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MARTIN MARIETTA

AN INTEGRATED ASSESSMENT OF ELECTRIC POWER RESOURCE OPTIONS IN THE U.S. VIRGIN ISLANDS

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MARTIN MARIETTA ENERGY SYSTEMS, INC.
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

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U.S. VIRGIN ISLANDS ENERGY OFFICE
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PREFACE

The funds for completing this study for the U.S. Virgin Islands Energy Office (VIEO) were made available from the U.S. Department of Energy (DOE), Grant DE-FG-44-88R-410584. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the authors and do not necessarily reflect the views of either the VIEO or DOE.

In addition, because this report has several audiences, it is written at several levels. For readers familiar with the U.S. Virgin Islands and its electric power sector, the background information on electricity in the islands may seem superficial. For readers sophisticated in such issues as demand-side management, integrated resource planning, and differences between financial and economic analyses, the background discussion of these issues may be tedious. There are always trade-offs in presenting different materials for diverse audiences. We hope that the proper balance was struck.

Finally, this assessment could not have been undertaken and completed without the cooperation and assistance of many people at the U.S. Virgin Islands Water and Power Authority (WAPA) and the Virgin Islands Energy Office (VIEO). Although there are too many to acknowledge individually, we would be remiss in not mentioning key people. At WAPA, Alberto Bruno-Vega, the Executive Director, and Donald Francois, the Chief Operating Officer, facilitated the collection of information by making themselves and their staff available throughout the study. Special thanks go to Glenn Rothgeb and George Shepherd who coordinated visits to the generating sites on St. Thomas and St. Croix, respectively. At VIEO, Director Claudette Young-Hinds's enthusiasm and interest in energy conservation and integrated resource planning set the over-all tone for the assessment. Onaje Jackson, Coordinator of the VIEO's Renewable Energy Center, and the project manager for the assessment, provided guidance and assistance throughout the course of the study. Finally, we thank Onaje, Beth Richards of Sandia National Laboratories, Skip Laitner of Economic Research Associates, and Eric Hirst of Oak Ridge National Laboratory for providing comments on draft versions of the report.

ABSTRACT

As with other island-based, insular power systems, the avoided cost of power for the Water and Power Authority (WAPA) of the U.S. Virgin Islands (USVI) is high relative to that of U.S. mainland electric utilities. First, the need to produce potable water requires that WAPA's electric generating system operate at efficiency levels lower than would result in the absence of the need to jointly produce water and power. Second, the inability to purchase power from neighboring utilities necessitates higher reserve margins than would be required if WAPA had sources from which to purchase power.

These two operating conditions suggest that integrated resource planning (IRP) should be especially attractive to WAPA. IRP is a planning paradigm that gives electric utilities more options to choose from when making resource selections and, therefore, generally results in lower costs. That is, rather than choosing from among conventional generating alternatives to satisfy future load requirements, utilities also look to the demand side as a source of resources--i.e., demand side management (DSM)--in this planning process. They then select the least-cost mix of resource options.

In this study, we take the first steps toward implementing an IRP process in the USVI. Using its existing resource base and the supply and DSM options that it has in the future, we simulated WAPA's resource selection process over a 20-year planning horizon using SafePlan, an IRP planning model. The results suggest that WAPA can significantly reduce its cost of providing electricity by implementing DSM programs. For example, under external conditions most favorable for generating electricity with fossil fuels--i.e., no increase in the real price of fuel input costs over the 20-year period--the cost of generating electricity and the amount of kWh needed over that period can be reduced nearly nine percent by implementing cost-effective DSM programs. Cost and kWh savings are greater under less favorable assumptions about (1) the input costs for generating electricity and (2) other conditions that WAPA will confront in the future. The results also indicate that DSM programs targeted at the residential sector can save 500 gallons of water annually for participants in the program.

These dollar and energy savings are only indicative of the potential. Although they include savings for the types of DSM programs that have proved cost-effective for mainland utilities (e.g., load management and commercial and industrial lighting programs), data limitations prevented development of other DSM programs that have also proved cost-effective on the mainland--especially for industrial customers. Therefore, a major recommendation of the study is that this data gap be closed. One way to accomplish this is to survey WAPA's customers to find out the penetration levels of appliances and characterize the consumption behavior of WAPA's customers. Information gained in the survey can supplement data obtained from running pilot DSM programs. The renewable energy district in Frederiksted created by the USVI Energy Office is a good place to conduct pilot studies because of the wealth of information already collected on its electricity customers.

EXECUTIVE SUMMARY

In this study, we show that, by implementing *cost-effective* demand-side management (DSM) programs, the Water and Power Authority (WAPA) of the U.S. Virgin Islands (USVI) can meet its future energy service needs at costs lower than constructing and/or operating electric generating units. The DSM activities include (1) setting cost-based prices and (2) implementing programs to improve the efficiency of electricity-using durables used by WAPA's customers. The dollar and kWh savings from implementing DSM programs under various assumed conditions are summarized in Table S.1.

Table S.1
Summary of Effects of Implementing DSM Programs
Five Scenarios
USVI Water and Power Authority
(In Percentages)

Scenario	Savings Resulting from DSM	
	Cost[a]	Energy[b]
No Fuel Price Increases[c]	8.9	8.5
EIA Fuel Price Forecasts[d]	8.8	8.9
High Fuel Price Increases[e]	10.0	8.9
High Peak Load Growth[f]	13.1	10.0
Environmental Externalities[g]	9.0	8.7

SOURCE: Section 5 in text.

[a]The cost savings (i.e., net present value) in 1992 constant dollars over the next 20 years resulting from implementation of cost-effective DSM programs. See Table 10 in text for additional detail.

[b]The percentage of kWh provided by cost-effective DSM programs in the year 2002. See Table 11 in text for more detail.

[c]Assumes that real fuel prices do not increase over the forecast period.

[d]Assumes that fuel prices increase at the rates projected by the Energy Information Administration (EIA).

[e]Assumes that fuel prices increase at two times the rate of growth forecasted by EIA.

[f]Assumes that peak load grows at one percentage point higher than that projected by WAPA.

[g]Includes a cost for environmental externalities, effectively increasing the cost of producing electricity using fossil fuel generating units.

The results in Table S.1 suggest that the conclusions are robust, prevailing over a wide range of conditions that WAPA could conceivably confront over the next 20 years. As Footnote a indicates, cost savings are the percentage reduction in costs over a 20-year planning horizon from implementing cost-effective DSM programs. Cost-effective DSM programs are those for which the estimated costs of implementation are less than their estimated benefits (see Table 9 in text for cost:benefit ratios for DSM programs under the five scenarios). Likewise, as Footnote b indicates, the energy savings are the amount of kWh saved as a result of implementing DSM programs (see Table 11 in text).

The results in Table S.1 were obtained by applying the principles of integrated resource planning (IRP) to WAPA's electric power delivery system. IRP is a management tool that allows utilities to consistently compare the cost-effectiveness of all their resource options--those on both the demand and supply side--taking into account the financial, economic and reliability differences of those resources. Simply put, the IRP process increases the choices available to an electric utility in meeting its load growth. The utility then selects the mix of options with the lowest cost. U.S. utilities have found that they can cost-effectively lower capacity requirements by more than 25 percent using the IRP process. This occurs while simultaneously meeting all customer service needs, and generally with lower costs per kWh.

All DSM options included in the simulations were compared to a 22-MW combustion turbine generating unit, WAPA's avoided unit. Because of data limitations, it was not possible to quantify the parameters for every potentially cost-effective DSM measure. Based on experiences elsewhere, it is expected that some of the most prominent savings lie in measures whose parameters cannot be quantified without further study. Therefore, the dollar and kWh savings shown in Table S.1 understate the cost-effective potential for DSM programs. The six DSM programs and corresponding measures that were included in the simulations (with results in Table S.1) are:

- residential time-of-retirement program
  - solar water heating
  - cooling

- residential retrofit program
  - lighting
  - other, including such measures as low-flow faucets and showerheads, increased insulation, and the like

- commercial and industrial time-of-retirement program
  - cooling

- commercial and industrial retrofit program
  - lighting

- new construction
  - residential

- load management program

- commercial

Measures that were not part of the simulations (and, therefore, their savings are not included in Table S.1), but which should prove cost-effective after quantifying the parameters of the program include:

- cost-based electricity pricing

- residential time-of-retirement program
  - refrigeration

- commercial and industrial time-of-retirement program
  - solar water heating
  - motors
  - other, including refrigerators, stoves, ovens, and the like

- commercial and industrial retrofit program
  - other, based on custom energy audits

- new construction
  - commercial

- load management program
  - industrial

Other conclusions emerging from the assessment include:

- Because of declining operating costs experienced over time in applications elsewhere, electricity generated from wind could be competitive in the USVI in the medium term if land can be made available at a reasonable price. Government-provided land can be used for other high-value purposes--i.e., it has a high opportunity cost.

- An offer from the Amerada-Hess Corporation to supply up to 15 MW of capacity on an interruptible basis on St. Croix has financial merit from WAPA's standpoint. However, from an economic point of view, DSM activities are more attractive because of the environmental externalities associated with the Hess power.

- Waste management is a pressing need in the USVI, but the energy potential from a waste to power operation is not sufficient for WAPA to expend its scarce resources. However, the plant(s) may be attractive to the private sector.

- The ocean thermal energy conversion (OTEC) proposition should only be considered if WAPA bears no risk beyond agreeing to buy the electricity and water at its avoided cost.

- The combination of small land mass, geological features, and relatively small total demand limits the cost-effectiveness of other central-station, supply-side renewable energy options on WAPA's system. As a result, options such as mini-hydro, solar thermal, and geothermal were not considered in this study. Their cost-effectiveness in the USVI awaits further technological development and/or experience elsewhere. However, there are many decentralized and demand-side applications of solar photovoltaics on the Islands.

- On the water side, the production facilities have a satisfactory performance record. Leaky distribution systems are the fundamental cause of water-supply problems to end users. Although an effort to remedy this is underway, there can be no real relief until funds are made available to repair these distribution systems.

