STATE OF VERMONT

PUBLIC SERVICE BOARD

Investigation into the	)	
Department of Public Service's	)	Docket No. 5980
Proposed Energy-Efficiency Plan	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE VERMONT DEPARTMENT OF PUBLIC SERVICE

Resource Insight, Inc.

AUGUST 11, 1997

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EXHIBITS

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is appended to this testimony as Exhibit DPS-PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and thirty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Vermont Public Service Board, Maine Public Utilities Commission, Rhode Island Public Utilities Commission, Connecticut Department of Public Utility Control, New Hampshire Public Utilities Commission, Texas Public Utilities Commission, New Mexico Public Service Commission, District of Columbia Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Public Utilities Commission of Ohio, South Carolina Public Service Commission, North Carolina Utilities Commission, Florida Public Service Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on issues of electric industry restructuring and market price determination?

A: Yes. I testified on market prices, among other topics, in the rulemaking portion of New Hampshire PUC Case No. DR 96-150, in the adjudicatory portion of the same docket regarding PSNH; in Massachusetts DPU Docket 96-100; and in New York PSC Case 96-E-0897.

Q: Have you testified previously on avoided costs?

A: Yes. Approximately 18 pieces of my testimony in Vermont, Maryland, Massachusetts, Florida, the Carolinas, Michigan, Ohio, and Illinois have included derivations of avoided costs. In addition, I have worked on avoided-cost issues in several collaborative and negotiating processes, in Vermont, Maryland, and Florida.

Q: Have you testified previously before the Board?

A: Yes. I testified in

- Docket No. 4936, on Millstone 3;
- Docket No. 5270 on DSM cost-benefit test, preapproval, cost recovery, incentives, and related issues;
- Docket No. 5330, on the conflict between the HQ purchase and DSM;
- Docket No. 5491, on the need for HQ power and the costs of alternative purchases;
- Docket No. 5686, on the avoided costs and water-heater load-control programs of Central Vermont Public Service (CVPS);
- Docket No. 5724, on CVPS avoided costs;
- Docket No. 5835, on design of CVPS of load-management rates.

Q: Have you been involved in other aspects of utility planning and regulation in Vermont?

A: Yes. My other activities have included

- participation in the CVPS and Vermont Gas DSM collaboratives;
- preparation of testimony on the avoided costs of Green Mountain Power (GMP) in Docket No. 5780, not presented due to settlement of the case;
- assisting the Department of Public Service (DPS) in the power-supply negotiations of the externalities investigation;

- providing consulting support to the Vermont Senate on stranded costs and Vermont Yankee economics;
- assisting the Burlington Electric Department (BED) on distributed utility planning.

Q: Are you the author of any publications on utility planning and ratemaking issues?

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation-program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Department of Public Service.

Q: What portions of "The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets" are you sponsoring?

A: I am sponsoring Chapter 4 and Appendices 4 and 5, of which I am the principal author.

Q: Do you adopt these portions of the report as part of your testimony?

A: Yes.

Q: Are they true and correct to the best of your knowledge?

A: Yes.

III. Avoided Costs

A. The Rationale for Statewide Avoided Costs

Q: Why have you presented avoided costs on a statewide basis, rather than on a utility-specific basis?

A: The rationale is different for generation costs than for T&D costs. For generation, avoided costs are uniform across the state, and nearly so across the entire New England region. For T&D, avoided costs vary geographically, but a statewide average may be a better estimate than a set of utility-specific values.

Q: Why are avoided generation costs uniform across the state?

A: The generation costs avoided by a reduction in load anywhere in Vermont will be determined by the New England regional power market. Whether DSM frees up power for sale into the market, or allows the avoidance of a purchase, the regional market price is the same. Similarly, that price is the same whether the power costs are avoided by a utility or by a marketer serving a customer with direct access. And since the avoided generation costs are based primarily on the costs of new power plants, the costs of new utility-owned generation (if there is any) should be very similar to the regional market price.

Q: Is the use of statewide generation costs consistent with past practice?

