STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NATIONAL GRID PROPOSED FY 2014 ELECTRIC	:	DOCKET NO. 4382
INFRASTRUCTURE, SAFETY AND RELIABILITY	:	
PLAN PURSUANT TO R.I.G.L. §39-1-27.7.1	:	

REPORT AND ORDER

I. Background & National Grid's Filing

On May 20, 2010, the Rhode Island General Assembly enacted R.I. Gen. Laws § 39-1-27.7.1[1] which states, in relevant part that The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company") shall file proposals with the Public Utilities Commission ("Commission") that contain:

> An annual infrastructure, safety and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget as developed in accordance with subsection (d) herein.
> (d) Prior to the beginning of each fiscal year, gas and electric distribution companies shall consult with the division of public utilities and carriers regarding its infrastructure, safety, and reliability spending plan for the following fiscal year, addressing the following categories:
> (1) Capital spending on utility infrastructure;
> (2) For electric distribution companies, operation and maintenance expenses on vegetation management;
> (3) For electric distribution companies, operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and
> (4) Any other costs relating to maintaining safety and reliability that are mutually agreed upon by the division and the company.
> The distribution company shall submit a plan to the division and the division shall cooperate in good faith to reach an agreement on a proposed plan for these categories of costs for the prospective fiscal year within sixty (60) days. To the extent that the company and the division mutually agree on a plan, such plan shall be filed with the commission for review and approval within ninety (90) days. If the company and the division cannot agree on a plan, the company shall file a proposed plan with the commission and the commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable

[1] P.L. 2010, ch. 15, § 1 and P.L. 2010, ch. 17, § 1 (enacted May 20, 2010).

distribution service over the short and long-term, approve the plan within ninety (90) days.[2]

On December 31, 2012, National Grid filed with the Commission its proposed Electric Infrastructure, Safety, and Reliability Plan ("Electric ISR Plan") for FY 2014. National Grid indicated that the Division of Public Utilities and Carriers ("Division") had reviewed the proposed Electric ISR Plan and had agreed to the spending portion of the plan but was continuing its review of particular plan provisions during the Commission's review.[3] In support of the Plan, National Grid submitted the Pre-Filed Direct Testimony of Jennifer L. Grimsley, Director, Network Strategy, New England Electric, and Craig M. Allen, Manager, Vegetation Strategy with National Grid USA Service Company, Inc. ("The Plan Witnesses"). In support of the development of the Revenue Requirement and to discuss the reconciliation process, National Grid submitted the Pre-Filed Direct Testimony of William R. Richer, Director of Revenue Requirements – Rhode Island for National Grid USA Service Company, Inc. In support of the new tariffs and to explain the calculation of the factors and to provide customer bill impacts, National Grid submitted the Pre-Filed Direct Testimony of Nancy Ribot, Senior Analyst for Electric Pricing, New England.

A. ISR PLAN

The Plan Witnesses indicated that the proposed Electric ISR Plan covers three budget categories for the fiscal year ending March 31, 2014. According to The Plan Witnesses, the Division had agreed that the expenses in the areas of capital spending on electric infrastructure projects, operation and maintenance expenses ("O&M") for vegetation management and O&M expenses for an Inspection and Maintenance ("I&M") program were necessary for the Company to provide safe and reliable service to its Rhode

[2] R.I. Gen. Laws § 39-1-27.7.1(c)(2)-(d).
[3] Filing Letter dated 12/31/12 at 1.

Island customers.[4] They explained that the Electric ISR Plan included a spending plan and proposed an annual reconciliation mechanism to "provide for recovery related to capital investments and other spending undertaken pursuant to the annual pre-approved budget for the Electric ISR Plan."[5]

The proposed capital spending plan for FY 2014 is $59.6 million. According to The Plan Witnesses, the Electric ISR Plan addresses the capital investment needed for five purposes: (1) to meet state and federal regulatory requirements applicable to the electric system (Statutory/Regulatory); (2) to repair failed or damaged equipment (Damage Failure); (3) to address load growth/migration (System Capacity and Performance); (4) to maintain reliable service (Asset Condition); and (5) to sustain asset viability through targeted investments driven primarily by condition (Non-Infrastructure).[6] Of these, the Company considers Statutory/Regulatory and Damage Failure to be non-discretionary "in terms of scope and timing" and "are subject to necessary and unavoidable deviations."[7] These items, totaling $26,559,000, account for forty-five percent (45%) of the proposed capital outlays in FY 2014.[8]

The remaining, System Capacity, Asset Condition, and Non-Infrastructure projects are meant to reduce the degradation of the service life of equipment, to allow for more flexibility in the system for purposes of meeting various contingencies such as load growth and migration, and to address poor condition of aged assets.[9] These items comprise the other fifty-five percent (55%) of the FY 2014 budget and of this, the System Capacity costs

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[4] National Grid Exhibit 1 (Pre-Filed Testimony of Jennifer Grimsley & Craig Allen) at 4.
[5] *Id.* at 4-5.
[6] *Id.* at 5-6.
[7] *Id.* at 8.
[8] *Id.* at 7.
[9] *Id.* at 9.

