Unitil
Unitil Service Corp.

ORIGINAL
N.H.P.U.C. Case No. DE 09-137
Exhibit No. #3
Witness Panel 2 Gantz Palma Axelrod
DO NOT REMOVE FROM FILE

August 5, 2009

BY OVERNIGHT MAIL AND E-MAIL

Debra A. Howland, Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. DE 09-

Dear Director Howland:

Enclosed on behalf of Unitil Energy Systems, Inc. ("UES" or "Company") is an original and six copies of the Company's initial filing for approval of investment in and rate recovery for Distributed Energy Resources ("DER") as authorized under RSA 374-G.

Consistent with the filing, UES seeks approval of its proposed DER cost recovery method, as provided for in the DER Tariff, Schedule DERIC Page Nos. 105-107, with a proposed effective date of October 1, 2009, attached hereto. In addition, the Company is also filing the following tariff changes which are necessitated by the new Schedule:

First Revised Page 1: Table of Contents
Second Revised Page 49 of Schedule D
Second Revised Page 55 of Schedule G
Second Revised Page 60 of Schedule OL

Included with the Tariff filing is a Petition for Approval, along with the Testimony and Exhibits of George R. Gantz, Howard J. Axelrod, Cindy L. Carroll and Justin C. Eisfeller.

UES' initial filing under RSA 374-G includes a detailed proposal for an annual, two-step regulatory review and approval process. The filing includes a proposed cost recovery method for the Company's DER investments and a proposed comprehensive screening model for evaluating the benefit/cost ratio of those investments. The filing also includes four specific projects for Commission approval: 1) a Smart Grid / Time of Use Pilot Program; 2) an investment in a solar hot water

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Chief Regulatory Counsel

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heating system at a low income housing facility in Concord, NH; 3) a Solar Photovoltaic ("PV") investment on a municipal facility in Stratham; and 4) an investment contributing to the cost of a Solar PV facility and a clean combined heat and power system for a school in Exeter.

Collectively, the projects are expected to cost a total of approximately $1.3 million, including capital investments of $761,000, and are expected to provide total benefits in excess of $3 million. Through the provisions of RSA 374-G and the proposed DER Tariff, the costs of these initiatives will be supported by the Company's electric ratepayers, with the recovery of investment costs spread over the life of the investment. In this way the costs of the projects will be matched to the benefits which are accumulated over time.

The Company notes that the Smart Grid / TOU Pilot Program is a joint, multi-state pilot program, and that its affiliate, Fitchburg Gas and Electric Light Company, has already applied for approval with the Massachusetts Department of Public Utilities ("Department"). The Department has docketed the filing as Docket D.P.U. 09-31. In addition, the Company is intending to file for grant funding for up to 50 percent of the project costs from the Department of Energy under the Smart Grid Investment Grant Program.

Please contact me if you have any questions concerning this filling. Thank you for your attention to this matter.

Sincerely,

Gary Epler
Attorney for Unitil Energy Systems, Inc.

Enclosure

cc: Meredith Hatfield, Esq., Consumer Advocate

BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

UNITIL ENERGY SYSTEMS, INC. Petitioner	)))))	DOCKET NO. DE 09-____

PETITION FOR APPROVAL OF DISTRIBUTED ENERGY RESOURCES INVESTMENT PROPOSAL AND PROPOSED TARIFF

Pursuant to the provisions of RSA Chapter 374-G, Unitil Energy Systems, Inc., ("UES" or "Company") submits this Petition to the New Hampshire Public Utilities Commission ("Commission") requesting:

1. approval of UES' proposed two-stage framework for review of its Distributed Energy Resources ("DER") investment proposal;
2. approval of UES proposed DER project screening process;
3. approval of UES' proposed DER rate recovery mechanism and DER Tariff, Schedule DERIC, which would be activated with an initial rate filing later this year; and
4. approval of UES' proposed 2009 DER program, which consists of four energy management and distributed generation projects.

In support of its Petition, UES states the following:

Petitioner

UES is a New Hampshire corporation and public utility primarily engaged in the distribution of electricity in the capital and seacoast regions of New Hampshire.

Background

Pursuant to RSA Chapter 374:G, electric public utilities may make investments in distributed energy resources ("DER"), as defined and limited in the statute, and, through

2) a Solar Domestic Hot Water (DHW) system to replace the existing electric DHW system at Crutchfield Place, a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority in Concord, NH;

3) a Solar Photovoltaic ("PV") investment to install 202 panels of BP Solar SX 3195, 195 watt or equivalent on the new Stratham Fire House in Stratham, NH; and

4) an investment contributing to the School Administrative Unit (SAU) 16 of Exeter's project to provide more efficient energy to the school system. This project will employ two forms of alternative, distributed energy generation: installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building; and the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Description of Exhibits

Attached to this Petition are the following Exhibits:

Exhibit – GRG-1: Testimony and Schedules of George R, Gantz.

Exhibit – HJA-1: Testimony and Schedules of Howard J. Axelrod.

Exhibit – CLC-1: Testimony and Schedules of Cindy L. Carroll.

Exhibit – JCE -1: Testimony and Schedules of Justin C. Eisfeller.

Proposed Tariffs

UES' proposed tariffs are included with this filing and are provided in clean and redline format. UES requests approval of these proposed tariffs.

Conclusion

For all of the foregoing reasons, UES requests that the Commission grant it the approvals requested in this Petition, and for such other relief as the Commission may deem necessary and proper.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.
By its Attorney:

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August 5, 2009

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Default Service Charge: For customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

Distributed Energy Resources Investment Charge: All energy delivered under this Schedule shall be subject to the Distributed Energy Resources Investment Charge as provided in Schedule DERIC of the Tariff of which this is a part.

LOW INCOME ENERGY ASSISTANCE PROGRAM

Customers taking service under this rate may be eligible to receive discounts under the statewide low-income electric assistance program ("LI-EAP") authorized by the New Hampshire Public Utilities Commission. Eligibility for the LI-EAP shall be determined by the Community Action Agencies. Customers participating in the LI-EAP will continue to take service under this rate, but will receive a discount as provided under this Tariff as applicable.

ELECTRICITY CONSUMPTION TAX

All customers shall be obligated to pay the Electricity Consumption Tax in accordance with New Hampshire Statute RSA Chapter 83-E, which may be revised from time to time, in addition to all other applicable rates and charges under this Tariff. The Electricity Consumption Tax shall appear separately on all customer bills.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff. Amounts not paid prior to the due date shall be subject to interest on past due accounts, as provided in Appendix A of the Terms and

OUTDOOR LIGHTING SERVICE
SCHEDULE OL (continued)

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire type.

OTHER FIXTURES AND EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

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DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC

LBR_x = The projected calculated lost base revenue in year x resulting from the implementation of approved distributed energy resource investments.

RAx_{-1} = The annual Reconciliation Adjustment defined as the difference between (a) the actual annual Revenue Requirement, Offset Revenues, and LBR in the previous year, and (b) the revenue actually collected in the previous year. Interest calculated on the average monthly balance shall also be included in the RA. Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

I_x = The estimated interest in the forecast period, calculated as defined above.

$FkWh_x$ = The forecasted kWh is the forecasted amount of electricity to be distributed to the Company's distribution customers for the year "x".

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GENERAL DELIVERY SERVICE
SCHEDULE G (continued)

MINIMUM CHARGE

The Minimum Charge per month or fraction thereof will be as follows:

Large General Service Schedule G1:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand and/or demand ratchet as defined under the Determination of Demand provision of this Schedule.

Regular General Service Rates G2, G2 kWh meter, Uncontrolled (Quick Recovery) Water Heating, and Space Heating:

The Minimum Charge per month shall be the Customer Charge for each type of service installed.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

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UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

GEORGE R. GANTZ

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is George R. Gantz. I am the Senior Vice President of Distributed Energy Resources for Unitil Service Corp. and an officer of Unitil Energy Systems, Inc. ("UES" or "Company"). My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. Please summarize your qualifications and current position.

A. I have been employed by Unitil since 1983. During that time I have held various positions with increasing responsibilities in areas including pricing, legislative and regulatory affairs, power supply planning and acquisition, marketing and business development, customer services, communications and strategic planning. I have appeared many times as a witness before this Commission as well as the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. I graduated from Stanford University with a B.S. in Mathematics and Honors Humanities in 1973. I have also been active in leadership roles in various organizations including the Business and Industry Association, The United Way of North Central Massachusetts and the Fitchburg State College Foundation.

In July 2009, Unitil undertook a reorganization under which I was reassigned from the Customer Services and Communications functions and given leadership for the energy efficiency, demand response, distributed generation and smart grid initiatives.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of SB451, codified as RSA 374:G, to discuss the regulatory process under RSA 374:G and to introduce UES' proposal for ratemaking under RSA 374:G. UES believes that implementing this innovative statute is an important milestone for the Company and for the state of New Hampshire. Distributed Energy Resources ("DER") offer the promise of more cost-effective electric energy supply and delivery and increased efficiency in our production and utilization of energy. Achieving this promise will require significant innovation and sustained investments. With this filing UES hopes to accelerate the process and begin a long term initiative to find and deploy an increasing portfolio of cost-effective DER projects in its service area.

In my testimony I will cover the following:

- Goals and Objectives for UES' DER initiative
- Overview of RSA 374:G requirements
- Proposal for an efficient, two-step regulatory process
- Step One: Filing for Commission Approval
- Step Two: Rate Recovery

The other witnesses in this proceeding include: Dr. Howard J. Axelrod of Energy Strategies Inc., who will describe in detail the screening process and screening model UES has developed for use in qualifying proposed DER projects for investment and rate recovery; Justin C. Eisfeller, Unitil's Director of Measurement and Control, who will provide information relative to the company's proposed Time-of-Use / Smart Grid pilot program; and Cindy L. Carroll, Unitil's Director of Business Services, who will discuss the three other project proposals being included in this filing:

Solar Hot Water Installation for Crutchfield Place (Concord Housing Authority)
Solar PV Installation at the Stratham Fire Station
Solar PV and Micro CHP in the Exeter School District

Q. Please explain how the proposed Time of Use / Smart Grid pilot program relates to what the Company's Massachusetts affiliate has proposed to the Department of Public Utilities?

A. The Time of Use / Smart Grid pilot program is being proposed as a joint program of both UES and its Massachusetts affiliate Fitchburg Gas and Electric Light Company (FG&E). FG&E filed the proposal in Massachusetts as a "Smart Grid Pilot" in April 2009 in compliance with the Green Communities Act. That proceeding is now underway with approval expected in October. The joint proposal allows the companies to gain the benefits of conducting a broader pilot program with a larger and more robust statistical sampling plan at lower cost to our customers in either state.

Q. Is the Company making a proposal for grant funding of its Time of Use / Smart Grid pilot program under the Department of Energy Smart Grid Investment Grant program?

A. Yes, the Company is filing an application to the DOE for the Time of Use / Smart Grid Pilot Program in order to help defray the costs of the program to our customers. The application is being filed on August 6th with anticipated award announcement in October. This grant program is competitive and the level of interest nationally is quite high, so the outcome of the application is unknown. The proposal included in this filing and testified to by Mr. Eisfeller does not assume that the Company is awarded grant funding from DOE.

II. GOALS AND OBJECTIVES FOR UES'S DER INITIATIVE

Q. What are UES' guiding goals and objectives in undertaking its DER initiative?

A. It is the Company's goal to promote an accelerated deployment of energy efficiency and local generation in order to displace central station generation and the fuels on which it relies – thereby providing customers with cost-effective and environmentally sound energy options. In addition, UES seeks to promote the orderly transition and transformation of the electric grid to a so-called "smart grid" in a cost – effective manner. Finally, we view DER as a potentially more cost-effective option for maintaining and improving distribution reliability and performance than traditional distribution investments.

Q. Are there other benefits that can be derived from DER investments?

A. Yes, there are. The DER projects that UES is pursuing are designed to reduce or control peak demand, promote energy conservation, or generate electricity close to the source of the demand. By substituting a DER solution for conventional generation investment and imported energy supply, more of the dollars expended will be directed to local businesses, thereby maximizing the economic impact of each dollar spent by UES. DER projects will also help reduce our dependence on fossil fired generation.

