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Peter F. Kilmartin, Attorney General

January 17, 2013

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: The Narragansett Electric Company – d/b/a National Grid – Interstate Reliability Project (Docket No. 4360)

Dear Ms. Massaro:

Enclosed for filing in the above-referenced matter are an original and nine (9) copies of the prefiled direct testimony of Gregory L. Booth, PE, filed on behalf of the Rhode Island Division of Public Utilities and Carriers. Please note that an electronic copy of this document has been sent to the Service List and that I will provide a hard copy to anyone that requests it.

Thank you for your attention to this matter. If you have any questions, please feel free to contact me.

Very truly yours,

Christy Hetherington

Christy Hetherington
Special Assistant Attorney General
Regulatory Unit
Extension 2425

Enclosure

cc: Service List

Docket No. 4360 - Narragansett Electric Co. d/b/a National Grid – Advisory Opinion to EFSB regarding need and cost-justification for proposed RI Interstate Reliability Project
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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

Issuance of Advisory Opinion to the Energy Facility Siting Board Regarding Narragansett Electric Company d/b/a National Grid's Application to Construct and Alter Major Energy Facilities (Interstate Reliability Project)	Docket No. 4360

PREFILED DIRECT TESTIMONY OF

Gregory L. Booth
President, PowerServices, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers

January 17, 2013

Prepared by:
Gregory L. Booth, PE

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Prefiled Direct Testimony of

Gregory L. Booth, PE, President
PowerServices, Inc.

On Behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4360

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DIRECT TESTIMONY OF GREGORY L. BOOTH, PE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER AND POSITION.

A. My name is Gregory L. Booth. I am President of PowerServices, Inc. ("PowerServices"), UtilityEngineering, Inc. ("UtilityEngineering"), and Gregory L. Booth, PLLC ("Booth, PLLC") all located at 1616 E. Millbrook Road, Suite 210, Raleigh, North Carolina 27609.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers.

Q. WHAT DOES YOUR POSITION WITH POWERSERVICES, INC., UTILITYENGINEERING, INC., AND BOOTH, PLLC ENTAIL?

A. As President of PowerServices, Inc., an engineering and management services firm, UtilityEngineering, Inc., a design/build firm, and Booth, PLLC, an engineering firm, I am responsible for the direction, supervision, and preparation of engineering projects and management services for our clients, including the corporate involvement in engineering, planning, design, construction management, and testimony.

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I graduated from North Carolina State University in Raleigh, North Carolina in 1969 with a Bachelor of Science Degree in Electrical Engineering. I am a registered professional engineer in twenty-two (22) states, as well as the District of Columbia. I am also a registered land surveyor in North Carolina. I am also registered under the National Council of Examiners for Engineering and Surveying.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. I am an active member of the National Society of Professional Engineers ("NSPE"), the Professional Engineers of North Carolina ("PENC"), The Institute of Electrical and Electronics Engineers ("IEEE"), American Public Power Association ("APPA"), American Standards and Testing Materials Association ("ASTM"), and the Professional Engineers in Private Practice ("PEPP"). I am also a member of the IEEE Distribution Subcommittee on Reliability and the National Fire Protection Association, and an advisory member of the National Rural Electric Cooperative Association ("NRECA")-Cooperative Research Network, which is an organization similar to EPRI.

Q. HAVE YOU ATTACHED TO YOUR TESTIMONY A COPY OF YOUR CURRICULUM VITAE?

A. Yes. My curriculum vitae is attached as *Exhibit GLB-1*, includes an overview of my experience since beginning my work in 1963, and lists some of my publications, seminars conducted, and testimony provided.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH ELECTRIC UTILITIES.

A. I have worked in the area of electric utility and telecommunication engineering and management services since 1963. I have been actively involved in all aspects of electric utility planning, design and construction, including generation and transmission systems, and North American Electric Reliability Corporation compliance.

Q. DO YOU HAVE OTHER INVOLVEMENT AND EXPERIENCE WITH COMPANIES THAT PROVIDE YOU WITH ADDITIONAL EXPERTISE RELEVANT TO THIS DOCKET?

A. Yes. My electric utility reliability assessment work for the Rhode Island Division of Public Utilities and Carriers ("Division"), the New Jersey Board of Public Utilities ("NJBPU") and at the Pennsylvania PUC and the Virginia State Corporation Commission ("SCC") over the last ten years has involved in-depth assessment and working with northeastern electric utilities on reliability enhancement and the costs associated with such enhancement, including annual construction work plan development for electric utility systems. Additionally, I investigate safety related accidents and testify as an expert in state and federal courts concerning safety related accidents involving electric utility systems averaging over 30 cases a year.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE STATE UTILITY COMMISSIONS, OTHER REGULATORY AGENCIES, AND/OR COURTS?

A. Yes. I have testified on numerous occasions before the Federal Energy Regulatory Commission ("FERC"), including pre-filed testimony in both wholesale rate matters as well as in electric utility reliability complaints, including Duke Power Company and Dominion Power issues. I have also testified before the New Jersey Board of Public Utilities, the Delaware Public Service Commission, Massachusetts Attorney General Office of Ratepayer Advocacy, Minnesota Department of Public Service Environmental Quality Board, Virginia State Corporation Commission, the Pennsylvania Public Utility Commission, and the North Carolina Utilities Commission, most of them on multiple occasions. I have also filed testimony in electric utility acquisition hearings in Florida. I have testified before the Rhode Island Public Utilities Commission on numerous matters, including Docket Nos. 2489, 2509, 2930, 3564, 3732, 3564, 4029, 4307, 4218, 4307, and D-11-94. My testimony in Rhode Island has included filed and live testimony on previous transmission projects associated with the NEEWS and Interstate Reliability Projects, such as Docket No. 4029.

Q. HAVE YOU BEEN ACCEPTED AS AN EXPERT BEFORE STATE OR FEDERAL COURTS?

A. Yes. I have been accepted as an expert in the area of electrical engineering and electric utility engineering, construction and reliability matters and the NESC, NEC, OSHA EMF, and forensic engineering, including standard and customary utility operation practices in the electric utility industry and the electric industry before 12 state and federal courts.

II. SCOPE OF TESTIMONY

Q. HAVE YOU REVIEWED THE PRELIMINARY DECISION AND ORDER DATED JULY 12, 2012 ISSUED BY THE ENERGY FACILITY SITING BOARD?

A. Yes.

Q. HAVE YOU REVIEWED THE TESTIMONY OF THE NATIONAL GRID WITNESSES, THEIR EXHIBITS, AND THE FILINGS, INCLUDING VOLUMES 1 AND 2 AND APPENDICES AND REVISIONS FOR NATIONAL GRID'S INTERSTATE RELIABILITY PROJECT ("PROJECT") WITH NATIONAL GRID'S ENERGY FACILITIES SITING BOARD ("EFSB") APPLICATION DATED JULY 19, 2012 FOR THE RHODE ISLAND PROJECT?

A. Yes, I have reviewed all of the documents as filed in Docket No. 4360.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("Division").

Q. WHAT IS THE SCOPE OF YOUR SERVICES FOR THE RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS ("DIVISION")?

A. Under the statute and regulations, the Division of Public Utilities and Carriers ("Division") is expected to assist the Commission in rendering its Advisory Opinion to the EFSB by its participation in the Commission Docket 4360. The Division has requested I provide an evaluation of the proposed project and review the original Narragansett Electric Company's (d/b/a National Grid ("National Grid")) application made to the EFSB addressing the project need, transmission modeling criteria, proposed solutions, cost estimates, and possible alternatives to the Project. As part of my scope of services to the Division, I have also examined: supplemental information filed by

National Grid; the Southern New England Transmission Reliability Needs Analysis Report as prepared by the ISO New England; and other materials provided by National Grid concerning the New England East-West Solution ("NEEWS") Interstate Reliability Project ("IRP") component as prepared by National Grid witnesses, Mr. David J. Beron, Mr. Gabriel Gabremicael, Mr. Mark Stevens, Mr. Judah L. Rose, and Mr. David M. Campilii. The Division has retained me as its expert, and, as such, I have participated in a conference call with National Grid, performed certain analyses to assist in formulating a recommendation, provided discussion with the Division regarding status of the review of the aforementioned documents, and produced this testimony which includes my conclusions and findings and recommendations.

