Issues in Evaluating Demand-Side Management Programs in the Least Cost Planning Process

by

Grace Hu, Ph.D.
Public Service Commission of District of Columbia[1]

In recent years, various methods and tests have appeared in the literature for screening demand-side management (DSM) programs to determine their cost-effectiveness. Two widely used tests are the All-Ratepayers Test and the No-Losers Test. Different state commissions have different regulations and emphases on these program screening tests.

The purpose of this paper is to discuss (a) the long-term, short-term rate and bill impacts and the cost-effectiveness of utilities' energy efficiency programs; and (b) marginal cost and program screening in an integrated least cost planning framework. Specifically, there are six sub-issues this paper discusses: (1) link the bill impact and rate impact with the cost-effectiveness tests; (2) identify the relationship between size of the conservation program and the (i) rate impact and (ii) bill impact; (3) link the rebate level determination with bill impact; (4) provide static and dynamic conditions under which a program will have negative rate impact or bill impact; (5) provide examples from DC utilities to illustrate the differences in results of rate impact test for electric and gas companies; and (6) marginal cost and program screening.

Size of the Conservation Programs and Rate Impacts

In 1986, Ann Bachman and Paul Chernick presented a paper "Assessing Conservation Program Cost-Effectiveness, Participants, Non-participants and the Utility System" at the BRIC conference. They argued the rate impact of a DSM program will be negative if the unit cost of conservation is smaller than the product of (a) the difference between marginal cost and average costs and (b) the ratio of baseload with conservation over baseload without conservation.

One of their conclusions is that a large conservation program is more likely to increase average unit costs than is a small program, even if the costs of conservation and the displaced energy do not vary between the two programs. (See Appendix A for their model and final inequality.)

However, their conclusion can be reversed through a dynamic example. Tables 1 and 2 in Appendix B illustrate why this is the

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1 The views and opinions of the author do not necessarily state or reflect the views, opinions or policies of the District of Columbia Public Service Commission (DCPSC) or Staff of DCPSC.

case. This example shows the higher the amount of conservation, the greater the favorable rate impact. The rate impact turns negative in an earlier year only under relatively high levels of conservation. The reason why Bachman and Chernick's conclusion does not apply is because when they developed their final inequality, they rearranged the terms for simplification. In so doing, they overlooked the fact that the terms have been rearranged to derive the final condition. Therefore, one can use the final inequality to determine the sign of the rate impact, but not the size of the rate impact.

In other words, as described in Appendix A, the rate impact is determined by cost of service per kwh after implementation of conservation programs minus cost of service per kwh under growth without conservation (S_c-S_g), which is not equal to or measured by:

$$P_c - (P_g-P_b) * Q_b / (Q_b+Q_g)$$

where P_c is average cost of conservation, P_g is incremental cost of supply, P_b is the base average cost, Q_b is the baseload kilowatthour sales, and Q_g is kilowatthour growth without conservation.

In fact, the rate impact is not a key concern from the customers' perspective. Most people do not know their electric rate per kwh. From a customer's perspective, it is more important to see the bill comes down. In this way, the effect of conservation may exceed the impact of rate increases and lead to lower customer bills. So the question is when a program will create a negative bill impact, rather than a negative rate impact.

Bill Impact -- Static and Dynamic Conditions

The static and dynamic conditions for a negative bill impact are different from those for a negative rate impact. The static and dynamic conditions are derived and included in Appendix C. The size of the bill impact is determined by the amount of conservation times the difference between the incremental cost of production minus the cost of conservation, then divided by number of customers. Therefore, the amount of conservation is proportional to the size of the bill impact. In a dynamic sense, the time when the bill impact turns negative is mainly influenced by the unit cost of conservation and the marginal cost of production. The larger the incremental cost of supply, the earlier the favorable bill impact will occur. Conversely, the larger the unit cost of conservation, the later the favorable bill impact will show up. Unlike the rate impact, the amount of conservation will not influence the time when the bill impact turns negative in this case. Tables 1 and 2 in Appendix B show as the amount of conservation is cut into half, the bill impact will also be reduced to half. The bill impact is proportional to amount of conservation.