Q. What does UES seek from the Commission in these proceedings?

A. This is UES' first application pursuant to RSA 374-G. It is our hope that the Commission in this proceeding will act favorably on the following proposals:

1. To authorize the two-stage DER regulatory framework we are proposing;
2. To approve our proposed DER rate recovery mechanism and DER Tariff, Schedule DERIC, which would be activated with an initial rate filing later this year;
3. To approve the DER project screening process we are proposing in this proceeding; and

4. To approve UES' proposed 2009 DER program, which consists of four innovative energy management and distributed generation projects.

III. OVERVIEW OF RSA 374:G REQUIREMENTS

Q. Please provide an overview of RSA 374:G.

A. As the Commission is aware, RSA 374:G became effective on September 9, 2008. A copy is provided for reference as Schedule GRG-1. The new law allows electric public utilities to make investments in DER as defined and limited in the statute, and requires the New Hampshire Public Utilities Commission to provide rate recovery for such investments. Specifically, the law authorizes rate recovery for utility investments in DER that "provide energy diversity by eliminating, displacing or better managing energy deliveries from the centralized bulk power grid". In essence, RSA 374:G allows electric utilities to either directly invest in or subsidize customer investments in a range of DER technologies, systems or processes that are cost effective, have environmental and economic development impacts and improve the reliability and security of the overall electrical system. For such investments, RSA 374:G provides for an expedited rate approval process and the potential for incentive returns for DER investments.

While RSA 374:G does allow distribution utilities to make investments in DER technologies and applications, it also contains certain limits particularly with respect to generation technologies. For example, the energy from utility-owned generation may only be used to displace energy for system losses or company use. This effectively limits this option to about four percent of the Company's kilowatt-hour throughput. In addition, generation projects must be smaller than 5 megawatts, and the total generation capacity may not exceed six percent of the company's system peak load, a limit of about 18 megawatts for UES. In addition, generation must be either renewable, or fueled with natural gas, in which case it must meet stringent emission limitations and additional restrictions on deployment levels.

While Chapter 374-G provides some clarity as to the types of DER investments that UES can make within the above categories, and outlines the broad criteria that the Commission should consider in its review process, it does not specify the regulatory process and rate recovery mechanism in any detail, nor does it delineate a precise cost/benefit test or evaluation process. These are matters left to the distribution utilities to propose and the Commission to decide.

IV. PROPOSAL FOR AN EFFICIENT TWO-STEP REGULATORY PROCESS

Q. What instruction does RSA 374-G provide regarding the regulatory process to be followed by a distribution utility and the Commission?

A. Section I of RSA 374-G:5 establishes the basic information required in a utility filing; Section II requires a pre-determination by the Commission of public interest; and Section III is a directive to the Commission to allow rate recovery for authorized and prudently incurred investments.

While 374-G:5 Section II does not stipulate the precise criteria that the Commission must use in pre-approving a utility's DER investments, it does require a finding of public interest based on the balancing of nine factors addressing economic cost benefit, environmental benefits and economic development. The provisions require the company to address cost and benefits to the utility ratepayers, to the participating customer and to the company's Default Service customers.

Section 374-G:5 Section III requires that investments being included in rates must be prudently incurred. An appropriate standard for a prudent investment would be meeting a public interest test – this implies that if the public interest test in Section II, relating to cost/benefit, environmental impact and economic development, is satisfied, then the investment would be prudent.

Section III also indicates that "authorized and prudently incurred investments shall be recovered." The inclusion of the word "authorized" implies that rate recovery will be provided for projects that have been approved, i.e. "authorized," by the Commission pursuant to the satisfaction of the public interest test.

In a single, contemporaneous filing, it is hard to see how the Commission could pre-approve the projects and simultaneously authorize recovery of prudently incurred costs in rates – unless the company had already made the investments. This would, of course, mean that the company would have funded the projects prior to Commission approval, putting the company at risk that one or more or all of the DER projects in which it had invested would fail to meet the Commission's standard of public interest.

Q. How does UES propose to implement RSA 374-G:5 in a manner that is consistent with the requirements and administratively efficient?

A. We think there is an approach that meets the requirements of RSA 374-G:5 in a reasonable and administratively manageable way. This will involve a bifurcated two-step process. In the first step the company files with the Commission, prior to making the actual investments, a detailed description of each DER project along with the required information needed to satisfy the public interest test. The Commission would then decide whether each project as presented meets or does not meet the public interest test. Essentially, the Commission would be authorizing the company to proceed with the project - and to recover the DER investments when incurred. The company would make a subsequent rate filing to recover the costs for DER projects that had been previously approved. In the cost recovery review process, the company would need to verify that project had met the designed objectives within a reasonable time frame and within the anticipated budget range.

Q. Does RSA 374-G specify when a utility should apply for DER rate recovery?

A. RSA 374-G:5 is written in such a way that a utility could file for each and every DER investment it makes. However, since the scale of particular investments is expected to be small and possibly spread out throughout a calendar year, it could be an administrative nightmare for all parties if separate DER filings are made for each and every DER investment. We think it would be far more efficient to implement the two-step approach described above as an annual process.

V. STEP ONE: FILING FOR COMMISSION APPROVAL

Q. Describe the elements of the initial DER project approval filing.

A. UES' DER project approval filing provides information on the proposed DER projects for the current year, along with sufficient information for the Commission to make a determination as to whether the proposed project is in the public interest.

Q. How will the Company demonstrate that proposed DER projects are in the public interest?

A. UES has developed an analytical screening process, described in detail by Dr. Axelrod, that is designed to address the questions posed by Section G:5 Section II items *a* through *i* regarding:

- Cost/benefit for participating customers, default customers and system-wide customers.

- Other tangible benefits including reduced environmental impacts, enhanced system reliability and diversity and increased regional economic output.

The Company's filing will describe each project and present an estimated cost along with the technical assessment of expected project performance, lifetime, etc. The output of the screening analysis will be presented and any additional factors or considerations relevant to the Commission's deliberation will be provided.

Q. Will there be any differences in the treatment of utility-owned and customer-owned DER investment?

A. RSA 374-G provides for two possible types of utility DER investment:

1. Traditional investment in utility owned technologies such as on-site distributed generation, energy storage technologies, and demand response and load control systems.
2. Utility investment in Customer Owned DER projects.

We propose that the public interest criteria for either utility or customer-owned projects be the same. There will be differences, however, in the allocations of costs and benefits. Specifically, it is anticipated that many customer-owned projects will involve some customer contribution to the project. The level of customer contribution will be an important factor impacting the level of net benefits to other UES customers.

Q. How does UES propose to determine the level of its investment in Customer-Owned DER?

A. While there are several possible approaches to determining the level of investment that the utility may make in a customer-owned DER project, UES proposes the following three-step process as a guideline. First, we would determine the level of benefit available to the Company and its distribution customers for the proposed project, excluding the benefits that would flow directly to the participating customer. Based on the expected project life and the Company's overall cost of capital, we would then calculate the level of investment those benefits would justify. Next we would look at the project's economics from the customer perspective. If those economic benefits are large we could seek to reduce the utility investment to balance the relative net benefits between the participant and all other customers. In the third step, we would look at the upfront financial requirement facing the customer and factor in the customer's ability and/or motivation to implement the project given an up-front financial threshold, the potential for other sources of funding and other factors. Ultimately, the goal will be to achieve a reasonable allocation of costs and benefits and an appropriate sharing of risks and responsibilities.

Q. Please address the requirements of RSA 374-G subsection I.

A. Section G:5 I identifies six filing requirements:

a) A detailed description and economic evaluation
b) A discussion of cost, benefits and risks
c) A description of any equipment specifications
d) A showing of efforts to involve local businesses
e) Evidence of environmental compliance
f) Copy of customer contracts

The Company believes its initial filing provides plans in sufficient detail as to satisfy the first four requirements. Item e) is a matter of compliance which the Company will document as necessary in the rate recovery reconciliation process. Similarly, the actual customer contracts would be a matter of compliance and filed in the rate recovery reconciliation filing, although the nature of that contract would be discussed in the DER program approval filing. In this current filing, we have included Memoranda of Understanding with the three host customers – the MOUs will guide the development of the definitive customer agreements which will be filed with the rate filing.

VI. STEP TWO: RATE RECOVERY

Q. Please explain the basis for UES' proposed rate recovery mechanism?

A. RSA 374 Section G5:III, provides electric utilities the opportunity to recover both prudently incurred investments and associated expenses for authorized DER projects. The statute also says that investments "shall be recovered under this section in a utility's base distribution rates as a component of rate base, and cost recovery shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment." In addition, Section IV stipulates that "the Commission may add an incentive to the return on equity component as it deems appropriate to encourage investment in distributed energy resources."

These provisions define clearly the elements of the revenue requirement to be included in the rate calculations. However, in the context of UES' proposed bifurcated regulatory process, we are proposing that the rate calculation and inclusion of DER investments in rates occur once annually.

Q. **Please describe the proposed cost recovery process.**

A. UES proposes to recover the costs associated with its approved DER investments through a fully reconciling rate under the proposed DER Tariff, Schedule DERIC, which is attached to my testimony as Schedule GRG-2. The DER Investment Charge ("DERIC") would be included in the Company's distribution rates for billing purposes. The rate calculation, as described in the Tariff, will be based on a revenue requirement calculation that factors in the investments the Company will be making in approved DER projects, recovered over the useful life of the investment, as well as the associated mobilization, operating and maintenance, and monitoring, verification and reporting costs. The revenue requirements will be tracked on a monthly basis and reconciled annually.

Q. **Please explain the proposed revenue requirements calculation.**

A. The revenue requirement begins with the capital investment in DER equipment being made by the Company. This investment will be tracked separately in the Company's plant records system. The accounting process will also provide for the calculation of depreciation and depreciation reserve as well as deferred income taxes and deferred tax reserves under tax normalization, all in accordance with standard utility accounting methods. The net investment and a provision for working capital provide the basis for calculating the rate base value, on which the return is calculated. The Company proposes to use the capital structure and debt costs for the previous year from the form F-1 Supplemental Quarterly Financial and Sales Information that is on file with the Commission, with the inclusion of a return on equity from the Company's most recent base rate case. This will be adjusted for the effective income tax-rate to provide a pre-tax return value. This is a simple, straightforward, easily audited method.

In addition to the return component, the calculated revenue requirement will include depreciation, other taxes (if any), mobilization, operating and maintenance, and monitoring, verification and reporting costs incurred by the Company. Until such time as the company implements revenue decoupling, a factor for lost base revenues (LBR) associated with the operation of the approved DER projects will also be included. This calculation will be available monthly and filed with the annual reconciliation filing.

Q. How will the rate be calculated?

A. The Company proposes to calculate a single DERIC for an annual period on the basis of an updated, pre-filed budget for the previously approved DER projects during the upcoming period. The estimated revenue requirement will be calculated based on the capital and expenses already incurred and expected to be incurred in the coming year. That figure will be divided by forecasted retail distribution sales to all customers. This will provide a single rate in cents/kilowatt-hour to be charged to all customers.

As the year proceeds, the Company will maintain a calculation of the actual revenue requirement, based on projects completed and expenses incurred. This will be matched against revenues received from the DERIC for that month. Over- or under-collections will be accumulated and deferred to the subsequent year, with interest at the prime rate.

When the rate for the subsequent period is calculated, any over- or under-collection will be netted with the forecast revenue requirement in the calculation of the rate.

All of the calculations included in the revenue requirement calculations and reconciliation will be transparent and will track to specific accounting entries so that the process can be easily audited and verified. The Company will use accounting procedures similar to those it presently uses in its energy efficiency programs. These procedures ensure that costs are properly allocated and accounted for.

Q. Assuming the Commission approves this two-phased DER rate recovery process, what are the filing dates that you propose?

A. We recommend moving towards an annual cycle that would involve making the DER project filings in the second quarter, with approval in three months. The rate recovery reconciliation filing would follow by mid-November, 45 days in advance of the proposed rate effective date of January 1.

Q. What is the anticipated budget for the DER projects being filed with the Commission in this filing?

A. The attached Schedule GRG-3 provides the anticipated budget for the four DER projects included in this filing. As indicated, the proposed DER budget for these projects includes an estimate of $761,241 in capital investments and an estimate of $577,346 for other operating expenses. The total outlay for these programs over the next year is therefore about $1.3 million. The calculated benefit for this expenditure is $2,980,710.

The expenditures for the Crutchfield, Stratham and Exeter DER projects are direct capital investments. In the case of the TOU / Smart Grid Pilot, we are proposing to recover this as an expense item, consistent with the pilot nature of the project and its one-year time horizon. In addition, for this project we are excluding internal staff time for purposes of proposed rate recovery in both Massachusetts and New Hampshire. Finally, we have not assumed any contribution of funding from the DOE SGIG grant for which we are applying – in the event our grant application is successful, the costs to be recovered from ratepayers would be reduced by half.