Q. WHAT OTHER INFORMATION HAVE YOU REVIEWED?

A. National Grid did not provide a helicopter tour of the project. It did, however, provide a combined Google Earth/PLS-CADD digital aerial and ground level video of the entire route. This was, in many ways, superior to a helicopter tour, since I was able to revisit any section of the system on multiple occasions throughout the analysis.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address my review, findings, and conclusions as they relate to the Project, as proposed, and the alternatives to the Project, including a No Build option, Non-Transmission Alternatives and various transmission alternatives to the Project. My analysis has specifically focused on the need and if the Project is cost justified, expressly determining the reasonableness of the cost of the Project and the rationale of National Grid's selection of the particular facility type and location. I have included in my review and consideration the economic and reliability benefits, and if the Project causes any unacceptable harm. My testimony will address the cost estimates and the appropriateness of any alternative. I will discuss areas of concurrence with the National Grid filing and witnesses, together with those areas of divergence from the testimony of the witnesses.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. I have organized my testimony by first discussing the methodologies employed to determine the need for the project as well as the cost estimates. I then briefly address the testimony of each National Grid witness, as well as the testimony of the Independent System Operator ("ISO"). I conclude with a summary of my findings and my conclusions.

III. TRANSMISSION MODELING CRITERIA

Q. HAVE YOU EVALUATED THE CRITERIA USED FOR THE PROPOSED PROJECT THAT PROVIDED THE SOLUTION AND THE ALTERNATIVE PROJECTS PRESENTED, INCLUDING THEIR UNDERGROUND ALTERNATIVE?

A. Yes. I have reviewed the design criteria set forth by the North American Electric Reliability Corporation ("NERC"), the Northeast Power Coordinating Council, Inc. ("NPCC"), and ISO-NE which this analysis has been built upon.

Q. WOULD YOU FIRST SUMMARIZE ANY ADDITIONAL ITEMS OR COMMENTS YOU HAVE IN REGARD TO YOUR EVALUATION OF THE DESIGN CRITERIA ESTABLISHED FOR THIS ANALYSIS?

A. Yes. While the analysis scope focuses on a ten year period, most notably bulk power transfer limitations on east-to-west transmission infrastructures, an expanded evaluation of the chosen Interstate Reliability Project's ("IRP") ability to serve the Southern New England area at a twenty or thirty year mark would be beneficial for overall project selection. Transmission infrastructure of the type and size being proposed typically has a useful life of over fifty (50) years. An additional look focusing on long term stability of the improvement projects being assessed outside of the 10 year planning horizon should be included as part of a final assessment. In addition to performing the analysis for a twenty or thirty year evaluation, a discussion of existing age of infrastructure for the 345kV assets currently in place should be evaluated. In addition to operations and maintenance procedures, components commonly need to be replaced due to age and the degradation of materials once the useful life established for the materials has been met or exceeded. This is commonly referred to as ordinary replacement and includes items such as reconductoring, replacement of poles and/or structures, and replacement of equipment needed to sustain current reliability from components as they age. If the existing transmission lines or major portions thereof are past their useful life or approaching the useful life of the assets, capital improvements will need to be implemented to continue functioning reliably regardless whether a need to correct thermal overloads or voltage performance issues exist. Furthermore, a 10 year planning horizon is relatively short, and could subject the IRP to early obsolescence if a 20 or 30 year analysis is not also a part of the decision process.

Q. HAVE YOU EVALUATED THE CRITERIA USED FOR THE PROPOSED CRITICAL LOAD LEVEL ANALYSIS THAT PROVIDED THE LOAD LEVELS IN WHICH DESIGN CRITERIA AND TRANSMISSION MODELING ANALYSIS WAS COMPLETED?

A. Yes. I have.

Q. WOULD YOU FIRST SUMMARIZE ANY DIFFERENCES OR COMMENTS YOU HAVE IN REGARD TO YOUR EVALUATION OF THE CRITICAL LOAD LEVEL ANALYSIS?

A. The critical load level (CLL) has been defined as the load level forecasted where reliability is effected on the bulk transmission area. This overall CLL was arrived at by adding each individual sub-region's CLL for the Southern New England territory to determine the overall CLL for the region. While this approach provides a worst case scenario for planning purposes it does not take into account the factor of diversity. Diversity on a system such as the one analyzed in New England will typically see a factor of 90% to 95% of the simple cumulative load level. This type of reduction may not change the outcomes provided on a large scale and how National Grid and the ISO should address whether such impact defers the need for the proposed IRP project.

IV. COST ESTIMATE

Q. HAVE YOU EVALUATED THE COST ESTIMATES PREPARED BY NATIONAL GRID FOR THE PROPOSED PROJECT AND THE ALTERNATIVE PROJECTS, INCLUDING THEIR UNDERGROUND ALTERNATIVE?

A. Yes. I have reviewed the cost estimates contained in its filing and in prior filings. I will comment on the National Grid estimates.

Q. WOULD YOU FIRST SUMMARIZE ANY DIFFERENCES OR COMMENTS YOU HAVE IN REGARD TO YOUR EVALUATION OF THEIR COST ESTIMATES?

A. Yes. First it must be recognized that National Grid has done a study grade estimate for the options at this point in the process. In the cost estimates performed for the overall project, there is a potential seventy-five percent spread in high to low for the cost estimate, based on the utilization of plus fifty or minus twenty five percent contingency in the analysis. Simply stated, that means that the proposed Project could cost as little as $406.5 million and as much as $813.5 million with the National Grid estimate being $542 million. The estimated cost of the Rhode Island project components have been computed with a potential fifty percent spread with plus or minus twenty-five percent contingency. The Rhode Island portion of the IRP is estimated at $180.8 million, with a possible cost range of $135.6 million to $226 million. The cost estimates, including the details provided, have been carefully evaluated. Although these estimates have been characterized as study grade estimates and are not based on detailed design, they do contain substantial specifics by project component that I evaluated and reached generally the same cost estimate. I have some differences of opinion concerning the inclusion of certain costs and the assumptions, which I will discuss in greater detail later in my testimony. I found the unit costs on the over head and underground project estimates to be consistent with the levels in the industry. My evaluation of the Project estimates for the overhead lines results in a cost estimate which would be closer to the low end of the National Grid study grade Project cost estimate. A similar analysis for all of the alternative overhead Project estimates was completed, and also resulted in general concurrence albeit the lower end of National Grid's cost estimates. A substantially different cost estimate result was reached for the underground alternatives. It is my opinion that National Grid's cost estimate for the underground alternative has failed to incorporate a significant level of likely cost on the upper limit, therefore significantly understating what the ultimate cost may be for an underground project along the potential route. This discrepancy is exacerbated by the use of different multiples of cost comparison to the overhead cost in Section 5.8 of the Interstate Reliability Project Environmental Report ("ER"). In one comparison of overhead to underground options, a cost adjustment factor of 4.39 was used; in another comparison, a cost adjustment factor of 6.5 was used. I have included *Exhibit GLB-2*, which is a year by year curve depicting the Producers Price Indices, which drive construction cost escalation. Even though there was a significant decline from 2008 to 2010 and the cost is once again escalating, I find it makes the higher limits of the National Grid overhead transmission cost estimates less likely.

Q. WOULD YOU OUTLINE THE DETAILS ASSOCIATED WITH YOUR REVIEW OF THE COST ESTIMATE AND ANY CLARIFICATIONS YOU BELIEVE ARE APPROPRIATE?

A. Yes. Beyond those listed above, there were details associated with the overall project alternative that were unclear.

1. It was noted that project A-3 includes increasing conductor clearances of 8.7 miles of existing 345 kV between Sherman Road Switching Station, the new Uxbridge Switching Station, and the ANP Blackstone Substation, but does not include the 9.2 miles of reconductor/rebuild of the existing 328 Line. It is not clear what criterion is used to determine the need to increase these conductor clearances. This project is not chosen in the A-1 option and it is not clear if a need exists to correct for safety violations in addition to correct thermal overload and voltage corrections.

2. Secondly, I note the omission of the reconductor/rebuild of existing line 328 in the A-3 option. It is unclear as to the need of this project in the A-1 option versus the A-3 option as these two options closely mirror each other in their location and types of improvements noted. Could the new 9.2 mile line 328 improvement be omitted from A-1 option and still achieve project goals for thermal overheads and voltage corrections? The reason I address this is that, when parties are comparing the proposed project and various alternatives, including the underground alternative, certain projects should be considered as bid options if construction costs are evaluated higher than estimated. While many other factors contribute to the determination of project need, such as current, system parameters, age of infrastructure, and reliability goals, a project should be addressed on its level of importance if cost factors become critical in the approval process moving forward.

Q. HAVE YOU EVALUATED THE UNDERGROUND ALTERNATIVES IN A SIMILAR MANNER AS YOU EVALUATED THE OVERHEAD PROJECTS?

A. Yes, I performed a detailed evaluation of the cost estimate as prepared by National Grid for the underground alternatives in a similar fashion to my evaluation of the overhead projects. I found several components which I believe substantially understate the costs associated with the underground project as well as irregularities in the cost structures.

Q. COULD YOU DELINEATE THOSE ITEMS YOU BELIEVE CONSTITUTE COMPONENTS THAT NATIONAL GRID FAILED TO REFLECT IN THEIR UNDERGROUND COST ESTIMATE?

