk analysis assumes it will take 24-hours to install a mobile transformer. Because of limited and highly utilized feeder ties, picking up all load from the substation is expected to be limited to approximately 5% (440 of 8,760 hours) of the year. The table below shows a load distribution profile for the existing Kilvert Street transformer. Hourly readings have been sorted to show the number of hours per year that load is above a certain value. The horizontal line indicates the available emergency capacity of feeder ties on peak. An analysis of available tie capacity coincident with the loading of the transformer for each of the 8,760 hours of the year was not done, therefore the number of hours of load at risk is understood to be conservative. Critical customers served from Kilvert Street substation include T.F. Green airport and the sewer facilities for the city of Warwick. With the available feeder ties these facilities could be backed up on peak.

Division 2-3 (Electric) continued p2
System Capacity and Reliability



For the load at risk analysis the company generally assumes a 24-hour time frame to install a mobile transformer in response to a transformer contingency. This is a general estimate since the time frame is dependent on many factors including road permits, unique station-specific cabling requirements, and unique station-specific protection settings. A hypothetical, perfect efficiency schedule is shown below.

Hypothetical Mobile Transformer Installation
- 1-Hour to call in crews.
- 2-Hours assembly (cables, battery trailer, mobile circuit switcher, mobile transformer).
- 2-Hours to transport equipment to location. (This may be significantly longer if the route has to be permitted.)
- 2-Hours to locate mobile equipment within the station provided the substation is equipped with necessary mobile connections. (If mobile connection does not exist, this effort will be significantly longer.)

Division 2-3 (Electric) continued p3
System Capacity and Reliability

- 8-Hours for cable installation and individual equipment testing. (This may be longer duration based on availability to make connections.)
- 3-Hours to install and perform secondary wiring for protection and program relay settings.
- 3-Hours for complete system testing.
- 3-Hours to place in service. This requires necessary switching to energize mobile, phase mobile and begin picking up load.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-4 (Electric)
System Capacity and Reliability

Request:

Are transformers that significantly under-loaded or idle evaluated as part of the Distribution Line Strategy? Does the $1.3M included in this category account for the value of recouped assets or loss reductions?

Response:

The Distribution Line Transformer program targets overloaded transformers and does not seek out transformers with spare capacity. However, options to relieve overloaded transformers do look to transfer load to nearby transformers with spare capacity as an alternative to upgrading an existing transformer. The $1.3M budgeted for this program covers the costs of installing a new transformer as well as the material and labor costs for any associated equipment (including fused cutout, grounds, and pole upgrade if necessary.) The cost of the transformer itself is accounted for in the Transformer Blanket (project numberCN4920) as these assets are capitalized on purchase rather than installation and therefore the material costs are only capitalized once and not if the transformer is moved from one location to another. There are no cost of losses included in the program budget.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-5 (Electric)
System Capacity and Reliability

Request:

Does the $1.5M budget item for the Feeder Hardening Strategy include only the estimated costs for performing the construction on the remaining four feeders for which the engineering and design has been completed? (127W40, 127W41, 22F2, 69F3) Will this work be completed in FY2013?

Response:

The budget for the Feeder Hardening Strategy includes the estimated costs for performing the construction on the remaining four feeders indicated above and engineering costs for construction package preparation and work order closeout. The program is planned to be completed in FY2013.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-6 (Electric)
System Capacity and Reliability

Request:

Is the Distribution Line Recloser Installation strategy part of complete system sectionalizing study? Is each distribution circuit part of a cyclical review process? Is circuit sectionalizing and recloser placement reviewed as part of new substation implementation?

Response:

The Distribution Line Recloser strategy is not part of a complete sectionalizing study. Rather it is a multi-year program to install line reclosers for reliability enhancement that is based on an asset management review that considered historic reliability performance and circuit exposure to rank feeders for consideration of additional line reclosers. Individual feeders were then evaluated to determine if additional line reclosers would provide future reliability enhancement based on the amount of line exposure and the number of customers impacted, as well as coordination with existing protection.

