Capital/Revenue Investment Proposal

RELAY REPLACEMENT STRATEGY PAPER

NE and NY Transmission

Project Numbers:
NMPC TxT C34690, DxT C34691
MECo DxT C35584
Narragansett TxT C35587, DxT C35586
NEP TxT C35583

A strategy paper by Mike Cooper and sponsored by Paul Renaud - October 2010

Description

This strategy seeks approval for $69.57 Million to replace relays, relay packages, communication packages and/or control houses over a span of six years that have reached end-of-life or are obsolete and are no longer supported by the manufacturer. Should the relays fail or misoperate, there is a risk of prolonged outages and a corresponding negative reliability impact with possible financial penalties.

A certain percentage of the electro-mechanical and solid state relay population is currently demonstrating a trend of decreasing reliability. Attempts to keep these relays in working order are being thwarted by a lack of spare parts and knowledge base due to the manufacturers terminating support. It is these relays that this strategy intends to replace. A separate strategy will address replacements for the remaining relay population as needed.

The primary intent of this strategy is to replace those relays that are deemed to have the highest probability of failure. The identified relays represent about 5% of the total deployed suite of electromechanical and solid state relays.

This multi-year strategy seeks approval to replace relay equipment as follows:

- 245 relay packages in NY
- 278 relays in NE

	New England	New York
Transmission (relay/pkg)	155	245
Underfrequency Relays	96	5
Transformer Relays	27	0
Comm Packages	0	18
Substation Count	116	59
Control House Replacements	0	7
Total Cost	$14.84 Million	$54.73 Million

Description (cont)

This strategy is included in the transmission business plan (FY11) but not the distribution business plan. It is intended that future distribution business plans will include funding for this project.

Category: **Policy - Provide for the network's safe, efficient and reliable operation.**

Spending Rationale: **System Capacity and Performance/Asset Condition**

Condition: **Replacement of obsolete relaying assets**

Risk score: **41, Reliability**

Finance

Cost	$**69.57 Million** in the range $**52.18**Million to $**104.36 Million**
Probability that project cost will exceed 10% tolerance:	**-25%/+50%**
Project included in approved Business Plan?	**Yes for TxT through year 2015. No for DxT through year 2015. Funding is planned to be included in future business plans.**
Project cost relative to approved Business Plan	**+16.43 Million.**
If cost > approved B Plan how will this be funded?	**Portfolio Management**
Other financial issues:	**N/A**

$m	Current planning horizon								
	Yr 1 FY12	**Yr 2 FY13**	**Yr 3 FY14**	**Yr 4 FY15**	**Yr 5 FY16**	**Yr 6 FY17**	***Total***	***Lower Range P20***	***Upper Range P80***
Capex investment	1.54	4.86	6.98	11.39	13.63	13.60	52.00	n/a	n/a
Opex	0.15	0.64	0.82	1.60	1.86	1.89	6.96	n/a	n/a
Cost of Removal	0.29	0.68	1.22	1.53	1.97	2.01	7.70	n/a	n/a
Totals:	1.98	6.18	9.02	14.52	17.46	17.50	66.66	n/a	n/a

Note: AFDUC adds $2.91 Million for a total of $69.57 Million.

Resources

Availability of internal resources to deliver project:	**Amber**
Availability of external resources to deliver project:	**Green**
Operational impact on network system:	**Green**

Key issues

- Identification of relay families that are obsolete or failure prone
- Replace known failure-prone relay families prior to failure
- Replace control rooms in poor condition
- Availability of internal resources is listed as Amber as this project will require significant resources which may not be fully available as required
- Replacement of relays will rely heavily on outages which may not be available on a timely basis

Key milestones – This strategy is a program. See section 6 for details.

Milestones for FY12 delivery	Target Date: Month/Year
Start Preliminary Engineering (kick-off meeting)	1/2011
Sanction	6/2011
Engineering Design Complete - EDC	10/2011
Construction Start	11/2011
Construction Complete - CC	2/2012
Ready for Load - RFL	3/2012
Project Closure Report	6/2012

Climate change

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

Prior sanctioning history including relevant approved Strategies

- No

Recommendations	
The Transmission Investment Committee is invited to:	
(a)	Endorse the investment of **$69.57 Million** in the range **$52.18** Million to **$104.36 Million** by **6/2012 (-25%/+50%)**
(b)	NOTE that a preliminary Works Sanction for the approval of **$300k** for preliminary engineering will be submitted upon endorsement of this strategy.
(c)	NOTE that **Paul R Renaud** is the Project Sponsor
(d)	NOTE that **Dan Glenning** is the Project Manager
Signature......Paul R. Renaud...... Date..11/5/10...	
	Paul R Renaud VP, Transmission Asset Management

Decision of the Transmission Investment Committee
I hereby approve the recommendations made in this paper.
Signature...NP Winser........... Date....9/11/10
Nick Winser, Executive Director Transmission

Capital/Revenue Investment Proposal
RELAY REPLACEMENT STRATEGY PAPER
NE and NY Transmission
Project Numbers:
NMPC TxT C34690, DxT C34691
MECo DxT C35584
Narragansett TxT C35587, DxT C35586
NEP TxT C35583

A strategy paper by Mike Cooper and sponsored by Paul Renaud - October 2010

1. Background

1.1. This paper outlines a $69.57 million, six year strategy to replace approximately 245 relay packages, 7 control houses and 18 communication packages in New York and 278 relays in New England that are at or near end-of-life or are obsolete and cannot be maintained any longer. The work is spread across approximately 175 substations.