A. Yes. The major components in National Grid's cost estimate being understated are as follows:

First, on projects such as a major 345 kV transmission line in duct bank being installed along highway rights-of-way where there is a high probability of encountering water, sewer, natural gas and other utility facilities, it has been my experience that the depth in which the line must be installed is greater than proposed by National Grid. I would anticipate that the average depth required in order to avoid conflict, most particularly with sewer lines, would require three (3) to four (4) additional feet. Current design depth calls for a minimum of 3 feet to the top of the concrete encasement. Although natural gas lines, telecommunication lines, water lines and other utility facilities, including the electric utilities (low and medium voltage distribution systems) can have some degree of flexibility in depth, a sewer system does not have the flexibility of adjustment, since sewer systems are based on gravity and not pressure. This means there is little if any adjustment in sewer line elevation that can be achieved. In underground projects, most particularly large transmission duct bank projects, I have found that a significant portion of the cost of the project is associated with other utilities and the handling and relocation and incorporation of those utilities into the total project. I have also found that the impact of sewer lines is the greatest as it relates to depth, overall location, and the associated excavation cost. Recognizing that this is a study grade estimate and there has not been identification of all the other utilities that would be in and along the DOT corridor in particular, and the amount of sewer line and its depth has not been identified, I believe it is necessary to incorporate substantially more dollars in what will be the inevitable cost that is not reflected in the estimate at this time.

Q. WOULD YOU OUTLINE THOSE DIFFERENCES WHICH YOU IDENTIFIED IN THE ALTERNATIVE UNDERGROUND CONSTRUCTION PROJECTS?

A. Yes. Beyond those listed above, there were details associated with the overall project I could not identify.

1. Using the cost comparisons noted in Table 5-16 for the Line 366 overhead versus underground costs the following was noted. The proposed Line 366 overhead cost scenario generates a total cost of $94.2 million (excluding the tower removals) while the underground costs are $441.6 million which exclude the two overhead to underground transitions. This relates to roughly $4.6 million per mile for overhead construction and $20.2 million per mile for underground construction resulting in a factor of 4.39 cost adjustment for underground construction. Using the cost comparisons of overhead and underground alternatives in Table 5-16 for Line 341, the proposed Line 341 overhead cost scenario generates a total cost of $116.8 million, while the underground costs are $761 million, excluding the two overhead to underground transitions. The overhead cost per mile is consistent with that of Line 366 at $4.6 million, whereas the underground cost per mile is $23 million. This results in a factor of 6.5 for the cost adjustment for underground construction.

   This latter cost adjustment factor is more consistent with what I believe it should be. Typically, a minimum factor of 6-8 times the overhead construction costs should be used to achieve the cost of the underground option. Using the overhead values stated in Table 5-16 of the ER, this would result in a total cost range for Line 366 and Line 341 underground alternatives of $1,284 million to $1,712 million. The cost adjustments and range identified here would include the costs that result from the extra buried depth of the ductbank, and rock removal.

2. In Section 5.8.10 Underground Dips, the total costs of a one mile generic underground dip are shown as $48 million. These values are comprised of underground cable totaling $21.9 million and two transition stations totaling $26.1 million, and show the cost factor would be 10 times the average cost of $4.6 million per mile of overhead line. This is inconsistent with the values in Table 5-16 used in comparing Line 366 and Line 341 for overhead and underground cost adjustments. The two transition stations in Table 5-16 total $31.1 million versus $26.1 million shown in Section 5.8.10. Secondly, the same comparison can be made for underground cable where it is calculated at $20.2 million per mile in Table 5-16 versus the $21.9 million per mile in Section 5.8.10.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS CONCERNING THE COST ESTIMATES FOR THE ALTERNATIVE UNDERGROUND ROUTES?

A. Yes. The cost estimates for the underground routes have been prepared for Line 366 and Line 341, and provide a comparison to the overhead line construction. Assuming these estimates contain the same plus fifty or minus twenty-five percent study grade differential as the total overhead estimate for the IRP, it has been found that this approach substantially understates the potential maximum cost associated with an underground project, most particularly an underground transmission project. The market has seen, in recent years, wild swings in the price of a barrel of oil. If a barrel of oil moves from $40 a barrel to $150 a barrel, we all recognize the impact at the gas pump, however, it must also be recognized that, because a substantial portion of the material cost associated with solid dielectric transmission cable is a petroleum product, this type of change in price of a barrel of oil will reflect itself in a significantly higher cost associated with the project. Based on the volatility of material cost, the volatility associated with the encountering of other underground utilities, and underground issues that cannot be anticipated until one begins the project, and my belief that, from a route observation standpoint, there may be rock encountered, the cost of construction for the underground alternative could easily be 100% higher than estimated. It is my opinion that, in order to provide a reasonable evaluation of the cost differential between the various alternative projects, it must be recognized that the underground transmission alternatives would instead have a cost spread of between minus 25% and plus 100%. I would estimate the underground construction project alternative of $1,264.5 million for Line 366 and Line 341 provided in Table 5-16 would result in a potential cost of between $1.8 billion to $2.55 billion.

Q. HAVE YOU INCLUDED AN EXHIBIT THAT REFLECTS YOUR COST ESTIMATE ADJUSTMENTS AS DISCUSSED?

A. Yes. *Exhibit GLB-2,* shows price fluctuations in the PPI for metals and distilled fuel oil.

Q. HAVE YOU REVIEWED THE PROPOSED PROJECT SCHEDULE INCLUDED WITHIN THE PACKAGE?

A. Yes. I have

Q. WHAT COMMENTS DO YOU HAVE IN REGARD TO THE PROPOSED PROJECT SCHEDULE INCLUDED?

A. Currently the construction schedule from Table 4-4 indicates a construction time frame consisting of two years for completion. While this time frame may be accomplished; it appears to be very aggressive considering the amount of construction, type of infrastructure, scheduling components involved, and the permitting and licensing required. Furthermore, there is a significant amount of transmission construction across the United States which has strained the contracting labor force, and substantially extended the time for steel pole deliveries to at least 10 months for standard poles, and a minimum of 1 year for specialty poles. As stated, outages on the existing transmission lines will need to be scheduled and this type of outage can take 6 months or more to schedule, along with the chance of being cancelled due to higher volume of capacity required due to longer runs during peak season or higher loads witnessed for weather related load profiles. During high demand scenarios during the summer peaking months outages may not be granted and would cause construction efficiency to diminish due to working around and near energized facilities if approved to do so. Secondly, it is worth mentioning the time frame shown for procurement of materials. A majority of the materials are shown to be procured during 2014 with only 6 months of time during 2013 before construction is to begin. The procurement of materials would need to be weighted heavier during 2013 due to long lead times currently seen within the supply chain for these types of construction activities. Lead times for transmission materials have been pushed out from suppliers and vendors, especially in the steel pole market, due to higher demand from expansive projects occurring throughout the country. While all material to complete the projects listed would not need to be purchased prior to construction; it would be greatly beneficial to acquire a backlog in order to ensure construction would not be stopped due to lack of sufficient materials on hand. It will be necessary to have adequate space allocated for the materials if procurement were to occur earlier and storage would need to accommodate these materials for construction crews to access during 2014. The National Grid proposed schedule should reflect at least a 3 year duration to realistically represent the present market.

V. ELECTRIC AND MAGNETIC FIELDS

Q. HAVE YOU REVIEWED THE ELECTRIC AND MAGNETIC FIELD RESEARCH UPDATE IN THE RHODE ISLAND RELIABILITY PROJECT, VOLUME 1?

A. Yes, I have.

Q. WHAT COMMENTS DO YOU HAVE IN REGARD TO THE ELECTRIC AND MAGNETIC FIELD RESEARCH UPDATE IN THE ER?

A. There have been numerous studies to attempt to determine any potential health risks associated with exposure to electric and magnetic fields. Also, there have been generally accepted ranges for EMF levels at the edge of transmission right-of-way in some states. My prior research and testimony, including a recent study in Virginia, are consistent with the materials contained in the ER.

Q. WHAT ARE THE RESULTS OF YOUR RESEARCH?

A. EMF has been the subject of a great deal of study both in United States and internationally. New York and Florida in their analyses have established 200 and 150 milliGauss, respectively, in each state as a preferred maximum level at the edge of transmission rights-of-way for new lines. The estimated levels for the proposed Project on Tables 8-3, 8-4, and 8-5 are within this limit. That is not to say that this is the highest acceptable level, it only gives a reference to a few other states that have established recommended levels. EMF can be measured in units of Gauss or Tesla, and there is significant data available to determine the milliGauss levels of electrical devices and equipment, however, there has been no definitive link to EMF being a carcinogen.

Q. HAS YOUR ANALYSIS IN THIS MATTER OR OTHERS DETERMINED THAT ANY STATE AGENCY HAS EVALUATED THE EMF ISSUE AND THEN TAKEN NO SUBSEQUENT ACTION?