A: The use of regional market prices is the culmination of a long-term trend, starting shortly after utilities first started projecting avoided costs in the mid-1980s. The avoided generation costs estimated by and for New England utilities were originally based on their own loads and resources, with new generic resources representing either entire units the utility might build, or (especially for small utilities) shares in jointly-owned units. Avoidable capacity costs were often set to zero until the utility had a capacity need, and then set to the cost of a peaking unit. Hence, at the same point in time, a capacity-long oil-burning utility would be projecting high avoided energy costs and no capacity value, while a neighboring utility might have low energy costs and a high capacity value.

This treatment was clearly unrealistic, since the utilities routinely bought and sold generation entitlements with one another, for periods from short-term economy transactions to life-of-unit sales. By the late 1980s, CVPS avoided costs were recognizing the opportunity for off-system energy purchases and sales. About the same time, avoided-cost projections came to recognize the potential for capacity purchases and sales, including transactions with the general market, rather than identified participants. More recent avoided-cost studies by CVPS and GMP have relied entirely on market prices for capacity costs.

FERC Order 888 completed the process of opening up the transmission system that FERC has been pursuing for some years in merger cases and elsewhere, reducing the remaining barriers to wholesale power transactions. With the inception of the NEPOOL ISO, and near-term plans for divestiture of generation and implementation of retail access, the wholesale power market in New England should be highly competitive, allowing for purchases and sales from parties throughout the region. Hence, the New England regional market prices will be the effective avoided generation cost for all Vermont utilities.[1]

Q: Why is the use of statewide T&D costs reasonable?

A: Some transmission costs, particularly at the VELCo level and for transmission into the state, are essentially statewide, since load anywhere in the state (or in a large portion of the state) contributes to the need for investments.

Other transmission and distribution costs vary geographically, between regions, feeders, blocks, and even buildings. Avoided T&D costs for any location are the sum of future avoidable investments at all these levels. For these costs, statewide averages reflect the range of costs that are likely to be avoided by widely-distributed market-transformation programs, and may well be more accurate than company-specific estimates.

Q: Why could a statewide average be more accurate than company-specific estimates of avoided T&D?

A: Statewide averages may be more accurate for several reasons. First, transmission and distribution costs vary geographically, but not necessarily on the scale of utility service territories. Some costs will vary from building to building, depending on whether the line transformers (for example) are old or new, heavily loaded or under-utilized. Other costs will vary between areas fed by different feeders, or substations, or transmission lines. There is no particular reason to believe that any of these differences will coincide with service-territory boundaries.

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[1]Even if a utility were to build new generation, the market prices would represent the opportunity cost for sales of that power into the market. Utilities are unlikely to build new generation tied to the retail franchise, so long as the prospect of retail access (or some form of competition in generation) remains.

Second, the statewide values are averaged over a wider base, which may better reflect the expected value of future conditions than the history of any one utility. For example, a small utility may not have needed to add any major facilities in the last ten years. The standard approach to estimating a utility-specific avoided T&D value would include only the costs of very local facilities (such as line transformers and service drops) and perhaps regional transmission costs. The next town over might have experienced just enough growth to require major T&D additions, and have very high T&D costs per kW of load growth. In the next few decades (the period relevant to evaluating the economics of most market-driven DSM), either town might require more T&D capacity. Indeed, the one with lower past additions may be more likely to require expensive additions in the future. An average over a larger period is more likely to reflect the expected value of future avoidable investment than the much smaller local sample.

Third, a statewide average will tend to average out the local variations in the T&D load and capacity relationship. T&D capacity rarely meets load exactly, due to the inherently discrete nature of T&D investments and the inevitable variations between local-area demand forecasts and actual loads. For example, the accelerated addition of a single development can make T&D supply critically tight, while the cancellation of a planned project can result in significant excess capacity. It is likely that some utilities and some areas were over-built in 1986 and under-built in 1995, or vice versa, resulting in highly skewed estimates of avoidable T&D per kW from the historical data.[2] The statewide value, averaging 1986 and 1995 conditions across

[2]Estimates from current ten-year projections would be similarly skewed, but in the opposite direction. The areas with large investments and little growth in the past decade are likely to see

regions and utilities, would generally be more representative of future conditions.

