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#94

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF THE

MARYLAND OFFICE OF PEOPLE'S COUNSEL

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1. INTRODUCTION AND QUALIFICATIONS

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts. Resource Insight, Inc. was formed in August 1990 as the combination of my previous firm, PLC, Inc., with Komanoff Energy Associates.

Q: Summarize your professional education and experience.

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

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

Q: Have you testified previously in utility proceedings?

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

Q: Have you testified previously before this Commission?

A: Yes. I testified on BG&E's least-cost plan in Case No. 8278.

Q: Have you been involved in least-cost utility resource planning?

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design project in Jamaica; to CLF interventions in a number of New England rulemaking and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago in reviewing the Least Cost Plan of Commonwealth Edison; to the South Carolina Consumer Advocate on least-cost planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the DC PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

Q: Have you authored any publications on utility planning and ratemaking issues?

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

Q: Are you engaged in any least-cost planning activities in Maryland?

A: Yes. I am a consultant for the Maryland Office of People's Counsel (OPC) to the DSM collaboratives for PEPCO and BG&E, which also include the Commission Staff, DNR, and in the case of the BG&E collaborative, other parties. I am responsible for issues concerning avoided costs, resource allocation, cost recovery and regulatory policy. I have also been involved in similar collaborative undertakings involving electric and gas utilities in Vermont, New York, and Massachusetts.

Q: On whose behalf are you testifying?

A: My testimony is being sponsored by the Maryland Office of People's Counsel (OPC).

Q: What is the purpose of this testimony?

A: This testimony will review the basic concepts in avoided-cost determination for DSM and examine the publicly available evidence on BG&E's avoided cost determination. I also discuss the valuation of the environmental externalities avoided by DSM, and BG&E's use of avoided costs in screening.

Q: Please summarize your testimony.

A: I conclude that the avoided costs used in BG&E's 1991 IR~~M~~P and in the 12/90 Conservation Plan are too low and appear to be internally inconsistent. The avoided costs are too low in that 10/22/91

- the demand-related costs of generation and transmission are understated, and transmission may be entirely omitted,
- distribution costs are entirely omitted,

- externality values are entirely omitted,
- no credit is given for risk mitigation,
- avoided energy costs do not appear to reflect the effects of the Clean Air Act Amendments (CAAA) of 1990.

The avoided costs are also estimated inconsistently, with the generation capacity costs apparently reflecting the combustion turbine (CT) portion of Perryman (which cannot be avoided without also avoiding the heat-recovery steam generator) and with the energy costs apparently reflecting marginal energy costs.

The available documentation of BG&E's avoided costs is very limited. It is not possible to determine how losses were incorporated in the avoided costs, or how any of the avoided costs were derived.

BG&E also improperly screens DSM programs, comparing the costs incurred in a fixed 15-year time period with the benefits in the same time period. BG&E thus includes the costs of 1991 installations and 15 years of benefits from those installations; this may understate the benefits, since the measures may last much longer than 15 years. More seriously, BG&E includes the cost of 2005 installations, but only 1 year of benefits from those installations. This is an entirely improper and unreasonable computation, which is biased against DSM.

OPC witness Plunkett describes the expected DSM resource available to BG&E, if it properly analyzed and implemented DSM. Mr. Plunkett's testimony also contains OPC's specific recommendation regarding the requested certificate of public convenience and necessity.

Q: How have you organized your testimony?

A: I present the remainder of my testimony in five more sections. Section 2 discusses the proper development of avoided costs for DSM. Section 3 compares BG&E's estimates of avoided costs to realistic values, and to its own Marginal Cost Study. Section 4 discusses problems in BG&E's screening of DSM. Section 5 expands on the valuation of externalities in resource selection. Section 6 describes the risk-mitigation benefits of DSM. Section 7 presents my conclusions and recommendations.

2. DEVELOPMENT OF DIRECT AVOIDED COSTS FOR DSM

Q: How should BG&E estimate the supply costs avoided by DSM?

A: BG&E should capture the avoidable costs of

- generating capacity, both that related to demand and that related to energy, and including purchases, capital recovery and O&M costs;
- transmission capacity, including capital recovery and O&M costs;
- distribution capacity, including capital recovery and O&M costs;
- fuel and other variable O&M generation energy costs;
- compliance with environmental regulations;
- line losses in the transmission and distribution system; and
- externalities.

2.1 Generating Capacity

Q: How should utilities estimate the generating capacity costs avoidable by DSM?

A: The utility should estimate the cost savings of altering the least-cost supply plan without the DSM to the least-cost supply plan with the DSM. The DSM should be assumed to have a realistic load shape (generally, similar to overall system load), and the amount of DSM should be comparable to the capacity of avoidable supply. The portion of the avoided capacity cost that is comparable to the cost of peaking capacity (generally combustion turbines (CTs)) should be assumed to be related to demand or reliability, while the excess should be assumed to be related to energy load.

Q: How would you apply this approach to BG&E?

A: I would treat as avoidable either the first Perryman combined-cycle (CC) phase or the entire Perryman plant. I would determine the demand-related cost by using the cost of the CTs, including O&M and the common plant they require. The excess of the plant cost, including the cost of selective catalytic reduction (SCR) and the extra O&M for the CC, would be assigned to energy costs.[1] All fixed costs should be real-levelized, that is, stated in terms of a first year $/kW such that the present value of the revenue scream of the escalated $/kW value times annual kW is equal to the present value of the expected revenue requirement stream. I would use this as the avoidable capacity costs from 1994 onwards. The PP&L purchase is avoidable in 1993.

Q: How should the demand costs be attributed to various types of load?

A: From the 1990 marginal cost study (MCS), about 45% of LOLP is in the summer on-peak period, and about 28% is in the winter on-peak. These portions might be allocated to peak demand reduction in the appropriate period. The remaining demand-

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[1]The extra fixed costs of a CC over a CT are incurred to allow for production of low-cost energy throughout the year.

related costs should be spread over the energy requirements in the intermediate and off-peak periods.

2.2 Variable Generation Energy Costs

Q: How would you estimate the variable generation energy costs avoided by DSM?

A: I would compare the dispatch costs (fuel, variable fuel handling, variable O&M) of the base case to the dispatch costs of the same case, minus the energy load of DSM (and without any avoided supplies), again at an appropriate DSM load shape. The difference is the avoided variable energy costs.

The resulting values must be time-differentiated, preferably by load level. The generation energy costs (the dispatch costs, plus capitalized energy) at each load level can then be multiplied by losses at that load level and weighted by the load level, to derive a weighted loss factor. This computation should be performed for each rating period. In BG&E's case, this would include 6 periods.

2.3 Transmission and Distribution Capacity

Q: How would you estimate avoidable transmission and distribution capacity for DSM?

A: In general, it is not possible to directly compute the difference in T&D investment for the base and DSM cases, due to the lack of system planning models comparable to the system models used in generation planning. Hence, it is usually necessary to estimate T&D costs from historical (and perhaps projected) relationships between investments and loads.

Regardless of where the customer's usage is metered, someone must provide distribution to the end use, which is almost always at secondary. Hence, avoidable T&D should be computed to the secondary level for all customer classes.

2.4 Environmental Costs

Q: How should BG&E include the costs of environmental compliance?

A: First, for effects that will be mitigated, BG&E should include reasonable estimates of the cost of mitigation. The incremental costs of all emissions-control and effluent-reduction equipment and measures, including all capital and operating costs, the costs of additional fuel consumed due to an increase in plant heat rate, and all other incremental costs should be included in the costs of the resource. The costs in this category cover current costs of existing rules, future costs of existing rules, and future costs of expected rules.

Second, for residual effects that will be internalized through taxes, fees, emissions caps or another method, BG&E should include a forecast of those costs, just as it considers future fuel prices in its cost analysis. Examples include the trading allowance provisions of the CAAA, and other rules that can be anticipated today, such as CO_2 emissions reductions and air toxics reductions. The costs in this category are simply projections of future internalized costs, and should be treated in the same manner as fuel price or other forecasts.

2.5 Line Losses

Q: What line losses should be included in DSM avoided costs?

A: Marginal losses should be included for demand costs and for energy costs, recognizing the variation in marginal losses with load level. Marginal energy losses should reflect the range of loads and costs within a period, rather than losses at the average load level in the period. Like distribution costs, losses should be included to the end-use level, which is almost always secondary.

2.6 Externalities

Q: How should externalities be incorporated into utility planning?

A: The residual environmental and other external effects of power plant construction and operation (the effects that remain after mitigation efforts and that will not be internalized) should be monetized, and estimates of the social cost should be included in resource planning and acquisition. Perryman and BG&E's existing system contribute to regional and global environmental concerns in a way that DSM or other clean resources would not.

2.7 Risk Mitigation

Q: How should the effects of risk be incorporated in DSM valuation?

A: DSM, due to its short lead times, small additions, and tendency to follow load growth and load levels, reduces risk compared to supply additions. This results in lower expected costs (often estimated to be about 10% lower than without risk), and lower volatility and long-run uncertainty in costs. Base-case avoided supply costs should thus be increased to reflect both the difference between base case avoided costs and the avoided costs under uncertainty, and the value of reduced volatility and uncertainty.

3. BG&E'S AVOIDED COSTS

Q: Did BG&E correctly estimate avoided costs for the purposes of DSM analyses?

A: No. BG&E's avoided costs are understated in several ways.

Q: What is the basis for your understanding of BG&E's approach?

A: I have reviewed the available documentation of BG&E's avoided costs in the 1990 Marginal Cost Study (MCS), the December 1990 Conservation Plan (CP), and the 1991 Integrated Resource Plan (IRP). The MCS is a source of estimates for BG&E avoided costs, while avoided costs are tabulated and used for screening DSM programs in the CP and IRP.