A. Yes. In 1985, the Virginia General Assembly adopted a resolution requesting the State Corporation Commission and the Virginia Department of Health monitor ongoing research on the health and safety effects of high voltage transmission lines and the correlation to EMF. In 1998, after 13 years of monitoring and reporting, the Virginia General Assembly decided it was no longer needed. The Virginia Department of Health in conjunction with the State Corporation Commission issued a final report on October 31, 2000. The conclusion of the report was "Evidence from laboratory studies has thus far failed to confirm that exposure to EMF causes cancer in experimental animals. Laboratory experiments have also failed to show how EMF could initiate or promote the growth of cancer." The Commonwealth of Virginia and the State Corporation Commission took no further action and established no minimum acceptable standards.

Q. DO YOU HAVE ANY OTHER COMMENTS THAT SHOULD BE CONSIDERED?

A. Generally, EMF levels associated with underground facilities are much higher than overhead due to the proximity.

VI. NATIONAL GRID WITNESSES' TESTIMONY

DAVID J. BERON

Q. HAVE YOU REVIEWED THE TESTIMONY OF DAVID J. BERON, PE, PMP, AND DO YOU HAVE ANY COMMENTS?

A. Yes, I reviewed Mr. Beron's testimony. He is National Grid's Project Manager who introduced the Project to the EFSB and sponsored the application and supporting information. Mr. Beron has outlined the overall project selection, the alternatives, and the estimated project cost along with current construction schedule. Although I have outlined in detail in my earlier testimony the comments which I have concerning my detailed evaluation of the National Grid cost estimates and construction schedule, I find that Mr. Beron's estimated project cost in 2012 dollars for the proposed Project of $542 million to be an acceptable cost estimate as well as the estimate of $181 million for the Rhode Island components. Mr. Beron states that the accuracy of the study grade estimates are expected to be +/-25 percent, whereas the ER states that the overall IRP estimates are minus 25%, +50%. Even with this inconsistency and all of my comments concerning the overhead construction cost being overstated, the $542 million is within the plus or minus twenty five percent study grade level estimate. The construction schedule does appear very aggressive and will be a challenge to accomplish within the time frame allotted.

<u>GABRIEL GABREMICAEL, PE AND MARK STEVENS, PE</u>

Q. HAVE YOU REVIEWED THE PRE-FILED TESTIMONY OF MR. GABRIEL GABREMICAEL, PE AND MR. MARK STEVENS, PE AND WOULD YOU PROVIDE COMMENTS?

A. Yes, I have reviewed the pre-filed testimony of Mr. Gabremicael and Mr. Stevens. As part of reviewing their testimony, I have also reviewed documents provided in the filing as Appendices A through E, N and O of the Environmental Report. The transmission project proposed in the National Grid filing concerning the New England East-West Solution (NEEWS) Planning Study and the need for the project, as outlined in the ER, is part of a broader solution as proposed in the NEEWS study. I had previously reviewed the NEEWS Planning Study and transmission solution as part of Docket No. 4029, and it was clear a solution to the thermal overload and voltage collapse is essential. Additionally, I reviewed the other documents as filed in the ER and as sponsored by Mr. Gabremicael and Mr. Stevens, along with the relevant New England ISO Needs Assessment. This includes a series of contingency scenario analyses with both single and double contingencies. I understand from Docket No. 4029 and ISO materials that the ISO expects National Grid to run its transmission outage scenarios with certain generator outage conditions or dispatch stress conditions. This would represent a highly stressed condition on the system which is less probable than a single contingency or double contingency transmission outage alone. It does, however, have a potential to occur, and would be a NERC and NPCC criteria assessment to be considered. The proposed Project resolves the planning criteria violations (voltage and thermal) and thus results in a more enhanced level of transmission system reliability. I reviewed Mr. Gabremicael's and Mr.

Stevens' testimony in light of the five alternative projects outlined and find that their explanations and conclusions are reasonable and appear supported by the load flow contingency analysis. The ER and the testimony outline a need that is supported by the study and the most severe planning criteria violations. In reviewing the proposed project and the alternative projects, including the no build option, in light of the transmission planning criteria and standards of National Grid, ISO New England, NPPC, and NERC, the proposed project stands out as a reasonable solution for Rhode Island while having the additional benefit of being the most prudent alternative to incorporate in the overall NEEWS Project.

Q. WOULD YOU AGREE WITH MR. GABREMICAEL AND MR. STEVENS CONCERNING THE CONSTRAINED GENERATION IN NEW ENGLAND?

A. Yes. I pointed out in my testimony in Docket No. 4029 on the transmission project that, based upon my assessment of the NEEWS, generation constraints will benefit. The IRP transmission project proposed will continue the expansion of benefits to New England regional transmission system reliability, relief of future constrained transmission, and increase the opportunity for improved generation dispatch for the economic benefit of New England power supply.

Q. WHAT COMMENTS DO YOU HAVE CONCERNING MR. GABREMICAEL AND MR. STEVENS SUMMARY OF THE SELECTED OPTION A-1?

A. I had originally reviewed in 2008 Needs Assessment as part of Docket No. 4029. This has been updated first to a 2011 Needs Assessment, and more recently a 2012 Follow-Up Needs Analysis, which was certainly prudent considering the continued economic downturn and very slow load growth which has resulted. This update obviously precipitated the 2012 Follow-up Solution Report which continues to support the Option

A-1. Mr. Gabremicael and Mr. Stevens only briefly mention that a No-Build alternative would mean National Grid would be unable to meet the identified system needs. Neither they or the ISO witness indicate what the potential adverse economic consequences are with a No-Build Option. There are the obvious adverse consequences of a potential blackout on the region. I believe NERC could and would step in with potential serious economic consequences if National Grid and the ISO elected to take no action to solve the identified reliability deficiencies. Such action has been taken in other regions by NERC.

Q. DO YOU CONCUR WITH THE CHARACTERIZATION THAT $15 BILLION TO $44 BILLION OF UNPRECEDENTED ACTIVE DEMAND RESOURCES WOULD BE REQUIRED IN LIEU OF THE PROPOSED TRANSMISSION PROJECT?

A. No. I cannot identify any evidence or study that would support this extreme level of expense. I do believe a level in excess of the estimated cost of the transmission project would be required and that there would still be some transmission expenditures.

<u>JUDAH L. ROSE</u>

Q. HAVE YOU REVIEWED THE TESTIMONY OF MR. COLLISON WITH ICF, AND THE REPORT THAT HE AND HIS FIRM PREPARED THAT WAS INCLUDED TO THE ENVIRONMENTAL REPORT ("ER") AS APPENDIX K, AND DO YOU CONCUR WITH ALL OF HIS FINDINGS?

A. Yes. I have reviewed Mr. Rose's testimony and the report included in the ER as Appendix K. Although I do not concur with all of the statements of his testimony, I do concur with the Conclusion. A non-transmission alternative cannot be implemented that would meet the needs designed to be met by the IRP Option A-1, as proposed.

Q. THE ICF TESTIMONY STATES A DEMAND REDUCTION OF 800 MW, OR 38%, IN 2015 AND 1100 MW, OR 50%, IN 2020 WOULD BE REQUIRED IN RHODE ISLAND TO RESOLVE THE THERMAL VIOLATIONS. IS SUCH A DEMAND REDUCTION FEASIBLE OR PRACTICAL?

A. A demand reduction, through demand side management resources and some forms of dispersed generation, in Rhode Island is neither practical nor feasible. I have seen levels approaching 20% accomplished effectively. I have never seen or heard of levels approaching 50%. Furthermore, I cannot foresee the current technology and land availability in Rhode Island accommodating 1100 MW of non-transmission demand side management options. In addition, passive demand reduction is rarely achievable above 15%, and it does not have sufficient predictability to be relied upon for reliability and thermal load relief.

Q. WOULD THE GENERATION OPTIONS IN CONNECTICUT AND MASSACHUSETTS DISCUSSED IN THE ICF ANALYSIS AND TESTIMONY OFFER A SOLUTION BEYOND RHODE ISLAND?

A. There are multiple problems associated with non-transmission alternatives, particularly at the level of active generation which would be required. First and foremost, there is simply not sufficient time to install the needed level of active distributed generation required to meet the load relief timeline. Second, the availability of land and the emissions issues present an additional hurdle which makes this solution not practical. Last, the cost is greater than Option A-1 and does not eliminate the need for transmission solutions. On page 16 of Mr. Rose’s testimony, the essence of the overall challenges associated with a non-transmission alternative is clearly listed. I not only concur with this list of seven (7) challenges, I would add land risks, emission risks, reliability and outage risks of distributed generation, and loss of economic generation dispatch.

Q. COULD YOU BRIEFLY OUTLINE THE AREAS OF WHICH YOU DO NOT CONCUR?

A. Yes. There are two areas in which I believe his testimony does not reasonably reflect today's technologies, capabilities, and price competitiveness.