The primary recommendation of this study is that this initial *IRP assessment* be converted into an *IRP process* at WAPA. That is, as Table S.1 suggests, changing conditions external to WAPA (e.g., changing fuel input prices, higher electricity demand growth rates) can change the cost-effectiveness of different resource options. This suggests that IRP is not a one-time assessment, but rather a continuing *process*. Recognizing the dynamics of this process, it is important that IRP be institutionalized at WAPA. One approach used by mainland utilities is to use a team concept with representatives from all departments of WAPA. The center of the process, an integration team, takes input from demand-side and supply-side teams. The integration team is ultimately responsible for developing the integrated plan and making resource acquisition recommendations to upper management.

Also, data collection on electricity customers is a first-order priority in institutionalizing the IRP process. One approach is to conduct surveys of WAPA's residential, commercial, and industrial customers on St. Thomas and St. Croix, supplementing the energy audit data being collected in the Frederiksted renewable energy district. Another complementary approach is to conduct pilot programs of potentially the most cost-effective DSM programs such as load management and commercial and industrial lighting programs. A good place to conduct the pilot programs is in the renewable energy districts created by the Virgin Islands Energy Office. Data collected from these pilots can be used to develop island-wide DSM programs.

Finally, to implement the IRP process in the USVI, we recommend that appropriate parties familiarize themselves with its phases and components. For commissioners of the USVI's PSC, the WAPA governing board, and upper-level WAPA management, we recommend an executive familiarization session, lasting three or four hours. For staff of WAPA and the VIEO, we recommend lengthier sessions, running for three to five days and using this report as the reference point for the sessions. Any additional training can be provided by general DSM and IRP workshops conducted on the mainland.

1. INTRODUCTION

1.1. PURPOSE OF THE STUDY

The U.S. Virgin Islands (USVI) has a number of electric power resource options available to it on the demand side to meet future load growth in addition to constructing and operating combustion turbine generating plants. The purpose of this study is to determine the most cost-effective mix of those demand and supply options over the next 20 years. To accomplish this, the principles of integrated resource planning (IRP) were applied to the electric power delivery system of the USVI's Water and Power Authority (WAPA), the sole public utility in the islands. The assessment was coordinated by Oak Ridge National Laboratory for the USVI Energy Office (VIEO) and WAPA.

1.2. A PRIMER ON IRP

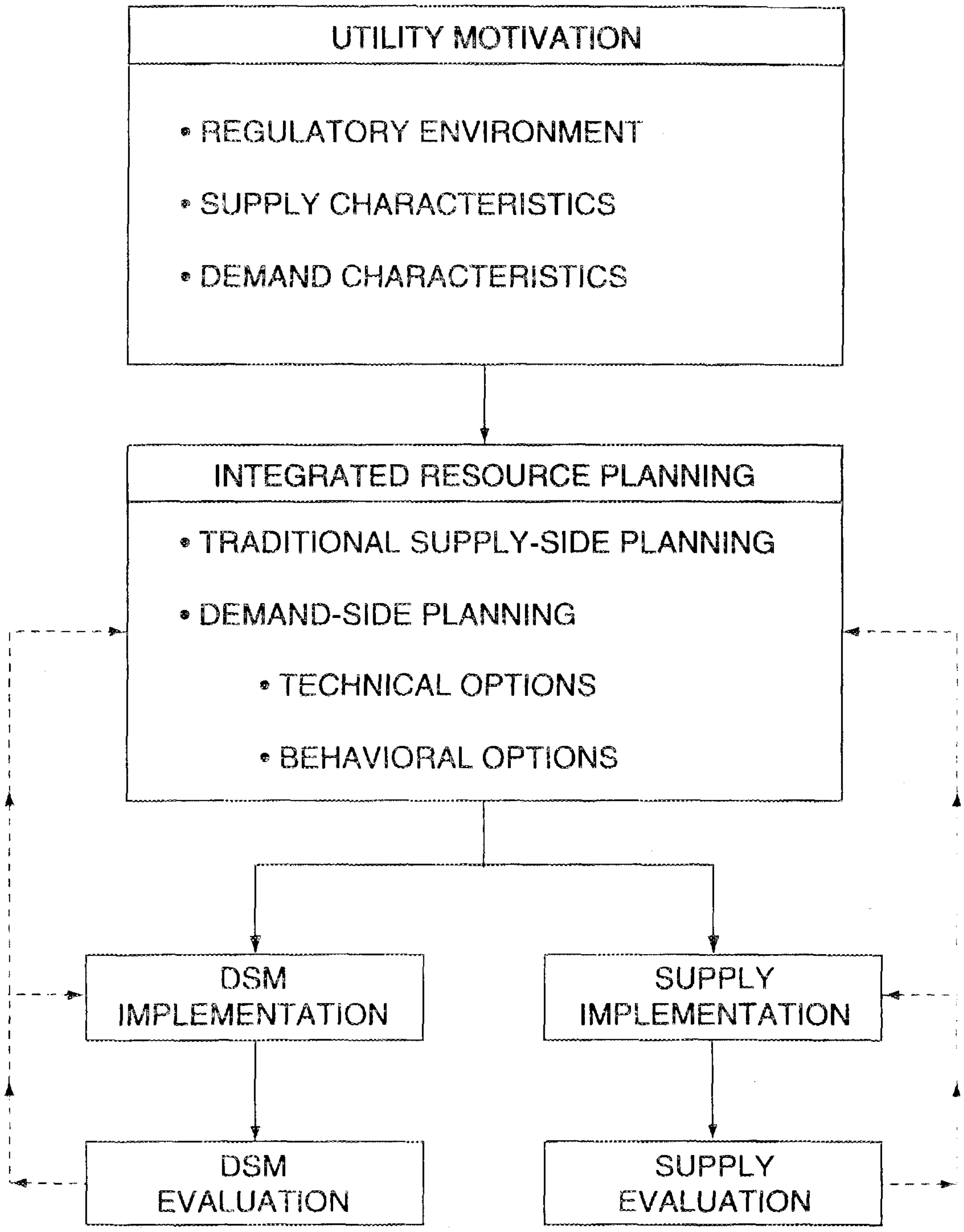
1.2.1. What is IRP?

Spurred by the rising costs of constructing new electric generating plants, high fuel costs, and increasing environmental concerns over emissions from fossil fuel plants, electricity producers in many countries are looking to the demand side as a source of resources for meeting energy (i.e., kWh) and load (i.e., kW) requirements. That is, changing the pattern and level of electricity demand (i.e., demand-side management (DSM)) is weighed as a resource option on an equal footing with traditional supply resources (e.g., building new generating stations, extending the life of old ones, or purchasing power from other sources). The process of selecting a resource mix on the basis of comparing the benefits and costs of demand and supply resources is referred to as integrated resource planning (IRP). The IRP process is a combination of (1) traditional least-cost planning, a process by which utilities minimized the cost of generating a given amount of electricity and (2) demand-side planning. Its goal is to provide needed electricity at the lowest possible economic, social, and environmental cost.

In Figure 1, we place DSM planning in the context of a dynamic electric utility planning framework, including (1) factors that motivate utilities to consider DSM planning, (2) the relationship between demand-side planning and the IRP process, and (3) the implementation and evaluation of both DSM and supply resources (Hill, Hirst, and Schweitzer, 1991). The process is dynamic not only because planning by its very nature is evolutionary but also, as we show in Figure 1, because the effectiveness of DSM programs has feedback effects on both the process of selecting the programs and the way in which they are implemented. The effectiveness of DSM programs, of course, can be determined only by systematic program evaluation (Hill, Hirst, and Schweitzer, 1992a).

As we show in Figure 1, the regulatory environment (discussed further in Section 1.2.3) and characteristics of a utility's power delivery system and customer demand influence decisions on whether to pursue IRP. For example, the types of generating units used by electric utilities can be a motivating force to consider the demand side. Based on statistical analysis of responses to a survey of 24 U.S. utilities, the percent of total peak (kW) resources projected to be met by DSM is larger for utilities with greater

Figure 1
Integrated Resource Planning as Part of a Dynamic Process



dependence on oil and gas generating units, which have higher costs per kWh generated. Similar conclusions result from energy consumption (kWh) avoided by conservation programs. That is, if production costs are higher, utilities try harder to promote reductions in their customers'consumption (Schweitzer, Hirst, and Hill, 1991). On the demand side, utilities with low load factors are more likely to seek ways to shave peak load. There are several powerful DSM tools that can be used to accomplish this, including electricity pricing (Hill, 1990, 1991a). The goal in all cases is to find the mix of supply and demand resources that lowers cost and, therefore, increases potential profits.

The final two sets of blocks on implementation and evaluation are important. DSM programs are implemented and evaluated in the same way that supply resources are. That is, DSM programs are treated parallel to the manner in which a utility chooses to (1) build a power plant, (2) construct it, and (3) evaluate its performance. The problem that many utilities confront in treating DSM and supply resources in a parallel manner is the lack of data on running DSM programs. The technical savings of these programs are generally well known. It is the marketing side where utilities are deficient because firms do not have enough information to know how their decisions will affect their potential profits. They need information on:

- the number of customers using different types of electricity-using durables and, therefore, the total amount of savings available from a program;

- the possible market penetration of energy-efficient durables;

- quantification of the trade-offs between marketing these durables and their penetration, and

- the most effective financing mechanisms for different programs.

1.2.2. Contribution of DSM Programs

In Table 1, we present some evidence on the contribution of DSM programs to meeting future electric energy (kWh) and peak load (kW) in the United States. The results are based on survey responses from 24 U.S. electric utilities (Schweitzer, Hirst, and Hill, 1991). The 24 utilities represent one-third of the U.S. electric utility industry in terms of peak load. The survey results are presented on two bases: (1) the percentage of total resources (i.e., energy services supplied) accounted for by running DSM programs, which can also be interpreted as the percentage reduction of total demand attributable to running DSM programs and (2) the percentage of incremental resources (i.e., energy services supplied) accounted for by running DSM programs, which is the fraction of additional resources added by utilities in the 10-year period from 1990 to 2000 that are accounted for by DSM programs.

