Jennifer Brooks Hutchinson
Senior Counsel

December 19, 2011

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4296 – The Narragansett Electric Company, d/b/a National Grid
2012 System Reliability Procurement Plan
<u>Responses to Commission Data Requests – Set 1</u>

Dear Ms. Massaro:

Enclosed are ten (10) copies of National Grid's[1] responses to the Commission's First Set of Data Requests issued in the above-captioned proceeding.

Thank you for your attention to this filing. If you have any questions, please feel free to contact me at (401) 784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

cc: Docket 4296 Service List
Jon Hagopian, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid.

Commission 1-1

Request:

How will the Company determine exactly which customers will participate in the Load Curtailment Program?

Response:

The Company will be targeting those customers with central air conditioning systems in their homes and businesses by using a multi-channel, educational outreach effort (e.g. direct mail, e-mail, print advertising, telemarketing, and social media) to customers for the Load Curtailment Program. Residential, small business, and commercial and industrial customers who respond will be directed to a National Grid website to sign up and answer a questionnaire. All customers will be asked to answer questions about internet connectivity, and residential customers, specifically, will be asked about home appliances such as central air conditioning, window air conditioning, pool pumps, and hot water heaters. A requirement for participation in the Program will be wi-fi internet connectivity so that load curtailment devices (e.g. thermostats and direct load control switches) can receive the load curtailment signal. Once the basic requirements to participate in the program are met, customers who meet the basic requirements and elect to participate will be enrolled. Enrollment per year will be based on a first-come, first-served basis.

Prepared by or under the supervision of: Timothy Roughan and Christina Skursky

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Commission 1-2

Request:

Please explain the following acronyms:

a. NECO PSA (p.5 of the Plan)
b. DLC (p.1, Appendix 10)
c. STAT (p.1, Appendix 10)
d. SBS (Project Management Schedule, Appendix 11)

Response:

a. NECO PSA mentioned on page 5 of the Plan stands for Narragansett Electric Company (NECO) Power Supply Area (PSA). The Company's load forecast is the sum of four Power Supply Area (PSA) forecasts that make up its service area. The four PSAs are Blackstone, Providence, Newport and Western NECO. The Western NECO PSA serves 22 cities and towns in central, western and southern Rhode Island, including Tiverton and Little Compton.

b. DLC mentioned on page 1, Appendix 10 stands for Direct Load Control (DLC) devices (i.e. heavy duty switches for central air conditioning, pool pumps, and other large point loads).

c. STAT mentioned on page 1, Appendix 10 stands for Sales, Technical Assistance and Training (STAT) for the third party web-based system needed to manage the DLC that will be installed.

d. SBS mentioned in the Project Management Schedule included in Appendix 11 stands for the Small Business Services (SBS)/Direct Install Program within the Company's energy efficiency plan.

Prepared by or under the supervision of: Christina Skursky

Commission 1-3

Request:

Regarding p. 14 of the Plan, please describe what specific pricing mechanisms the Company would consider to encourage load reduction, if rebate strategies are not effective.

Response:

The Company would consider a number of different types of pricing initiatives. The potential options could be: (1) a demand based tariff that encourages customers to minimize their maximum demand; (2) a Time-of-Use rate that encourages reduction of use during peak periods, possibly with a demand charge applicable to peak period usage only; (3) Critical Peak Pricing that applies Time-of-Use pricing principles to the 200 or so hours per year with the highest loads; or (4) Peak Time Rebates which provide the capacity benefits to customers in the form of a credit when customers lessen demand in the same 200 peak hours per year. Application of these rates would require an hourly meter or demand meter at a participating customer's facility, the associated billing and notification systems to operate the tariff and associated recovery of these costs.

For customers on Rate G-30 or Rate G-60, the Company would consider the above tariffs plus the potential for an hourly pricing tariff, i.e. "real-time" pricing which sends to customers energy prices the day ahead based upon conditions forecast for the New England energy market. In addition, a price for capacity would be added to the hours in the year, 200 or less, which are forecast to have peak loads for New England.

Prepared by or under the supervision of: Peter T. Zschokke

Commission 1-4

Request:

Please enlarge the Project Management Schedule to a readable level including legends such as meaning of numbers and colored areas.

Response:

Please see Attachment COMM 1-4 for an enlarged version of the Project Management Schedule broken down yearly from 2012 to 2014. This schedule has been updated to reflect activities starting from January 2012.