The available documentation of BG&E's avoided costs in the CP and IRP are very limited. It is not possible to determine how losses were incorporated in the avoided costs, or how any of the avoided costs were derived.

Q: What problems have you found?

A: The avoided costs used in BG&E's 1991 IRM and in the 12/90 Conservation Plan are too low, in that

- the demand-related costs of generation and transmission are understated, and transmission may be entirely omitted,
- distribution costs are entirely omitted,
- externality values are entirely omitted,
- avoided energy costs do not appear to reflect the effects of the Clean Air Act Amendments of 1990.

The avoided generation costs are also estimated inconsistently.

3.1 Generation Costs

Q: What are the problems with the generation demand avoided-cost estimates?

A: Both the CP and the IRP report a value for demand-related generation capacity of $445.48/kW, with demand measured in terms of contribution to coincident peak (CP), in roughly 1991$. This value is not an annualized cost, but some sort of investment cost or present value.

BG&E actually appears to use a capacity cost of $57.82/kW-yr for each year.[2] Regardless of when a measure is installed, BG&E assumes that it has a *present value* capacity benefit of $57.82/kW-yr (present-valued to 1991) for each year from the installation to 2005. Thus, a 1991 installation is assumed to be worth $867/kW of CP, while a 2005 installation is worth only $58.[3] The BG&E methodology does not appear to be able to evaluate measures lasting less than its analysis period; if BG&E did evaluate a 7-year measure starting in 1991, it would presumably be valued at about $400/kW.[4]

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[2]This number can be derived, for example, by dividing any of the values in the "Generation" column of a PV Avoided Capacity Costs table by the product of the cumulative program (i.e., non-free-rider) participants in that year and the CP savings per participant.

[3]This error is discussed again below.

[4]The importance of using real-levelized carrying costs, rather than nominally-levelized carrying costs or present values of capacity costs, in evaluating resources with different lives is

Q: Are these values consistent with the MCS?

A: No. The MCS reports an investment of $522/kW (1989$) for a 125 MW CT. Including BG&E's assumed 5.25% annual inflation in capital costs, materials and supplies (M&S) of 2.33% of investment,[5] and at a 10.5% real carrying charge,[6] this is $59/kW-year in 1991$. With reserves of 18% and marginal losses of 20%, the cost per kW of CP at the end-use level is about $84/kW-yr.

In addition to capital-related costs, generation has demand-related operating costs. Table 2 computes the cost of O&M, with the adders from the MCS, for the MCS CT as about $5/kW-year of load at the end use. Thus, the total cost of the MCS CT is about $88/kW-year in 1991$. With average inflation of about 5.2% and a 12% discount rate, the present value of a 1991 installation of a measure lasting 40 years would be about $1500, the present value of a 15-year measure would be about $870, and that of a 7-year measure would be about $500. For measures starting in 2005, the 1991 present values would be 60% lower.

Q: How do these values compare to BG&E's estimates of the costs of Perryman?

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demonstrated in the testimony of Dr. Parmesano (Exh. HSP-4). Nonetheless, Mr. DeWitt's testimony computes the cost of Perryman in nominally-levelized dollars (Exh. DDD-2).

[5]This value is from the MCS.

[6]Matt Kahal of Exeter Associates supplied this value, which is slightly lower than I have seen or computed elsewhere for similar parameters.

A: Only the cost of peaking capacity is demand-related. The cost of the Perryman peakers (including their share of the common costs) is computed in Tables 1 and 2.[7] The total real-levelized capital cost at the end use is $79/kW-yr. Thus, the cost of the Perryman peakers are about 10% lower than that of the smaller unit used in the MCS.

In addition, the extra costs of the heat-recovery steam generator (HRSG) are equivalent to about $5/MWH of capitalized energy costs. To this value should be added the cost of selective catalytic reduction (SCR), which is about $1.5/MWH.[8]

Q: What do you conclude about the value of generation capacity used in the CP and IRP?

A: This value is generally understated. The treatment of the capacity cost is clearly incorrect, and does not properly reflect the differences in capacity value of measures with different lives and different installation dates.

Q: Are the generation variable energy costs estimated more reasonably?

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[7]Mr. DeWitt's testimony assumes that only 25% of Perryman common costs would be avoided by the elimination of the first full CC phase. In fact, all common costs are avoidable in the early years. If we treat the first phase as avoidable, all common is avoidable until 1997 and the first-phase common is phased in from 1997-2000. After the year 2000, the avoided common is the phase 2 portion, until the next CC would be needed (sometime early in the next decade), after which phase 1 of the new CC would be avoided. Detailed modelling of these savings would be complicated; as a first approximation, I have assumed that all the common listed in the IRP is designed for two full CC phases, and have assigned it on the basis of capacity.

[8]This value is from Matt Kahal of Exeter Associates.

A: No. There is no indication that either the CP or the IRP uses the difference in costs between a base-case least-cost supply plan without DSM, and a least-cost supply plan with DSM. As shown in Table 4, the CP avoided energy costs are very similar to the marginal energy costs estimated in the MCS.[9] In some cases, the CP avoided energy costs appear to be consistent with the MCS, if BG&E uses very low loss factors. In other cases, the CP avoided energy costs are somewhat too low to be derived directly from the MCS.

Table 4 compares the MCS estimates, escalated to 1991, to the CP and IRP estimates. The computation corrects an oversight in the MCS, in which BG&E failed to include A&G on non-fuel energy costs.

Q: Are the MCS values appropriate estimates of avoided energy costs for screening DSM?

A: No, for three reasons. First, the MCS energy costs are the marginal costs (system lambda) of an extra kWh in a single, so they exclude some of the real energy costs of operating power plants, such as ramp-up of plants and the maintenance of minimum power levels in cycling plants. The full avoided energy cost is also usually higher than the marginal cost.

Second, the MCS costs apparently represent operating conditions in the early 1990s, when the system is particularly rich in base-load capacity. As the system grows into its base

[9]The avoided energy costs in the IRP do not seem to be correlated with any other available source. They are too low to be derived from the MCS.

load, and with the addition of combined-cycle intermediate plants in the late 1990s, more expensive units will be operated more often, and the marginal energy cost would be expected to rise faster than the inflation in fuel costs. BG&E escalates avoided fuels costs at its gas price inflation rate.

Third, the MCS marginal energy costs do not represent a least-cost response to DSM and a reduction in demand and energy load requirements. Avoiding the first CC phase at Perryman with an equivalent amount of DSM would result in avoidance of Perryman's mix of gas and oil, plus other effects due to the difference between the load shapes of DSM and of Perryman.

3.2 Transmission and Distribution Costs

Q: What is BG&E's estimate of marginal transmission costs?

A: Tables 1 and 2 restates the MCS estimates for marginal transmission cost to real-levelized 1991$. The result is about $23/kW of CP in 1991, escalating at about 5.1%.

Q: What value of avoided transmission cost does BG&E use in the CP and IRP?

A: BG&E does not even list a transmission cost value. Since BG&E reasonably treats transmission as being related to CP, the "generation" costs in the CP and IRP may be the sum of generation and transmission. If this is the case, these values are even more grossly understated than was discussed in the previous section. If transmission is not reflected in the "generation" cost, BG&E has simply omitted a significant cost item.

Q: Do utilities generally include marginal transmission costs in their estimates of the costs avoidable by DSM?

A: Yes. I can recall only one other utility that excludes transmission costs from avoided costs.[10] Virtually all major utilities with which I am familiar (e.g., all seven New York utilities, New England Electric, Northeast Utilities, Boston Edison, Potomac Electric Power) treat transmission as avoidable. Since transmission is a bulk service, driven by demand growth, this treatment is clearly correct.

Q: What is BG&E's estimate of marginal distribution costs?

A: The MCS estimates marginal distribution costs at $44-$54/kW-year of customer NCP in 1989$.

Q: Is this range reasonable?

A: No. These costs are clearly understated. The only capital distribution item which is computed in the MCS is for substations. BG&E estimates an average cost of $114/NCP kW for 1985-94 by dividing an average 1989$ investment of $29.9 million by an average load growth of 269 MW. The latter figure appears to be incorrect. According to Table 2 of the MCS, CP load growth in the period 1985-94 was expected to be

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[10]That utility is Commonwealth Electric, which primarily supports this action by its interpretation of a regulatory order, rather than fundamental engineering relationships. The Massachusetts DPU has not approved CommElec's exclusion of transmission.

1371 MW. From the loss study, the sum of NCPs is about 14.5% higher than CP, so 1985-94 growth would have been 1570 MW, not 2670 MW. The resulting corrected substation cost is $190/kW, 67% higher than BG&E's value.

BG&E's estimates of avoidable capital costs for primary and secondary lines, and for transformers, are entirely undocumented. These numbers are also very low, compared to other utilities' estimates. Nor are the differences in these estimates by class explained. The small magnitude of the marginal costs for these items suggest that they may estimated for $/kVA of customer connected load, or some other measure of demand with a high number of units and hence a small cost per unit.

Q: Does BG&E include any distribution costs in screening DSM?

A: No. In the 1990 IRP, BG&E did its DSM cost-effectiveness computations both with and without T&D savings. I noted in my testimony in Case No. 8278 that this was pointless for conservation, since T&D is certainly avoided by conservation. In both the 1991 IRP and the 1990 CP, BG&E omits distribution savings. In the CP, distribution savings are given a value of $53.32/kW of NCP (presumably referring to class non-coincident peak, but neither the classes nor their peaks are defined in the CP), but NCP savings are set to zero. In the IRP, distribution savings are given a zero value.

Q: Is this treatment correct or plausible?

A: No. Ignoring distribution savings seriously understates the value of DSM.

3.3 Line Losses

Q: What line losses does BG&E use in its avoided cost computations?

A: This is not specified, and I cannot derive line losses from any of the data provided with the avoided costs.