To facilitate understanding these two bases, we characterize them in Figure 2 (Hill, Hirst, and Schweitzer, 1991). The No Incremental DSM curve is a reference forecast from the Current Year forward, a best-guess of what load is going to be before including the estimated effects of DSM options. The Projected Load curve is a forecast of future load requirements, including the effects of DSM programs. Existing Supply Resources refers

Table 1
U.S. Electric Utilities
Estimated Energy and Peak Load Savings from DSM Programs
(In Percentages)

Type of Savings	Energy[a]		Peak Load[a]	
	1990	2000	1990	2000
Total Resource Basis	0.5	3.8	1.3	6.2
Incremental Resource Basis	NA	15.5	NA	27.7

SOURCE: Schweitzer, Hirst, and Hill, 1991.

[a]Weighted average, based on responses from 24 utilities. Peak could occur in the summer or winter depending on the demand characteristics of individual utilities.

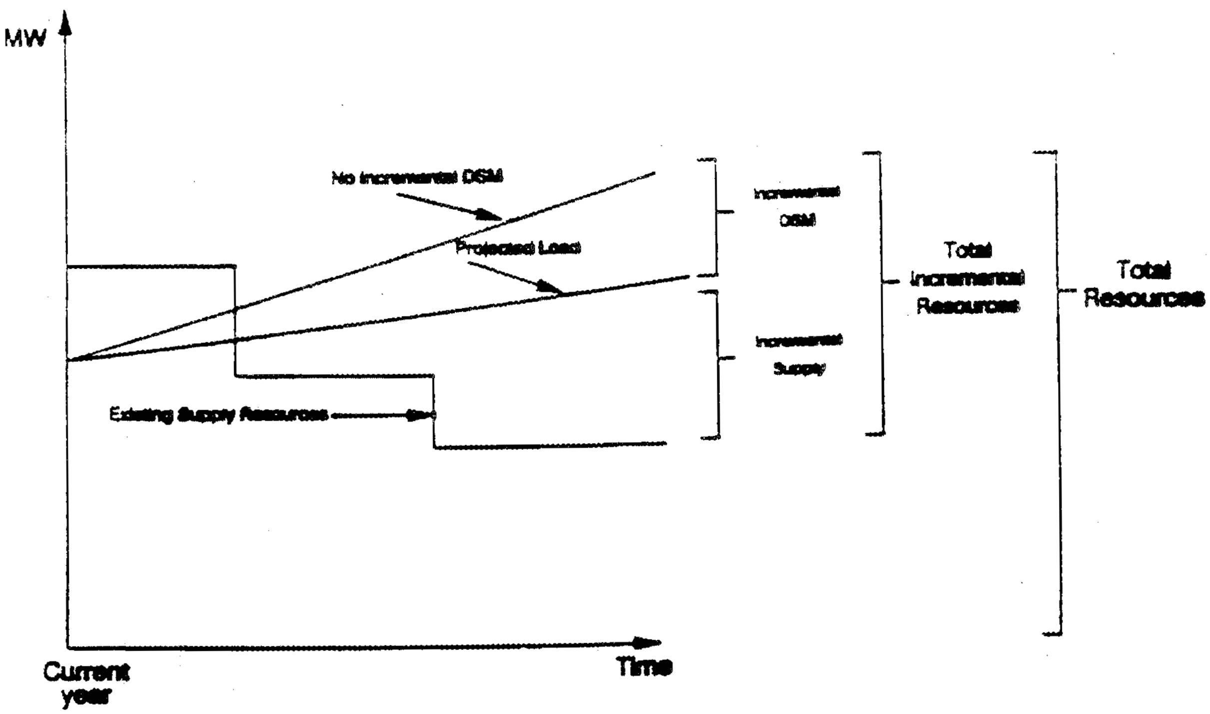
NA - Not Available

to the amount of generating capacity that is committed and known at the time the plan is being developed. That amount is shown declining over the forecast horizon in Figure 2, implying a net depreciation of supply resources.

The survey results shown in Table 1 indicate that U.S. utilities will significantly increase their DSM activities on a total resource basis from 1990 to 2000. In the year 2000, peak demand, for example, is forecasted by these 24 utilities to be 6.2 percent less than it otherwise would be if DSM programs were not implemented. The savings on an incremental basis are much larger, of course. Nearly 30 percent of additional peak electric power resources (kW) will come from the demand side in 2000. Projected energy savings (kWh) are one-half of projected peak load savings, suggesting that load management programs (e.g., direct load control programs that change the time when electricity is used) are more pervasive and/or effective than those aimed at improving energy efficiency (e.g., conservation programs). This will likely increase from state initiatives and from recent passage of the Energy Policy Act of 1992 (as discussed in Section 1.2.4 of this report).

The data in Table 1 are weighted averages of the 24 utilities responding to the survey. Clearly, different utilities with different operating conditions will have different potentials for DSM savings. For example, all other conditions the same, utilities that aggressively pursued DSM programs in the past will not have the same savings potential ten years from now as those utilities just beginning DSM planning. Utilities with different climates and different load factors will also have different DSM potentials. To demonstrate

Figure 2
Characterization of Incremental and Total Resources



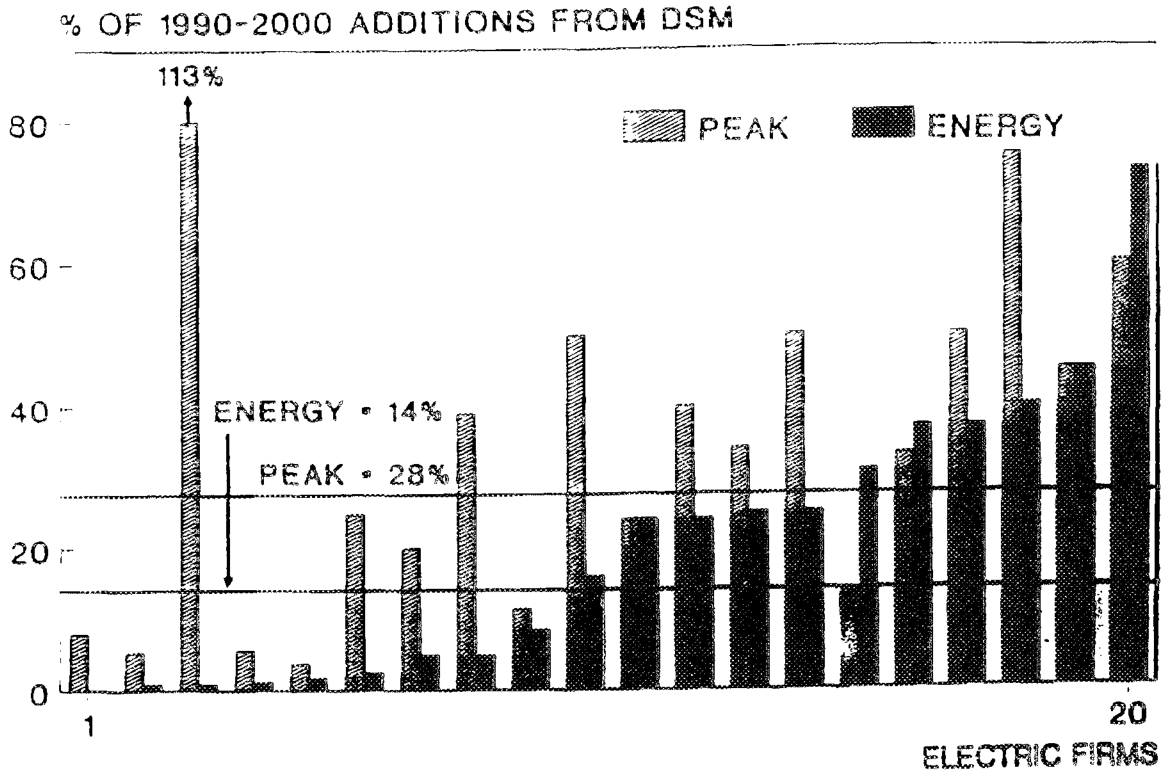
different potentials across utilities, we disaggregate the survey results presented in Table 1 to individual utilities in Figure 3 for the incremental resource projections. Some of the utilities are projected to get as much as one-half of their additional energy and peak load resources from DSM resources in the the next ten years. Other utilities, however, will not obtain as much as five percent of their energy requirements from DSM programs. The variation across utilities is large.

1.2.3. IRP and the Regulatory Environment

An important feature of the resource planning environment is the relationship between a utility and its state regulatory commission. The nature of this relationship varies substantially from state to state due to a variety of factors, including the history of relations between utilities and their regulators, regional regulatory and political culture, and the nature of legal requirements imposed by legislation or administrative order.

Studies focusing on various aspects of this relationship (e.g., Mitchell and Wellinghoff, 1989; Chamberlin, Fry, and Braithwait, 1988) concluded that, while virtually all states encourage resource planning, many do not require that the plan be approved by the state. In some cases, a long-range plan must be submitted for regulatory

Figure 3
DSM Contributions to Resource Additions
Utility Survey



approval, but the contents of the plan are not prescribed. In others, formal approval is not required; but the plans must address certain issues, such as treatment of uncertainty. A number of states have recently passed regulations requiring that DSM resources be treated equally (or even preferentially) with supply resources. Other states are in the process of passing similar regulations.

Of the 24 states included a survey of utilities (Schweitzer, Hirst, and Hill, 1991), legislation or administrative order in 18 require utilities to prepare integrated resource plans. And, eleven of the commissions in the 18 states formally approve the plans. Finally, approval by the commission for use of a resource depends on its inclusion in a formal resource plan in seven of the states. Statistical analyses of the responses of these utilities in these 24 states suggest that utilities required by legislation or administrative order to prepare long-term integrated resource plans rely more heavily on DSM to meet additional peak demand than those utilities not required to prepare a plan .