Fourth, for the small and interwoven service territories of Vermont utilities, there must always be great uncertainty about which territory will house future developments. Even if we expect growth of a particular type, such as in the ski industry or in retailing, even small changes in location can shift a major load (and the need for distribution reinforcement) to a different utility. Hence, utility-specific avoided T&D for individual utilities in Vermont will always be subject to greater uncertainty than statewide estimates.

Fifth, load growth in one utility's service territory may require investments by another utility, for any of a number of reasons. Utility-specific data may not properly match costs and loads. For example, the load of utility A may require utility B to add capacity to an existing transmission line or substation that serves the utility A. Similarly, increased loading by either utility on equipment that serves both utilities may require the other utility to add new supply paths, shifting part of its system off the overloaded equipment. These interactions are particularly important in Vermont's small, interspersed territories, with extensive sharing of facilities.

Q: Is the use of statewide avoided T&D costs consistent with standard practice?

A: Yes. Avoided T&D costs for DSM screening (and marginal T&D costs for rate design) are normally estimated on an average basis for an entire utility.

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little investment in the next decade, even with increased growth. Areas with large growth and little investment are likely to be due for higher investment per kW in the next decade.

For most of the load in New England, avoided T&D is aggregated to a scale larger than all of Vermont.[3] Outside of New England, utilities are usually larger, and T&D costs are averaged over even larger areas and larger loads.

If the 22 Vermont distribution utilities and VELCo merged into a single utility, standard practice would compute a single avoided T&D value for the entire system. Even where the utilities are separately owned, small companies frequently borrow load and cost data from larger neighbors, to avoid performing their own analyses.

For another perspective, it is useful to recall that CVPS is about half of Vermont load, and uses only a single avoided or marginal T&D cost for its system. If one value is appropriate for half the state, it is difficult to see why 21 values are necessary for the other half of the state.

Q: If localized T&D estimates were, on average, slightly more accurate than the statewide estimates, would development and use of the local estimates be preferable?

A: Not necessarily. Developing 22 sets of avoided T&D costs, or dozens of feeder-specific projections, or any other highly disaggregated set of avoided T&D costs would increase costs substantially. In addition to the increase in the amount of data and the number of analyses, this disaggreggation would require careful accounting of transmission services exchanged between utilities and an allocation of avoidable VELCo costs. The more detailed analyses are also likely to exhibit more data problems, such as extreme

[3]This would be true for avoided costs as normally estimated on a company-wide basis for Connecticut Light and Power, United Illuminating, Narragansett Electric, Western Massachusetts Electric, Massachusetts Electric, Boston Edison, Public Service of New Hampshire, and Central Maine Power.

volatility in loads (which complicates selection of an appropriate analysis period) and a greater range in the age of equipment being retired (which complicates the adjustment for replacement investments described in Appendix 4-3). Even with a great deal of care, the disaggregated values are likely to be more accurate in some areas and less accurate in other areas than the statewide average.

Once the multiple sets of avoided costs were developed, DSM options and programs would need to be screened for each of the multiple sets. This process would increase the cost of program development.

If the range of disaggregated avoided costs resulted in the selection of all the same options, the additional expense and complication in analysis and screening would have no effect, and would be wasteful. If different sets of options passed in different areas, programs would need to be designed to deliver each of the sets of locally cost-effective options.

If multiple versions of each program were developed, implementing and delivering those programs would be more expensive, and probably less effective, than a uniform statewide program. Marketing would be more difficult, especially through mass media, if only a portion of Vermont electric customers are eligible for a particular program or measure. The same is true of point-of-sale rebates, incentives to wholesalers to stock equipment, training of builders, and many other delivery mechanisms. Since a single store, distributor, or contractor will generally serve large portions of the state, covering many utilities and more feeders, they might need to deal with multiple eligibility and incentive schemes.

Unless there were some reason to believe that disaggregated estimates of avoided T&D costs would be vastly—not just marginally—superior to statewide estimates, the costs of producing and using the disaggregated estimates, and implementing the resulting programs, is unlikely to be justified.