1. Mr. Rose's testimony indicates Non-Transmission Alternatives, including Demand Side Management (DSM), distributed generation capabilities, and Combined Heat and Power Resources (CHP), cannot be real time dispatched efficiently or effectively, they cannot be relied upon to a significant degree of reliability, and distributed generation can take a very long time to be brought online (up to 30 minutes). This has not been my experience with actual projects and equipment. The technology exists that allows distributed generation and CHP and DSM to be as reliable if not more reliable than nearly any other form of utility generation that can be brought online in a timely fashion. Combustive turbines and other gas fired generation can be block started and on line in a few minutes.
2. On page 2 of Mr. Rose's testimony, he states the Aggressive Demand Response Case has a cost of $15.1 billion. Based on my experience, the cost would be between $4 and $5 billion. This is still significantly above the transmission solution cost.

Q. ARE YOU RECOMMENDING NON-TRANSMISSION ALTERNATIVES FOR THE IRP AS PROPOSED?

A. No. At a minimum, I see the installation of the required level of integrated generation in Rhode Island presenting the following problems:

1. Availability of land and generation siting issues and environmental impact on virgin lands.
2. Availability of adequate fuel supply, natural gas being the most likely choice.
3. Adequate availability of gas pipeline capacity.
4. Construction of high pressure natural gas lines and the routing and environmental impact.
5. Construction of the substation and switching station and transmission interface facilities and the environmental impact on virgin lands.
6. The duration associated with the generation addition process could be well beyond the time frame when transmission system stability and criteria violations are severe and in excess of the 800 MW up to 1100 MW loss of load scenario.
7. The project construction cost would easily approach $1.6 billion in Rhode Island alone.
8. The 800 MW to 1100 MW of generation only defers the transmission need and does not eliminate the need for the same transmission project in the future.

The proposed IRP will conservatively provide 3 times the immediate needed capacity relief. I support the IRP Option A-1 Project as a better long term solution, a more readily achievable solution in the near term and a lower cost solution with less environmental impact.

<u>DAVID M. CAMPILII</u>

Q. HAVE YOU REVIEWED THE PRE-FILED TESTIMONY AND EXHIBITS OF MR. DAVID M. CAMPILII, PE AND WOULD YOU PROVIDE US WITH YOUR COMMENTS?

A. Yes. I have reviewed the pre-filed testimony of Mr. Campilii, including his exhibits in regard to the two alternative underground projects outlined in the filing and in the ER. In general, I am in agreement with most of the testimony as presented by Mr. Campilii. Most specifically, I agree that operation and maintenance presents a much higher ongoing cost than overhead transmission. I concur with his list of five (5) issues. Mr. Campilii's discussion of O&M issues, although accurate, does not fully depict the challenges associated with 345 kV and the explosion controls and other protection issues.

The Department of Transportation will be very concerned with underground facilities along highway rights-of-way as they were in Docket No. 4029. It is important to point out that the Department of Transportation typically views the installation of an underground transmission system along its highway right-of-way as having an adverse impact. If undergrounding were to be pursued it may be necessary to review, in light of D.O.T.'s view on underground transmission, whether the roadway network alternative is in fact the preferred or viable underground alternative.

Q. YOU HAVE PREVIOUSLY PROVIDED TESTIMONY CONCERNING YOUR COMMENTS ON THE COST ESTIMATE ASSOCIATED WITH THE UNDERGROUNDING ALTERNATIVES. SINCE MR. CAMPILII IS THE CONSULTING ENGINEER WHO IS RESPONSIBLE FOR THE DEVELOPMENT OF THIS COST ESTIMATE AND DISCUSSES THE UNDERGROUND TRANSMISSION ALTERNATIVES IN HIS TESTIMONY, DO YOU HAVE ANY COMMENTS CONCERNING HIS COST ESTIMATE AND TESTIMONY?

A. Yes. Mr. Campilii, on page 7 of his testimony, states the underground alternative to Line 366 and Line 341 in Rhode Island is $1.26 billion, compared to $214 million for the overhead transmission line. Although not specifically stated, I assume this is a study grade estimate with a +/- 25% accuracy. At 345 kV there are many special design and fault explosion considerations that must be factored into the cost. Mr. Campilii's cost estimate reflects the conceptual design, and it does not reflect the substantial amount of volatility in many areas that can result in a much more costly underground project than +25%. I did not find in Mr. Campilii's testimony or work product any evaluation or reflection of a variety of components that can result in substantial cost volatility, resulting in a project that could cost not 25% more than a conceptual estimate, but rather upwards of 50% to 100% more. I believe the upper limit on the underground construction cost could easily be $1.8 billion based on the following volatile factors that do not appear to be reflected in Mr. Campilii's testimony, nor would they be factored into a general plus or minus 25% accuracy estimate. The components of volatility which I believe are not fully reflected in an upper limit for the cost are:

1. The need to install the transmission duct bank system upwards of three to four feet deeper as a result of conflicts with other utilities including water, sewer, electric and gas.
2. Increased costs associated with project delays, redesigns, mobilization, and demobilization due to encountering unknown or unexpected underground obstructions, including more rock at greater installation depths.
3. The significant cost impact associated with the removal of large quantities of rock during the construction process, which significantly impacts the trenching and duct bank installation cost. Mr. Campilii has substantial rock removal cost based on his more shallow depth. I believe this could be understated due to the need for greater installation depth.

4. The volatile petroleum market, which has seen swings in raw petroleum product cost of upwards of 300% will significantly impact the cost of solid dielectric cable. See *Exhibit GLB-2* for a recent Producer Price Indices ("PPI") analysis.
5. Significant cost overruns as a result of delays associated with encountering unexpected and adverse components in the underground construction, which can compound material cost due to substantial escalating cost in raw materials because of time delays, which result in swings much greater than the 25% plus or minus contingency level discussed with study grade estimates.

Overhead line construction is substantially less volatile and the plus or minus 25% levels imposed on study grade estimates is well within acceptable industry standard. In recent years with significant volatility in raw material cost including steel, concrete and most particularly petroleum, underground projects, most particularly underground transmission projects, can and will see significantly greater volatility than a plus 25% contingency level will provide. In order for there to be a reasonable evaluation of the economic considerations of the proposed project versus alternative overhead projects and alternative underground projects, the range of the cost of the projects needs to be reasonably reflected. The upper limit of the cost associated with the overhead alternatives for Line 366 and Line 341 is $214 million plus 25% or $268 million. The underground alternatives for Line 366 and Line 341 are estimated at $1.26 billion, but could have a potential upper limit closer to $2.25 billion. This would mean that we are looking at a close to $1 billion difference between the proposed project and the underground alternative.

Q. EVEN THOUGH YOUR UNDERGROUND ALTERNATIVE COST ESTIMATE IS MUCH HIGHER THAN MR. CAMPILII'S, DO YOU AGREE WITH HIS CONCLUSIONS?

A. Yes. The underground transmission alternative is much more expensive, adds significant operation and maintenance challenges and cost, and results in adverse environmental impact, particularly during construction not encountered with the overhead Option A-1.

ISO NEW ENGLAND ("ISO") TESTIMONY

Q. HAVE YOU REVIEWED THE DECEMBER 19, 2012 FILING BY THE ISO, INCLUDING THE JOINT DIRECT TESTIMONY OF STEPHEN ROURKE AND BRENT OBERLIN?

A. Yes. I have reviewed their testimony and Attachments.

Q. WOULD YOU BRIEFLY OUTLINE THE AREAS IN WHICH YOU HAVE COMMENTS?

A. Yes. First, the ISO has described its Mission and Responsibilities, which are consistent with the "Independent System Operator" concept across the United States, including all eight (8) Regional Reliability Organization (or Regional Entities). Second, I will comment on the project benefits as outlined by the ISO. Lastly, I will comment on the 10 year planning horizon.

Q. HOW DOES THE ISO MISSION AND RESPONSIBILITY IMPACT NATIONAL GRID AND THIS TRANSMISSION PROJECT?

A. The ISO has the same significant level of responsibility across the region to the Regional Entity (NPCC) and North American Electric Reliability Corporation ("NERC") as any transmission owner/operator or "Independent System Operator" in other Regions. The regulations and standards have very little flexibility associated with "No-Build" Options. Additionally, they impose significant responsibility on the ISO with NERC having enforcement capability, including the ability to impose very significant fines. As such, the ISO Attachments A and B are among the guideline documents and procedures it has developed which allow compliance with the much broader NPCC and NERC requirements. National Grid, although responsible for the transmission planning and construction implementation, has much less flexibility than the citizens and customers may perceive. Since the formation of NERC in 1968, driven predominately by the November 1965 blackout and the certifications of NERC as the Electric Reliability Organization ("ERO") in July 2006 precipitated in part by the worst North American blackout in history on August 14, 2003, the Bulk Power System standards and transmission reliability standards, regulations, and requirements have continually become more sophisticated imposing greater levels of evaluation and system integrity enhancement. Therefore, the ISO characterization of its requirement to maintain a level of system reliability that meets the criteria established by NERC and NPCC planning standards is a non delegable duty and carries with it, in my opinion, a higher responsibility level than even outlined in the ISO testimony. Although National Grid is a major stakeholder and participant in the transmission reliability process, as part of the Planning Advisory Committee ("PAC"), National Grid could not unilaterally refuse to resolve reliability deficiencies without unacceptable consequences.