of $12,544,000 make up twenty-one percent (21%) with Asset Condition of $20,242,000, making up thirty-three percent (33%) of the FY 2014 budget. Non-Infrastructure spending of $255,000 makes up the remaining one percent (1%).[10]

The Electric ISR Plan also includes the proposed FY 2014 spending levels for the Company's Vegetation Management Program of approximately $8.5 million. Finally, the I&M spending includes capital amounts already accounted for above plus $3.5 million for O&M costs related to the I&M program. The Company agreed to provide the Commission with quarterly reports on the progress of executing the ISR Plan and an annual report at the time the Company files its annual reconciliation. Additionally, the Company and Division had agreed that if circumstances require, National Grid will be allowed reasonable deviations from the plan with explanation of significant deviations in its quarterly and year-end reports.[11]

B. SUMMARY OF THE PROPOSED FY 2014 ELECTRIC ISR PLAN

The Capital Plan budget is proposed at $59,600,000 of which, $3,615,000 is related to non-capital I&M activities. The budget for capital improvements is five percent (5%) higher than the Company's FY 2013 budget for the same category.[12] A brief summary of the categories follows:

> Statutory/Regulatory ($16,509,000) – These are considered "non-discretionary" in that the spending is required to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates. The scope and timing is primarily defined by those external to the Company. The actual and proposed spending are net of contributions in aid of construction ("CIAC"). Almost half of the budget is expected to be used to establish electric delivery service to customers. The remainder is work on the Shun Pike Project, primarily driven by a large industrial customer request, Rhode Island Department of Transportation ("RIDOT") I-195 work, constructing and/or relocating assets to accommodate

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[10] *Id.* at 7.
[11] *Id.* at 11-13.
[12] National Grid Exhibit 1, Section 2: Electric Capital Investment Plan FY 2013, at 6.

RIDOT, municipalities, or customers. The proposed budget is seventeen percent (17%) lower than the FY 2013 budget.[13]

Damage/Failure ($10,050,000) – These are considered "non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged." The proposed budget is comparable to the average level of spending during the period FY 2009-FY 2012. This line item includes small failures, specific failures in excess of $100,000 based on recent trends, and major storms. The latter two categories allow the Company to continue with its planned work in the capital program while addressing the unexpected failures.[14]

Asset Condition ($20,242,000) – This category includes capital expenses in the I&M program. This category focuses on the replacement of assets to maintain reliability performance. The proposed budget is seventy percent (70%) higher than the FY 2013 budget. The Company indicated that a portion of the increase results from a shift in spending from the almost completed feeder hardening program located in System Capacity and Performance to this category. Another portion of the increase relates to an increase in proposed spending for Underground Residential Development ("URD") Cable Strategy, a plan for replacing or rehabilitating (through cable injections) these cables. The plan also includes replacement of primary underground cable with poor performance, replacement of substation batteries over 20 years old, replacement of metalclad switchgear that has operating issues or is of the same type as others with operating issues, replacement of obsolete circuit breakers, replacement of obsolete or faulty relays, relay packages, communication packages and control houses, purchase of spare transformers, work on Eldred Substation (Jamestown) to address asset condition concerns, and installation of engineering controls related to the Company's Network Arc Flash Program.[15]

Flood Mitigation ($5.56 million included in the Asset Condition budget line item and System Reliability and Performance budget) – One of the projects in Hopkinton, RI is a Load Relief Project that includes flood mitigation work. Therefore the total amount of the project was included in the $4.37 million related to that project. The remaining flood mitigation work relates to engineering studies, engineering and procurement, or engineering and construction on various substations prone to flooding.[16]

Non-Infrastructure ($255,000) – These are capital expenditures that do not fit into one of the other categories, such as general and telecommunications equipment, but which are necessary to run the electric system.[17]

[13] *Id.* at 14-16.
[14] *Id.* at 16-17.
[15] *Id.* at 17-23.
[16] *Id.* at 23-26.
[17] *Id.* at 7.

System Capacity & Performance ($12,544,000) –Load Relief projects make up 83% of this line item. This budget item also includes Distribution Line Transformer Strategy (with evaluation of the transformer condition included in I&M), the final capital investment portion of the Potted Porcelain Cutout Replacement to complete work begun in FY 2013 (now included in I&M going forward), the final capital investment portion of the Feeder Hardening Strategy (to be included in I&M in the future), a Distribution Reliability Blanket for work under $100,000, a Tunk Hill Reliability Project pilot program to reconductor an area from bare conductor to tree wire in a spacer cable arrangement to improve customer reliability in an area with an exponentially greater number outages during Minor Storms, Substation EMS/RTU SCADA Additions Program with the goal of reducing customer outage duration, and a proposed Volt/Var Management Program. The Volt/Var Management Program would involve a Rhode Island company, UtiliData, a control system integrator providing certain automation to "optimize the voltage use on the system [which] may result in reduced losses on the system and more reliable performance of the system for customers. The proposed Electric ISR Plan discussed the planning and engineering design process which would result in cost proposals which would be reviewed with the Division "and implementation would commence in FY 2014 on an agreed upon plan."[18]