Q: What line losses does BG&E use in its MCS?

A: Those line losses are also not specified. By comparing the costs given in the text of the MCS to those reported by class in Appendix A.3 of the MCS indicate that BG&E is assuming 8% energy losses and 10.9% CP demand losses.

Q: Are these values plausible?

A: No. They appear to be estimates of <u>average</u> losses, not marginal losses. Energy losses, either average or marginal, should vary by load level, and hence by time period. The marginal losses are roughly twice the average losses and vary roughly linearly with load. This would suggest that the marginal peak demand losses are about 20%, and losses at average load are about 12%. Since more energy is sold at the higher-load hours, and since these are the most expensive hours, the average difference between energy costs at generation and energy costs at the end use would be about 15%.

These values would be representative for DSM at the premises of all customers. While the MCS is properly concerned only with losses to the meter, DSM saves energy losses all the way to the end use, which for primary customers includes transformers and secondary lines.

3.4 Costs of Environmental Compliance

Q: Is there any indication that BG&E has included in its DSM avoided costs any estimate of the costs of compliance with the Clean Air Act Amendments of 1990?

A: No. The IRP indicates that BG&E has not yet determined its compliance plan, and there is no indication that BG&E has included in its avoided costs the increased fuel costs from fuel-switching or from co-firing; increased heat rates, increased variable O&M, and decreased capacity from scrubbing; or allowances purchased or not sold due to incremental generation. This apparent omission understates the value of DSM.

Witness Switzer testified (Tr. 1/29/91 at 288) that to the extent BG&E incurs costs to comply with environmental standards, those costs are reflected on the generation side. I have not reviewed BG&E's avoided costs in enough detail to determine whether BG&E is properly reflecting those costs. However, witness Kinney testified (Tr. 1/30/91 at 374) that the spring 1990 forecast of electricity prices does not include the costs of the (at that time proposed) CAAA, nor was he certain that they would be included in the 1991 electricity price forecast, which he expected would be filed in the spring of this year. It would have been reasonable for BG&E to include estimates of the impacts of the CAAA in its 1990 forecasts since the form, costs and effects of the legislation have been debated for about a decade and passage (in essentially the final form) appeared inevitable. Leaving out the costs of the CAAA would be an egregious omission from the 1991 forecasts, given the adoption of the amendments in October of 1990 after such a lengthy debate.[11] I find it difficult to believe that BG&E has not had time to generally evaluate the effects of the CAAA on its avoided costs.

Q: What effect do the Clean Air Act Amendments have on BG&E?

A: The most important immediate effect of the acid gas provisions of the CAAA require SO_2 emissions reductions at a number of plants serving BG&E before 1995. Among the units listed in the CAAA are BG&E's Crane 1 and 2 and the jointly-owned

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[11]Kinney went on to testify that the increase in costs caused by the CAAA would tend to dampen demand for electricity. A reduction in demand would affect the timing of new resources. The CAAA is therefore important to the selection and timing of the Perryman units due to its effect on loads, as well as due to its effects on DSM benefits.

Conemaugh 1 and 2.[12] These reductions will generally require addition of a scrubber or the conversion to low-sulphur coal.

The 1995 requirements will tend to increase avoided costs. If plants are switched to low-sulphur coal, BG&E's fuel costs and hence its avoided costs will be higher than currently projected, starting in 1995.[13] If scrubbers are installed, capacity and availability will tend to be reduced, requiring the use of more expensive replacement fuels. Scrubbers also increase non-fuel variable O&M.

Starting in about 2000, every ton of SO_2 emitted by BG&E plants will require BG&E to buy one allowance (if it is over its baseline emission level), or sell one less allowance (if BG&E is under the baseline emission level). More energy generated by the coal units implies more allowances used, for a given fuel type and set of emission controls. A coal unit which just met the proposed 1995 emission requirements would emit 1.2 lb of SO_2 per MMBTU, while BG&E's oil plants (burning 0.9% S #6 oil) would emit about 1 lb of SO_2 per MMBTU. At 10,000 BTU/kWH, 1 MWh would require 10 MMBTU; for a typical BG&E unit, that would produce about 10 lb of SO_2. So if an allowance is worth $1,500/ton SO_2 (the price set forth in the

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[12]The CAAA also lists many other PJM units, including the remainder of Conemaugh, several PP&L units (Brunner Island 1-3, Martins Creek 1-2, and Sunbury 3-4), and others. Since BG&E buys and sells large amounts of power with other PJM utilities, increases in PJM system costs may affect BG&E's avoided costs.

[13]The prices for low-sulphur coal are likely to rise, although the magnitude of the increase will depend on the response of utilities to the legislation.

CAAA, section 416(c) for an allowance auction), the additional cost of 200 MWH of coal-fired generation, which produces about 1 ton of SO_2, would be $1,500, or $7.50/MWh.

The value of each allowance will depend on the demand for allowances, which is a function of new coal- and oil-fired power plant construction, retirements and repowerings, and usage of existing units, and on the supply of allowances, which is a function of the cost of low-sulfur fuels and of emission control technologies. ICF (1989) estimated that allowances would trade for $651-711/ton SO_2 in 2000, $527-650 in 2005, and $575-800 in 2010, all in 1988 dollars, based on the then-current Administration bill.[14] National Acid Precipitation Assessment Program (NAPAP) projects a cost of allowances of about $800-$1,200/ton SO_2.[15] The Allegheny Power System projects least-cost control costs on its system of about $576/ton SO_2 for flue gas desulfurization (FGD) on its Harrison plant, $782/ton for fuel switching to low sulfur coal, and $960/ton SO_2 for FGD on its Hatfield plant.[16] The

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[14]ICF Resources Inc., Economic Analysis of Title V (Acid Rain Provisions) of the Administrations's Proposed Clean Air Act Amendments (H.R.3030/S.1490), Prepared for the U.S. EPA, September, 1989.

[15]NAPAP Key Results, Statement of James R. Mahoney, National Academy of Sciences, September 5, 1990.

[16]Figures expressed in 1991$. Allegheny Power System, "West Penn Power Company's strategy to comply with the requirements of the Clean Air Act Amendments of 1990," February, 1991. APS expected to meet its Phase I targets through scrubbers on Harrison and its Phase II targets through fuel switching and/or scrubbers on the Hatfield units.

CAAA require the EPA to offer a small number of allowances each year at $1,500 in 1990 dollars.[17] Thus, the value of an allowance might be $600-1500/ton SO_2, and each MWh of marginal fossil generation might cost $3.00 to $7.50 in emissions allowances, in 1990 dollars.

Q: How will the CAAA affect the need for Perryman?

A: The most important effect will be to raise the company's avoided costs, which will generally dampen BG&E customer demand. The higher costs will also tend to raise the avoided costs against which DSM is screened. Both of these effects will tend to delay the need for new supply by BG&E, including construction of some or all of the stages of Perryman. If BG&E did not pursue DSM, the CAAA could serve to accelerate the Perryman combined cycle units.

Q: Does BG&E include costs of compliance with future environmental regulations?

A: Witness Bourquin testified that the company designs its plants to comply with existing regulations, and does not include costs for future "unknown" standards (Tr. 1/29/91 at 183). Despite a regulatory finding that SCR should be required at Perryman, BG&E still does not include the cost of SCR in its estimate of Perryman costs. Therefore, it appears that BG&E simply reacts to regulations, and (at least for planning purposes) ignores their potential impacts prior to the

[17]CAAA, Title IV, Section 416(c). This subsection requires the price of allowances to rise with inflation based on the Consumers Price Index.

adoption of formal regulations, as evidenced by its treatment of the CAAA prior to their adoption in October, 1990.

3.5 Externalities

Q: Does BG&E include any externalities in its avoided costs?

A: No. None of the sources I have reviewed indicates that monetized externalities at any value are included in any of BG&E's marginal or avoided cost estimates.

Q: What externality values should BG&E use in screening DSM?

A: From 1995 on, if DSM is assumed to displace Perryman, the externality value would be somewhat greater than that of Perryman, or about 1.5 ¢/kWh, plus losses to the end use. The increment is due to the fact that DSM will tend to displace more of the dirtiest off-peak coal generation.

Until 1995, DSM would primarily displace existing coal, oil and some gas generation on BG&E's system and the similar PJM system. As derived in Section 5, the externalities of existing plants are on the order of 4-5¢/kWh.

3.6 Risk Mitigation

Q: Does BG&E include any credit for DSM to reflect the risk mitigation benefits of DSM?

A: No.

4. BG&E'S SCREENING OF DSM

Q: Is it clear how BG&E has been screening DSM?

A: No. As I noted in my testimony in Case No. 8278, it is not possible to determine how BG&E determines what measures and programs to implement. It has been almost exactly a year since I described these problems in BG&E's screening process, but BG&E has not yet publicly documented that process, in the 1991 IRP or elsewhere.

Q: How should BG&E screen DSM?

A: A comprehensive screening process would start with screening of measures, assuming that cost-effective programs into which they could be fit will be developed. In this screening, only the incremental cost of the measure is included. All program overhead costs (e.g., marketing) and fixed delivery costs (e.g., getting an installer to the customer) are ignored. Similarly, measure enhancements (increased SEER requirements, thicker insulation, installation on equipment with lower hours' use) can be screened, based on their incremental costs.

In these first screening steps, and in all other screening, it is important to

- include all relevant costs and benefits,
- recognize the difference between average conditions and conditions for suitable applications of a measure,
- maximize the difference between benefits and costs, rather than the ratio of benefits to costs, and

- reject options which are not cost-effective on an incremental basis, even if they can be combined with other options to form packages that are cost-effective.