In addition to the direct project costs, we have included in the budget an estimated entry for the external consulting costs associated with the initial development and start-up of the DER proposals, as well as an estimate of the costs for the ongoing program management and reporting. The costs associated with these activities are incremental for the company, directly attributable to the DER projects and of an ongoing nature, and therefore appropriate for inclusion in the rate recovery mechanism.

VII. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374-G
ELECTRIC UTILITY INVESTMENT IN DISTRIBUTED ENERGY RESOURCES

Section 374-G:1

374-G:1 Purpose. – Distributed energy resources can increase overall energy efficiency and provide energy diversity by eliminating, displacing, or better managing energy deliveries from the centralized bulk power grid, in keeping with the objectives of RSA 362-F:1. It is therefore in the public interest to stimulate investment in distributed energy resources in New Hampshire by encouraging New Hampshire electric public utilities to invest in distributed energy resources including clean and renewable generation benefiting the transmission and distribution system under state regulatory oversight.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:2

374-G:2 Definitions; Exclusions. –
I. The following definitions shall apply in this chapter except as otherwise provided:
(a) ""Commission" means the public utilities commission.
(b) ""Distributed energy resources" means electric generation equipment, including clean and renewable generation, energy storage, energy efficiency, demand response, load reduction or control programs, and technologies or devices located on or inter-connected to the local electric distribution system for purposes including but not limited to reducing line losses, supporting voltage regulation, or peak load shaving, as part of a strategy for minimizing transmission and distribution costs as provided in RSA 374-F:3, III.
II. ""Distributed energy resources" in this chapter shall exclude electric generation equipment interconnected with the local electric distribution system at a single point or through a customer's own electrical wiring that is in excess of 5 megawatts.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:3

374-G:3 Electric Generation Equipment Funded by Public Utility; Requirements. – Any electric generation equipment funded in part by a public utility under this chapter is subject to the following requirements:

I. The energy produced by electric generation equipment owned by the public utility shall be used as an offset to distribution system losses or the public utility company's own use;

II. The energy produced by electric generation equipment utilizing a non-renewable fuel source that is owned by a customer, or sited on a customer's property shall be used to displace the customer's own use;

III. The energy produced by electric generation equipment utilizing a renewable fuel source that is owned by a customer, or sited on the consumer's premises shall be used to displace the customers own use; however, if energy is occasionally generated in excess of the customer's energy requirements, it may be credited to the customer's account in a subsequent period.

IV. Any biomass-fueled generation shall meet the emission requirements to qualify as eligible biomass technology under RSA 362-F:2, VIII.

V. Any fossil-fuel fueled generation shall produce combined heat and power with a minimum energy efficiency of 60 percent, measured as usable thermal and electrical output in BTUs divided by fuel input in BTUs, shall be installed as an integrated combined heat and power application, and shall meet the following emission standards (in lbs/MW-H): NOx--0.07; CO--0.10; VOCs--0.02. A credit to meet the emission standard may be applied at the rate of one MW-H for each 3.4 million BTUs of heat recovered.

VI. These requirements apply in addition to and do not preempt or replace any emission standards or permitting requirements applicable to a given generation facility under any other applicable state or federal law.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:4

374-G:4 Investments in Distributed Energy Resources. –

I. Notwithstanding any other provision of law to the contrary, as provided in RSA 374-G:5, a New Hampshire electric public utility may invest in or own distributed energy resources, located on or inter-connected to the local electric distribution system.

II. Distributed electric generation owned by or receiving investments from an electric utility under this section shall be limited to a cumulative maximum in megawatts of 6 percent of the utility's total distribution peak load in megawatts.

III. In addition, once the cumulative generation authorized under this chapter for a given public utility reaches 3 percent of the utility's total distribution peak load in megawatts, then that utility shall not be allowed to add any additional non-renewable generation under this chapter, until the cumulative renewable generation installed pursuant to this chapter, as a percentage of total generation installed pursuant to this chapter, shall equal or exceed twice the sum of the then-applicable percentage requirements for class I and class II under RSA 362-F:3.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:5

374-G:5 Rate Filing; Authorization. –

I. A New Hampshire electric public utility may seek rate recovery for its investments in distributed energy resources from the commission by making an appropriate rate filing. At a minimum, such filing shall include the following:

(a) A detailed description and economic evaluation of the proposed investment.

(b) A discussion of the costs, benefits, and risks of the proposal with specific reference to the factors listed in paragraph II, including an analysis of the costs, benefits, and rate implications to the participating customers, to the company's default service customers, and to the utility's distribution customers.

(c) A description of any equipment or installation specifications, solicitations, and procurements it has or intends to implement.

(d) A showing that it has made reasonable efforts to involve local businesses in its program.

(e) Evidence of compliance with any applicable emission limitations.

(f) A copy of any customer contracts or agreements to be executed as part of the program.

II. Prior to authorizing a utility's recovery of investments made in distributed energy resources, the commission shall determine that the utility's investment and its recovery in rates, as proposed, are in the public interest. Determination of the public interest under this section shall include but not be limited to consideration and balancing of the following factors:

(a) Whether the expected value of the economic benefits of the investment to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers.

(b) The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3.

(c) The costs and benefits to any participating customer or customers.

(d) The costs and benefits to the company's default service customers.

(e) The energy security benefits of the investment to the state of New Hampshire.

(f) The environmental benefits of the investment to the state of New Hampshire.

(g) The economic development benefits and liabilities of the investment to the state of New Hampshire.

(h) The effect on the reliability, safety, and efficiency of electric service.

(i) The effect on competition within the region's electricity markets and the state's energy services market.

III. Authorized and prudently incurred investments shall be recovered under this section in a utility's base distribution rates as a component of rate base, and cost recovery shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment.

IV. The commission may add an incentive to the return on equity component as it deems appropriate to encourage investments in distributed energy resources.

V. The commission shall approve, disapprove, or approve with conditions a utility rate filing under this section within 90 days of its filing. The commission may extend this deadline to 6 months at its discretion for any filing involving an investment in excess of $1,000,000. The commission may also extend the deadline at its discretion for failure of the applicant to respond to data requests on an expedited timeline.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:6

374-G:6 Exemption; Rural Electric Cooperatives. – The requirements for commission authorization for recovery of investments under RSA 374-G:5 shall not apply to rural electric cooperatives for which a certificate of deregulation is on file with the commission.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:7

374-G:7 Exclusion. – Any renewable generating equipment funded in part by a distribution utility under this chapter shall not be included in the calculation of the total rated generating capacity under RSA 362-A:9, I for purposes of limiting net energy metering.

Source. 2008, 373:1, eff. Sept. 9, 2008.

DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC

The Distributed Energy Resources Investment Charge ("DERIC"), as specified on Calculation of the Distributed Energy Resources Investment Charge, shall be billed by the Company to all customers taking Delivery Service from the Company. The purpose of the DERIC is to recover, on a fully reconciling basis, the costs of the Company's investments in distributed energy resources.

The DERIC shall be established annually based on a forecast of includable costs, and shall include a full reconciliation with interest for any over- or under-recoveries occurring in the prior year(s). Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. The Company may file to the change the DERIC at any time should significant over- or under-recoveries occur or be expected to occur.

Any adjustment to the DERIC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five (45) days after the filing of the notice, or such other date as the Commission may authorize. The annual adjustment to the DERIC shall be derived in the same manner as that provided by Calculation of the Distributed Energy Resources Investment Charge.

The DERIC shall be calculated according to the formula below.

$DERIC_x = (RR_x - OR_x + LBR_x + RA_{x-1} + I_x)/ \; FkWh_x$; where

$DERIC_x$ = The annual Distributed Energy Resources Investment Charge for the year "x". "x" is the forecast year.

RR_x = The projected annual Revenue Requirement for the recovery of the investment and operation and maintenance costs of the Company's distributed energy resource investments approved by the Commission pursuant to RSA 374:G. The annual revenue requirement shall consist of the return on rate base and associated income taxes, along with depreciation and amortization expense, operation and maintenance expenses and taxes other than income taxes.

OR_x = The projected annual Offset Revenues received from any source that the Company is able to secure to support the cost of its investments.

Authorized by NHPUC Order No. ______ in Case No. DE _____ dated _______________

DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC

LBR_x = The projected calculated lost base revenue in year x resulting from the implementation of approved distributed energy resource investments.

RAx_{-1} = The annual Reconciliation Adjustment defined as the difference between (a) the actual annual Revenue Requirement, Offset Revenues, and LBR in the previous year, and (b) the revenue actually collected in the previous year. Interest calculated on the average monthly balance shall also be included in the RA. Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

I_x = The estimated interest in the forecast period, calculated as defined above.

$FkWh_x$ = The forecasted kWh is the forecasted amount of electricity to be distributed to the Company's distribution customers for the year "x".

**CALCULATION OF THE
DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE**

1.	(Over)/under Recovery - Beginning Balance January 1, 2010	to be filed
2.	Estimated Total Costs (January 2010 - December 2010)	to be filed
3.	Estimated Interest (January 2010 - December 2010)	to be filed
4.	Costs to be Recovered (L.1 + L.2 + L.3)	to be filed
5.	Estimated Calendar Month Deliveries in kWh (January 2010 - December 2010)	to be filed
6.	Distributed Energy Resources Investment Charge ($/kWh) (L.4/L.5)	to be filed

UNITIL ENERGY SYSTEMS, INC
DER ESTIMATED BUDGET

LINE NO.	(1) DESCRIPTION	(3) AMOUNT	
	CAPITAL INVESTMENT:		
1	Crutchfield: Solar Domestic Hot Water (DHW) system	$ 101,920	
2	Stratham Municipal: Solar Photo Voltaic (PV)	$ 399,321	
3	SAU 16: Solar Photo Voltaic (PV) and Micro-Turbine CHP	$ 260,000	
	Total Investment	$ 761,241	
	OTHER OPERATING EXPENSE:		
4	Time-of-Use Pilot Program	$ 312,136	External Cost:
5	DER Start-up Consulting Services	$ 120,000	External Cost:
6	Ongoing Program Management and Reporting	$ 145,210	Internal Costs
	Total Expense	$ 577,346	

UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF
HOWARD J. AXELROD

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DE 09-___
AUGUST 5, 2009

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I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Howard J. Axelrod. I am President of Energy Strategies, Inc. and my business address is 5 Danbury Court, Albany, New York

Q. Please summarize your qualifications and affiliation to Unitil.

A. I have been a management consultant for the last 25 years and the owner and chief executive officer of Energy Strategies, Inc., since 1995. Energy Strategies, Inc. specializes in energy planning and analysis. Our clients have included a number of electric utilities, regulatory agencies and large industrial customers throughout the United States and within New England in particular. (See www.energystrategiesin.com) Energy Strategies, Inc. was retained by Unitil to assist in the development of this DER program including model development and the rate application framework.

Prior to my consulting career, I served for nearly fourteen years in a number of senior level positions with the New York State Public Service Commission (PSC), the Consumer Protection Board (CPB) and the Energy Research and Development Authority (NYSERDA). I was also appointed by Governor Cuomo as the Chief Economist on the Shoreham Commission. At the PSC I served as a special assistant to Chairman Alfred Kahn where I oversaw the development of productivity measures and research and development programs funded by electric and gas utilities in New York. At the CPB, I was Director of Utility Intervention, the Nation's largest residential advocacy organization at that time. Finally, at NYSERDA I managed a number of innovative research and development projects including the development of one of the first comprehensive DSM screening models.

Over the last 25 years I have personally performed a number of studies and analyses relating to power systems requirements, alternative generation and renewable resources and emerging technologies including vehicle to grid (V2G) applications, smart meters and superconducting applications for transmission and distribution systems. For the later, I served as Executive Director of CCAS, the Coalition for Commercial Advancement of Superconductors.

I am a graduate of Rensselaer Polytechnic Institute where I earned my Doctor of Philosophy degree in Managerial Economics, from the State University of New York (Albany) with an MBA in Marketing and from Northeastern University with MSEE and BSEE degrees in Power Systems Planning. I also completed General Electric's 3-year training program as an Application Engineer. I am a Senior Member of the Institute of Electrical and Electronic Engineers and a Professional Engineer (retired.)

