STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Investigation into the Restructuring of	)	
the Electric-Utility Industry in Vermont:	)	Docket No. 5980
Statewide Energy-Efficiency Plan	)	

REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE VERMONT DEPARTMENT OF PUBLIC SERVICE

Resource Insight, Inc.

DECEMBER 12, 1997

The rebuttal testimony of Mr. Chernick responds to direct testimony from other parties concerning avoided costs, externalities, and the Department's proposed guidelines for distributed-utility planning.

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I. Introduction

Q: Please state your name, occupation and business address.

A: My name is Paul L. Chernick. I am the President of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What points will your rebuttal testimony cover?

A: This rebuttal will respond to:

- The testimony of Dr. Lesser and the Bentley-Cater-Deehan panel on distributed utility planning.
- The testimony of the Bentley-Cater-Deehan panel, IBM, and Vermont Marble on avoided costs.
- The testimony of Dr. Lesser, Mr. Rosenberg, AIV, the group of 14 municipal utilities, the Bentley-Cater-Deehan panel, and Vermont Marble on externalities.
- The justification offered by Mr. Grimason of GMP's reductions in its DSM activity, starting in 1994.

My understanding of the other parties' positions is based on their prefiled testimony or comments, and by their responses to discovery. I cite the discovery responses as "IR DPS-Party xx-yy," where *Party* is GMP, CVPS, IBM, Muni (for the 14 municipals), and so on; *xx* is the discovery set number, and *yy* is the question number. The discovery responses related to DU planning are attached as Exhibit DPS-PLC-R-1, those related to avoided costs are attached as Exhibit DPS-PLC-R-2, and those related to externalities are attached as Exhibit DPS-PLC-R-3.

Q: Please summarize your rebuttal testimony on distributed-utility planning.

A: There is no factual basis for Dr. Lesser's claims that the Department's Distributed Utility Planning Guidelines would require the installation of uneconomic distributed resources, or otherwise misdirect DU activities.[1] He has not identified any specific problems in the Guidelines, or proposed any improvements. Many of Dr. Lesser's criticisms are vague, and his few numerical examples are riddled with errors.

Dr. Lesser's observations about the role of uncertainty in planning are valid, at least in principle. Dr. Lesser's characterization of uncertainty as "critical" to DU planning is on weaker ground, since GMP has yet to complete a reasonable DU analysis, with or without uncertainty. His resulting recommendation—that the Board suspend DU planning until EPRI's probabilistic DU model is available—is unacceptable. The EPRI model is entirely undocumented and untested. Dr. Lesser been unable to describe (let alone provide examples of) the process of developing the complex inputs required for that model to work properly, including contingent probability distributions for load growth and supply curves for DSM and distributed generation. The EPRI approach may be useful some day, or it may prove unworkable for planning. Neither GMP's modeling efforts, nor the

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[1]The Guidelines are Appendix 5 of "The Power to Save: A Plan to Transform Vermont's Energy-Efficiency markets," filed by the Department in Docket No. 5854

characterization of DU planning advanced by EPRI, provide any reassurance that EPRI's modeling will produce a valuable planning tool.

The proposal by CVPS that the Board abandon the societal test for DU planning, if and when generation becomes a competitive service, should be rejected.

Q: Please summarize your rebuttal testimony on avoided costs.

A: No party has shown that avoided T&D costs or losses estimated for individual utilities are better estimates of avoided costs than the Department's statewide estimates. While CVPS and Vermont Marble purport to show that their costs differ from the statewide average (for T&D costs and line losses, respectively), these assertions are based on erroneous comparisons and computational errors.

The market generation costs estimated by CVPS are understated, due to a combination of errors in the modeling of short-run energy prices with excessively optimistic projections of the costs and performance of new combined-cycle plants and of the costs of their fuel.

The cost-levelization issue raised by CVPS appears to be a simple error; no real dispute appears to exist.

Q: Please summarize your rebuttal testimony on externalities.

A: Various parties raise a number of theoretical or procedural objections to the Department's estimates of environmental costs of energy use, suggesting that the estimation could reflect additional factors, use other methods, occur in another proceeding, and be administered by another party. The arguments are generally vague and unsubstantiated. None of these objections demonstrates that the Department's estimates are incorrect or supports any alternative externality values.

Q: Please summarize your rebuttal testimony on GMP's reductions in its DSM activity.

A: The reductions in GMP's avoided-cost estimates cited by Mr. Grimason were partially due to arbitrary changes that GMP made in its avoided-cost methodology.

II. Distributed Utility Planning

Q: What points will you rebut concerning distributed utility planning?

A: I will rebut the following positions of various witnesses in their direct testimony:

- The assertions of Dr. Lesser concerning the objective of the distributed utility (DU) planning guidelines.
- The comments of Dr. Lesser regarding the treatment of uncertainty in DU planning.
- The position of the Bentley-Cater-Deehan panel on the treatment of generation costs by distribution utilities.

A. The Objective

Q: What is Dr. Lesser's point concerning the objective of the distributed utility (DU) planning guidelines?

A: Dr. Lesser agrees with my direct testimony that DU planning should attempt to minimize the societal cost of providing energy services. He asserts that the Guidelines are inconsistent with this objective.

Q: What is the basis for Dr. Lesser's opinion?

A: I do not know. The Guidelines and my testimony clearly state that the purpose of DU planning was to explore "options for using DSM and distributed generation to reduce the cost of maintaining the reliability of power delivery" (Guidelines, 1). My direct testimony further clarified the objective of cost minimization:

> 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. (16, lines 15–17)

> 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. (17, lines 5–7)

I believe that the Department has clearly stated its commitment to minimizing societal costs to Dr. Lesser throughout our interaction concerning distributed utility planning.

Q: Did you attempt to clarify the basis for Dr. Lesser's misunderstanding of the Guidelines?

A: Yes. In IR DPS-GMP 4-24, the Department asked,

> Please specify exactly what portions of the DPS guidelines are inconsistent with the [least-cost] objective, and indicate how the wording could be changed to correct the perceived inconsistency.

To which GMP replied,

> The DPS Guidelines require more than just "wording" changes. It is not GMP's role to provide the DPS with language for DPS Guidelines.

In short, GMP has declined to identify any specific problems with the Guidelines, or to provide an alternative set of Guidelines, so the Department's Guidelines are the best available guidance for utilities. Since neither

GMP nor any other party opposes DU planning, the Department's Guidelines should be adopted.[2]

Q: Does Dr. Lesser present any evidence that the Guidelines would not lead utilities to use DU planning to minimize societal costs?

A: He does not provide any specific evidence, but he does offer some general lines of argument. Dr. Lesser asserts that the Guidelines mischaracterize the "main issue" in DU planning and prescribe the use of average, rather than marginal, costs.

1. The Main Issue

Q: Please describe Dr. Lesser's argument regarding the alleged mis-characterization of the main issue in DU planning.

A: Dr. Lesser argues that the Guidelines err in stating the purpose of DU planning to be the deferral of traditional T&D investments by DSM and local generation, and asserts that "the main issue in DU planning is not deferral of traditional T&D investments" (5, lines 19–20). He then claims that the "main issue" in DSM planning is "whether smaller, more modular, more flexible investment can permit planners to delay larger, more capital intensive investments, until future needs become clearer."

Q: What is the difference between these two formulations?

A: The distinction between "deferring traditional T&D investments" and "delaying" the same investments is subtle, to say the least. From Dr. Lesser's other writings, it appears that he may be arguing that the identification of DSM and distributed generation options with lower total costs than identified

[2]The Department may propose clarifying language, if that appears to be warranted.

T&D options is too simple to be an interesting problem. He is more interested in the more difficult, and as yet unsolved, problem of minimizing DU costs under uncertainty, as suggested by his reference to delaying decisions "until future needs become clearer."

Dr. Lesser is correct in identifying the modular nature of distributed resources as creating an additional benefit, the ability to defer expensive decisions. Unfortunately, he dismisses the major benefit, which is that the cost of distributed resources (net of other benefits) is often less than that of new lines and substations. This is a serious error.

Q: Is the selection of DSM and distributed generation options that are less expensive than planned T&D investments really a simple process?

A: No. Neither GMP, nor any other utility in Vermont, has developed a procedure for selecting and implementing less-cost distributed resources when they identify the need for a traditional T&D investment. As I discuss in my DU planning testimony in Docket No. 5983 (GMP's current rate case), GMP's efforts in DU planning to date have been plagued with poor communication, inappropriate characterization of problems and resources, and flawed modeling.

Q: Have you given GMP the opportunity to explain its position on the main issue in DU planning?

A: Yes. In IR DPS-GMP 4-23, the Department asked GMP to "explain why 'deferral of traditional T&D investments' is not 'the main issue' in DU planning."

Q: What was GMP's response?

A: The Company provided no explanation. The answer consisted of a reference to the 22-page Feinstein-Lesser paper (attached as Exhibit DPS-PLC-R-4), without any further explanation of what point in that paper might be responsive to the question.[3]

Q: Does Dr. Lesser's testimony suggest what GMP may find inappropriate about "deferral of traditional T&D investments?"

A: Perhaps. Dr. Lesser (13–14) argues that something in the Guidelines requires T&D be deferred until the total cost of deferral is equal to the total benefit of deferral, resulting in zero net benefits.[4] If the Guidelines required deferral of T&D beyond the point where benefits were maximized, they would indeed overemphasize deferral. However, the Guideline require nothing of the sort, and Dr. Lesser does not cite any specific portion of the Guidelines that would require excessive deferral.

When the Department requested "a numerical demonstration that the DPS method results in 'the deferral merely paying for the DU investments' (Lesser, p. 14, lines 9–10)" in IR DPS-GMP 4-44, GMP also cited the Feinstein-Lesser paper, without specifying where the example might be found.

Q: Does the Feinstein-Lesser paper explain Dr. Lesser's positions?

A: The Feinstein-Lesser paper raises two points that might have something to do with Dr. Lesser's vague assertions about the role of deferral in DU planning. First, the paper follows Dr. Lesser's testimony in starting with the assertion

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[3]The response to IR DPS-GMP 4-23 is in included in Exhibit DPS-PLC-R-1.

[4]This complaint by Dr. Lesser may be related to his testimony on marginal costs, which I discuss below. –

that DU planning methodologies have been designed to maximize deferral periods for T&D investments, and that the objective of DU planning should be cost-minimization. Perhaps GMP's discovery responses simply intended to refer to this vague and generic assertion as evidence that the Guidelines overemphasized deferral. If so, the Feinstein-Lesser paper has no bearing on the Guidelines, which require cost minimization.[5] If this is Dr. Lesser's point, GMP is simply confused about the purpose of the Guidelines.

Second, the paper provides an example of how its authors believe DU planning should be conducted (19–20). This poorly developed example assumes that distributed resources would allow T&D planners to defer decisions about capacity additions, but would not otherwise affect the costs of the T&D system.[6] This distributed resource does not correspond to the characteristics of DSM, co-generation, or permanent distributed generation; it is more like a temporary generator.[7] This suggests a previously unstated motivation for GMP's vehement but poorly explained hostility towards the Guidelines: a desire to limit the scope of DU planning.

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[5]Perhaps GMP is confused by passages of the Guidelines that specify starting the DU analysis early enough and examining opportunities broadly enough to allow for identification and acquisition of the least-cost alternative. The purpose, "to maximize the number of situations in which DSM will have sufficient time to work" (Guidelines, 1) is not the same as maximizing deferral periods, regardless of economics.

[6]The paper assumes that the "present value cost of installing the substation" in a particular year varies with load growth, so this cost measure apparently reflects some non-substation costs other unserved energy, line losses, or generation costs.

[7]Perhaps this is why GMP has investigated the cost of renting generators for the Dover-Wilmington area, as shown in Exhibit DPS-PLC-R-5.

Q: Please describe Dr. Lesser's argument regarding the alleged prescription of average, rather than marginal, costs.