1.2. The protection afforded by relays is critical to the stability of the electric transmission system. The relays are designed to protect high-value system components from the effects of system failures and to quickly isolate system failures so that no additional damage can occur.

1.3. Protection and Telecom Operations personnel have identified several families of electro-mechanical and solid state relays that are no longer sustainable on the transmission system. Further, many of these relays suffer from lack of manufacturer support such that technical support and spare parts are no longer available. The targeted relays were selected based on family history, performance, field O&M experience and available manufacturer support.

1.4. Challenges with the aging electro-mechanical fleet of relays include settings drift, worn parts, spare parts depletion and attrition of the internal knowledge base. Many of the remaining relays in stock have been scavenged and can no longer be redeployed to the system. Many of these challenges are experienced by solid state relays as well.

1.5. While in the longer-term thousands of electro-mechanical relays may need replacement based on a simple life cycle analysis, the company has identified an immediate need to replace the worst performing relay families. The table in Appendix D lists the targeted relay families and describes the reason for being included in this strategy.

1.6. These relays include line differential, transformer differential, reclosing and under-frequency types. Although the under-frequency relays are connected to the distribution system, their function is to protect the transmission system so their replacement is also funded by this strategy. The selected relays protect the transmission system which is defined as 69kV and above in NE and 115kV and above in NY.

1.7. The total relay population protecting the transmission system is as follows;

	New York	New England	Total
Electromechanical	13,447	4,324	17,771
Solid State	578	792	1,370
Microprocessor	1,779	950	2,729
Total	15,804	6,066	**21,870**

The NE counts do not include auxiliary relays. In New England the design is generally a direct trip through diodes instead of contact multiplying aux relays.

The proposed strategy replaces nearly 5% of the current relay population.

1.8. The microprocessor based relays that will be replacing the electromechanical relays offer advanced functionality as a core element of the equipment. This functionality makes it possible to query the relay electronically to retrieve and review operational information. Further, the relay can interoperate with other relays forming the foundation for advanced relaying applications in the future. Other benefits include:

- Calculating distance-to-fault information
- Latest industry standard protocols
- power quality monitoring
- Multiple settings groups
- Event reporting
- Self-diagnostics and testing
- Sequence of events recording
- Remote communication access
- Accurate event timestamping

2. Drivers

2.1. This strategy is driven by the need to ensure that reliable protective relay systems are in place to preserve the integrity and stability of the transmission system. The protection system protects against faults and ensures the continued safe and reliable operation of the transmission system.

2.2. The transmission system is protected by nearly 22,000 relays. The majority of these relays (88%) are electro-mechanical or solid state types. Many electromechanical and solid state relays are at or near their end-of-life. A replacement plan targeting the worst performing or obsolete relay families is required before equipment failure occurs and reliability suffers.

2.3. The benefit of this strategy will be increased reliability of the transmission protection and control system where known poor performing relay families are replaced with microprocessor based relays. Protective relays that are functioning properly are essential to a rapid isolation of faults on the system, protecting customers from potential outages and protecting equipment from damage. The new relays will also yield additional operational data that was not previously available, permitting better analysis of system failures to prevent reoccurrences.

2.4. System protection can limit the extent and duration of outages thus improving key system performance metrics such as CAIDI, SAIDI and SAIFI. For example, a mis-operation by a relay could result in a potential loss of between 5m and 20m customer-minutes. This translates to a SAIDI of between 1.5 to 6 minutes. Failure or mis-operation of key protection and control system components may have the effect of negatively impacting our ability to deliver power resulting in customer outages and poor public perception. Failure to stay within the system reliability targets can result in fines by state regulators.

2.5. Modern microprocessor based relays will supply information not previously available from electromechanical relays. With the availability of this real time data, future applications can be developed such that more of the transmission system can be automated and designed to respond automatically to system events. The speed of data acquisition and analysis would present system operators with a better understanding of system anomalies and recommendations for remedial actions. For example, distance-to-fault data will now be available to identify fault location with greater accuracy than currently possible. This data will be brought back to the control center for use by operations and engineering personnel.

2.6. Proper protection operation is required by certain regulatory bodies. Compliance with certain FERC, NERC, NPCC regulations are mandatory and failure to comply can result in substantial fines.