Once the cost-effective measures have been identified and made as cost-effective as possible, they can be combined into programs for screening. The screening of programs should include overheads, joint costs, free riders, and free drivers. The results of the screening determine which programs are worth undertaking, not how much the utility should pay toward the costs of the measures. Participant cost shares should be determined as part of program design since participant costs are closely tied to many market barriers.[18]

Multiple cost-effective options may compete with one another, especially where they would occupy the same physical space or the same energy service role. For example, in a new home, only one water-heating system can be installed, which may be a high-efficiency electric resistance water heater, a wrapped resistance water heater, a heat-pump water heater, or a gas water heater. The preferred option is the one with the highest present value of net benefits, i.e., the difference between benefits and cost. The highest-value alternative can be identified by adding to an accepted option all enhancements

[18]Participant cost shares must be determined as part of program design, since participant costs will determine participation rates, which in turn determine the overhead program costs per unit of savings. Since cost-effectiveness is determined by participant costs, it would be somewhat circular to use measures of cost-effectiveness in determining the share of program costs to be borne by participants.

with positive incremental benefits, and rejecting those with negative incremental benefits.

Q: What problems are still evident with BG&E's screening process?

A: BG&E improperly screens DSM programs, by including such essentially pointless tests as the participant test, non-participant test, and the utility cost test.[19]

BG&E is also inconsistent in its choices of cost and benefits to compare. BG&E compares the costs incurred in a fixed 15-year time period with the benefits in the same time period. BG&E thus includes the costs of 1991 installations and 15 years of benefits from those installations; this may understate the benefits, since the measures may last much longer than 15 years. More seriously, BG&E includes the cost of 2005 installations, but only 1 year of benefits from those installations. This is an entirely improper and unreasonable computation, which is biased against DSM.

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[19]BG&E's version of the utility test has problems beyond those of the standard utility revenue requirements test. As I noted in Case No. 8278:

> What BG&E calls the utility test is really an amalgam of the two viewpoints of the utility ratepayers and utility shareholders, which does not really reflect the perspective of either interest. It does not reflect ratepayers' interest since it counts unrecovered costs incurred between rate cases, a shareholder concern. Yet BG&E's version of the utility test does not really represent shareholders' concerns, since it counts costs that ratepayers will eventually cover. Thus, BG&E is not properly applying the utility test . . . The Company's version of the test is devoid of any real economic meaning.

Finally, BG&E uses a discount rate of 12% for evaluating DSM. This value is too high. BG&E's current estimate of its cost of capital, on which it bases its discount rate used in evaluating Perryman, is 11.87%. Using a lower discount rate for Perryman than for DSM is biased in favor of Perryman. Furthermore, using BG&E's allowed return on equity, allowed capital structure, and current or recent costs of its debt and preferred, Table 5 estimates a cost of capital of 10.5%. The lower the cost of capital and the discount rate, the more capital-intensive resources (e.g., conservation investments) are preferred to fuel-intensive resources (e.g., Perryman, fuel-switching).

5. EXTERNALITIES

5.1 The Need to Incorporate Environmental Externalities

Q: Why is it important to include environmental externalities in 10/22 evaluating the Perryman project, and comparing Perryman to DSM?

A: DSM will reduce the environmental effects of BG&E's generation system, compared to existing sources, Perryman, or the combination of Perryman and the existing system DSM will actually displace. Those external effects impose costs on Maryland, the region, the nation, and the world that are not currently included in BG&E's planning. Including externalities would make additional DSM attractive, which may affect the need and timing of the Perryman project. Aggressive pursuit of DSM could delay the need for new supply, including some or all of the Perryman units.

Including externalities may also affect the choice of Perryman over other supply alternatives. Cogeneration projects can have considerable efficiency and fuel switching benefits, producing lower pollutant emissions than the separate steam and electricity plants. For example, the replacement of an old #6 oil-fired industrial boiler with a new gas-fired cogenerating steam and electricity plant can produce significant emissions reductions, due to improved plant efficiency, cleaner fuel, and more stringent emissions control equipment. Of course, the benefits of specific cogeneration projects will depend on many factors including the emissions currently produced from the steam boiler (which depend on the type of fuel and control equipment which would otherwise be used for steam generation), and the emissions otherwise produced from equivalent electricity generation.

Renewables and highly efficient resources (like fuel cells) can also have emissions-reducing benefits. BG&E limited its choice of projects to a few fossil resources, and did not consider the costs and benefits of many supply resources.

Q: Are there other reasons for including externalities in utility planning in general?

A: There are several reasons for including externalities in utility resource planning. First, the externalities of electricity generation are significant. Electricity generation contributes about two-thirds of national sulfur dioxide (SO_2) emissions, one-third of national nitrogen oxides (NO_x) emissions, and one-third of national carbon dioxide (CO_2) emissions.[20]

Second, a growing number of state utility commissions are including the impact utilities have on the natural environment in resource planning, and have determined that the value of externalities are significant in relation to the direct costs of electricity generation. The New York Public Service Commission (PSC) estimates that a coal plant that just meets the new source performance standards (NSPS) has externalities on the order of 1.4 cents/kWh.[21] The Massachusetts Department of Public Utilities (DPU) and Nevada Public Service Commission (PSC) estimate that the same coal plant would have externalities greater than 5 cents/kWh.[22] Current estimates

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[20]"Statistical Abstract of the United States 1990," U.S. Department of Commerce. "Greenhouse Warming: Abatement and Adaption" Resources for the Future Climate Resource Program, 1990.

[21]Putta, S. Consideration of Environmental Externalities in New York State Utilities' Bidding Programs for Acquiring Future Electric Capacity. New York Public Service Commission, 1990.

[22]Massachusetts Order in Docket DPU 89-239, "Investigation by the Department of Public Utilities on its own motion into proposed rules to implement integrated resource management practices for electric companies in the Commonwealth." August 31, 1990, and Public Service Commission of Nevada Order in Docket 89-752, January

indicate that the externality value of various conventional generation options may range from 15% to over 100% of the direct cost of the power supply options, depending on the option and the valuation assumptions.[23]

Third, different resource options have different environmental effects. For example, in general, coal-fired power plants produce much higher CO_2 emissions per kWh generated than similar plants fired by oil or natural gas, while DSM has few or no related CO_2 emissions. Since CO_2 contributes to the greenhouse effect, Maryland would be better off with lower CO_2-emitting options, all else being equal.[24] Similarly, different plant technologies using the same fuel, such as a pulverized coal boiler, an atmospheric fluidized bed coal (AFBC) and an integrated gasification combined cycle (IGCC), produce different amounts of various externalities. If included, these differences may affect resource selection.

Fourth, some of the most expensive control measures required on new polluting sources such as new power plants can be avoided through the use of cleaner resources. The savings associated with the use of the clean resource include the direct costs of the controls that would otherwise have been required to meet air quality or emissions goals. For example, Maryland is considered part of a "transport region for ozone" under the Clean Air Act Amendments of 1990 (CAAA),[25] which encompasses all of the Northeast states including Pennsylvania and the SMSA that includes the District of Columbia.

22, 1991.

[23]Chernick, P. and Caverhill, E. "Comparison of Total Costs of Supply Options for 89-239." Memo to Greg Tomlinson, May, 1990.

[24]In the case of greenhouse gases, everyone would be better off with a reduction in CO2 emissions, not simply Maryland residents. For other pollutants and effects, such as SO_2 and NO_x emissions reductions the benefits are more localized.

[25]Clean Air Act Amendments of 1990. Title I, Section 184 (a).

Additional fossil generation in this transport region will contribute incrementally to NO_x and volatile organic compound (VOC) emissions, which are precursors to ozone, at a time when reductions of these pollutants must occur to comply with federal regulations. Incremental additions to area emissions are caused by new sources even if best available control technology (BACT) control equipment for these pollutants is installed.[26] Meeting air quality targets will require increasingly expensive control measures. On the other hand, a resource that does not emit NO_x or VOCs, such as DSM, will not add to area emissions and will not require additional control measures to neutralize its impact.

Further, a resource that does not emit NO_x or VOCs, such as DSM, will not use up offsets that are valuable for mitigating emissions from other sources. The transport region encompasses large areas that are in various stages of non-attainment of the federal ozone standard. In these areas all future emission sources must be offset by reductions in existing sources. In addition, these areas must implement plans to reduce current ozone levels, which will require further reductions from existing sources of ozone precursors. To the extent a new source must obtain offsets simply to neutralize its own impact, more expensive offsets will be required to achieve further reductions in emissions. Conversely, if a new source requires no offsets (because it has no NO_x or VOC emissions), the cheaper offsets will be available for emissions reductions, sparing Maryland (and the region) large additional costs.

Fifth, for each polluting resource there may be several control mechanisms to achieve different levels of control. Including externalities should reward utility and non-utility

[26] BG&E is resisting the installation of selective catalytic reduction (SCR) for NO_x control on Perryman. SCR is generally required in many areas in the Northeast.

generator (NUG) proposals that are relatively easily adapted to comply with more stringent environmental regulations, and proposals that are as environmentally benign as is cost-effective based on the environmental analysis.

5.2 Method for Incorporating Externalities

Q: How can the externalities of different supply- and demand-side resources be incorporated into utility planning?

A: Incorporating externalities into utility planning includes determining the important externalities of each resource option and estimating the value of reducing each externality relative to the other attributes of the resource including its cost.[27]

The list of important externalities for each resource should include all important externalities, including both regulated and currently unregulated pollutants, effluents, and other potentially harmful actions or effects directly or indirectly caused by the resource. The list used for resource decisions may be bounded for practical purposes; however, every effort should be made to include any externality (or group thereof) which might effect utility resource decisions.[28]

In order to consistently compare the externalities with other project attributes, the externalities should be expressed on a basis consistent with the cause of the externality. Most monetized externalities are energy-related.

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[27]The considerations discussed here are discussed further in Attachments 2. See also the Massachusetts DPU order in DPU 89-239, August 1990.

