PRENTISS

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May 4, 2011

VIA: REGULAR MAIL & ELECTRONIC FILING

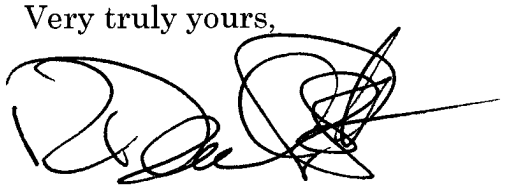
Luly E. Massaro, Commission Clerk
Rhode Island Public Utility Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: RIPUC Docket No. 4202

Dear Luly:

I enclose an original and 9 copies of a corrected response to Commission data request 3-1. This corrects a formatting error in the response previously submitted.

Very truly yours,



R. Daniel Prentiss
EERMC Counsel

RDP/ka
Enclosures
Cc: Service List
874/92/7619

CHAPTER 2 – System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investments

A. The Utility shall propose pilot distribution and, if appropriate, transmission projects in their first system reliability procurement plan for which they will examine alternative resource strategies as alternatives or enhancements to the distribution or transmission upgrade. These pilot projects should be used to inform or revise the system reliability procurement process in subsequent plans.

B. Non-Wires Alternatives (NWA) may include but are not limited to:

a. Least Cost Procurement energy efficiency baseline services.

b. Peak demand and geographically-focused supplemental energy efficiency strategies

c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[1]

d. Demand response

e. Direct load control

f. Energy storage

g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.

a. The need is not based on asset condition.

b. The wires solution, based on engineering judgment, will likely cost more than $1 million;

c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;

d. Start of wires alternative is at least 36 months in the future; and

A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:

e. Ability to meet the identified system needs;

f. Anticipated reliability of the alternatives;

g. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)

h. Potential for synergy savings based on alternatives that address multiple needs

i. Operational complexity and flexibility

j. Implementation issues

k. Customer impacts

l. Other relevant factors

[1] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where a NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:

a. Characterization of the need

i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.

ii. Identification and description of the T&D investment and how it would change as a result of the NWA

iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade

iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.

b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade

c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.

d. Development of NWA investment scenario(s)

i. Specific NWA characteristics

ii. Development of an implementation plan, including ownership and contracting considerations or options

iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives;

ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.

iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved;

iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

v. Identification of significant customer contribution or third party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties.

vi. Any other funding that might be required and available to complete the NWA.

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:

m. A summary of projects where NWA were considered;

n. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;

o. Implementation plan for the selected NWA projects;

p. Funding plan for the selected NWA projects;

q. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;

r. Status of any previously selected and approved projects and pilots;

s. Identification of any methodological or analytical tools to be developed in the year;

t. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

~~A.~~

~~B. Alternative Resource Technologies (ART) shall include but not be limited to:~~

~~C. Distributed generation generally~~

~~D. Combined heat and power~~

~~E. Renewables (predominantly wind and solar, but not constrained)~~

~~F. Demand response~~

~~G. Peak demand and geographically focused energy efficiency programs~~

~~H. In order to meet the statute's environmental goals, unless a compelling showing to contrary technologies selected or supported should:~~

~~I. achieve a CO_2 emissions rate equal to or better than the ISO New England marginal emissions rate on an output basis (thermal and electric) – current rate ~ 1,100 lbs/MWh; and~~

~~J. utilize best available control technology for NOx emissions~~

K. For each pilot the utility should identify an evaluation process that allows for input from the Council and other stakeholders and includes elements such as the following:

1. Identification and description of the T&D investment

2. Description of the need, requirements, and drivers such as demand growth (load curve and timing issues)

3. Description of the business as usual upgrade in terms of technology, costs (capital and O&M), and schedule for the upgrade

4. Identification of the level of peak demand savings required to avoid the need for the upgrade

5. Development of ART alternative investment scenario(s)

a. Specific ART characteristics

b. Development of an implementation plan, including ownership and contracting considerations or options

c. Development of a detailed cost estimate (capital and O&M) and implementation schedule

6. Reporting and recommendations

a. Compare the investment options from a cost perspective – cost assessed on a net present value basis to the state's ratepayers (common assumptions across scenarios)

b. Include a summary of environmental impacts and a discussion of any co-benefits such as benefits to local businesses or industry

c. Recommend preferred solutions

L. The utility pilot program(s) should be reviewed and approved by the PUC as part of the System Reliability Procurement Plan submitted on September 1.

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Section 2.2 Renewables

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A. The utility shall consider opportunities to integrate renewable energy resources with measurable benefits into the system reliability plan and in a coordinated fashion with the implementation of efficiency procurement. Activities may include but not be limited to:

1. Small to medium scale renewable energy projects that compliment the distribution and transmission pilot projects or provide other system benefits;

2. Small scale distributed renewable energy projects such as photovoltaics wind or solar thermal; and

3. Where appropriate, the Utility should coordinate its programs with the renewable energy fund.

B. The utility plan shall document current activities and commitments to increase renewable energy production and contracting and how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

C. Renewable projects may benefit from changes to existing standby rates and improved interconnection standards.

Section 2.3 Combined Heat and Power

A. The electric and natural gas efficiency programs should support and expand programs for CHP applications that are cost-effective, deliver net reductions in energy consumption, and provide environmental benefits.

B. The utility plan shall include discussion of CHP potential in the state based on the Opportunity Report and should set targets or goals for CHP penetration and if necessary propose new programs to support the development of CHP. The plan should describe how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

C. CHP programs or projects supported by the Utilities should be sited at facilities with adequate thermal loads to ensure high levels of efficiency on an annual basis

D. CHP projects may benefit from changes to existing standby rates and improved interconnection standards.

Section 2.4 Demand Response

A. The Utility shall examine and implement where cost-effective, demand response measures or programs in coordination with the electric and natural gas efficiency program offerings. Such measures and programs will be designed to supplement cost-effective procurement of long-term energy and capacity savings from efficiency measures.

J. The Demand and capacity value of CHP and other distributed generation strategies shall be identified and quantified.