Cost-Effectiveness Tests

In general, two tests are used to screen DSM programs -- the All-Ratepayers Test and No Losers Test. On the cost side, the major difference between these two tests is the No-Losers Test treats revenue loss from reduced sales and program rebates as cost items, while the All-Ratepayers Test does not include these items as costs. Therefore, in general, the benefit cost ratio from the No-losers Test is smaller than from All-Ratepayers Test for the same program.

In addition, there are two versions of the All-Ratepayers Test. One was adopted by the California Public Service Commission and the other adopted by Maine Public Service Commission. In the Maine version, the participant avoided cost for alternate fuel devices is not counted as a benefit of the program, whereas in the California version, savings from alternate fuel are counted as a benefit of a program.

The No-Losers Test is also called the Rate Impact Test or Non-Participant Test. This test compares the revenue requirements per kwh before and after implementation of the program. A program which passes the No-Losers Test definitely has a negative bill impact. A program which does not pass the Non-participant Test may not have a negative bill impact.

Bill Impacts and Rebate Level Determination

To determine the rebate level of a DSM program, two approaches are often used:

(a) the Utility Avoided Cost Method, and
(b) the Customer Payback Method.

The Customer Payback Approach chooses the rebate which is sufficient to make an energy-efficient option attractive to the customer to make the investment.

The Utility Avoided Cost Approach calculates the utility's rebate level based on the value of the savings in KWs and Kwhs from the installation of the end-use option. The maximum rebate that would be considered under this approach is equal to the utility's avoided cost for the energy saved by the option. This result is because the unit cost of conservation (P_c) must be less than the incremental cost (P_g) to reach the negative bill impact. Part of the conservation cost is the program rebate. Therefore, the rebate level should not exceed the marginal cost to maintain a negative bill impact.

Empirical Examples

The District of Columbia Public Service Commission regulates two energy utilities: the Potomac Electric Power Company (PEPCO) and Washington Gas (WG). Based on the conditions discussed above, in general, the electric utility will have either a positive or negative rate impact because its marginal cost is greater than average cost. See Table 3 on page 1 of Appendix D. This table indicates for programs passing the All-Ratepayers Test, the benefit/cost ratios in the No-Losers Test may be greater than one (negative rate impact) or less than one (positive rate impact).

However, for the gas local distribution companies (LDCs), in general, its rate impacts are positive. This is because its marginal cost is less than average cost. As a result, almost all the programs in Washington Gas have failed the No-Losers Test or Rate Impact Test.

Therefore, the more gas the customer uses, the lower rate he pays. Because of the implementation of conservation programs, the customers will use less but pay a higher rate. But the customer's bill will be reduced in the long-term as a result of implementation of cost-effective DSM programs. See page 2 of Appendix D.

Different state commissions vary by their emphasis on benefit cost tests used for program screening. In the District of Columbia, the All-Ratepayers Test (Maine version) was adopted in DSM program screening. However, the utilities are allowed to perform the Non-Participant Test to test the rate impact of the program. In the State of Maine, both the All-Ratepayers Test and Non-participant Test are required for program screening. A rate impact greater than 1% is considered having significant adverse rate impact. In Maine, any program reasonably likely to satisfy the All-Ratepayers Test and to fail the Rate Impact Test, but not reasonably likely to have a significant adverse rate impact, may be continued or implemented without Commission approval. The Maryland Public Service Commission mainly employs the All-Ratepayers Test for the initial cost-benefit screening of demand-side conservation programs. However, programs passing the All-Ratepayers Test but failing the Rate Impact Test are subject to further evaluation before implementation.