The ISO planning process, procedures, and standards are consistent with industry practices and are followed throughout the North American Electric Industry. The Standards, processes, and procedures utilized by the ISO to identify the reliability deficiencies and plan the solutions is comprehensive, and results in a solution necessary to comply with NERC and NPCC requirements along with the expectations of the electric consumer for reliable electric power delivery. The ISO has outlined how the process is ongoing and continually updated to reflect changes. The filing by National Grid in November 2012 does reflect the latest September 2012 Solution Study from the ISO. The ISO studies, including the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report" dated February 2012 made it clear that, without the transmission improvements, the system may fail to provide reliable service in New England under the year 2022 projected system conditions of the September 2012 Needs Assessment. Although the proposed project provides relief for Connecticut, Massachusetts, and Rhode Island, Rhode Island should have a significant interest in its completion. Without this transmission system upgrade, Rhode Island is vulnerable to protective equipment operations, voltage collapse, thermal overload, and associated customer equipment damage and significant loss of load.

Q. DO YOU AGREE WITH THE ISO CHARACTERIZATION OF THE BENEFITS?

A. Yes. The two new 345 kV lines into West Farnum create a significant reliability improvement for all of Rhode Island and parts of Massachusetts. Additionally, Connecticut and western New England will benefit. The ISO analysis makes it clear a weak link in New England transmission can jeopardize each state as a result of thermal overload or voltage collapse, including Rhode Island.

Q. WHAT COMMENTS DO YOU HAVE CONCERNING THE ISO 10 YEAR PLANNING HORIZON?

A. The ISO is continually updating its analysis with the moving 10 year planning horizon and associated loads. The load growth has clearly been anemic, since the economic downturn. There is no evidence that load growth will return to pre-downturn levels during the 10 year planning horizon. The ISO has determined, with this knowledge, that the Interstate Reliability Project is still essential to mitigate potential voltage collapse, thermal overloads, and even a worst case blackout scenario. My only concern is not the need for the IRP, but the utilization of only a 10 year planning horizon. The lack of a longer planning horizon and associated load levels allows any project to be subject to early obsolescence. The ISO and National Grid should address, in its support for the proposed IRP, how long the currently proposed IRP is expected to provide a solution. This should include, specifically, defining both the load levels and anticipated year the proposed solution will last. The customers deserve to know the period of time any significant transmission upgrade solution will provide the needed reliability solution. That information is most appropriately communicated by the ISO.

VII. CONCLUSION

Q. IN YOUR EVALUATION OF THE NATIONAL GRID FILING AND ENVIRONMENTAL REPORT, DID YOU ARRIVE AT AN OPINION ABOUT THE NEED FOR THIS PROJECT? WHAT WAS THE BASIS FOR YOUR ASSESSMENT AND OPINION?

A. Yes. I concur there is a critical need to solve the transmission system capacity limitations in the near term. The solution needs to remedy voltage violations, potential voltage collapse, and thermal overloads that arise from the contingency scenarios evaluated by National Grid and the ISO. I have evaluated the entire filing by National Grid, including all of the appendices, testimony, exhibits attached to testimony, and additional documents produced. Additionally, a portion of the basis for my opinion of the need for this Project includes the years I have been involved with the Rhode Island Division of Public Utilities and Carriers and the reliability assessment process associated with evaluating the National Grid system in Rhode Island, including my NEEWS project evaluation in Docket No. 4029. It is clear that Rhode Island expects a high level of reliability from the electric utility system. It would be incongruent for the Division, and me as a consultant to the Division, to expect distribution system improvements and the achievement of a high level of distribution system reliability, while not expecting a comparable and superior level of reliability associated with the transmission delivery system. Therefore, part and parcel to my opinion is the overall reliability expectation that I have seen exhibited through my work with the Division. Additionally, I believe the testimony and analysis not only of National Grid and its consultants, but also the ISO New England and materials presented, upon which my opinion is based, have been presented fairly and accurately, recognizing the ongoing study revisions.

Q. IS IT YOUR TESTIMONY THAT THE COST ESTIMATE FOR THE PROPOSED PROJECT IS REASONABLE?

A. Yes. Although my evaluation found the National Grid overhead cost estimate to be higher than one I would prepare, it is certainly within a reasonable study grade level. The $542 million for the proposed project is a reasonable estimate, of which $180.9 million is the cost estimate for the portion to be constructed in Rhode Island. I will point out that Section 5.3.7.2 of the ISO study indicates the cost estimates are minus 25% and plus 50%, whereas the National Grid Volume 1 of the ER Table 4-3 indicates the cost estimates of the Rhode Island project components are +/-25%.

Q. DO YOU BELIEVE THE PROPOSED PROJECT REPRESENTS THE MOST COST EFFECTIVE METHOD TO MEET THE NEED AS IT HAS BEEN PRESENTED?

A. Yes. The proposed Project utilizes existing rights-of-way and provides the preferred reliability solution and the greatest capacity. I would not recommend a No Build option and the alternative options presented, including the Non-Transmission and Underground Transmission options, do not represent the best solution for Rhode Island or the New England East-West Solution. I have evaluated the proposed Project based both on Rhode Island need alone, as well as a portion of a greater New England East-West Solution (NEEWS). The proposed Project meets a very specific reliability and load serving need in Rhode Island. An additional benefit is its interrelationship with the NEEWS as proposed by the ISO New England. Furthermore, although there is little discussion of a potential larger benefit to customers by allowing more transmission capacity and flexibility to move more economical generation into the area, this is an inherent benefit of eliminating potential transmission constraints and developing a stronger networked system. The Project increases the ability of customers to purchase power from suppliers outside of the area and move that power into the area without congestion. Considering the numerous cases of congestion I have seen over recent years that have presented significant cost to customers, this is an additional benefit to Rhode Island customers that I find very important, particularly when this benefit comes with needed reliability enhancement at no additional cost beyond relieving a loss of load risk.

Q. IS A NO BUILD OPTION ACCEPTABLE?

A. A No Build option, in my opinion, is unacceptable.

Q. WHY DO YOU BELIEVE A NO BUILD OPTION IS UNACCEPTABLE?

A. My review of the National Grid contingency analysis indicates the level of transmission system reliability would be unacceptable low without a solution to the loss of load risk which exists. The risk of a major interruption of power to a broad segment of Rhode Island electric customers is real and should not be allowed to persist. Not implementing a solution to the present and continually increasing risk of a significant portion of Rhode Island elective load being interrupted for a potentially extended duration would, in my opinion, subject the electric customers to an unacceptably low level of service reliability and likely adverse economic harm. The project proposed in this Docket is fully integrated with the transmission approved in Docket No. 4029 and the entire New England East West Solution.

Q. SINCE YOU HAVE RULED OUT A NO BUILD OPTION AND THE NON-TRANSMISSION ALTERNATIVES THROUGH YOUR EVALUATION, DOES THE PROPOSED PROJECT CAUSE UNACCEPTABLE HARM?

A. Because the proposed Project will be constructed on lands already being utilized for transmission facilities, the minimal short term harm to the environment during the construction phase would be acceptable. The proposed mitigation of land impact outlined in the ER further reduces any short term environmental consequences. The long term impact on such items as water quality, wetlands, noise, visual and other factors will be negligible and only marginally measurable based on the amount of maintenance activity. Considering the improvements to existing lines and right-of-way as part of the Project, it is highly likely the maintenance activity and its associated disturbance to the lands will be less for the next 40 years than would be expected without the Project improvements. Therefore, I conclude the Project does not cause any unacceptable harm.

Q. YOUR TESTIMONY INDICATES THAT YOU NOT ONLY REVIEWED THE PROPOSED IRP, BUT ALSO ALL OF THE ALTERNATIVES TO THE PROPOSED PROJECT INCLUDING THE UNDERGROUND ALTERNATIVE, THE NO BUILD ALTERNATIVE, AND THE NON-TRANSMISSION ALTERNATIVE, IS THAT CORRECT?