Q. What is the purpose of this testimony?

A. In response to the recently enacted DER legislation, Unitil Energy Systems, Inc. ("UES"), asked me to assist in the development of a set of analytical screening tools to be used to evaluate:

- DER Cost/benefit
- Environmental impact
- Particpating and non-participating customer costs and benefits
- Economic Development Impact

In my opinion, these tools provide the appropriate information necessary for the company and ultimately the Commission to determine whether a DER project meets the test for being in the "public interest." The models can also used to assess the level of company contribution to any DER project that would be owned by the customer. In this testimony I will describe the models and methods used by UES to evaluate those DER projects it seeks to pursue.

Q. What factors need to be considered in determining whether a DER project meets the test for public interest?

A. RSA 374-G:5, paragraph II, identifies a number of factors that the Company should address in establishing whether a project is in the public interest. In summary those factors should consider:

- The "economic benefits of the investments to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility ratepayers."
- The relative economic cost/benefit to participating customer as well as default service customers
- The environmental benefits
- The economic development benefits

The models that I will discuss in this testimony were designed to provide exactly the information called for in this section of the DER statute.

Q. Are there any other requirements that UES must provide in supporting its finding that the proposed 2009 DER program is in the public interest?

A. Paragraph II also requires the Company to assess energy security benefits, effects on reliability, safety and efficiency and effect on competition. It is our contention that each of the DER projects, by their very design will, at a minimum, have a neutral effect on each of these objectives, but should have a positive intrinsic benefit although the degree of impact will be difficult to quantify.

Q. What is the basis for your finding that there will be an intrinsic benefit?

A. The DER projects that UES is considering are designed to improve system reliability by reducing distribution congestion, improve system stability and mitigate equipment degradation due to overload conditions. If we can design a DER project to defer the need for conventional distribution investments by reducing load conditions that tax the distribution network, UES's system reliability will be improved while concurrently reducing distribution network investments. Furthermore, the very fact that these projects offer a wider range of innovative and diversified solutions to traditional distribution network enhancements, by definition, enhances the competitive market.

II. DEVELOPMENT OF THE SCREENING MODEL

Q. What are the criteria for Utility DER Investments?

A. RSA 374-G contemplates utility investment in DER technologies, including utility-owned DER, to offset distribution system losses (3 – 5 percent of energy sales) or internal company use, as well as customer-owned DER equipment. While the legislation identifies a range of economic and environmental criteria, and also seeks impacts on affected customers as well as default customers and overall system impacts, it does not stipulate that all of the criteria have to have some minimum positive benefit. In fact, under a number of plausible circumstances, the benefits attributed to one class of criteria (e.g. cost/benefit ratio) can be inversely linked to the attributes of another. For example, the cost benefit ratio of a particular DER initiative might be negatively affected by an environmental objective. Similarly, if one of the goals is to enhance local economic development, cost/benefit might be sacrificed for higher cost in-state procurement. Bottom line, the criteria for determining if a DER project should be consistent with a standard prudency test where net benefits exceed net costs, considering both tangible (internal) and implied (external) factors.

Q. Does the NHPUC apply similar standards for other utility programs?

A. Yes, it does. Specifically, in the area of Energy Efficiency programs funded by the System Benefits Charges, the Commission approves programs based on a demonstration of positive benefit-costs based on total societal costs and benefits. UES documents that it meets the Commission's standards for cost-effectiveness testing by relying on the UES Screening Model. This model, which calculates avoided system costs for energy efficiency expenditures, is used to evaluate the Company's energy management and conservation "investments." This provides the same types of analysis and information needed to assess DER investments.

Q. Will UES use exactly the same model as previously used before this Commission?

A. The UES Screening model as applied to the proposed DER projects did require some enhancements in order to meet all of the DER assessment requirements, specifically including:

- Adding an environmental impact analysis – This component can be developed using the environmental impact analysis developed for the Massachusetts utilities and included in cost-benefit of energy efficiency programs in that state.
- Adding a module for economic impact - The United State Bureau of Economic Analysis Regional Input/Output Modeling System (RIMS) has been acquired for the Rockingham and Merrimack Counties that UES serves in New Hampshire. RIMS provides economic multipliers for 60 industry categories for the following economic measures:
    - Employment
    - Income
    - Value-Added
    - Regional Output

For every dollar invested in New Hampshire, the RIMS multipliers can determine impacts on wages, numbers of new employees and overall economic development.

Q. Will the UES Screening Model be the only analytical tool used to evaluate DER investments?

A. The UES Screening Model computes system-wide impacts based on avoided costs. However, some DER projects could have a very localized and specific benefit that produces even greater benefits. For example, a distribution substation might be approaching maximum load conditions necessitating the addition of a new bus bar or transformer bank at a very substantial cost. A strategically located DER investment could defer or even eliminate the need for such a traditional utility investment. In order to capture the potential benefits of localized DER technologies the following analysis has been performed:

- An assessment of distribution system limitations including potential upgrades for the following conditions:
- Low voltage conditions and frequency modulation
- Substation and transformer overload
- Excessive line losses
- An estimation of system upgrade costs and project schedule
- An estimation of minimum corrective response via DER investments to affect deferment or avoidance.

Based on this analysis we have been able to identify potential avoided costs for certain classes of DER investments that would be in addition to the system-wide benefits derived by the UES model.

Q. Please summarize the quantitative models used by UES to evaluate the DER projects.

A. In order to fully evaluate each of the proposed DER projects we incorporated the features of three separate models. Our primary analytical tool is the 2009 UES Screening tool. This screening tool was developed for energy conservation and load management evaluations and has been accepted by the Commissions in New Hampshire and Massachusetts.

The Company has projected the expected benefits and costs associated with its four proposed 2009 DER projects consistent with the requirements delineated in RSA 374G:5. Where appropriate, the Company has included values for non-electric and non-resource benefits related to expected program installations in its assessment of cost-effectiveness. Factors included in the calculation of the benefit/cost ratios are the same as those used in the Company's 2008 Energy Efficiency Plan. Two additional factors were also identified – the values for the benefits for CO_2 reductions and energy-related demand reduction induced price effect (DRIPE).

Q. Further explain how the 2009 UES Model addresses the cost/benefit tests required in Paragraph II of RSA 374G:5.

A. The Total Resource Cost Benefit Test (TRC) is the benefit / cost test used in examining the overall economics of the DER programs. It compares the present value of future electric system and other customer savings to the total of the expenditures and customer costs necessary to implement the programs. The benefit of a measure is the net present value of the avoided costs (i.e.; value of the savings) associated with the net savings of a measure over the life of that measure. The net savings include impact factors and realization rates that result from evaluation studies. The measure life is based on either the technical life of the measure or study results.

Q. Please explain how avoided costs were derived.

A. The avoided costs used to determine program cost effectiveness in the 2008 Energy Efficiency Plan were developed in the "Avoided Energy Supply Costs in New England: 2007 Final Report" prepared by Synapse Energy Economics, Inc. for the New England Avoided-Energy-Supply-Component Study Group in August 2007 ("AESC Study"). In addition to the biennial updating of avoided generation capacity and energy values, the report developed recommendations for the inclusion of the demand reduction induced price effect (DRIPE) as an additional capacity benefit, which were adopted by the Massachusetts utilities and used in the b/c analysis in this plan.

Avoided electric energy and capacity values incorporate a reserve margin, pool transmission losses incurred from the generator to the point of delivery to the distribution companies, and a retail adder as recommended by the AESC Study consultant. The current ISO-NE reserve margin is incorporated, since energy efficiency avoids the back-up reserves for that generation as well as the generation itself. The avoided costs do not include non-pool transmission losses or distribution losses. They also do not include company specific avoided transmission and distribution capacity values.

Q. Then how are company specific avoided transmission and distribution values quantified?

A. As noted, avoided Transmission and Distribution ("Avoided T&D") capacity values used in the analysis are utility specific. The Company's avoided T&D values were developed from the Long-Run Marginal Cost of Service and Loss studies from Docket D.T.E. 02-25, the Company's petition for a General Increase in Electric Rates, filed in May 2002. The 2008 avoided T&D values are $17.13/kWYr for transmission and $155.56/kWYr for distribution capacity. These values are assumed to be constant in 2008 $ throughout the TRC analysis period.

Demand and energy losses account for local transmission and distribution losses from the point of delivery to the distribution companies' system to the ultimate customer's facility. Since they are a function of the individual utility's system, losses are also calculated on a utility-specific basis.

Q. How does the model compute the net value of the DER project under review?

A. The dollar value of the program's benefits is calculated by multiplying the expected savings by the appropriate avoided value component. The avoided value component for each benefit (fuel, non-fuel or non-resource) is the cumulative net present value (2009$'s) of lifetime avoided costs for each year of the planning horizon from the base year. For example, the avoided value component in Year 10 for any given benefit is the sum of the net present value of the annual avoided costs for the resource for Year 1, Year 2, Year 3, etc. through Year 10, in 2009 dollars. This value is applied to the annual savings for a measure with a 10 year life to generate the lifetime avoided benefit for that measure. Since all of the future year values are in constant 2009 dollars, lifetime benefits thus calculated are discounted back to 2009 using a real discount rate equal to [(1 + Nominal Discount Rate) / (1 + Inflation)] -1.

Q. When calculating the DER benefits for the Participating customer, aren't the actual benefits simply the sum of the reduced electricity bills over the life of the DER project?

A. Technically, that is correct. However, from a practical matter, the calculation of offset electricity costs based on actual customer rates will be predicated on a number of forward looking assumptions including rate schedule, monthly usage (hourly usage for time-of-use customers), peak demands and generation cost adjustments. As a result, the analysis of each DER project would require a very detailed and customer-specific assessment of cost savings resulting from the proposed DER project. Considering the relative size and scale of each project, the time commitment and cost to perform such a study for each individual project does not outweigh the potential impact on forecast accuracy when using avoided costs as a surrogate.

Q. Is it your belief that the use of avoided costs as a surrogate for average prices is a conservative assumption?

A. Yes, I do. First, over the long run average prices should approach avoided costs. So, a long term DER project will likely result in very similar results whether using average prices or avoided costs. Second, and pragmatically, a large percentage of retail electricity prices are generation based (between 40% – 60%), which is priced at near term clearing prices. This means that for either approach we would use the same or similar assumptions to calculate generation based benefits. In conclusion, we believe that the use of the UES avoided cost model provides a reasonable assessment of DER project benefits without undo bias in either direction.

Q. You also mentioned that this model computes the demand reduction induced price effect or DRIPE. Please explain how the DRIPE is computed and why it is an essential component of the DER cost/benefit analysis?

A. The AESC Study also quantified a price reduction benefit associated with energy efficiency. This benefit is referred to as the Demand Reduction Induced Price Effect (DRIPE). DRIPE is the reduction of wholesale energy and capacity market prices that results from reductions in demand as a result of conservation efforts. The AESC study recommended that these reductions be included in benefit-cost screening. Briefly, capacity DRIPE was estimated using projections of the theoretical effect DSM would have on what the cost of new generation would be. Energy DRIPE was estimated by analyzing the interactions of small changes in load in each zone on the clearing prices in that zone and on neighboring zones. These estimates are very small when expressed in terms of impacts on the market prices of energy and capacity, i.e., reductions of a fraction of a percent. These impacts are projected to dissipate over four to five years as the market reacts to the new, lower level of energy and capacity required. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Thus, consideration of DRIPE impacts can increase the cost effectiveness of DSM programs on the order of 15% to 20%, because the estimated absolute dollar benefits of DRIPE are being attributed to a relatively small quantity of reductions in energy and/or capacity.

Q. Are there any other economic factors that the 2009 UES model derives?

A. Yes, there are. The 2009 UES model also computes the estimated environmental benefits associated with the avoidance of electric generation. The 2009 UES model estimates the amount of carbon dioxide that is avoided should the design of a DER project result in energy savings either through improved efficiencies or a shift in demand from peak periods when greenhouse gases are at a maximum to off-peak period when a greater portion of generation is nuclear and hydroelectric.

III. LOCALIZED SYSTEM BENEFIT MODEL

Q. As discussed above, the 2009 UES model does calculate utility specific benefits for avoided T&D investments. Does this assessment accurately quantify DER projects that can reduce or defer the need for a specific distribution investment?

A. While the UES model does compute avoided T&D investments, they are generic representations of the average system impact. DER provides the added benefit of deferring system infrastructure improvements on a localized level. In order to derive this very specific effect, a model has been developed to be used as a method to quantify the benefit DER projects have on a local level.

