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Case No. 8278

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

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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 attached to this testimony as Attachment 1 to this testimony.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately seventy 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 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 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; 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 collaborative for PEPCO, which also includes the Commission Staff and DNR. I am responsible for issues concerning resource allocation, cost recovery and regulatory policy. OPC, PEPCO and the other parties voluntarily entered this process with the common goal of developing programs that will capture the maximum amount of cost-effective savings in all sectors of opportunity. It is worth noting that the parties to this unprecedented effort intend to improve and expand PEPCO's current limited conservation portfolio, which is already far superior to BG&E's unambitious plans. I am also 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 reviews the adequacy of the Integrated Resource Plan (the IRP, or Plan) of the Baltimore Gas and Electric (BG&E or the Company). (Page references in this testimony are to the Plan and its Appendices, except as noted.) My review concentrates on BGE's treatment of DSM, the role of DSM in BGE's plan, and suggestions for improvements in BGE's approaches.

To place BG&E's activities in their proper perspective, I also present evidence on conservation and load management options which Maryland statute directs the Commission to consider in judging the reasonableness of resource planning by BG&E. Specifically, my testimony sets forth principles for integrating these demand-side options into utility resource planning, and then assesses BG&E's current demand-side activities. I recommend that the Commission require BG&E to remedy the severe limitations in its demand-side planning. BG&E should also be put on notice that failure to correct these deficiencies could jeopardize future rate treatment, including the possibility of reductions in allowed return on equity. I also urge further action by the Commission to ready demand-side investments for deployment as viable options to future power plants contemplated by BG&E in the future.

Q: Please summarize your testimony.

A: BG&E's planning considers only a narrow set of options for meeting resource requirements, while neglecting the much wider range of resource alternatives it could choose from. The Commission adheres to the principle that Maryland utilities must consider all reasonable options for meeting their service obligation reliably and efficiently at least cost. BG&E's failure to examine a full range of options calls into question the reasonableness of its long-range resource planning, and ultimately, its cost of service.

Among the serious options which BG&E's resource planning ignores are abundant opportunities to save electricity for much less than it will cost to produce. These opportunities persist because, historically, powerful and pervasive market barriers have motivated customers to spend far less on saving energy than they pay for using it. Regulators and utilities are recognizing that forgoing such savings now will force utilities into unduly high levels of expensive supply for years to come. Only by tapping and integrating its economical demand-side potential can Maryland obtain truly least-cost electric service.

This fundamental principle is embodied both in previous Commission decisions and in the unprecedented collaborative program design process now in progress with PEPCO, OPC, the Commission Staff, and DNR. Based on these least-cost imperatives, BG&E should pursue all available demand-side savings that are less costly than new supply. In doing so, BG&E should be willing to spend up to its avoided costs of capacity and energy, adjusted to include the value of environmental and other externalities.

Q: Why does the Commission need to consider alternatives beyond those presented by the Company?

A: The Commission is under an obligation to assure that the long-range plans of all electric utiliites include adequate measures to promote conservation. (Public Service Commission Law, Section 59A) Not only has BG&E omitted a vast array of conservation resources from its resource plan, it has not even readied demand-side strategies to compete realistically with new supply. By failing to explore viable alternatives as mandated by statute, BG&E provides the Commission with no foundation upon which to approve its plans as submitted. This severely restricts the Commission's ability to fulfill its responsibilities under the statute. It also leads the Company's ratepayers to support unnecessary amounts of expensive generating resources. A utility's failure to develop and exhaust the potential for least-cost demand-side resources could therefore provide the grounds for a downward adjustment to allowed return on equity.

These concerns are not idle speculation. The Company has already begun proceedings seeking a certificate of need for the Perryman generating station. The Commission must not allow BG&E to dismiss prospects for substituting a more flexible, least-cost combination of options for the capacity BG&E is about to propose. As discussed further below, BG&E could scale back its current expansion plans by aggressively promoting direct investment in its customers' energy efficiency.

Regardless of the rate relief the Commission decides to grant BG&E in this proceeding, I recommend that it put the Company on notice that its future earnings are subject to the Company's fulfillment of least-cost planning objectives.

This should include immediate and vigorous actions to: (1) build the capability to deliver comprehensive energy-efficiency programs throughout its service area, and (2) pursue "lost-opportunity" efficiency resources, which arise when customers construct new facilities and when they add or replace appliances and equipment.

Q: How have you organized your testimony?

A: I present the remainder of my testimony in six more sections. Section 2 discusses the multitude and magnitude of market barriers, and how they weaken the price signals which would otherwise produce least-cost conservation investment. The resulting "payback gap" between customer and utility investment horizons creates a large potential for low-cost utility-sponsored efficiency savings. Failure to tap this potential will unnecessarily raise the cost of energy services.

I stress the urgent need for BG&E to begin building the capability to deliver efficiency savings on a strategic scale -- that is, on a scale large enough to influence supply decisions. I also emphasize the need to pursue transient resources immediately, which will otherwise become lost opportunities.

With the least-cost planning principles of Section 2 as a backdrop, I assess BG&E's action on demand-side resources in Section 3. That Section demonstrates that the Company is neglecting savings that can defer or displace generating sources intended to provide both energy and capacity. I draw on utility experience elsewhere to show that the most reliable and economical strategy for BG&E to acquire efficiency resources is with comprehensive, facility-based investment programs. BG&E's shortcomings in this regard call for a major redirection of BG&E's demand-side planning.

Section 4 provides a summary of the DSM budgets and program scale in place or proposed by aggressive utilities, especially in New England, California and Wisconsin.

In Section 5, I recommend how the Commission and the Company should proceed with developing demand-side resources in Maryland. I offer specific guidelines for the capability-building BG&E must undertake to develop demand-side programs into viable resource options.

Section 6 discusses the quantification and valuation of externalities in least-cost planning, and proposes initial values to be used by BG&E in its DSM planning. Section 7 summarizes my conclusions and recommendations.

2. THE RATIONALE FOR UTILITY DEMAND-SIDE MANAGEMENT

Q: Please summarize how demand-side investments should influence utility resource planning.

A: The goal of utility resource planning should be to minimize long-run costs of providing adequate and reliable energy services to customers. Minimizing total costs requires that utilities choose resources with the lowest costs first, drawing on progressively more expensive options until demand is satisfied.[1] But much of the demand being forecast by utilities is arising because most customers are unwilling to spend more than a small fraction of the price they pay for using electricity on saving it. This market failure leaves a significant but unquantified potential for economical efficiency investment available for less than the cost of utility supply.

Least-cost planning requires utilities to pursue savings their customers would otherwise miss. These efficiency gains are worth pursuing to the point that any further savings would cost more than supply -- counting all costs

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[1] Uncertainty and risk complicate this task. Future demand is unknown. This makes some resources riskier than others. In general, larger resources with longer lead times carry greater risks for the system. Once utilities gain the capability to deploy efficiency resources, they can be acquired in small increments over short lead times. Some efficiency resources, such as programs to raise new buildings' efficiency, naturally vary with demand growth. More efficient loads generally are more stable loads, less sensitive to economic and weather fluctuations, implying lower load uncertainty.

incurred by both utilities and their customers. How much of this untapped efficiency potential is economical depends on (1) the shape of "efficiency supply curves," and (2) where customers have positioned themselves in relation to utility avoided costs. Utilities need to develop both types of information and integrate it into their resource planning.

2.1 Economic Rationale for Utility Market Intervention

Q: Why should utilities intervene in matters of customer choice?

A: The imperative for utility investment in demand-side resource arises because customers typically require <u>efficiency</u> investments to pay for themselves in two years or less. But utilities routinely accept <u>supply</u> investments with payback periods extending beyond twelve years. I show below that this "payback gap" has the same effect as an exceedingly high markup by customers to the societal costs of demand-side resources. It leads utility customers to reject substitutes for supply which, if scrutinized under utility investment criteria, would appear highly cost-effective.

Q: Are short-payback requirements confined to a few, relatively unsophisticated customers?

A: No, not according to extensive research. Consider the following passage from the handbook on least-cost utility planning prepared for the National Association of Regulatory Utility Commissioners:

> According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short or even shorter payback requirements, sometimes as little as a month. This phenomenon is not only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved. ("Least-Cost Utility Planning: A Handbook for Public Utility Commissioners," Vol. 2, The Demand Side: Conceptual and Methodological Issues, December 1988, p. II-9)

Q: Why do customers act as if they attach high markups to efficiency investments?

A: Limited access to capital, institutional impediments, risk perception, inconvenience and information costs are all factors that compound the costs and dilute the benefits of energy efficiency improvements. The cumulative impact of these barriers is even stronger because they interact. Utilities can accelerate investment in cost-effective demand-side measures with comprehensive programs that reduce or eliminate these barriers.

Q: How can utilities substitute demand-side measures such as energy efficiency improvements for utility supply?

A: Customer demand for energy services such as lighting, space conditioning, and shaft power can be met in a multitude of ways, involving varying combinations of electricity, capital, fuel and labor. It is often possible to reduce the sum of these costs, without compromising the level and quality of service that customers demand, by substituting capital behind the meter for capital behind the busbar. If so -- if it costs less to save a kilowatt-hour (kWh) with a more efficient air-conditioner than to produce it with generating capacity, for example -- total costs will be lower if efficiency is chosen over production. This least-cost perspective requires utilities to integrate all options on both the customer's and the utility's side of the meter into resource planning.

Q: Can the pricing of electricity provide sufficient price signals to encourage customers to make these trade-offs between efficiency and consumption?

A: Yes. In principle, pricing electricity at marginal cost could automatically lead customers to select the optimal mix of demand and supply resources. But in reality, customers routinely decline efficiency investments which, if evaluated with a utility's economic yardstick, would appear to be extremely attractive resources. Based on utility price signals -- which often exceed estimates of long-run marginal costs -- typical customers require efficiency investments lasting as long as 30 years or more to pay for themselves within two years. By contrast, utilities choose among supply options with the same investment horizons and accept those with apparent payback periods of 12 years or longer.

By persistently forgoing efficiency investments that would otherwise reduce electric demand, consumers compel utilities to expand supply.

This disparity between individuals' and utilities' investment horizons can be thought of as a "payback gap" that leads society to over-invest in electricity supply. Utilities can bridge the payback gap, thereby avoiding more expensive supply investments, by investing directly to supplement price signals.

2.2 The "Payback Gap" as Evidence of Market Failure

Q: How does a rapid payback requirement translate into a stricter investment criterion?

A: The required payback period for an investment can be translated into an equivalent required rate of return. A higher required return means one requires future benefits to be relatively large in order to sacrifice the use of funds today. Table 2.1 presents the required rates of return implied by different combinations of investment lives and payback requirements.

For example, a customer who requires a 20-year investment to pay for itself in two years reveals a 64% required rate of return (as shown in Table 2.1, at the intersection of the 20-year investment column and the 2-year payback row). By discounting future benefits so highly such a customer would only spend a dollar today to save a $1.64 a year from now.

Table 2.1: Required Rates of Return Implied By Payback Criteria Under Different Economic Lives

Payback Period (Years)	Economic Life of Investment (Years)				
	10	15	20	25	30
1	162%	162%	162%	162%	162%
1.5	92%	92%	92%	92%	92%
2	63%	64%	64%	64%	64%
3	37%	39%	39%	39%	39%
5	17%	21%	22%	22%	22%
7	8%	13%	14%	15%	15%
10	0%	6%	8%	9%	10%
12		3%	6%	7%	8%
15		0%	3%	5%	5%
20			0%	2%	3%

Note: Assumes monthly savings equate to a single cashflow at mid-year, with no inflation.

By contrast, a utility that requires a 20-year supply project to yield a 6-percent return on investment (compared to alternatives) will accept a 12-year payback period (as shown at the intersection of the 20-year investment column and the 12-year payback row).

Q: How does a required return lead customers to reject efficiency investments that would otherwise be attractive under a utility's lower discount rate?

A: The payback gap between utility and customer investment horizons is equivalent to a high markup to the life-cycle cost a utility would estimate for efficiency measures if the

Table 2.2: Derivation of Customer Markup to Societal Cost of Efficiency Improvement

ASSUMPTIONS	
Societal discount rate	7%
Cost of one-time efficiency investment, in cents/kWh/year	31.8 ¢/kWh-Yr
Economic life of efficiency measure	20 years
Customer's required return, implied by 1-year payback on 20-year measure (From Table 2.1)	64%
RESULTS	
Levelized cost per kWh of efficiency, at societal discount rate	3 ¢/kWh
Levelized cost per kWh of efficiency, based on required customer return	20.4 ¢/kWh
Implicit customer markup to societal cost: 20.4/3 - 1 =	578%

utility paid for them directly and entirely.

For example, Table 2.2 considers the impact of a home builder requiring that two-year maximum payback period. Suppose a builder and BG&E are independently evaluating the merits of installing low-emissivity windows in new houses. ("Low-E" windows provide the heating and cooling savings of a third layer of glass for about a 10% price premium.) Suppose further that the incremental cost of the Low-E windows is a 31.8 cent investment for each kWh saved each year.

BG&E's 12% discount rate translates roughly into a 7% real rate net of BG&E's assumed 4.4% inflation. (These assumptions are from Exhibit III.B.2, page 32.) The Company amortizes the price premium for the Low-E windows over their 20-year lives and comes up with a lifetime cost of 3 cents per saved kWh, which it should consider to be a bargain compared to the cost (probably at least 6 cents) for energy from new capacity over the same period. BG&E should be indifferent to investing in the efficiency measure, or paying 3 cents one kWh at a time over the 30-year life of the investment.

Now consider the same choice from the homebuilder's perspective. Referring to Table 2.1, observe that her one-year payback period requires the same up-front investment of 31.8 cents/kWh-Yr savings to yield a return of 64%. At this rate, the low-E windows have a levelized cost of (same present worth as) 20.4 cents per kWh saved. The homebuilder acts as if the low-E windows cost almost seven times as much as the cost to the utility.

Q: How would the six-fold markup on efficiency measures in your example affect resource allocation?