2.7. Replacement will eliminate incremental maintenance time and costs associated with these relays, allowing relay maintenance personnel to focus on other critical protection Issues.

2.8. The risk score has been calculated to be 41. Since the relays in this paper represent only 5% of the relay population, it is appropriate for the targeted relays to share the same risk score such that the risk score assumes that each relay targeted by this program has an equal likelihood and consequence of failure. The determinants are as follows;

2.8.1. Reliability (loss of 50-250 MWs) ► 5

2.8.2. Likelihood (time to failure = 3 yrs) ► 6

3. Strategy Description

3.1. This project proposes to replace the selected relays and/or relay packages with modern microprocessor based relays. The microprocessor based relays package greater capability into a single integrated piece of equipment.

3.2. Several approaches for replacement are available and will be considered during preliminary engineering. Replacing the targeted relays in the following order will result in replacing the most amount of relays in the least amount of time;

- Identify relay replacements that can be achieved on a like-for-like basis.
- Identify relay replacements that have the same form factor.
- Identify relay replacements that can use space in the existing panel.
- Identify relay replacements that will require a new panel.
- Identify relay replacements that will require a replacement of the control house

3.3. Where certain targeted relays are one-of-a-kind or are considered more critical than the others, those relays will be prioritized to be replaced first. The remaining relays will be prioritized based upon which relays can be replaced expeditiously and inexpensively with the minimum of engineering and field work. Prioritization will be made by PTO personnel who have the best experience in determining the health of specific relays packages.

3.4. When a relay is replaced on a line that connects to another utility, coordination with the other utility must take place to ensure no gap in protection coverage. The Project Manager will coordinate contact with the neighbouring utility with the assistance of the Transmission Commercial Department.

3.5. As part of this project, seven control buildings are recommended for replacement based on condition. The drivers for replacement include inadequate environment for microprocessor relays, insufficient room for necessary panel additions, or where the existing building is not worth the additional investment of panel work and new relays. Control houses that would be recommended for replacement but are planned to be replaced under other strategies are not included in this strategy.

3.6. Electro-mechanical and solid state relays will be replaced with modern micro-processor based relays with communications capability. Consideration for establishing communication capability between the relays and EMS will be made during the preliminary engineering phase.

3.7. A list of the work scheduled for FY12 is attached as Appendix A. A list of all assets targeted for replacement under this strategy is attached as Appendix B.

3.8. The strategy will be delivered over six years as follows:

Dates	NY	NE
Year 1	2 Packages 3 Comm Pkgs	25 Relays
Year 2	22 Packages 3 Comm Pkgs	50 Relays
Year 3	24 Packages 3 Comm Pkgs 1 Control House	60 Relays
Year 4	60 Packages 3 Comm Pkgs 1 Control House	65 Relays
Year 5	68 Packages 3 Comm Pkgs 2 Control House	60 Relays
Year 6	69 Packages 3 Comm Pkgs 3 Control House	18 Relays

This schedule is consistent with the investment profile in the current capital plan. It is anticipated that the first year will largely be spent performing engineering activities.

3.9. The table in Appendix C describes a proposed investment profile for the project. The investment profile was developed to be consistent with funding that is in the current business plan through FY15. The overall strategy spend profile was developed based on assumptions presented in the conceptual engineering reports. The intent is to modify future business plans to adopt the investment profile detailed in the table.

3.10. The strategy will be sanctioned and delivered on a year-by-year basis thus affording the business the opportunity to alter the delivery and/or investment profile throughout the life of the strategy. The prioritized list of relays can be reassessed annually to account for any changes that may be required. NY and NE should be sanctioned independently.

3.11. The Project Manager, in conjunction with Transmission Asset Strategy, will determine the best sanctioning approach for each year of the program. Options include, but are not limited to, replacing relays on a line-by-line or station-by-station basis or some other agreed upon approach.

3.12. Preliminary engineering can occur on a rolling basis to match the expected investment for the following years.

3.13. NERC-CIP considerations will need to be reviewed for newly installed microprocessor based relays due to their advanced functionality.

3.14. Provision of communications to enable data retrieval from microprocessor based relays will be reviewed during the preliminary engineering phase.

3.15. The Project Manager will determine annually whether the project will be delivered using internal, external or a combination of resources.

3.16. A separate strategy is under development to address the remaining relays population in need of replacement. The new strategy is evaluating an approach whereby a prefabricated, pretested control house can be ordered and delivered to a site and connected to the primary equipment. This approach has the advantage of replacing an entire control house worth of relays at once. Further, this approach will reduce the need for internal control house wiring which is time consuming and can be error prone. The equipment selected for the control house will adhere to the latest standards such as IEC 61850 to ensure interoperability with other equipment so that advanced protection schemes can be applied. This strategy is being developed based in part on the experiences of our UK business, collaboration with another large US based utility and utility trade groups such as EPRI. Development of the separate strategy will occur concurrently with this strategy and is expected to take about two years to complete.