Q. Explain how this model was developed.

A. The approach we took was to conduct an engineering review of the specific benefits of DER projects located in different parts of the system. In an attempt to make the benefit analysis on the local system more efficient, three categories were developed: 1) System Level Benefit, 2) Substation Level Benefit, and 3) Circuit Level Benefit.

Q. Please describe what the system level benefit is.

A. A DER project that provides System Level Benefit can be connected anywhere on the system. Any load offset from the system will have an effect of deferring system level projects such as new system supply points or added capacity at existing supply points.

Q. And what is the substation level benefit?

A. A DER project that provides Substation Level Benefit is generally connected close to, if not directly, at the substation. Any load offset from the substation will have an effect of deferring substation level projects such as new substation power transformers or upgrading other substation equipment. DER projects that provide Substation Level Benefit also provide a System Level Benefit.

Q. Finally, please explain what the circuit level benefit is?

A. A DER project that provides circuit level benefit is physically connected on the circuit level or even at a customer location. The amount of load offset through DER would have an effect of deferring circuit level improvements (reconductoring, voltage conversions, load transfers, etc.) for a given period of time. Projects that provide circuit level benefit would also provide a System Level Benefit and a Substation Level Benefit.

Q. How do you then calculate total system benefits?

A. The model used to complete the benefit analysis is a combination of: 1) the most recent three year capital budget forecast of known capital improvement projects; and 2) system level, substation level, and circuit level peak demand load forecasts. The model is designed to develop the benefit of deferring 1 kVA of demand for by one year. The benefit is calculated by dividing the average annual cost of a project in a certain category by the average peak demand growth each project is trying to address. That amount is then multiplied by the weighted average cost of capital to develop the savings produced by deferring a project within a specific category by one year.

To use this model, you can add up the applicable system level, substation level, and circuit level benefits and multiply that amount by the expected kVA of the DER at the time of the system peak demand. The result is the cost that the Company has deferred through the installation of the DER.

IV. ECONOMIC DEVELOPMENT BENEFITS

Q. RSA 374G:5 also requires an assessment of economic development benefits. Please explain how economic impacts are assessed?

A. Generally, it is our belief that most of the DER projects that we are considering will have a direct and immediate impact on the local economy. Recall that a DER project will be one that addresses a need at the local distribution level. For DER projects that improve the customer's operational efficiency, the most immediate benefit is the reduction of electric consumption. Assuming, hypothetically, the cost benefit analysis results in a break even between DER installation and operation expenses as compared to avoided production costs, the local economy benefits as a greater percentage of those same dollars are spent locally. The greater the benefit cost ratio, the greater the impact on the local economy.

Q. So the economic development benefit will, at maximum, be equal to the investment and operational costs of the DER project, assuming all components are manufactured locally?

A. That is not correct. The actual local investment and operational costs only measure direct impacts on the local economy. For example, $100,000 spent on a DER project as opposed to $100,000 spent on electricity generated in another state, would have a direct impact of $100,000 infused into the local economy. However, this direct affect also has a number of secondary impacts often referred to as the multiplier effect.

Q. Please explain what the multiplier effect is.

A. Using the above example, $100,000 infused into the local economy may take the form of wages & salaries, materials and goods and machinery and equipment. As salaries and wages increase, workers tend to spend locally on such things as groceries, new cloths and even new houses. As materials and goods are purchased, local distributors and manufacturers expand their facilities and add new employees. Once again, this expansion is met with growth in demand and supply. For each dollar spent locally, depending of course on the nature of the expenditure, the multiplier effect is the number of times that initial dollar is spent in the local economy. We can measure those impacts in terms of new employees, salaries and wages and net economic growth.

Q. How is the economic multiplier derived?

A. For each business category, for example restaurants versus hospitals, the local impact can be derived. The more labor intensive the business function, the greater the employment multiplier. As an example, a typical multiplier for general economic output is about 2, namely for every dollar invested in a community, roughly two dollars are actually spent.

Q. Please explain how UES has derived these economic development multipliers?

A. There are a number of economic services who provide such analysis. UES has acquired from the federal Bureau of Economic Analysis (BEA), its Regional Input-Output Modeling System or RIMS II for the two counties that UES serves in New Hampshire, namely, Rockingham and Marrimack. A copy of the RIMS summary report is attached as Schedule HJA-1. It is my opinion that the RIMS II economic multipliers are the most widely used and impartial assessments of economic impact available to governmental agencies and businesses. The RIMS II output tables provides economic multipliers for employment, wages and salaries and output that specifically measures changes in these two counties.

Q. Can you briefly explain how the RIMS II process works and what are its key advantages over other economic models?

A. In response to this question, I have extracted from the BEA website the following information.

In summary, "RIMS II is based on an accounting framework called an I-O table. For each industry, an I-O table shows the distribution of the inputs purchased and the outputs sold. A typical I-O table in RIMS II is derived mainly from two data sources: BEA's national I-O table, which shows the input and output structure of nearly 500 U.S. industries, and BEA's regional economic accounts, which are used to adjust the national I-O table in order to reflect a region's industrial structure and trading patterns.[1]

Using RIMS II for impact analyses has several advantages.[2] RIMS II multipliers can be estimated for any region composed of one or more counties and for any industry or group of industries in the national I-O table. The cost of estimating regional multipliers is relatively low because of the accessibility of the main data sources for RIMS II. According to empirical tests, the estimates based on RIMS II are similar in magnitude to the estimates based on relatively expensive surveys." [3]

Q. Please explain how the RIMS multipliers are used.

A. The BEA states that to "effectively use the multipliers for impact analysis, users must provide geographically and industrially detailed information on the initial changes in output, earnings, or employment that are associated with the project or program under study. The multipliers can then be used to estimate the total impact of the project or program on regional output, earnings, or employment."

As a first step in our process, for each DER project we assumed that the types of investments that will be locally made fall into one of two categories: either utilities or construction. For each dollar investment, we can then determine what the multiplier is for the region, in general, or among some sixty end-user groups.

It is interesting to note that the Final-Demand Output multiplier, which is a broad measure of regional economic development impact, is 1.85 for the construction trades versus 1.23 for utility investments. This further suggests the positive economic development impact of shifting utility investments for local construction. While not all

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[1] See U.S. Department of Commerce, Bureau of Economic Analysis, *Benchmark Input-Output Accounts of the United States, 1987*(Washington, DC: U.S. Government Printing Office, 1994); and U.S. Department of Commerce, Bureau of Economic Analysis, *Local Area Personal Income, 1969–92* (Washington, DC: U.S. Government Printing Office, 1994).

[2] 4. For a discussion of the limitations of using I-O models in impact analysis, see Daniel M. Otto and Thomas G. Johnson, *Microcomputer-Based Input-Output Modeling* (Boulder, CO: Westview Press, 1993), 28–46.

[3] See *Regional Input-Output Modeling System (RIMS II)*, 39–57 ; and Sharon M. Brucker, Steven E. Hastings, and William R. Latham III, "The Variation of Estimated Impacts from Five Regional Input-Output Models," *International Regional Science Review* 13 (1990): 119–39.

DER investments will be considered construction, this is a strong indicator that any DER investments should have a positive economic development impact.

Q. Who else uses the RIMS multipliers to assess economic impact?

A. The BEA claims that "RIMS II is widely used in both the public and private sector. In the public sector, for example, the Department of Defense uses RIMS II to estimate the regional impacts of military base closings, and state departments of transportation use RIMS II to estimate the regional impacts of airport construction and expansion. In the private sector, analysts, consultants, and economic development practitioners use RIMS II to estimate the regional impacts of a variety of projects, such as the development of theme parks and shopping malls."

Q. Do the BEA RIMS II multipliers provide an accurate forecast of economic benefits resulting from a DER investment?

A. The RIMS multipliers provide a reasonable assessment of economic impact. Because the multipliers are based on historical relationships, any forward looking projection is limited to the understanding that the past may not represent the future. However, the RIMs multipliers do represent a reasonable approximation or ballpark estimate that provides at good estimate of how dollars invested in a community impact employment and the economy in general. We can also tell from the RIMs multipliers the relative advantage of one type of investment over another. For example, the utility employment multiplier is 2.13 versus the construction trades at 11.62. This means that for every $1 million invested in the community, if it were done by a utility it would generate 2.13 jobs as compared to 11.62 jobs if the same amount of money was spent at a general construction site.

V. SUMMARY SCREENING REPORT

Q. Have you prepared a summary report which identifies the costs and benefits for each DER project and how those costs are allocated between the project participant, default customers and all other customers?

A. Yes, I have. Schedule HJA-2 is a sample summary report that was developed for each DER project. This report presents the costs and benefits as derived from the three analytical models we used to assess each DER project. The three models included the UES marginal cost spreadsheet, the locational specific distribution analysis and the RIMSII economic impact assessment.

The Summary Report identifies the project name, project cost as well as Until's expected contribution. Other non-monetary or intangible benefits such as load reduction, energy saved and jobs created are also provided. The primary economic benefits include both capacity and energy related decremental costs resulting from the reduction in peak loads and electric energy saved. Other benefits such as DRIPE (Demand Reduction-Induced Price Effect), CO_2 Credit and Renewable Energy Certificates (RECs) are listed.

Q. How did you allocate the derived DER benefits among UES's customers including default customers as well as the DER project participant?

A. For the proposed DER projects we assumed that the energy and capacity saved by the application of the DER project would be derived by the participating customer via reduced energy and capacity expenses. All other distribution customers would reap the benefit of DRIPE savings, CO_2 credits and the benefits of increases in economic output, wages and salaries and additional jobs induced by the local investment in DER projects. Default Service customers would also see the benefits of any RECs credits retained by the Company, under the assumption that those credits would be used by the Company towards fulfillment of its RPS compliance obligations.

Finally, the Benefit/Cost (B/C) ratio is derived for the total project, participant and all other customers. A B/C ratio of greater than one means that benefits exceed costs. A B/C ratio of less than one does not necessarily mean that a project should not be supported. Other less tangible benefits might offer either economic or environmental advantages that may not be easily translated into a monetary value.

VI. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

RIMS II Multipliers (2006/2006)
Table 2.5 Total Multipliers for Output, Earnings, Employment, and Value Added by Industry Aggregation
New Hampshire