Vegetation Management ($8,476,000):
Cycle Pruning ($5,230,000) – Making up 62% of the Vegetation Management budget, this consists of the scheduling of every distribution circuit for pruning based on a dimension specification on a fixed timeframe or rotation, in this case, a four year cycle. The costs in this line item are to cover the continuation of four year cycle. The FY 2014 ISR Plan anticipates pruning of 1,321 miles with a cost of approximately $3,959 per mile. The Company also has an Enhanced Hazard Tree Mitigation ("EHTM") program ($750,000) to identify and remove dying or structurally weakened trees along the three phase sections of distribution circuits.[19]

Sub-Transmission (off & on road) ($724,000) – The Company noted that while this work is also conducted on a four-year cycle, because of the smaller population of circuits, the cycle is not balanced each year. FY 2014 represents an area twice the size of FY 2013; Police/Flagger ($525,000); All Other Activities, includes Interim/Spot Trim, Customer Requests, Emergency Response and Worst Feeders ($1,247,000).[20]

I&M Plan ($3,615,000 – Non-Capital):
This line item represents an expansion of the I&M program to include inspections of the sub-transmission system and manhole based underground

[18] *Id.* at 26-39.
[19] National Grid Exhibit 1, Section 3: Vegetation Management Program, at 4-7.
[20] *Id.* at 7-9. National Grid noted that Verizon has not agreed to contribute to the Vegetation Management costs on the basis that Verizon conducts its own line maintenance, including tree trimming. *Id.* at 9-10.

assets, a reduction of the distribution overhead inspection cycle from six years to five, the addition of underground asset inspections on a fifteen year cycle, reduction of the the manual contact voltage cycle from six years to five, a reduction of the manual contact voltage cycle for streetlights from five years to three, and the addition of a mobile contact voltage testing program.[21] The total for the I&M Program includes $8,515,000 of capital expenses related to I&M as reflected in the total capital cost discussed. In FY 2014, there is an additional $3.6 million allocated to Removal Costs that did not appear in the FY 2013 I&M Program summary.[22]

C. REVENUE REQUIREMENT

Mr. Richer explained that the revenue requirement of the FY 2014 Electric ISR Plan includes (1) an O&M expense related to vegetation management and the Company's I&M Program and (2) the Company's capital investment in electric utility infrastructure.[23] The forecasted FY 2014 revenue requirement of $12,133,495 represents an incremental increase of $1,606,595 from the FY 2013 Electric ISR Plan revenue requirement of $10,526,900. The amount related to O&M expenses was $12,091,251, of which $8,476,000 related to Vegetation Management and $3,615,251 related to Inspection and Maintenance O&M expenses.[24] The net amount of revenue requirement necessary to support FY 2014 infrastructure was $42,244.[25]

In April of 2012, the Company filed a base rate case for both its electric and gas operations. The case, Docket 4323, ultimately ended in a settlement agreement approved by the Commission on December 20, 2012. Items included in base rates relative to FY 2012, 2013 and 2014 investments are excluded from the FY 2014 ISR revenue requirement.[26] To

[21] National Grid Exhibit 1, Section 4: Inspection and Maintenance Program, at 1-3, 6-8. The Commission approved the Company's Contact Voltage Plan in Docket No. 4237 on October 4, 2012. *Order No. 20871* (issued November 9, 2012).
[22] National Grid Exhibit 1, Section 4: Inspection and Maintenance Program, at 8. *Compare* Chart 2 with National Grid Exhibit 1, Section 4: Inspection and Maintenance Program, at 5 (Docket No. 4307).
[23] NGrid Exhibit 1 (Pre-Filed Testimony of William R. Richer), p. 3.
[24] NGrid Exhibit 1, Section 5: Attachement 1, p. 1.
[25] Id.
[26] NGrid Exhibit 1 (Pre-Filed Testimony of William R. Richer), p. 4-5.

calculate the capital related revenue requirement, electric infrastructure investments were divided into two categories, non-discretionary and discretionary capital investments. The amount of capital additions ultimately allowable in the ISR plan is limited to amounts no greater than the cumulative amount of discretionary project spending.[27] Average rate base for purposes of the ISR revenue requirement is typically calculated as the average year end cumulative change in rate base. Since a portion of FY 2014 non-growth capital investment is reflected in the rate case and the other portion is not, a separate calculation was performed to determine the appropriate level of weighted average rate base for FY 2014 investment. The calculated FY 2014 weighted average rate base associated with FY 2014 plant additions is $1,716,751.[28]

D. DEVELOPMENT OF ISR FACTOR

Ms. Ribot explained that the ISR Factor contains two mechanisms: (1) an Infrastructure Investment Mechanism to recover costs associated with incremental capital investment ("IIM") and (2) an Operation and Maintenance Mechanism ("O&MM") to recover O&M expenses related to I&M and vegetation management activities. To design the CapEx factors to develop the IIM, following Commission review of a cumulative revenue requirement, a rate base allocator will be applied based on the most recently approved cost of service study. Similarly, the design of the O&MM is to allocate the I&M and vegetation management expenses to the rate classes based on the percentage of total distribution O&M expense allocated to each rate class per the most recent cost of service

[27] NGrid Exhibit 1 (Pre-Filed Testimony of William R. Richer), p. 6.
[28] NGrid Exhibit 1 (Pre-Filed Testimony of William R. Richer), p. 5-6. Section 5, Attachment 1, Page 10.