A: If electricity is priced at the marginal cost of 6 cents, the home builder would only be willing to invest in measures that would cost BG&E less than one cent/kWh -- one-seventh of the price of electricity. The builder will reject all other measures (high-efficiency heat-pumps, extra wall insulation) that would cost more than a cent per kWh from BG&E's perspective. This decision would force BG&E to supply power for the less-efficient houses at our assumed marginal cost of 6 cents/kWh. Moreover, these opportunities will be lost for the lives of the houses once they go up, since it would not be economical to remove the conventional windows and replace them with the more efficient ones. Anything BG&E can do to get the low-E windows and other measures into the house is cost-effective as long as the measures (and BG&E's administrative costs) are less than 6 cents/kWh.[2]

Q: In general, what are the consequences when customers place a high markup on the costs of efficiency investments?

A: The result is that setting prices at marginal costs does not generate the market response predicted by economic theory; in reality, customers do not readily substitute efficiency for electricity. This is because the payback gap drives a wedge between what consumers will pay to save electricity and what utilities spend to produce it. The six-fold markup in this example means that an electric rate of 6 cents/kWh would not motivate a customer to spend 6 cents per conserved kWh. Rather, the customer would only invest in efficiency that to a utility would cost less than one cent/kWh. Equivalently, a utility would have to set prices six times

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[2] The incentives (rebates, grants, etc) are not costs in themselves, since they are offset by the reduced net cost to the home builder.

higher than marginal cost to stimulate the customer response that is optimal in this example, namely, installing the more efficient windows.

Q: Why does the payback gap imply that utilities need to invest in customer efficiency improvements?

A: Market barriers force customers to apply more exacting investment criteria to efficiency choices than utilities apply to supply options. Without utility intervention, the payback gap will lead customers to under-invest in efficiency and utilities to over-invest in supply. As the NARUC least-cost planning handbook states,

> Demand-side resources are opportunities to increase the efficiency of energy service delivery that are not being fully taken advantage of in the market. To make use of demand-side resources requires special programs, which try to mobilize cost-effective savings in electricity and peak demand. Without such programs, these savings would not have occurred or would not have materialized without significant delay, and in any case could not have been *relied upon*, forcing utilities to construct expensive back-up capacity and causing higher rates. (NARUC 1988, page II.1; emphasis in original)

Explicitly acknowledging the payback gap leads to two conclusions about the potential for demand-side resources and strategies needed to realize it:

1. Utility price signals are much weaker than most analyses assume as a tool for stimulating investment changes.

2. There is a vast amount of economical efficiency potential left for utilities to tap as demand-side resources.

Q: Please summarize how market barriers weaken price signals and leave a large potential for cost-effective utility investment in demand-side resources.

A: The NARUC handbook sums up this relationship as follows:

> The short-payback requirements for efficiency investments usually result from different combinations of these factors [market barriers]. But the multitude of dynamics involved explains why the payback gap is not just found for particular end uses or particular customer groups, but is so universal. It also explains why consumer investment[s] in efficiency and load management are not governed solely or even mainly by an economically efficient response to prevailing prices. For these reasons, the redesign of utility rates alone, or any other strategy limited to the correction of prices only, is insufficient to mobilize the bulk of demand-side resources. Direct intervention is needed to strengthen market mechanisms and remove institutional and market barriers. (NARUC 1988, p. II.15)

2.3 Market Barriers Contributing to the Payback Gap

Q: Are customers being irrational when they mark up the direct costs of efficiency measures?

A: Not at all. An aversion to capital-intensive electricity substitutes may be perfectly valid, especially since efficiency is paid for so much differently from electricity. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were -- either through market innovation, utility market intervention, or both -- even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity.

Q: What other factors contribute to customers' apparent aversion to efficiency investments?

A: At least four factors interact to compound the costs and dilute the benefits of efficiency measures to utility customers:[3]

1. Limited access to relatively high-priced capital can constrain payback periods to durations far shorter than the useful lives of the investments;

2. Split incentives diminish the benefits that both owners and occupants of buildings receive from efficiency investments by conferring them on the other party;[4]

3. Real and apparent risks of various forms impede individual efficiency investments, particularly the limited liquidity of conservation investments (financial risk), uncertainty over market valuation of efficiency (market risk), fear of "lemon technologies" (technological risk), and perceptions of service degradation; and

4. Inadequate, conflicting, and expensive information makes the search and evaluation costs of efficiency improvements high in terms of a customer's own time, effort, and inconvenience.

Q: How does limited access to capital constrain efficiency investment?

A: Efficiency investments lower operating outlays over time in exchange for higher initial outlays on the part of the investor. Individuals and businesses are often in no

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[3] The NARUC Handbook lists these and other market barriers at pages II-12 through II-14.

[4] Economists refer to this market imperfection as "unassigned property rights."

position to obtain capital to fund such commitments.[5] Homeowners and small business are often fully leveraged and unwilling to deplete savings to finance all economically justifiable efficiency investment. And while some consumers may be able to borrow the money to finance desired efficiency investments, borrowing terms are often far shorter than the life of the efficiency investment. The short amortization schedule pushes debt-service costs above the cashflow savings of the efficiency investment, shortening the maximum acceptable payback period.

Q: What do you mean by split incentives?

A: Many property owners do not pay the utility bills of the buildings they lease. Many building occupants do not own the buildings for which they pay utility bills. Making investments to lower the operating costs of tenants is rarely a high priority for landlords, just as spending money to raise property values (and therefore rents) is not terribly attractive to renters.

Equally serious institutional impediments retard efficiency investments at other stages of the real estate market. Developers do not pay to operate the appliances, heating and cooling systems, or lighting in the homes and offices they build. Quite often they see their objective as

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[5] This is frequently because lenders fail to appreciate the value of efficiency. This could be characterized as an institutional impediment, a further consequence of inadequate information and risk perceptions.

minimizing the completion costs of their buildings. This keeps margins high during tight markets, and protects against losses during slow periods.

Q: Explain how the elements of risk you listed restrain efficiency investments.

A: A higher level of perceived risk raises the rate of return required on the investment. Energy efficiency investments expose individual consumers to a variety of risks which a utility can reduce through diversification in its demand-side resource portfolio. Specific risks that tend to raise consumers' required return include the following:

Financial risk: Efficiency investments are illiquid. Future savings from efficiency improvements are not marketable securities: there may be substantial penalties for earlier withdrawal. Often the efficiency investment becomes part of the building it is installed in, making it extremely difficult to liquidate the investment without selling the building.

Technological risk: Few volunteer to be guinea pigs. For example, the perceived technological risks of advanced lighting equipment may be the single greatest obstacle to widespread market acceptance to date.

Market risk: Homeowners may reject efficiency investments whose annual savings look good on paper because they are unsure that the resale value of the home would increase enough to recover the costs. Similar concerns are justified for businesses contemplating an investment in highly efficient chillers or state-of-the-art lighting.

Q: Why does lack of information about efficiency constitute such a significant barrier?

A: Acquiring and critically evaluating information on the costs and performance of competing efficiency options is often prohibitively expensive for all but the largest and most sophisticated end-users. Not only do consumers need to understand individual technologies; they need to know how measures interact. Savings from combining some measures are less than the sum of their individual savings (for example, high-efficiency glazing and insulation). Other measures are complementary (insulation and high-efficiency furnaces) or mutually reinforcing (lighting efficiency and cooling systems).

3. PROBLEMS IN BG&E'S APPROACH TO PLANNING

3.1 Basic Approach to DSM Planning

Q: What basic problems have you identified in BG&E's approach to DSM planning?

A: Most fundamentally, BG&E does not treat DSM, and particularly energy efficiency or conservation, as a resource comparable to other resources which it must identify, study, prepare for implementation, and acquire. This shows up in the Plan as an understatement of the future role of conservation, in the concentration of the DSM program on load management measures, in the limitation of BG&E's few conservation programs to informational activities, and in the low projected penetration of measures.

The Plan does not approach DSM as part of BG&E's fundamental responsibility to its customers to control costs. It remains to be seen whether future filings will indicate a change in this basic attitude.

3.1.1 The role of future conservation

Q: How does BG&E understate the future role of conservation?

A: BG&E includes only two conservation programs in its Integrated Resource Plan (Table V-7): commercial/industrial motors and lighting. By 2004, these two programs contribute only 11.5 and 17.9 MW of load reduction; out of a total pre-

DSM forecast of 7,632 MW, BG&E's conservation programs reduce otherwise projected load by a paltry 0.385 percent.

The energy savings generated by BG&E's conservation programs barely register. Energy reduction from the motor program is 11.7 out of a post-DSM total of 36,550 GWH, or 0.03 percent.; BG&E does not even report the annual energy savings from eleven lighting program components. Given the apparent cost-effectiveness of the energy savings available from lighting efficiency investment, this omission is like ignoring the energy output of a low-cost cycling or baseload plant.

Q: Has BG&E considered a complete list of conservation options?

A: No. BG&E's resource plan excludes savings available from all residential efficiency options, all HVAC options for commercial customers, all building shell and building design options, all efficiency improvements in industrial processes, and savings from high-efficiency commercial and industrial refrigeration. Thus, BG&E's resource planning ignores virtually scores of efficiency options available for dozens of end-uses in all customer market segments.

Q: Does BG&E assume wide acceptance of the conservation programs it does consider?

A: No. BG&E assumes that, by 2004, 2400 rate GL customers would participate in the motor program. These customers account for only 16.4% of BG&E sales, and each participant reduces its energy consumption by about 0.3%. It is not clear how large BG&E estimates its motor load to be (or even if BG&E has such an estimate).

While BG&E's projections for the lighting program are somewhat more complicated, the result is just as insignificant as the Company's motor-efficiency program. This is even more striking, since BG&E's own estimates of the costs and performance of lighting efficiency measures show them to be extremely economical to supply options it is readying for deployment now.

Q: Is this treatment of energy-efficiency options consistent with BG&E's treatment of supply options?

A: No. BG&E's treatment of efficiency resources is completely at odds with its supply planning. Unlike the Company's assessment of supply options, BG&E has not screened a complete range of efficiency programs to see what might fit into later resource plans. To be consistent with its resource planning on the supply side, BG&E should be conducting thorough DSM program screening to identify which options might compete favorably with specific supply options. Likewise, BG&E should determine when and how best to start planning and acquiring specific energy efficiency options in order for those options to make meaningful contributions to its future resource mix.

Q: Other than the relatively small contribution of the programs you mentioned, is there specific evidence of this inconsistency from BG&E's testimony or filings?

A: Yes. Two inconsistencies between BG&E's supply and demand-side resource planning are clearly evident. The first stems from the mismatch between the types of generating supply and demand-side investment that BG&E emphasizes in its current resource plan. This imbalance can be traced partly to the second inconsistency -- BG&E's failure to value capacity provided by energy-saving resources in the same way that it values capacity from energy-producing supply options.

Q: What is so different between the kinds of supply and demand options BG&E is planning?

A: On the supply side, BG&E is not just planning to increase the amount of peaking capacity on its system. BG&E's President testified that the Company's "least cost planning also indicates that we intend to convert those peaking units to combined cycle units as the load grows ... You convert the peaking aspect of the generation to the more base load oriented type of generation." Tr. at 47 (Crooke). Thus, BG&E is committed to expanding the energy-producing capability of its system.

But BG&E's supply orientation is precisely the opposite of that embodied in the Company's DSM planning. As shown in Revised Exh. III.B., there is 18 times as much peak savings targeted from load management (which saves no energy) as there is from energy efficiency (which saves energy in addition to reducing demand).[6] On the demand side, the energy-saving capability of efficiency options is an afterthought, if it is considered at all. This imbalance between energy and demand savings does not match the emphasis on energy generation reflected in BG&E's current resource plan.

Q: How would BG&E evaluate demand-side options if it adopted the approach it uses to compare supply options, the second inconsistency you found in BG&E's planning approach?

A: If BG&E were consistent in determining the relative merits of supply and demand-side resources, it would incorporate the energy value from energy-efficiency investments directly into the screening process. This is exactly what BG&E does to determine the capacity cost of supply options. As the Company explains in its Integrated Resource Plan,

> Baseload capacity is installed to take advantage of favorable operating (fuel) economics. As such, netting the lower fuel costs out against the higher installed cost of the baseload unit will result in a cost per avoided kW less than or equal to the installed cost of a combustion turbine. (p. III-60)

Thus, a new baseload plant with high investment costs gets immediate credit for its life-cycle fuel savings. On the demand-side, however, an energy-efficiency option with

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[6] On Revised Exh. III.B., p. 3, BG&E shows total DSM of 557.3 MW in the year 2004. The only energy-efficiency programs are commercial and industrial lighting and motors programs, which are projected to reduce forecast peak demand by 29.5 MW. The 18-to-1 ratio is the difference between the DSM total and efficiency savings divided by the efficiency savings.

zero fuel costs, and thus even greater operating savings per kW of installed "capacity," does not get the same "boost" at the resource screening stage. Energy savings do not count until <u>after</u> efficiency options have survived BG&E's resource screening stage; thus, energy savings do not enter BG&E's analysis when they matter most in deciding which options merit further development.

Q: How does the inconsistency between BG&E's supply and demand show up in its selection of supply and demand resources?

A: Since energy savings don't matter at the initial screening stage, BG&E's resource planning doesn't give priority to energy-saving demand-side resources. Energy savings only help the apparent economics of surviving efficiency measures during detailed cost-effectiveness evaluation -- after it's too late to effect the kinds of demand-side options BG&E pursues. The result is undue emphasis on demand-side options that save no energy combined with supply investments justified by their energy cost savings. A consistent approach would lead BG&E to place a much higher priority on energy-saving demand-side resources. This in turn would prompt BG&E to invest in a much wider range of efficiency options from all customer classes; it would also call for much more ambitious targets, employing more aggressive investment strategies, to achieve highly cost-effective savings much more rapidly.

Q: Can you illustrate how BG&E's approach to supply resources would alter its outlook on energy-efficiency options if applied consistently?