A: Dr. Lesser (7–12) starts by creating a hypothetical DU-planning example. This particular example assumes smooth growth (100 kW/yr.), one supply alternative (a 1-MW distribution feeder costing $200,000), and one distributed resource (fuel-switching at $1,000/kW). He then argues that the value of deferring the distribution line falls over time, from $18/kW-yr. in the first year, to $7/kW-yr. in the tenth year, due to discounting of the deferral of the investment (12–13). Dr. Lesser claims that the Guidelines would use the initial deferral value, without reflecting the smaller present value of later deferrals, leading to the wrong solution.

Dr. Lesser then makes a number of sweeping and vague assertions about the relationship of the Guidelines to marginal and average costs. (13–15)

Q: Does Dr. Lesser's example demonstrate the errors he claims are inherent in the Guidelines?

A: No. Dr. Lesser's example is riddled with simple errors and does not describe any realistic application of the Guidelines.

- In the example, the value of the first year deferral of the project is much more than the $18/kW-yr. that Dr. Lesser asserts.
  - The $18,000/yr. value of deferral is understated, since Dr. Lesser forgot that the investment would be capitalized and financed over time, incurring taxes (IR DPS-GMP 4-32). The present value of the year's deferral would be more like $23,000.
  - Since the distribution line could be deferred by a load reduction of 100 kW (rather than its full 1-MW capacity), the value of a year's deferral would be about $230/kW-yr.

- Dr. Lesser discounts the feeder's cost at 10% for each year of deferral. "The 10% discount rate is intended to be a nominal rate" (IR DPS-GMP 4-33). For each year the feeder is deferred, the cost would increase at the inflation rate (about 3%) and the present value would be reduced by 10%. Hence, the net effect of deferral is to reduce the avoided cost by the real (inflation-adjusted) discount rate, about 7%. If the first year's deferral were worth $18/kW-year, the present value of another year's deferral in year 10 would be $9.40/kW-yr., not $7/kW-yr.
- The example is set up so that no DSM is cost-effective. The cost of even the first year's deferral is $100,000/yr., since the fuel-switching costs $1,000/kW and 100 kW are required for a one-year deferral of the feeder (Lesser, 7–8). This is about four times the deferral benefit of $23,000 I computed above (and more than five times Dr. Lesser's estimate of the value of deferral). The Guidelines would reject the use of the fuel-switching alternative in such a case.
- Finally, Dr. Lesser's major point about discounting is just plain wrong. He is correct that the *value* of additional deferral, present-valued to today, falls as the length of deferral increases. But the same is true for the *costs* of distributed resources in those future years. If the costs of the incremental distributed resources and the load reduction required to defer the feeder another year both remain constant over time, discounting should not affect the decision to continue deferring the feeder.[8] Dr. Lesser acknowledges that "[a]ll costs would be discounted,"

[8]Interestingly, the same error is made in Feinstein and Lesser at page 15, in an example that also reaches the remarkable conclusion that the T&D addition should be deferred half a year.

but was not able to explain how "discounting of both the costs and benefits of the DSM would affect the cost-effectiveness computation." (IR DPS-GMP 4-35).

These errors in applying even these simple economic concepts demonstrate the need for close supervision of the utilities in DSM and DU planning.

2. *Marginal and Average Costs*

Q: What does Dr. Lesser assert about the relationship of the Guidelines to marginal and average costs?

A: Dr. Lesser's testimony on these points is often difficult to follow. I will respond to the assertions, as best I understand them.

- Dr. Lesser claims that I "explicitly recommend the use of the *average cost* of T&D deferral to determine DSM investments" (14, lines 24–25, original emphasis).
- He claims that following the Guidelines would result in a situation in which "a marginal amount of fuel switching is not being added." (13, lines 23–24).
- Dr. Lesser claims that the Guidelines would require the addition of distributed resources until the costs of the total distributed resources equal the total costs of the deferred T&D investments, even if some lower level of distributed resources would produce a lower total cost (14, lines 2–11).

Such a deferral would not be not meaningful for a normal distribution circuit with a single seasonal peak.

- Dr. Lesser asserts that the Guidelines require the installation of distributed resources so long as they are *"cost-effective* in the non-marginal sense, as defined with respect to actual (non-marginal) changes in cash flows" (13–14, original emphasis).
- Dr. Lesser (14–15) cites various portions of my testimony as evidence that I am supporting some improper use of average costs.
- Dr. Lesser asserts that no distributed resources should ever be acquired if they cost more than the average cost of avoided T&D resources (16, lines 19–20).

Q: Is Dr. Lesser correct in claiming that you "explicitly recommend the use of the *average cost* of T&D deferral to determine DSM investments?"

A: That depends on what he means. The quote from my testimony that he uses to support this assertion is irrelevant to his claim:

> 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. (17)

This passage simply places the costs of distributed resources and the avoided T&D costs in perspective.

On discovery, GMP asserted that "Step 4 on page 5 of the Guidelines appears to use an average cost approach" (IR DPS-GMP 4-45), but does not explain how GMP reached this conclusion. Since that part of the Guidelines describes the computation of either the benefit of avoiding the T&D addition entirely (for situations involving a single spike of load growth), or deferring it one year (for continuing load growth), the discussion clearly focuses on incremental avoided costs.[9]

Q: What does Dr. Lesser mean by "a marginal amount of fuel switching is not being added," and is it a valid criticism?

A: I am not sure what he means. The Department's attempts to clarify GMP's position drew only this response:

> Dr. Lesser interprets the Guidelines as evaluating marginal additions of DSM measures by comparing their cost to the cost of the T&D addition, which the Guidelines incorrectly treat as a "marginal" cost. (IR DPS-GMP 4-37, also cited by IR DPS-GMP 4-38)

Perhaps Dr. Lesser is arguing that the cost of distributed resources should be compared to the benefits of a marginal deferral of T&D capacity, where a marginal deferral would consist of one year.[10] That would be consistent with the Guidelines, so long as longer deferrals were also evaluated, to the extent feasible.

Alternatively, Dr. Lesser may be pointing out that the T&D deferral occurs in non-marginal lumpy amounts, so marginal costs are not meaningful. The point of much of the Guidelines is to guide utilities through the

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[9]There is a brief reference in that passage of the Guidelines to computing a dollars-per-kWh-year value of deferral for use in screening DSM options, to identify resources that may fit in a least-cost DU plan. Since Dr. Lesser was unable to explain "any difference between screening of DSM options and the construction of a resource plan," (IR DPS-GMP 4-39), perhaps he is under the impression that every DSM option that passes initial screening would be included in the DU plan. In fact, options that screen initially may later be rejected, either because there is no feasible set of distributed resources with a cost lower than the cost of the T&D option, or because the T&D option can be avoided without the use of some higher-cost resources.

[10]In the rather odd situation imagined by Feinstein and Lesser, the marginal deferral could be as little as half a year, and perhaps less.

process of determining whether enough distributed resources are available to defer some T&D and reduce total costs, in a situation in screening measures against a fixed set of marginal avoided costs is not sufficient. I find it difficult to believe that Dr. Lesser would criticize the Guidelines for under-emphasizing that point.

Q: Is Dr. Lesser correct in asserting that the Guidelines would require the addition of distributed resources beyond the level that would minimize costs?

A: This is not the intention of the Guidelines, and Dr. Lesser points to nothing in the Guidelines that would require this result. The use of the societal test in determining whether additional levels of distributed resources are cost-effective would avoid this problem. To ensure that there was no confusion on this point, I testified as follows:

> 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.[11] 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. (16, lines 3–13)

I do not know how I could have been clearer.

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[11]In a footnote that was part of my testimony at this point, I noted, "The same is true for plans with the same period of T&D deferral and various combinations of distributed resources."

Q: What does Dr. Lesser mean when he says (13–14) that, in the Guidelines, "an investment of arbitrary capacity is being added if it is *cost-effective* in the non-marginal sense, as defined with respect to actual (non-marginal) changes in cash flows?"

A: This portion of Dr. Lesser's testimony is particularly obscure. Dr. Lesser's testimony does not explain what he means by non-marginal actual cash flows, but the testimony appears to criticize the Guidelines for using actual cash flows as opposed to marginal cash flows. When asked for clarification,

> Please describe the difference between actual cash flows and marginal cash flows.

GMP responded,

> Marginal cash flows should reflect actual cash flows, rather than an arbitrarily small increment. (IR DPS-GMP 4-41)

This response does not explain the difference between "marginal" and "actual," as used in Dr. Lesser's testimony, and instead seems to say that marginal and actual should be the same. It also asserts that "marginal" costs should not be computed for "an arbitrarily small increment," even though *marginal* normally means "for an arbitrarily small change."

To further confuse this already contradictory testimony, GMP also asserts,

> [In] the example on page 12 of Dr. Lesser's testimony,...the actual cash flow is $200,000. The marginal cash flow computed using the DPS Guidelines is $18/kW. (IR DPS-GMP 4-42)

Here Dr. Lesser again says that marginal and actual costs are different, even though he says they should be the same. Since the example on page 12 of Dr. Lesser's testimony argues that the Guidelines should rely on the marginal cost of $18/kW, which Dr. Lesser computes for an arbitrarily small load reduction, this response seems to advocate the use of marginal costs in the traditional sense, which he rejects in IR DPS-GMP 4-41.

This vague and apparently shifting usage of "actual," "average," and "marginal" costs creates only confusion. Utilities should simply compare the costs of a local resource plan with an increment of distributed resources sufficient to defer targeted T&D investments, to the costs of a plan without such distributed resources, as required by the Guidelines.[12] The Board should reject any model or methodology that does not accomplish this comparison.

Q: Do the Guidelines use "cost-effective in the non-marginal sense, as defined with respect to actual (non-marginal) changes in cash flows," as Dr. Lesser alleges?

A: No. As emphasized in my direct testimony, the Guidelines consider distributed resources to be cost-effective if they reduce total resource costs compared to the next-best alternative, that is, at the margin, or for the next feasible incremental change.[13]

Q: Do the references in your testimony to deferral of T&D and to average costs support Dr. Lesser's criticisms of the Guidelines?

A: No. The passages to which he objects (16–17) include the following:

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[12]If several levels of T&D deferral or avoidance are feasible, GMP should apply the Guidelines and select the least-cost option.

[13]I do not really understand what problem Dr. Lesser sees in the use of actual cash flows. In general, the costs compared under the Guidelines would be present values or real-levelized costs, not the underlying cash flows.

> The Department's approach 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 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.

Nothing in these citations supports any of Dr. Lesser's criticisms of the Guidelines.

Q: Is Dr. Lesser correct that no distributed resources should ever be acquired if they cost more than the average cost of avoided T&D resources?

A: No. Dr. Lesser spends much of page 15 quoting and commenting on an example I provided on page 17 of my direct testimony. In a complex inversion of logic, he correctly states that the $400/kW average cost of the T&D upgrade in the example is not a marginal cost, but then argues that my example would be incorrect if the $400/kW *were* a marginal cost.[14] Dr.

[14]On page 15 of his testimony, Dr. Lesser emphasizes the word "averaging" in a quote from this section of my testimony describing a group of low-cost distributed resources, but does not explain why that word is emphasized.

Lesser is thus arguing about a hypothetical situation that neither he nor I believes to be applicable to DU planning.

If the \$400/kW were a marginal cost, as are the avoided costs used for generation and bulk T&D, each kW of load reduction would have the same expected value.[15] For most DSM applications *other than DU applications,* it is reasonable to treat each kW of load reduction as avoiding a kW of generation capacity (plus reserves) and a kW worth of typical T&D investments. In these situations, each DSM option should be pursued only if its cost is less than the avoided costs, which remain constant over wide ranges of DSM penetration. Each DSM option can be screened on its own merits, without reference to whether other options will turn out to be cost-effective. The Department's screening of statewide DSM programs in this proceeding uses that continuous approach.

For DU applications, however, including the example in my direct testimony to which Dr. Lesser takes such exception, the \$400/kW average cost of the avoided T&D is not the marginal avoided cost. Most load reductions, from 0 to 9,999 kW, would have no value for avoiding the T&D upgrade, which would require 10 MW of load reduction. The 10,000th kW would be worth \$4 million. This discrete (or lumpy) avoided-cost situation requires a different approach to screening options than the approach applied to screening with continuous avoided-cost. GMP's arguments do not properly reflect the difference between the continuous and lumpy costs.