[28]For example, the states that include externalities in utility planning have not yet considered nuclear externalities. The exclusion of these externalities is not usually important, since no new nuclear units are currently proposed. However, before new nuclear units could be evaluated, the externalities unique to nuclear would have to be valued.

Therefore, it is appropriate to express externalities in terms of an externality cost in cents/kWh.

Some analysts have proposed the use of qualitative schemes, such as subjective weighting of the environmental effects. In effect, BG&E currently uses a subjective method to evaluate other project attributes, like the risk of not obtaining environmental permits, in its selection of resources. However, there are serious problems with the subjective consideration of externalities, including inconsistency between valuation of the same pollutant in different proceedings, inconsistency between the relative value assigned pollutants with similar effects, results that cannot be reproduced consistently, reliance on utility planners (in some cases) to determine relative values of reducing emissions of air pollutants and reduction of water impacts, and others.[29]

Q: How can the value of reducing externalities, in $/kWh, be estimated?

A: There are three primary steps to expressing externality values in terms of $/kWh. The first step is to count the important effects of each resource. Typical units are pounds of pollutant per kWh generated (lbs/kWh), or more generally, units of the externality per kWh generated (units/kWh). Many of the emissions, effluents, and effects are already monitored by the utilities or the state environmental agencies. Examples of externalities that are currently reported include: emissions of regulated air pollutants, SO_2, NO_x, CO, and TSP; water throughput and consumption; and land use for power plants. The amounts of other externalities not currently

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[29]See Chernick, P. and Caverhill, E. "Monetizing Externalities in Utility Regulations: The Role Of Control Costs," Paper prepared for NARUC conference (October, 1990) for a list of the flaws and shortfalls of this method. The New England Electric System (NEES) proposed a subjective rating method in Massachusetts, where the DPU rejected it in favor of an explicitly quantitative approach.

controlled can often be easily calculated through the use of well-known operating characteristics such as fuel type, heat content and plant configuration. Externalities that can be estimated in this way include emissions of CO_2, which are based on the carbon content of the fuel and the plant efficiency, and emissions of toxic air pollutants such as heavy metals, whose emissions depend on the fuel, plant efficiency, and sometimes the control equipment installed to reduce particulate and SO_2 emissions.

The second step is to determine the value of reducing the externalities, expressed in units such as cost per pound of pollutant ($/lb) or cost per unit of the externality ($/unit).

The final step is to estimate an externality cost per kWh ($/kWh) for each resource, which is done by multiplying the quantity of the externality (units/kWh) by its value ($/unit).

5.3 Monetizing Externalities

Q: Why should utilities estimate dollar values for externalities rather than use a subjective method of comparison?

A: There are several reasons why explicit valuation is preferable to more subjective methods for considering externalities in utility planning.

1. Explicit valuation provides consistent externality values. For example, within a prescribed area, a pound of NO_x is worth the same regardless of its source. Similarly, similar impacts of different power plants on the same water body should be valued the same. Subjective methods do not generally preserve this relationship.

2. Explicit valuation provides consistency across utility resource options. A gas-fired CT located within Maryland should receive the same externality cost regardless of its owner, all else being equal. Similarly, a NUG should receive the same value regardless of the contracting utility.

3. Explicit valuation is simple to use. The value, in \$/unit of externality, is multiplied by the externality related to the supply option, in units/kWh, to get the externality cost in \$/kWh. The externalities of a resource option are then summed to get the total externality cost.[30]

4. Explicit valuation can be used by the utilities to encourage individual plant innovation to improve efficiency, reduce emissions, and reduce other externalities beyond required levels where it is cost-effective to do so. A subjective analysis does not send a clear signal about the worth of these innovations or improvements.

5. There is growing support for explicit valuation, specifically the cost of control approach, across the country. The Massachusetts DPU, the New York PSC, the California Energy Commission (CEC) and the Nevada PSC have broken the ground in this area by placing explicit values on several externalities using versions of the cost of control approach tailored to their specific air quality, control costs and needs.[31]

5.3.1 Estimation Methodologies

Q: Once the important externalities have been identified, how can the value of reducing each externality be estimated?

A: The states that require explicit valuation of externalities in utility planning use and have considered one or both of two methods. The methods differ in their applicability to certain types of externalities, but they are similar in that each estimates a unit value (\$/unit of externality) for reducing externalities. The methods are:

1. Direct estimation of the environmental effects of a pollutant, and the valuation of each of those effects; and

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[30]Comparing two resources with different load shapes also requires the estimation of the changes in dispatch of the remainder of the system. This is generally straightforward.

[31]The California PUC has since adopted the CEC values for resource acquisition.

2. Determination of the implied societal value of reducing the pollutant, and the direct benefit of reducing pollution at the margin, from the maximum cost society has committed (or appears ready to commit) to pay for reductions of this pollutant.

Q: Please briefly describe each method.

A: In the first method, direct costing, the direct human health and environmental effects of an externality are counted and a value is placed on each effect to develop a direct estimate of the damages caused by that pollutant. This method is weakened by several scientific uncertainties, including the synergistic and poorly understood effects of pollutants. It is also complicated by societal value uncertainties, including the value of protecting a human life or an endangered species. Where sufficient information is available, the direct impact analysis is often cited as the preferred method of externalities valuation.[32]

The second method, the cost-of-control approach is concerned with developing the value to society of reducing an externality as it is implied in current or future regulations. A simple example would be that if the Clean Air Act required SO2 mitigation that costs $2.00/lb SO2, then the value to society of reducing SO2 at the margin is at least $2.00/lb. This method has been termed implied valuation, marginal-cost-of-control approach, shadow pricing and revealed preference. This method relies on the legislators and environmental regulators, rather than the utilities and their rate-regulating agencies, to assign dollar values to the external effects of utility operations, including effects on human life and health, wildlife, natural ecosystems, historical monuments and visibility.

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[32] For example see Massachusetts DPU Order 89-239, October, 1990.

Q: Which states or commissions use each method?

A: The direct costing approach has been reviewed in several states, including Massachusetts and New York and by the Bonneville Power Administration (BPA). Massachusetts rejected its use for current utility planning, in favor of the second approach listed above. New York also rejected its use for near-term utility planning, although the New York utilities and the New York State Energy and Research Development Authority (NYSERDA) are embarking on a multi-year analysis of the direct effects of power production in New York. The results of this study, to be complete in 1994, may be incorporated into utility planning at that time.

BPA has proposed starting-point externality values for use in the Northwest based on a series of direct-costing studies performed for BPA in 1985-1988. These values are currently under review and have not yet been incorporated into utility planning. New Jersey relied on a direct costing study prepared by the Pace University Law School to estimate the externality benefits of DSM to be used by New Jersey utilities.[33] The values proposed by BPA and those estimated in the Pace study are listed in Table 6, the last three columns.

The values adopted by the CEC, the New York PSC, the Massachusetts DPU and the Nevada PSC are generally based on the cost of control approach. The adopted values are also shown in Table 6. Even though these commissions all used similar valuation techniques, they did not always arrive at similar estimates for the value of reducing certain externalities. The main differences in the value estimates stem from differences in the regional air quality, control measures required in the region, uncertainty about future

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[33] Ottinger, et al., "Environmental Costs of Electricity," Pace University Center for Environmental and Legal Studies, Oceana Press, 1990.

regulations or the effects of particular externalities, and slightly different application of the cost-of-control method.

Generally, the values adopted by the CEC for use on power plants to be built within California are very high to reflect the severely degraded air quality in the L.A. basin, and the generally poor air quality in the rest of California. The values adopted by the CEC for plants outside California are generally lower, to reflect the much better air quality in the regions from which California imports electricity, such as the Northwest and the desert Southwest. For both within and outside California, the Energy Commission adopted a very optimistic estimate of the cost of CO_2 mitigation, based on the costs of planting trees in an urban environment to increase shading and reduce energy usage.

The New York PSC values are lower than the marginal costs of control for power plants within that state or within the region. They rely primarily on the average costs of measures which will be taken to reduce emissions in the near future, rather than the marginal cost of control. The CO_2 value adopted by the PSC was one-tenth that estimated by the State Energy Office.

The Massachusetts DPU relies on estimates of the value of SO_2 allowances under the CAAA for SO_2. For NO_x, the DPU relies on the cost of SCR on cogenerators, which is required in the state, and generally in the region. For CO_2, the DPU relies on a low estimate of the cost of planting trees in the U.S.

The Nevada PSC largely adopted the Massachusetts externality values (inflated to 1990$) with the exception of the value for VOCs, which was independently estimated for Nevada.[34]

[34]Nevada is largely in attainment for ozone.

5.4 Valuing Externality Estimates in Maryland

Q: Are the externality values developed in other states applicable to Maryland?

A: The usefulness of the other estimates for Maryland vary significantly. The estimates based on the direct costing method, those developed for the BPA and relied upon by New Jersey, are preliminary and are probably understated for Maryland. Among other considerations, population densities are generally lower in the BPA service territory than in Maryland. In addition, in response to pressure from the Administration, the BPA (a Federal agency) omits global warming considerations entirely.

Many estimates of the value of local and regional externalities derived using the cost-of-control approach in other states should be generally applicable for Maryland, though they may not translate directly into exact valuations for Maryland. The CEC in-state estimates in some cases represent control measures that are more strict than those currently required in Maryland or elsewhere in the Northeast transport region. However, as evidenced by the recommendation by NESCAUM (Northeast States for Coordinated Air Use Management, the joint planning agency of most of the states in the Northeast Air Transport Region) that the Northeast adopt the new California requirements for automobile emissions, the Northeast is rapidly moving toward California level of controls, especially for NO_x. The New York values are not particularly relevant, since they are based on average rather than marginal costs of control.