A: The best way to do this would be to re-examine specific efficiency options BG&E has explicitly rejected because of this approach. A complete reanalysis of BG&E's planing is beyond the scope of this testimony. However, it is relatively simple to demonstrate that investment in lighting efficiency appears to be overwhelmingly cost-effective using BG&E's method for costing energy-saving supply options. While BG&E is already pursuing lighting efficiency savings through an information program, my restatement of their economics using BG&E's supply approach shows that much more ambitious efforts are extremely worthwhile.

Q: What what is the result of applying BG&E's method for costing new generating capacity to the costs BG&E used to screen lighting efficiency measures?

A: Using BG&E's suply-side approach, I found that BG&E is essentially refusing to invest in demand-side resources offering negative capacity costs. After deducting the present worth of avoided energy costs from the incremental capital costs of two specific lighting "programs," their capacity savings has a negative cost per kW. This is precisely the method BG&E uses to compute the marginal capacity cost of the generating resources in its expansion plan which also produce energy cost savings, as I explained earlier. If BG&E paid customers directly for the incremental costs of installing high-efficiency lighting options, then more customers would install them. As even BG&E acknowledges, the higher costs of lighting efficiency measures prevent customers from installing them. Thus, BG&E's decision not to offer rebates represents a decision to accept lower savings from an information-only program. My analysis shows that BG&E has effectively decided not to pursue resources which appear extremely economical by the standards the Company applies when screening supply resources.

Q: How did you use BG&E's own assumptions to arrive at a negative capacity cost for lighting efficiency options?

A: BG&E assumes that an electronic ballast equipped with 28-watt T-8 lamps costs $33 more than its less-efficient counterpart (presumably a magnetic ballast with 34-watt lamps). According to BG&E, this fixture saves 74 watts in coincident peak load. This means that the incremental cost of the fixture is $448/kW saved. That cost of saved capacity would appear to be only marginally cost-effective compared to the Company's estimate of marginal capacity cost of $446/kW. (All figures are taken or derived from the IRP, Section III, pp. 38-41, and from Exh. III.J.2.)

Yet BG&E's program cost-benefit analysis also implies that each fixture saves 292 kWh per year. I calculated the avoided energy costs based on the Company's assumptions about the distribution of energy savings over its costing periods and the unit avoided energy costs. These assumptions imply an avoided energy cost per kWh saved by the fixture of 3.7 cents.[7] Using a weighted average life of 14.3 years for the ballast and lamp (based on incremental cost), and BG&E's 12-percent discount rate, each 14.3 year stream of one kWh saved annually is worth 24.8 cents. Thus, the 292 kWh of energy savings is worth a credit of $72.33 -- more than double the incremental cost of the fixture. So when divided by the coincident peak savings of 74 watts, this energy credit is worth $981/kW. The result is that after subtracting the energy credit from the apparent capacity cost of $448/kW derived above, the measures have a net capacity cost of negative $534/kW.

At such amazingly low costs compared to supply, BG&E should be investing vigorously to obtain as much of these resources as possible. Furthermore, it is likely that other opportunities abound among other end-uses and customer segments which would also appear highly advantageous when evaluated according to BG&E's supply-side screening method.

3.1.2 Capability-building and lost opportunities

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[7]This is BG&E's estimate of avoided energy cost. It is not clear what to year this value in intended to apply, and it appears that BG&E assumes no escalation in avoided energy costs. These costs are likely to be understated.

Q: Explain why utility demand-side investment deserves a high priority at BG&E now, rather than later when it plans to bring new capacity on line.

A: Two important considerations should lead the Commission to conclude that substantial investment in demand-side strategies is urgently needed. First, it will be impossible for BG&E to fully integrate least-cost demand-side resources if it is incapable of delivering them. Studies and workshops will not produce this capability; only specific utility experience can. Failure to develop the capability will frustrate BG&E's ability to minimize the cost of electric service.

Second, one-time opportunities for saving large amounts of energy cost-effectively over long periods arise and then disappear regularly. These opportunities are lost most often in new construction and when appliances must be replaced. In order to avoid the cost of meeting needlessly higher power demands over the long lifetimes of new buildings and equipment, utilities needs to act swiftly and strongly to capture such lost-opportunity resources. BG&E's current resource plan lacks any concerted strategy for doing so.

Q: What capabilities do utilities such as BG&E need in order to acquire the cost-effective efficiency resources that would lead to a least-cost resource plan?

A: Utilities must master new and rapidly advancing technologies; they must tailor and perfect marketing methods, incentive structures, and program delivery for different types of customers and efficiency measures; they must adopt reliable measurement and evaluation techniques, as well as management strategies that accept rapid feedback to allow mid-course correction. Most of all, it is essential that BG&E advance the existing market infrastructure: the vendors, installers, engineers, and architects who need familiarity and confidence with energy-efficient equipment to specify and supply it.

Q: Why is transforming the market infrastructure so critical to utility capability-building?

A: Customers cannot invest in more efficient equipment if it is not available locally. Architects and engineers will not specify it if they are not familiar with it.[8] Suppliers tend not to carry more expensive, high-efficiency equipment if customers do not ask for it. Utility demand-side programs can create the necessary demand for such products.

For example, Low-E windows were available only on special order in the Pacific Northwest and in Connecticut prior to large-scale utility programs. Now they have become a stock item in these areas. Similarly, the availability of energy-

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[8] These practitioners are rarely willing to take the initiative with new products unless they are presented with convincing evidence, technical assistance, and financial incentives.

saving electronic ballasts and triphosphor lamps tends to coincide with aggressive utility lighting programs.

Q: Must BG&E develop such capability on the demand side before the Company's resource planning can be truly integrated?

A: Yes. Energy-efficiency programs must yield cost-effective and reliable savings if they are to compete directly with supply options. If demand-side programs are to yield reliable demand-side resources in the future, BG&E must be able to obtain electricity savings from its customers with confidence.[9] BG&E must also be able to measure the costs and benefits of doing so. The Company therefore needs to build and maintain the capability to deliver efficiency savings on a strategic scale before they can deploy and integrate them as supply substitutes. Successful deployment depends on BG&E's demonstrated ability to motivate large numbers of their commercial, industrial and residential customers to install a variety of energy-efficient equipment.

Q: What do you mean by "capability-building"?

A: The Northwest Power Planning Council explains that capability-building programs "provide essential experience for turning efficiency potential into real resource options

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[9] Mr. Crooke emphasized BG&E's need to count on the savings from demand-side programs. Tr. 50-52. His testimony implies that energy-efficiency measures are more reliable than other demand-side options such as time-of-use rates.

before they are actually needed." The Council offers the following definition of capability-building investment:

> Capability-building programs are implemented in the absence of data on measured costs and savings, as a means of verifying working assumptions and predictions. Capability-building programs tend to be considerably more costly, per unit of electricity saved, than the resource acquisition programs they may eventually lead to. Because the initial development and demonstration costs are high, electricity savings will appear much more expensive than when programs are taken to the acquisition stage. The Hood River Conservation Project is an example of a capability building project.[10]

Q: Are demand-side capability-building efforts comparable to development activities associated with supply-side options?

A: Yes. Capability building is directly analogous to the pre-operation expenditures that utilities incur in the pursuit of promising supply-side resources. Demand-side programs require start-up and testing equivalent to the environmental, engineering, feasibility, and design studies that routinely precede commercial operation of utility supply resources.

Q: How soon should BG&E begin investing in capability-building efforts?

A: Building capability to acquire any resource takes time. This is especially true for resources with which utilities lack experience and understanding. Electricity surpluses

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[10] "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," 1987, at p. 4-8.

have afforded many utilities a window of opportunity to develop the capability to deliver efficiency resources. Unfortunately for BG&E and its ratepayers, this window is closing rapidly, and may soon slam shut insofar as the Company's pending application is concerned. To take advantage of this window for meeting future resource needs, capability-building must begin now.

Q: How should BG&E be building capability?

A: First, BG&E should identify all programs which appear to be cost-effective either immediately or later in the planning period, when avoided costs rise. Second, BG&E should be testing all currently cost-effective programs with large-scale efforts, as soon as feasible; all clearly cost-effective programs should be fully implemented as soon as possible.[11] Third, BG&E should identify all programs which would be cost-effective over its planning horizon, and determine when it will have to start implementing test programs to ramp them up to full capability by the time they are needed.[12]

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[11]A special effort should be made to scale up lost-opportunity programs quickly, since their potential savings are not deferrable.

[12]"Need," in this context, refers to the sum of capacity and energy savings, including line losses, T&D savings, and externalities. In particular, CECo should be determining how far it would need to have programs scaled up in order to allow CECo to enter into all off-system sales which would reduce revenue requirements.

Q: What sorts of decisions must BG&E make in deciding how and when its capability-building investment campaign should proceed?

A: For each potential efficiency program that BG&E should consider for possible inclusion it its resource plan, the Company needs to make the following determinations:

(1) what information BG&E needs about potential efficiency programs in order to determine their cost-effectiveness as resources, including their available magnitudes, costs, and performance;

(2) what steps are necessary to generate this information in order to decide on the likely cost-effectiveness of these resources;

(3) how long it will take to develop enough information to determine whether each efficiency resource appears likely to be cost-effective at any time in the planning horizon; and

(4) what steps to follow, and how long they would take, in order to deliver the resource, once the decision is reached that it is cost-effective to deploy.

By working backward from the time that BG&E expects to need additional resources, the Company should develop explicit schedules and budgets for capability-building investment in all market segments.

Q: Will BG&E's current approach build its capability to deliver conservation programs?

A: No. BG&E's limited approach will not build much capability for transforming the marketplace by directly influencing customer options and choices. The bulk of the Company's programs are load-control and rate-design programs, which will probably not teach BG&E much about analyzing its customers' energy use patterns, delivering comprehensive retrofits, affecting design decisions, intervening in the renovation cycle, or changing purchasing patterns. The information programs for commercial lighting and motors will weakly respond to but one of the major constraints on customer purchasing patterns; BG&E's efforts neglect the other severe market barriers that affect different customers in different ways. These programs will not contribute greatly to BG&E's ability to design and deliver cost-effective conservation programs, nor add much to market forces guiding current customer behavior.

In general, BG&E should think less about providing information, and orient its capability-building more towards large-scale programs that squarely address specific investment barriers confronting each market segment. Only large-scale programs will demonstrate the costs and benefits of full-scale acquisition of efficiency resources, which must happen before BG&E can reliably generate savings from efficiency investments on a strategic scale. Only comprehensive programs will teach BG&E how to achieve all cost-effective conservation.

Q: Will BG&E need DSM delivery capability prior to the date at which it needs capacity?

A: Yes. There are several reasons for acquiring early DSM-delivery capability. First, for lost opportunities (e.g., new construction, rehabilitation, renovation, expansion, routine equipment and appliance replacement, and industrial process modifications), BG&E must be able to realize all cost-effective opportunities as they occur. A building constructed in 1994 will not be rebuilt in 1999, if BG&E then decides that it needs the capacity and energy benefits of the efficient building.

Second, many DSM programs will be less expensive than operating BG&E's existing marginal power supplies, including line losses and T&D requirements. As such, BG&E can reduce costs long before it avoids generating capacity.

Third, if BG&E is to avoid some of the costs of the Perryman project, starting in 1995, it will need to implement a significant amount of DSM prior to 1995 to ramp up capability. Going from virtually no DSM effort to saving over a third of projected energy each year will require substantial investment increases.

Fourth, BG&E will have to convince itself that its DSM programs will produce real savings before it can avoid capacity additions. In order to avoid adding a CT in 1995, BG&E would have to decide in 1992 whether to order the equipment and pursue licensing.[13] Thus, by 1992, BG&E would have to have run enough large-scale programs to demonstrate that significant demand reductions would be achievable by

[13]The lead time may be longer if turbine manufacturers are operating at or near capacity.

1995. To allow time for implementation, evaluation, and review, BG&E would have to start those programs immediately.

Hence, if BG&E is to minimize costs to its ratepayers and to society, it will have to build real DSM delivery capability rapidly.

Q: What are lost-opportunity resources?

A: The Northwest Power Planning Council defines lost-opportunity resources as those "which, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use." (Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, Vol. 1, p. Glossary-3) On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition. ("Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," at 7)

Q: Where are lost-opportunity resources usually found?

A: Opportunities to secure inexpensive efficiency savings present themselves when new residential and commercial buildings are designed and constructed. Similar one-time opportunities also arise when households and businesses add or replace appliances and equipment. Once foregone, these "resources" will have to be replaced in the future either with alternative supply or more costly conservation (e.g., as retrofits to the newly built facilities). In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life. (Id. at 9)

Q: Why should BG&E pursue these transient resources?

A: These opportunities represent rapidly vanishing resources because builders, businesses and consumers are making essentially irreversible choices on a daily basis. The window of opportunity for influencing these decisions is quite short. For new commercial construction, this window may be a matter of weeks or months; for appliances, a utility's opportunity to acquire cost-effective savings may be limited to hours or at most days. The consequences of these decisions can last anywhere from a decade to a century.

Moreover, lost-opportunity resources are the most flexible demand-side resources available to utilities. They tend to correlate with demand growth since rapid demand tends to correspond to construction booms and facility expansion. Unlike any other option available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.

Q: How should BG&E pursue lost-opportunity resources?

A: BG&E should concentrate on capturing lost opportunities that arise in the marketplace due to inaction by customers or those acting on customers' behalf. Utilities should also make every effort to avoid creating lost-opportunities by their own incomplete action -- for example, efficiency programs that capture only the easiest and cheapest savings potential.

Q: What types of programs should BG&E pursue to capture opportunities occurring in the marketplace which would otherwise be lost?

A: The Company can implement programs that seek to "beat the standards" that apply to both residential heating and cooling equipment as well as commercial lighting equipment, and concentrate on programs aimed at new construction in the commercial and residential sectors. National appliance efficiency standards also present a unique opportunity.

Q: Have other utilities or regulators recognized the imperatives of capability-building and potentially lost conservation opportunities?