[15]Note that the particular example in my direct testimony deals with the avoidance of an addition, in dollars per kW, rather than the usual deferral examples in dollars per kW per year.

Q: Does Dr. Lesser's critique of your example properly adapt the continuous-avoided-cost approach to the situation of discrete avoided costs for DU planning?

A: No. Given the choice of building the $4-million upgrade, or implementing $2.4 million in distributed resources, Dr. Lesser says he would select the more-expensive upgrade, to avoid violating his dictum that "on a marginal basis, no DSM should be acquired that has costs in excess of $400/kW" (15, lines 19–20). A moment's inspection of the example, as presented in my direct testimony or Dr. Lesser's, should convince any reasonable person that Dr. Lesser's choice is more expensive. My solution would cost $2.4 million in distributed resources; his would cost $4 million in T&D, plus perhaps $0.4 million in distributed resources that his marginal analysis would screen in, even though they are insufficient to defer the T&D.

Dr. Lesser's error is curious, since he acknowledges that the costs he identifies are *not* really marginal (15, lines 14–16), but he then proceeds to act as if they *were* marginal. If it were possible to avoid 8 MW of the expensive upgrade at $50/kW, and build the remaining 2 MW at $400/kW, Dr. Lesser would be correct that no DSM that has costs in excess of $400/kW should be acquired. Since the example assumed that the 10-MW upgrade was a single, indivisible project, the least-cost plan may require some DSM in excess of the $400/kW average cost of the T&D project.[16]

Q: On page 11, Dr. Lesser compares the Guidelines to a paper by Hoff. What points of similarity does he allege?

[16]It is interesting that Dr. Lesser, who is so vehemently critical of any use of the term *average* in my testimony, places such emphasis on the $400/kW average cost of the T&D upgrade in this example.

A: Dr. Lesser claims that Hoff and the Guidelines would evaluate all distributed resources against the value of deferring the T&D addition for the first year, without reflecting the smaller present value of later deferrals, leading to the wrong solution.

The Feinstein-Lesser paper (to which GMP refers repeatedly in its discovery responses) asserts that Hoff advocates the following practices:

- Adding all distributed resources, so long as the total cost of the distributed resources is less than the savings due to deferral of the T&D equipment (Exhibit DPS-PLC-R-4, 6, note 2).
- Continuing to add distributed resources, even if the additional deferral benefits are less than the cost of the additional distributed resources (ibid., 7).

Lesser claims the guidelines require these practices.

Q: What is the relevance of the Hoff paper to the Guidelines?

A: None. The Hoff paper (attached to IR DPS-GMP 4-31, part of Exhibit DPS-PLC-R-1) was not the basis of the Guidelines.

Q: Is Dr. Lesser's criticism of the Hoff paper justified?

A: Not so far as I can see. The criticisms of Hoff in Dr. Lesser's testimony and in the Feinstein-Lesser paper appear to parallel Dr. Lesser's criticisms of the Guidelines, and with as little basis. For example, Hoff describes his "break-even" equation (on which most of Feinstein and Lesser's criticisms are based) as computing "the most that the utility can spend on a distributed resource and the investment still be cost-effective" (Hoff, 99). This is a true statement, at least in aggregate.

I do not see Lesser's basis for asserting that Hoff would add distributed resources at costs above the value of deferral; indeed, he may require every resource to cost less than the deferral (in dollars per kW). This is too-strict a standard, as I showed in my direct testimony. While Hoff does not explicitly address selecting the least-cost deferral of additions, he appears to determine the cost-effectiveness of deferral for the first year, and then for the second year, and so on. Dr. Lesser (and his co-author Feinstein) appear to invent bases for disagreements with Hoff, just as with the Guidelines.

B. Uncertainty

Q: Please describe the position of Dr. Lesser regarding the treatment of uncertainty in DU planning.

A: Dr. Lesser faults the Guidelines for "not addressing the importance of uncertainty" and claims that "GMP's work with EPRI has found that addressing load growth uncertainty, for example, is critical when evaluating alternative DU investments" (16, lines 1–2).

Q: Is Dr. Lesser's criticism valid?

A: In principal, and ignoring practical considerations, explicitly modeling the uncertainty in load growth would certainly be desirable for DU planning. Dr. Lesser is correct that the strategy with the lowest expected cost is not necessarily the strategy with the lowest cost under expected conditions.

Q: Do important practical considerations reduce the importance of this criticism?

A: Yes. There are several important practical considerations that suggest that the probabilistic modeling Dr. Lesser proposes may not be useful in DU planning for a long time, if ever.

- The model Dr. Lesser proposes to use, the EPRI DU model (see Lesser, 16), is in "beta" testing and no example of its application has ever been released.[17] No documentation is available for the model. GMP was not even able to

> explain exactly how each of the following considerations is modeled in the EPRI model: DSM (e.g., number of options, timing, demand and energy savings, lead time, uncertainty); and distributed generation (e.g., number of options, cost escalation over time, alternative timing, lead time, uncertainty, dispatch pattern). (IR DPS-GMP 4-50)

- The utility's own attempt to force DU planning through a probabilistic model for the Mad River Valley was an abject failure, as described in my DU testimony in Docket No. 5983. That exercise was not rooted in the actual T&D situation or DSM options in the Valley, its modeling of risk was arbitrary, it was structured to ensure that the T&D option would be selected, and it rejected distributed resources that should have

[17]When asked for "the inputs, assumptions, and results of applying the EPRI investment strategy software, to the Dover-Wilmington area," its supposed beta-test site for the EPRI model, GMP claimed, "This has been previously supplied to the DPS as part of GMP's responses to the DPS' First and Second set on interrogatories in Docket No. 5983" (IR DPS-GMP 4-49). In fact, GMP has provided only some studies that might be used to develop inputs, and has not provided any "inputs, assumptions, or results." If the inputs have not been developed, the Dover-Wilmington beta test could hardly be underway. Certainly, GMP has not been able to demonstrate that the EPRI model even runs, let alone that it produces plausible results.

Green Mountain Power has suggested that some results of some model runs may exist, by stating that it "will make electronic copies of all available results of 'beta' testing after the DPS has satisfied all confidentiality requirements and obtained a copy of the Investment Strategy Model from EPRI" (IR DPS-GMP 4-27). GMP has not requested confidential treatment of any material in this case, and has not provided these results in hard copy. It is not clear what GMP is seeking to keep confidential, or whether GMP expects that a confidential model, that has no written documentation, and produces only confidential output, could be used in least-cost planning by a regulated utility.

been selected (given GMP's arbitrary inputs and modeling). Yet the Mad River Valley report is GMP's only basis for asserting that "load growth uncertainty is critical" (IR DPS-GMP 4-46).

- The utility has not proposed any method for estimating probability distributions for load growth in the relatively small areas targeted for DU planning.
- EPRI's approach would require the development of three-dimensional supply curves for distributed resources (plotting megawatts versus cost, versus time), which would represent a significant additional effort, before the determination of which portion of the supply curve (in any dimension) is relevant to the problem at hand. GMP does not appear to have developed any methodology for creating distributed-resource supply curves, as demonstrated by the record in Docket No. 5983 and GMP's response to IR DPS-GMP 4-51 in this proceeding.[18]
- The probabilistic modeling approach that Dr. Lesser proposes to apply to DU planning has not yet been applied to the simpler problem of planning traditional T&D capacity (in lines and substations).[19] Until T&D planners have established that this approach produces acceptable results in traditional applications, relying on probabilistic modeling for

[18]In addition, the inputs requested in IR DPS-GMP 4-49 would include whatever approximation of a DSM supply curve GMP intended to use. Since GMP has not been able to provide those inputs, and has not provided any DSM supply curve in any form, its approach must be regarded as entirely theoretical.

[19]While GMP asserted on discovery that "Wisconsin Electric and Ontario Hydro have both used decision-tree models as the basis for selecting T&D equipment," it also admitted that "Dr. Lesser has no specific documentation on either the structure of the problem to be solved or the model used" (IR DPS-GMP 4-29).

DU planning seems premature, and may bias integrated resource planning toward T&D investment over DSM investment.

- Probabilistic optimization has been difficult to apply in some parts of utility planning. Models that attempt to take this type of uncertainty into account have been developed for generation planning, but they have been limited in capability and difficult to use, and have not been used much for selecting resource plans. The same is true for deterministic optimization models, which are intended to design expansion plans without uncertainty in load growth.[20] Computational requirements have limited the number of resource options that can be included in the optimization runs. Once EPRI produces a functioning DU optimization model, potential users will need to determine whether it is able to reflect enough options in enough detail to improve on manual analysis, in either a probabilistic or a deterministic framework.
- Finally, I am not as optimistic as I was in my direct testimony that the EPRI model is even being constructed to ask the right questions. The errors in the paper by Feinstein (one of the leaders of the EPRI modeling effort) and Lesser—the error in discounting, the assumption that T&D projects can be deferred half a year, and the curious assumption that distributed resources would allow T&D planners to defer decisions about capacity additions but not otherwise affect loads or costs—raise the prospect that EPRI's modeling will be no more successful than GMP's.

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[20]The UPLAN model used by most Vermont utilities has this optimization option, but utilities generally use UPLAN to compute costs for specific cases the utility has developed, rather than as an optimizing tool.

Q: Should the Board hold up DU implementation until a probabilistic DU planning model is available and tested?

A: No. GMP suggests that, until such time as the EPRI model is commercially available and fully tested, and all the required stochastic inputs have been estimated and verified, DU planning should be limited to "identifying target areas and developing necessary inputs" (IR DPS-GMP 4-58).[21] The Board should reject this indefinite delay in DU planning and implementation.

C. Miscellaneous Issues

Q: What other DU planning issues does Dr. Lesser raise?

A: Dr. Lesser quibbles with such obvious observations in the Guidelines as "DSM reduces load growth uncertainty" and "DSM potential increases with load growth." These points were added to the Guidelines in response to GMP's failure to recognize in the Mad River Valley Study that new loads would provide new DSM opportunities. So far as I know, the EPRI model will repeat this error.

Dr. Lesser also argues that the inclusion of a societally cost-effective measure in a targeted DSM program would be "perverse...if it had no peak-reduction benefits" (19). GMP's explanation of how reducing social costs could be perverse is as follows:

> It is contrary to sound DU planning principles to select a DSM measure that provides no area peak reducing benefits as a solution to a local area peak capacity problem. (IR DPS-GMP 4-57)

[21]As I point out above, GMP has not shown that it can "develop necessary inputs," or even describe the necessary inputs.

We can only wonder what "sound DU planning principle" GMP believes precludes the minimization of societal costs.

Q: Do any of GMP's comments on the Guidelines have merit?

A: None of GMP's comments on the Guidelines reveal any error in the Guidelines. GMP's confusion on some points by indicate that the Guidelines could be clarified. However, since none of the other utilities appear to have the some problems understanding the Guidelines, GMP's complaints may be driven by GMP's desire to limit the scope and effectiveness of DU planning, delay implementation indefinitely, and maintain control of the DU planning process by use of a complex and undocumented model.

D. Distribution Utilities and Generation Costs

Q: What is the position of the Bentley-Cater-Deehan panel on the treatment of generation costs by distribution utilities?

A: The panel suggests that, if the existing integrated utilities are restructured into competitive generation companies and regulated distribution utilities, the distribution utilities should conduct T&D planning without considering avoided generation energy and capacity costs (Exhibit BCD-1, 17). In other words, CVPS proposes to ignore the effects of DSM measures on its customers' total energy bills when conducting DU planning. On discovery, CVPS reiterated its position that distribution utilities should only be concerned with costs they pay. In response to the question,

> Please state whether CVPS maintains that the least-cost planning solution will be reached if generation energy and capacity costs are not added to the value of area-specific T&D costs.

the company responded,

> It is the Company's position that from the perspective of a distribution utility, the least-cost delivery system expansion plan will be reached by comparing the marginal cost of the T&D supply facilities to the marginal cost of DSM and DU alternatives without regard to associated avoided generation costs. If the distribution entity is charged with the responsibility of managing total societal resource costs, then the T&D system planner would have to factor in avoided generation costs. It is not at all clear to us that the responsibility for managing total societal resource cost would properly reside wholly within distribution entities in the restructured industry. This issue raises significant market function, cost allocation, rate level, and rate design questions which should not be lightly set aside. (IR DPS-CV 3-12).