4. Business Issues

4.1. About 5% of electromechanical and solid state relays were identified as being at or near end-of-life, are obsolete or there are no spare parts or manufacturing support available. These relays were identified for priority replacement.

4.2. The proposed replacement relays would be microprocessor based relays with multiple functions consolidated into a single package. The digital nature of the relays offers advanced data capabilities not previously available in electromechanical or early generation solid state relays. To maximize the benefits from the replacement relays, a communications link may be necessary to transfer data between the relay and back office systems.

4.3. Certain relays are housed in control houses which have been determined to be in poor condition. In these cases, the strategy recommends the entire control house be replaced.

4.4. A choice to not replace these relays exposes the company to the risk that a failed relay system may be out-of-service for an extended period of time. Many of the targeted relays protect transmission lines where the second protection scheme is also an older model relay that may be targeted for asset replacement due to obsolescence or poor product support. The Project manager will determine the replacement sequence for lines where both the A & B packages will be replaced.

4.5. A propensity for settings to drift exposes lines protected by the targeted relays to false trips, or failure to trip when called upon to do so.

4.6. The continued deployment of microprocessor based relays will require a work force with the appropriate skills. It is likely that current employees may require training. Newly hired employees will be required to have the necessary skills to design, operate and maintain microprocessor based equipment.

4.7. Deployments of microprocessor based relays are a relatively recent phenomena such that there is insufficient evidence to determine the typical useful life of these assets. One leading microprocessor based relay manufacturer observed its Mean Time Between Failure (MBTF) at 300 years or put another way, a failure rate of 0.33% per annum. The same manufacturer estimates the typical asset life to be on the order of 30 years.

5. Options Analysis

5.1. Option 1 – Do Nothing:

- This option would allow the current situation to persist**.**
- Relays would continue to deteriorate at a rate greater than our capability to replace them.
- The targeted relays will not be able to be further maintained and will require ad-hoc replacement with digital relays. This would likely be a more expensive approach.
- Panel space will be inefficiently used due to the use of discrete relays to comprise a relay package and a heterogeneous mix of electromechanical, solid state and digital relays.
- A choice not to replace these relays will result in increased maintenance costs as the relays continue to degrade. It will also result in failed relays being replaced on an unplanned basis; resulting in additional expense.
- In-service relays failures that result in customer outages could also incur reliability penalties.

5.2. Option 2 – Defer replacements

- This option may result in an increased failure rate possibly resulting in outages due to relays failing before they are scheduled for replacement.
- This option only defers the project during which time additional relays will reach obsolescence increasing the scope of the project.
- This option would also delay the advent of a more comprehensive asset management strategy for the relay population.

5.3. Option 3 – Adopt a replace-on-fail plan

- This option adopts a plan to only replace the targeted relays once they fail.
- Such a plan would naturally result in decreased system reliability due to the increased rates of failure and the duration of subsequent outages.

- This approach may not be palatable to our regulators or ISO's.
- Increased failure frequency or extended outages as a result of this option may result in performance fines by our regulators.

5.4. Option 4 – Adopt modular replacement systems

- This option calls for the replacement of entire protection and control rooms with modular, pre-fabricated rooms.
- The prefabricated control rooms would arrive completely wired and tested to our specifications for each substation.
- This approach is a good candidate for a long term strategy to modernize our protection and control environment however it is premature at this stage. Additional study is currently underway to determine the viability of this approach.
- This would be a costly solution in regards to surgically replacing targeted relays but remains a good alternative to a broader systematic modernization of the protection and control system.

5.5. Option 5 (Recommended) – Replace relays (and control houses where necessary)

- Surgically replace the targeted relays with a minimum of impact to neighbouring equipment. Limit replacements to only those targeted relays or relay packages and restrict scope creep for ancillary equipment as much as possible.
- This approach provides a comprehensive and systemic approach to updating our aging relay population while also addressing the environment the relays are contained within.
- In addition to replacing the identified relays, this recommended approach will also identify control houses in poor or fair condition and replace the control house in addition to the relays within or where the majority of the relays in a control room are obsolete and meet the criteria for replacement, including a significant risk to reliability and/or safety.
- A follow on strategy to manage asset replacement for the remaining fleet of electro-mechanical and solid state relays can be prepared to follow completion of this strategy for a seamless transition to a broader replacement program.

6. Milestones

6.1. This strategy will replace the relays following a priority list based on field experience with the relay families. Following the order of priority, the relays will be replaced on a station-by-station basis unless outages provide for relays to be replaced at line terminus points at the same time. The exact approach will be determined during the preliminary engineering phase.

6.2. The number of relays, communications packages and control houses that will be replaced during each year of the program was determined based on a preliminary review of relative priorities.

This strategy will commence in 2011 and continue through 2017 as shown in the table in Section 3.8.

6.3. The exact relays that will be replaced in each year will be determined the year ahead from the prioritized list and an assessment of outage availability.