Q: Is the statewide scale of aggregation appropriate for Vermont for statewide programs?

A: Yes. There are always choices to be made in selecting a level of aggregation. Avoided T&D costs could be disaggregated (at least in principle) to the level of individual buildings, or aggregated to the level of the state or an even wider area. The statewide approach is rational, cost-effective, and potentially more accurate than more localized estimates, as explained above.

B. Summary of Avoided Costs

Q: Please summarize the Department's avoided costs.

A: The avoided costs are presented in various ways in Chapter 5 and Appendix 4. The following table summarizes avoided generation costs, T&D, and externalities, in 1997 dollars, all without losses. The generation-related costs (including externalities) change rapidly in the first few years as the marginal supply changes from existing generation to new capacity, and are then fairly stable.

	Generation Capacity ($/kW-yr.)	Generation Energy ($/MWh)	Trans. & Distrib. Capacity ($/kW-yr.)	Externalities ($/MWh)
1998	41.65	28.28	121.28	39.28
1999	57.32	30.18	120.58	38.89
2000	57.32	32.08	119.88	12.93
2001	57.32	32.64	119.67	12.93
2002	57.32	33.56	119.33	12.93
2003	57.32	34.56	118.96	12.93
2004	57.32	35.30	118.69	12.93
2005	57.32	36.05	118.42	12.93

1. *Generation Costs*

Q: Please summarize the derivation of the avoided generation costs.

A: The avoided generation costs reflect the regional power market. Avoided capacity costs are set at the costs for new combustion turbines from 1999 on, and avoided energy costs at the energy-related costs (fuel, variable O&M, and capitalized energy) of a gas combined-cycle plant from 2000 on. Avoided energy cost rise modestly with fuel costs, based on the Department's latest fuel-price forecast. Short-term capacity and energy costs are based on interpolation between recent market values and the costs of new resources.

These avoided generation costs are very similar to those prepared by the Department in February 1996, and used in CVPS and GMP presentations to the legislature on stranded costs.

2. *T&D Costs*

Q: Please summarize the derivation of the avoided T&D costs.

A: This derivation is described in detail in Appendix 4-3. Most of this derivation follows the traditional method, such as that laid out in the *NARUC Cost Allocation Manual* (1992, 127–142). In a nutshell, the analysis

- divided what the Vermont utilities invested in T&D between 1986 and 1995 by the growth in load in that period, to get investment per kW of growth,
- annualized the investment, and
- added O&M expenses.

To avoid adding up data for more than twenty utilities, we used investment, load and expense data from the four largest Vermont utilities—CVPS, GMP, BED, and Citizens' Utilities (CU)—and the Vermont Electric Power

Co. (VELCo). We made a number of adjustments, to account for inflation, replacement of retired equipment, customer-related costs, and the value of T&D additions in reducing line losses.

Q: Why doesn't the computation of avoided T&D cost follow the outlines of the computation of avoided generation costs, starting with avoiding a specific type of capacity?

A: Planning a T&D system is much more complex than planning generation expansion, since it includes

- geographical diversity in system design, peak-load timing, and excess capacity;
- planning for local loads;
- lumpy additions;
- multiple levels of the delivery system (transmission, substation, feeders, primary laterals, line transformers, secondary, and service drops);
- effects of high loads on equipment lifetime;
- replacement of existing equipment due to deterioration, relocation requirements, and upgrade to higher capacity;
- additions to improve equipment required by earlier load growth;
- the effect of increasing capacity on reducing line losses;
- expenditures that are made to meet varying combinations of previous, current, and projected load growth, not all of which occurs or persists.

To further complicate the determination of avoided T&D costs, the loads that drive the need for additions vary over voltage level and region. The size of a service drop is determined by the peak load of the building (which may house one customer or many), the size of a line transformer (or the number of transformers) is typically determined by the loads of several customers, the size of a feeder by the loads of hundreds of customers, and the size of a substation by thousands. The timing and magnitude of a customer's contribution to each of these types of equipment may vary. In any particular time period, loads on some components will be growing, while on other components it will be stable or falling. Hence, relating T&D additions to any particular measure of load growth is always a matter of approximation, rather than precision.