In IR DPS-CV 4-51, CVPS similarly states, "It would be our policy recommendation to the PSB that distribution entities not consider generation supply cost since they won't be providing generation supply."

Q: Is this position consistent with the Board's societal test?

A: No. The market price of generation is a societal cost, whether it is being paid by the utility (as it is today) or directly by the customer (as it may be in the future). Generation costs, and associated externalities, should always be taken into account in the cost-benefit analysis of utility DSM programs.[22]

Q: Is the panel's position consistent with current utility practice?

A: No. Utilities currently are expected to count other costs paid directly by customers, including the costs of fossil fuels (such as in fuel-switching programs), O&M, water, equipment replacement, and customer shares of DSM investments.[23] If they did not do so, they would (for example) find

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[22]The same would be true for distributed generation, where that affects the customers' generation bills.

[23]Central Vermont acknowledges in IR DPS-CV 4-51(b) that its does "not ignore non-electric fuel and maintenance costs in the design of DSM programs," even though CVPS does not provide these services.

fuel-switching to be widely cost-effective, even where fuel-switching does not pass the societal test.

Q: Does CVPS's position in opposition to minimizing societal costs have any other implications for this proceeding?

A: Yes. The continuing opposition of CVPS to minimizing societal costs, following similar efforts in other dockets, even eight years after the order in Docket 5270, supports the prudence of removing CVPS from responsibility to plan and deliver DSM programs. If CVPS continues to oppose responsibility for minimizing societal costs in DU planning, that function should be taken away from the Company as well. Since DU planning is not easily divisible from distribution planning and maintenance, if CVPS cannot properly carry out DU planning, the Board should consider turning the distribution function over to a more socially responsible entity.

III. Avoided Costs

Q: What points will you rebut concerning avoided costs?

A: I respond to the direct testimony of

- The Bentley-Cater-Deehan panel and Vermont Marble on the use of utility-specific T&D costs and/or line losses.
- The proposal of the Bentley-Cater-Deehan panel to use smaller generation market prices than those in the Department's filing.
- The Bentley-Cater-Deehan panel on levelized costs.
- Rosenberg on risk adjustment.

A. *Utility-Specific Avoided Costs*

1. T&D Costs

a) Conceptual Arguments

Q: What is the argument advanced by CVPS's Bentley-Cater-Deehan panel and Vermont Marble regarding utility-specific avoided T&D costs?

A: The utilities assert that avoided T&D costs should be computed and applied for each utility, rather than statewide. They argue that a statewide average fails to reflect the utility's individual characteristics, such as customer density, terrain, customer mix, and pre-existing plant characteristics (CVPS Exhibit BCD-1, 10; Allard testimony, 16; CVPS response to IR DPS-CV 4-40). They suggest that a particular utility's avoided T&D costs may differ from the statewide average, and argue that statewide avoided T&D costs "may over or under-value the benefits of energy efficiency in particular utility service territories." (CVPS Exhibit BCD-1, 10)

Q: Does this argument have merit?

A: No. Calculation of avoided T&D costs is necessarily based on an aggregation of investment and load data, across areas and over time. Even a utility-specific estimate averages investment per kW over areas with different cost characteristics *within* its service territory.

Q: Did your direct testimony in this proceeding explain why this aggregation of investment and load data was inevitable and desirable?

A: Yes.

Q: Did the utilities respond to your explanation?

A: No. None of the facts I presented in my direct testimony have been challenged. Neither CVPS nor Vermont Marble presented any evidence that the variation in avoided cost *within* a utility is any less than the variation between individual utilities and a statewide average. Nor do they rebut any of the other points I make in favor of statewide avoided costs, including the stability of the estimates, the interrelationship of adjacent utilities' T&D systems, the scale of variation in T&D costs, balancing of over- and under-building, and uncertainty in the location of future growth.

The utilities' recommendations on behalf of utility-specific avoided are based on little more than the assertion that 22 utility-specific estimates would be better than a statewide estimate.

Q: Does the utility testimony support any of the positions in your direct testimony?

A: Yes. In my direct, I pointed out that

> 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. (Chernick Direct, 10, lines 9–11)

Far from disputing this observation, CVPS presents in its testimony an estimate of avoided T&D costs that averages investment and load growth for all the scattered portions of its service territory, and even its Connecticut Valley Electric Company subsidiary in New Hampshire in with Vermont. If a single avoided T&D value is appropriate for Brattleboro and St. Albans, St. Johnsbury and Sunderland, Middlebury and Claremont NH, Danby and Ascutney, it is difficult to see why different avoided T&D values would be required for Proctor, Rochester, Ludlow, Groton, and all the other towns between and around the CVPS territory.

In calculating its preferred estimate of avoided T&D costs, CVPS also includes plant additions and load data from as far back as 1957. I would expect that GMP's data from 1987 would tell us more about CVPS's current avoided costs than CVPS data from 1957, especially given changes in technology and construction standards in the past 30 years.

Q: What is the significance for estimating avoided T&D costs of Vermont Marble's observation that its load factor is higher than the statewide average?

A: I see no practical significance. Since some T&D costs are increased by greater energy use, there would be a slight tendency for feeders with higher load factors to have higher avoided T&D costs. Nonetheless, I see no reason to believe that the narrow range of load factors will significantly affect utility-specific estimates of avoided costs.[24]

Q: Did the utilities propose avoided T&D costs for each utility?

A: No. The only utility-specific estimates of avoided T&D costs filed in this proceeding are those of CVPS. Even Vermont Marble, which protests the use of the statewide avoided costs, offers no alternative.

2. Avoided T&D Costs Estimated by CVPS

Q: Where did CVPS provide its estimate of avoided T&D costs?

A: Those estimates are presented in Exhibit BWB-2.

Q: Are those estimates documented in CVPS's filing?

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[24]Since avoided T&D costs are estimated in dollars per kW per year, the cost per kWh will be lower for utilities, customers, or DSM measures with higher load factors.

A: No. CVPS asserts that the "workpapers for the T&D avoided costs" are attached to its filing (CVPS Exhibit BCD-1, 11, fn. 5). This attachment does not actually document the derivation of the estimate of the avoided T&D costs CVPS presents in Exhibit BWB-2. Indeed, the workpapers do not derive any values in dollars per kW per year, and the dollars-per-kW values in the workpapers are different from CVPS's filed estimates.

In response to IR DPS-CV 4-41, CVPS explained that the values in the workpapers were "reexamined" and that the estimates in Exhibit BWB-2 were based on Sheet B of OTHER01.WK4. Since OTHER01.WK4 does not contain a Sheet B, I assume that the Company meant to refer to Sheet B of AV_COST.WK4, which derives values that are much closer to, but still different from, CVPS's current estimates.

While CVPS has not documented the values that it proposes the Board adopt in preference to the Department's statewide estimates, I have assumed for the purpose of this testimony that Sheet B of AV_COST.WK4 presents the basic methodology on which CVPS relies.

Q: Have you been able to review the basis for CVPS's avoided T&D costs?

A: Yes, with some difficulty. On discovery, CVPS provided a series of spreadsheets, some of which were actually used in deriving the CVPS estimates.

Q: Does the CVPS estimate of avoided T&D costs differ from the Department's estimate of statewide avoided costs?

A: Yes, substantially. CVPS currently estimates avoided T&D costs (excluding losses) to be $13/kW-year for transmission and $9/kW-year for distribution for a total of about $22/kW-yr. in 1998 dollars (CVPS Panel testimony, 12;

Exh. BWB-2, 1). The Department's estimate is $136/kW-yr. in 1998 dollars and excluding losses.[25]

Q: Please provide a brief description of CVPS's avoided cost methodology.

A: CVPS calculates avoided transmission and distribution costs as the total net plant additions over several decades (37 years for transmission and 30 years for distribution), divided by total load growth over the same period.[26] Net additions for each year were calculated as the year's gross additions minus an estimate of the cost of replacing the plant retired in that year.

Q: Do you find CVPS' estimate to be convincing evidence that statewide avoided costs should not be applied?

A: No. CVPS's methodology has a number of flaws that result in an underestimate of its avoided cost, namely

- overstating the replacement cost of retirements.
- excluding VELCo plant additions.
- including load growth of full-requirements wholesale customers in the calculation of avoided distribution cost.
- excluding fixed O&M and overheads.
- omitting several years of cost escalation.

Q: How does CVPS estimate the replacement cost of retirements?

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[25]This estimate is that of the DPS Plan (Appendix 4-3, Attachment 1, 2), restated in 1998 dollars and adjusted to remove from the calculation the 14.2% loss factor and the T&D offset.

[26]The utility selected the 37-year and 30-year periods to coincide with the average depreciation lives of transmission and distribution equipment, respectively. There is no logical connection between the depreciation life and the period of time for which the ratio of additions to load growth is computed. The data periods are arbitrary and unnecessarily long

A: The basic approach that CVPS takes is similar to that used by the Department: CVPS estimates the cost of replacement equipment in each year *t* by inflating the book cost of retirements in the year to the cost levels of year *t*. The critical assumption in this computation is the amount of inflation that occurred between the installation of the average dollar of retired plant and year *t*, that is, the vintage of the retired plant. The Company assumes that distribution plant retired in year *t* was installed 30 years earlier, and transmission plant 37 years earlier. This was based on CVPS's assumption that the average dollar of retired plant had survived to the end of its depreciation life.

Q: How does the Company's approach overstate the replacement cost of retirements?

A: It over-inflates the book cost of retirements by failing to recognize that

- the average age of retirement dollars is much lower than the expected life of the equipment.
- for some FERC distribution plant accounts, the Company's accounting data on the book cost of retirements exceeds the actual original cost of the equipment and already contains some inflation.

Q: Why is the average age of retirement dollars much lower than its expected life?

A: This effect is explained in the DPS Plan (Appendix 4-3, 1–2). Since equipment is retired over a range of ages (some transformers when they are one year old, some when they are 50 years old), the retirements in any year represent a mix of units of various ages. If every unit of equipment were purchased at the same price and the same number were purchased in each year, CVPS's assumption might be reasonable (e.g., the average age of the dollars of retired transformers would be equal to their average life, say 30 years). In reality, there is generally more younger equipment, due to load growth, so there are more transformers younger than 30 to be retired than there are transformers older than 30 years. In addition, younger equipment was purchased with inflated dollars, so the younger units represent a larger fraction of the dollars retired than they do of the physical units retired. The more-numerous and -expensive young lead to in a relatively low average age of the dollars retired, requiring a relatively low retirements multiplier.

In the absence of a depreciation study for a Vermont utility, and based on prior experience, the DPS assumed that retirements should be adjusted upward by a factor of 4 to take into account inflation. CVPS's assumption, on the other hand, results in retirement multipliers as high as 8.

As a result of applying these excessively large multipliers, CVPS calculates negative net plant additions in many years, as shown in Exhibit DPS-PLC-R-6. Over an entire 22-year period from 1972 through 1993, CVPS estimates a total net additions of −$1.5 million. Of the 30 years of distribution data, 12 show negative net additions; of the 37 years of transmission data, 13 show negative net additions.[27] CVPS's method contains the implicit assumption that about 40% of the time, the distribution investment needed to meet CVPS's load growth is negative.

[27]Applying the Department's estimate for the retirement multiplier, rather than CVPS's, results in only one year with negative net additions in the 37 years of transmission data and another in the 30 years of distribution data. (In each of these two cases, these negative net additions follow one or more years of much larger positive net additions, and may reflect situations in which replacement equipment entered service one year and the retirement of the old equipment was booked the next year.) This result supports the reasonableness of the Department's retirement multiplier.

Q: Has CVPS provided any support for its assumption that the average age of retirement dollars is the expected life of the plant?

A: No. The Department explained the basis for its assumption that the age of the average dollar of retirements is less than the depreciation life of the equipment. CVPS did not rebut the Department's argument for using its retirement multiplier of 4.0.

Q: Did CVPS provide any data that would allow you to test the validity of CVPS's assumptions that all retired transmission plant is 37 years old and all retired distribution plant is 30 years old?