A: Yes. Without being exhaustive, I can cite a considerable list. The Northwest Power Planning Council first urged Bonneville Power Administration and the region's utilities and regulators to pursue capability-building strategies and lost-opportunities in its 1983 Plan. Its 1986 plan reaffirmed this recommendation, in spite of a large capacity surplus. (1986 Northwest Plan, op. cit., at 9-28 through 9-30) In Vermont, the Public Service Board and the utilities it regulates are making capability-building and lost-opportunity resources their top priorities. (Docket 5270, Vol. III, at 58-59, 92-102.) The Idaho Public Utilities

Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan" and a "Capability-building Plan." (Order No. 22299, Case No. U-1500-165, January 27, 1989)

The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape:

> The importance of improving the energy efficiency of commercial buildings as soon as possible must be emphasized. These buildings represent long-term investments (up to 70 years) which will significantly affect the use of energy once they are constructed. Retrofitting to achieve energy efficiency, as experience has shown, is usually expensive, if possible at all. Therefore the commission is not willing to allow these 'lost opportunities' for energy efficiency to continue unabated." (Fifth Advance Plan Order, op. cit., at 33-34)

New England Electric and Northeast Utilities have adopted this same perspective in their demand-side programs, which they developed under unprecedented collaborative design processes spearheaded by the Conservation Law Foundation.[14] Utilities in Massachusetts and Vermont are re-orienting their current demand-side strategies toward capability-building and lost-opportunity resources.

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[14] See Northeast Utilities, "Power by Design: A New Approach to Investing in Energy Efficiency," submitted to the Massachusetts DPU by CLF on behalf of NEES, September, 1989; CL&P Conservation and Load Management Program Plans, Filed in response to DPUC Order No. 3, Docket No. 87-07-01.

3.2 BG&E's Evaluation of DSM Options

Q: What other problems have you identified in BG&E's evaluation of DSM?

A: There are discrepancies between the Company's projections of conservation savings in the IRP and the savings presented in the underlying program analyses. There are also ambiguities and inconsistencies in BG&E's demand-side screening process. In addition, the exclusion of environmental externalities from BG&E's economic evaluation of demand-side programs is a major shortcoming. I will return in a subsequent section to the subject of valuing environmental and other externalities; here I discuss the other issues in turn.

3.2.1 Inconsistencies

Q: What problems did you find when you compared the integrated plan with the Company's underlying analysis of DSM programs?

A: The detailed evaluation of lighting measures (the only conservation options considered in any detail in the plan) in Exh. III.J.2 is inconsistent with the summary results in Exh. II.Q, which seems to provide the source for the integrated plan. Specifically, I was unable to reconcile BG&E's estimates of demand impacts in the two documents. In Exh. III.J.2, BG&E projects, for example, that two customers each year will install electronic ballasts instead of energy-saving magnetic ballasts as a result of the BG&E information campaign running through 2004. This exhibit

projects that each installation will reduce coincident peak by 131.2 kW. This suggests cumulative savings of 3.9 MW by the final year of the program. But the results presented in Exh. III.Q show cumulative savings in the year 2004 of only 0.59 MW. The IRP does not explain this discrepancy. This inconsistency pervades all of the lighting "programs" considered by BG&E. Table 3.1 shows the extent of this inconsistency among other DSM programs.

Q: Are there other ambiguities in BG&E's evaluation of specific energy-efficiency options?

A: Yes. The Company's analysis of lighting efficiency savings is faulty in several significant respects. In the IRP's description of BG&E's lighting program, it is not clear whether the electronic ballasts are being targeted as retrofits, or whether they are aimed at routine replacements, early retrofits, or new construction. (The combination of electronic ballasts and T8 lamps is aimed at new construction, according to the Company's explanation; however, BG&E does not indicate to which type of customer the electronic ballasts alone are being marketed.)

BG&E confuses measures with programs, which further compounds the problems with the Company's savings projections. The five programs are really a set of <u>measures</u> applicable to any customer. In fact, there is no reason a customer shouldn't participate in all "programs." To maximize the amount of cost-effective savings realized by

BG&E's investment, it should encourage customers to install as many measures -- or "programs" -- as their savings justify in terms of avoided costs.

Q: What conclusion do you draw from the inconsistencies you found?

A: Seen from this perspective, BG&E's programs do not even scratch the surface of its potential customers. The total participation reported by BG&E is deceptively large. For example, ultimate sales by participating customers are only 4% of the class total, if we confine the eligible population to large Schedule G customers (total use by participating customers in III.Q is 309 GWh in "program" 1, divided by the total class sales of 7,289 GWh for 2004, given on p. 13 of the sales forecast, Sec. II of the IRP.) None of the "programs" is mutually exclusive, other than "programs" 1 and 5. In other words, it is not correct to add the "participants" in each program to reach the total number of customers participating in all BG&E's lighting "programs". In fact, it is entirely likely that BG&E is reaching no more than 150 customers in the next 14 years, since essentially all programs are applicable to the same 150 customers. See Table 3.1.

BG&E is promoting only two conservation "programs," which essentially boil down to two end-uses: lighting and motors. Neither of these "programs" offers direct incentives to customers to overcome the market failure impeding investment on their own.

BG&E mistakenly rejects other "programs." From its analysis of several other measures, BG&E draws the sweeping conclusion that these strategies are inapplicable or uneconomic to its customers. According to the Company (in the 1989 IRP, p. III-25), for example, there is no reason to offer a small customer cooling efficiency program because, according to BG&E, there is no range of efficiencies for small (under 30-ton) cooling equipment. This is a surprising result, given the range of efficiencies for larger and smaller equipment. BG&E argues that small cooling equipment has "reached an equilibrium between investment cost and operating cost." If this is true, equipment optimized for New York City electric rates would be high-efficiency units in Baltimore. Nadel and Tress (1990) report that 5% of packaged air conditioning equipment has an EER over 10, while sales average about 8.5. To the extent that higher-efficiency units are not readily available in its service territory, this is an important market barrier for BG&E to overcome.

Similarly, BG&E declares that automatic lighting control options are too expensive or too hard to find for its customers; plans by other utilities to promote this technology appear to contradict this conclusion.

BG&E's reasoning in these situations is extremely flawed. First, the relevant comparison should be between the cost of electricity saved from such measures and BG&E's full avoided costs. If savings cost less than supply, and the measures are applicable and acceptable to some customers if BG&E pays their costs, then they should be included in a comprehensive program serving those customers. "Hard-to-find" efficiency measures tend to become common practice once a utility succeeds in transforming the marketplace with aggressive programs.[15]

3.2.2 BG&E's central screening process

Q: What screening test does BG&E use in its evaluation of DSM programs?

A: That is not clear. BG&E computes results of various sorts for the al-ratepayers test, a "utility" test, a paticipants' test, and the non-participants' test.[16] However, it is not clear how BG&E used these tests in determining what it considered to be a beneficial program.

Q: What test should BG&E have used in screening programs?

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[15] BG&E even recognizes this dynamic in explaining the objectives of its lighting information program. See IRP at III-41.

[16] All the tests were run both with and without T&D capacity credits. For most programs, it is far from clear why this would be necessary, since load reductions will provide T&D savings. The load-shifting programs should be run without T&D benefits, and even with a distribution penalty, to reflect the rebound of load at the end of the control period.

A: For screening measures and programs against the Company's supply costs, BG&E should rely primarily on the societal or all-ratepayers test to compare benefits and costs. The all-ratepayers test is a close cousin of the societal perspective; it counts those societal costs that are internalized in market prices to ratepayers. BG&E should count the total costs of delivering energy-efficiency programs, including direct costs to BG&E and participants, as well as administrative and monitoring costs.

Under the societal test, benefits are not confined to only BG&E's avoided supply costs. They also include all savings unrelated to electricity savings, such as the marginal value of other regulated utilities affected by the program (e.g., water, gas). Accurate resource comparisons using the societal test also include unpriced environmental externalities.

Only the societal or all-ratepayers test will consistently reflect the true value of efficiency programs to BG&E, its customers, and the general public. Any measure which passes the societal screening -- i.e., cheaper than supply -- is worth pursuing. Least-cost planning requires that BG&E attempt to realize the potential of all such measures, since failing to do so would deliberately and unnecessarily lead to higher total costs.

Q: What role should the utility test play?

A: A proper utility revenue requirements test reflects the incremental costs a utility would incur to obtain different resources on ratepayers' behalf. Its treatment of free riders helps utilities focus their attention on efficiency savings that are unlikely to occur without demand-side investment. For example, the utility test is useful for designing financial incentives to "beat the standards" on appliances and fluorescent ballasts. It ignores costs the utility does not pay, such as those borne by customers to obtain demand-side measures. While the utility cost test indicates whether a resource is cost-effective for the utility system, if used alone it can lead to uneconomical resource allocation by ignoring costs that customers incur.

Q: Is BG&E using the utility test properly in its economic evaluation of demand-side options?

A: No. 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 as I have described it here. The Company's version of the test is devoid of any real economic meaning.

Q: What role should the non-participants' test play?

A: The non-participants' test is not very meaningful on a measure-by-measure or program-by-program basis. The non-participants' test is a measure of equity, of the effect on other customers of the operation of a particular utility DSM program or measure. However, individual measures and programs cannot really be considered equitable or inequitable in isolation. Rather, the costs and benefits of the entire portfolio of conservation programs either produce an equitable outcome, or do not. The effect on equity of each program will depend on the cost recovery from that program,[17] whether the participants in this program are already participating in other programs, and how the bills of members of various classes and sub-classes are affected by the program.

Once an entire portfolio is designed, it is relevant to ask whether the effects are equitable overall. If there are equity problems, they can be addressed by changing cost recovery patterns, by increasing the penetration of programs to groups which would otherwise face higher bills, and possibly by changing the timing of program implementation.

Some utilities have mistakenly decided that unrealized billing revenues from conservation constitute real costs. While such lost revenues may pose strong financial

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[17]For example, the equity effects will depend on how the costs are recovered from various rate classes.

disincentives for utility investment, they are transfers among groups of ratepayers and not true costs. The Commission is considering mechanisms to remedy the disincentives that revenue losses create for utility efficiency investment in the Cost Recovery Task Force initiated earlier this year.

Q: Is the non-participants' test a misleading indicator for least-cost planning?

A: Yes. The non-participant or no-losers test leads utilities to reject energy efficiency savings whenever utility prices exceed utility marginal costs -- no matter what the cost of the efficiency resources. To my knowledge, every regulatory authority which has seriously examined the no-losers test -- including this Commission -- has recognized its fallacies, and rejected it as a threshold measure of resource cost-effectiveness.[18]

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[18] See Wisconsin PSC, Findings of Fact, Conclusions of Law and Order in Docket 05-EP-4, 5 August 1986, at pp. 8-9. Wisconsin re-affirmed its rejection of the no-losers test in its fifth Advance Plan decision in April 1989 in Docket 05-EP-5. Vermont utilities are prohibited from using the no-losers test to reject efficiency investments in the PSB's Recommended Decision in Docket 5270, pp. III 85-88. The Washington D.C. Commission rejected the no-losers test as a primary screen on demand-side investments in its March 1988 order in D.C. PSC F.C. 834 (Phase II). So did the Idaho Commission in Order No. 22299, Case No. U-1500-165 (Jan. 27, 1989); the Connecticut DPUC in its June 11, 1986 decision in Docket 85-10-22 at pp. 35-86; the Nevada Commission in its October 1986 decisions in Docket 86-701 regarding the resource planning of Sierra Pacific Power; and the New York PSC in its 26 July 1988 decision in Opinion No. 88-20 in Case 29409, pp. 23-49. The Massachusetts Department of

Q: What role should the participants' test play?

A: The participants' test can be useful for gauging the need for, and possible effects of, utility financial incentives to customers designed to overcome market barriers to efficiency investment. BG&E appears to recognize these aspects of the participant test. BG&E can use the participant test to help determine the size of incentives needed to achieve specific payback periods for different types of measures.

Q: Can BG&E use the participant test now to fine-tune the optimal incentive levels for least-cost planning?

A: No. BG&E must recognize that its complete lack of experience limits the usefulness of this test. Just because a particular measure looks attractive under the participants' test does not imply that it will be widely adopted. Thus, the participants' test will not be particularly useful for quantifying the extent of participation likely from a given incentive level.

Such extrapolation requires much more experience. To gain an understanding of how incentives influence participation, BG&E should start with full funding of incremental efficiency costs to establish the upper limits on achievable participation. Once these upper limits are

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Public Utilities firmly rejected the no-losers test in its Decision and Order in DPU 85-266-A/85-271-A, 26 June 1986, pp. 147-48. It reaffirmed this policy in subsequent orders, including DPU-86-36-E, November, 1988.

established, BG&E will be in a position to "back into" optimal incentive levels without sacrificing cost-effective participation. Taking the opposite approach -- trying to determine optimal incentives by starting too low -- runs the risk of delaying capability building and under-estimating the size of efficiency resources.

3.3 BG&E's Program Design Philosophy

Q: What do you mean by "program design philosophy?"

A: I refer here to the general approach taken to identifying desirable measures and packaging them into programs, and to the central concepts guiding program design.

Q: On what points is BG&E's program design philosophy deficient?

A: First, it is not easy to identify BG&E's philosophy. BG&E provides very little rationale for its approach. In many cases, it is difficult to determine how BG&E came up with the results reported in the Plan and the Appendices. Even where it is possible to determine <u>what</u> BG&E did, it is not always clear <u>why</u> BG&E made those choices.

That said, there are several areas in which BG&E's approach is deficient or inappropriate. These include:

- comprehensiveness,
- market-oriented design,
- capability-building,
- service delivery, and

- cost sharing.

3.3.1 Market-Oriented design strategy

Q: What do you mean by "market-oriented" program design?

A: A market-oriented DSM design process starts with a segment of the market, and designs a program to achieve all cost-effective conservation within that market. The cost-effectiveness of the resulting program is also determined at the level of the entire package. This can be thought of as a "top-down" design process, as opposed to BG&E's "bottom-up" process of enumerating and evaluating each technology (or end-use, or measure) individually.

Q: What types of segments might be useful for BG&E's analysis?

A: The segments should be defined in terms of the type of delivery mechanisms which would be appropriate; that is, small customers as opposed to large ones, lost opportunities as opposed to discretionary programs, and customer-driven choices as opposed to those usually made by contractors. For the residential class, useful segments might include:

- heating retrofits,
- water-heating retrofits (possibly including heat pumps),
- new-appliance efficiency, including choice and water-heater installation measures (wraps, pipe insulation, end-use reductions),

- new-building efficiency, and
- lighting, probably broken into direct retrofit, demonstration programs, and retail market shifting.