INDUSTRY	Multiplier					
	Final Demand				Direct Effect	
	Output/1/ (dollars)	Earnings/2/ (dollars)	Employment/3/ (jobs)	Value-added/4/ (dollars)	Earnings/5/ (dollars)	Employment/6/ (jobs)
1. Crop and animal production	1.4992	0.2614	18.7793	0.6533	1.5437	1.1990
2. Forestry, fishing, and related activities	1.6461	0.3432	11.9843	0.8060	1.5984	1.6239
3. Oil and gas extraction	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4. Mining, except oil and gas	1.4950	0.2754	5.7675	0.8887	1.5282	1.7736
5. Support activities for mining	1.8755	0.4441	10.2824	1.0345	1.7572	2.1368
6. Utilities*	1.2345	0.1333	2.1336	0.7381	1.5481	2.6009
7. Construction	1.8523	0.4282	11.6215	0.9784	1.6449	1.6900
8. Wood product manufacturing	1.8664	0.2974	8.2395	0.7936	2.2022	2.1416
9. Nonmetallic mineral product manufacturing	1.7301	0.2947	6.4332	0.8465	1.9006	2.2001
10. Primary metal manufacturing	1.5931	0.2349	5.1948	0.5986	1.9101	2.1293
11. Fabricated metal product manufacturing	1.6303	0.2745	6.2623	0.7731	1.7933	1.9531
12. Machinery manufacturing	1.7511	0.3110	6.3031	0.8079	1.8630	2.2750
13. Computer and electronic product manufacturing	1.8436	0.2920	5.4320	0.8305	2.2838	3.4656
14. Electrical equipment and appliance manufacturing	1.7282	0.2573	5.3623	0.7778	2.1178	2.5267
15. Motor vehicle, body, trailer, and parts manufacturing	1.6664	0.2455	5.1693	0.5621	2.0756	2.5448
16. Other transportation equipment manufacturing	1.3871	0.2155	3.8710	0.6776	1.5577	2.0790
17. Furniture and related product manufacturing	1.7746	0.3309	9.1364	0.8013	1.8116	1.7430
18. Miscellaneous manufacturing	1.7633	0.3512	7.1845	0.8808	1.7160	2.0567
19. Food, beverage, and tobacco product manufacturing	1.8095	0.2465	7.0789	0.6707	2.6533	3.6504
20. Textile and textile product mills	1.6615	0.2269	5.2152	0.6307	2.1250	2.2771
21. Apparel, leather, and allied product manufacturing	1.5642	0.2134	6.9030	0.8293	1.9528	1.6570
22. Paper manufacturing	1.5981	0.2552	5.3221	0.6574	1.8456	2.2035
23. Printing and related support activities	1.7133	0.3654	9.2072	0.8724	1.6223	1.6627
24. Petroleum and coal products manufacturing	1.5309	0.1596	3.0735	0.4619	2.8340	4.9699
25. Chemical manufacturing	1.7045	0.2429	4.6945	0.7173	2.2310	3.0268
26. Plastics and rubber products manufacturing	1.6825	0.2489	5.5931	0.7059	2.0037	2.2113
27. Wholesale trade	1.6178	0.3352	6.7948	1.0240	1.5767	2.0026
28. Retail trade	1.6687	0.3475	12.4131	1.0251	1.5735	1.3954
29. Air transportation	1.5179	0.2292	5.7437	0.6520	1.9169	2.4286
30. Rail transportation	1.5665	0.2645	5.0500	0.9049	1.7240	2.4726
31. Water transportation	1.7186	0.2090	5.9081	0.6918	3.5341	2.9261
32. Truck transportation	1.7414	0.3329	8.6801	0.8959	1.8068	1.8725
33. Transit and ground passenger transportation*	1.7399	0.4510	20.8259	0.9240	1.5096	1.2665
34. Pipeline transportation	1.5613	0.2410	4.2828	0.6663	2.0175	4.0398
35. Other transportation and support activities*	1.4895	0.3642	8.5748	1.0619	1.3677	1.5124
36. Warehousing and storage	1.6315	0.4696	13.3678	1.1406	1.3331	1.3632
37. Publishing including software	1.7510	0.3273	6.9389	0.9722	1.8708	2.5652
38. Motion picture and sound recording industries	1.5659	0.2720	12.2666	0.7867	1.6694	1.3547
39. Broadcasting and telecommunications	1.8426	0.2130	4.6477	0.9012	2.6233	3.6648
40. Information and data processing services	1.6740	0.2944	7.4652	0.8290	1.8449	2.1394
41. Federal Reserve banks, credit intermediation and related services	1.4265	0.2294	5.3911	1.0211	1.6153	1.8247
42. Securities, commodity contracts, investments	1.7882	0.4735	8.8753	0.9860	1.5191	1.9625

(Continued)

Region Definition: Merrimack, NH; Rockingham, NH

*Includes Government enterprises.
1. Each entry in column 1 represents the total dollar change in output that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
2. Each entry in column 2 represents the total dollar change in earnings of households employed by all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
3. Each entry in column 3 represents the total change in number of jobs that occurs in all industries for each additional 1 million dollars of output delivered to final demand by the industry corresponding to the entry. Because the employment multipliers are based on 2006 data, the output delivered to final demand should be in 2006 dollars.
4. Each entry in column 4 represents the total dollar change in value added that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
5. Each entry in column 5 represents the total dollar change in earnings of households employed by all industries for each additional dollar of earnings paid directly to households employed by the industry corresponding to the entry.
6. Each entry in column 6 represents the total change in number of jobs in all industries for each additional job in the industry corresponding to the entry.
NOTE.--Multipliers are based on the 2006 Annual Input-Output Table for the Nation and 2006 regional data. Appendix C identifies the industries corresponding to the entries.
SOURCE.--Regional Input-Output Modeling System (RIMS II), Regional Product Division, Bureau of Economic Analysis.

RIMS II Multipliers (2006/2006)
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	Output/1/ (dollars)	Earnings/2/ (dollars)	Employment/3/ (jobs)	Value-added/4/ (dollars)	Earnings/5/ (dollars)	Employment/6/ (jobs)
43. Insurance carriers and related activities	2.0575	0.3534	6.8718	0.9965	2.1553	2.6893
44. Funds, trusts, and other financial vehicles	1.7487	0.3190	9.3564	0.6600	2.1970	1.7034
45. Real estate	1.4127	0.1212	4.5590	0.9396	2.7875	1.9345
46. Rental and leasing services and lessors of intangible assets	2.0073	0.3002	8.7230	0.9824	2.7767	2.6818
47. Professional, scientific, and technical services	1.7762	0.4678	10.4853	1.0842	1.5125	1.7992
48. Management of companies and enterprises	1.6745	0.3305	5.5618	0.9996	1.6316	2.6890
49. Administrative and support services	1.7474	0.4306	15.5683	1.0619	1.5403	1.4170
50. Waste management and remediation services	1.7661	0.3319	7.7966	0.9105	1.8258	2.1619
51. Educational services	1.8132	0.4987	17.1852	1.0689	1.4391	1.3694
52. Ambulatory health care services	1.7534	0.5037	11.2058	1.1122	1.4200	1.6438
53. Hospitals and nursing and residential care facilities	1.8606	0.4877	13.1142	1.0496	1.5066	1.5945
54. Social assistance	1.7396	0.4369	23.1636	1.0350	1.4657	1.2135
55. Performing arts, museums, and related activities	1.7031	0.5061	26.2689	1.1020	1.4266	1.2603
56. Amusements, gambling, and recreation	1.6978	0.3817	19.4657	1.0434	1.5147	1.2402
57. Accommodation	1.6012	0.2675	10.2459	0.9658	1.7549	1.4709
58. Food services and drinking places	1.6633	0.3093	15.9131	0.8674	1.6102	1.2788
59. Other services*	1.7626	0.3852	13.9918	0.9305	1.6218	1.4378
60. Households	1.1037	0.2177	6.8272	0.6487	0.0000	0.0000

Region Definition: Merrimack, NH; Rockingham, NH

*Includes Government enterprises.
1. Each entry in column 1 represents the total dollar change in output that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
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NOTE.–Multipliers are based on the 2006 Annual Input-Output Table for the Nation and 2006 regional data. Appendix C identifies the industries corresponding to the entries.
SOURCE.–Regional Input-Output Modeling System (RIMS II), Regional Product Division, Bureau of Economic Analysis.

Summary Report
Sample DER Project

Unitil Investment	$130,000
Total Project Cost	$130,000
Other Intangible Benefits	
Load Reduction	
Summer	39
Winter	39
Lifetime	512
MWh Saved	
Annual	103
Lifetime	1,343
Economic Development	
Jobs Created	1
Wages & Salaries	$48,506

Allocation of Economic Benefits

	Total	Participant	All Customers	Default
Capacity				
Generation				
Summer	$51,109	$51,109		
Winter	$0	$0		
Transmission	$5,024	$5,024		
Distribution	$15,499	$15,499		
DRIPE	$10,346		$10,346	
Localized Distribution	$3,256		$3,256	
Total Capacity	**$85,235**	**$71,632**	**$13,603**	**$0**
Energy				
Winter				
Peak	$33,310	$33,310		
Off peak	$28,403	$28,403		
Summer				
Peak	$16,783	$16,783		
Off peak	$13,775	$13,775		
Total Energy	**$92,272**	**$92,272**	**$0**	**$0**
Other				
Energy				
Dripe	$13,074		$13,074	
Non-Electric				
CO_2 Reduction	$34,559		$34,559	
REC Credit	$10,335		$10,335	$10,335
Total Other	**$57,968**	**$0**	**$57,968**	**$10,335**
Economic Development				
Total Output	**$89,605**		**$89,605**	
Total Benefits	**$325,079**	**$163,904**	**$161,176**	**$10,335**
B/C Ratio	**2.50**	**N/A**	**1.24**	

UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

CINDY L. CARROLL

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business affiliation.

A. My name is Cindy Carroll and I am the Director of Customer Field Services, formerly Business Services, with Unitil Service Corp., and I am testifying on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company"). As Director of Business Services I have been responsible for energy efficiency program design, evaluation, administration, reporting and implementation as well as key customer account management and business and economic development. With the recent organizational changes, the responsibility for energy efficiency and DER program planning and management fall into the new DER group reporting to Mr. Gantz, and my responsibilities will focus on customer field services including the field delivery of energy efficiency and DER initiatives. My business address is 325 West Road, in Portsmouth, NH.

Q. Please summarize your qualifications and current position with the company.

A. I joined Unitil Service Corp. in 1997. I also have 20 years of professional experience in the utility industry primarily in business development. My primary responsibilities have included the development, implementation and advancement of the Company's business expansion and economic development programs, energy efficiency programs and critical customer management.

I received an MBA from Southern New Hampshire University in 1998 and my Bachelor of Arts degree in Communications from the University of New Hampshire in 1985. Since joining Unitil Service Corp. as Business Development Executive in 1997, I have held several progressively challenging management positions in the areas of sales, marketing, business and economic development. Prior to joining Unitil Service Corp., I was a Regional Sales Executive with Bay State Gas Company where I generated revenue from the sale of natural gas and other energy related products and services, and developed positive, long-term business relationships with large commercial and industrial customers and trade allies.

I have been active in various industry associations, committees and events. I am also a member of the Board of Directors of Big Brothers Big Sisters of the Greater Seacoast, the Maine State Chamber of Commerce and Maine & Company Inc. and a past member of the Board and Chair of the Exeter Area Chamber of Commerce.

Q. What is the purpose of your testimony?

A. In my testimony I will describe three DER projects that UES plans to complete during 2009 and early 2010. I will also demonstrate that based upon our cost/benefit analysis, including an assessment of environmental and economic impacts, each of the projects meet the public interest test as defined in RSA 374:G. For each project I will provide the following information:

- A description of the project
- An estimate of the installation costs
- A determination of system impact: both general or specific
- An assessment of cost/benefit, and economic and environmental impact.
- A projection of expenses and capital charges.

Q. Please identify the three DER projects being offered in this testimony.

A. This filing will present three DER projects to be completed in 2009:

- Solar Domestic Hot Water: Crutchfield Place – Concord Housing Authority
- Solar PV Electric Project - Stratham Municipal
- Solar PV and Micro Combined Heat and Power (CHP) – Exeter SAU 16

Q. At what stage of development is each project and is UES prepared to immediately begin installation upon Commission approval?

A. During 2008 and 2009, UES staff assessed a wide variety of possible DER projects, both company owned and company supported. We have met with equipment manufacturers, vendors, developers and UES customers who have indicated an interest in partnering with UES in such a program.

Based on this assessment, three DER projects were identified as technologically feasible, and economically viable, with a high probability of being completed quickly. While actual start-up will depend on a number of factors including permitting, final design and delivery of equipment, we are confident that construction, testing and start-up can be accomplished in 2009 and early 2010 assuming, of course, that they are approved by the New Hampshire Public Utilities Commission ("Commission"). It should be further noted that at this juncture UES is only seeking the Commission's endorsement that as proposed, each of the DER projects meet the public interest test as outlined in Chapter 374G:5. If the Commission also approves our proposed bifurcated DER rate process, UES will file for cost recovery during the fourth quarter of this year.

Q. How will the Company move forward with these customers in terms of procuring equipment and services necessary to complete the projects?

A. Once approval from the Commission has been received, the Company expects to work in collaboration with the customers and our consultants on the identification and selection of equipment and vendors. In this effort, the Company recognizes its obligation to promote the development of local economic activity including support for local vendors and contractors and will insure that those interests are incorporated in the procurement process.

II. Solar Domestic Hot Water System (Crutchfield Place)

Q. Please provide a summary description of the proposed solar domestic hot water system.

A. Schedule CLC-1 is a copy of the signed Memorandum of Understanding (MOU) between UES and the Concord Housing Authority. The MOU provides detailed information as to the scope and purpose of the Crutchfield Place DER project. In summary, this project is a Solar Domestic Hot Water (DHW) system to replace the existing electric DHW system at Crutchfield Place, a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority. The existing system is a 120KW, 333Amp, 208V 3 phase electric heating element contained within a 1500 gallon water storage tank. The system is supplemented by a 170KBtu gas Ray Pac heater. We propose to replace this system with a solar water heating system including storage tanks and solar collectors.

Q. Why is UES proposing to install this solar hot water heating system and what are the primary benefits associated with this DER project?

A. This project offers a number of benefits to both UES and its customers. First and foremost, this solar hot water heating system is highly cost effective for both Crutchfield Place as well as all other UES customers. Schedule CLC-2 is a summary report of the economic and environmental benefits that we expect from this solar domestic hot water heating system. The summary provides the output for the Screening model developed by Mr. Axelrod, with the input data for the project as identified in Schedule CLC-1.