A: Yes. While CVPS initially refused to provide its latest depreciation study, on the grounds that it did not use the study in developing its estimates of avoided costs, it belatedly provided that study in Supplemental Response to IR DPS-CV 4-37. Unfortunately, while the depreciation study clearly indicates that the authors relied on the breakdown of retirements by age cohort (as requested in IR DPS-CV 4-38) in developing their recommendations on depreciation rates, the report does not generally provide that information. Hence, CVPS continues to withhold data in its possession that would undermine its position.

Fortunately, the report does provide the distribution of retirements by age cohort for one account—distribution poles, Account 364—as an example of the aging method used for mass plant, as discussed below. Those data are provided in Attachment A-4 of the depreciation study, the relevant portions of which are attached as Exhibit DPS-PLC-R-7.

In Exhibit DPS-PLC-R-8, I apply CVPS's limited estimates of plant vintage to estimate the multiplier for distribution poles. In that Exhibit, I compute the retirement rate for each vintage implied by the change in expected life between vintages, apply that retirement rate to the plant in service in nominal and real dollars, and find that the inflated cost of the retired plant would be about 3.7 times the nominal cost. This multiplier is slightly less than the multiplier of 4 that the Department used in deriving avoided T&D costs in its filing in this case, and much smaller than the multipliers CVPS used in its analysis.

Q: Why do you believe that CVPS's accounting data on book cost overstates the original cost of the equipment?

A: According to CVPS's 1994 depreciation study, for what it calls "mass accounts" (such as Account 364—Poles, Towers, and Fixtures, and Account 365—Overhead Conductors and Devices) the retirement price is not recorded at the original cost of the equipment (Attachment IR DPS-CV 4-37 Supp., IV-10; excerpts provided as Exhibit DPS-PLC-R-7). When one pole is retired, for example, the retirement price is estimated at the average cost of all of the poles on CVPS's books *at the time of the retirement.* Therefore, inflation is already reflected in the accounting data for retirements. Even *if* all retired plant survived to the end of its expected life, say 30 years, the Company's avoided cost calculation would overstate the replacement cost; it would be applying 30 years of inflation to an average cost of all equipment installed between now and 30 years ago, not to the original cost of the 30-year-old plant.

In Exhibit DPS-PLC-R-8, I also estimated the average cost of retirements, using the method that CVPS applies to distribution poles. This value is about twice the cost of the units actually retired. As a result, the multiplier needed to inflate the average pole cost to current dollars at the time of retirement is slightly less than 2. Using this smaller multiplier for appropriate accounts would further reduce the inflated retirements, increase net additions, and increase the estimate of avoided distribution costs.

Q: What is the effect of CVPS's exclusion of O&M and overheads associated with new T&D equipment?

A: The company acknowledges in response to IR DPS-CV 4-42 that it included neither O&M nor associated overheads in its estimate of avoided T&D costs. O&M for 1996 that should be included in a CVPS estimate of avoided T&D costs comes to

- $5/kW-year for CVPS transmission,
- $3/kW-year for VELCo transmission,
- $23/kW-year for distribution,

for a total of $31/kW-year (in 1996 dollars), or $37/kW-year including a 20% overhead rate.

Q: Where does CVPS adjust for inflation in its calculations?

A: According to its documentation, the Company attempts to convert historic FERC T&D data to 1/1/94 dollars, to calculate an avoided cost in 1994 dollars based on these data, and to inflate the result to 1998 dollars.

Q: In what ways has CVPS understated cost escalation?

A: In the following ways:

- In converting historic costs to 1/1/94 dollars, CVPS omits a half-year's inflation. It apparently assumes that FERC data on expenditures and retirements reflect end-of-the-year dollars.[28] Since expenditures are

[28]The company inflated the FERC cost data by applying a ratio of the 1994 Handy-Whitman Index to the index for the then-current year. The CVPS formula uses the wrong years, but the right *number* of years. For example, 1990 FERC costs are inflated 3 years, but based on ratio of the 1994 to the 1991 index, rather than on a ratio of 1993 to 1990. The 1993 FERC

made throughout the year, the FERC data should be treated as mid-year-dollar costs. The avoided costs that CVPS derives from these data in the spreadsheet AV_COST.WK4 are therefore mid-1993-dollar values, not 1994-dollar values as CVPS claims.

- The CVPS estimate of avoided T&D costs in 1/1/98 dollars differs from the estimate claimed to be in 1994 dollars by only 2 years of inflation.
- CVPS intends to state its avoided T&D costs in beginning-of-the-year dollars. Avoided costs in mid-year dollars is a more appropriate measure of the annual benefits per kW from a DSM measure.

In short, CVPS should have adjusted for 5 years of inflation between mid-year 1993 and mid-year 1998, but included only two.

Q: Have you adjusted CVPS' calculation of avoided costs for the errors you have discussed.

A: I made the following adjustments:

- Recalculated replacement cost, by applying a multiplier of 4 to the book cost of retirements.
- Added in a CVPS-specific estimate of O&M with overheads based on an average of historic CVPS expenditures over the period 1986–1995.
- Deducted a T&D offset, as calculated by the DPS.[29]
- Added in the missing years of inflation, applying the CVPS general inflation rate of 2.75% per year.

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costs are multiplied by a ratio of the 1994 to the 1994 index, and therefore not inflated at all. CVPS does not explain why it pegged the inflation multipliers to the 1994 index, but its approach clearly does not result in costs restated in 1/1/94 dollars.

[29]My use of the DPS calculation of the T&D offset is based on the DPS estimate of energy prices. A recalculation of the T&D offset to be consistent with CVPS's low fuel price assumptions would increase the estimate of CVPS-specific avoided T&D costs.

As shown in Exhibit DPS-PLC-R-9, these adjustments to the CVPS calculation increase the estimate of CVPS-specific avoided costs to values very close to the Department's estimate of statewide avoided costs, namely $21/kW-year for the levelized carrying charge on transmission plant, $66/kW-year for the levelized carrying charge on distribution, and $40/kW-yr. for O&M, for a total of $127/kW-yr. in 1998.[30]

Q: How do the current estimates of avoided T&D costs compare to other analyses?

A: Utility estimates of avoided T&D often omit numerous avoided costs, and may improperly match load growth and investment. However, the CVPS 1987 marginal-cost study presented in Docket No. 4364 was reasonably complete, although some avoidable costs were excluded. (J. C. Cater Direct, Docket No. 4364, Exhibit JCC-5; Cater Rebuttal, Docket No. 5294, Exhibit JCC-9.) CVPS continued using this estimate into 1994. Correcting a few computational errors, I found that CVPS's T&D estimate was equivalent to $98.40/kW-yr. of coincident peak load in 1993 dollars (Chernick Direct, Dockets No. 5270 CV-1 and 3 and No. 5686, April 4, 1994). This would be about $110/kW-yr. in 1997 dollars, plus another $5/kW-yr. or so for VELCo transmission, or only about 16% less than the Department's current estimate.

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[30] I did not adjust for CVPS's omission of VELCo avoided T&D plant costs, which the DPS estimates to be $2/kW-year. To adjust for this omission, CVPS calculates avoided cost based on peak growth excluding non-full requirements wholesale sales and wheeling transactions (spreadsheet AV_COST.WK4, Sheet B; CVPS Panel Testimony, Workpapers, 24–25). However, there is no reason to expect that arbitrary reductions in transmission-level load growth will compensate for an understatement of the plant additions.

3. Line Losses

Q: Please explain briefly Vermont Marble Power's position on utility-specific line loss factors.

A: The Company asserts that statewide loss factors are not applicable to its service territory because its total system losses are less than 4% while the statewide average variable losses are estimated to be 14.2%.

Q: Do you agree that Vermont Marble Power's low system loss factor indicates that the application of statewide avoided costs is inappropriate?

A: No. Vermont Marble Power's system average losses are low because a large percentage of this company's total sales are made to the Vermont Marble factory at transmission voltage. These losses are likely to be less similar to the losses to Vermont Marble Power's residential and commercial customers than are the average losses for the state. Since those residential and commercial losses are the losses that would be avoided by most DSM programs, they are much more relevant than the utility's overall average. In addition, even DSM at the factory would generally avoid more losses than the 4% reported by the utility, since the factory incurs losses in the transformers that reduce voltages from the transmission level (46 kV) to the much lower voltages (typically secondary) used by its lights and motors, as well as in the internal distribution wiring. None of those internal losses would be reported in the FERC loss computation. Vermont Marble's estimate also excludes all VELCo losses.

Hence, for most DSM programs, the Department's statewide loss estimate would be more accurate than Vermont Marble's estimate, or at least as accurate.

B. Generation Market Prices

Q: How did CVPS estimate market prices?

A: The utility divided the forecast period into two sub-periods based on NEPOOL's capacity need date, and projected market prices separately for each. CVPS assumed that NEPOOL would not need new capacity until 2001. CVPS estimated a short-term market price for the period 1998 through 2000. For the period beginning 2001, the market price was assumed to reflect the annual fixed and variable costs of a gas-fired combined cycle unit (CVPS Exh_(BCD-1), 18–19).

1. Short-Term Market Prices

Q: How did CVPS estimate short-term market prices?

A: The utility estimated a market energy price for 1996–97, based on the prices of its "off-system sales of capacity and energy" (CVPS Exhibit BCD-1, 19). CVPS then split that price between capacity and energy in some undocumented fashion, and extrapolated it to 1998 through 2000.

Q: Are CVPS's short-term estimates appropriate?

A: No. The short-term estimates are too low even to cover energy prices, don't reflect any capacity value, assume no real price increase from 1997 to 1998, and fail to reflect the higher dollars-per-kWh value of a DSM load shape.

Q: What is the basis of CVPS's estimate of short-term market price?

A: Central Vermont based its estimate on the average of its May 1996–April 1997 spot sales of capacity and energy, weighted by monthly sales, inflated to 1998 and then interpolated between 1998 and 2001 (CVPS Exh_(BCD-1), 18–19). The utility has not explained why it chose to weight monthly prices by CVPS's monthly sales, which vary erratically and without any clear connection to the monthly pattern of CVPS's retail sales or DSM savings.

Q: Is this method a valid basis for estimating the 1998–2001 market price?

A: No, for at least two reasons. First, CVPS arbitrarily reduced its estimate of market price by assuming no increase in the market energy prices between 1996–97 and 1998. Second, spot sales by CVPS in May 1996–April 1997 are not necessarily representative of the New England market in that period. The CVPS estimate would have been much more reliable if it had at least considered its purchases as well as its sales. According to its responses to IR DPS-CV 4-9 through 4-13, CVPS considers data on its spot purchases as well as data on NEPOOL lambdas and short-term power transactions in the regional market to be irrelevant to the determination of market price.

Q: What is CVPS's justification for not interpolating market energy prices between 1996–97 and 1998?

A: Central Vermont explains that it interpolated from 1998 to 2001 to reflect the tightening of the market in that period (IR DPS-CV 4-8). Central Vermont does not explain why it expects no market tightening in the 19 months from 1996–97 to 1998. The utility claims without support that market tightening will not be a factor before 1998 (ibid.).

Q: Why are CVPS sales a poor proxy for New England market prices?

A: There is no reason to assume that CVPS sales are representative of the New England market. The Company may, for example, tend to sell in the off-peak hours and buy in the on-peak, or vice versa. In either case, the average of its off-system purchase and sale prices would be a much better indicator, and a broader market index would be better still.

Q: What evidence do you have that CVPS sales in May 1996–April 1997 are not representative of the market price in that period?

A: *Power Markets Week* estimates short-run, non-firm energy prices for New England. Based on the PMW index for the twelve months ending May 1997, the average market energy price in that period was $24.6/MWh. The NEPOOL marginal energy cost (or *system lambda)* was $24.3/MWh for the same period. These values are almost 10% more than CVPS' estimate for energy plus capacity. These data are presented in Exhibit DPS-PLC-R-10.

Q: How does CVPS adjust its energy values to reflect the shape of the loads avoided by DSM?

A: Central Vermont ignores the differences between the load-following shape of DSM and the shape of its short-term energy sales. Central Vermont does not even compute avoided energy costs by time periods.

Q: What additional value should CVPS have included for capacity?