Marginal Cost and Program Screening

In the least cost planning process, marginal costs are used to evaluate both supply-side and demand-side options. Marginal cost plays a key role in both supply-side build vs. buy decision making and demand-side DSM program screening. In program screening, marginal costs are used to evaluate program benefits or program savings. There are lots of marginal cost related issues in program screening.

The first issue is which type of marginal cost to use in program screening. Some suggest we should use marginal energy cost, marginal capacity cost, marginal transmission cost, marginal subtransmission cost and marginal primary distribution cost in program screening. However, it is under great debate whether the marginal secondary distribution costs should be used for program screening. Others maintain that the reduction in energy consumption will occur when peak demand is being experienced on individual elements of the secondary distribution system. Therefore, marginal secondary distribution costs should be used in program screening. The opposing side argues the cost savings on secondary distribution are highly uncertain and speculative.

The second issue is the selection and determination of the level of load forecast. The load forecast is a key determinant of marginal costs. The amount of savings from DSM programs, the gross load forecast and the load decrement; all of these will influence the level of load forecast used for calculating marginal costs. Some argue a higher load forecast should be used to compute marginal costs to screen demand-side programs. And lower load forecasts should be employed for estimating marginal costs used to evaluate supply-side options. The reason is that only when utilities exhaust demand side resources will they consider supply-side resources.

The third issue is marginal costs estimated at different points of time have different values. The model used to estimate marginal costs has different input values at different points of time. For example, if this year's marginal costs are lower than those for last year, a program which passed the All-Ratepayers Test last year may no longer have a B/C ratio greater than one this year. This is because its estimated benefit decreases as a result of lower marginal cost. Then, the policy issue is "Should this program be continued?"

Furthermore, an overestimation of marginal costs may lead to adding some programs which are not cost effective. Underestimation of marginal costs will deflate program benefits and therefore screen-out cost-effective programs. Either underestimation or overestimation of marginal cost will lead to high cost or revenue requirements. This violates the least cost principle. So the key issue of program screening is not only which test to consider, but also whether one's marginal cost estimate is accurate or not.

In addition, programs with Benefit/Cost ratios close to one will be more sensitive to changes in marginal cost estimates. If a utility has very few "marginal" programs (programs with B/C ratio close to one), the effect of a biased marginal cost will be relatively small.

On the other side of the equation, program screening involves estimating the energy and demand savings. Should we use econometric savings estimate or engineering savings estimate? Therefore, the determination of savings estimates is another issue in program screening. Either overestimating or underestimating savings will lead to biased B/C ratio.

To summarize, program screening is influenced by many factors -- the accuracy of marginal cost, the accuracy of program savings, the forecasted number of participants, program saturation, and the selection and use of cost-effectiveness test. All of these will influence the results of DSM program screening. It is essential to consider all these factors to achieve the objective of using electricity more efficiently and lowering customers' bills.

Appendix A

Ann Bachman and Paul Chernick's final inequality

Assuming: Q_b = Baseload Kilowatthour Sales

Q_g = Kilowatthour growth without conservation

C_b = Cost of Service for Q_b

C_g = Incremental Cost of Supplying Q_g

C_c = Cost of avoiding Q_g growth through Conservation

P_b = Base average cost = C_b/Q_b

P_g = Average Cost of Serving growth = C_g/Q_g

P_c = Average Cost of conservation = C_c/Q_g

S_g = Average cost of service after growth or revenue requirement per kwh

S_c = Average cost of service after conservation or revenue requirement per kwh

If the DSM program will reduce rate, then S_c will be smaller than S_g. Where $S_g = (C_b + C_g) / (Q_b+Q_g)$, and $S_c = (C_b+C_c) / Q_b$.

Static Condition for negative rate impact:

$$P_c < (P_g - P_b) * Q_b / (Q_b+Q_g)$$

"Negative" rate impact means conservation programs will reduce rates. This inequality states that in order to have negative rate impact, unit cost of conservation must be smaller than the difference between marginal cost and average cost times the ratio of baseload with conservation programs over baseload without conservation programs.