A legend can be found on the bottom left corner of the schedule; project milestones (defined as an activity that needs to be done on/by a certain date) are represented by black diamonds and the duration of tasks are illustrated by the length of the blue bars. The only varying task color on the schedule is green and represents the implemented, active NWA beginning in January 2014.

Prepared by or under the supervision of: Christina Skursky

Commission 1-5

Request:

Please fully explain the two tables shown on p.16.

Response:

The first table on p.16 shows the value of deferring the proposed $2,690,000 feeder upgrade at the Company's Tiverton substation starting in 2014. The Company calculated a thirty-three (33) year revenue requirement on this project assuming an in-service year of 2014. The Company calculated the same revenue requirement for the project assuming the plant was placed in service in 2015, 2016 and 2017. The cost of the project was inflated by 2% each year. The value of the stream of revenue requirements over the life of the unit was present valued using the Company's rate of return and the net present value is shown in Table 1. The $133,733 under the '1 Yr Delay' column represents the delta of the NPV of the revenue requirement by delaying the in-service date from 2014 to 2015 and similarly for 2016 vs. 2015 and 2017 vs. 2016.

The second table (Table S-2) on p.16 shows the cost effectiveness of 2012, the first year of this six-year pilot. The cost effectiveness was determined using the same Total Resource Cost test as is used in the 2012 Energy Efficiency Program Plan (EEPP).

The Total Incremental Costs represent the 2012 costs that are incremental to the Tiverton/Little Compton area as a result of this pilot. Those costs are divided into two parts: Incremental Program Implementation Costs and Incremental Evaluation Costs. The Total Incremental Benefits represent the 2012 benefits that are incremental to the Tiverton/Little Compton area as a result of this pilot. This value is inclusive of the net present value of benefits over the entire lifetime of installed measures.

The Incremental Program Implementation Costs are comprised of Targeted Base Energy Efficiency costs and System Reliability Procurement Costs. The Targeted Base Energy Efficiency costs are those associated with focusing traditional energy efficiency (EE) efforts to the Tiverton/Little Compton area. The System Reliability Procurement costs are comprised of additional incentives on top of traditional EE incentives, additional marketing and additional administration costs associated with this project.

Since the 2012 System Reliability Plan Report was filed, the Company has made corrections to Tables S-2 and S-5 based on errors discovered in the $/kWh assumptions for base, EE costs in the 2012 EEPP and the incorporation or DRIPE benefits in the Total Benefits calculation. The corrected benefit/cost results as well as the corrected benefits are in the updated Table S-2 and S-5 respectively, below.

Commission 1-5, p2

Table S-2
Calculation of 2012 Cost-Effectiveness
Summary of Benefit, Expenses, Evaluation Costs ($000)

Incremental Program Implementation Costs	**$317.2**
Targeted Base Energy Efficiency Costs	$133.2
System Reliability Procurement Costs	$184.0
Incremental Evaluation Costs	**$25.0**
Total Incremental Costs	**$342.2**
Incremental Benefits	**$424.7**
Benefit/Cost Ratio	**1.24**

Commission 1-5, p3

Table S-5
2012 System Reliability Procurement
Summary of Benefits by Program

	Benefits ($)												
		Capacity					Energy					Non Electric	
		Generation					Winter		Summer				
Commercial & Industrial	**Total**	**Summer**	**Winter**	**Trans**	**MDC**	**DRIPE**	**Peak**	**Off Peak**	**Peak**	**Off Peak**	**DRIPE**	**Resource**	**Non Resource**
Small Business Direct Install	$12,000	$892	$0	$485	$2,040	$243	$3,320	$805	$1,986	$396	$718	-$217	$1,333
Non-Low Income Residential													
EnergyWise	$412,738	$21,417	$0	$10,010	$42,059	$4,297	$22,110	$28,844	$20,808	$15,905	$10,691	$206,664	$29,935
TOTAL	**$424,738**	**$22,309**	**$0**	**$10,495**	**$44,098**	**$4,540**	**$25,430**	**$29,649**	**$22,793**	**$16,300**	**$11,409**	**$206,447**	**$31,267**

Prepared by or under the supervision of: Timothy Roughan and Lindsay Perry

Commission 1-6

Request:

If the evaluation conducted by ODC does not address the Plan's effectiveness as a T & D deferral strategy, as stated in Appendix 6, then what specific evaluation/criteria did the Company use in developing its projections about the impact of the 2012 SRP on deferred investments?