Many of these markets would have separate requirements and investment strategies, depending on the strength and configuration of market barriers impeding different customers' investment in cost-effective efficiency options. Thus, BG&E should offer different incentives and assistance for owner-occupied and rental housing, and for low-income and other customers, since the barriers differ among these groups. For the commercial, institutional and governmental customers, there may be similar differences in requirements for delivery mechanisms and incentive levels for large and small customers, and for business and non-profit customers. Appropriate segments might include:

- comprehensive retrofit, including lighting, HVAC, building shell, window treatments, refrigeration, and motors (e.g., elevators);
- new construction, renovation, and rehabilitation; and
- routine equipment replacement (e.g., chillers).

For industrial customers, the categories would be similar to those for commercial customers. However, the "new construction" category should probably also include major equipment and process changes (analogous to the commercial rehab, but not necessarily affecting the spacial layout). In addition, the retrofit program must allow for customer-originated improvements in equipment and processes.

Depending on how the segments are defined (e.g., whether the low-income residential retrofit market is counted as a subset of the residential retrofit, or as a separate market), this approach would focus on roughly one or two dozen packages, rather than many dozens of technologies and measures.

3.3.2 Direct delivery of services

Q: What general criticisms do you have of BG&E's approach to delivering DSM services to customers?

A: In general, BG&E appears to have different approaches for load shifting and for conservation measures. While BG&E is willing to install most load-control measures directly, it is content to leave market barriers undisturbed by direct utility investment. Information is the only extra ingredient which BG&E adds to the operation of market forces when it comes to efficiency investment, but in the case of load control, BG&E will either install measures directly, or for thermal storage systems, the Company will offer rebates.

However, as discussed earlier in this testimony, there are many barriers to customer action which will not be adequately or efficiently addressed by providing information or by offering partial rebates. Uncertainty, lack of knowledge, split incentives, lack of time for exploring options, limited retail availability, and aversion to dealing with contractors will not be overcome by rebates. A customer who has not found the time to seek out compact fluorescent bulbs is not likely to find the time to seek out the bulbs and fill out rebate forms.

Q: How should BG&E address these barriers?

A: For many measures, BG&E should offer direct design and/or installation services.[19] For example, a residential heating retrofit program should provide for an audit, selection of cost-effective measures, and installation, with as little demand on customer time as possible. To the extent that BG&E designs, arranges, finances, oversees and warranties the work, the customer avoids most of the hassle factors that complicate any major home improvement. This is particularly important for residential and small commercial customers, and may also be significant for larger customers in some segments.

In other cases, BG&E may need to change the way that products and services are priced and delivered in its service territory. Offering incentives to appliance dealers, heating contractors, plumbers (for water-heater replacement) and lighting dealers may be more effective than

[19] The actual delivery would usually be through a contractor, rather than by BG&E employees.

offering rebates to customers. For lighting, BG&E may need to get compact fluorescents into homes through direct delivery or discount mail order (so that customers gain some experience with them) and also get them onto store shelves (so that customers can buy them). Rebates may be appropriate as part of some programs, but they are often only part of the best solution, and are sometimes totally inappropriate.

3.3.3 Comprehensiveness

Q: What do you mean by "comprehensiveness"?

A: We refer here primarily to achieving all cost-effective efficiency improvements, for each customer involved in a program. In addition, BG&E's programs should be comprehensive in addressing all customers and all market segments.

Q: In what ways does BG&E overlook comprehensiveness?

A: BG&E appears to examine individual measures, or small bundles, rather than the total opportunities for improving the efficiency of a customer. The comprehensive approach delivers all the efficiency services which are economical as a package; the single cost of getting an installer to the house is spread across a large number of measures, and no potential cost-effective savings are left "on the table."

As one example, BG&E's proposed residential water-heater control program appears to be completely isolated from other water-heating measures, let alone measures for other end-uses. Before BG&E installs a control on an electric water heater, it should determine whether that control is more beneficial than alternatives, such as converting the customer to a gas water heater, installing a water-heating heat pump, or improving efficiency. Even if BG&E finds that controlling the water heater is not cost-effective, all the efficiency improvements are still likely to be cost-effective. While BG&E has an installer on the premises, it should ensure that the water heater and pipes are wrapped, and that efficient showerheads and faucet aerators are installed. With little additional cost, the same installer can screw in a few compact fluorescent light bulbs.

Q: Can you cite an example of BG&E's lack of comprehensiveness causing particular problems in its program designs?

A: Perhaps BG&E's most glaring failure to invest comprehensively is in new construction. The Company's only effort to tap the efficiency potential in this important lost-opportunity sector is to offer information to encourage the installation of electronic ballasts and T-8 lamps. There are many other unrealized opportunities to save electricity extremely cost-effectively in new buildings, many of which interact. For example, BG&E recognizes (commendably, I might add) that lighting efficiency measures reduce cooling load. BG&E credits these cooling savings to lighting efficiency measures.

A comprehensive approach would carry these savings further. For example, BG&E should intervene in the design process to translate cooling savings into reduced chiller capacity. In general, BG&E should be pursuing cost-effective savings available from all end-uses involved in new buildings. This applies to all customer sectors. Failure to invest comprehensively will sacrifice many cost-effective opportunities to improve efficiency and reduce BG&E's supply requirements.

Q: How should utilities proceed to overcome market barriers to cost-effective efficiency improvements?

A: Utilities should invest in as much savings from customers as they can for less than the avoided costs of supplying power. <u>Comprehensive investment strategies</u> are needed to obtain the optimum amount of least-cost efficiency resources.

Q: How does the strategy you recommend differ from other approaches a utility might take to demand-side investments?

A: Buying efficiency savings is a markedly different proposition from selling or marketing conservation measures. As the Vermont PSB found in Docket 5270 (pp. III-42 to 43), the latter tends to concentrate on individual technologies. It often leads utilities to fragmented and passive efforts to convince customers to adopt individual measures which marketing research indicates they are most likely to want and accept. Another frequent but misguided objective is to seek savings from customers as inexpensively as possible.

Such a strategy may tend to overlook more costly savings that might still be available at less than utility avoided costs. Both alternatives, while intuitively attractive at face value, could well lead utilities to acquire more supply than least-cost planning criteria would justify.

Q: What are the practical implications of this "efficiency-buying" approach to utility demand-side investments?

A: Treating each customer as if it has a definite amount of electricity resources available for capturing leads to some fundamental principles about the way to design and implement programs. Successfully capturing economical energy efficiency opportunities requires that utility programs be comprehensively targeted. This means that utilities should realize efficiency potential customer by customer, not end-use by end-use. Otherwise, utilities would have to re-visit their customers many times over to tap all available, cost-effective efficiency savings. In the end, less of the efficiency resource would be recovered at higher costs than if the utility extracted all the efficiency potential one customer at a time.

Addressing technologies and end-uses comprehensively among customers avoids two common mistakes in utility efficiency programs: failing to account for interactions between technologies and end-uses; and "cream-skimming" -- neglecting measures that would be cost-effective at the time other measures are installed, but whose savings would not justify the administrative, diagnostic, and other overhead costs of a "re-retrofit" later. Absolute savings always decrease as more measures are applied to a single building or factory. However, unit costs of saved energy are likely to be significantly higher if individual measures are engineered and installed singly and administered under separate programs.

Q: Define comprehensive demand-side strategies.

A: The Vermont PSB's Proposal for Decision in Docket 5270 provides the following definition:

> Utility demand-side investments should be comprehensive in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide. Comprehensive strategies for reducing or eliminating market obstacles to least-cost efficiency savings typically include the following elements: (1) aggressive, individualized marketing to secure customer interest and participation; (2) flexible financial incentives to shoulder part or all of the direct customer costs of the measures; (3) technical assistance and quality control to guide equipment selection, installation, and operation; and (4) careful integration with the market infrastructure, including trade allies, equipment suppliers, building codes and lenders. Together, these steps lower the customer's efficiency markup by squarely addressing the factors that contribute to it. (p. III - 44)

Q: Why are comprehensive strategies needed to overcome market barriers to customer efficiency investment?

A: Addressing market barriers individually might be appropriate if market barriers operated in isolation. Unfortunately, this is typically not the case for groups of customers. It is the <u>multiplicity</u> of strong and <u>mutually reinforcing</u>

market barriers that explains the pervasiveness of the payback gap among utility customers. Individual customers may decline particular cost-effective efficiency measures for one reason or another; but chances are that a variety of barriers explain why any given group of consumers does not tap economically feasible efficiency potential. Short of customizing a different program for every customer, utilities need to design programs that address the full array of obstacles preventing least-cost customer efficiency investments.

Q: Can you provide an example of how market barriers interact?

A: Low-income households offer a classic example of how market barriers can interact to retard efficiency investment. Low-income households have virtually no access to capital on any terms. Residents rarely own their own homes, so have little motivation to invest even if they had the means. Even with access to enough capital to finance efficiency investments and the incentive to invest it, the specific financial risks of parting with the funds would pose a high hurdle. Finally, low-income people are less able to obtain and act on the information needed to choose between efficiency options. Hence, the least-cost strategy is probably to invest directly and completely in measures needed to yield all cost-effective efficiency savings.

This combination of forces is strong enough to justify direct utility investment in the dwellings occupied by low-income customers.[20]

Q: Isn't it unrealistic to expect utilities to take over the responsibility for investing in all customer efficiency, and attempting to complete them in "one-shot deals"?

A: Except in special circumstances such as low-income housing, utilities ordinarily need not pay all the costs of efficiency. In fact, it may be wise to preserve the customer's self-interest in minimizing costs in some instances by requiring a limited amount of cost-sharing (e.g., 20 percent).

Moreover, treating efficiency potential thoroughly does not mean installing all measures in one visit. In fact, successful programs find that a thorough analysis should be done, and should include the installation of one or a few measures to "hook" the customer with results. The utility then follows up with a detailed investment plan offering a range of financial options for achieving the full potential. An example is offering a rebate for a downsized, higher-efficiency chiller when an existing unit needs replacing,

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[20]Various regulators have required utilities to target low-income customers with efficiency investments, including Wisconsin (Findings of Fact and Order in Docket 05-UI-12, April 20, 1982, at 13-15), Vermont (Docket 5270, Vol. III, pp. 60-62, and 158-159), and New York (Case 89-M-124, Order of June 29, 1989).

after cost sharing, full engineering and contract management for relighting.

Nor is it essential that one program cover all end-uses for customer groups. Comprehensiveness should be judged by how completely a utility's full set of programs covers relevant end-uses. For example, utilities use several programs to cover residential efficiency potential. They target weatherization retrofits and appliance replacement separately because of the different nature and timing of the decisions involved. Such an approach is comprehensive if the two programs are carefully linked. For instance, the energy analysis associated with the weatherization retrofit should alert the customer to the savings opportunities available from high-efficiency furnace replacement.

3.3.4 Participant cost-sharing

Q: How does BG&E determine how much of the cost of a conservation measure it will bear?

A: In general, BG&E appears to have used a different standard for conservation than for load management. For load management, BG&E will pay whatever is necessary to ensure adoption of the measures, up to avoided cost. For conservation, BG&E has only committed itself to providing information and advice, and not to any direct investment.

Q: Should utilities rely on information programs as their primary strategy for achieving cost-effective efficiency?

A: No. Information programs alone will not overcome the barriers to cost-effective efficiency investment that I describe here. Programs that offer no tangible incentives are rarely effective in generating meaningful or measurable demand savings.

Q: Are you saying that information is unimportant?

A: No. Providing customers with more information about efficiency opportunities is necessary but not sufficient for fully realizing economical efficiency potential. Utility experience confirms that <u>reinforcing information</u> with aggressive marketing, financial incentives, and installation assistance yields increased savings at lower program costs.

Q: Please substantiate this claim.

A: Consider utility experience with the Residential Conservation Service (RCS). Throughout the U.S., utilities spent millions of dollars on programs to provide energy audits to their customers between 1981 and 1986. But relatively few utilities did much to help customers <u>act</u> on this information. Consequently, few customers participated in most audit programs, and even fewer participants installed the costly but ultimately cost-effective measures recommended by the audits. Costs were high, and savings were low in a program that most observers agree was a disappointment.

However, some utilities provided financing that more closely matched savings with debt service, offered contract management and quality control, and paid local community organizations to market the programs to residents. Such efforts were not cheap, but additional savings were generally considered to have outweighed incremental costs.[21]

At the opposite extreme of the RCS program was Bonneville Power Administration's Hood River Conservation Project. This program sought to establish the outer limits of cost-effectiveness by deliberately installing as many measures as possible in as many homes as possible, including those previously treated under previous utility weatherization programs. The result was 90% participation and large savings.[22]

Q: How should BG&E determine the sharing of costs between participants and the utility's ratepayers as a whole?

A: BG&E should start by identifying an efficient mechanism for delivering services in each market. Given that mechanism, and the nature of the market barriers in each market, BG&E

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[21] See, for example, Stern, <u>et al.</u>, "The Effectiveness of Incentives for Residential Energy Conservation," Evaluation Review, Vol. 10, No. 2, April 1985, 147-176; Stern, <u>et al.</u>, "Residential Conservation Incentives," Energy Policy, April 1985, pp. 133-142; Berry, L., "The Role of Financial Incentives in Utility-Sponsored Residential Conservation Programs," Evaluation and Program Planning, Vol. 7, pp. 131-141, 1984.

[22] See "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," 1987, pp. 15-20.

should select a funding level which will achieve essentially all of the achievable potential by the time that it is cost-effective, and which will not significantly increase the costs of program delivery. BG&E should not arbitrarily refuse to pay for the bulk of the cost of efficiency improvements, and even for the full incremental cost, if that is the most effective and efficient means of securing those improvements.

To the extent that some program costs are recovered from participants, the participants should be given the option of having the recovery flow through their bills. This may be very important for some customers (such as government agencies) which would have to secure numerous and complicated approvals to put up cash or to sign a loan agreement. It may also be important for customers with cash constraints, and may overcome a psychological barrier even for those customers who are not cash-constrained.