Appendix B - A Counter-example

This example indicates the higher the amount of conservation, the larger the negative rate impact.

In this example, the unit cost of consumption Pc is not a constant along the forecasting horizon. Assuming $C_c = a + b X$. X = No. of participants. Where a is the fixed costs and b is the variable costs. As more and more people join the program along the forecasting horizon, the average cost of conservation will decrease as time advances. Table 1 assumes higher conservation reduction and Table 2 assumes the amount of savings from conservation programs has been reduced to half.

In this simulation, I have assumed: (a) Marginal cost increases slowly along the forecasting horizon; (b) The amount of saving is increasing along the forecasting horizon; and (c) Either programs have high fixed costs or most programs start from roughly the same time, the beginning of forecasting horizon; therefore, the conservation cost per kwh is decreasing along the forecasting horizon.

Because of learning effect and because more and more participants join the program as time goes by, the cumulative conservation effect is increasing. The rate impact turns negative in year 9 or year 2000 in this instance assuming our forecasting horizon is 1992-2006. Suppose we cut the amount of conservation, according to Bachman and Chernick (1986), the average rates will be lower. But actually average rates are higher from 2000 to 2006 as a result of lower amount of conservation (See Table 2). So their conclusion can be reversed easily.

In other words, based on Table 1 and Table 2, Table 1 represents the case where the savings from conservation is higher and Table 2 assumes half of the savings. In Table 1, the rates after implementation of conservation programs are lower compared to those in Table 2 for year 2000 to 2006. (This can be seen more easily when more decimal places are printed out.) Comparing Table 1 with Table 2, we found when the saving is reduced to half, the first year when rate impact turns negative changes from year 9 (year 2000) to year 13 (year 2004). So the amount of conservation will influence the time when the rate impact turns negative.

It should be noted this example is hypothetical. It does not reflect actual cost or load of any utility. We can see that the bill impact is negative because the incremental cost is greater than cost of conservation for all the 15-years in the forecasting horizon. In addition, when the savings are reduced to half, the bill impact is also cut into half.