7. Safety, Environmental and Planning Issues

Safety

7.1. Employees and/or contractors will be in close proximity to voltages and currents from VTs and CTs respectively and must be aware of the possible ramifications of contact with them. In the control house, work will be performed on secondary circuits to include current circuits, voltage circuits, breaker control circuits and protective relay circuits. Caution will have to be exercised when working with secondary circuits. Personnel will have to take appropriate measures such as making sure to avoid open current circuits and isolating protective relay trip circuits to avoid inadvertent tripping. Appropriate insulated tools and personal protective equipment shall be worn as necessary when working on energized equipment.

7.2. Where work rules differ between NE and NY, personnel shall ensure they are following the latest procedures for the work they are undertaking in the appropriate region. This will be accomplished by ensuring oversight with adequate supervision.

Environmental

7.3. Whereas most work will be completed within the existing control house, there should be no environmental issues.

7.4. Where control houses are to be replaced, all proper environmental issues need to be addressed and will be properly identified during the preliminary engineering phase. Upon completion of the preliminary engineering, all appropriate permits will be acquired where necessary prior to work taking place.

Planning

7.5. The replacement of the relays and associated equipment will require coordination among personnel doing the physical installation; those setting and testing the relays; and those installing the communication facilities. The Project Manager will ensure that the work is properly sequenced such that proper coordination is accomplished.

7.6. The replacement of these relays in some locations will require coordination with neighboring utilities, and Non-Utility Generation companies. These entities may be required to change their relay systems as well. The Project Manager will coordinate contact with the neighbouring utilities and non-utility generators with the assistance of the Transmission Commercial Department.

7.7. The relay replacement strategy is subject to the availability of National Grid resources or contractors to complete the tasks. The Project Manager will determine annually whether internal, external or a mix of resources is to be utilized.

7.8. The Project Manager will ensure the necessary outages are acquired. The relay priority list may be altered based on outage availability.

7.9. The Project Manager will ensure that permission to complete the work is coordinated with the owners of facilities where National Grid owns the relays but not the control house (Continuing Sites).

7.10. The insulation of the wiring between the control house and the primary equipment can deteriorate over time. The condition of the existing control cables will be reviewed during preliminary engineering. The results may increase the scope and cost of the project.

Investment Recovery

8. Investment Classification

8.1. This strategy is completely driven by internal policy. Specifically it is driven by the Asset Management Policy to provide for the network's safe, efficient and reliable operation.

8.2. The breakdown of spend by company and FERC/Function is as follows;

Company and code	Funding #	Spend (mil)
Company 5 DxT	C35584	$5.82
Company 10 TxT	C35583	$3.79
Company 49 TxT	C35587	$1.07
Company 49 DxT	C35586	$4.16
Company 36 TxT	C34690	$54.28
Company 36 DxT	C34691	$0.46
Total		$69.57

TxT is $59.13m and DxT is $10.44m.

8.3. <u>New England Power Company</u>

The NEP portion of the project is split between PTF and non-PTF.
NEP PTF accounts for approximately $1.1M and non-PTF accounts for approximately $2.1M.

PTF Plant:
The actual costs of PTF capital investment are recoverable under formula rates in Section II of ISO-NE's Transmission, Markets and Services Tariff (ISO-NE Tariff), as approved by FERC. The Regional Network Service (RNS) formula is updated annually, effective June 1st of every year. The rate is set based upon prior calendar year actual costs, plus a forecast for capital additions expected to go into service in the current year. A full true-up of the forecast to actual costs is also included in the following year's annual update. To the extent there are any timing differences between forecasted and actual capital additions placed in service prior to the annual true-up, that difference is captured monthly through NEP's Local Network Service (LNS) formula rate under Schedule 21-NEP of the ISO-NE Tariff.

* New PTF capital projects are subject to stakeholder review and approval by ISO-NE through the regional system planning process set forth in Attachment K to the ISO-NE Tariff.

Under Schedule 12© of the ISO-NE Tariff, ISO-NE also conducts an independent cost review of transmission projects (with stakeholder input) to determine whether the full cost of a project will be permitted to be included in RNS rates.

* Actual cost and performance of a project may also be reviewed by the Federal Energy Regulatory Commission, either due to a complaint filed with the Commission or on the Commission's own motion, to determine whether actual project costs are unjust and unreasonable. Such costs would be disallowed from rate recovery.

Non-PTF Plant:

The costs of Non-PTF capital investment are fully recoverable through NEP's Local Network Service (LNS) formula rate, which is under Schedule 21-NEP to Section II of the ISO-NE Tariff. The LNS rate is adjusted on a monthly basis. Cost recovery is effective when construction is completed and the capital investment is placed "in-service".

New Non-PTF capital projects are subject to stakeholder review through the local system planning process set forth in Attachment K-1 to the ISO-NE Tariff. Actual performance on a project may be subject to review and approval by appropriate the Federal Energy Regulatory Commission to determine whether the costs of the project are just and reasonable in the provision of transmission service.