The values derived in Massachusetts, Nevada and by the California Energy Commission for power plants outside of California appear to be the most readily applicable to Maryland. Maryland has air quality problems, regulations and control measures similar to or more severe than those in these states. Maryland is in non-attainment status under the federal regulations for ozone, is subject to similar federal regulations governing acid gas emissions, and is located in the same ozone transport region as Massachusetts.[35] The cost-of-control estimates from these states are suitable starting points for Maryland.

The major Massachusetts and Nevada externality values are based on the following sources:

- SO_2: national control requirements,
- NO_x: the cost of SCR on medium-sized power plants,
- CO_2: very low costs of tree planting, much lower than the costs of measures likely to be required to meet the CO_2 reductions generally believed to be necessary.

5.5 Externality Costs of BG&E Resource Options

Q: Is the Perryman project particularly environmentally damaging?

A: Not compared to other conventional fossil-fired supply options. The Perryman Project has several environmental benefits including its staged construction, which allows it some flexibility to respond to future environmental regulations. Also, from the company's description and analysis of Perryman, the site of Perryman appears to have small or no effect on local human and endangered wildlife populations. The addition of heat recovery units will improve the plant heat rate, and provide power at relatively low emissions per kWh generated, relative to other fossil options. The use of gas as the primary fuel by the Perryman project should result in lower emissions of each of the major air pollutants than for a similar oil-fired project or competing oil or coal-fired intermediate load supply options, and very little solid waste will be generated.

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[35] For ozone, Baltimore is rated "severe" and the D.C. SMSA is rated "serious". Nevada is actually in attainment, Massachusetts ranges from moderate to serious and New York ranges from moderate to severe.

On the negative side, Perryman will have emissions of greenhouse gases including CO_2, emissions of acid rain precursors including SO_2 (from burning oil) and NO_x, emissions of ozone precursors including NO_x and small amounts of VOCs, and effects related to gas production and transportation, plant construction and land use. Perryman will also use fresh water, which will be taken from the ground (352 mgy) and from either the Baltimore City Susquehanna Pipeline or the effluent from the Sod Run Wastewater Treatment Plant (about 700 mgy). The water impact may be lessened if the bulk of the water required is supplied by the effluent from the treatment plant, rather than the city pipeline.

Despite its advantages compared to some other supply resources, Perryman is more polluting than is DSM. Perryman will also tend to displace primarily existing gas and oil units, since its dispatch cost will not be competitive with coal. Conservation will tend to displace more of the most-polluting generation of the BG&E and PJM systems, the coal plants.

Q: What might the three air emissions, CO_2, SO_2 and NO_x be worth for typical units in Maryland?

A: If we use the Massachusetts DPU values for these pollutants, inflated to $1990 of $0.78/lb SO_2, $3.40/lb NO_x, and $0.011/lb CO_2 (which are identical to the Nevada PSC values) the costs are the following:

For an existing <u>low-sulfur coal plant</u> with emissions of 1 lb SO_2, 0.7 lb NO_x, 210 lb CO_2 per MMBTU, the total externality would be about $5.45 per MMBTU or (at 10,000 BTU/kWh) 5.5 cents per kWh. High-sulfur coal plants would have higher costs, and scrubbed plants lower costs. NO_x emissions and heat rates also vary.

For an existing <u>oil-fired steam plant</u> with emission rates of 1 lb SO_2, 0.4 lb NO_x, and 170 lb CO_2 per MMBTU, the total externality would be $4.00 per MMBTU or (at 10,000 BTU/kWh) 4.0 cents per kWh.

For a combustion turbine with water injection burning 0.2% #2 oil, with emissions of 0.2 lb SO_2, 0.194 lbs NO_x, 162 lbs CO_2 per MMBTU, and .018 lbs TSP/MMBtu the total externality would be $2.60/MMBtu or (at 13,000 Btu/kWh) 3.4 cents/kWh.

For a combined-cycle plant, burning firm gas, with emissions of 0.0006 lb SO_2, 0.118 lb NO_x and 114 lb CO_2 per MMBTU,[36] would have a total externality value of $1.65 per MMBTU or (at 8,500 BTU/kWh) 1.4 cents per kWh.

In addition, the power plants (except those burning gas) would have monetizable externality costs from particulate emissions.

Q: What are the externalities of the Perryman project?

A: I have not done a complete analysis of the externalities of the Perryman project. However, the air emissions externalities of four air pollutants, NO_x, SO_2, CO_2 and TSP for combined cycle units, CTs and IGCC are estimated in Table 7, along with that of a new pulverized coal plant, at the Massachusetts DPU externality values. Based on these calculations, the combined cycle units (CCs) using 10 months of interruptible gas, 2 months of 0.2% S #2 oil, and the vendor's with guaranteed NO_x emissions, will have air emissions externalities of about 1.35 cents/kWh, the CTs using interruptible gas and fitted with water injection for NO_x control will have externalities of about 2 cents/kWh, and the IGCC units would have externalities of roughly 2.5 cents/kWh. A new pulverized coal plant would have externalities of roughly 4 ¢/kWh.

[36]This assumes a 65% reduction in NO_x emissions from steam injection.

5.6 Anticipating Environmental Policies and Regulations

Q: Do anticipated future environmental policies and regulations represent internal or external costs?

A: In the short-term, they represent estimates of the value of external environmental effects. In the longer term, they represent internalized costs.

Q: What affect might the air toxics provisions of the CAAA have on the direct costs of new fossil resource options like Perryman?

A: Title III of the CAAA requires stringent controls on a long list of toxic air emissions from industrial sources. Electric utilities are explicitly exempt from these general provisions for the next couple of years. However, it is recognized in the CAAA that electric utility steam generating units emit some of these pollutants, and the EPA is required to study the "hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units..." The Administrator is required to report to Congress the findings of this study within three years of the date of enactment of the CAAA (four years for mercury), and describe alternative control strategies for pollutants which may warrant control under this section.

It is unlikely that the Perryman project will be required to install specific controls for air toxics, given the combustion turbines' (CTs) low capacity factors and the use of natural gas as the primary fuel of the combustion turbines. However, air toxics regulations could affect coal units owned by BG&E, which would raise the avoided costs used to determine the cost-effectiveness of DSM, encourage additional DSM, improve the cost-effectiveness of conservation compared to Perryman, and perhaps delay the need for new supply resources. These regulations could also result in Perryman's use of more expensive cleaner fuels to replace oil, or in the use of more 10/22 expensive firm gas, both of which will increase Perryman's costs.

Although the CAAA do not specify future control requirements on utility steam plants to control toxic air emissions, any regulations that are adopted are likely to be in place for most of BG&E's current planning horizon. BG&E should consider the likelihood of such regulations, the effects of air toxics regulations on BG&E (including the types and costs of control measures), and effects on existing BG&E resources and new supply resource decisions. These supply-related costs will increase the value of DSM and other clean resources.

Q: What affect would a national CO_2 emissions reduction target have on the direct costs of new fossil resource options like Perryman?

A: The adoption of a CO_2 reduction strategy will not generally affect the capital costs of new fossil options, in the sense that control equipment, such as CO_2 scrubbers, is unlikely to be required in the near future. However, a CO_2 reduction strategy may raise the operating costs of fossil plants through taxes on CO_2 emitted, or by other costs associated with overall caps or reduction targets on CO_2 emissions. Raising the fuel-related costs of BG&E's fossil options would raise the avoided costs used to evaluate the cost-effectiveness of DSM, calling into question both the timing of BG&E's need for new supply.

Q: How likely is the adoption of a CO_2 emissions reduction policy in the U.S.?

A: The administration has resisted establishing a specific CO_2 reduction policy. Indeed, the National Energy Strategy advocates increased CO_2 emissions. However, there is considerable pressure in the international community for a U.S. CO_2 policy, and most industrialized countries and some individual U.S. states have independently adopted CO_2

emissions stabilization or reduction policies.[37] In fact, the U.S. is the largest single contributor to global CO_2 emissions,[38] and is one of the few western countries that has not adopted CO_2 emissions reduction targets, as shown in Table 8. Reading the goals summarized in Table 8, many countries require reductions in the range of 10-40% from base-case forecasts. Krause, Bach and Koomey estimate that reductions of 20% from present levels by 2005 or 2010 (or roughly 50% reductions from base case emissions), and reductions of 80% from current levels by 2030 are required to limit global warming to a tolerable rate. It seems possible, even likely, that within BG&E's planning horizon there will be a national greenhouse gas policy including CO_2, which will affect all fossil generation in the U.S.

Q: Once externality values are established, in $/kWh for each resource, how should the results be included in DSM measure screening?

A: When BG&E carries out a DSM program, the reduction in demand in BG&E's service territory (or reduction in growth of demand) affects the energy supplied on the PJM Power Pool margin, since PJM power pool is centrally dispatched. Therefore, in the short term the externality benefits of the DSM are the avoided externalities of the PJM marginal units. The units on the PJM margin should have externality values similar to the ones calculated above. When the avoided energy cost is based on an avoided unit, then the externality benefit should also reflect the avoided unit's externalities to the extent that the energy avoided by DSM would have come from that unit.

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[37]States that have some global climate change policy, CO_2 emissions policy, or CO_2 valuation policy for utility planning include California, New York, Massachusetts, Nevada, Oregon, and Vermont.

[38]Oak Ridge National Laboratory, The Carbon Dioxide Information Analysis Center, "Trends '90, A Compendium of Data on Global Climate Change." August, 1990.

6. RISK MITIGATION VALUE

Q: Does BG&E's 1991 IRP address the risk-mitigating advantages of DSM in its demand-side resource planning?

A: No. Such advantages are not considered in the 1991 IRP.