A. Yes.

Q. HAVE YOU PRIORITIZED THE RHODE ISLAND RELIABILITY PROJECT SOLUTIONS AND DOES YOUR PRIORITIZATION RESULT IN THE SAME PROPOSED PROJECT AS NATIONAL GRID HAS PRESENTED, OR HAVE YOU SELECTED ONE OF THE OTHER ALTERNATIVES, OR HAVE YOU IDENTIFIED ADDITIONAL ALTERNATIVES THAT SHOULD BE CONSIDERED BEYOND THOSE OUTLINED IN THE FILINGS OF NATIONAL GRID?

A. I have carefully considered all of the projects as proposed by National Grid and I have evaluated their cost estimates, the cost effectiveness of those projects, and the no build option together with the non-transmission alternative options. I have evaluated each solution based on its reasonableness, effect on the surrounding environment, and its ability to meet the needs cost effectively in a timely manner. Although, as I have testified, I do not fully concur with all of the National Grid assumptions, I do, at the end of my entire assessment, reach the conclusion that the proposed Project is needed. It represents the best and most cost effective solution for achieving the needed system improvements to sustain a reliable transmission system with the capability of transporting competitively priced power into the region, while also providing an integrated transmission solution for the New England East-West Solution.

Q. DO YOUR ANALYSES AND CONCLUSIONS MEAN NONE OF THE ALTERNATIVE PROJECTS REPRESENT A SOLUTION?

A. No, many of the alternative projects in fact are a solution. However, they do not represent the best solution. Some appear to potentially have an even more adverse impact on the environment, particularly during the construction phase. Many of the alternatives would result in much more harm to the environment than the proposed Project. Furthermore, the underground alternative is not just exceedingly expensive, it will very likely result in greater damage to the environment during construction than any overhead solution.

Q. THROUGH YOUR EVALUATION HAVE YOU REACHED AN OPINION SATISFACTORY TO YOU AND TO A REASONABLE DEGREE OF ENGINEERING CERTAINTY THAT THE PROPOSED PROJECT IS NEEDED?

A. Yes. I am of the opinion that the need for the proposed Project is clearly demonstrated in filings by National Grid and the ISO. I believe the studies, including the scenario analyses, have been prepared on a reasonable basis utilizing reasonable and acceptable assumptions within the utility industry, including the standards as outlined by the ISO

New England and as expected by NERC and NPCC. I believe that the study's contingency analyses, overall ER, and its appendices demonstrate that, if a solution is not approved, eventually a situation will occur under one of the contingency scenarios that will result in a significant loss of load. I do not believe that it is in the best interest of the electric customers to accept a contingency analysis scenario resulting in the likely loss of load approaching 800 megawatts and potentially even greater in future years. This, in my professional opinion, would be an unacceptable risk to impose on the State of Rhode Island and potentially a broader New England area. Therefore, a solution is necessary. My evaluation concludes that the proposed Project, including the new 345 kV lines, the reconductor/rebuild of the existing 345 kV line, switching station upgrade, and methodology of design, construction and routing represents the best solution for Rhode Island.

Q. CAN YOU SUMMARIZE YOUR TESTIMONY IN ONE SENTENCE?

A. Yes. It is unacceptable to allow a realistic transmission outage risk to jeopardize electric service to 90,000 or more customers when the proposed Project is the lowest cost solution with the least harm that can be implemented in a timely manner.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Exhibit GLB-1

Gregory L. Booth, PE
Resume

GREGORY L. BOOTH, PE, PLS
President
PowerServices, Inc.
Gregory L. Booth, PLLC

RESUME

Gregory L. Booth is a registered professional engineer with engineering, financial, and management services experience in the areas of utilities, industry private businesses and forensic investigation. He has been representing over 300 clients in some 40 states for more than 40 years.

Mr. Booth has been accepted as an expert before state and federal regulatory agencies, including the Federal Energy Regulatory Commission, the Delaware Public Service Commission, the Florida Public Service Commission, the Minnesota Department of Public Service Environmental Quality Board, the Massachusetts Attorney General Department of the Advocacy, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, and the Virginia State Corporation Commission. He has been accepted as an expert in both state and federal courts, including Colorado, Delaware, Florida, District of Columbia, New York, North Carolina, Pennsylvania, South Carolina, Virginia, West Virginia, Wisconsin and numerous Federal Court jurisdictions. Investigation and testimony experience includes areas of wholesale and retail rates, utility acquisition, territorial disputes, electric service reliability, right-of-way acquisition and impact of electromagnetic fields and evaluation of transmission line options for utility commissions. Additionally, Mr. Booth has extensive experience serving as an expert witness before state and federal courts on matters including property damage, forensic evaluation, fire investigations, fatality, and areas of electric facility disputes and Occupational, Safety and Health Administration violations and investigations together with National Electric Code and National Electrical Safety Code and Industry Standard compliance.

The following pages provided are the education and experience from 1963 through the present, along with courses taught and publications.

January 16, 2013

Resume

GREGORY L. BOOTH, PE, PLS

Mr. Booth is a Registered Professional Engineer with engineering, financial, and management experience assisting local, state, and federal governmental units; rural electric and telephone cooperatives; investor owned utilities, industrial customers and privately owned businesses. He has extensive experience representing clients as an expert witness in regulatory proceedings, private negotiations, and litigation.

PROFESSIONAL EDUCATION:	NORTH CAROLINA STATE UNIVERSITY; Raleigh NC, Bachelor of Science, Electrical Engineering, 1969
REGISTRATIONS:	Registered as Professional Engineer in Alabama, Arizona, Colorado, Connecticut, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas, Commonwealth of Virginia, West Virginia, and Wisconsin Professional Land Surveyor in North Carolina Council Record with National Council of Examiners for Engineering and Surveying

EXPERIENCE:

1963-1967 Technician Booth & Associates	Transmission surveying and design assistance, substation design assistance; distribution staking; construction work plan, long-range plan, and sectionalizing study preparation assistance for many utilities, including Cape Hatteras EMC, Halifax EMC, Delaware Electric Cooperative, Prince George Electric Cooperative, A&N Electric Cooperative; assistance generation plant design, start-up, and evaluations.
1967-1973 Project Engineer Booth & Associates	Transmission line and substation design; distribution line design; long-range and construction work plans; rate studies in testimony before State and Federal commissions; power supply negotiations; all other facets of electrical engineering for utility systems and over 30 utilities in 10 states.
1973-1975 Professional Engineer Booth & Associates 1975-1994 Executive Vice President Booth & Associates	Directed five departments of Booth & Associates, Inc.; provided engineering services to electric cooperatives and other public power utilities in 23 states; provided expert testimony before state regulatory commissions on rates and reliability issues; in accident investigations and tort proceedings; transmission line routing and designs; generation plant designs; preparation and presentation of long-range and construction work plans; relay and sectionalizing studies; relay design and field start-up assistance; generation plant designs; rate and cost-of-service studies; reliability studies and analyses; filed testimony, preparation and teaching of seminars; preparation of nationally published manuals; numerous special projects for statewide organizations, including North Carolina

EMC. Work was provided to over 130 utility clients in 23 states, PWC of the City of Fayetteville, NC, Cities of Wilson, Rocky Mount and Greenville are among the utilities in which I have provided engineering services in North Carolina during this time frame. Services to industrial customers include Texfi Industries, Bridgestone Firestone, Inc and many others.

1994-2004
President
Booth & Associates

Responsible for the direction of the engineering and operations of Booth & Associates, Inc. for all divisions and departments. The engineering work during this time frame has continued to be the same as during 1974 through 1993 with the addition of greater emphasis on power supply issues, including negotiating power supply contracts for clients; increased involvement in peaking generation projects; development of joint transmission projects, including wheeling agreements, power supply analyses, and power audit analyses. The work during this time frame includes providing services to over 200 utility clients across the United States, including NCEMC and NRECA.

2004-Present
President
Gregory L. Booth, PLLC

Providing engineering and management services to the electric industry, including planning and design. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serving as an expert witness in state and federal regulatory matters and state and federal court.

2005-Present
President
PowerServices, Inc.

Providing engineering and management services to the electric industry, including planning and design and utility acquisition. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serving as an expert witness in state and federal regulatory matters and state and federal court.

WORK AND EXPERTISE:

ELECTRIC UTILITIES:
(more than 300 clients)

- Utility acquisition expert, including providing condition assessment, system electrical and financial valuation, electrical engineering assessment, initial Work Plan and integration plans, acquisition loan funds, testimony, assessment and consulting services for numerous electric utility acquisitions. Utility clients for acquisition projects include Winter Park, FL acquisition of Progress Energy, FL, system in the City limits, A & N Electric Cooperative acquisition of the Delmarva Power & Light Virginia jurisdiction, Shenandoah Valley Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, Rappahannock Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, and numerous other past and currently active electric utility acquisitions.