study. Within each rate class, a per unit charge is calculated based on kWh usage for non-demand classes and on a kW basis for demand classes.[29]

Each year, by August 1, the Company will propose CapEx Reconciling Factors and an O&M Reconciling Factor to become effective on October 1 for the following twelve-month period. The reconciliation will compare the actual cumulative revenue requirement to actual billed revenue generated from the CapEx Factors and any over- or under-recovery will be refunded to or collected from customers through the CapEx Reconciling Factors. The O&M reconciling factor will compare the actual I&M and vegetation management O&M expense to actual billed revenue generated from the O&M factors and any over- or under-collection of actual expense will be refunded to or collected from customers through a uniform per kWh charge applicable to all rate classes.[30]

Ms. Ribot explained that the CapEx Factors are designed to collect the cumulative revenue requirement of $42,244 related to incremental capital investments through the end of FY 2014. The cumulative revenue requirement is allocated to the various rate classes based on the total rate base allocator which was included in the Commission-approved Amended Settlement Agreement filed in Docket No. 4323.[31] The O&M Factors are designed to collect the $12,091,251 in forecasted FY 2014 I&M and Vegetation

[29] National Grid Exhibit 1 (Pre-Filed Testimony of Nancy Ribot), pp. 2-6. G-02 and G-32/B-32 customers whose charges include both demand and usage, the CapEx Factors will be charged as demand charges and the O&M Factors will be charged as usage so as "to not significantly change the relationship between the existing charges and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts." National Grid Exhibit 1 (Pre-Filed Testimony of Nancy Ribot), p. 7.

[30] *Id.* at 5, 7-8.

[31] *Id.* at 8. *See Order Nos. 20943 (issued January 31, 2013), 21011 (issued April 1, 2013), and 21054 (issued May 29, 2013).*

Management O&M related activities. The monthly rate increase on the bill of a typical residential customer using 500 kWh per month would be $0.16 per month.[32]

II. Division's Filing

On March 1, 2013, the Division submitted a Memorandum of Gregory L. Booth, P.E., its consultant in which he described the process by which the FY 2014 ISR Plan was developed and provided some additional recommendations to the Commission. The Division supported the FY 2014 Electric ISR Plan as filed but with four additional recommendations. Mr. Booth indicated in his Memorandum that the filed plan represented a $4,400,000 reduction from that which was originally presented to the Division in the Fall of 2012.[33] Mr. Booth stated that the FY 2014 Electric ISR Plan balances the need for safety and reliability against an attempt to achieve the most efficient benefit/cost considerations.[34]

After summarizing the proposed FY 2014 Electric ISR Plan, Mr. Booth proposed that National Grid be required to submit a cost-benefit analysis for cycle clearing and EHTM prior to the Division's review of the FY 2015 Electric ISR Plan which utilizes its Outage Management System, subdivides Damage/Failure Capital Cost between tree related and non-tree related costs, and cost by circuit including the identification of whether the circuit has been part of the cycle clearing or EHTM Program.[35] Mr. Booth also recommended that National Grid track vegetation related outages caused by hazard trees, that the Company track the expenses and capital costs incurred when conducting restorations after a vegetation related outage event. Mr. Booth explained that this was necessary because National Grid had not yet demonstrated what portions of the

[32] National Grid Exhibit 1 (Pre-Filed Testimony of Nancy Ribot), at 8-10.
[33] Division Exhbit 1 (Pre-Filed Testimony and Memorandum of Gregory L. Booth, P.E.), Exhibit GLB-1 at 5-6.
[34] Division Exhibit 1 (Memorandum of Gregory L. Booth, PE), Exhibit GLB-1 at 29.
[35] *Id.* at 30.

Damage/Failure Capital Cost budget category are driving the overall upward trend for this type of spending.[36]

With regard to the issue between National Grid and Verizon concerning the Joint Ownership Agreement and Vegetation Management that was raised during the review of the FY 2013 Electric ISR Plan, Mr. Booth stated that "[t]he acceptance of this level [of spending on Vegetation Management] does not, however, mean PowerServices or the Division expect the Company to forego its rights to collect a portion of its costs from Verizon."[37] Mr. Booth noted that National Grid and Verizon have been in negotiations. He stated that "[t]here are clearly certain costs that should be borne by the telecommunications customers of Verizon, and not the electric ratepayers of the Company."[38]

Mr. Booth recommended that, at least 120 days prior to filing its proposed FY 2015 ISR Plan with the Division, the Company submit its detailed substation capacity expansion plans, including load projections in order to give the Division sufficient time to review the proposals.[39] Likewise, noting that the projected costs are expected to increase substantially, Mr. Booth recommended that "by the end of August of each year, the Company provide to the Division the Capacity Relief Plan to include the proposed and alternate plans for additional substations and increased substation capacity."[40] Similarly, Mr. Booth recommended that National Grid "submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division no later than August 31, 2013, in order to give the Division adequate time to evaluate this long term capital intense program."[41]

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[36] *Id.* at 21-23.
[37] *Id.* at 24.
[38] *Id.* at 25.
[39] *Id.* at 31.
[40] *Id.* at 32.
[41] *Id.*