Table 1
Higher Conservation Reduction -- Rate Impact and Bill Impact

Year	Load Growth w/o DSM Gwh (1)	No. of Customers (2)	Cons. per customers (3)	Incre. Cost $/kwh (4)	System Total Cost Mill. $ (5)	Average Cost $/kwh (6)	Average Bill (7)	Reduction from Conservation Gwh (8)	Unit Cost of Conservation $/kwh (9)	Total Cost Mill. $ (10)	System Load After Conservation Gwh (11)	per cust. cons. (12)	Prod. Cost Mill. $ (13)	Total Cost Mill. $ (14)	Average Rate $/kwh (15)	Total Bill (16)	Rate Impact $/kwh (17)	Bill Impact (18)
1992	1500.000	193.000	7.772	0.130	181.000	0.121	0.938	8.000	0.090	0.720	1492.000	7.731	179.960	180.680	0.121	0.936	0.000	-0.002
1993	1515.000	194.000	7.809	0.130	182.950	0.121	0.943	10.000	0.080	0.800	1505.000	7.758	181.650	182.450	0.121	0.940	0.000	-0.003
1994	1530.150	195.000	7.847	0.130	184.919	0.121	0.948	12.500	0.060	0.750	1517.650	7.783	183.294	184.044	0.121	0.944	0.000	-0.004
1995	1545.452	196.000	7.885	0.140	188.363	0.122	0.961	15.625	0.060	0.938	1529.827	7.805	186.176	187.113	0.122	0.955	0.000	-0.006
1996	1560.906	197.000	7.923	0.140	190.527	0.122	0.967	19.531	0.050	0.977	1541.375	7.824	187.792	188.769	0.122	0.958	0.000	-0.009
1997	1576.515	198.000	7.962	0.150	194.477	0.123	0.982	24.414	0.040	0.977	1552.101	7.839	190.815	191.792	0.124	0.969	0.000	-0.014
1998	1592.280	199.000	8.001	0.150	196.842	0.124	0.989	30.518	0.030	0.916	1561.763	7.848	192.264	193.180	0.124	0.971	0.000	-0.018
1999	1608.203	200.000	8.041	0.150	199.230	0.124	0.996	38.147	0.030	1.144	1570.056	7.850	193.508	194.653	0.124	0.973	0.000	-0.023
2000	1624.285	201.000	8.081	0.160	203.886	0.126	1.014	47.684	0.020	0.954	1576.601	7.844	196.256	197.210	0.125	0.981	-0.000	-0.033
2001	1640.528	202.000	8.121	0.160	206.484	0.126	1.022	59.605	0.020	1.192	1580.923	7.826	196.948	198.140	0.125	0.981	-0.001	-0.041
2002	1656.933	203.000	8.162	0.160	209.109	0.126	1.030	74.506	0.020	1.490	1582.427	7.795	197.188	198.678	0.126	0.979	-0.001	-0.051
2003	1673.503	204.000	8.203	0.160	211.760	0.127	1.038	93.132	0.020	1.863	1580.370	7.747	196.859	198.722	0.126	0.974	-0.001	-0.064
2004	1690.238	205.000	8.245	0.160	214.438	0.127	1.046	116.415	0.010	1.164	1573.822	7.677	195.812	196.976	0.125	0.961	-0.002	-0.085
2005	1707.140	206.000	8.287	0.160	217.142	0.127	1.054	145.519	0.010	1.455	1561.621	7.581	193.859	195.315	0.125	0.948	-0.002	-0.106
2006	1724.211	207.000	8.330	0.160	219.874	0.128	1.062	180.000	0.010	1.800	1544.211	7.460	191.074	192.874	0.125	0.932	-0.003	-0.130
																	T=9	T=1

Assumption: 168 million dollars including 1400 Gwh of production cost

Note: (3)=(1)/(2)
(5)= 168 + ((1)-1400) * (4)
(6) = (5)/(1)
(7)= (5)/(2)
(10)= (8)*(9)
(11)=(1)-(8)
(12)=(11)/(2)
(13)=168 + ((11)-1400)* (4)
(14)=(13)+(10)
(15)=(14)/(11)
(16)=(12)*(15)
(17)=(15)-(6)
(18)=(16)-(7)