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.

8.4. <u>Massachusetts Electric Company (TxT)</u>

Massachusetts Electric's transmission capital investment costs are recoverable through the Integrated Facilities Agreement (IFA) in place between Massachusetts Electric and NEP, as approved by FERC 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 any charges received under the IFA through the Regional Network Services rate or the Local Network Services rate, depending 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.

8.5. <u>Massachusetts Electric Company (DxT)</u>

Distribution rates of Massachusetts Electric are subject to a fixed rate plan agreement which does not provide for incremental revenues associated with specific capital projects.

Upon consultation with management within US Distribution, it has been determined that this project is not included in the current budget and forecast but is intended to be included in the FY12-17 business plan and should proceed forward with approvals and scheduling of work.

8.6. Narragansett Electric Company (TxT)
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.

8.7. Narragansett Electric Company (DxT)
Distribution rates of Narragansett Electric are subject to a fixed rate plan agreement which does not provide for incremental revenues associated with specific capital projects. Upon consultation with management within US Distribution, it has been determined that this project is not included in the current budget and forecast but is intended to be included in the FY12-17 business plan and should proceed forward with approvals and scheduling of work.

8.8. Niagara Mohawk Power Corporation
Niagara Mohawk's bundled delivery rates for T&D in New York are currently fixed within a 10-yr rate plan that was set to expire on December 31, 2011. In January 2010, Niagara Mohawk filed a proposal to revise the fixed cost recovery levels effective January 1, 2011. Embedded in both the current and proposed bundled rates are fixed levels of annual capital investment recovery. To the extent the annual capital projects are within the capital program forecast allowed in the rate plan, the company recovers the associated costs.

8.9. Regulatory Implications

8.10. Failure of aging relays could possibly result in momentary or sustained outages which could result in reliability based penalties.

8.11. No regulatory approvals are known to be required to complete this strategy.

9. Customer Impact

9.1. As the project will require outages to be implemented, there may be impact to certain customers. The Project Manager will work with the Transmission Commercial Department to coordinate outages to the mutual satisfaction of the company, ISO and the affected customer.

Financial Impact

10. Cost Summary

	$m	Yr 1 FY12	Yr 2 FY13	Yr 3 FY14	Yr 4 FY15	Yr 5 FY16	Yr 6 FY17	*Total*	*Lower Range P20*	*Upper Range P80*
		Current planning horizon								
Capital Investment	Proposed sanction	1.54	4.86	6.98	11.39	13.63	13.60	52.00	N/A	N/A
Capital Investment	Capital plan	3.71	6.93	9.61	15.33	0	0	35.57		
Capital Investment	Variance to plan	-2.17	-2.07	-2.63	-3.93	13.63	13.60	16.43		
Capital Investment	Unit cost allowance	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
O&M	Proposed Sanction	0.15	0.64	0.82	1.60	1.86	1.89	6.96		
Removal	Proposed Sanction	0.29	0.68	1.22	1.53	1.97	2.01	7.70		
	Totals	1.97	6.18	9.02	14.52	17.47	17.50	66.66		

Note: Figures above exclude AFDUC of $2.91 Million.

10.1. Should communication capability be desired but not currently available at the substation, there could be an additional monthly OPEX cost if sufficient communications are not available.

10.2. These estimates are study grade (-25%/+50%) not adjusted for inflation. Sanction grade estimates will be developed at the sanction level.

10.3. Note that the approved business plan only extends through FY15 thus years FY16 and Fy17 have a 100% variance between business plan and planned spend. It is expected that future approved business plans will correct this deficiency.

11. Cost Assumptions

11.1. Costs were estimated using PET tools and visits to selected sites for inspection.

11.2. The conceptual engineering reports are available upon request.

12. NPV

12.1. This strategy is not financially driven.

13. Additional Impacts

13.1. Premiums regarding such factors as overtime and access to remote locations will be considered at the sanction level. These premiums are not expected to exceed 25%.

14. Execution Risk Appraisal

14.1. System conditions could impact schedules for installing and testing relays and associated communication equipment.

14.2. Personnel will be working in a bulk power substation in the protective relay circuits. There is a risk that that during construction and testing that circuit breakers could inadvertently trip due to human error. Proper coordination of personnel and review of company safe work practices, procedures and policies will minimize this risk.

14.3. As outages are necessary, scheduling of outages may impact this project.

14.4. Access to facilities not owned by National Grid yet house National Grid relays may not be readily available. Proper coordination between National Grid and the facility owner will be required.