Addressing the proposed Volt/Var program, Mr. Booth noted that there were a significant number of data requests submitted in this docket.[42] He described the program as one intended "to achieve optimization of line voltage and line power factor for better circuit performance, voltage delivery to the customers, and reduction in power line losses." Originally, according to Mr. Booth, the Company was proposing a multi-year program costing between three million and six million dollars, with $1,500,000 being spent in FY 2014.[43] However, he explained that he determined that "the Company had not thoroughly developed the scope for the pilot program, and [was] proposing to implement a potentially costly pilot program prematurely."[44] It was his position that the Company may be able to achieve similar results using conventional power factor optimization and voltage optimization programs in a more cost effective manner.[45] Therefore, the Company had agreed with Mr. Booth to include $500,000 in the FY 2014 Electric ISR Plan to conduct a pilot on six of its feeders using its engineering software and revamping the control scheme on its capacitors.[46] The Company will put in metering and evaluation of those feeders to determine the economic benefit. According to Mr. Booth, "[b]ased on what is accomplished in FY 2014, a detailed scoping document and program detail will be developed for future fiscal years, in combination with cost benefit analyses."[47]

In his conclusion, Mr. Booth noted that there will be near term challenges through FY 2016 given "the competing interests of safety, reliability, benefit to cost, and economic

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[42] *Id.* at 13. *See* Commission Exhibit 2 (National Grid's Responses to Commission's First Set of Data Requests which included all of the Data Requests the Division had made prior to National Grid's filing).
[43] *Id.* at 13-14.
[44] *Id.* at 14.
[45] *Id.* at 14.
[46] *Id.* at 15-16.
[47] *Id.* at 16.

pressures…."[48] He stated that the substation flood-related mitigation and capacity projects could make up more than ten percent of the FY 2015 and FY 2016 budgets. Therefore, he maintained that it is "critical" that National Grid provide its plan, loading criteria and load projections on the time schedule he recommended.[49]

III. National Grid's Response to Division's Testimony

On March 14, 2013, National Grid filed with its Responses to the Division's Pre-Filed Testimony. National Grid agreed to Mr. Booth's recommendations regarding the submission of a cost-benefit analysis on the Vegetation Management Cycle Program and EHTM Program by August 31, 2013. The Company agreed to submit to the Division by no later than August 31, 2013, detailed substation capacity expansion plans, including local projections. The Company further agreed to submit to the Division no later than August 31, 2013, a cost-benefit analysis for the Company's Metal-Clad Switchgear Replacement Program.[50] However, the Company stated that it could not agree to the August 31, 2013 date to submit the results of its negotiations with Verizon regarding vegetation management due to the fact that it was unsure of when the negotiations would be concluded.[51]

Additionally, National Grid agreed with Mr. Booth's recommendation that the Volt/Var pilot not be commenced until additional planning and modeling tools are developed. However, the Company proposed that the modeling be undertaken for both the traditional approach and the centralized approach prior to expending funds on the traditional approach. According to the Company, this approach "would allow Mr. Booth and the

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[48] Division Exhibit 1 at 29.
[49] *Id.* at 29-30.
[50] National Grid Exhibit 2 (National Grid's Response to Division's Pre-Filed Testimony) at 1.
[51] *Id.* at 1-2.

Division to review the potential benefits for customers from a centralized control approach to Volt/Var optimization prior to further investment."[52]

IV. Hearing

On March 22, 2013, the Commission conducted a Hearing at its Offices at 89 Jefferson Boulevard, Warwick, Rhode Island for the purpose of discussing and considering the Electric ISR Plan for FY 2014. The following appearances were entered:

FOR NATIONAL GRID:	Thomas Teehan, Esq.
FOR DIVISION:	Leo Wold, Esq. Assistant Attorney General
FOR COMMISSION:	Cynthia G. Wilson-Frias, Esq. Senior Legal Counsel

National Grid presented Jennifer Grimsley, Craig Allen, William Richer, Nancy Ribot, and Michael Hrycin, Director of Overhead Lines, Rhode Island, in support of the Electric ISR Plan. Using a power point presentation, Ms. Grimsley provided a high level overview of the Electric ISR Plan. Discussing the URD Cable Strategy, Ms. Grimsley explained that this program is to address a certain type of cable that was used in the 1970s, when the URDs were direct buried cable that now requires the Company to dig up people's yards in order to repair faults in the line. In the 1990s, the Company began putting cable in conduit and manhole systems which allows for more unfettered access to underground circuits.[53]

During the discussion of the reliability performance, and the continued impact of vegetation related interruptions, Mr. Allen noted that the Vegetation Management Plan is

[52] *Id.* at 2.
[53] Tr. 3/22/13 at 18-19.