Q. How does this project generate such savings?

A. The existing hot water system is heated with a 120KW electric element contained within a 2,400 gallon pressurized water storage tank. The existing system is also equipped with an 85% efficient natural gas boiler for emergency backup. Demand for domestic hot water at Crutchfield is approximately 2,536 US Gal per day for its elderly permanent residents. The system draws approximately 18,260 kWh per month at an average cost of $0.168 per kWh or $3,067.68 monthly.

The proposed Apricus Solar DWH system provides one hundred percent of building DHW needs from April through November and sixty percent from December through March. Based on these operating characteristics, nearly 190,000 kWh are saved each year, which would have cost approximately $32,000. On a non-inflation adjusted basis, it would take about 2.4 years to save enough electricity to pay back the initial cost for this project.

Q. What are the estimated project costs?

A. Schedule CLC-1 provides a breakdown of projected capital costs. Note that added to the initial direct costs of $78,400 for the system, we have added a factor of thirty percent to account for estimated overhead and administrative costs that UES expects to incur in the process of working with the customer on the completion of the design and installation of the project. UES will account for the direct costs and overheads in accordance with its normal plant accounting procedures and document all charges in its construction work order process. The total estimated investment for this project is $101,920.

Q. Please summarize the benefits that this project will have for both the Concord Housing Authority and all other customers including default customers?

A. Overall, this initial investment of approximately $102,000 will produce over $387,000 in direct benefits for the participating customer, Crutchfield Place, over $218 thousand for all other UES customers and nearly $19 thousand for UES' default customers. From a benefit/cost (B/C ratio) perspective, this DER project has an overall B/C ratio of 5.95 and 2.14 for all other UES customers.

Q. What other benefits are derived from this DER project?

A. We have also evaluated the environmental and economic development impacts as well. The annual energy savings of approximately 190,000 kWh reduces the amounts of air emissions derived from electric production in New England. Assuming this displaced electricity was produced by an efficient combined cycle gas turbine, carbon emissions would be reduced by about 760 tons (CO_2) each year. This is based upon an emissions rate of .4 tons per MWh. To put this in some perspective, the 760 tons saved is equivalent to the emissions from 100 automobiles.

Because this system utilized renewable solar energy, it should also qualify for Renewable Energy Cerificates or RECs. Although the value of each REC in New England varies, at an assumed value of $100 per MWH, this DER project could generate approximately $19,000 in REC-based benefits.

Q. What is the estimated economic value of this environmental benefit?

A. CO_2 emissions are currently being traded within the RGGI (Regional Greenhouse Gas Initiative) conference of which New Hampshire is a member. Under the RGGI process, the participating states will stabilize power sector CO_2 emissions at the capped level through 2014. The cap will then be reduced by 2.5 percent in each of the four years 2015 through 2018, for a total reduction of 10 percent. In September 2008, RGGI held its first CO2 auction and all of the 12,565,387 allowances offered for sale on September 25, 2008 were sold at a clearing price of $ 3.07 per allowance. The 760 tons saved by this DER project would have an added environmental benefit of approximately $2,333 assuming the RGGI auction rate. However, there have been a number of international (KYOTO Accord) and federal legislative initiatives to create either a Carbon Tax or a CO_2 Cap and Trade program that many estimate will cause CO_2 allowances to rise to $20 - $40 per ton. At $20 per ton, this DER project could save and additional $15,000 a year.

Q. Are there any additional economic development benefits derived from the installation of this DER project?

A. Yes, there are. Since the investment in this DER project substitutes local construction for central station generation, imported fuels and utility transmission and distribution investment, there are direct economic development benefits. Dr. Axelrod obtained from the RIMS II tables the Final-Demand multipliers for regional Output, a measure of overall economic development and growth in employment. The Final Demand multipliers can be used to estimate economic impacts associated with known changes in the local economy, for example, a capital injection such as a new stadium or military base. In our case, we are using the initial capital cost of the DER project, which is estimated at $78,000. The Final Demand multiplier for Output is 1.8523, which means the $78,000 investment will translate into approximately $144,479 of local economic development. The Final-Demand multiplier for Employment is 11.6215. This means there are 11.6215 jobs per million dollars of investment. The $78,000 investment therefore translates into roughly one new full time job ($78,000/1,000,000 times 11.6215 = .906 FTE jobs)

III. Solar PV Electric Project - Stratham Municipal

Q. Please describe your second DER project, the Stratham Municipal Solar project.

A. Schedule CLC-3 is the signed MOU between UES and Stratham and provides a detailed description of this DER project. The proposal is to install 202 panels of BP Solar SX 3195, 195 watt or equivalent on the new Stratham Fire House, which has been prepared for the array. The PV array will be on a ballasted racking system, with no penetration of roof membrane. The installation will also include a SMA Sunnyboy 7000 inverter or equivalent, Sunny WebBox central data acquisition and diagnosis unit. Not only will this solar project produce over 100,000 kwh of electricity per year, it will reduce UES' peak demand by nearly 40 kilowatts.

Q. What is the total cost for this DER project?

A. Schedule CLC-3 provides a breakdown of project direct costs, which totals $307,174. With overheads included we estimate a total cost of $399,321.

Q. Please summarize the economic and environmental benefits that will be derived from this solar electric DER project.

A. Schedule CLC-4 is a summary report, similar to Schedule CLC-2, which provides a breakdown of economic and environmental benefits that we expect from this DER project. In summary, the Stratham Municipal photo-voltaic system will generate approximately $510,000 in total benefits, with $163,000 in savings for the Stratham municipality and $347,000 in benefits for all other UES customers. The overall B/C ratio is positive (1.28), however the B/C ratio for UES's other customers is .87. Given the educational and public benefits of this project and the fact that our estimates for lifetime benefits are conservative, we feel funding this project is, on balance, in the public interest. In fact, we hope that this DER project will serve as a model for other municipalities in New Hampshire and that future economy and technological advancements will validate the true economic benefit of PV systems such as being proposed for Stratham.

IV. Solar PV and Micro Combined Heat and Power (CHP) – Exeter SAU 16

Q. Please describe your third DER project, the Stratham Municipal Solar project.

A. Schedule CLC-5 is the signed MOU between UES and School Administrative Unit (SAU) 16 of Exeter and provides a detailed description of this DER project. In summary, SAU 16 is seeking to carry out an innovative project designed to provide more efficient, environmentally friendly energy to the school system. Through the incorporation of the microturbine and solar PV array, the school aims to reduce overall energy costs through the generation of onsite electricity, lower heating fuel related expenses through the installation of a more efficient heating system, divert the related energy savings to critical curriculum based programs, and demonstrate the possibilities available to SAU districts (and others) across the State regarding alternative forms of energy. This project is truly unique to New Hampshire, and should establish the high water mark for school districts throughout the State to strive for. In light of current economic conditions, and state and municipal budget environment in particular, providing that every dollar possible go toward educational programs benefits our society as a whole.

The SAU 16 project will employ two forms of alternative, distributed energy generation. The first form is through the installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building. The second form will be the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Q. What is the total cost for this DER project?

A. Schedule CLC-5 also provides a breakdown of direct project costs of $860,000, of which UES has committed $200,000. Including overhead costs, we estimate total charges to the Company will amount to $260,000.

Q. Please summarize the economic and environmental benefits that will be derived from this solar electric DER project.

A. Schedule CLC-6 is a summary report, similar to Schedule CLC-2, that provides a breakdown of economic and environmental benefits that we expect from this DER project. In summary, this DER projects produces over $1.3 million in avoided costs for a net B/C ratio of 1.52. Because UES' investment is only $260,000, the B/C ratio is 2.46 based on net savings in avoided costs of $639,000. Default customers also reap a $45,000 benefit as well.

The environmental benefits from this DER project are also significant. As the largest photovoltaic array in New Hampshire, annual avoided electric production will be 453 megawatt-hours. This translates into an annual reduction of 579 tons of CO_2, the equivalent to removing 117 cars or light trucks from New Hampshire's roads. Finally, UES' $260,000 investment in this DER project should generate two additional full time jobs in New Hampshire.

Q. Why does UES plan to invest 100 percent of the projects costs for the Crutchfield and Stratham DER projects, but only 23 percent for SAU 16?

A. We believe that all three DER projects are important to New Hampshire, not only for the economic and environmental benefits as discussed above, but also as an important educational mechanism to stimulate the further development of renewable resources and alternative solutions to energy distribution investments. For Crutchfield and Stratham, neither entity had the alternative financial resources to move forward. UES believes that the economic, environmental and business development benefits clearly support UES's total investment in these DER projects. For SAU 16, the school district already had significant funding commitments and UES's portion allowed for the project to move forward at an expedited pace.

V. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

MEMORANDUM of UNDERSTANDING
BETWEEN
Concord Housing Authority (CHA)
and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal
(DRAFT 7-6-09)

WHEREAS: CHA intends to install a DER project as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and CHA (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and CHA confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $78,400 up to a maximum of $__<+10%>___. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. CHA will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

* 5.0 CHA will make a reasonable and timely effort to seek and secure any additional funding that may be required to completely fund the project.

6.0 CHA will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. CHA will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

* CHA will explore the availability of ARRA funding to support the project. JH

7.0 CHA agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between CHA and Unitil.

Acknowledged and agreed this 14 day of July, 2009:

By:

John Hoyt Jr.
(Name)
(Title) Executive Director
Concord Housing Authority

By:

Unitil Energy Systems, Inc. ("Unitil")

(Name)
(Title) Director, Business & Economic Development

Distributed Energy Resources (DER) Project Proposal

Project Title: Crutchfield Place – Concord Housing Authority

Description of Technology:

This project proposal is for the installation of a medium sized solar hot water pre heating system. The system would consist of (16) Apricus AP30 evacuated tubes roof rack mounted in four rows of four tilted at 50 degrees.

Solar water heating systems include storage tanks and solar collectors. The solar collectors used in this application are Evacuated-tube solar collectors (ETSC). The system has parallel rows of transparent glass tubes. Each tube contains a glass outer tube and metal absorber tube attached to a fin. The fin's coating absorbs solar energy but inhibits radiative heat loss. The system will also require one or more well-insulated storage tanks. Solar storage tanks have an additional outlet and inlet connected to and from the collector.

Description and Scope of Project:

Crutchfield Place is a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority. The existing system is a 120KW, 333Amp, 208V 3 phase electric heating element contained within a 1500 gallon water storage tank. The system is supplemented by a 170KBtu gas ray pac 85% efficient Natural Gas boiler for emergency backup. Demand for DHW at Crutchfield is approximately 2,536 US Gal per day for elderly residents. The system draws approximately 18,260 kWh per month at an average cost of $0.168 per kWH or $3,067.68 monthly. The proposed Apricus Solar DWH system will provide 100% of the facilities DHW needs April through November and 60% December through March, the system would be capable of heating 500 gallons of water approximately 80 degrees per average day.

Breakdown of Estimated Project Costs:

Project costs below include the equipment acquisition and equipment installation costs, the breakdown is as follows:

MEMORANDUM of UNDERSTANDING
Attachment A

Equipment	**Cost**
Apricus Collectors	$24,400.00
Racking	$9,900.00
Roofing	$7,200.00
Pipe and insulation	$16,200.00
Coring and patching	$2,900.00
Storage or heat exchanger	$13,800.00
Misc	$4,000.00
Total	**$78,400.00**

Any additional work will be billed at a rate of $65.00 per man per hour and actual cost plus 35% on all materials.