14.5. Resource availability could delay the project beyond the current schedule.

15. 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:

- Director – Transmission Investment Management – Tom Sullivan
- Director – Transmission Planning – Carol Sedewitz
- Director – Transmission Asset Strategy – Alan Roe
- Director – Transmission Commercial Services – Bill Malee
- Director – Transmission Finance – Steve Bern
- Director – Regulatory Strategy – Peter Zschokke
- Director – Project Management – Dan Glenning
- Director – Substation Engineering – Don Angell
- Director – Protection and Electric Meter Engineering – Bryan Gwyn
- Director – Protection and Telecom Operations – Len Fiume
- Director – IS Transmission Electric Operations – Sheena Anand

APPENDIX A

PRIORITY LIST FOR FY12

New England
<u>25 Relays</u>
Riverside (24-GCX17)

New York
<u>2 Relay Packages</u>
Courtland, Line 2 (2-CEY15/16)

<u>2 Comm Packages</u>
Reynolds Road

<u>0 Control Houses</u>
N/A

APPENDIX B

COMPLETE REPLACEMENT LIST

New York

Substation	Priority	Packages	Comm
[redacted]	1	6	0
MORTIMER	2	8	0
LOCKPORT	3	7	0
BATAVIA	4	5	0
CORTLAND	5	2	0
[redacted]	6	4	0
TILDEN	7	5	0
ROTTERDAM	8	10	3
[redacted]	9	13	0
HOMER HILL SW. STR.	10	10	0
[redacted]	11	7	0
GOLAH	12	2	0
TEMPLE	13	3	1
WATKINS	14	3	0
[redacted]	15	4	1
REYNOLDS RD	16	2	1
NORTH TROY	17	2	1
STA 64 (grand island)	18	2	2
SCHUYLER	19	4	0
CURTIS	20	4	0
[redacted]	21	1	1
[redacted]	22	26	2
WOODLAWN	23	2	1
[redacted]	24	4	0
[redacted]	25	4	2
TRINITY	26	3	1
SE BATAVIA	27	2	0
[redacted]	28	3	0
[redacted]	29	4	2
WALCK RD	30	1	0
ASH	31	3	3
GREENBUSH	32	2	0
S RIPLEY	33	2	0
TERMINAL	34	4	0
LONG LANE	35	2	3
CARR ST	36	4	0
FEURA BUSH	37	3	3
MCINTYRE	38	1	0
N OGDNSBRG	39	1	0
SECENA TERMINAL STATION	40	4	0
RIVERSIDE	41	7	3
ROSA RD	42	4	2
[redacted]	43	4	0
GROOMS RD	Comm	0	1
INDIAN RIVER	uf	1	0
LOWVILLE	uf	1	0
MALONE	uf	1	0
N CARTHAGE	uf	1	0
OGDNSBRG	uf	1	0
Total		**199**	**33**
Control House			
Substation	Priority	Packages	Comm
BOONVILLE	1	12	0
GERES LOCK	2	18	0
MENANDS	3	4	1
WOODARD	4	2	0
MOUNTAIN	5	4	0
TEALL	6	2	2
YAHNNDSIS	7	4	0
Total		**46**	**3**
Single Comm Packages			Comm
ROTTERDAM			1
[redacted]			1
[redacted]			7
NORTH TROY			3
REYNOLDS RD			2
ALPS			1
ALTAMONT			1
BETHLEHEM			1
GROOMS RD			1
Total			**18**
Grand Total		**245**	**54**

New England

Substation	Priority	Relays
[redacted]	1	7
RIVERSIDE	2	24
VALLEY	3	4
[redacted]	4	7
ADMIRAL ST	5	5
[redacted]	6	2
WOOD RIVER	7	3
EAST HOLBROOK	8	4
DEXTER	9	6
READ ST	10	4
STAPLES	11	5
ROBINSON AVE	12	20
MEADOWBROOK	13	5
WARREN	14	2
HARRIMAN	15	3
WEST METHUEN	16	1
SOMERSET	17	9
BELL ROCK	18	2
FRANKLIN SQ	19	3
PARKVIEW	20	2
WASHINGTON	21	2
[redacted]	22	2
BELMONT	23	3
ADAMS	24	9
AYER	25	2
DEERFIELD 4	26	5
DEERFIELD 5	27	2
MEADOW ST	28	2
PROSPECT ST	29	2
SHUTESBURY	30	2
WARE	31	5
NASHUA ST	32	1
Total		**155**
MOORE	Tx	9
[redacted]	Tx	6
SOCKANOSSET	Tx	6
VALLEY	Tx	3
WILDER	Tx	3
Total		**27**