In addition to these targeted reviews for the application of additional reclosers, a distribution circuit will be re-evaluated for sectionalizing for various reasons including a planned circuit reconfiguration, a circuit suffering multiple outages impacting reliability, large new service requests or any event resulting in the need to review the current circuit configuration. As new distribution circuit routes are proposed for new substations and feeders, a sectionalizing review may be performed to identify potential recloser locations, either as part of the new feeder project or aligned with the recloser program project if it was not included in the original scope.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-3 (Electric)
System Capacity and Reliability

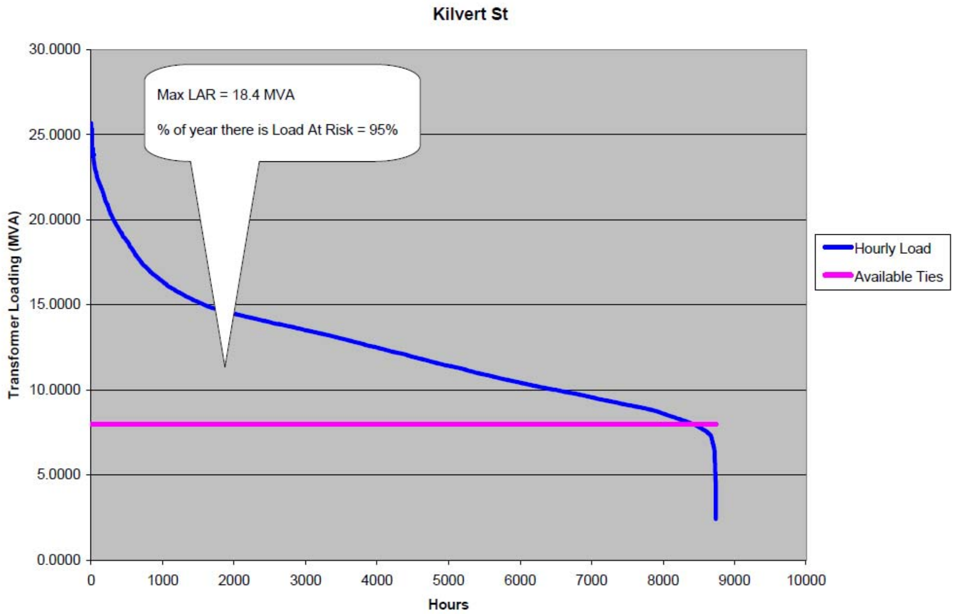
Request:

The Kilvert substation is planned for a significant upgrade and capacity increase through the addition of a second transformer. Has the company completed a risk assessment and contingency study which identified the maximum number of MW hours at risk of outage? We presume the peak load of 26.4 MVA and the 18.4 MVA of load at risk of a 24 hour outage due to a transformer failure is based on the failure occurring on peak and for that peak load to be sustained until a mobile is connected. Is that how it is represented in the report? How many hours of the year if the transformer fails could adjacent substations serve all or most of the load? Also, fully explain why it will take 24 hours to transport and install a mobile into the substation in order to pickup the load? Additionally, how much non residential and "critical" load is served form this substation that could not be served from adjacent substations during an outage?

Response:

As part of its annual planning process the Company completed a risk assessment for loss of the single transformer at Kilvert Street substation. After transfers of Kilvert Street load to adjacent stations, it was estimated that approximately 18.4 MVA (or approximately 440 MWh on a peak day) of customer load could remain un-served for loss of the Kilvert Street transformer. The load at risk analysis assumes it will take 24-hours to install a mobile transformer. Because of limited and highly utilized feeder ties, picking up all load from the substation is expected to be limited to approximately 5% (440 of 8,760 hours) of the year. The table below shows a load distribution profile for the existing Kilvert Street transformer. Hourly readings have been sorted to show the number of hours per year that load is above a certain value. The horizontal line indicates the available emergency capacity of feeder ties on peak. An analysis of available tie capacity coincident with the loading of the transformer for each of the 8,760 hours of the year was not done, therefore the number of hours of load at risk is understood to be conservative. Critical customers served from Kilvert Street substation include T.F. Green airport and the sewer facilities for the city of Warwick. With the available feeder ties these facilities could be backed up on peak.