A: As shown by the Department in its filing, capacity measures costing as much as $50/kW-year were implemented in 1997. An update to Attachment 3 to Appendix 4-1 of the filing is attached as Exhibit DPS-PLC-R-11. The Department's estimated market capacity price of $40.43/kW-yr. in 1998 is much more realistic than CVPS's nominal estimate of $6/kW-yr. or its effective estimate of zero (since the capacity value is subtracted from a short-term energy sales value, rather than being added to the total).

2. Market Prices after 2000

Q: How did CVPS estimate market prices after 2000?

A: Central Vermont used the cost of new combustion turbine and combined-cycle plants. In many situations, Central Vermont relied on the Department's data and selected different values, without providing any rationale for rejecting the Department's estimates.

It is important to recall that CVPS did not provide any documentation for its avoided-cost estimates in its testimony. Its workpapers, provided to the DPS only on discovery, are poorly organized, largely hand-written, and incomplete. Central Vermont has not made it easy for the Department, let alone the Board, to understand what CVPS is proposing, or why.

Q: Are there any problems with CVPS's estimate of market price after 2000?

A: Yes. First, CVPS underestimated the capital charges for a combined-cycle unit by applying too small an economic carrying charge. CVPS based the charge on a cost of equity of only 11%, which is more appropriate for a utility than for a competitive firm. CVPS apparently assumed that an investment in a merchant plant will have as low a risk as a regulated-utility investment.[31]

Second, the cost of a new combined-cycle plant that CVPS uses appears to be equivalent to $590/kW in 1996 dollars, as compared to the Department's $623/kW. This $590/kW value is apparently computed by averaging $350 and $500/kW (I cannot find any documentation of either of these values) to derive a "core plant" cost of $425/kW in 1997 dollars, to which CVPS added $115/kW in site costs. I have not been able to follow how CVPS determined these adders, or how it reflects the adjustments in the

[31] I do not cite to particular workpapers, since CVPS's workpapers are not paginated or labeled in any consistent manner.

Department's filing, which amount to \$140–\$210/kW. I see no basis for the Board to prefer CVPS's estimate over the Department's.

Third, CVPS's estimate of the fuel costs (and fixed pipeline costs) for the combined-cycle unit relies on optimistic projections of heat rates, assuming an annual average heat rate of 6,830 Btu/kWh, compared to the Department's estimate of 7,200 Btu/kWh. Central Vermont reports that manufacturers claim efficiencies of 58–60% for units to be available in the future, and appears to have selected the bottom end of that range. The 58% efficiency is equivalent to the heat rates claimed for the very best combined-cycle units available for order in 1996.[32] Central Vermont does not appear to have compared its assumed heat rates to actual experience or reconciled the heat-rate and capital-cost assumptions.

Fourth, CVPS's fuel-price forecast for firm gas is quite optimistic. Central Vermont projects a firm gas price for 2001 of about \$2.15/MMBtu in 1996 dollars. Actual 1996 gas prices delivered to New England were about \$3.50/MMBtu; actual prices in 1997 have run about \$3/MMBtu. Even after this dramatic fall of over 30% in real price, CVPS projects that prices will continue to fall after 2001, throughout the forecast period.[33] While it is difficult to rule out any particular fuel-price trajectory, CVPS's projection

[32]This heat rate may be achievable only for units that operate at 50 Hz, rather than the 60 Hz used in the United States. The 58%-efficient unit is also listed as having a cost about 15% higher than the core plant cost assumed by CVPS.

[33]The CVPS forecast of firm gas price is the sum of pipeline charges that remain constant in nominal terms from 2001 on and the commodity cost of gas that is assumed to increase at the general rate of inflation.

appears to be very optimistic. In the face of growing demand for gas, especially for generation, these low prices seem unlikely.[34]

Q: How does CVPS adjust its long-term energy values to reflect the shape of the loads avoided by DSM?

A: As with the short-term values, CVPS does not explicitly adjust avoided energy costs for the differences between the load-following shape of DSM and the baseload shape of combined-cycle generation. Central Vermont does reduce the capacity factor of the combined-cycle plant to 65.13%, which may be intended to approximate its retail load shape. The reduced capacity factor increases the estimate of capitalized energy costs per kWh, presumably to reflect the higher market energy prices during the periods when customers use the most energy. Any similarity between the magnitude of these effects would be largely coincidental. Again, CVPS does not even compute avoided energy costs by time periods.

C. Cost Levelization

Q: How does the CVPS panel's levelization method differ from the one the Department proposes?

A: It is not clear that there is any difference. In the sample calculation in CVPS Exhibit JCC-2, the nominal benefits of deferring a project one year are derived by applying an economic carrying charge (calculated as a standard annuity factor) to an "initial investment." According to IR DPS-CV 4-23 and the calculation of the combined-cycle capital charges, CVPS would in

[34]Central Vermont appears to agree that most new and replacement generation in New England will be gas-fired.

practice apply the charge to revenue requirements, not to the initial investment. If so, CVPS's proposed methodology and the Department's appear to be equivalent.

D. Risk Adjustment

Q: Does Dr. Rosenberg's proposal to eliminate the risk-adjustment adder have merit?

A: No. Dr. Rosenberg offers no support for his recommendation.

IV. Externalities

Q: What points will you rebut concerning externalities?

A: I will rebut the following positions:

- The position of Mr. Johnson that environmental externalities should not be included in DSM evaluation.
- The positions of the municipal utilities, Mr. Johnson, Dr. Lesser, and Mr. Allard that externalities should not be addressed in this proceeding.
- The position of the Bentley-Cater-Deehan panel—partly supported by the municipals, Mr. Allard and Dr. Lesser—that the Board's rebuttable presumption of a five-percent adder to avoided costs should stand.
- The positions of Dr. Rosenberg and the municipals that the DPS adders mischaracterize the impacts of DSM on regional emissions.
- Dr. Lesser's claim that the Department's valuation methodology is too flawed to be a basis for policy.
- The positions of the Dr. Lesser, the municipals, and Dr. Rosenberg that the use of externality values, particularly those proposed in the

Department's Plan, will cause economic harm to Vermont's consumers or businesses.

- The positions of Drs. Lesser and Rosenberg that using externality values, particularly those proposed in the DPS Plan, will cause environmental harm to Vermonters.

A. Positions of the Witnesses on Externalities

Q: In the Department's Plan, the external costs of generation were included in the avoided costs used for screening DSM measures. Would you summarize the positions of the other parties in regard to this proposal?

A: Six witnesses commented on the inclusion of externality values in the DSM evaluation process in Department's Plan.

One witness, Mr. Rosenberg, offered no opinion as to the appropriate treatment of externalities in this Docket, though he opposed the use of the DPS values and offered some criticisms that seem to apply equally to any externalities valuation.

Another, Mr. Johnson, testifying on behalf of Associated Industries of Vermont, recommended that "the Board should remove the ability of the Department to justify any measure or program based on the concept of externalities" (3).

The remaining four witnesses oppose the use of the Department's values, and to varying extents implicitly or explicitly support the use of the five-percent adder to avoided costs that was adopted in Docket No. 5270.

Q: What is Dr. Rosenberg's primary objection to the DPS values?

A: Dr. Rosenberg objects to the DPS proposed values because "they may not be accurate." His primary evidence seems to be the lack of scientific consensus on methods or values, which he believes is demonstrated by the disparity among the values adopted in different states. Dr. Rosenberg does not advocate the use of any of the values he puts forward.

Q: How do you respond to Dr. Rosenberg's concern?

A: Like the many other estimates required for avoided costs (fuel costs, capital costs, load growth, etc.), there is uncertainty in the projection of externalities. The presence of this uncertainty should not necessarily preclude the development and adoption of reasonable projections. Regulators around the country use a range of estimates, based on a variety of methodologies, for such difficult-to-measure values as marginal T&D costs or the fair rate of equity return for utilities, as well as for projections of future fuel prices and inflation rates.

Moreover, while there are disagreements about the means for calculating externality values, the differences to which Dr. Rosenberg points are explained in part by factors that *should* cause externality values to vary geographically. For instance, Minnesota's values are less than those in Massachusetts because Minnesota (and surrounding areas) has a less-dense population and no ozone non-attainment areas, and because the ecosystems of the upper Midwest are less subject to acidification than those in the Northeast. Rather than demonstrating a lack of consensus on externality values in the scientific community, these differences show the ability of regulators to develop workable pollutant-specific externalities policies.

The difference between New York and Massachusetts CO_2 values is due largely to the fact that the New York PSC, as the first state to adopt externality values, chose to include only a placeholder value for CO_2, despite evidence in the record for much greater values. The basis of the New York externality values was known to the participants in the Massachusetts proceedings. In general, the Massachusetts DPU selected revised and refined values, and used a serious estimate of the costs of offsetting incremental CO_2 emissions.[35]

While some of these differences are due to differences in methodology, all of these values (except perhaps the New York value for CO_2) have a stronger evidentiary basis than an arbitrary zero values or the Board's 5% rebuttable presumption.

Q: What is the basis for Mr. Johnson's extreme recommendation?

A: Mr. Johnson makes three claims in support of his recommendation, none of which justifies his conclusion. He believes that

- the Board has not previously ruled on *whether* externalities should be counted at all when screening DSM;
- externalities should not be considered in this proceeding, because the Board has not fully investigated and ruled on the issue;
- his clients' use of control technologies and compliance with permit conditions means that they have internalized environmental costs.

Q: How do you respond to Mr. Johnson's claims?

A: The first claim is not supported by the Board's previous decisions. The Board has clearly indicated its intention to include externalities in DSM evaluation through its order in Docket 5270, creating the rebuttable presumption of a

[35]Allard (17, lines 1–4) refers to the Massachusetts Supreme Judicial Court decision on the DPU's authority to include external costs in resource acquisition. It is important to note that the SJC decision was on the legal issues of jurisdiction. See Department Reply Brief, 36. As a *factual* matter, the DPU's values were reasonable.

five-percent externality adder in utility least-cost planning, and through its order initiating Docket 5611.

The second claim has the same problem. Since this case involves the evaluation of DSM, some policy will have to be adopted. As discussed below, the Board requires use of the best available estimate of externalities.

The third claim is simply incorrect. Environmental compliance by AIV members is laudable (and, generally, required by law), but in no way addresses the emissions from their use of grid-delivered electricity. Even utility compliance with permit conditions is largely irrelevant, since the externalities, by definition, are the costs associated with the residual, uncontrolled emissions.

Q: Please describe the positions of the various witnesses who support the five-percent adder.

A: Only the CVPS panel explicitly recommends the use of the adder.

The other three witnesses (Dr. Lesser, the Municipals and Mr. Allard) charge that this is not the appropriate forum to address the issue of externalities, and/or refer back to the five-percent adder, though they do not explicitly endorse it.

For instance, the municipals state (7) that since marginal externalities will decline in the near future with the need for new gas combined-cycle plant that "the need to change from the arbitrary but accepted externalities factor established by the Board in Docket No. 5270 does not appear to be compelling." However, they seem to oppose any externalities valuation in this Docket, preferring that specific policy be deferred to the legislature.[36]

[36]The municipals claim to seek a more-comprehensive treatment of the issue so as not to disadvantage Vermont business, essentially including externality values in dispatch. This

Likewise, although Dr. Lesser points out that the rebuttable presumption of a 5% adder has not been superseded, most of his objections to the Department's proposals (including his core complaint that the externality values are only acceptable if they equal societal willingness-to-pay for emissions reduction), apply at least as strongly to the five-percent adder.

Q: How do you respond to the claim that this is not the appropriate forum for addressing externalities?

A: As a practical matter, the Board will need to settle on an externalities policy for use in this proceeding, whether it is the DPS proposal, the five-percent adder, or some other value. Ignoring externalities entirely would amount to adopting a zero value for environmental externalities, which would clearly be too low. Exhibit DPS-PLC-R-12 lists the known or suspected environmental effects of the major pollutants monetized by the Department; the total societal cost of these effects cannot be zero.

The Department's Reply Brief on Jurisdiction (34–35) addresses the legal objections to consideration of externality valuation in this proceeding, and concludes that this is an appropriate forum.