New England Continued

Substation	Priority	Relays
ANDOVER	uf	1
APPONAUG	uf	1
ARCTIC	uf	1
[redacted]	uf	2
BARRON AVE	uf	1
BLOSSOM ST	uf	1
CHARTLEY POND	uf	1
CONCORD RD	uf	1
COVENTRY	uf	1
CRAFT HILL	uf	1
DEPOT ST	uf	1
DIVISION ST	uf	1
DYER ST	uf	1
EAST BEVERLY	uf	1
EAST MAIN ST	uf	1
EAST WINCHENDON	uf	1
EASTON	uf	1
ELMWOOD INDOOR	uf	1
ELWOOD OUTDOOR	uf	1
FARNIM PIKE	uf	1
FORREST ST	uf	1
GENEVA	uf	1
GLOUCESTER	uf	2
GREENDALE	uf	1
HARRIS AVE	uf	1
HATHAWAY	uf	2
HILLSIDE	uf	1
HUMPHREY	uf	1
HUNTINGTON PARK	uf	1
JOHNSTON	uf	1
LANGWORTHY CORNER	uf	1
LAWRENCE	uf	2
LEBANON	uf	1
LIPPETT HILL	uf	1
LYNN	uf	1
MALDEN	uf	1
MEDFORD	uf	1
MELROSE	uf	1
[redacted]	uf	1
MILL ST	uf	2
NASONVILLE	uf	2
NEWBURYPORT	uf	1
NORTH ABINGTON	uf	2
NORTH BEVERLY	uf	1
NORTH CHELMSFORD	uf	1
NORTHBORO RD	uf	1
NORTON	uf	1
NORWELL	uf	2
PARK ST	uf	1
PAWTUCKET	uf	3
PELHAM	uf	1
PLAINVILLE	uf	1
PLEASANT ST	uf	1
PONDVILLE	uf	1
QUINN	uf	1
RANDOLPH	uf	1
REVERE	uf	1
RISINGDALE	uf	1
RIVER RD	uf	1
SALEM 1	uf	1
SALEM 2	uf	1
SALEM 3	uf	1
SCITUATE	uf	1
SOUTH MARLBOROUGH	uf	1
SOUTH WEYMOUTH	uf	1
SPRAGUE ST	uf	1
STOUGHTON	uf	2
SWANSEA	uf	2
VILAS BRIDGE	uf	1
WALNUT ST	uf	1
WARWICK	uf	1
WATER ST	uf	1
WATERMAN AVE	uf	1
WENDEL DEPOT	uf	1
WESMINISTER	uf	1
WEST CHARLTON	uf	1
WEST CRANSTON	uf	1
WEST GREENVILLE	uf	1
WEST HORWARD	uf	3
WEST NEWBURY	uf	1
WESTERLY	uf	1
WORTHEN ST	uf	1
Total		**96**

APPENDIX C

OVERALL REPLACEMENT BUDGET AND SCHEDULE

New England	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	Total
Relays to replace	25	50	60	65	60	18	278
Average cost	53,379	53,379	53,379	53,379	53,379	53,379	
Total Cost NE	**1,334,475**	**2,668,950**	**3,202,740**	**3,469,635**	**3,202,740**	**960,822**	**14,839,362**
New York							
Packages to replace	2	22	24	60	68	69	245
Average cost	152,000	152,000	152,000	152,000	152,000	152,000	
Package cost	304,000	3,344,000	3,648,000	9,120,000	10,336,000	10,488,000	**37,240,000**
Communication Pkgs	3	3	3	3	3	3	18
Average Cost	137,850	137,850	137,850	137,850	137,850	137,850	
Comm Cost	413,550	413,550	413,550	413,550	413,550	413,550	**2,481,300**
Control houses	-	-	1	1	2	3	7
Average Cost	2,145,000	2,145,000	2,145,000	2,145,000	2,145,000	2,145,000	
Control house cost	-	-	2,145,000	2,145,000	4,290,000	6,435,000	**15,015,000**
Total Cost NY	**717,550**	**3,757,550**	**6,206,550**	**11,678,550**	**15,039,550**	**17,336,550**	**54,736,300**
Grand Total	**2,052,025**	**6,426,500**	**9,409,290**	**15,148,185**	**18,242,290**	**18,297,372**	**69,575,662**

APPENDIX D

RELAY REPLACEMENT RATIONALE BY FAMILY

Relay families	Replacement reasons	Inspection Results
G.E. (GCX13/17,CEY14/15/16/GEYG, CEB)	obsolete, no manufacture support, no spare parts	Contact wear, bearing damage, metal degration, setting drift, resistors, capacitors, transitors, diodes decomposition, failed power supply & hardware board, setting drift.
ABB (MDAR,REL301, REL302)	obsolete, no manufacture support, no spare parts	
RFL (3253, 6710, 6745, 9300)	obsolete, no manufacture support, no spare parts	
ABB (RAZFE)	obsolete, no manufacture support, no spare parts	
ABB -SKDU/SBFU (U SERIES)	obsolete, no manufacture support, no spare parts	
ABB (HCB, LCBII)	obsolete, no manufacture support, no spare parts	
AREVA (OPTIMHO)	obsolete, no manufacture support, no spare parts	
G.E. (CFD, CPD, Type 40, MOD10)	obsolete, no manufacture support, no spare parts	
G.E. (CFF, CR61/CT61, CS28A)	obsolete, no manufacture support, no spare parts	
ABB (KF)	obsolete, no manufacture support, no spare parts	