Filing requirements vary widely. In Nevada, for example, utilities are required to file an Electric Resource Plan with the Public Service Commission every three years, extending 20 years into the future. Utilities in North Carolina, on the other hand, must file a comprehensive description documenting the planning process every three years; an update is required in the intervening two years.

A recent survey of all PUCs (Cohen *et al.*, 1990) shows the extent to which state regulatory authorities require externalities to be considered in utilities' selection of resources.[1] States were placed in one of four categories, depending on the degree to which externalities were required to be considered in selecting resources: (1) operational: approaches developed or rules passed; (2) developing approaches: not as yet implemented or failed to pass; (3) awareness of the problem, but no formal procedures established; or (4) no evidence of treatment of externalities. Combining the latter two categories into one, the results showed the following:

- 17 states had operational approaches;
- 7 states were developing approaches; and
- 24 states had not addressed the problem.

Therefore, more than one-third of the states had rules for treating externalities. The study showed that three approaches are used to take account of externalities:

- qualitative treatment in which externalities are assessed by relative degrees of environmental degradation;
- a percentage adder approach that either increases the cost of supply-side resources or decreases the cost of ones on the demand side; and
- quantification of the cost of externalities.

Eight of the 17 states that have rules for treating externalities require quantification of the environmental effects of using different resources. Also, several regulatory commissions indirectly incorporate externalities in the ratemaking process by permitting higher rates of return for resources which do not affect the environment. For example, Connecticut allows up to an additional five percent rate of return for investment in DSM programs.

1.2.4. Impact of the Energy Policy Act of 1992 (EPACT)

EPACT is a wide-ranging piece of energy legislation that has implications for how energy is produced and used for many years to come. Although many provisions of EPACT do not directly pertain to the USVI, certain provisions will have a significant impact: (i) energy efficiency--including those relating to electric utilities, (ii) changes to the Public Utility Holding Company Act, (iii) renewable energy, (iv) provisions for grants, taxes, and subsidies, and (v) policies directed at insular areas . The purpose here is not to go into detail on how each of these provisions will affect the USVI. That already has been

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[1] Tennessee and Nebraska, which are dominated by publicly owned utilities, were excluded from the survey.

accomplished (Laitner and Holmes, 1993). Rather, here we provide pieces of EPACT relating to IRP, energy efficiency, and electric utilities.

EPACT amends the Public Utility Regulatory Policies Act of 1978 to include the following suggestion for PUCs to consider:

> Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

The profitability of investments on the demand side was also addressed by EPACT, again as a suggestion to PURPA's language:

> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

1.3. CONDUCT OF THE ASSESSMENT

An assessment team, organized and coordinated by Oak Ridge National Laboratory, conducted the study in three phases. In the first phase beginning in January 1992, the team concentrated on the power delivery system. It involved discussions with WAPA staff members and on-site visits to WAPA's generating sites on both St. Croix and St. Thomas. The purpose of the discussions and site visits was to gain a better understanding of WAPA's power generating operations and to gather data on units presently in operation and those committed for the future.

The goals in this first phase were (1) to gain an understanding of the operations, maintenance, dispatch, and new capacity planning strategy and practices used by WAPA and (2) to review about 18 months worth of operations data (12 for St. Croix) to look at efficiencies and availabilities achieved, etc. The 12- and 18-month periods were selected as the best post-Hugo periods after the chaos of the hurricane, and with the coming of normal operations. Pre-Hugo operations were not considered relevant for the current IRP activity. The least-cost expansion plans were reviewed; the plants were given a walk-through inspection; operation and maintenance data files were examined and selected information copied; O&M staff were interviewed, and supervisory and management staff were interviewed. Finally, the activities were coordinated with staff of the VIEO.

The purpose of the second phase was to gather information on demand-side options. The first-order priority was to gather data to quantify the parameters of such measures as improvements in residential and commercial lighting efficiency, residential solar water heaters, and load management programs. Data sources included information gathered from the renewable energy district on St. Croix and WAPA's customer billing data.

The information gathered in the first two phases was combined in the final phase. Resource options were ranked on the basis of cost:benefit ratios using SAFEPLAN, a flexible utility planning model designed to simulate resource selection.

1.4. REMAINDER OF THE REPORT

The remainder of the report has five sections. In the next section, we discuss the energy and water situation in general terms. After discussing the relevant institutions, we turn to the physical water and power supply systems and historical consumption patterns. In Sections 3 and 4, we discuss WAPA's existing and future supply and demand options, respectively. In Section 5, we discuss the simulation of resource selection, including the modeling tool, the scenarios, and the results. Our recommendations are presented in the final section.

2. ELECTRICITY IN THE USVI: AN OVERVIEW

2.1. RELEVANT INSTITUTIONS

The U.S. Virgin Islands Water and Power Authority (WAPA) is a publicly owned, regulated utility responsible for the generation, transmission, and distribution (in reality generation and distribution) of electricity on the 3 main islands of the U.S. Virgin Islands chain, plus the production and distribution of water through large-scale distillation systems integrated with the major power plants on St. Thomas and St. Croix. Prior to 1988, WAPA produced and sold water to the water distribution system which was also owned by the government, but organized separately from WAPA. On January 1, 1988, the water distribution system was transferred to WAPA's control. The two systems are separately financed. The water system is a customer of the electric system, paying for both electricity and other shared administrative expenses of their joint operation. The tariffs of the water and electric power systems are regulated by the Public Service Commission in the islands.

Similar to mainland energy offices, the U.S. Virgin Islands Energy Office (VIEO) is an agency of the territory's government. For the past three years, it has offered a rebate program to WAPA's electricity customers for purchases of energy-efficient appliances, including solar water heaters, air conditioners, and refrigerators.

2.2. JOINT PRODUCTION OF WATER AND POWER

The St. Thomas and St. Croix electric systems are isolated from each other and the power systems of neighboring islands. Therefore, each has no fall-back position other than its own reserve capacity. St. John relies on an underwater cable connection from St. Thomas. It has a diesel generator that can handle about one-half of the island's peak demand.

The isolation of these systems is an important consideration in their daily operation because the power system dispatch strategy must take into account the vulnerability of the system to both routine and catastrophic failure. There is a severe economic penalty to be paid for power outages. WAPA does not have the advantage of inter-connection with other grids as either a shock absorber, or as sources for power purchases should it become necessary. Therefore, in comparison with other electric utilities, WAPA must maintain a larger generating capacity reserve margin to prevent against a catastrophic failure of the system.

The other important characteristic of the generating system is the production of distilled water from sea water that is normally accomplished with turbo-generator extraction steam in a true cogeneration fashion. That is, the electric and water systems share dual-purpose plants for the production of electricity and water. Boilers used to supply steam for the operation of water desalination units also provide steam for turbines used in generating electricity. The steam demand of the evaporation systems is flat (i.e., a constant demand in pounds per hour of steam), which does not allow for the turbo-generators to be operated in a load following mode.

Water production has a satisfactory record, but plagued by poor distribution facilities. The desalination systems perform admirably, but new capacity is not the best technical choice at this time. The distribution system is old and leaks badly. Between a marginal amount of water storage and the underground losses, the supply is almost always strained. The existing I.D.E. desalination systems are state-of-the-art systems. Experience over the years has proven that the integrated operations of water and electricity production equipment involves some loss of flexibility of dispatch on the electricity generation side.

Both the St. Thomas and St. Croix plants have a similar operations strategy based on similar equipment availability. Operations are tied directly to the production of water in such a way as to limit the operational efficiency of the power generation activities for about 12 hours per day. The insular nature of the electricity grids on both islands also dictates a certain conservative operational approach--and unit size selection for new capacity additions.

WAPA's operational strategy must be considered in the context of the current and projected future 24-hour demand curves. The curves differ between St. Thomas and St. Croix a little, mainly because of the heavier commercial, tourist-oriented mid-day air conditioning load on St. Thomas. This load extends the mid-day peak virtually flat for up to 5 hours, followed a little later by another shorter peak when the work force gets home. In terms of the ratio between the daily peak and daily minimum, there is similarity with a ratio of less than 2 to 1 for both systems. This is attributable to the night-time air conditioning load. St. Thomas should have a new gas turbine on-line shortly (sitting on-site with installation scheduled to imminently begin), which will give it a reasonably safe reserve capacity margin, plus the makings of a combined cycle installation with a waste heat boiler addition. St. Croix, on the other hand, has a tight reserve margin, a pressing need to do a major overhaul on 2 combustion turbines, a growing demand, and a wait of perhaps 12 to 18 months for the Southshore installation of 2 X 24mW Frame 5 combustion turbines to come on-line.

Looking at plant availability for the two sites explains the dispatch strategy. The steam units are efficiently operated throughout the day as baseload units. The extraction steam is productively used for the first stage driving heat for the multi-stage distillation process for seawater. The combustion turbines are operated for peaking at reasonably efficient load conditions during the day, and at night for outage protection at rather inefficient load conditions. These gas turbines are of the type that have very steep reductions in efficiency as the load is reduced. Therefore, there is a penalty in terms of fuel cost/kWh of production. The simple cycle gas turbines are operating at a heat rate on average a third above full load expectations. This strategy is appropriate under the current load conditions, and with current equipment.

The additional cost can be approximately quantified using simple assumptions. Of the total generation for the last 18 months, the combustion turbines produced about one quarter. Of their dispatch, about one-fifth of the hours are under poor load conditions. The load during these hours would is approximately 55 percent of the average, or a total of 15.6 MW. The extra fuel cost/kWh is about a fifth above the average cost (.2 X .07) equals $0.014 per kWH. Therefore, the annual cost penalty for maintaining system flexibility for unforeseen problems is 15,600 kW X 2000 hours per year X $0.014 equals $436,800 per year. That translates to an additional cost of about .1 cents per kWH produced, if spread out over the annual production. This is not an unreasonable burden to purchase operating security. Even if the cost is really double the estimate (upper extreme considering probability), it is still reasonable with what is currently available for WAPA.