Response:

Energy efficiency measures proposed for deployment in the SRP all have net demand reductions associated with them, as determined through engineering analysis and/or impact evaluations. Net demand reductions include a coincidence factor, representing the coincidence of the savings with system peak. For energy efficiency programs, the application of summer coincidence factor represents the average demand savings between the hours of 1 pm and 5 pm on weekdays in June through August. The local area peak in the SRP subject feeders occurs between the hours of 3:30 pm and 7:30 pm (see page 7, and appendix 7 of SRP). Therefore, while there is a small misalignment of the system average coincidence factors with the local peak period, they are a good approximation of the demand reduction impacts available from SRP deployment. (In some cases, for example residential lighting, the coincidence factor in SRP deployment will be greater than the system coincidence factor, because more lights are used in homes as people return from daytime activities.) The Company intends to study the impact of SRP deployment on deferred investments as part of this project.

Prepared by or under the supervision of: Jeremy Newberger

Commission 1-7

Request:

Is the Company asserting confidentiality of the internal planning document referenced on page 3 of the Plan? Why?

Response:

No.

Prepared by or under the supervision of: Timothy Roughan

Commission 1-8

Request:

Please revise and submit Table 3 (Appendix 6) to include appropriate numbers and/or kilowatt-hour savings.

Response:

The 'X's in Table 3 of Appendix 6 indicate which of the energy efficiency programs the Company used for the baseline and pilot time periods for both the Aquidneck Island area as well as the comparison area. There are no savings numbers associated with Table 3.

Prepared by or under the supervision of: Timothy Roughan

Commission 1-9

Request:

Referring to page 33 of Appendix 6, at what stage of completion is the Company's model for evaluating T&D impacts of energy efficiency and NWAs? Does the Company expect it to be completed for use in planning its 2013 SRP?

Response:

The model will be complete by January 2012, and the Company will, therefore, expect it to be used in planning for the 2013 SRP. Currently, the model is under final review and testing by a small group that has been hands-off during the creation process in order to garner unbiased feedback on improvements and final debugging of the tool.

Prepared by or under the supervision of: Timothy Roughan and Christina Skursky

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.

____________________________ 12/19/2011

Joanne M. Scanlon Date

Docket No. 4296 - National Grid's 2012 System Reliability Plan Report
Service List – Updated 12/19/11

Name/Address	E-mail Distribution List	Phone/FAX
Jennifer Brooks Hutchinson, Esq. National Grid 280 Melrose St. Providence, RI 02907	Jennifer.hutchinson@us.ngrid.com Thomas.teehan@us.ngrid.com Joanne.scanlon@us.ngrid.com Jeremy.newberger@us.ngrid.com	401-784-7288
R. Daniel Prentiss, P.C. (for EERMC) Prentiss Law Firm One Turks Head Place, Suite 380 Providence, RI 02903	dan@prentisslaw.com	401-824-5150
S. Paul Ryan (for EERMC)	spryan@eplaw.necoxmail.com	
Scudder Parker VEIC	sparker@veic.org	
Jon Hagopian, Esq. (Division/AG) Dept. of Attorney General 150 South Main St. Providence, RI 02903	Jhagopian@riag.ri.gov Dstearns@ripuc.state.ri.us Sscialabba@ripuc.state.ri.us Acontente@ripuc.state.ri.us mcorey@riag.ri.gov dmacrae@riag.ri.gov	401-222-2424
Jeremy McDiarmid, Esq. (ENE) Environment Northeast 101 Tremont St., Suite 401 Boston, MA 02108	jmcdiarmid@env-ne.org aanthony@env-ne.org	617-742-0054

Seth H. Handy, Esq. (ENE) HANDY LAW, LLC 42 Weybosset Street Providence, RI 02903	seth@handylawllc.com	401 626.4839
Tim Woolf Synapse Energy Economics 22 Pearl Street Cambridge, MA 02139	twoolf@synapse-energy.com	617-661-3248
Bob Fagan Synapse Energy Economics	rfagan@synapse-energy.com	
Tim Woof Synapse Energy Economics 22 Pearl Street Cambridge, MA 02139	twoolf@synapse-energy.com	
Jerry Elmer, Esq. Conservation Law Foundation 55 Dorrance Street Providence, RI 02903	JElmer@clf.org	401-351-1102
Original & 11 copies to be filed w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Lmassaro@puc.state.ri.us Adalessandro@puc.state.ri.us Anault@puc.state.ri.us Dshah@puc.state.ri.us Nucci@puc.state.ri.us	401-780-2107 401-941-1691