not yet a mature program, with only two years of the four-year cycle being completed.[54] The final year of the four-year cycle will occur in FY 2015.[55] He testified that the cycle pruning benefit has translated into 28 percent reduction in tree-related customer interruptions.[56] Similarly, with regard to the EHTM program, he stated that the Company had completed "just under twenty percent of the three-phase miles in Rhode Island."[57] He testified that in FY 2013, approximately fifteen trees per mile were removed under this portion of the program, an amount he classified as a high number of removals.[58] However, Mr. Allen noted that the Company had conducted an analysis showing a seventy-five percent improvement in tree-related customer interruptions on the circuits where EHTM has been performed.[59] He conceded that the EHTM is difficult to justify if one were to review the benefits on a dollar for dollar basis. He stated that from FY 2008 through FY 2011, the Company spent $1.6 million to achieve a $19,000 savings in damage costs. Therefore, he stated, "it simply points out the fact that there's a lot more to this, the vegetation management program…[and] we really need to figure out a way to value customer interruptions" and customer satisfaction."[60]

Ms. Grimsley stated that the Company could have some trouble implementing Mr. Booth's recommendations regarding the cost benefit analysis, "particularly on the area of capturing the actual costs because not all of the costs are going into the capital portion of the plan in the damage failure category."[61] She explained that some repairs are not included in the ISR because they are recovered as general O&M expenses or capital. Tracking the

[54] *Id.* at 25-26.
[55] *Id.* at 25-26, 44.
[56] *Id.* at 45.
[57] *Id.* at 28.
[58] *Id.* at 44-45.
[59] *Id.* at 25, 45.
[60] *Id.* at 46-47.
[61] *Id.* at 47-48.

expenses on such a granular level, she maintained, would be very burdensome for the Company "and given that the level of savings we don't think is very great based on the estimated work we had done in the last cost benefit report, we're just not sure that that's the right way to go."[62] Therefore, she proposed the Company meet with the Division to further refine the analysis.[63]

Discussing other costs related to the Vegetation Management program, Mr. Allen testified that police detail costs have been rising recently. Oftentimes, the Company will not find out until the morning the work is to be performed that they are required to have a police detail. Additionally, some cities and towns have moved from a four-hour minimum to an eight-hour minimum cost. Sometimes the Company is able to negotiate where a police detail is needed, but often they are not successful.[64] He testified that it is understandable to have a police detail in a busy area, but does not see the need on a quiet cul-de-sac.[65]

Providing more information on the Tunk Hill reliability (storm hardening) project, Ms. Grimsely explained that Grade B construction uses a higher class pole which is stronger, has stronger cross arms, or doubling cross arms which gives the structure more strength. Mr. Allen explained that the Company is "proposing to use basically a brand new strategy just recently written about...called overhead branch reduction" where the length or

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[62] *Id.* at 48.

[63] *Id.*

[64] *Id.* at 49-50.

[65] *Id.* at 51-52. In response to a Commission Record Request, National Grid provided police detail documents from thirteen municipalities in Rhode Island. They highlighted the following policies which concerned them from a cost standpoint: Three communities charge in excess of $42 per hour for police detail rates. Four towns charge at least $20 per hour for the police cruiser. While most towns include an administrative fee in the hourly rate, two towns charge an extra fee on top of the total bills, with one town charging an additional 20%. Most towns have a 1-2 hour cancellation requirement prior to the scheduled time but one town has a 12 hour cancellation policy and another a 24 hour cancellation policy or the Company is charged for four hours. On the other side of the spectrum, Cumberland and Burrillville currently allow certified flaggers in place of police details, allowing the Company much more flexibility and reduced costs for similar safety benefits. (National Grid's Response to Commission RR-1).

volume of branches is reduced by thirty percent.[66] According to the research, Mr. Allen explained that a thirty percent reduction can result in a fifty percent enhancement to reliability in the "branch fracture zone."[67] It is less intrusive and much less expensive than ground to sky pruning.[68]

The purpose of this pilot project is to "decide whether [the Company] should consider it in [the] cycle pruning program."[69] In order to make this decision, the Company will be looking at three years of pre-project performance and then approximately three to five years thereafter. Additionally, Mr. Allen stated that the Company needs to determine "what the cost is for contractors to do this work and to start to get a sense of how easy it is to convey the decision making to the foremen in the field so that we can ensure that it's actually being performed correctly." Therefore, Mr. Allen concluded, it would be three years before the Company could provide estimates of the increased price if it is to be included for all cycle pruning.[70]

Discussing the Volt/Var pilot program, Ms. Grimsley explained that the goal is to manage the system to reduce losses, reduce peak demand, release capacity, maintain the appropriate voltage on the system and meet certain power factor requirements. She stated that the Company has met its ISO-NE requirements but is looking to future compliance.[71] Volt/Var management is not a new concept, but the proposal by the Company to engage an outside vendor to provide automated Volt/Var management is new. According to Ms. Grimsley, National Grid would like to implement the program offered by the Rhode Island

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[66] *Id.* at 95-96.
[67] *Id.* at 96.
[68] *Id.* The Company is also conducting storm hardening pilot projects in Massachusetts and New York on different types of trees. *Id.* at 97-98.
[69] *Id.* at 99.
[70] *Id.* at 100.
[71] *Id.* at 103-04.