Table 2
Half of the Savings from Conservation
Rate Impact and Bill Impact

year	Load Growth W/o DSM Gwh	No. of Customers	Cons. per cust.	Incre. Cost $/kwh	System Total Cost Mill. $	Average Cost $/kwh	Average Bill	Conservation Reduction Gwh	Unit Cost of Conservation $/kwh	Total Cost Conservation Thous $	System Load After Conservation Gwh	Cons. per Cust.	Total Cost Mill $	Average Rate $/kwh	Rate Impact	Average Bill	Bill Differences
	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1992	1500.000	193.000	7.772	0.130	181.000	0.121	0.938	4.000	0.090	0.360	1496.000	7.751	180.840	0.121	0.000	0.937	-0.001
1993	1515.000	194.000	7.809	0.130	182.950	0.121	0.943	5.000	0.080	0.400	1510.000	7.784	182.700	0.121	0.000	0.942	-0.001
1994	1530.150	195.000	7.847	0.130	184.919	0.121	0.948	6.250	0.060	0.375	1523.900	7.815	184.482	0.121	0.000	0.946	-0.002
1995	1545.452	196.000	7.885	0.140	188.363	0.122	0.961	7.813	0.060	0.469	1537.639	7.845	187.738	0.122	0.000	0.958	-0.003
1996	1560.906	197.000	7.923	0.140	190.527	0.122	0.967	9.766	0.050	0.488	1551.140	7.874	189.648	0.122	0.000	0.963	-0.004
1997	1576.515	198.000	7.962	0.150	194.477	0.123	0.982	12.207	0.040	0.488	1564.308	7.901	193.134	0.123	0.000	0.975	-0.007
1998	1592.280	199.000	8.001	0.150	196.842	0.124	0.989	15.259	0.030	0.458	1577.021	7.925	195.011	0.124	0.000	0.980	-0.009
1999	1608.203	200.000	8.041	0.150	199.230	0.124	0.996	19.073	0.030	0.572	1589.130	7.946	196.942	0.124	0.000	0.985	-0.011
2000	1624.285	201.000	8.081	0.160	203.886	0.126	1.014	23.842	0.020	0.477	1600.443	7.962	200.548	0.125	0.000	0.998	-0.017
2001	1640.528	202.000	8.121	0.160	206.484	0.126	1.022	29.802	0.020	0.596	1610.726	7.974	202.312	0.126	0.000	1.002	-0.021
2002	1656.933	203.000	8.162	0.160	209.109	0.126	1.030	37.253	0.020	0.745	1619.680	7.979	203.894	0.126	0.000	1.004	-0.026
2003	1673.503	204.000	8.203	0.160	211.760	0.127	1.038	46.566	0.020	0.931	1626.936	7.975	205.241	0.126	0.000	1.006	-0.032
2004	1690.238	205.000	8.245	0.160	214.438	0.127	1.046	58.208	0.010	0.582	1632.030	7.961	205.707	0.126	-0.001	1.003	-0.043
2005	1707.140	206.000	8.287	0.160	217.142	0.127	1.054	72.760	0.010	0.728	1634.380	7.934	206.228	0.126	-0.001	1.001	-0.053
2006	1724.211	207.000	8.330	0.160	219.874	0.128	1.062	90.000	0.010	0.900	1634.211	7.895	206.374	0.126	-0.001	0.997	-0.065
															T=13		T=1

Assumption: 168 Million dollars including 1400 Gwh of production cost

Appendix C - Static and Dynamic Conditions for Negative Bill Impact

Static Condition

Assuming U = No. of Customers;

A favorable bill impact implies that

$$C_g/U \; - \; C_c/U \; > \; 0$$

$$Q_gP_g/U \; - \; Q_gP_c/U \; > \; 0$$

$$Q_g \; (P_g - P_c)/U \; > \; 0$$

Therefore, the magnitude of bill impact is equal to $Q_g * (P_g - P_c)/U$. The higher the Q_g, the greater the bill impact. It is proportional to the amount of conservation.

Dynamic Condition

Assuming the amount of conservation is increasing with time and incremental cost is increasing with time. In other words, let us assume Q_{gt} and P_{gt} are linear function of time.

Assume U_t = No. of customers,

$$Q_{gt} = Q_g * T,$$

$$P_{gt} = P_g * T, \text{ and}$$

$$C_{gt} = Q_g * P_g * T^2$$

$$\frac{C_b + Q_g \; P_g \; T^2}{U_t} > \frac{C_b + C_c \; T}{U_t}$$

$$C_b + Q_g \; P_g \; T^2 \; > \; C_b + C_c \; T$$

$$Q_g \; P_g \; T^2 \; - \; C_c \; T > 0$$

$$(Q_g \; P_g \; T - C_c) \; T \; > \; 0$$

$$T > 0 \quad \text{Therefore, } Q_g \; P_g \; T - C_c > 0$$

$$Q_g \; P_g \; T > C_c$$

$$T \; > \; (P_c \; Q_g)/\;(Q_gP_g)$$

$$T \; > P_c \; / \; P_g.$$

Therefore, when a favorable bill impact occurs is mainly determined by unit cost of conservation and unit marginal cost.