Q. Which attributes of efficiency resources improve a utility's ability to manage risk?

A. The Northwest Power Planning Council found that, more than any other resource, efficiency can help utilities adapt to an uncertain future through: (1) flexibility; (2) short lead time; (3) availability in small increments; and (4) ability to grow with load.[39]

Q. In what ways do efficiency resources exhibit these characteristics?

A. Demand-side resources are *flexible* because once a utility has developed the capability to acquire them, it can change its acquisition plans as circumstances warrant relatively quickly and inexpensively. While unexpected changes in resource requirements can wreak havoc with a utility's supply acquisition plans, discretionary efficiency programs can be scaled up or down as needs change. Utilities have a number of "throttles" at their disposal to accomplish this. They can raise or lower financial incentives, add or subtract eligible measures, or expand or contract the target population. In addition, exposure to cost increases for demand-side resources is confined to the acquisition stage. Unlike nuclear and coal-fired stations, for example, efficiency resources are generally unaffected by future cost escalation once they are in place.

As with supply, the lead times of demand-side resources correspond with the magnitudes in which they are available. If a utility maintains the capability to deliver full-scale efficiency programs, it can measure the time between resource

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[39] "A Review of Conservation Costs and Benefits", *op. cit.* at 2.

expenditure and resource service in days or weeks rather than in years. Each project will yield savings on the order of kilowatts or several megawatts. Because efficiency investments produce electricity savings almost immediately, a utility need not invest in resources far in advance of need as is the case with most supply options. Together, the short lead times and small increments associated with efficiency resources allows a utility to more closely match resource acquisition with resource need. This in turn helps lower the risks associated with forecast uncertainty.[40]

Q. How do efficiency resources coincide with variations in load?

A. The ability of efficiency resources to grow with load originates in three distinct ways. First, I testify below that the potential for lost-opportunity resources varies directly with service area load growth. Thus, a utility committed to pursuing all efficiency opportunities that would otherwise be lost will automatically synchronize its *new* resource acquisitions with swings in resource needs.

In addition, the savings produced by *previous* efficiency investments will also tend to track load. For example, an industrial customer will expand output when increased economic activity raises demand for its product. Increasing industrial output will naturally raise electricity use. But if existing facilities employ high-efficiency motors, the increase in electricity use will be less than would otherwise be expected. Similar expectations should also hold for commercial and residential customers.

The third way that higher energy efficiency benefits the utility system directly is by *stabilizing* loads. New buildings that use electricity more efficiently reduce their owners' sensitivity to changes in both electricity and the prices of alternative energy forms. Ensuing loads are more stable since they are less susceptible to fuel switching or

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[40] Id. at 5.

curtailment actions by their owners and occupants. Id. at 11.[41] Compared to supply, efficiency resources therefore reduce the uncertainty surrounding the rate and magnitude of future load growth, thereby reducing the number of options that must be readied for the future.[42]

Q. Can you cite any analysis that recognizes these benefits of efficiency resources?

A. While these advantages are extremely difficult to quantify, efforts are increasing to understand and account for them. For example, a recent analysis conducted by Eric Hirst of Oak Ridge National Laboratory illustrates how demand-side resources with estimated costs identical to supply alternatives may ultimately cost less to implement. The greater flexibility of the demand-side option allows the utility to raise or lower the amount it acquires as needs change, thereby reducing the occurrence and cost of errors. According to Hirst,

> This comparison suggests that utility DSM programs offer benefits related to flexibility not generally considered in assessing their economic worth. The amount of benefit associated with a DSM program depends on the speed with which it can be increased or decreased, the size and construction time of power plants, and the uncertainty associated with future load growth. E. Hirst, "Benefits and Costs of Small, Short-Lead-Time Power Plants and Demand-Side Programs in an Era of Load-Growth Uncertainty", ORNL/CON-278, March, 1989 at 24.

Other analyses indicate that raising efficiency of new appliances can substantially reduce load growth uncertainty --

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[41] Id. at 11. This also benefits a utility's shareholders by reducing competitive pressure from cogeneration. See, for example, J. Plunkett, "Pursuing Least-Cost Strategies for Ratepayers While Promoting Competitive Success for Utilities," Least-Cost Planning Conference, National Association of Regulatory Utility Commissioners, Aspen, CO, April, 1988.

[42] Id. at 5.

that is, the amount of variation between high and low forecasts. Hirst reports that hypothetical calculations suggest demand variance reductions on the order of 17%. (E. Hirst, "Effects of Energy-Efficiency Programs on Load-Growth Uncertainty for Electric Utilities," ORNL/CON-278, August 1988.) Another recent study evaluated this benefit for the Bonneville Power Administration. It concluded that widespread improvements in the efficiency of new buildings could reduce load uncertainty by 24%. (A. Ford and J. Geinzer, "The Impact of Performance Standards on the Uncertainty of the Pacific Northwest System", 1988, at 18, 21.)

Q. How important are these advantages of efficiency resources?

A. These advantages convinced the Northwest Power Planning Council to make conservation the cornerstone of regional energy policy:

> By calling for development of conservation when new resources are needed, the plan embodies its principle of choosing the most flexible resources first -- the ones with the shortest lead times, smallest units and least cost. This approach allows the region to reduce the cost and likelihood of making mistakes. 1986 Northwest Plan, *op. cit.*, at 10-1.

The risk-reducing advantages should make efficiency resources the preferred option in BG&E's resource planning.

Q: Have any regulators explicitly recognized the risk-mitigating advantages of energy-efficiency resources?

A: The Vermont Public Service Board found the "comparative risk advantages" of efficiency resources to be so compelling that it directed utilities to apply a 10% discount to the costs of demand-side resources when comparing them with supply. This translates into an 11% addition to avoided supply costs.[43]

7. CONCLUSIONS AND RECOMMENDATIONS

Q: What are your principal conclusions?

A: I conclude that BG&E has understated the value of DSM by understating the costs avoided by DSM. It appear to have done this in several ways, including:

- understating avoidable generation costs,
- omitting important costs of environmental compliance, including SCR on Perryman and compliance with the acid rain requirements of the Clean Air Act Amendments of 1990,
- omitting all transmission costs,
- omitting all distribution costs,
- omitting or understating distribution losses, and
- omitting all external effects of electric generation.

BG&E also improperly screens DSM, using too high a discount rate, including investment costs while excluding much of the associated benefits, and applying irrelevant tests.

Q: Does this conclude your testimony?

A: Yes.

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[43] Decision in Docket 5270, Vol. IV, Appendix B.

Table 1: GENERATION AND TRANSMISSION CAPITAL COSTS

	Year's $	$M	MW	$/kW	1991$	with reserves 18%	with losses 20%	M&S 2.5%	$/kW-yr 10.5%	$/MWH @ 58% cf
Perryman CTs										
direct	1994	$135	280	$481	$412	$486	$584	$598	$63	
/w common					$506	$597	$716	$734	$77	
/w trans					$659		$900	$923	$97	
cc direct	1995	$108	160	$672	$548					
cap energy					$135			$139	$15	$2.87
common	1994	$96	880	$109	$93					
transmission	1989			$139	$153		$184	$189	$20	

Table 2: GENERATION AND TRANSMISSION O&M COSTS

		$/kW-yr	1991$	A&G @ 42.60%	PayTax @ 3.52%	CWC @ 0.78%	Total	Including Reserves 18%	With Losses @ 20%	$/MWH @ 58% cf
MCS CTs	1989	$2.09	$2.27	$0.97	$0.08	$0.02	$3.34	$3.94	$4.65	
Perryman CTs	1991		$1.01	$0.43	$0.04	$0.01	$1.48	$1.74	$2.06	
Perryman CCs	1991		$8.70	$3.71	$0.31	$0.07	$12.79	$15.09		
Cap Energy							$11.31			$2.23
Transmission	1989	$2.43	$2.64	$1.13	$0.09	$0.02	$3.88		$4.58	
Perryman CT + Transmission									$6.64	

Table 3: Demand-related G&T (Perryman Avoided)
($/kW-year)

	Total Capital	Total O&M	Grand Total	Only Tran capacity to 1992
				$0.0
1991	$96.9	$6.6	$103.5	$20.9
1992	$102.0	$6.9	$108.9	$22.0
1993	$107.3	$7.2	$114.5	$114.5
1994	$113.0	$7.5	$120.5	$120.5
1995	$118.9	$7.8	$126.7	$126.7
1996	$125.1	$8.2	$133.3	$133.3
1997	$131.7	$8.5	$140.2	$140.2
1998	$138.6	$8.9	$147.5	$147.5
1999	$145.9	$9.3	$155.2	$155.2
2000	$153.6	$9.7	$163.2	$163.2
2001	$161.6	$10.1	$171.7	$171.7
2002	$170.1	$10.5	$180.6	$180.6
2003	$179.0	$10.9	$190.0	$190.0
2004	$188.4	$11.4	$199.8	$199.8
2005	$198.3	$11.9	$210.2	$210.2
2006	$208.8	$12.4	$221.1	$221.1
2007	$219.7	$12.9	$232.6	$232.6
2008	$231.2	$13.5	$244.7	$244.7
2009	$243.4	$14.0	$257.4	$257.4
2010	$256.2	$14.6	$270.8	$270.8
2011	$269.6	$15.3	$284.9	$284.9
2012	$283.8	$15.9	$299.7	$299.7
2013	$298.7	$16.6	$315.2	$315.2
2014	$314.3	$17.3	$331.6	$331.6
2015	$330.8	$18.0	$348.9	$348.9
2016	$348.2	$18.8	$367.0	$367.0
2017	$366.5	$19.6	$386.1	$386.1
2018	$385.7	$20.4	$406.2	$406.2
2019	$406.0	$21.3	$427.3	$427.3
2020	$427.3	$22.2	$449.5	$449.5
2021	$449.7	$23.1	$472.9	$472.9
2022	$473.3	$24.1	$497.5	$497.5
2023	$498.2	$25.1	$523.3	$523.3
2024	$524.4	$26.2	$550.6	$550.6
2025	$551.9	$27.3	$579.2	$579.2
2026	$580.9	$28.5	$609.3	$609.3
2027	$611.4	$29.7	$641.0	$641.0
2028	$643.4	$31.0	$674.4	$674.4
2029	$677.2	$32.3	$709.5	$709.5
2030	$712.8	$33.6	$746.4	$746.4
2031	$750.2	$35.1	$785.3	$785.3
2032	$789.6	$36.6	$826.2	$826.2
2033	$831.0	$38.1	$869.2	$869.2