3. Externalities

Q: Please summarize the derivation of the externality values used in the avoided costs.

A: This analysis was limited to air emissions, the major environmental effects of fossil generating plants (which are assumed to be the avoidable resources in estimating avoided generation costs) and direct fossil fuel use. As explained in Appendix 5, the Massachusetts externality values are generally reasonable; additional data that has become available since MDPU 91-131 generally support values at least as great as those adopted by the DPU. The only major pollutant for which an adjustment to the Massachusetts values seems justified is particulates, for which the Department uses a value twice that of the MDPU, based on higher damage-cost and control-cost estimates, recent evidence of still higher damages, and EPA proposals for stricter control of fine particulates. Only two of the air emissions—carbon dioxide (CO_2) and nitrogen oxides (NOx)—contribute significantly to electric generation externality valuation after 1999, once the avoided energy source is a new gas-fired combined-cycle, with high efficiency and good NOx controls. Two other pollutants—particulate matter (PM) and sulfur dioxide (SO_2)—

contribute to the higher externalities in 1998 and 1999. In addition, emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) are included for direct fossil use.

IV. Distributed Utility Planning

Q: Please summarize the Department's approach to distributed utility planning.

A: The Department's approach (as detailed in Appendix 5) starts by identifying the major T&D additions in the utility's budget that could be avoided or deferred by reductions in forecast loads. For each area in which load is driving avoidable major additions, DU planning would then seek combinations of DSM and distributed generation (DG) that would avoid the additions at lower total costs.

Q: What is the basic test for determining whether targeted DSM and DG is superior to construction of a planned T&D addition?

A: The societal test is appropriate for these decisions. So long as the total cost of a plan with distributed resources is lower than the costs with the traditional T&D expansion, avoidance or some deferral of the expansion is economic. Much of the targeted DSM will typically have net costs (that is, net of other avoided costs) far below the average cost of the T&D project, i.e., the cost of the planned addition divided by the kW of load that requires the additions. The least-cost resource portfolio might therefore include some resources with costs per kW that are greater than the average cost of the planned T&D project, if they are needed to produce sufficient load reductions.[4]

Q: If a utility finds more than one targeted resource plan that would defer the T&D addition, how should it choose between them?

A: The societal test is also the basis for choosing between alternative plans with various levels of distributed resources, and hence various periods of deferral for the targeted T&D addition.[5] If a planned addition can be deferred for three years by distributed portfolio A, and for five years by distributed portfolio B, the utility should compare the present value benefit of the additional two-year deferral to the present value of the net costs of the additional resources in portfolio B. If the incremental benefits exceed the incremental costs, portfolio B should be pursued; otherwise, the utility should plan for portfolio A and the three-year delay.

Q: Are the Department's DIRP guidelines intended to be a detailed prescription for every utility's DIRP process for every application?

A: No. The Department's guidelines are not meant to restrict the utilities' flexibility or creativity, so long as they can demonstrate that their approaches are no less effective than the guideline approach in identifying opportunities

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[4]For example, suppose a 10 MW increase in load would require a $4 million T&D upgrade, for an average cost of $400/kW. If the utility can find 8 MW of low-cost resources, with net costs averaging $50/kW (or $0.4 million), it could spend $1,000/kW for the last two MW (or $2 million) needed to avoid the upgrade, and still save $1.6 million. Of course, some other combination of distributed resources and T&D investment might have a still-lower cost.

[5]The same is true for plans with the same period of T&D deferral and various combinations of distributed resources.

for reducing total social costs with targeted distributed resources replacing or deferring traditional T&D investments.

The complexity of the analysis required and justified will depend on the scale of the T&D project, the design of the system, the nature of the load growth, and other factors. For example, for a very large addition in an area served by a single small feeder, the utility may reasonably concentrate its analysis on DSM for the new load and DG, since no other T&D options or DSM programs are likely to provide much relief.[6] The analysis is likely to concentrate on a single choice of building or avoiding, rather than deferral. On the other hand, a project planned for a gradually growing area, with several adjacent feeders (or substations, or transmission lines) will require more analysis of the relevant target areas, options for shifting loads between facilities, many DSM options, and a range of deferral periods.