4. POTENTIAL FOR COST-EFFECTIVE CONSERVATION

Q: What indications are there that BG&E's customers offer enough potential for cost-effective efficiency savings to help meet the Company's future resource needs?

A: The economic potential for efficiency savings in BG&E's service area depends on the costs and performance of different technologies for providing energy services to its customers, and the extent to which customers will adopt them. As discussed earlier, there is strong evidence that market barriers prevent households and businesses from investing in efficiency measures unless they are extremely profitable. Market barriers also keep customers from retrofitting buildings and factories with such conservation measures as high-efficiency lighting.

There is every reason to believe that BG&E and its customers confront similar opportunities. Commercial, residential and industrial customers generally require energy efficiency measures to pay for themselves within 2 to 3 years (with even shorter payback requirements for some groups), while developers may insist on payback periods of no more than one year. This implies that BG&E's residential, commercial and industrial customers are all persistently eschewing efficiency measures that from BG&E's standpoint would save electricity for much less than it costs BG&E to produce and deliver.

Q: Where should BG&E seek such opportunities for cost-effective efficiency investment?

A: Everywhere. The prevalence of strong market barriers led the Vermont PSB to find that there is probably some cost-effective efficiency potential to be "harvested" in every building in the state. (Docket 5270, Vol. II, p. 57) In particular, BG&E should expect to find large reservoirs of untapped efficiency potential in the facilities of its existing industrial and commercial customers. These customers comprise about 60% of BG&E's electric sales. Promising end-uses where inexpensive efficiency savings may be widespread include lighting (which BG&E estimates to comprise 60-65% of commerical load) and HVAC systems in both existing and new buildings and motor drives and process uses in existing industries.

As discussed earlier in this testimony, cost-effective savings are also likely to be available from BG&E's residential customers. Aside from new construction, BG&E should be able to gain further savings with rebates to "beat the standards" governing appliance efficiency which take effect in 1990 and 1992.

4.1 Studies of Potential

Q: How large might the potential for cost-effective electricity conservation in BG&E's service territory be?

A: No precise answer to that question is currently available. The amount of cost-effective conservation depends on the social avoided cost (including externalities and risk reduction), on the composition of current and future stocks of buildings and equipment, on the evolution of efficient technologies, and other factors. No comprehensive study of conservation potential has been performed for BG&E. Since the best way to determine the potential for most markets is to implement an aggressive program and measure the response, it is not clear how useful a comprehensive study would be.[23]

We can get a rough sense of the potential by examining the results of studies performed in other states. It should be noted that these studies generally reflect technology options from several years ago: the cost of efficiency improvements have fallen, and potential has increased. The values of avoided costs used in these analyses vary, but they generally represent some proxy for new baseload plant construction, without any adjustment for line losses, T&D costs, load factor, or the benefits of reduced risk or avoided externalities. Also, these studies generally do not

[23]Improvements in technology and in delivery strategies will also continually increase the achievable potential, so any study of potential can be "comprehensive" only for a short period of time. On the supply side, utilities generally commit to investing in technologies even though they do not know exactly what heat rate each unit will achieve or exactly how many sites may be available in the service territory. So long as an initial unit appears to be cost-effective, and a site has been identified, the utility can start using a new type of resource long before it knows exactly how much it will build or exactly how the units will perform.

examine fuel-switching from electricity to direct fuel use, which my work for the Boston Gas Company and (with others) for the Central Vermont Public Service Corporation collaborative has indicated is highly cost-effective, both in terms of direct costs and in terms of total social costs, including externalities. All of these stduies conclude that the economic and/or achievable potential for conservation is quite large.

Miller, et al. (1989), a study for the New York State Energy Research and Development Authority, estimated that efficiency investments in the 1986 building stock that were cost-effective under their "societal" test would yield 34% savings in the residential class, 47% reduction in commercial electric usage, and 16% savings in the industrial class, for total savings of 34%.

In a recent follow-up study, Nadel and Tress (1990) assessed the achievable potential for cost-effective efficiency improvements for three of the largest New York utilities. Through a combination of tighter efficiency standards and aggressive, comprehensive utility investment programs, they found that about 80% of the economical potential identified in Miller, et al., is achievable. As with the Miller report, Nadel and Tress did not consider new technologies or fuel-switching.

Chernick, et al. (1989), a study prepared for the Minnesota Department of Public Service, determined that the total cost-effective conservation potential for Minnesota's electric utilities was 52%. We estimated that potential cost-effective efficiency savings were 60% in the residential class, 50% for farms, 60% for commercial customers, and 35% in industry.

Lovins (1986a) estimated a 50% cost-effective potential savings in energy use of the 1984 building and equipment stock in Ontario. In the industrial sector, 70% savings were possible, in the commercial sector 32% savings, and in the residential sector, 46% savings.

Lovins (1986b), a report to the Austin (TX) Electric Utility Department, found that cost-effective efficiency investment by 2005 could reduce annual peak demand by 73%, and energy usage by 72%.

Usibelli, et al., (1983), a study commissioned by DOE, found that technically feasible energy conservation measures costing less than 40 mills (roughly equal to the Northwest Power Planning Council's estimate of avoided supply costs) could reduce residential electricity demand in 2000 by 36.5% in the Pacific Northwest.

Geller, et al., (1986), prepared for Pacific Gas and Electric, examined seven end-uses representing 70% of PG&E's residential electricity consumption. They found that cost-effective efficiency investment could reduce electric energy needs in 2005 by 25%-44%, depending on the penetration of current and prototype technologies.

Gertner, et al., (1984) limited their scope to retrofit technology and capability for office and retail buildings built before 1983. That study concluded that full implementation of cost-effective measures, with pay-back periods of one to three years, would reduce the electrical usage in those buildings by 36%.

Krause, et al., (1988) studied the residential loads of Michigan's two largest utilities, and estimated technical conservation potential from existing and prototype technologies at 42% of usage in 1995 and 56% in 2005. The same study estimated that cost-effective conservation programs (with realistic limits on participation) could achieve energy reductions of 21% in 1995 and 29% in 2005. Technical potential of 19% of 1985 sales was identified for fuel-switching of appliances, excluding space heat.

Overall, it seems reasonable to expect achievable cost-effective energy efficiency potential to lie in the 30-50% range, depending on the level of avoided costs, the time frame used, and other variables.

4.2 Commitments and Plans of Specific Utilities

Q: Which utilities' conservation commitments and plans have you reviewed?

A: I have reviewed the conservation plans of a number of utilities located throughout New England, as well as utilities in California and Wisconsin, that have shown a commitment to rely on energy-efficiency programs to make a significant contribution to their resource plans. I summarize the plans of New England and Wisconsin utilities in Table 4.1. I also discuss ongoing efforts of the major California utilities, summarized in Table 4.2. Finally, I describe the DSM programs of a major Wisconsin utility.

Q: What do you conclude from your examination of conservation plans by other utilities?

A: Utilities that make a concerted effort to tap all cost-effective potential for energy efficiency resources generally spend much more on energy conservation and expect much larger savings than does BG&E. Such utilities are counting on demand-side resources to meet roughly 20 - 80% of their additional sales growth in any given year. On average, these utilities expect to reduce annual anticipated sales growth by approximately 40%. To obtain such savings, these utilities are spending in the range of 3% to 5% of their annual operating revenues on conservation and load management programs. Based on this experience, a utility with DSM funding budgeted at the 3% to 5% level could reasonably plan on capturing 33% to 50% of its expected sales growth.

Q: Please describe the results of Table 4.1.

A: Table 4.1 summarizes the conservation expenditures and savings for selected utilities. The most interesting columns in Table 4.1 are columns [4], [6], [8], and [9]. Column [4] expresses each utility's conservation expenditures as a percentage of its projected revenues at the program midpoint. This figure ranges between 1.8% for United Illuminating (UI) and 6.4% for the program proposed for Central Vermont Public Service (CVPS), with an average of 3.6%.

Column [6] expresses the total energy saved in the last year of the program as a percentage of projected sales for that year. UI saves 1.2% of its projected MWh sales at the end of its three-year program. The plan proposed for CVPS saves 14.3% of sales after ten years; overall the plans average 5.5% in savings from projected sales.

Note that because the savings in the last year of the program include the effects of all the conservation measures installed in the course of the program, longer programs will tend to show more impressive results.

Similarly, column [8] shows the MW saved in the last year of each utility's conservation program, expressed as a percentage of projected peak load for that year. The percentages range from 1.6% for Wisconsin Electric (WEPCo)

to 18.3% for NEES. WEPCo's figure is low because it represents the results of only a two-year program. Average savings are 6.8% of program-end peak load.

Column [9] provides each utility's "DSM capacity factor" This is the capacity factor of the theoretical power plant generating the same number of MW and MWh as the DSM programs save. As with a power plant, the DSM capacity factor is a good indication of what kind of resource the utility is adding. A low number means the utility is aiming mostly for capacity savings; a high DSM capacity factor implies the utility is seeking substantial energy output from each kW of DSM resource capacity. It is a good basis of a plan's bias towards saving capacity rather than energy. WMECo has a very high DSM capacity factor, 82%, and NEES, with 22%, has the lowest. The average capacity factor is 47.7%.

Q: Please describe Table 4.2.

A: Table 4.2 is a summary of projected 1990-91 conservation expenditures and savings for major California utilities. The utility expenditures and savings were taken from the January 1990 Report of the Statewide Collaborative Program, An Energy Blueprint for California. Utility revenues and sales are from the Energy Information Administration's Financial Statistics of Selected Electric Utilities, 1987.

The table gives figures for three utilities, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The first column represents each utility's spending on conservation programs in 1990 and 1991. The dollar figures are nominal dollars. The Blueprint specifies that the SCE figures assume a 3.5% increase for inflation plus incremental costs. Inflation figures are not given for the other utilities.

Column [2] expresses annual conservation expenditures as a percentage of 1987 ultimate consumer revenues. Column [3] lists the incremental MWh saved in each year. Column [4] expresses those savings as a percentage of 1987 ultimate consumer sales.[24]

Not covered in this table is the extremely ambitious efficiency investment campaign recently announced by the Sacramento Municipal Utility District (SMUD). According to the July 1990 plan, SMUD intends to build the equivalent of a 600 MW power plant through efficiency investments over the next ten years.[25]

Q: Can you provide details on the kinds of programs that such expenditures buy?

A: During the past three years, more U.S. utilities have been using comprehensive strategies to secure large amounts of efficiency resources quickly throughout their service areas,

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[24] Both PG&E and SDG&E have both gas and electricity conservation programs. The Blueprint provided PG&E expenditures specifically for electricity conservation. SDG&E expenditures appeared to only include only the costs of the electricity conservation program, and no gas conservation costs, but this was less clear than for PG&E.

[25] SMUD 1990, p. 1.

particularly in New England, Wisconsin, and more recently, California and Maryland. I will describe in further detail efforts by one utility which demonstrate the effectiveness of such comprehensive strategies for obtaining maximum yield from utility demand-side investments: Wisconsin Electric's "Smart Money" Program, which offers a range of incentives for a variety of efficiency measures throughout the company's service area.

Q: Please explain how Wisconsin Electric's conservation programs relate to the value of comprehensive demand-side programs for BG&E.

A: For the last two years, WEPCo has been implementing an $84 million energy conservation strategy aimed at all major customer sectors. This strategy satisfies the criterion I set forth earlier for utility demand-side strategies -- investing whatever it takes up to utility avoided costs to secure the maximum possible efficiency potential from utility customers.

Q: What aspects of WEPCO's program fit this description?

A: WEPCO's "Smart Money" program is aimed at commercial, industrial, and farm customers. The program offers a broad range of incentives; these incentives are specified in terms of utility avoided resource costs; and the programs are designed to capture savings available from a diverse set of technologies and end-uses.

Q: How does the range of incentives ensure comprehensiveness?

A: WEPCO has taken the trouble to offer a menu of incentives to acquire savings, rather than simply selling one type of financial assistance. In addition to comprehensive feasibility analysis, WEPCO offers customers two types of rebates: standard rebates reimbursing specific amounts for various types of equipment, or "custom" rebates calculated on the basis of the value of efficiency savings to the utility system. In addition, customers may choose a no-interest loan to reduce the cashflow burden of amortizing long-lived measures, or combine a low-interest loan with partial rebates. WEPCO's flexible incentive approach ensures that efficiency investment will be attractive to as many participants as possible.

Q: What efficiency measures are eligible for WEPCO incentives?

A: Rebates are available for lighting improvements, including lamps, ballast, fixtures and reflectors; cooling efficiency improvements (high EER air conditioning, window film); improvements in refrigeration, water heating, and control systems.

A WEPCo staff member explains the decision to include this broad range of equipment as follows:

> In order to increase the effectiveness of the Smart Money program, it was determined that our efforts should not be focused on just a few key conservation measures but should include a wide variety of measures. While focusing on a few conservation measures would have made the program easier to develop, it would have limited our ability to quickly reach much of the potential conservation market. (Thomas E. Hawley, "Wisconsin Electric and the Smart Money

Energy Program," Proceedings of the 1988 Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy, pp. 6.70-6.74.)

Q: How effective has the Smart Money program been so far?

A: WEPCO estimates that demand-side measures enacted as of August 1989 will reduce peak demand by 131 MW and reduce annual energy requirements by 614 GWh. These savings are the result of about two years of effort. They are equivalent to a 131 MW generator (i.e., a power plant with capacity equal to WEPCO's peak load reduction) running at 53.5% capacity factor, comparable to the utilization of a base-load or cycling facility.

Q: Should the Commission recognize the collaborative design process which PEPCO entered with OPC and other parties when considering the adequacy of BG&E's DSM investment?