As the demand grows, and newer more efficient dispatch choices become available, (more efficient combustion turbines and an ability to operate in combined cycle mode), this penalty should be reduced. The basic problem is that at least one extra unit must be kept on-line all night at a fairly low load so that it can rapidly pick-up load with any other failure because of the desalination process requirement.

2.3. ELECTRICITY CONSUMPTION PATTERNS

In Table 2, we provide information on WAPA's electric power consumption, divided between St. Thomas (including St. John) and St. Croix. The two sets of data define WAPA's two separate power systems. WAPA's customers have increased by more than two percent per year on average over the past five years. For both islands, the majority of the increase on a percentage basis is attributable to the commercial sector. The growth in electric power consumption is somewhat deceiving because it includes data for 1990, the fiscal year in which Hurricane Hugo hit the islands. Electricity demand growth on St. Thomas is much greater than that on St. Croix, explained in part by the effect of Hurricane Hugo on St. Croix.

Table 2
Electric Consumption, Customers, and Average Usage
USVI Water and Power Authority
1987 and 1992

	St. Thomas		St. Croix	
	1987[a]	1992[a]	1987[a]	1992[a]
Electricity Consumption (MWh)				
Residential	94,005	112,008	73,810	81,032
Commercial	52,664	67,082	28,195	34,695
Industrial	108,747	144,130	71,080	64,589
Total[b]	258,353	328,296	178,029	180,311
Number of Customers:				
Residential	18,121	19,522	16,380	18,307
Commercial	3,065	3,890	2,454	3,203
Industrial	358	442	345	357
Total	21,544	23,854	19,179	21,867
Average Annual Usage (kWh):				
Residential	5,227	5,789	4,541	5,090
Commercial	17,777	17,522	11,834	12,986
Industrial	297,123	337,541	207,230	212,991

SOURCE: USVI Water and Power Authority.

[a]As of June 30, the end of WAPA's fiscal year.

[b]Includes amounts for street lighting.

3. THE SUPPLY SIDE

3.1. EXISTING AND COMMITTED GENERATING UNITS

In Table 3, we summarize characteristics of WAPA's existing electric generating units and those for which commitments have been made. The information is divided between the St. Thomas and St. Croix systems, reflecting the two insular power systems in the USVI. As the data indicate, we provide some background information on existing and committed units and the recent operating experience of the units, including average load, average heat rate, and fuel cost per unit generation. The 6-month difference in operating experience data between St. Thomas and St. Croix reflect the relative severity of problems on St. Croix since Hurricane Hugo.

The capacity and other operating variables at each plant have not been summed to a total for each of the islands. This is deliberate because of the integrated operations of the No. 6 oil steam turbine plants and the steam-consuming seawater distillation plants. When the distillation plants are operated, the extracted steam is taken at the expense of available electric generation capacity. The water production steam demand is nearly constant and the availability of the desalination systems is nearly 94 percent. Therefore, there is a built-in capacity restriction for the electricity plants. Also, because the steam demand for water production is virtually flat, there is another limiting factor--the system's capability to follow electricity demand changes without upsetting the stability of water production. A summing of capacity amounts, therefore, is without foundation.

As the data in Table 3 indicate, St. Thomas should have a new gas turbine on-line shortly, which will provide a reasonably safe reserve margin, plus the prospect of a combined cycle installation with a waste heat boiler addition. St. Croix, on the other hand, has a tight reserve margin, a pressing need to perform a major overhaul on 2 combustion turbines, growing demand, and a delay of 12 to 18 months for the Southshore installation of 2 X 24 MW, Frame 5 combustion turbines to come on-line.

The daily operation of both systems was described in detail in Section 2.2 above.

3.2. FUTURE GENERATING OPTIONS

3.2.1. Combustion Turbines

A 22-MW combustion turbine is used as the avoided generating unit in this study. That is, the capacity benefits of employing any resource--whether that resource is another type of generating unit (discussed below) or a DSM program--is based on the capacity cost of a 22-MW combustion turbine. The combustion turbine costs $400/kW and uses No.2 fuel. The cost of the fuel is scenario-based and will be discussed at length in Section 5. The fixed O&M cost is $16/kW/year. The total cost of the combustion turbine, therefore, is assumed to be $8.8 million and its construction period is assumed to be three years with 20 percent completed in the first two years and 60 percent completed in the year prior to its coming on line.

Table 3
Key Variables for Existing and Committed Generating Capacity
USVI Water and Power Authority

Unit Type (Number)	Background Information				Recent Experience[a]		
	Fuel Type[b]	Rated (Actual) Capacity (MW)	Heat Rate (Btus/kWh)[c]	First Year[d]	Average Load (MW)	Avg. Heat Rate (Btus/kWh)	Fuel Cost/ kWh (c/kWh)
St. Thomas/St. John							
Steam Turbine #11	No. 6	18.8 (16.0)	14,226	1968	13.3	15,874[e]	5.6
Combustion Turbine #12	No. 2	15.1 (14.0)	15,500	1970	7.6	20,778	7.4
Steam Turbine #13	No. 6	36.9 (36.0)	13,179	1973	23.6	13,967[e]	4.8
Combustion Turbine #14	No. 2	15.1 (14.0)	15,000	1972	8.6	19,894	7.1
Combustion Turbine #15	No. 2	24.1 (21.2)	13,659	1981	12.1	17,972	6.4
Diesel #7J	No. 2	2.5 (2.5)	11,375	1985	2.0	12,276	5.6
Combustion Turbine #18	No. 2	24.1 (22.0)	12,500	NA	NA	NA	NA
St. Croix							
Steam Turbine #10	No. 6	7.5 (7.5)	12,000	1967	5.2	15,160[e]	6.4
Steam Turbine #11	No. 6	19.2 (16.0)	12,000	1970	13.2	12,949[e]	4.9
Combustion Turbine #16	No. 2	24.1 (20.0)	13,659	1981	10.2	22,564[f]	8.0
Combustion Turbine #17	No. 2	24.8 (21.2)	12,450	1988	11.6	18,367[f]	6.5
Diesel	No. 2	4.2 (2.5)		1968			
Combustion Turbine	No. 2	24.1 (22.0)	11,850	NA	NA	NA	NA
Combustion Turbine	No. 2	24.1 (22.0)	11,850	NA	NA	NA	NA

SOURCE: Water and Power Authority.

Table 3 (Cont.)

[a]For St. Thomas, recent experience is defined to be an 18-month period from the middle of 1990 until the end of 1991. For St. Croix, recent experience is the calendar year 1991.

[b]Type of petroleum.

[c]The heat rate is an estimated achievable value at 100% rated load based on HHV, and for steam plants with no extraction steam used.

[d]The year that the unit was first operated.

[e]Adjusted for productive cogeneration extraction.

[f]Waste heat boiler performance is not considered.

NA - Not applicable.

3.2.2. Wind Energy

Until the actual wind resource at specific Virgin Island locations can be defined, it is possible to use some other Caribbean Island experience plus U.S. cost standards to give the wind option a tangible feel. Land availability and cost are the main determinants after the resource is defined. The important facts about wind are that reliability is increasing while the capital and O&M costs have been steadily dropping. Wind is a legitimate utility supply option with acceptable reliability, and competitive kWH production cost if both the resource and land are available. In Section 5, we define the operating characteristics of a 250 kW wind plant.

3.2.3. Purchased Power

A short-term contract with Hess to provide some reserve margin during the next 12 to 18 months on St. Croix should be considered. Assuming energy sales of 180 MWh for St. Croix in 1992 and the interconnection with Hess costs $1.25 million, the burden on WAPA customers would be about 0.5 cents per kWH for this security. If the power can be purchased for a lower price than it costs WAPA to produce peak power, then it should be dispatched regularly for peaks to compensate for the costs born for the hook-up, and not be used exclusively as a back-up reserve. For example, if Hess uses a mix of commercial and non-commercial fuels (refinery gas), the fuel cost should be below that of WAPA's. Assuming that Hess pays less for No.2 fuel than what WAPA pays for distillate, the estimated incremental fuel cost per kWH for Hess can be calculated. With a better heat rate (higher efficiency) than WAPA can achieve because of a better demand profile, Hess should profit and the transaction can be cost-effective for WAPA. Estimating Hess' No. 2 fuel cost to be $0.40 per gallon, and at a heat rate of 10,666 BTU per kWH, the fuel cost increment is approximately $0.03/kWh. With other incremental cost elements also lower for Hess than for WAPA, this would give Hess and WAPA the proper amount of negotiating room to arrive at a favorable price for Hess and a savings for WAPA. This could substantially reduce the potential 0.5 cents per kWH customer burden by simply connecting to the Hess capacity.

3.3. OTHER RENEWABLE POSSIBILITIES

3.3.1. Power from Waste

Both St. Thomas and St. Croix have municipal garbage problems that are related to space shortages and the environment. The volume of garbage is not large (below 200-250 tons per day per island), and the energy potential is only 1.0 to 2.0 MW per island. The possibility of transferring garbage from one island to the other is interesting, but not feasible for aesthetic reasons. The waste problem is real, but it is an environmental problem. From a policy standpoint, options should be pursued, but WAPA should not have its resource base diluted by responsibility for a complicated problem that has only a limited energy benefit.

One alternative worth considering is the potential of locating the waste to energy plants at or adjacent to the existing WAPA plants (extremely sensitive and politically volatile consideration), and using the steam source to displace the need for total reliance on the existing conventional steam plants to drive the desalination units for potable water production. The steam could be produced by, and purchased from a private entity, along with any power produced, or power could be swapped for water from the waste-fired steam plant. Options such as these need to be reviewed in detail. Their viability needs to be verified in the public arena, and a development strategy prepared, if viability is indicated.