Not like rate impact, the amount of conservation will not influence the time when the bill impact turns negative in this case.

The final inequality shows that the larger the average cost of conservation, the higher the T. The larger the incremental cost, the smaller the T. T is a time index which indicates the first year bill impact turns negative.

Appendix D Table 3

PEPCO Commercial Sector Screening Results

-- District of Columbia --

ram	MW Poten. by 1998	GWh Poten. by 1998	Benefit/Cost Ratios No-Losers	Benefit/Cost Ratios All Rates	Avg. Bill Chg./yr Res.	Avg. Bill Chg./yr Com.	ARP Levelized Cost ($/KW)	ARP Levelized Cost ($/KWh)
ustom Rebates	27.9	106.5	1.02	4.73	(0.16)	(3.55)	120.88	0.0316
: Cooling/ventilation comp.	10.0	37.4	1.08	7.07	(0.30)	(6.79)	86.73	0.0232
: Lighting component	15.3	58.4	0.96	4.70	0.17	3.75	113.91	0.0299
: Refrigeration component	2.5	10.7	1.03	1.83	(0.02)	(0.52)	312.16	0.0736
ustom Rebates, High Incen	54.1	206.9	0.93	5.17	1.21	27.15	109.83	0.0268
: Cooling/ventilation comp.	19.4	72.6	1.07	8.17	(0.53)	(11.84)	74.62	0.0199
: Lighting component	29.9	113.7	0.90	5.13	0.84	19.00	103.75	0.0273
: Refrigeration component	4.8	20.5	0.63	1.87	0.89	19.99	302.55	0.0714
hared Savings/Performanc Contracting	14.7	56.3	0.99	4.13	0.06	1.38	138.33	0.0361
: Cooling/ventilation comp.	5.1	18.9	1.05	6.15	(0.10)	(2.18)	99.95	0.0267
: Lighting component	7.9	30.2	0.92	4.31	0.17	3.87	123.70	0.0325
: Refrigeration component	1.7	7.2	1.02	1.77	(0.01)	(0.31)	325.41	0.0768
ommercial Lighting	88.0	334.7	0.86	4.48	3.35	75.47	117.07	0.0308
litz Lighting	26.9	102.5	0.82	1.39	1.02	24.37	344.60	0.0906
ommercial Lighting/ Dealer Incentive	111.5	424.0	0.87	3.95	4.01	0.26	131.59	0.0346
hermal Energy Storage	9.6	-2.3	1.04	1.49	(0.13)	(2.85)	182.52	N/A
mall Commercial oad Reduction	4.2	0.2	1.22	1.80	(0.05)	(1.12)	71.61	1.2175
nall Commercial Shop Doctor*	3.6	17.8	0.78	2.81	0.23	5.14	200.59	0.0407
w Commercial fficient Design	14.8	32.9	1.01	4.42	(0.07)	(1.59)	117.97	0.0530
r Mutually Exclusive ms (1,3,4,7,8,9,10)	162.7	546.1						

Source: Potomac Electric Power Company, 1990 Energy Plan, page 84

Appendix D

Washington Gas -- Rate Impact and Bill Impact

Table 4

AVERAGE RATE & TYPICAL BILLS BY SCENARIO (NOMINAL $'S IN 2000)

SCENARIO	AVG. RATE (S/THERM)	PERCENT CHANGE IN RATE	TYPICAL BILL ($/YEAR)	PERCENT CHANGE IN BILL
BASE CASE	$1.24	-	$1,831	-
75% TARGET*	$1.36	9.7%	$1,620	(11.5%)
COMMISSION GOAL	$1.42	14.5%	$1,542	(15.8%)
125% TARGET	$1.49	20.2%	$1,515	(17.3%)

* : Commission set a saving target for utility to follow. The higher the target, the higher the savings from DSM programs.

Source : Washington Gas, 1990 Integrated Least Cost Plan, Executive Summary and Plan, page VII-26.