A: Yes. The fundamental principles underlying the collaborative design process are no different for BG&E than for PEPCO. As stated in the memorandum of understanding filed with the Commission, the parties agreed that

> The purpose of the program design process is to develop programs to yield the maximum cost-effective savings achievable in all sectors of opportunity in PEPCO's Maryland service area. Additional demand savings will be considered cost-effective if they comply with the provisions of Commission Order No. 68660. PEPCO commits to reasonable funding for all cost-effective demand-side strategies developed through this collaborative effort. It is likely that PEPCO's planned expenditures for efficiency programs during 1991-1995 will increase substantially beyond the four demand side management programs approved in November 1989 by the Maryland Public Service Commission.

The relationship between the collaborative process and the Commission's approval of PEPCO's four new conservation programs is especially significant. The PSC had approved five-year DSM plans by PEPCO involving cumulative expenditures of $55 million on conservation programs for residential air-conditioning, commercial lighting and new commercial construction. These plans marked significant improvements over PEPCO's previous efforts. Yet despite PSC approval, PEPCO has joined with OPC, Staff and DNR to further enhance its entire DSM investment portfolio.

Q: How does this relate to BG&E?

A: While there is much room for improvement and expansion of PEPCO's DSM programs, they are vastly superior to BG&E's. The fact that PEPCO has entered a collaborative process to further improve its own programs shows how far BG&E must progress before its DSM planning will become adequate.

Q: What magnitude of effort would constitute a major DSM effort for a utility the size of BG&E?

A: BG&E should expect to ramp up to spending three to five percent of its annual revenues on conservation, or roughly $65 million a year on DSM. BG&E should also assemble a plan in the short term (e.g., within a year) which would save 1% of 1990 sales each year, or roughly 248 GWH. Over the first 15 years of the program, BG&E should be looking for savings on the order of 33-50% of expected sales growth, or 3100 - 4700 GWH. Subsequent plans may well identify larger amounts of cost-effective DSM, so these targets should be considered as starting points.

5. SUGGESTIONS FOR SHORT-TERM PROGRAM PRIORITIES

Q: As BG&E ramps up its capabilities to deliver all cost-effective DSM services, are there any principles which might guide its prioritization of markets and programs?

A: Yes. BG&E should

- concentrate on capturing lost opportunities,
- concentrate on markets with naturally low levels of free riders,
- build capability in delivering comprehensive programs to large groups of customers, and
- improve the equity of service delivery.

Q: What markets would represent lost opportunities?

A: This category would include new construction, renovation, rehabilitation, routine replacement of appliances and equipment, and major changes in industrial equipment and processes.

Q: What types of markets would tend to have low levels of free riders?

A: These are markets with low current penetration of efficient technologies. For state-of-the-art equipment, design and systems, most markets appear to have low current penetrations. However, some sectors tend to be particularly slow to adopt even well-known and conventional improvements. These sectors tend to include government and non-profit entities (especially those with severe budget constraints), low income residential customers, and end uses for which the landlord supplies the equipment and the tenant pays the bills.

Q: Can you provide some examples of the kinds of programs that might be appropriate for BG&E?

A: Yes. For low-income residential, the most important opportunity might be a door-to-door delivery program emphasizing high-efficiency lighting. While they are in the house, the delivery staff can also offer minor tune-up and maintenance services on room air conditioners and refrigerators, and attach information to the refrigerator (which is probably owned by the landlord) on landlord-oriented efficient appliance incentives, to assist the tenant in securing prompt refrigerator replacement (at the time of failure) with an efficient unit. Targeted programs could also be designed to reach the low-income customers with water- and space-heating improvements. Most of these services should probably be delivered through local agencies and organizations, to reduce costs and improve communication and customer acceptance. The effectiveness and efficiency of the door-to-door program would probably be increased by coordinating with the gas division to deliver services specific to gas (e.g., water-heater insulation and water use reductions, space heating efficiency, range replacement programs) in the same visit. Michigan has recently committed to such a direct investment approach to residential efficiency with the Energy Fitness Program, patterned after the program pioneered by the City of Santa Monica.[26]

In the commercial class, the avoidance of lost opportunities argues strongly for a concentrated efforts on new-construction, renovation, and rehabilitation. These efforts would affect primarily lighting and (in new and rehabbed space) HVAC, with smaller effects on refrigeration and other end uses. Virtually all the utilities treated in Tables 4.1 and 4.2 place a high priority on such lost-opportunity resources; so does PEPCO.

Also in the commercial class, it would be appropriate to accelerate a public-sector institutional program, such as a comprehensive retrofit program for electrically-heated schools. As noted above, this is a group of customers that is likely to have seriously under-invested in efficiency, to have severe market barriers to further investment, and to impose significant costs on the public. As staffing allows, other government and institutional customers could be included in this program, which would be part of the ramp-up to comprehensive retrofit throughout the commercial class.

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[26] Kushler, et al, "Are High-Participation Residential Conservation Programs Still Feasible? The Santa Monica RCS Model Revisited", August, 1989 Conference Proceedings, Energy Program Evaluation: Conservation and Resource Management, Chicago, IL, pp. 365-371.

6. VALUING EXTERNALITIES IN LEAST-COST PLANNING

Q: Please clarify the term externalities.

A: The societal costs of power generation include many environmental and economic effects on humans and their environment. Many of these effects are not reflected in the cost of electric power, so they are termed "externalities." External environmental effects generally include impacts on humans and their environment, such as reductions in air and water quality, reduced enjoyment or loss of recreation, and increased risk of catastrophic accident. External economic effects we have identified so far include an oil import premium and employment effects. Chernick and Caverhill (1989) gives a general description of the types and origins of energy-related externalities (Section 1).

Q: How should environmental and other external effects of power plant construction and operation be reflected in utility planning?

A: The effects should be reflected in three ways. First, for effects which will be mitigated, BG&E should include reasonable estimates of the cost of mitigation. For example, the costs of complying with the proposed Clean Air Bill can be estimated and should be included in utility planning now to reflect the relative certainty that the Clean Air Act will be adopted in the next year or so. Second, for residual effects which will be internalized through taxes and fees, BG&E should include those internalized costs. For instance, such a tax might be required for carbon released in fossil fuel combustion. Third, for the residual effects which remain after mitigation efforts, and which will not be internalized, BG&E should include estimates of the social cost of these effects in the societal cost tests. The costs in the third category are truly externalities; the costs in the first two categories are simply projections of internalized costs.

6.1 Internal Cost Effects of Acid Rain Legislation

Q: What costs are likely to be internalized, beyond those traditionally included in utility cost projections?

A: The pending amendments to the Clean Air Act would internalize a number of costs, either by requiring reduction of emissions at the plant or by imposing tradable allowances.

Q: What is the likely effect of the pending acid rain bill on BG&E's internalized costs?

A: The most dramatic and immediate effect is the requirement of significant SO_2 emission reductions by 1995 at a number of plants serving BG&E. Among the units listed in the Senate clean air bill (S. 1630) are BG&E's Crane 1 and 2 and the jointly-owned Conemaugh 1 and 2.[27] These reductions will generally require addition of a scrubber or the conversion to low-sulphur coal.

Starting in 2000, all of BG&E's coal and oil units will have to purchase SO2 allowances, for emissions above a base level, which will generally be their emissions level in 1985.[28] If the units produce less than their allowed level,

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[27]The Senate bill also lists nine PP&L units: PP&L's share of Conemaugh, Brunner Island 1-3, Martins Creek 1-2, and Sunbury 3-4). Since BG&E is expecting to purchase between 42 and 226 MW of PP&L system power each year 1993-2000, increases in PP&L system costs may affect BG&E's costs.

[28]The base period may be 1985-87 for some units as outlined in Title IV, Sec. 402 of the Clean Air Act Amendments of 1990 (April 3, 1990 draft); the base calculation may also change in the final stages of the legislative process.

they will be able to sell the extra allowances to other utilities or independent power producers. Low-NO_x burners (which are not very expensive) will be required on tangentially-fired and dry bottom wall-fired (coal) boilers. NO_x control requirements for wet bottom wall-fired boilers, cyclones and all other types of utility boilers will be established by EPA, but they are unlikely to be much more expensive than the low-NO_x burners.

Q: What effect will the legislation have on the value of DSM for BG&E?

A: First, the 1995 requirements will tend to increase avoided costs. If the 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.[29] 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.

Second, the SO_2 emission trading program will increase BG&E's avoided costs. 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

[29] 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.

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 Title IV, Sec. 403(a), April 3, 1990 draft), the additional cost of 200 MWH of 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 details of the final legislation, on the demand (a function of new coal and oil-fired power plant construction, retirements and repowerings, and usage of existing units) and on the supply (a function of the cost of low-sulphur fuels and of emission control technologies). For the Administration bill, 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. The current legislation provides for the EPA to offer a small number of allowances each year at $1500 in 1990 dollars. 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. These values, or improved estimates as they become available, should be incorporated in BG&E's utility and societal cost tests.

6.2 Valuing Externalities

Q: The inclusion of internalized costs appears quite straightforward. How can the residual externalities be valued in comparing demand and supply options?

A: BG&E can, and should, include the value of externalities, either by directly estimating the cost to society, or by inferring that cost from the costs of required controls. These techniques are briefly outlined below and are discussed in Attachment 3 and Chernick and Caverhill (1989, 1990).[30]

In the first method, 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 has been attempted,[31] but suffers from several scientific uncertainties, including the similar and synergistic effects of pollutants, and societal value uncertainties, including the value of protecting a human life or an endangered species. With better information at all levels of the direct impact analysis, this is often cited as the preferred

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[30]The costs in these reports are sometimes expressed in terms of $/pound of sulphur and of carbon, and sometimes in terms of $/pound of SO_2 and of CO_2. The conversions are: $0.011/lb CO_2 = $0.04/lb C, and $0.88/lb SO_2 = $1.75/lb S. Care should be exercised in comparing the estimates in various sources.

[31]For instance Chernick and Caverhill (1989) and Ottinger, et al., 1990.

method of externalities valuation.[32] The difficulties associated with the use of this method are described in more detail in Chernick and Caverhill, (1989).

To date, we have identified only one case in which direct estimation is clearly preferable. That is for an economic externality, the oil import premium. Chernick and Caverhill, (1989) provides an estimate of the societal value of reducing our reliance on oil imports which is not currently reflected in the price of oil (Section 4).

The second method is concerned with developing the value to society of reducing an externality as it is implied in current regulations. For instance, if the Clean Air Act requires 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. Attachment 3 gives a concise overview of the implied valuation approach, and Chernick and Caverhill (1989, 1990) provide additional detail and apply this method.

Q: Please describe the rationale behind the implied valuation approach.

A: The marginal cost of pollution control, or the implied value of an externality, is sometimes described as if it were a proxy for the cost of emissions. In fact, the costs of

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

controls can be thought of as providing direct information on the societal value of emission reductions, under either of two theoretical approaches.

First, the cost of the required controls provides an estimate of the price that society is willing to pay to reduce the pollutant. If legislators and regulators require measures that cost as much as $2/lb to reduce sulfur emissions, it seems reasonable to assume that reducing emissions from those sources must be worth at least $2/lb, and that reductions from other sources (as by conservation or fuel choice) must also be worth $2/lb. This is the rationale behind the "revealed preference" approach to the use of control costs for valuing externalities.

Second, the costs of required controls may directly establish the social benefits of reducing emissions, to the extent that they define the direct pollution-control costs that can be avoided by an exogenous reduction in emissions. If the objective of environmental regulation is to maintain a given level of ambient air quality, the construction of a less polluting plant, or the reduction in output requirements due to conservation, will allow regulators to back down from the most expensive control measures that would otherwise have been required.

Society has demonstrated through regulation that it is willing to pay substantially to reduce externalities. Historically, the primary motive behind many regulations was the health impacts of certain pollutants. More recent provisions protect the natural environment as well as public health. The current debate on the Clean Air Bill is an excellent example of how our national society weighs the costs of the required measures under the regulations against the targeted reduction in air emissions, an important externality. From analysis of the Clean Air Bill, its costs and the reductions in air emissions which will be realized, we can gain a sense of the "implied social value" of the remaining emissions of precursors to ozone, acid rain and air toxics emissions on a national level.

Regulations at all levels of government contribute to our knowledge of the social value of reducing emissions or other externalities. The method of using regulations to estimate the value of an externality is concisely presented in Attachment 3. Basically, the costs of the control equipment or measures that are explicitly or effectively required by a regulation can be divided by the incremental reduction of the targeted externality to estimate a cost per unit of externality reduced. For example, if we take the incremental cost of an SO_2 scrubber, and divide it by the incremental emissions reduction received by the installation of that scrubber, then we have an estimate of the cost/lb of reducing emissions of SO_2 using this technology. If society adopts the installation of SO_2 scrubbers into law, or adopts emissions targets which effectively require SO_2 scrubbers, then the implied social value of reducing SO_2 emissions is greater than or equal to the cost of the scrubber.

Since we are interested in the value of reducing the next unit of the externality, we look at the marginal costs and reductions implied in the regulations, as explained in Attachment 3.

Chernick and Caverhill, 1990 updates the figures provided Chernick and Caverhill, 1989 (principally NO_x) and estimates values for additional externalities for use in Massachusetts, including N_2O, CO, VOCs, particulates, and a preliminary figure for water use. The application of these figures to Baltimore will be explained below.

The marginal societal value of a particular externality can vary nationally, regionally and locally, just as regulations vary. For instance, some regulations governing NO_x and VOC emissions vary depending on whether the area is in attainment of the national ozone standard. The implication is that the value of reducing emissions of those pollutants is higher in certain areas because of unacceptable local air quality. Therefore, more stringent control requirements must be met, which require more expensive controls. Clearly, the value of ozone reductions in non-attainment areas is higher, at least from a public health standpoint, than in attainment areas. However, even for areas that have excellent air quality, the value of avoiding additional emissions of air pollutants, through energy conservation or other clean technologies, is still reflected by the marginal cost of control to the extent that this control cost will be avoided.

For this reason, estimates of the value of local and regional externalities derived for New England, New York, California, or any other region may not translate directly into estimates meaningful for the Maryland and D.C. region. Certainly, the values may even vary within the states. However, we can use these estimates as valuable starting points for our discussion of Maryland and D.C. regional externalities.

We should note that other methods of estimating externalities have been attempted. Attachment 3 provides an overview of four estimation techniques, their applicability, and their limitations. In our experience, the cost-of-control or implied-valuation approach has been the most tractable.