3.3.2. Ocean Thermal Energy Conversion (OTEC)

Some private U.S. energy companies have been soliciting WAPA for participation in an OTEC project off the shore of St. Croix where an excellent OTEC potential exists. Because no commercially operating OTEC plants exist in the world, WAPA is not in a position to take any position that involves risk in such a project. It can, however, structure an agreement that would encourage a private sector developer in assuming the development risk. For example, WAPA could offer a take or pay contract that only binds it to guarantee payment for kWh delivered, if the construction is started by a certain date, and the plant is commissioned by a certain date.

Perhaps of greater importance to WAPA is the potential for an OTEC plant to produce distilled seawater. While this aspect of the technology needs to be carefully evaluated further because of the possibility of extremely low temperatures (the temperatures would dictate a very severe vacuum condition at some expenditure of energy to allow the flashing to take place). If the distillation proves feasible, then the value of dual production of electricity and water could overcome an OTEC plants high capital cost. A reasonable cost range for the first commercial, 5-MW OTEC plant producing 2 million gallons per day of seawater is $40 million to $50 million. With a power sales price of $0.10 per kWH, and a water sales price of $10/1000 gallons, the private sector might be tempted to take the risk for a long-term take or pay sales contract.

3.3.3. Other Renewable Supply Options

The limited extent of the land masses, the nature of the terrain, and the relatively small electricity demand all serve to limit the options for other renewable energy sources. For example, there are no potential water sources with sufficient volume, consistency, and head to consider hydro as an option. The grid is essentially everywhere, and with land issues, this inhibits the options for solar photovoltaics, except for specialized applications. Total electricity demand is too low to consider solar thermal, especially within the constraints of the desalination plants. There are no evident geothermal resources.

4. DSM OPTIONS

In this section, we define demand-side possibilities for WAPA's two delivery systems. We organize the discussion around two topics: (1) behavioral possibilities (i.e., a tariff structure reflecting cost-based rates) and (2) technical ones (i.e., programs to improve the technical efficiency of electricity use by WAPA's customers).

4.1. ELECTRICITY PRICING

4.1.1. The Current Situation

The USVI's Public Service Commission (PSC) approves all changes in electricity rates proposed by WAPA. In this process, the overall ***level*** of electricity rates is set to ensure that WAPA generates a 1.25 interest coverage ratio. Defined as the ratio of earnings to debt service costs, the coverage ratio is an indication of WAPA's ability to service its fixed interest charges. It is part of the covenant between WAPA and its debt-holders.

Partially to ensure that WAPA achieves this coverage level, in August 1981 the PSC approved a levelized energy adjustment clause (LEAC) for the rate structure. The LEAC establishes the level of fuel costs to be recovered by WAPA for six-month periods. It is based on projections of those costs and is adjusted for any prior period's over or under recovery of actual fuel costs. From July through December 1991, the LEAC rate was $.016152 per kWh.

In addition to LEAC, in April 1991 the PSC allowed WAPA to petition for a temporary increase in the LEAC rate in excess of fuel costs to satisfy any deficiency in funds necessary to acquire the St. Thomas waste heat recovery boiler. The increase was limited to a maximum two mills per kWh of electricity sales.

Finally, a Maintenance and Capital Fund Surcharge was allowed by the PSC in August 1982 to compensate WAPA for increases in the cost of producing electricity. In April, 1991, the PSC ordered the Maintenance and Capital Fund Surcharge to be a part of WAPA's base rates. The surcharge is currently $0.016897 per kWh of electricity sales.

WAPA's current electricity rate ***structure*** was implemented in July, 1979 by PSC Order No. 23-1979. The order established five classes of electric service: residential, commercial, large power (demand-metered), street lighting, and private security lighting service.

Residential users pay a fixed, customer charge of $2.73 or $7.45 per month, depending on the type of service. The variable charge is $0.09 per kWh for consumption less than 200 kWh and $0.0741 per kWh for consumption exceeding 200 kWh per month. Similarly, all commercial customers pay a monthly fixed charge: $2.68 for single phase and $9.71 for three phase service. The kWh charge for the amount of electricity consumption also varies: 11.59 ¢/kWh up to 1,000 kWh per month, and 9.74 ¢/kWh thereafter.

Charges for large power users depend on the amount of contracted capacity. That is, although the demand charge of $1.62 per month is the same irrespective of the amount of contracted capacity, the variable charge is a function of the amount of contracted capacity.

Currently, the 'average' residential customer on St. Thomas--consuming 393 kWh/month and using a single-phase system--paid $48.02 for electric service (i.e., $2.68+200*$0.09+193*$0.0741). On, St. Croix, the average residential customer with 297 kWh per month pays $34.50. Because the 'average' customer on St. Thomas uses more electricity than the average on St. Croix, the average price paid by the typical St. Thomas customer is higher. Similarly, the 'average' commercial customer on St. Thomas consuming 1,321 kWh per month and using a single-phase system--paid $193.50 per month for electric service. On St. Croix, the corresponding amount is $124.67. Again, because of higher usage by the average customer, the average price per customer is lower for St. Thomas' commercial customers.

4.1.2. Future Possibilities

WAPA's residential, commercial, and industrial tariffs are block rates, consisting of a fixed customer charge and declining energy charges--i.e., declining block rates. That is, the more consumption that a customer has in succeeding rate 'blocks,' the lower the average rate paid. Or, alternatively, the marginal price charged for succeeding blocks of electricity consumption declines as more electricity is used.

Declining block rates are addressed by the Public Utility Regulatory Policies Act Of 1978:

> The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs which are attributable to such energy component decrease as such consumption increases during such period.

There is ample room for WAPA to use electricity pricing as a DSM strategy by devising cost-based electricity rates. The costs of serving different customer classes depends on the pattern of customer loads. Ideally, a tariff could be devised to capture the customer habits of each individual customer. In practice, of course, this is infeasible. An option to aggregate WAPA's customers into broad categories is the use of block rates, as WAPA has currently implemented. However, their current tail block rate structure was devised in 1979; consuming habits have changed dramatically since then.

In other jurisdictions, cost-based electricity pricing has proved a powerful tool to manage electricity demand. Using electricity pricing as a DSM strategy is a behavioral complement used by many Western utilities as part of their technical DSM strategies. It can be used both by itself and as a financial incentive for other demand-side measures (Hill, 1990, 1991a).

To influence the pattern of electricity demand, the most widely adopted pricing strategy by Western utilities other than block rates is time-of-use (TOU) pricing, which refers generally to electricity rates which vary over the course of a year: hour-by-hour, day-by-day, or season-by-season (Hill, 1990). Time-of-day (TOD) pricing, a form of the general class of TOU rates, has generally been effective in shifting electricity consumption from peak to off-peak periods. And, at least for higher volume users (high-volume residential and higher-voltage commercial and industrial users), it has proven to be cost-effective in the United States. Western utilities have also used another form of a TOU tariff, an interruptible or curtailable (I/C) one, to reduce demand on days when capacity utilization is approaching its limit, usually offering rate incentives to large-volume, high-voltage consumers in return for shedding load for a limited amount of time on short notice. From every indication, these tariffs have been successful in reducing both U.S. and Western European capacity requirements.

In the immediate future, time-of-day pricing does not seem to be cost-effective for the residential sector in the USVI. For it to be cost-effective, average consumption levels should be around 1200 kWh per month, typically caused by the penetration of air conditioners and swimming pools (Hill, 1991c). With average consumption levels less than 500 kWh in the USVI's residential sector, devising a residential TOD rate structure does not seem to be worthwhile.

Cost-based electricity pricing does seem to be cost-effective in the commercial and industrial sectors. However, to devise cost-based prices for these two customer classes, a cost-of-service study must be undertaken. The most recent cost-of-service study was completed in 1987 (Beck and Associates, 1987).[1]

4.2. TECHNICAL DSM PROGRAMS

We consider six technical DSM programs, cutting across different end uses and sectors of WAPA's customers:

- a residential time-of-retirement program, including solar water heating, cooling, and refrigeration measures.
- a residential retrofit program, including lighting and other, miscellaneous measures;
- a commercial and industrial time-of-retirement program, including water heating, cooling, electric motors, and other measures;
- a commercial and industrial retrofit program, including lighting and other measures;
- a commercial and industrial load management program; and

[1]Beck and Associates was completing an updated cost-of-service study at the time this report was being prepared.

- a new construction program, including measures to improve the energy efficiency of new residential and commercial establishments.

In the next three sections, we discuss assumptions of the DSM programs for (1) residential customers, (2) commercial and industrial customers, and (3) new construction programs, respectively.

4.2.1. Residential Programs

In Table 4, we summarize characteristics of five residential DSM measures. The measures fall into one of two program categories: time-of-retirement (TOR) or retrofit programs. The TOR measures are targeted at customers when they replace their air conditioners, water heaters, and refrigerators. For the lighting measure of the retrofit program, bulbs and lighting fixtures are installed by WAPA directly because customers lack sufficient information on lighting technologies and their applications. The 'other' measure of the retrofit program is related to the lighting measure. It is implemented simultaneously with the lighting measure. As the note to Table indicates, starred entries (i.e., '***') for the refrigeration measure in the TOR program indicate that sufficient data to quantify the parameters of this measure are not available. The data in Table 4 are divided between those specific to St. Thomas (including St. John) and St. Croix and those common to both islands. Detail on common program data are in Appendices A.1 and A.2 for the TOR and retrofit programs, respectively.

Total customers for each of the five measures are total residential customers as of June 1992, the end of WAPA's fiscal year. They are the same for each measure. The customer program base is the number of customers *assumed* to have the durable under consideration. For example, we assume that all residential customers have lighting fixtures and bulbs. However, we assume that only three-quarters of households have water heaters (footnote e in Table 4), one-fifth have room air-conditioners (footnote f), and 90% have electric refrigerators (footnote g). Also, we only consider room air conditioners because of insufficient data on the penetration of central air conditioners in households.