Q: What is the basis for these parties' support of the five-percent adder?

A: As noted above, only the CVPS panel explicitly supports the five-percent adder. The CVPS witness panel provides no support for its recommendation or even objections to the Department's values.

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interesting possibility is far beyond the jurisdiction of the Vermont General Assembly, given NEPOOL's regional nature, and would be nearly impossible to implement in the competitive wholesale generation market.

In fact, no party—in this docket or any other to my knowledge—has offered any evidence supporting the five-percent adder on any basis other than that it was approved by the Board in an earlier docket.

Q: If the Board approved of the five-percent adder, why are you offering different values?

A: When the Board adopted the five-percent externalities adder, it explicitly ruled that this default value is a "rebuttable presumption." The five-percent adder is arbitrary; there is no reason why the external costs of electric generation would be proportional to the direct costs. To the contrary, any percentage adder would tend to produce some counterintuitive results. For instance, if additional environmental controls on the marginal energy source raise its cost, actual external costs will decline, but the five-percent adder would increase with direct costs. Further, the five-percent adder does not reflect the fact that avoidable emissions may change over time relative to other avoidable costs.

The Department believes that the scope of this docket requires a better alternative. The values proposed in the Department's Plan are supported by substantial evidence and represent the only reasonable alternative offered by any party. To the extent that various witnesses have criticized aspects of the Department's proposal or externality valuation in general, I address their concerns below.

B. DSM's External Costs

Q: What is Dr. Rosenberg's concern about the external costs of DSM?

A: In his testimony, Dr. Rosenberg (28) states, "In order not to bias the evaluation process, externalities would have to be included in the costs of the

DSM programs, too. For example, there are PCB's in older magnetic ballasts, mercury in fluorescent lamps, and CFCs in old refrigerators."

Q: Does Dr. Rosenberg offer estimates of the externalities of DSM measures?

A: No. Dr. Rosenberg offers nothing beyond the two sentences above. In response to our inquiry (IR DPS-IBM 3-2) as to "whether and how DSM programs would create external costs or benefits" relating to substances in end-use technologies, he referred us back to his testimony, and confirms that he has not quantified any external costs.

Q: Should the Board be concerned about the external costs of DSM?

A: In principle, Dr. Rosenberg raises a valid point. I agree that if there are significant and quantifiable external costs associated with DSM, they should be included in the evaluation process. This is the very reason that the Department advocates including the external costs of the fuel burned at the end-use when evaluating fuel-switching measures.

Practically speaking, however, Dr. Rosenberg has offered no evidence that DSM has significant external costs. Furthermore, the specific examples to which he points are of questionable relevance, and might cut in favor of DSM. Well-designed DSM programs are more likely to result in the safe and efficient disposal of the CFCs in old refrigerators or PCBs in old magnetic ballasts, compared to leaving these technologies in place, eventually to be tossed in the trash. The Department has incorporated the environmentally responsible disposal or recycling of waste in the programs it has designed, and would incorporate any relevant costs in screening.

So, while Dr. Rosenberg is correct in principle, he has provided no evidence to support the addition of external DSM costs to the evaluation process at this time.

C. Externality Valuation and Regional Emissions

Q: Have any parties disputed the Department's characterization of the emissions that would be reduced by DSM?

A: Yes. Several objections have been raised. First, the municipals seem to believe that DSM will not affect generation dispatch and associated emissions at all, while Dr. Rosenberg argues that the impacts are unpredictable and possibly nil. Second, Dr. Lesser and Dr. Rosenberg more specifically argue that SO_2 emissions will not be affected by any DSM, including DSM selected using externality values.

Q: What is the basis for the municipals' position?

A: The municipals argue that because the externalities values will not determine *which* plants are operated, the adders will not affect emissions (Municipals, 8; IR DPS-Muni 2-33 and IR DPS- Muni 2-34). However, they have failed to recognize the simple fact that a reduction in load—such as the reduction from DSM programs—will reduce generation, and a reduction in generation will generally reduce emissions. The Department's dollars-per-kWh values take into account the fact that DSM will not necessarily displace the dirtiest plants, but rather the economically marginal plants. If, when external avoided costs are taken into account, more DSM is found to be cost-effective and is implemented, then that additional DSM will result in additional load reductions, and, in turn, less generation and less emissions.

Q: Is Dr. Rosenberg making the same point as the municipals?

A: Dr. Rosenberg's point is related, but framed slightly differently. He also contends that the resources that we describe as the NEPOOL margin "may not be impacted by an incremental change in usage by Vermonters" (27). To illustrate the supposed uncertainty in the results of a Vermont-load reduction, he alludes to the possibility of utilities selling HQ power, rather than turning down the marginal NEPOOL resources.

Q: Is the scenario Dr. Rosenberg describes realistic? Might a Vermont utility respond to a load reduction by selling some HQ power?

A: It's a possibility, but not a *relevant* one. What really matters in determining the impact of a load reduction is how the NEPOOL system as a whole will react. While a load reduction could lead one utility to sell HQ power to another (and, in turn, to a chain of unpredictable transactions), NEPOOL dispatch will still be driven by predictable plant economics, not by paper transactions. A reduction in load in Vermont will result in reduced generation at some fossil plant in the Northeast. As I explained above, the DPS adders account for which plants are likely to be turned down, based on plant economics.

Q: What is the particular concern about SO_2 emissions?

A: Dr. Lesser and Dr. Rosenberg argue that even if generation is reduced in the NEPOOL system as a result of DSM in Vermont, the total amount of SO_2 emissions will not be affected, because SO_2 is subject to a nation-wide cap. The right to emit that pollutant will simply be transferred to some other utility plant.

Q: How do you respond to this argument?

A: Drs. Lesser and Rosenberg raise an interesting point, peculiar to SO_2. However, their argument fails to recognize that the SO_2 cap will not be widely applied before the year 2000. Furthermore, after 2000 the SO_2 value contributes very little to the Department's proposed adders.

In the 1998–99 period, when we model avoidable emissions as coming from existing units on the NEPOOL margin, it is not the case that reductions in New England sulfur emissions will lead to greater emissions elsewhere. This is because the SO_2 cap and trading program is being implemented in two phases. In Phase 1, prior to the year 2000, the cap on SO_2 emissions does not apply to the great majority of plants that make up the New England margin.[37] In 1998–99, very little of the marginal emissions sources underlying our estimates will be covered by the national emissions cap.

Starting in the year 2000, the DPS estimates of NEPOOL externalities reflect the emissions of a gas combined-cycle unit. Of the $12.93/MWh (1997 dollars) in external costs that we project from 2000 onward, only *eight cents per MWh* are attributable to sulfur. Eliminating the SO_2 component of the externality adder has a less-than-one-percent effect on the external cost estimate.[38]

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[37]Only Merrimack was required to participate, but Newington and Mt. Tom are designated as substitution units, and Ohio Edison has designated Brayton 1–4 and Salem 1–3 as "reduced utilization" units. All these units are baseload coal-fired plants, other than Newington and Brayton 4, which burn oil and gas.

[38]Moreover, even if in Phase 2 there were no net reductions in SO_2 emissions on a nationwide basis, reduced generation could result in a geographical shift in emissions. Given the Northeast's high population density and acid-sensitive soils, SO_2 emissions in the Northeast are likely to impose higher costs that those in most other parts of the country.

D. Dr. Lesser's Complaints

Q: What is Dr. Lesser's complaint about the DPS Plan's values and methodology?

A: Dr. Lesser objects to the methodology behind the DPS values. Broadly, he denies that there is any relationship between the environmental control costs imposed by regulators and legislators (the basis for the DPS values) and the theoretical definition of societal willingness-to-pay for emissions reductions (the sum of all of the individuals' willingness-to-pay), which he claims should provide the basis for externality values.

Q: Has Dr. Lesser prepared an alternative estimate of external costs using a methodology that he finds acceptable?

A: No. Dr. Lesser has provided no alternative, either quantitative or methodological. He has made no attempt to quantify societal willingness to pay, as confirmed in response to our query (IR DPS GMP 4-3c):

> Q: On page 26 of his testimony, Mr. Lesser states that "By aggregating damage estimates over all affected individuals, it is possible to derive an aggregate willingness to pay to reduce the environmental impact." ....
>
> Please provide any such analysis performed by Mr. Lesser or caused by GMP.
>
> A: .... Neither Dr. Lesser nor GMP has performed such a study.

Further, while Dr. Lesser has described in theoretical terms *what* societal willingness-to-pay is (26, lines 6–19), neither his testimony nor his responses to our inquiries provide any evidence that he knows *how* one could actually go about measuring societal willingness-to-pay for air emissions reductions (IR DPS GMP 4-1, GMP 4-3).

The one exception may be SO_2. Dr. Lesser has indicated that he believes that the cost of SO_2 allowances is equal to society's willingness-to-pay for reductions in SO_2 (24, lines 3–8). I will explain on pages 64–65 below that this assertion is erroneous and irrelevant.

Q: What is the basis for Dr. Lesser's position that cost-of-control tells us nothing about societal willingness to pay?

A: Dr. Lesser's argument hinges on his claim that the costs that regulators are willing to impose on society are not based on economic-efficiency criteria and do not reflect the trade-offs that members of society would be willing to make between pollution and costs.

Q: Is it true that regulators do not look at economic efficiency when setting control requirements?

A: No. In the decisions on which we have relied to develop costs of control for regulated pollutants, the regulators had cost data available to them prior to adopting the regulations, and there is evidence in most cases that the regulators considered costs in their requirements.[39]

Specifically, the NOx controls in Massachusetts are based on a best-available-control-technology assessment that explicitly considers the cost and effectiveness of competing emissions control technologies; cost is an explicit integral part of a BACT determination. The requirement that new #2-oil-fired plants use lower-sulfur fuel is based on the Massachusetts Department of Environmental Protection's comparison of emission reductions to increased

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[39]The same is usually true for legislators, although the paper trail tends to be less clear.

fuel costs.[40] The Massachusetts decision to require vapor-recovery devices on refueling stations prior to the adoption of the Federal Clean Air Act was at least partially based on a cost-effectiveness study performed by the DEP.[41] Finally, the EPA now has a top-down BACT policy similar to the policy in Massachusetts, which requires the best available control technology unless the petitioner can justify something less stringent "taking into account energy, environmental, and economic impacts and other costs."[42] Thus, while it is possible that not all regulations are based on cost-effectiveness, the regulations relied upon in developing the externality values recommended by the DPS all considered costs.

Exhibit DPS-PLC-R-13 contains the sources referred to above as well as other references that demonstrate how the EPA and other regulators use cost-effectiveness in determining control requirements.

Q: Do environmental regulators require all cost-effective measures?

A: No. Many factors can influence whether or not a regulation is adopted. For example, issues of equity and administrative feasibility may eliminate some options that appear to be technically cost-effective. Furthermore, environmental regulators have limited regulatory authority, and cannot, for example, require utilities or other polluters to increase efficiency or institute DSM

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[40]See the "Edgar Energy Park Supplemental Draft Impact Report, Prevention of Significant Deterioration, Best Available Control Technology Supplement," (February 1991), 8, provided in Exhibit DPS-PLC-R-13.

[41]"Stage II Gasoline Vapor Recovery Program: Background Information and Technical Support Document," Massachusetts DEQE, January 1989, in Exhibit DPS-PLC-R-13.

[42]"New Source Review Workshop Manual," US EPA Office of Air Quality Planning and Standards, October 1990, B.2, in Exhibit DPS-PLC-R-13.

programs. Hence, many cost-effective pollution-reduction options may not be required by environmental regulators.

Q: Is there any other reason that regulatory control costs tell us something about the trade-offs that society is willing to make concerning pollution control?

A: Yes. In some situations, an overall regulatory constraint will *determine* the avoided costs. If the region will need to comply with an ambient pollution limit, such as for ozone, every ton of pollutant avoided by DSM will be a ton of reductions that regulators will not need to require somewhere in the region. Those avoided reductions are likely to be at or above the current marginal control cost (or else they would already have been required).

Q: Dr. Lesser states that, in using the Department's proposed externality values, it is extremely unlikely that Vermont consumers will realize benefits equal to or greater than the resulting additional DSM costs. What is the basis for his charge?