Q: How does this analysis apply to BG&E?

A: Baltimore has considerable local air quality problems indicated by violations of the federal ambient air quality standards. Baltimore is a severe non-attainment area for ozone. The primary ozone precursors are NO_x and VOCs, both of which are emitted by fossil fuel-fired power plants.[33]

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[33]Power plants are much more important contributors to NO_x emissions than VOC emissions.

Other pollutants emitted by fossil fuel-fired power plants include particulates, carbon monoxide and air toxics. Baltimore County occasionally exceeds the the annual primary guideline for ambient levels of particulate matter. Clearly, the reduction of emissions of these pollutants has considerable health and visibility benefits to residents of Baltimore, and residents of Maryland and D.C. in general. These benefits extend beyond simply meeting the federal standards. Their values can be estimated from several existing sources and from the new Clean Air Bill.

Baltimore power plants also have externalities which have regional or global importance. Emissions of SO_2 and NO_x not only have local air quality impacts, but also contribute to acid precipitation in the Northeast. Greenhouse gas emissions from fossil fuel combustion are globally important. They include CO_2, methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO) and nitrogen oxides (NO_x) (as a global ozone precursor).

Many of the air quality problems experienced in Maryland and surrounding areas are similar to those in other areas where significant work has been done on externalities valuation. These areas include New England (specifically Massachusetts), New York and California, as mentioned above. This work is an useful start for externalities valuation for BG&E.

Q: Based on your analysis of externalities in other similar jurisdictions, what are the major externalities important to BG&E's service territory?

A: There are at least three important air emissions that have significant external costs. These are: SO_2, because of its contribution to acid rain and acid aerosols; NO_x, because of its contribution to acid rain, smog, ozone and global warming; and CO_2, because of its contribution to the greenhouse effect. Any analysis of externalities in the BG&E service territory must include at least these three air emissions.

Q: What does the proposed federal clean air bill imply about the value of reducing these externalities?

A: We have conducted a preliminary review of the provisions in the Senate bill as they relate to Baltimore. Some explicit estimates of the average cost per pound of pollutant reduced ($/lb) are provided in the text of the Senate Committee Report, which we discuss below. These estimates further illustrate the significant value of residual emissions of the pollutants addressed. However, they are not estimates of the marginal cost of reducing emissions. In order to estimate the marginal cost, the marginal control measure for each of the pollutants covered under the bill must be identified and its cost/lb of pollutant reduced estimated. We have not performed this analysis here.

Sections of the Senate version of the bill that are particularly relevant to externalities valuation are Titles I to IV, which deal with the topics of ambient air quality standards, mobile source controls, air toxics, and acid deposition control. The estimates we review here were published in the Senate Committee Report (SCR), or were adapted from consultants reports on the costs of specific provisions of the Clean Air Bill. Generally, the estimates taken from the Senate Committee Report reflect the average cost of meeting the regulation, and do not reflect the cost of the marginal control measure required. Therefore, these figures are likely to be understated for use in externalities valuation. On the other hand, the estimates presented still demonstrate a high social value of reducing many major air pollutants and acid rain precursors.

Q: What values for the acid rain precursors SO_2 and NO_x does the clean air bill provide?

A: The costs of the acid rain legislation of the Clean Air Bill, adapted from several analyses prepared by Temple, Barker and Sloane (TBS) for the Edison Electric Institute and an analysis prepared by ICF Resources for the EPA, are provided in Chernick and Caverhill, 1989 (Section 6.1.1). The implied value for SO_2, estimated from the analysis of the incremental costs of moving from one program to the next most stringent one, falls in the range \$1.26 to \$2.57/lb S, or \$0.63 to \$1.29/lb SO_2 (Chernick and Caverhill, 1989, Table 6.1.1).

For SO_2 and NO_x (as acid rain precursors) there is to be a \$2000/ton (\$1.00/lb) penalty, plus offsetting requirements, for emissions above the allowable limit. The cost of this provision for emissions that are not offset would be even higher.

ICF Resources performed an analysis of EPA's WEPCO and Greenwood decisions to assess their cost, environmental and energy implications.[34] In the two cases, the EPA held that modifications to the facilities triggered the application of federal prevention of significant deterioration (PSD) requirements. The EPA indicated that it will determine the applicability of the WEPCO and Greenwood cases to specific power plants on a case by case basis. ICF analyzed several cases for different numbers of power plants that would be affected by these two decisions. ICF apparently used the same model and assumptions in this analysis as it did in its work for the USEPA in the analysis of the Administration's acid rain legislation proposals.

The ICF cases we reviewed include the adoption of the Acid Rain Bill in the base case. For the low impact case, which refers to the number of affected facilities, the

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[34] ICF Resources Incorporated, "Analysis of the Potential Cost, Environmental and Energy Implications of EPA's Recent WEPCO and Greenwood Decisions." Prepared for the Utility Air Regulatory Group, January, 1990.

implied cost for acid rain precursors fall in the range \$2,436/ton to \$13,500/ton. For the high impact case, the implied cost for the acid rain precursors is in the range \$2,345/ton to \$16,287/ton. Simply averaging the eight estimates provided by ICF, we get an implied value of \$9,734/ton, or \$4.87/lb for the acid rain precursors. This calculation assumes that the reduction of NO_x and SO_2 have the same value per lb. If the entire cost was assigned to the NO_x reductions, which make up the largest portion of the reduced emissions, then the implied value for NO_x would be somewhat higher. Therefore, this analysis suggests a marginal value of reducing acid rain precursors in the range of \$1.00-\$5.00. Finally, this estimate for NO_x does not necessarily reflect its contribution to ground-level ozone.

Q: What is the value of reducing the greenhouse gas CO_2?

A: The value of greenhouse gas emissions cannot be estimated in the same way the local or regional pollutants can, because of the lack of current regulation of greenhouse gases. However, many estimates exist for the costs of various greenhouse mitigation strategies. Mitigation strategies include improving energy efficiency, reducing global deforestation, carbon sequestration through tree planting, and CO_2 scrubbers. The costs of the latter two mitigation strategies are discussed in Chernick and Caverhill, 1989 (Section 7).

Since greenhouse gas emissions contribute to a global problem, it is appropriate to import values of greenhouse gases from other sources. Chernick and Caverhill (1989) develops a range of costs for carbon sequestration through tree planting (Section 7.1.2). From this range of about \$0.02-0.10/lb C sequestered (Table 7.1.3), we can estimate an implied value of reducing CO_2 emissions. In Chernick and Caverhill (1989), we recommend the use of \$.04/lb C, or \$0.011/lb CO_2, a lower value in the range, to reflect uncertainty in finding the marginal sequestration effort which will be required to stabilize the global climate.

Q: What values of externalities would you recommend using in BG&E supply planning at this point?

A: We suggest the following values for evaluating major utility air emissions:

CO_2	\$0.011 per pound
SO_2	\$0.88 per pound
NO_x	\$2.00 per pound

As discussed above, the CO_2 and SO_2 values are derived in Chernick and Caverhill (1989). The NO_x value is at the conservative (low) end of the range \$1.50-\$5.00/lb No_x implied by the ICF analysis for the Greenwood and WEPCO decisions, and is also lower than the marginal cost of selective catalytic reduction (SCR) control as estimated in Chernick and Caverhill (1990).

To these major pollutants should be added estimates of the values of other air emissions, water consumption, oil spills, the economic externality of oil imports, and other external impacts. However, the three air emissions enumerated above are likely to comprise a large portion of the value of the externalities associated with BG&E's marginal generation.

Q: Have any regulatory jurisdictions adopted values similar to those you propose above?

A: Yes. The California Energy Commission, in evaluating resource options for Southern California Edison, uses a rather low value for CO_2 of $0.0035/lb; a value for SO_2, at $5.75/lb, that is much higher than ours; and a slightly higher NO_x value, at $2.95/lb.[35] The Massachusetts Department of Public Utilities has recently adopted values which are identical or very similar to ours: $0.011 for CO_2, $0.75 for SO_2, and $3.25 for NO_x.[36]

Q: On what basis did the Massachusetts DPU base its decision to monetize externalities?

A: Attachment 3 outlines the reasons for explicitly monetizing externalities. The Massachusetts DPU cited similar reasons.

Q: How did the Massachusetts DPU choose externality values?

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[35] State of California Energy Resources Conservation and Development Commission, <u>Committee Order for Final Policy Analysis</u>, Docket 88-ER-8, March, 1990.

[36] Massachusetts Department of Public Utilities, Order in Docket 89-239, August 31, 1990.

A: Once the DPU had adopted the concept of implied valuation, it chose estimates of the marginal cost of abatement presented by intervenors (the Massachusetts Division of Energy Resources (DOER)) in the docket 89-239, that blended the estimates of independent consultants (including some developed by Resource Insight).

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

A: At emission rates of 1 lb SO_2, 0.7 lb NO_x, and 210 lb CO_2 per MMBTU, the total externality for a low-sulfur coal plant would be about $4.60 per MMBTU or (at 10,000 BTU/kWh) 4.6 cents per kWh. At emission rates of 1 lb SO_2, 0.4 lb NO_x, and 170 lb CO_2 per MMBTU, the total externality for an oil-fired steam plant would be $3.55 per MMBTU or (at 10,000 BTU/kWh) 3.6 cents per kWh. A combined-cycle plant, burning gas for 9 months and 0.3% S #2 oil for 3 months, with emissions of 0.04 lb SO_2, 0.08 lb NO_x and 123 lb CO_2 per MMBTU,[37] would have a total externality value of $1.54 per MMBTU or (at 8,500 BTU/kWh) 1.3 cents per kWh.

Further analysis is likely to support higher values for these three air pollutants, especially for NO_x, and the additional externalities will also add to the value. On the other hand, acid-rain controls are likely to reduce the

[37]We assume a 65% reduction in NO_x emissions from steam injection, based on the Plan's description of the Perryman plant. It is possible that BG&E's steam injection proposal would not be this effective.

emission rates, and much of the SO_2 cost will be internalized starting in 2000. As BG&E conservation starts to displace not just the energy from existing power plants, but the construction of cleaner new power plants (in the late 1990s on other utility systems or about 2005 on BG&E's own system), the avoided externalities will tend to decline, as demonstrated by the difference between the environmental externalities of the existing oil and coal plants, and the new combined-cycle plants.

7. **CONCLUSIONS**

Q: Please summarize your conclusions with regard to BG&E's Least-Cost Plan.

A: BG&E has not properly analyzed DSM potential or economics. BG&E should prepare a plan for identifying and capturing all conservation which passes the societal cost test, including the effects of off-system sales and externalities. In evaluating programs and measures, BG&E should compare the cost of an option to its lifetime benefits. BG&E should orient its plan around market sectors, and the elimination of market barriers.

BG&E should capture all cost-effective lost-opportunity DSM as soon as administratively feasible, should promptly implement large-scale capability-building programs concentrating on disadvantaged and vulnerable customer groups, and should ramp up to full implementation of all cost-effective programs in time to allow profitable long-term off-system sales and to avoid capacity additions.

Q: Should such action be ordered by this Commission?

A: Absolutely. The Commission should require that BG&E immediately begin readying demand-side options in time to compare and compete with the supply it would otherwise acquire over the next decade. Otherwise, BG&E places the Commission in the untenable position of either approving sub-optimal resource plans or compromising service reliability. Serious penalties would be warranted for such egregious management failure.

Q: Have other regulators made adequate utility investment in demand-side resources a prerequisite for permission to proceed with, or recover costs of supply side investments?

A: Yes. Both the Wisconsin PSC and the Vermont PSB require that utilities demonstrate that they have exhausted all reasonably available least-cost resources before committing to new supply or recovering costs thereof. Both regulatory bodies have concluded that failure to fully develop demand-side resources as viable supply-side alternatives can, in and of itself, lead to denial of regulatory approval for specific supply acquisition or rate recovery. The Wisconsin Commission explained the ramifications of a utility's obligation to pursue demand-side resources in these terms:

> Failure to implement cost-effective conservation programs in a timely way can lead to situations in which the only feasible resource to meet near-term load is new generating capacity which is more costly than the conservation programs would have been ... A utility which makes choices that put it and the commission in the position of having to choose either to degrade service or approve construction can expect to have the prudence of the costs of the construction reviewed by the commission in the light of the conservation options it should reasonably have pursued, considering the identified cost-effective conservation potential in the utility's service territory. (Findings of Fact, Conclusion of Law and Order in Docket 05-EP-5, April 9, 1989, at 37)

Q: Please specify how the Commission should require BG&E to prepare demand-side options.

A: The Commission should direct BG&E to immediately initiate efficiency investments in accord with the principles set forth above. These efforts should be comprehensive, as that term is defined and illustrated above. They should seek to develop long-lasting capability to deliver and integrate demand-side resources into the Company's resource planning. In particular, BG&E should target lost-opportunities arising in new construction and in equipment replacement.

The specific details of how BG&E should accomplish these objectives are beyond the scope of this testimony. The responsibility for devising and executing these actions should rest with the Company; however, as I testify below, it would be to BG&E's advantage to enlist the expertise and creativity of other parties. Moreover, while it is beyond my scope to provide a "laundry list" of programs and targets for BG&E to pursue, I can recommend a specific range of expenditures as well as practical guidelines for achieving these objectives.

Q: How much should BG&E spend now to pursue demand-side resources?

A: BG&E should be prepared to commit between $48 million and $80 million annually over the next two years. Subsequent budget levels would depend on the success of these initial efforts and the Company's resource needs.

Q: Please explain how you arrived at this range.

A: Based on the range of conservation expenditures shown in Table 4.2, we feel that a utility commited to DSM should be spending between 3% and 5% of its electric revenues on conservation. The Energy Information Administration's Financial Statistics of Selected Electric Utilities, 1988 gives BG&E's 1988 electric revenues as $1,425,687,267. In projecting this figure to 1990, an inflation rate of 4% and a growth rate of 2% are assumed. The projected 1990 revenues are $1,604,321,000. $48 million represents 3% of this revenue figure, and $80 million represents 5%.

Q: Does this conclude your testimony?

A: Yes.

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