Q: Does this conclude your testimony?

A: Yes.

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[6]If avoidance of the project appears to be feasible, smaller DSM savings along the existing feeder may provide additional assurance of adequacy, and lower costs than the DG options.

CVPS Estimate of Annual T&D Additions Net of Replacements

	TRANSMISSION PLANT	DISTRIBUTION PLANT
1993	(115,282) <	(5,494,254) <
1992	863,609	7,206,958
1991	882,954	5,335,081
1990	(198,218) <	2,098,707
1989	507,742	274,838
1988	(150,559) <	(1,431,593) <
1987	306,532	(507,893) <
1986	1,447,269	2,760,967
1985	16,653,735	(408,512) <
1984	200,783	827,228
1983	265,205	1,244,300
1982	(274,221) <	(266,108) <
1981	66,905	482,886
1980	(660,541) <	256,233
1979	(213,970) <	1,207,841
1978	563,127	(206,728) <
1977	(137,215) <	(2,837,696) <
1976	(424,655) <	(880,373) <
1975	40,061	(3,113,387) <
1974	(3,727,669) <	(4,163,408) <
1973	4,111,134	(2,910,316) <
1972	395,979	(949,207) <
1971	2,698,051	3,896,337
1970	2,701,186	3,311,688
1969	3,519,014	5,677,357
1968	5,408,682	4,280,909
1967	3,483,177	3,238,559
1966	(179,460) <	4,747,360
1965	4,255,682	2,291,077
1964	1,019,401	2,376,309
1963	235,372	1,846,615
1962	(462,980) <	
1961	1,253,385	
1960	(162,975) <	
1959	(1,435,242) <	
1958	280,197	
1957	830,235	

Source: AV_COST.WK4, Sheet B

Exhibit DPS-PLC-R-8

Reitirement Multipliers Computed From CVPS Data

Installation Date	remaining life	retired in year	surviving 12/94	retired in 1995	H-W index	retired in 1995 (1994$)	Plant in 1994$
1946	0.5	100%		-	29	0	
1947	0.5	100%		-	34	0	
1948	0.5	100%		-	38	0	
1949	0.5	100%	3	3	39	26	26
1950	0.5	100%	4	4	42	32	32
1951	0.5	100%	6	6	46	43	43
1952	0.5	100%	9	9	48	62	62
1953	0.5	100%	11	11	50	73	73
1954	0.5	100%	18	18	51	117	117
1955	0.9	60.0%	27	16	53	101	169
1956	1.1	57.1%	32	18	57	107	186
1957	1.4	43.8%	52	23	58	130	298
1958	1.7	36.8%	44	16	60	90	243
1959	2	31.8%	67	21	60	118	371
1960	2.3	28.0%	85	24	60	132	470
1961	2.6	25.0%	138	35	58	197	790
1962	2.9	22.6%	139	31	58	180	796
1963	3.2	20.6%	171	35	58	202	979
1964	3.5	18.9%	194	37	61	200	1,056
1965	3.8	17.5%	234	41	64	212	1,214
1966	4.1	16.3%	302	49	66	247	1,519
1967	4.5	13.0%	334	44	70	207	1,584
1968	4.9	12.0%	428	51	72	237	1,974
1969	5.3	11.1%	517	57	76	251	2,258
1970	5.7	10.3%	701	73	82	294	2,838
1971	6.1	9.7%	815	79	88	298	3,075
1972	6.6	7.6%	812	62	92	222	2,930
1973	7.1	7.0%	884	62	100	207	2,935
1974	7.6	6.6%	962	63	107	196	2,985
1975	8.2	4.9%	648	32	135	79	1,594
1976	8.8	4.6%	625	29	144	66	1,441
1977	9.4	4.3%		-	149	0	-
1978	10	4.0%	697	28	157	60	1,474
1979	10.6	3.8%	869	33	166	66	1,738
1980	11.3	2.7%	972	26	185	47	1,744
1981	12	2.5%	906	23	203	38	1,482
1982	12.7	2.4%	897	22	217	33	1,372
1983	13.4	2.3%	1132	26	225	38	1,670
1984	14.2	1.4%	1401	20	228	29	2,040
1985	15	1.4%	1037	14	238	20	1,447
1986	15.7	1.9%	1185	23	243	31	1,619
1987	16.5	1.2%	1543	19	244	26	2,099
1988	17.4	0.6%	1932	11	253	15	2,535
1989	18.2	1.1%	1815	20	280	24	2,152
1990	19	1.1%	2296	25	291	28	2,619
1991	19.9	0.5%	2604	13	305	15	2,835
1992	20.8	0.5%	2268	11	307	12	2,453
1993	21.7	0.5%	2125	10	325	10	2,171
1994	22.5	0.9%	2966	27	332	27	2,966
sum			34,907	1300.47		4,842	66,474
Retirements in 94$/nominal retirements						**3.72**	
Retirements by CV method						2,543	
Retirements in 94$/CV retirements						**1.90**	