A: Dr. Lesser relies on his broad claim that there is "little, if any, relationship" between the Department's values and societal willingness-to-pay, and on the "example" of the sulfur-dioxide-allowance market.

It is mystifying to me that Dr. Lesser concludes that the DPS values are likely to be *in excess* of societal willingness-to-pay, given that he

- has made no estimate of societal willingness-to-pay,
- states that there is no relationship between the DPS values and societal willingness-to-pay, which would seem to preclude any systematically biased relationship.

Q: What does Dr. Lesser believe can be learned from the example of the SO_2-allowance market?

A: Dr. Lesser has correctly observed that the cost of a sulfur-dioxide allowance (the right to emit one ton of SO_2) is less than the SO_2 externality value that the DPS proposes.

From this fact, he jumps to the following two conclusions:

- Societal willingness-to-pay for SO_2 reductions is less than the Department's SO_2 values;
- Societal willingness-to-pay for other pollutant reductions are likely to be less than the Department's values for those pollutants.

Q: Why do you object to this extrapolation?

A: First, the cost of SO_2 allowances tells us nothing about societal willingness-to-pay for SO_2 reductions. Second, there is no basis for extrapolating from SO_2 to other pollutants.

Q: Why doesn't the price of an SO_2 allowance represent societal willingness-to-pay for SO_2 reductions?

A: As Dr. Lesser explains in his testimony, societal willingness-to-pay should be calculated as the *sum* of all individuals' willingness-to-pay for air emissions reductions. What Dr. Lesser does not explain in his testimony is that the SO_2 allowance market merely measures the marginal costs that any *one* individual (or entity) *alone* is willing to pay for the benefits to that individual.[43]

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[43]Dr. Lesser's testimony does not clearly explain why he believes that the allowance price tells us anything about societal willingness to pay. His discovery response does nothing to clarify his position. When asked, "Do allowance prices reveal an individual's willingness-to-pay for emissions reductions or societal willingness-to-pay?" Dr. Lesser responds: "An allowance price equals what the marginal individual is willing to pay. Assuming a competitive

The distinction is crucial, because air quality is a *public good.* If one person purchases air quality benefits (i.e., a reduction in emissions), the benefits will be shared by a large population. The social benefits may be very great, but the environmental benefits to the purchaser will be very much less.

Consider this hypothetical situation. Suppose that one million people would each be willing to pay one-tenth of a cent to eliminate one ton of SO_2 emissions; that is, the retirement of one allowance would benefit each of them by \$0.001. The societal benefit from retiring that allowance would be 1,000,000 people × \$0.001/person = \$1,000. In this example, it is easy to see that no one individual would be willing to shell out the \$100 market price of an allowance—an amount grossly in excess of each individual's benefits—to retire an SO_2 allowance, though it would be well worth it from a societal perspective.

What we find in the real allowance market is consistent with this model. For the most part, the active participants in the market are not individuals or even environmental groups trying to buy air quality, but utilities who are required to buy the right to emit, in order to keep operating their plants.

Thus, because air quality is a public good, and there is no effective means for aggregating the demand of all affected individuals, the market for SO_2 allowances does not capture societal demand (also known as willingness-to-pay) for SO_2 reductions.

Q: Is Dr. Lesser correct in arguing that since society could pay the allowance price to purchase SO_2 reductions, consumers should not pay more?

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market for such allowances, it also represents the amount that society is required to pay to reduce emissions. Presumably there will be some consumer surplus realized." (IR DPS-GMP 4-10)

A: While it would be nice for consumers to get emissions reductions at a lower cost, as noted above, there is no mechanism to make those purchases.[44] In the meantime, as long as reductions cost consumers less than the benefits they provide—and that is the cut-off point that the DPS values represent—the net benefits justify the purchase.

Q: Does Dr. Lesser suggest a reason for the difference between the price of an SO_2 allowance and the Department's externality value?

A: Dr. Lesser suggests, though he does not claim directly, that (in addition to being based on a flawed methodology) the DPS value may be greater than the market price of an allowance, because societal willingness-to-pay for air-emissions reductions has declined since the regulations on which the Department's externality value was based. Dr. Lesser offers no evidence to support any claim that willingness-to-pay has declined. On the contrary, the recent strong stance taken by the governors of the northeastern states on NOx emissions within OTAG and the more stringent NAAQSs adopted by the EPA suggest the opposite trend.

E. Economic Impacts

Q: What are the concerns about economic impacts of valuing externalities?

A: The municipals, Dr. Lesser, and Dr. Rosenberg all touch upon the potential economic impacts of externalities valuation.

[44]Dr. Lesser's only proposed mechanism for such purchases is personal investments by DPS staff members (28, lines 9–16).

Drs. Lesser and Rosenberg both seem to imply that using the DPS externality values will directly increase societal costs. However, their warnings are strongly qualified, as I emphasize in the below quotations:

> *To the extent that the control-cost-based 'adders' recommended by the DPS exceed Vermont consumers' willingness to pay,* and the amounts they are required to pay in a market, Vermont consumers will suffer economic harm. (Lesser, 28)

> *[U]sing an inflated value for externalities*...will increase societal costs, not decrease them.... [I]t will raise the energy bill for Vermonters. (Rosenberg, 28)

Dr. Lesser has not shown that the DPS adders do exceed willingness-to-pay, as he has no estimates of willingness-to-pay (IR DPS-GMP 4-1, 4-3). Dr. Rosenberg does not even directly assert that the DPS adders are inflated, let alone provide any evidence to that effect. There is no reason to believe that their warnings, however correct in principle, are applicable to the Department's externality values, which do not exceed societal willingness-to-pay and are not inflated.

Q: What is the economic issue raised by the municipals?

A: The municipals, along with Dr. Lesser, are concerned that price increases resulting from externalities valuation will hurt Vermont businesses, either driving them out of state or placing them at a competitive disadvantage relative to out-of-state competitors.

Q: Have any of these parties analyzed the economic impacts of including externalities in DSM evaluation?

A: No. No one has provided any estimate of the rate or bill impacts associated with externality valuation, let alone the alleged potential for hurting businesses.

Although I have not prepared an analysis, given the significant differences among current electric rates in different areas, it seems unlikely that any rate increase from externalities valuation would be noticeable by comparison, or sufficient to discourage businesses from operating in Vermont.

Furthermore, no party has given any indication that they even considered the economic benefits that would accrue to business through internalizing externalities, such as

- reduced future compliance costs. The lower the pollution levels from utilities, the less stringent the air pollution rules will need to be for industrial and commercial pollution sources.
- healthier employees, leading to higher productivity. Lower levels of particulates, ozone, and SO_2 should result in healthier Vermonters.
- reduced health insurance costs. Healthier Vermonters should lead to lower health-care costs, much of which are paid by employers.

F. Environmental Effects of Externality Valuation

Q: Please explain Dr. Lesser's concerns about environmental repercussions that were not anticipated in the DPS Plan.

A: Dr. Lesser (30) postulates that including the Department's proposed externalities adders in avoided costs will lead to the selection of more-expensive DSM. As a result, electric rates will increase, and consumers will tend to substitute "other unregulated fuels for electricity, such as wood and oil. This has the potential for exacerbating local environmental impacts."

Q: Is Dr. Lesser's concern justified?

A: Theoretically, including environmental externalities in DSM selection could cause a fuel-substitution effect, as could anything that increased rates (such as *any* DSM, or an increase in the Company's rate of return). However, Dr. Lesser has provided no evidence of the likelihood or magnitude of such an effect. Further, he has merely presumed that fuel-substitution would harm the environment, and ignored other secondary effects of increased rates that could potentially lead to environmental improvement.

He seems not to have considered

- whether burning oil or wood, instead of using electricity, actually increases environmental costs, locally or globally. The inefficiency of electric generation may make it more polluting than fuel-consumption at the end use.
- the extent to which consumers faced with higher rates would conserve electricity without substituting any other fuel.
- the extent to which consumers faced with higher rates would switch to lower-emission fuels, such as gas or propane.

If such secondary effects are to be considered, they should all be considered together. It is not evident that the net result of these secondary effects would be to increase environmental impacts, even locally, as Dr. Lesser suggests. Moreover, it is not evident that any combined negative impact would weigh significantly against the primary benefits of the increase in DSM resulting from the inclusion of externalities in DSM screening.

Since Dr. Lesser has provided no evidence of these speculative impacts, they should not weigh against either the Board's general commitment to including external costs in DSM evaluation nor against the specific values offered in the Department's Plan.

Q: Do other parties warn of environmental damages resulting from the use of externality values?

A: Yes. Dr. Rosenberg describes two possible mechanisms through which he envisions environmental damage resulting from the inclusion of externality values. Like Dr. Lesser's fuel-substitution effect, both potential effects are the secondary result of increases in electricity prices, and neither is supported by any evidence.

Dr. Rosenberg's first concern is that higher electricity prices will "retard the development of electrotechnologies that could potentially reduce emissions." His second concern is that higher electricity prices will cause customers to move their load out of Vermont, where he imagines they will purchase generation from "an out-of-state source that is a higher pollutant" (29).

Q: How do you respond to Dr. Rosenberg's concerns?

A: Dr. Rosenberg's first concern is really a special case of Dr. Lesser's worry about fuel substitution. Again, absent any evidence to the contrary—and none has been provided—there is no reason to believe that this particular secondary effect would be significant. It seems particularly farfetched that the *development* of technologies would depend on the price of electricity in Vermont, a relatively small portion of the market for those technologies.[45]

Dr. Rosenberg's claim that increased prices would lead to a shift in load that would lead to a shift in generation is possible but improbable. First, the price increase that is likely to result from including externalities in DSM

[45]Furthermore, including externalities in the evaluation of emission-reducing electro-technologies would tend to favor them over polluting fossil technologies.

evaluation is small by comparison with the price differentials that currently exist among different parts of the country. If customers have not yet been convinced to move for lower electricity prices, it seems unlikely that externalities would make the difference. Second, there is no basis for Dr. Rosenberg's presumption that moving load out of state would lead to higher emissions. If the load were still in the NEPOOL region, the move would have virtually no impact on regional generation or emissions. If it were moved out of NEPOOL, the net change is unknown.

V. The Rationale for Declining DSM Efforts

Q: Do you have any comments on the testimony of Mr. Grimason regarding the rationale for GMP's reduced DSM efforts, starting in 1994?

A: Yes. Mr. Grimason asserts that GMP reduced its DSM efforts due, in part, to falling avoided costs (3, lines 15–16). While it is true that forecasts of fuel prices and of the costs of new power plants have declined since the late 1980s or early 1990s, a large portion of the 1994 decline in GMP's estimates of avoided costs was due to GMP's unreasonable and unrealistic changes in its avoided-cost methodologies, including

- an arbitrary overstatement of the period during which GMP would have a surplus. GMP's 1994 avoided costs were based on the assumption that the Company would have no need for new generation capacity until 2011, yet the load and capacity summary that GMP claimed to have relied upon actually showed deficiencies starting in 2005.

- assuming that excess capacity is not 100% marketable unless NEPOOL is projected to be deficient in both summer and winter, even though new capacity would be needed for deficiencies in either season.
- an unreasonable and inaccurate formula for projecting the market price of peaking capacity as a function of NEPOOL reserve surplus. GMP's formula was inconsistent with historical relationships between excess capacity and market prices, predicting a zero capacity price in periods when CVPS reported sales at half the cost of a new unit.
- an excessive discount to the market price of capacity to reflect wheeling charges.
- the assumption that DSM in any rating period has a flat load shape, rather than being shaped like load, as GMP had assumed from 1990 through 1992.
- the failure to reflect off-system economy energy sales, resulting in implausibly low energy costs in some periods.
- arbitrary elimination of load-related expenditures from the computation of avoided T&D costs.
- the use of arbitrary and mismatched periods for loads and investment in the computation of avoided T&D costs.

The utility's manipulation of avoided costs to justify reduction in DSM efforts (which is unfortunately not unique among Vermont utilities) is yet another reason for the Board to transfer responsibility for implementation of the core programs to the proposed efficiency utility.

Q: Does this conclude your rebuttal testimony?

A: Yes.