Summary of Project Benefits :

- Peak Demand Reduction: 120 KW maximum
- Installed Cost per Reduction in Peak Demand: $653.33 per KW
- Reduction in Customer Consumption 189,904 kWh/yr max, 120KW demand max
- Future O&M Estimated Cost: $ TBD per (month, quarter, annual)
- Demand Response dispatchable? No
- Renewable Energy Credits: Yes
- Tax Incentives: no

Summary Report

Crutchfield

Unitil Investment	$	101,920
Total Project Cost	$	101,920

Other Intangible Benefits	
Load Reduction	
Summer	120
Winter	90
Lifetime	
MWh Saved	
Annual	190
Lifetime	2,469
Economic Development	
Jobs Created	1
Wages & Salaries	$38,029

Allocation of Economic Benefits

	Total	Participant	All Customers	Default
Capacity				
Generation				
Summer	$155,702	$155,702		
Winter	$0	$0		
Transmission	$15,305	$15,305		
Distribution	$47,218	$47,218		
DRIPE	$31,520		$31,520	
Localized Distribution	$9,920		$9,920	
Total Capacity	**$259,664**	**$218,224**	**$41,440**	**$0**
Energy				
Winter				
Peak	$61,210	$61,210		
Off peak	$52,193	$52,193		
Summer				
Peak	$30,840	$30,840		
Off peak	$25,313	$25,313		
Total Energy	**$169,556**	**$169,556**	**$0**	**$0**
Other				
Energy				
Dripe	$24,024		$24,024	
Non-Electric				
CO2 Reduction	$63,505		$63,505	
REC Credit	$18,990		$18,990	$18,990
Total Other	**$106,520**	**$0**	**$106,520**	**$18,990**
Economic Development				
Total Output	**$70,250**		**$70,250**	
Total Benefits	**$605,990**	**$387,780**	**$218,210**	**$18,990**
B/C Ratio	**5.95**	**N/A**	**2.14**	

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TOWN OF STRATHAM

MEMORANDUM of UNDERSTANDING
BETWEEN
The Town of Stratham, New Hampshire
and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal
(DRAFT 7-6-09)

WHEREAS: The Town of Stratham, New Hampshire intends to install a DER project as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and The Town of Stratham, New Hampshire (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and The Town of Stratham, New Hampshire confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $ 300,000.00. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. The Town of Stratham, New Hampshire will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

5.0 The Town of Stratham, New Hampshire will make a reasonable and timely effort to seek and secure additional funding to offset Unitil's investment that may be required to completely fund the project. Examples of sources for additional funding may include; RGGI grants, rebates available through the Renewable Portfolio Standard – Alternative Compliance Payment administered by the NH Public Utility Commission or by town Warrant Article.

6.0 The Town of Stratham, New Hampshire will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. The Town of Stratham, New Hampshire will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

7.0 The Town of Stratham, New Hampshire agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between The Town of Stratham, New Hampshire and Unitil.

Acknowledged and agreed this 13th day of July, 2009:

By:

David Canada

David Canada
(Name) Chair,
(Title) Board of Selectmen

By:

Unitil Energy Systems, Inc. ("Unitil")

(Name)
(Title) Director, Business + Economic Development.

Unitil

Unitil Energy Systems, Inc.

July 14, 2009

Project Title:
STRATHAM MUNICIPAL SOLAR PROJECT
Appendix A

Project Sponsor:
TOWN OF STRATHAM
Contact: Caroline Robinson, 772-6646

Description of Technology:
+/- 202 PV solar panels + 1 inverter, to be bid by contractor following new RFP.
(Information below is from a January 2008 bid.)

The system design and components will meet all national, state, and local utility regulations for utility interconnected photovoltaic systems.

Description and Scope of Project: Grid connected photovoltaic power system

1. Installation of +/- 202 panels of BP Solar SX 3195-195 watt (or equivalent) on the new Stratham Fire House. The PV array will be mounted on a ballasted racking system, with no penetration of roof membrane;
2. Installation of one SMA Sunnyboy 7000 inverter (or equivalent), one Sunny WebBox central data acquisition and diagnosis unit;
3. Installation of all equipment and conduit, cables, fittings, connectors to NEC 690 standard;
4. Sign-off with Unitil and the local permit authority.

Breakdown of Estimated Project Costs:
Initial low bid as of January 2008: $307,174
New 2009 bids to be solicited through RFP.

Justification and Project Benefit (include major assumptions):

- Peak Demand Reduction: 39.390 kW
- Installed Cost per Reduction in Peak Demand: $7798 per kW
- Reduction in Customer Consumption: 64,698 kWh per year
- Generation: 64,698 kWh per year
- Future O&M Estimated Cost: To be estimated by contractor
- Ownership: 100% Town of Stratham
- Demand Response dispatchable? No
- Renewable Energy Credits: estimated at 64.7

- Tax Incentives: Zero at this time, as it will be funded by a gift from Unitil to the Town of Stratham, as per MOU.

  The Town of Stratham will also pursue funds from the State of NH's Renewable Energy Fund.

- Societal Benefits:

  1. The project will reduce our municipal footprint by at least 48 tons of CO_2 per year, the equivalent of taking at least 9.8 cars off the road.
  2. It will provide the Town of Stratham with an alternative source of renewable energy.
  3. It will zero out the expected yearly electrical costs associated with the Stratham Fire Station.
  4. It will provide a benefit to all Stratham residents through a reduction of taxes for municipal energy costs.
  5. In the case of a major regional or town-wide power loss, the solar system will continue to provide the firehouse with electricity. This will greatly benefit the emergency response capability of the staff and volunteers.
  6. It will serve as a model for other municipalities in NH.
  7. As of August 2009, it will become the fourth largest solar array in the state.
  8. It will generate positive publicity for municipal solar power, for Unitil, for the Town of Stratham and for the State of New Hampshire.

Concerns or Challenges:

1. Verifying the structural stability of the building.
2. Meeting the need for electrical engineering and design to fully integrate the solar system with the existing electrical systems and back-up systems of the firehouse. This is a potential set-up cost to the town.
3. Working out the details and negotiating the parameters of the pilot study with Unitil and the staff and volunteers of the Stratham Fire Department.

Relevant reference material: RETScreen analyses (available on request).

Summary Report
Stratham Municpal

Unitil Investment	$399,321
Total Project Cost	$399,321
Other Intangible Benefits	
Load Reduction	
Summer	39
Winter	39
Lifetime	512
MWh Saved	
Annual	103
Lifetime	1,343
Economic Development	
Jobs Created	4
Wages & Salaries	$148,997

Allocation of Economic Benefits

	Total	Participant	All Customers	Default
Capacity				
Generation				
Summer	$51,109	$51,109		
Winter	$0	$0		
Transmission	$5,024	$5,024		
Distribution	$15,499	$15,499		
DRIPE	$10,346		$10,346	
Localized Distribution	$3,256		$3,256	
Total Capacity	**$85,235**	**$71,632**	**$13,603**	**$0**
Energy				
Winter				
Peak	$33,310	$33,310		
Off peak	$28,403	$28,403		
Summer				
Peak	$16,783	$16,783		
Off peak	$13,775	$13,775		
Total Energy	**$92,272**	**$92,272**	**$0**	**$0**
Other				
Energy				
Dripe	$13,074		$13,074	
Non-Electric				
CO2 Reduction	$34,559		$34,559	
REC Credit	$10,335		$10,335	$10,335
Total Other	**$57,968**	**$0**	**$57,968**	**$10,335**
Economic Development				
Total Output	**$275,240**		**$275,240**	
Total Benefits	**$510,714**	**$163,904**	**$346,810**	**$10,335**
B/C Ratio	**1.28**	**N/A**	**0.87**	

MEMORANDUM of UNDERSTANDING
BETWEEN
NHSEP and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal

WHEREAS: **New Hampshire Seacoast Energy Partnership LLC "NHSEP"** intends to install a DER project through and on behalf of Exeter Region Cooperative School District as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and **NHSEP** (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and **NHSEP** confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $ 200,000.00 <+10%>. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. **NHSEP** will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

5.0 **NHSEP** will make a reasonable and timely effort to seek and secure any additional funding that may be required to completely fund the project.

6.0 **NHSEP** will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. **NHSEP** will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

7.0 **NHSEP** agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between **NHSEP** and Unitil.

Acknowledged and agreed this 16 day of July, 2009:

By:

NHSEP

Clay Mitchell
Member - NHSEP

By:

Unitil Energy Systems, Inc. ("Unitil")

(Name)
(Title) Director, Business & Economic Development

Distributed Energy Resources (DER) Project Proposal

Project Title: School Administrative Unit (SAU) 16

Description of Technology:

The SAU 16 project will employ two forms of alternative, distributed energy generation. The first form is through the installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building. The second form will be the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Description and Scope of Project:

SAU 16 is seeking to carry out an innovative project designed to provide more efficient, environmentally friendly energy to the school system. Through the incorporation of the microturbine and solar PV array, the school aims to reduce overall energy costs through the generation of onsite electricity, lower heating fuel related expenses through the installation of a more efficient heating system, divert the related energy savings to critical curriculum based programs, and demonstrate the possibilities available to SAU districts (and others) across the State regarding alternative forms of energy. This project is truly unique to New Hampshire and shall establish the high water mark for school districts throughout the State to strive for. Schools are created to educate our children and providing every dollar possible to go toward educational programs benefits our society as a whole.

The project scope will include the following actions:

- Removal of the existing oil fired boilers
- Installation of one (1) natural gas Capstone C65 CARB Microturbine Unit
- Installation of a 100 kW solar PV array (roughly 450 panels)
- Ten (10) year service contract for the equipment between SAU 16 and the vendor

Breakdown of Estimated Project Costs:

Project costs will fall into one of three main categories: project development and oversight; equipment acquisition; and equipment installation. Following The three main cost parameters, the breakdown is as follows:

Project Development and Oversight –

Solar PV Array:	$ 100,000.00
Design of system configuration Engineering & Interconnectivity Permitting	
Microturbines:	$ 50,000.00
Design of system configuration Engineering & system Interconnectivity Permitting	
Total:	**$ 150,000.00**

Equipment Acquisition –

One (2) Capstone C65 CARB Microturbine Unit:	$ 135,000.00
100 kw Solar PV Array and Inverters:	$ 450,000.00
Total:	**$ 585,000.00**

Equipment Installation –

Capstone Microturbine Installation:	$ 50,000.00
100 kw Solar PV Array Installation:	$ 75,000.00
Total:	**$ 125,000.00**

Total Project Cost:	**$ 860,000.00**
Project Request: (23% Project Cost)	**$ 200,000.00**

Summary of Project Benefits :

- Peak Demand Reduction:
    - Solar PV Array – 80 kW (variable)
    - Microturbines – 62.5 kW

- Reduction in Customer Consumption:
    - Solar PV Array – 147,400 kWH per year, 80 kW Demand
    - Microturbine – 306,000 kWH per year, 62.5 kW Demand

- Generation:
    - Solar PV Array – 147,400 kWH per year
    - Microturbine – 306,000 kWH per year

- Future O&M Estimated Cost:
    - Solar PV Array – $12,000.00 per year
    - Microturbine – $7,500.00 per year

- Demand Response Dispatchable? Yes

- Renewable Energy Credits: Yes

- Tax Incentives:
    - 30% Federal Tax Credit Solar Array
    - 10% Federal Tax Credit Microturbine

- Social Benefits:
    - Reduced operating costs for the school district
    - Significant example of community/utility partnership opportunity.
    - Annual reduction of 579 tons of CO^2, equivalent to removing 117 cars or light trucks from the road.
    - Largest solar array in New Hampshire.
    - Project can be reproduced on many similar facilities in the Unitil service area with the same partners and the same benefit ratio.

- Key Assumptions:
    - Figures presented in this worksheet are based on rough, conservative financial estimates

Schedule 6

Summary Report

SAU 16

Unitil Investment	$260,000
Total Project Cost	$860,000

Other Intangible Benefits	
Load Reduction	
Summer	143
Winter	143
Lifetime	1,853
MWh Saved	
Annual	453
Lifetime	5,889
Economic Development	
Jobs Created	2
Wages & Salaries	$81,461

Allocation of Economic Benefits

	Total	Participant	All Customers	Default
Capacity				
Generation				
Summer	$184,896	$184,896		
Winter	$0	$0		
Transmission	$18,174	$18,174		
Distribution	$56,071	$56,071		
DRIPE	$37,430		$37,430	
Localized Distribution	$11,780		$11,780	
Total Capacity	**$308,351**	**$259,141**	**$49,210**	**$0**
Energy				
Winter				
Peak	$146,012	$146,012		
Off peak	$124,502	$124,502		
Summer				
Peak	$73,565	$73,565		
Off peak	$60,382	$60,382		
Total Energy	**$404,461**	**$404,461**	**$0**	**$0**
Other				
Energy				
Dripe	$57,308		$57,308	
Non-Electric				
CO_2 Reduction	$151,486		$151,486	
REC Credit	$45,300		$45,300	$45,300
Total Other	**$254,094**	**$0**	**$254,094**	**$45,300**
Economic Development				
Total Output	**$336,476**		**$336,476**	
Total Benefits	**$1,303,383**	**$663,602**	**$639,781**	**$45,300**
B/C Ratio	**1.52**	**1.11**	**2.46**	