For common program characteristics in Table 4, the dollar cost and energy savings per participant are based on specific features of each measure. They will be discussed in more detail below. Maximum participation rates and the number of years required to 'ramp up' to the maximum vary across measures. That is, given characteristics of customers such as income and education levels, a relationship exists between the (1) percentage of an electricity-using durable's cost financed by the utility, (2) utility spending for promotion of the program, (3) maximum customer participation, and the (4) 'ramping' rate to maximum participation. For example, if WAPA were to finance more of the cost of an energy-efficient air conditioner, it is likely that more than 50 percent of the customers would purchase the efficient one after three years--i.e., the maximum participation rate would be greater than 50 percent. For the measures listed in Table 4, we assume conservative ramping rates and maximum participation levels, loosely based on the experiences of other utilities running similar programs. The year-by-year participation for each of the measures is provided in Appendices A.1 and A.2.

The conservation load factor (CLF) for each of the measures in Table 4 defines

Table 4
Key Variables for Residential DSM Programs
U.S. Virgin Islands

Category	Time-of-Retirement Program[a]			Retrofit Program[b]	
	Water Heating	Cooling	Refrigeration	Lighting	Other[c]
St. Thomas/St. John					
Total Customers[d]	19,522	19,522	19,522	19,522	19,522
Customer Program Base	14,642[e]	3,904[f]	17,570[g]	19,522	19,522
St. Croix					
Total Customers[d]	18,137	18,137	18,137	18,137	18,137
Customer Program Base	13,603[e]	3,627[f]	16,323[g]	18,137	18,137
Common Program Characteristics					
Cost per Participant	$980[h]	$64[i]	***	$179[j]	$40[k]
Savings per Participant (kWh)	1,698[l]	400[m]	***	304[n]	233[o]
Maximum Participation (%)	75	50	***	60	60
Years to Attain Maximum	3	3	***	10	10
Conservation Load Factor[p]	60	40	***	40	50
Cost of Conserved Energy (¢/kWh)	4.2	1.4	***	3.3	3.3

An entry of '***' means that reliable data are not currently available to quantify the parameters of this portion of the program.

[a]The DSM measures under time-of-retirement programs are implemented when a new replacement durable is purchased--e.g., at the time the durable is depreciated.

[b]A retrofit program refers to house-to-house, direct installation of appropriate DSM measures by representatives of WAPA.

[c]Refers to audit-based, custom energy retrofits on a house-by-house basis. The data in the column reflect amounts for timers, showerheads, low-flow

Table 4 (Cont.)

faucetts, and water heater tank wraps for those not purchasing solar water heaters.

[d]Customers as of June 30, 1992, the end of WAPA's fiscal year.

[e]Assumption: 75% of households have electric hot water heaters.

[f]Assumption: 20% of households have room air conditioners.

[g]Assumption: 90% of households have electric refrigerators.

[h]Assumption: WAPA pays one-half the cost of a solar water heater ($850 average). Assuming a 15% administration cost, the utility's cost per unit is $980.

[i]The incremental cost of the higher-efficiency unit is $112. Assuming that WAPA pays one-half of this amount with a 15% administration fee, the average cost to WAPA is $64 per customer.

[j]Assumption: one-third of the customers are high-usage lighting homes ($220 cost to WAPA) and two-thirds are low-usage homes ($158). The $179/customer is a weighted average of the two. The high-usage homes need on average 3.3 magnetic compact fluorescents, 2.2. electronic compact fluorescents, and one lighting fixture. The total cost is $123. Assuming three hours of labor at $20/hour to install the retrofits and a 20% administrative fee for labor and materials handling, the total cost to WAPA for high-usage homes is $220. Low-usage homes need 2 magnetic compact fluorescents, one electronic, and one lighting fixture for a total cost of $82. Assuming 2.5 hours of labor at $20/hour and a 20% administrative fee for labor and materials handling, the total cost to WAPA is $158.

[k]Assumption: $20/customer for shower heads, faucetts, and hot water heater wraps and a $20 installation fee.

[l]Assumption: one-third, two-thirds, weighted average savings of high-usage (3,000 kWh/year) and low-usage (1,200 kWh/year) customers. High-usage customers save only 90 percent of total usage because they continue to use electricity as a backup to their system.

[m]The average high-efficiency air-conditioner is assumed to save 400 kWh per year.

[n]Assumption: one-third, two-thirds, weighted average savings of high-usage (399 kWh/year) and low-usage (256 kWh/year) customers.

[o]Assumption: one-third, two-thirds weighted average for customers needing all the retrofits (300 kWh savings per year) and customers needing only a portion (200 kWh per year of savings). Also, the water saving measures save 500 gallons of water per year for the average household.

[p]The ratio of average annual load savings for the conservation measure to the amount that the measure saves at the time of the utility's peak.

the relationship between the energy savings of a program (i.e., kWh) and the demand savings (i.e., kW) at the time of WAPA's peak. The CLF is used primarily for modeling purposes, defining the amount and timing of a measure's savings. As the data in Table 4 indicate, the CLF varies for each measure. Finally, the cost of conserved energy (CCE) for each of the programs is listed in Table 4, indicating the relative attractiveness of the DSM measures. The CCE for each of the measures is calculated in Appendices A.1 and A.2 and shown for information purposes only. In comparing DSM measures with generating capacity alternatives in the modeling simulations (Section 5 below), the components of CCE are used: the annual costs of the measures and the total amount of energy saved annually relative to respective amounts for generating alternatives.

The USVI appears to have the climate to support a cost-effective residential solar water heating program. These programs are cost-effective in regions with similar climates such as Jamaica (Conservation Law Foundation, 1990). WAPA could use a number of different financing and promotion mechanisms for this program. One would be to subsidize local solar water heater dealers to reduce the retail price of units so that they will be competitive with other types of water heaters. Another would be to finance the price difference between a solar water heater and other types with no financing charges for buyers. Another method would be to pay the total cost of installing solar water heaters. In this study, we assume that WAPA pays the difference between a solar heater and a conventional one.

We further assume that 14,642 households on St. Thomas and 13,603 on St. Croix have water heaters (Table 4). We further assume that a conventional water heater has an eight-year life. Therefore, the number of customers requiring solar water heaters each year is 1,830 on St. Thomas and 1,700 on St. Croix. After running the program for three years, 75 percent of the customer base participate (Table 4). To attain this penetration rate, WAPA must pay one-half the additional cost of a solar heater in comparison with a conventional one. As footnote h in Table 4 indicates, that amounts to $850 per heater. Assuming 15 percent administration, WAPA must expend $980 on each participant.

Given conditions in the USVI, a number of possibilities exist to improve the efficiency of room air conditioners used in households. One possibility would be to establish progressive performance standards for new room air conditioners that are sold and/or imported into the USVI. This results in a phase-in time for the air conditioners to reach the maximum technical potential of energy efficiency. However, based on a preliminary analysis, it seems that most air conditioners are imported from the U.S. mainland which already has energy efficiency standards.

Another mechanism for increasing the penetration of more efficient air conditioners would be to provide financial incentives to customers purchasing efficient models. Here, we assume that financial incentives are provided to customers at the time of retirement of their old air conditioners. As footnotes i and m to Table 4 indicate, we assume that one-half of residential customers purchase Japanese mini-split air conditioners and the other half purchases high-efficiency window units. Assuming that WAPA pays one-half of the incremental cost of these air conditioners over conventional ones, this results in an out-of-pocket expenditure of $388 per participant by WAPA including 15 percent for administration (Table 4). We further assume that one-tenth of the air conditioners are replaced each year. This means that 390 and 363 are replaced annually on St. Thomas and St. Croix, respectively. After three years, one-half of these customers are assumed to participate in the program--i.e., 50 percent maximum participation. The parameters of this measure are defined further in Appendix A.1.

The amount of savings and cost-effectiveness of a DSM measure to increase refrigeration efficiency depends, of course, on the number, type, and energy-efficiency of refrigerators currently used in the USVI. As indicated in Table 4, data were not available to reasonably estimate the parameters of a refrigeration measure in the residential TOR program.

A DSM measure to increase the penetration of efficient household lighting in the USVI could achieve significant energy savings for WAPA while lowering energy costs for household customers. There are many different types of energy-efficient compact fluorescent bulb and ballast combinations that could be used in USVI households. Selection should be made on a house-by-house basis as part of a direct-installation, retrofit program to provide the required amount of lighting and to fit existing fixtures in USVI homes. An example would be to replace incandescent bulbs with ballasts that have screw-in adapters so that lighting fixtures would not have to be replaced. In cases in which screw-in replacements are not appropriate, fluorescent fixtures would be used as replacement lighting.

Although the initial cost of energy-efficient fluorescents is significantly higher than their incandescent counterparts, a fluorescent bulb will outlast 13 incandescents. Because of high up-front costs, however, this measure must be made attractive to customers when designing a DSM program. The most appealing option is to provide the energy-efficient lights and fixtures at no cost to customers. And, because it is difficult for the average customer to identify the appropriate lighting retrofits, the measure should be part of a direct-installation program. In this program, representatives of WAPA visit customers' homes and install the appropriate lighting retrofits in high-use locations. Because of limited data on lighting in the USVI, we use features of the Jamaican experience (Conservation Law Foundation, 1990) in developing the residential lighting measure in this study. As Footnotes j and n to Table 4 indicate, we assume that two-thirds of residences are small-usage and the other two-thirds are high-usage.

As part of the direct-installation lighting retrofit, an audit of other end-uses of households can be conducted. As footnotes c, k, and o in Table 4 indicate, other measures in the retrofit program include low-flow showerheads, low-flow faucetts, and water heater tank wraps for those customers that do not purchase solar water heaters. Although the energy savings is fairly small (i.e., 233 kWh/year) but financially attractive (3.3 c/kWh CCE), a significant aspect of this program is the water savings that can be obtained. Conservatively estimating that 500 gallons of water can be saved annually by each participant translates into over 11 million gallons annually.

4.2.2. Commercial and Industrial Programs

In Table 5, we provide information for commercial and industrial DSM programs similar to that provided for residential programs in Table 4 with two major differences.