company, Utilidata in order to determine whether the technology can produce the additional benefits over the traditional approaches which Utilidata claimed.[72] However, because the Division raised several questions during its review of the proposed Electric ISR Plan, Ms. Grimsley explained that the Company would be budgeting $500,000 to install capacitor banks and the related controls which would be common to using National Grid's current software and to using Utilidata's technology.[73] She stated that the $500,000 is required regardless of the path ultimately chosen and that the program would be back before the Commission in the FY 2015 Electric ISR Plan for its further review prior to implementation in order to assess whether to continue with the integrated approach or rather resort to the more traditional approach.[74]

In order to provide more clarification regarding National Grid's proposal, the Company presented Alan LaBarre, Manager of Advanced Engineering. Mr. LaBarre explained that Volt/Var management is the control of voltage regulating devices to try to optimize system performance so that capacity is released to serve real load. The goal is to maintain acceptable voltage on all points of the system for customers ultimately minimizing system losses.[75] Currently, National Grid "deploys capacitors with controls that act on local conditions," turning on or off as they receive a signal that the voltage level needs to be corrected.[76] Integrated Volt/Var management is a centralized control system which "couples real time measurements, communications and devices talking to one another."[77]

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[72] *Id.* at 104-05.
[73] *Id.* at 110.
[74] *Id.* at 127-28.
[75] *Id.* at 116-17.
[76] *Id.* at 117.
[77] *Id.* at 118.

Mr. LaBarre testified that the Company has been working with Utilidata at no cost to develop an order of magnitude cost estimate for application of their Volt/Var technology.[78] Once this study is completed, the Company has committed to working with the Division to decide whether to move forward to develop a detailed engineering design and commence acquisition of materials. He admitted that the Company was struggling with the comparison of the traditional approach to the integrated approach without putting the integrated system in place. He stated that the Company will be challenged to show the benefits of an integrated system and that the best way is through a pilot.[79] Mr. LaBarre explained that analysis of customer energy savings will be somewhat dependent on which vendor the Company chooses. He stated:

> Customer energy savings that result from the application of these devices, is not something that is straight forward to model in our distribution feeder analysis software, and the vendors in this area have all developed methodologies to estimate savings based on performance characteristics...the measurements being taken once the system has been put into place....Everyone does it a little bit different.[80]

Mr. LaBarre indicated that the Company has discussed Utilidata's product with another utility and is encouraged by their results. He advised that there are other vendors that offer integrated products but that Utilidata's is unique.[81] However, Mr. LaBarre stated that the Company has not yet decided whether to attempt a sole source contract or issue a Request for Proposals, stating that "sole source would require an awful lot of defense from the sponsor of the project to suggest that this is the only organization we can go with."[82] He clarified that the Company had made no commitment to Utilidata that it would ultimately

[78] *Id.* at 112.
[79] *Id.* at 113-14.
[80] *Id.* at 121.
[81] *Id.* at 114-16.
[82] *Id.* at 119.

get a contract with National Grid.[83] He explained that Utilidata's proximity to National Grid in Rhode Island coupled with their willingness to work with National Grid at no cost has been a positive attribute and a primary reason for focusing on Utilidata.[84]

Mr. LaBarre agreed that Volt/Var management has been shown to be an effective way to reduce consumption. When asked why this program is being proposed as an ISR program rather than an energy efficiency program, Ms. Grimsley stated that because it requires the installation of capital equipment and reduces peak loads, thus affecting other capital projects, she believed the ISR program is a better fit. Conceding that it will have energy efficiency benefits, it is similar to other projects in the ISR plan because it is installing infrastructure typical to the infrastructure the Company routinely installs.[85]

The Division presented Mr. Booth for cross examination. Mr. Booth explained that his understanding of the agreement between National Grid and the Division on the Volt/Var issue was to undertake a study to determine what economic benefit the Company can capture with current conventional mechanisms (locally controlled capacitors). If it captures, for example, ninety (90) percent, "is the remaining ten percent to go to the most modern system possible actually worth it or should you first get the more conventional optimized system in place and then maybe rather than next year or the year after further down the road modernize your system completely. So it's really a timing issue."[86] He explained that the first step is to determine what is already available and the second is to determine whether to utilize current technology or undertake the overall modernization separately or at the same

[83] *Id.* at 118.
[84] *Id.* at 118.
[85] *Id.* at 130-31.
[86] *Id.* at 138-39.

time.[87] Mr. Booth agreed that the equipment National Grid installs would be the same voltage regulators and capacitors and the controls regardless of the approach taken. Therefore, the $500,000 would be required either way.[88] However, the settled approach was reasonable because in his initial review of the proposal, Mr. Booth did not believe the Company had appropriately evaluated or justified a multi-million dollar pilot project.[89]

Discussing the tracking of capital costs for restorations after a vegetation related incident, Mr. Booth indicated a willingness to engage in further discussions on the appropriate approach to the tracking, stating, "we're not expecting the Company to develop new specialty accounting systems, but what we want to do is have a collaborative effort of taking the accounting systems [the Company has] and the systems that [the Company is] using to bring data back in from the field in the outage processes to see how to best take that data and evaluate the cost benefit associated with the cycle clearing program."[90]