- System studies, including long-range and short-range planning, sectionalizing studies, transmission load flow studies, system stability studies (including effects of imbalance and neutral-to-earth voltage), environmental analyses and impact studies and statements, construction work plan, power requirements studies, and feasibility studies.
- Fossil and hydro generation plan analysis, design, and construction observation.
- Transmission line design and construction observation through 230 kV overhead and underground.
- Switching station and substation design and construction observation through 230 kV.
- Distribution line design and staking, overhead and underground.
- Design of submarine cable installations.
- Supervisory control and data acquisition system design, installation and operation assistance.
- Load management system design, installation and operation assistance.
- Computer program development.
- Load research and alternative energy source evaluation.
- Field inspection, wiring, and testing of facilities.
- Relay and energy control center design.
- Mapping.
- Specialized grounding for abnormal lightning conditions.
- Ground potential rise protection.
- Protective system/relay coordination.

GENERATION DESIGN / FAILURE ANALYSES:

- Intermediate and peaking generation (gas and oil fired through 400 MW).
- Peaking generation (diesel and gas through 10,000 kW)
- Wind generation.
- Solar (PV) generation.
- Hydroelectric generation.

TELECOMMUNICATION: UTILITIES:

- Subscriber and trunk carrier facilities design.
- Stand-by generation and DC power supplies
- DC-AC inverters for interrupted processor supplies.
- Plant design and testing.
- Fiber optics and other transmission media.
- Microwave design.
- Pole attachment designs.
- Pole attachment agreements and rental rates calculations.

FINANCIAL SERVICES:

- Long-term growth analyses and venture analyses.
- Lease and cost/benefit analyses.
- Capital planning and management.
- Utility rate design and service regulations.
- Cost-of-Service studies.
- Franchise agreements.
- Corporate accounting assistance.
- Utility Commission testimony (State and Federal).

FORENSIC ENGINEERING:

- Compliance with NESC, NEC, OSHA, IEEE, ANSI, ASTM and other codes and industry standards.
- Equipment and product failure and analysis and electrical accident investigation (high and low voltage equipment).
- Stray voltage, electrical shocking, and electrocution investigations.
- Building code investigations.
- New product evaluation.
- MCC, MDP failure analysis and arc flash analysis
- Electrical fire analysis

INDUSTRIAL/ELECTRICAL ENGINEERING:

Building design (commercial and industrial).
Building code application and investigation.

- Electric thermal storage designs for heating, cooling, and hot water.
- Standby generation and peaking generation design.
- Electric service design (residential, commercial, and industrial).

INSTRUCTIONAL SEMINARS AND TEXT:

- Seminars taught on arc flash hazards and safety, including National Electrical Safety Code regulations for utilities.
- Courses taught on Distribution System Power Loss Evaluation and Management.
- Courses taught on Distribution System Protection.
- Text prepared on Distribution System Power Loss Management.
- Text prepared on Distribution System Protection.
- Seminars taught on substation design, NESC capacitor application, current limiting fuses, arresters, and many others electrical engineering subjects.
- Courses taught on accident investigations and safety.
- Courses taught on Asset Management.
- Courses taught on OSHA and Construction Safety.

TESTIMONY AS AN EXPERT:

- Concerning rate and other regulatory issues before Federal Energy Regulatory Commission and state commissions in Delaware, Florida, Maryland, Massachusetts, Minnesota, New Jersey, North Carolina, Pennsylvania, Rhode Island, and Virginia.
- Concerning property damage or personal injury before courts in Colorado, District of Columbia, Florida, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, South Carolina, Texas, Virginia, West Virginia, and Wisconsin.

FIELD ENGINEERING:

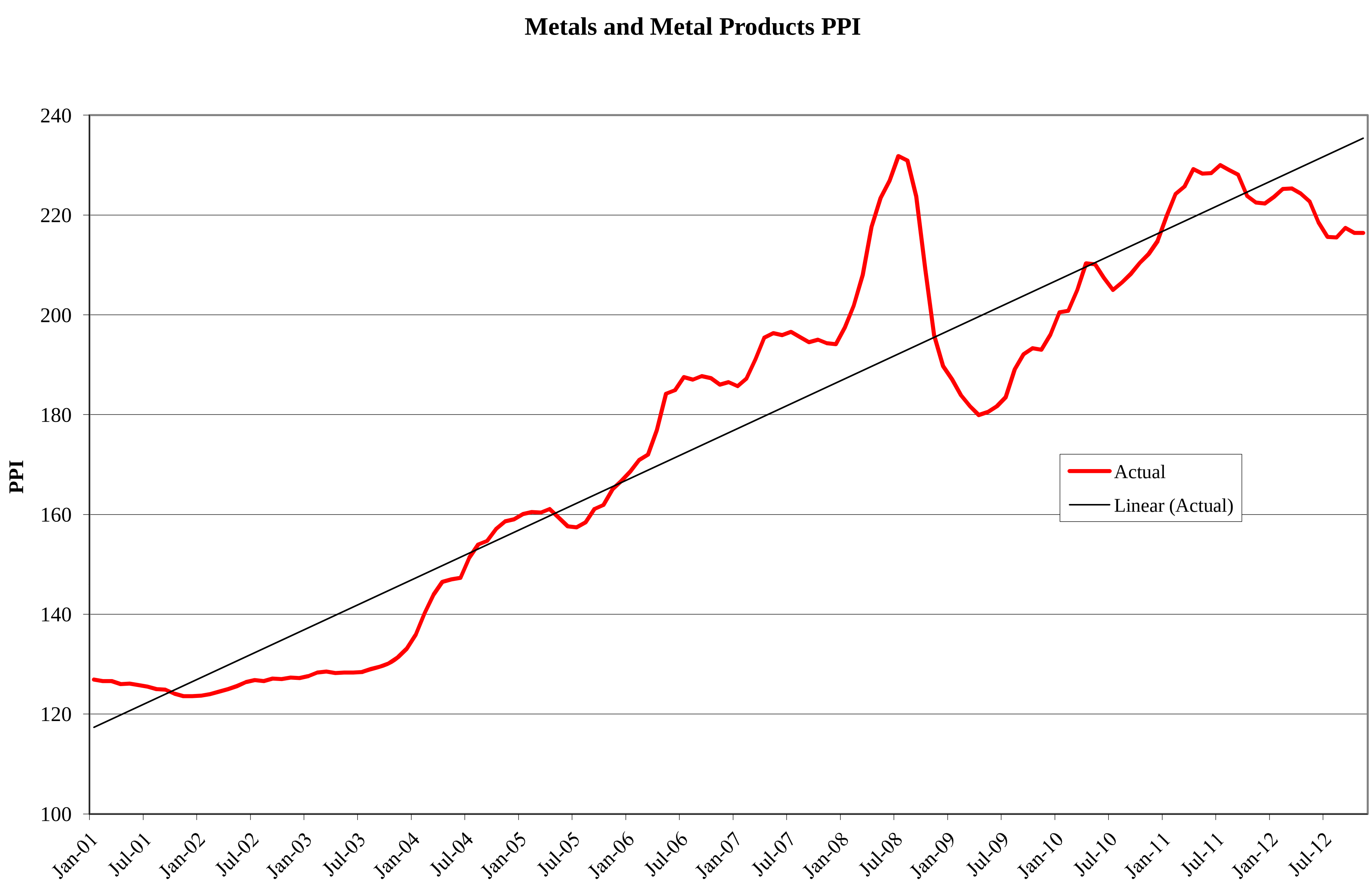
- Transmission line survey and plan and profile.
- Distribution line staking.
- Property surveying.
- Relay and recloser testing.
- Substation start-up testing.
- Generation acceptance and start-up testing.
- Ground resistivity testing.
- Work order inspections.
- Operation and maintenance surveys.
- Building inspection and service facility inspection.
- Construction Management
  - Generation
  - Transmission
  - Substation
  - Distribution
  - Building Electrical Installations
  - GSA construction projects
  - NASA construction projects
  - University construction projects

PROFESSIONAL ORGANIZATIONS:

a. National Society of Professional Engineers (NSPE)
b. Professional Engineers in Private Practice (PEPP)
c. National Council of Examiners for Engineering & Surveying (NCEES)
d. Professional Engineers of North Carolina (PENC)
e. National Fire Protection Association (NFPA)
f. Associate Member of the NRECA
g. NRECA Cooperative Network Advisory Committee (NRECA-CRN)
h. The Institute of Electrical and Electronics Engineers (IEEE) (Distribution sub-committee members on reliability)
i. American Standards and Testing Materials Association (ASTM)
j. Occupational Safety and Health Administration (OSHA) Certification
k. American Public Power Association (APPA)
l. American National Standards Institute (ANSI)

Exhibit GLB-2

PPI for Metals and Metal Products Indices and Distillate Fuel Oil


Metals and Metal Products PPI
PPI
240
220
200
180
160
140
120
100
Jan-01
Jul-01
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Jul-02
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Jul-09
Jan-10
Jul-10
Jan-11
Jul-11
Jan-12
Jul-12
Actual
Linear (Actual)

Distillate Fuel Oil PPI