	2034	$874.7	$39.7	$914.4	$914.4
	2035	$920.6	$41.4	$962.0	$962.0
	PV @ 12%				
15 years	'90-'04			793.3	665.5
	'95-'09			1134.8	1134.8
20 years	'90-'09			945.1	817.3
	'95-'14			1330.4	1330.4
30 years	'90-'19			1137.3	1009.5
	'95-'24			1578.0	1578.0
40 years	'90-'29			1196.6	1068.8
	'95-'34			1654.4	1654.4

Table 4: Comparison of Energy Avoided-cost Estimates

			Summer Period			Non-Summer Period		
			Peak	Intermed	Off-Peak	Peak	Intermed	Off-Peak
MCS study								
variable fuel handling			0.01081	0.01081	0.01081	0.01081	0.01081	0.01081
fuel			0.03656	0.02695	0.01223	0.02635	0.02260	0.01325
variable O&M			0.00073	0.00073	0.00073	0.00073	0.00073	0.00073
PayTax	3.52%	FH+O&M	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041
CWC	0.78%	F+FH+O&M	0.00038	0.00030	0.00019	0.00030	0.00027	0.00019
Fuel M&S	1.93%	F	0.00071	0.00052	0.00024	0.00051	0.00044	0.00026
A&G	42.60%	FH+O&M	0.00492	0.00492	0.00492	0.00492	0.00492	0.00492
BG&E total			0.04959	0.03972	0.02460	0.03910	0.03525	0.02565
Corrected Total			0.05450	0.04463	0.02951	0.04402	0.04016	0.03056
Non-fuel			0.01695	0.01695	0.01695	0.01695	0.01695	0.01695
Fuel			0.03755	0.02768	0.01256	0.02706	0.02321	0.01361
1990$								
Non-fuel	4.4%		0.01770	0.01770	0.01770	0.01770	0.01770	0.01770
Fuel	7.2%		0.04025	0.02967	0.01347	0.02901	0.02488	0.01459
Total			0.05795	0.04737	0.03116	0.04671	0.04258	0.03229
Marginal Losses			18%	15%	10%	17%	15%	10%
Energy at end use			0.0684	0.0545	0.0343	0.0547	0.0490	0.0355
BG&E 12/90 Conserve Plan			0.0621	0.0494	0.0305	0.0488	0.0438	0.0317
BG&E 1991 IRP			0.0520	0.0425	0.0273	0.0409	0.0405	0.0239

Table 5: BG&E Marginal Cost of Capital

	Capitalization Ratio	Cost Rate	Weighted Cost
Long-term Debt	43.45%	9.00%	3.91%
Short-Term Debt	2.61%	8.33%	0.22%
Preferred Stock	13.19%	8.73%	1.15%
Common Equity	40.75%	12.87%	5.24%
Total	100.00%		10.52%

Sources: All data from Order No. 69054, p. 106, except:
LT Debt from recent yields on BG&E bonds.
Preferred from most recent offering, Order No. 69054, p. 105.

Table 6. Comparison of Monetized Values of Externalities in the U.S. Sept 18, 1991
Units are 1990$/lb of pollutant emitted

	California Energy Commission in-state	California Energy Commission out-of-state	Massachusetts DPU	Nevada PSC	New York PSC	Bonneville Power Association west-side	Bonneville Power Association east-side	Pace University (Ottinger, 1990)
Date adopted	Oct 1990	Oct 1990	Aug 1990	Feb 1991	1990	pending	pending	1990
<u>Externality</u>								
SO2	6.48	0.56	0.78	0.78	0.43	1.8013	0.2025	2.11
NOx	6.53	1.52	3.40	3.40	0.93	0.4421	0.0344	0.85
VOC's	1.83	0.17	2.77	0.59	NE	NE	NE	NE
CO	NE	NE	0.46	0.46	NE	NE	NE	NE
Particulates	4.39	0.45	2.09	2.09	0.17	0.7698	0.0833	1.24
CO2	0.0036	0.0036	0.011	0.011	0.001	NE	NE	0.007
CH4	NE	NE	0.11	0.11	NE	NE	NE	NE
N2O	NE	NE	2.07	2.07	NE	NE	NE	NE
Water use (cents/kWh)	NE	NE	NE	NE	0.10	NE	NE	NE
Land use (cents/kWh)	NE	NE	NE	NE	0.42	0.001	0.001	NE

NE = not estimated

Massachusetts values have been inflated from 1989$.

Table 7. Externalities of the Perryman Project

Sept 18, 1991

	Massachusetts DPU values (1990$)	Emissions in lbs/MMBtu							
		CC firm gas	CC #2 oil 0.2% S	CC interupt gas	CT firm gas	CT #2 oil 0.2% S	CT interupt gas	IGCC coal 2.4%	Pulverized coal 2.4%
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]
1. NOx	$3.40	0.059	0.322	0.103	0.060	0.323	0.104	0.06	0.404
2. SOx	$0.78	0.0	0.205	0.0	0.017	0.205	0.048	0.14	0.36
3. CO2	$0.011	114	162	122	114	162	122	210	210
4. TSP	$2.09	0.007	0.006	0.007	0.007	0.006	0.007	0.011	0.019
5. VOC	$2.77	0.002	0.004	0.002	0.002	0.004	0.002	0.000	0.003
6. Externalities ($/MMBtu)		$1.53	$3.14	$1.80	$1.55	$3.14	$1.81	$2.75	$4.12
7. Heat rate (Btu/kWh)		7,500	7,500	7,500	11,000	11,000	11,000	9,200	10,000
8. Externalities (cents/kWh)		1.15	2.36	1.35	1.70	3.46	1.99	2.53	4.12

Notes:

1,2,4,5,7,[b],[c],[e],[f]. Emissions figures are "Vendor guaranteed" and are from "Supplemental Testimony of Kennard F. Koskey on behalf of BGE," PSC Case No. 8241, 11/90, except the NOx emissions for gas which have been reduced to reflect 15 ppm, and SO2 emissions for gas, for which the vendor guarantee was 25.6 lb/hr (.017 lb/MMBtu).
CC units will have lower NOx emissions if SCR is required; CT NOx emissions assume steam injection.
Heat rates are for "1991 Outlook" from "Rebuttal Testimony of Ralph Bourquin, Jr. on behalf of BGE." Jul 19, 1991.

3. Emissions of CO2 were estimated based on 31 lbs carbon/MMBtu for natural gas, 44 lbs carbon/MMBtu for #2 oil, and 58 lbs carbon/MMBtu for coal.

6. Externalities ($/MMBtu heat input) = sum of {(value) x (emissions in each column)}.

8. Externalities (cents/kWh output) = [6]x[7]/10000

[a]. Massachusetts DPU values have been inflated to 1990$ assuming 4.5% inflation from 1989.

[d],[g]. Interruptible gas emissions are a combination of 5/6ths gas and 1/6th oil emissions.

[h]. Emissions are from "California Energy Comission Generic Emissions factors," 1989. Sulfur emissions are 4% of potential emissions; heat rate was estimated from EPRI TAG 1989.

[i]. New pulverized coal plant has low NOx burners, FGD with 90% removal efficiency, and ESP with 99% removal efficiency; heat rate was estimated from EPRI TAG 1989.

Table 8. Selected CO2 Reduction Targets

Sept 18, 1990

Source		Target for CO2 Emission Reductions	Implied % reduction from base, assuming base annnual growth of CO2 emissions of: 2%	1%
[1]	IPCC	Over 60% immediate reduction needed to stabilize concentrations at today's levels.	NA	NA
[2]	Krause, et al.	25% reduction required by industrialized countries from 1990 levels by 2005.	44%	35%
		50% reduction required by industrialized countries from 1990 levels by 2015.	70%	61%
[3]	Canada	Stabilization at 1990 levels by 2000.	18%	9%
[4]	United Kingdom	Stabilization at 1990 levels by 2005.	26%	14%
[5]	Norway	Stabilization at 1990 levels by 2000.	18%	9%
[6]	Japan	Stabilization at 1990 levels by 2000.	18%	9%
[7]	Sweden	Stabilization at 1990 levels by 2000.	18%	9%
[8]	Denmark	20% reduction from 1990 levels by 2000.	34%	27%
[9]	Netherlands	3-5% reduction from 1989-90 levels by 2000.	20-22%	12-14%
[10]	Austria	20% reduction from 1990 levels by 2005.	41%	31%
[11]	New Zealand	20% reduction from 1990 levels by 2000.	34%	27%
[12]	Oregon	20% reduction from 1990 levels by 2005.	41%	31%
[13]	Germany	25% reduction from 1990 levels by 2005.	44%	35%

Sources:

[1]: Global Environmental Change Report, Vol II, No. 11 (6/8/90). p. 4.
[2]: Krause, Bach and Koomey, "Energy Policy in the Greenhouse," Vol 1 (1989), figure 1.6.2.
[3]-[9]: Global Environmental Change Report, Vol II No. 16 (8/17/90), p.4.
[10]: Global Environmental Change Report, Vol II, No. 17 (9/14/90). p. 3.
[12]: Clearing Up, No 368 (6/2/89), p. 2.
[11],[13]: Science News, Mar 1991.