V. Commission Findings

At the conclusion of the hearing, the Commission approved the FY 2014 Electric ISR Plan finding that it complies with the statutory mandates. The Commission approved the proposed revenue requirement of $12,133,495 which results in an incremental fiscal year rate adjustment of $1,606,595 and also approved the proposed rates for each rate class. The impact on a standard residential customer using 500 kWh per month is an increase of $0.16 per month. During the hearing, the Commission questioned some of the projections, particularly in the area of statutory/regulatory costs, noting that the spending level was higher than historical costs. National Grid and the Division witnesses all concurred that the

[87] *Id.* at 139.
[88] *Id.* at 143-44.
[89] *Id.* at 143.
[90] *Id.* at 140-41.

proposed statutory/regulatory costs in the FY 2014 ISR Plan had been appropriately reduced from the prior year and were at least closer to reasonable projections than in the past.[91] However, because National Grid was unable to provide the Commission with its required quarterly reports due to a problem with a recent software conversion, there was no way to compare the proposed FY 2014 budget to the FY 2013 costs to date.[92] The Commission will continue to review the statutory/regulatory budgets in future ISR filings and expects that the Division will do the same to ensure the rates are not set higher than necessary in the first instance.

During the proceeding, similar to last year, the Division raised the issue of tracking the benefits related to the costs of the Vegetation Management. The Company filed a cost benefit analysis in accordance with Commission Order No. 20724 issued in 2012. However, a year later, the Division and Company had not yet agreed to a final methodology for appropriate tracking of the costs and benefits of the Vegetation Management program. The Division's witness made several suggestions which the Company argued were overly burdensome and costly. The parties agreed to continue working toward an appropriate methodology of tracking the benefits and costs of the Vegetation Management program. The Commission believes this is an important issue to be worked out and strongly urges the parties to come to an agreeable methodology in the FY 2015 Electric ISR Program proposal. Development of an appropriate cost benefit analysis methodology for the cycle pruning is important given the level of spending each year. Likewise, an appropriate methodology for

[91] Tr. 3/22/13 at 34-40, 145-46.

[92] *Id.* at 32-33. In fact, at the time of the issuance of this written order, the Commission still has not received either the third quarter report for FY 2013 for the period ending December 31, 2012 or the fourth quarter report for the period ending March 31, 2013. National Grid's reconciliation of FY 2013 costs is due to be filed on or before August 1, 2013. The Commission is concerned that it has received no actual numbers from National Grid since November 12, 2012 for the period ending September 30, 2012. It would not be unreasonable for the Commission to suspend or reject a proposed rate change in the absence of compliance filings or other verifiable documentation to support the proposed change.

the EHTM program is imperative, particularly in light of Mr. Allen's testimony that the EHTM is difficult to justify if one were to review the benefits on a dollar for dollar basis.

The evidence in this case indicates that police detail costs have not only been rising, but further that there are disparate policies being pursued by various municipalities across the state. This Commission is keen on safety and recognizes the importance that police details play in protecting worker safety and the public in general. However, the Record also suggests that some municipalities may be imposing unreasonable requirements on National grid that translate into unnecessarily higher costs to ratepayers. National Grid, the State's dominant electric utility clearly has the ability to draw judgments on what municipally-driven requirements are appropriate and reasonable in the name of safety, and alternatively which requirements may impose unnecessary costs or unreasonable mandates. The Commission draws the Company's attention to R.I. Gen. Laws § 39-1-30, and encourages National Grid to use its judgment in determining whether to invoke the Commission's jurisdiction in such matters. Now being on notice, the Comission will continue to scrutinize these cost items and policies in the context of future ISR filings.

Finally, National Grid agreed to two of Mr. Booth's other recommendations contained in his Report, specifically, the submission to the Division of detailed substation capacity expansion plans, including load projections, at least 120 days prior to filing of the FY 2015 Electric ISR Program proposal with the Division and submission to the Division of the Metal-Clad Switchgear replacement program cost-benefit analysis no later than August 31, 2013. The Commission accepts these recommendations. National Grid did not agree that it could submit the final resolution of the Verizon vegetation management negotiations prior to the filing of the FY 2015 Electric ISR Program proposal with the Division, but did agree to submit the results as soon as available.

Accordingly, it is hereby

(21121) ORDERED:

1. Narragansett Electric Company d/b/a National Grid's Revised Electric ISR Plan filed on December 31, 2012 and associated compliance tariffs are hereby approved for usage on and after April 1, 2013.

2. Narragansett Electric Company d/b/a National Grid shall comply with all other instructions contained in this Order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON APRIL 1, 2013 PURSUANT TO A BENCH DECISION ON MARCH 22, 2013. WRITTEN ORDER ISSUED JULY 26, 2013.

PUBLIC UTILITIES COMMISSION

*Elia Germani, Chairman

Mary E. Bray, Commissioner

Paul J. Roberti, Commissioner

*Chairman Germani concurs with the decision but is unavailable for signature.

NOTICE OF RIGHT OF APPEAL PURSUANT TO R.I. GEN. LAWS SECTION 39-5-1, ANY PERSON AGGRIEVED BY A DECISION OR ORDER OF THE COMMISSION MAY, WITHIN SEVEN DAYS (7) DAYS FROM THE DATE OF THE ORDER, PETITION THE SUPREME COURT FOR A WRIT OF CERTIORARI TO REVIEW THE LEGALITY AND REASONABLENESS OF THE DECISION OR ORDER.