Division 2-3 (Electric) continued p2
System Capacity and Reliability



For the load at risk analysis the company generally assumes a 24-hour time frame to install a mobile transformer in response to a transformer contingency. This is a general estimate since the time frame is dependent on many factors including road permits, unique station-specific cabling requirements, and unique station-specific protection settings. A hypothetical, perfect efficiency schedule is shown below.

Hypothetical Mobile Transformer Installation
- 1-Hour to call in crews.
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- 2-Hours to locate mobile equipment within the station provided the substation is equipped with necessary mobile connections. (If mobile connection does not exist, this effort will be significantly longer.)

Division 2-3 (Electric) continued p3
System Capacity and Reliability

- 8-Hours for cable installation and individual equipment testing. (This may be longer duration based on availability to make connections.)
- 3-Hours to install and perform secondary wiring for protection and program relay settings.
- 3-Hours for complete system testing.
- 3-Hours to place in service. This requires necessary switching to energize mobile, phase mobile and begin picking up load.

Prepared by or under the supervision of: Jennifer L. Grimsley

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Division 2-4 (Electric)
System Capacity and Reliability

Request:

Are transformers that significantly under-loaded or idle evaluated as part of the Distribution Line Strategy? Does the $1.3M included in this category account for the value of recouped assets or loss reductions?

Response:

The Distribution Line Transformer program targets overloaded transformers and does not seek out transformers with spare capacity. However, options to relieve overloaded transformers do look to transfer load to nearby transformers with spare capacity as an alternative to upgrading an existing transformer. The $1.3M budgeted for this program covers the costs of installing a new transformer as well as the material and labor costs for any associated equipment (including fused cutout, grounds, and pole upgrade if necessary.) The cost of the transformer itself is accounted for in the Transformer Blanket (project numberCN4920) as these assets are capitalized on purchase rather than installation and therefore the material costs are only capitalized once and not if the transformer is moved from one location to another. There are no cost of losses included in the program budget.

Prepared by or under the supervision of: Jennifer L. Grimsley

Division 2-5 (Electric)
System Capacity and Reliability

Request:

Does the $1.5M budget item for the Feeder Hardening Strategy include only the estimated costs for performing the construction on the remaining four feeders for which the engineering and design has been completed? (127W40, 127W41, 22F2, 69F3) Will this work be completed in FY2013?

Response:

The budget for the Feeder Hardening Strategy includes the estimated costs for performing the construction on the remaining four feeders indicated above and engineering costs for construction package preparation and work order closeout. The program is planned to be completed in FY2013.

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Division 2-6 (Electric)
System Capacity and Reliability

Request:

Is the Distribution Line Recloser Installation strategy part of complete system sectionalizing study? Is each distribution circuit part of a cyclical review process? Is circuit sectionalizing and recloser placement reviewed as part of new substation implementation?

Response:

The Distribution Line Recloser strategy is not part of a complete sectionalizing study. Rather it is a multi-year program to install line reclosers for reliability enhancement that is based on an asset management review that considered historic reliability performance and circuit exposure to rank feeders for consideration of additional line reclosers. Individual feeders were then evaluated to determine if additional line reclosers would provide future reliability enhancement based on the amount of line exposure and the number of customers impacted, as well as coordination with existing protection.

In addition to these targeted reviews for the application of additional reclosers, a distribution circuit will be re-evaluated for sectionalizing for various reasons including a planned circuit reconfiguration, a circuit suffering multiple outages impacting reliability, large new service requests or any event resulting in the need to review the current circuit configuration. As new distribution circuit routes are proposed for new substations and feeders, a sectionalizing review may be performed to identify potential recloser locations, either as part of the new feeder project or aligned with the recloser program project if it was not included in the original scope.

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