Corrections to CVPS's Estimates of Avoided T&D Costs

Exhibit DPS-PLC-R-9

	CVPS avoided costs	Revisions to CVPS Avoided Costs					DPS Statewide Avoided Costs		
		CVPS estimates with revised replacement cost of retirements		Addition of O&M w/ overheads					
	(in 1993$) [1]	(in 1993$) [2]	(in 1998$) [3]	(in 1996$) [4]	(in 1998$) [3]	Total (in 1998$)	Avoided capital costs (in 1998$) [5]	O&M w/ ovhds (in 1998$) [5]	Total (in 1998$)
Transmission	10.8	18.4	21.1	9.5	10.0	**31.1**	28.1		
Distribution	8.8	57.8	66.1	28.0	29.6	**95.7**	75.8		
Total	19.7	76.2	87.2	37.5	39.6	**126.8**	103.9	31.8	**135.7**

NOTES:

[1] CVPS spreadsheet AV_COST.WK4, Sheet B
[2] Calculation of avoided costs in Spreadsheet AV_COST.WK4, Sheet B revised by substituting multiplier of 4 for all HW ratios in the ADJ RET formulas
[3] Inflated using CVPS's general inflation rate of 2.75%
[4] Calculated as CVPS's T&D O&M expenditures divided by its annual peak averaged over the ten years, 1986 through 19
The value for transmission includes the VELCO O&M per kW of VELCo load, also averaged over the ten years, 1986 through 1995.
[5] DPS Plan Appendix 4-3, page 2 of Attachment 1, restated in1998$ (using the DPS inflation factor of 3%) with losses removed for comparison purposes.

Comparison of Market Price Estimates ($/MWh)

	CVPS Off-System Sales Price [1]	Average NEPOOL Lambdas [2]	PMW Weekly Peak Indexes [3]	PMW Weekly Off-Peak [4]	Average of PMW Peak & Off-Peak [5]	As percent of CVPS: Average NEPOOL Lambdas	PMW Weekly Peak Indexes	PMW Weekly Off-Peak	Average of PMW Peak & Off-Peak
May 96	25.9	19.4	24.8	18.1	21.3	75%	96%	70%	82%
Jun 96	24.1	21.2	25.0	17.3	21.0	88%	104%	72%	87%
Jul 96	2.4	22.9	27.3	18.1	22.5	954%	1136%	754%	936%
Aug 96	22.8	24.8	28.7	18.3	23.3	109%	126%	80%	102%
Sep 96	26.3	22.9	28.0	19.0	23.3	87%	106%	72%	89%
Oct 96	16.6	24.9	31.7	20.7	25.9	150%	191%	125%	156%
Nov 96	16.2	26.7	34.2	21.5	27.5	165%	211%	133%	170%
Dec 96	24.8	26.5	33.7	22.0	27.5	107%	136%	89%	111%
Jan 97	26.8	28.1	34.3	22.8	28.3	105%	128%	85%	105%
Feb 97	30.4	25.7	31.9	23.6	27.5	85%	105%	78%	91%
Mar 97	24.9	23.2	26.5	20.8	23.5	93%	107%	83%	94%
Apr 97	24.3	22.3	26.4	20.2	23.2	92%	109%	83%	95%
May 97	24.0	22.0	26.6	18.5	22.4	92%	111%	77%	93%
Avg [6]	21.9	24.3	29.5	20.2	24.6	111%	135%	92%	113%

Notes

[1] From CVPS Docket no. SC97-__-00, Exhibit No. __ (CV-302).

[2] Straight average of hourly data.

[3] Straight average of the weekly peak-period indexes for weeks ending after the third of the stated month and through the third of the following month.

[4] Straight average of the weekly low- and high off-peak prices for weeks ending after the third of the stated month and through the third of the following month.

[5] 48% of [3] + 52% of [4]. Weights based on 5*16 peak period.

[6] Average of June 1996 - May 1997 data, weighted by hours.

Exhibit DPS-PLC-R-11

Generating Resources for Summer 1997

Unit Name	Fuel Type	MW	Cumm. MW	Cost $	Cost ($) Status (7/10/97)	$/KW	Confidence for 7/1/97 Availability	Project Status	Dispatched at what Action of OP 4	Comments
Mass Power	gas	15	15	0	0	0	100%	Done	10	Upgrade-no fixed cost, variable costs only
AT&T Fairhaven	oil	0	15	0	0	0	0%	withdrew	N/A	AT&T withdrew this resource
Nantucket	oil	23	38	300,000*	100,000	4.35	100%	Done	14	Existing back-up gen.-environmental permitting obtained
Ocean State Power	gas	18	56	250,000	250,000	13.89	100%	Done	10	Upgrade
Canal 2	gas/oil	25	81	500,000*	0	0.0	100%	Done	12	Uprating-environmental permitting obtained.
Indeck Jones. & W.E.	wood	49	130	1,300,000**	1,300,000	26.53	100%	Done	ED	Reactivation - units are under pool dispatch
CPC Lowell	gas	24	154	550,000	550,000	22.92	100%	Done	ED	Reactivation - units are under pool dispatch
Bridgeport Harbor 1	oil	81***	154***	2,400,000	1,500,000	18.52	100%	Done	ED	Reactivation/maintenance
Groton Navy Yard	oil	15	169	500,000	531,000	35.40	100%	Done	14	Reactivation/reinstall-unit under pool control
Mason 3, 4, & 5	oil	99	268	3,350,000	3,350,000	33.84	100%	Done	Limited ED	Reactivation-environmental permitting obtained Limited to 369 hours of operation
W. Springfield 1 & 2	oil	100	368	5,100,000	5,100,000	51.00	100%	Done	ED	Reactivation-environmental permitting obtained
Devon 11-14	gas	32	400	1,056,000	1,648,000	51.50	100%	Done	ED	Temporary Chillers were ready for service on June 12.
S. Meadow 15	oil	8	408	264,000	412,000	51.50		Done	ED	Operating Permit not issued by Conn.
Manchester St 9-11	gas	6	414	none	30,000	5.00	100%	Done	12	Steam Injection - $100/hour, $30,000 are for mobilization and stand-by costs associated with portable demineralizers
Worcester Energy	wood	23	437	713,000	713,000	31.00	100%	Done	ED	Reactivation-no add. permitting required (for 6/15-9/30)
Salem Harbor 4	oil	0	437	0	0	.00	0%		N/A	Withdrew from being an upgrade candidate
			437	16,283,000	15,484,000	35.43				
		x .9 =	393 MW firm			39.40/KW firm				
Bridgeport Harbor 2	oil	15	452	0		0	100%	Done	ED	Restoration of rating through maintenance/upgrade-Participant own-load resource
		x .9 =	407 MW firm							

ED = Economic Dispatch prior to OP 4
*Preliminary estimate.
**Revised to reflect an additional cost ($200,000) associated with a June 15th in-service date.
*** Not included in totals - unit was reactivated for 1996 summer.

7/9/97

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UWUA-1-19 Attachment - 2 (1 page)