Table 5
Key Variables for Commercial and Industrial Programs
U.S. Virgin Islands

Category	Time-of-Retirement Program[a]				Retrofit Program[b]			Load Mgmt Program
	Water Heating	Air Conditioning[c]	Electric Motors	Other[d]	Commercial Lighting	Industrial Lighting	Other[e]	
St. Thomas								
Total Customers[f]	4,332	4,332	4,332	4,332	3,890	442	4,332	4,332
Customer Program Base	***	3,890[g]	***	***	3,890	442	***	3,890[g]
Cost per Participant	***	$388[h]	***	***	$526[i]	$10,126[i]	***	$500
Savings per Participant (kWh)	***	430[h]	***	***	1,752[j]	33,754[j]	***	5 kW
St. Croix								
Total Customers[j]	3,531	3,531	3,531	3,531	3,177	354	3,531	3,531
Customer Program Base	***	3,177[g]	***	***	3,177	354	***	3,177[g]
Cost per Participant	***	$352[h]	***	***	$390[i]	$6,389[i]	***	$500
Savings per Participant (kWh)	***	500[h]	***	***	1,299[j]	21,298[j]	***	5 kW
Common Program Characteristics								
Maximum Participation (%)	***	75	***	***	90	90	***	50
Years to Attain Maximum	***	3	***	***	10	10	***	10
Conservation Load Factor[k]	***	40	***	***	40	40	***	10
Cost of Conserved Energy (¢/kWh)	***	6.0	***	***	2.5	2.5	***	NA

An entry of '***' means that reliable data are not currently available to quantify the parameters of this portion of the program.

[a] The DSM measures under time-of-retirement programs are implemented when a new replacement durable is purchased--e.g., at the time the durable is depreciated.

[b] A retrofit program refers to house-to-house, direct installation of appropriate DSM measures by representatives of WAPA.

Table 5 (Cont.)

[c]Includes only room air conditioners and is based on the conservative assumption that, on average, each commercial customer has one that will be retiredduring the planning period. Although significant energy savings likely exist for central air conditioners, sufficient data are not available to reasonably estimate the precise costs and savings for central air conditioners. Also, although savings are expected to be substantial, sufficient data do not exist to reasonably estimate the amount of savings for industrial customers.

[d]Depending on the types of activities in the VI's commercial and industrial sectors, substantial savings could be realized from a program targeted at other types of durables such as refrigerators, stoves, and the like.

[e]This portion of the retrofit program targets custom-tailored DSM measures for individual commercial and industrial establishments. Therefore, the types of retrofits and their cost and energy savings will be available only when audits are conducted.

[f]Customers as of June 30, 1992, the end of WAPA's fiscal year. Total customers for all measures except lighting are the sum of commercial and industrial customers.

[g]Because of data limitations, data includes only commercial customers.

[h]Assumption: one-half of the participants purchase a mini-split system (i.e., window 9.0 to mini-split 12.0); the other half purchase higher-efficiency window units (i.e., 9.0 to 12.0). The incremental cost of the mini-split system is $500; the incremental cost for the higher-efficiency unit is $112. Assuming WAPA pays one-half and a 15% administration fee, the average cost to WAPA is $352. Mini-splits save 600 kWh per year; high-efficiency air-conditioners save 400 kWh per year. Assuming a 50-50 split, the savings is 500 kWh per year.

[i]Assumption: the cost of lighting savings for both commercial and industrial customers is $300/MWh/year of energy savings.

[j]Assumption: lighting is 25% of the commercial-industrial load and 40% of this load can be saved through a lighting retrofit program. The average annual usage for commercial and industrial customers on St. Thomas is 17,522 kWh and 337,541 kWh, respectively. The corresponding amounts for St. Croix are 12,986 kWh and 212,981 kWh.

[k]The ratio of average annual load savings to peak load savings for the DSM measure.

First, the cost and amount of savings for the lighting measure are based on experiences elsewhere, rather than on specific retrofits. That is, as footnote j indicates, we assume that lighting accounts for 25 percent of the electricity consumed in the commercial-industrial sector and that a direct-installation lighting measure can save 40 percent of this amount. Therefore, the lighting program can save 10 percent of the total electricity consumption of commercial and industrial customers that participate in the program.

Second, our knowledge of the penetration of electricity use in the commercial-industrial market and, therefore, the potential for energy savings is limited, accounting for the large number of starred entries in Table 5. A good example is the penetration of electric motors for industrial customers. On the U.S. mainland, electric motors account for two-thirds of electricity consumption in the industrial sector with a large potential for energy savings through use of more efficient electric motor systems. Using this as a reference, we surmise that there is a large potential for energy savings in the USVI. However, current data limitations preclude approximation of a program for this study.

Therefore, as shown in Table 5, we only quantify two measures for the commercial-industrial sector--one each for TOR and retrofit programs--recognizing that this vastly underestimates the potential for cost-effective DSM measures for these customers. For the cooling measure, we assume that one-tenth of conventional air conditioners are replaced each year. Therefore, 389 and 318 are replaced annually on St. Thomas and St. Croix, respectively. At 75 percent maximum participation after three years (Table 5), 292 and 238 customers are assumed to participate in the program (Appendix A.3). We conservatively assume that the average commercial customer has one window air conditioner. Again, as with the residential cooling measure, we only consider room air conditioners because the penetration of central air conditioners cannot be accurately estimated. And, we do not have information on the types of air conditioners used by WAPA's industrial customers.

Based on experiences elsewhere, commercial and industrial lighting measures rank toward the top in terms of financial attractiveness to electric utilities. Based on the CCE for these measures in Table 5, there is reason to believe that that should also be the case in the USVI. As noted above, we do not use a fixed number of bulbs or fixtures to estimate savings from the lighting measure. Rather, based on experiences elsewhere, we assume that a lighting program will save 10 percent of average electricity consumption in the commercial and industrial sectors. For the commercial sector as Table 5 shows, this amounts to an annual savings of 1,752 and 1,299 kWh per customer for St. Thomas and St. Croix, respectively. The corresponding amounts are 33,754 and 21,298 for industrial customers. Again, based on experiences elsewhere, we assume that it will cost WAPA $300/MWh/year to achieve this savings. Given this expenditure, we assume that 90 percent of WAPA's commercial and industrial customers will participate in the program after 10 years (Table 5).

The load management program described in Table 5 is defined conservatively to cost $100 per saved kilowatt. Assuming that 5 kW can be obtained from each participant on average, the total cost is $500/participant. We assume that it takes 10 years of program operation to reach maximum participation of 50 percent. 'Ramping rates' and total program savings are defined in detail in Appendix A.5.

4.2.3. New Construction Program

The programs defined in Tables 4 and 5 apply to existing customers as of June 1992. In Table 6, we quantify key variables for a DSM program that applies to new construction after June 1992 for the residential and commercial rate classes. As Footnotes b and c indicate, we assume that the growth rate of new construction is one-half of the annual average rate over the five-year period from 1987 through 1992. For the residential sector, the cost per participant and energy savings for WAPA noted in Table 6 are the sums of the amounts for the solar water heating and cooling portions of the residential TOR program (Table 4). Again, quantities for the commercial sector are difficult to estimate with data currently available.

Table 6
Key Variables for New Construction Programs
U.S. Virgin Islands

Category	Residential[a]	Commercial
St. Thomas/St. John		
Total Customers	145[b]	93[b]
Customer Program Base	145	93
St. Croix		
Total Customers	185[c]	82[c]
Customer Program Base	185	82
Common Program Characteristics		
Cost per Participant	$1,680[d]	***
Savings per Participant (kWh)	1,298[e]	***
Maximum Participation (%)	75	***
Years to Attain Maximum	3	***
Conservation Load Factor[f]	50	***
Cost of Conserved Energy (¢/kWh)	4.7	***

An entry of '***' means that reliable data are not currently available to quantify the parameters of this portion of the program.

[a]The solar water heating and cooling portions of the residential time-of-retirement program are included for newly constructed residences.

[b]Assumption: the growth rates of new construction in the residential and commercial sectors are assumed to be one-half the average annual five-year historical rate over the years 1987 to 1992. The historical rates for the residential and commercial sectors over that five-year period are 1.5% and 4.8%, respectively.

[c]Assumption: the growth rates of new construction in the residential and commercial sectors are assumed to be one-half the average annual five-year historical rate over the years 1987 to 1992. The historical rates for the residential and commercial sectors over that five-year period are 2.0% and 5.2%, respectively.

[d]The sum of costs of the solar water heating and cooling portions of the residential time-of-retirement program shown in Table 5, plus a 15% administration fee.

[e]The sum of the savings from the solar water heating and cooling portions of the residential time-of-retirement program shown in Table 5.

[f]The ratio of average annual load savings to peak load savings of the DSM measure.

5. MODEL SIMULATIONS

5.1. DESCRIPTION OF SAFEPLAN

A number of models have been developed to assess DSM and supply resources with varying degrees of analytical complexity and data requirements. Examples include the Multiobjective Integrated Decision Analysis System (MIDAS) developed for the Electric Power Research Institute (Temple, Barker, and Sloane, 1988), UPlan developed by the Lotus Consulting Group (1988), the Decision Impact Assessment Model (DIAMOND) developed by Oak Ridge National Laboratory (Gettings, Hirst, and Yourstone, 1991), and Scenario Analysis Framework for Expansion Planning (SAFEPLAN) (Policy Planning Associates, 1990). The more important characteristics of these models include (with possibilities):

■ capacity expansion capability (yes, no); i.e., the capability to determine the optimal set of generating plant options, given assumptions about future load growth, fuel prices, and the like.

■ treatment of time-of-use variations in demand (load duration curve, chronological); i.e., the extent to which the model allows the user to provide detail of changes in the load over 8,760 hours of the year on an hourly basis (chronological) or a more aggregated basis (an annual load duration curve).

■ production costing routine (yes, no); i.e., the ability of the model to determine the optimal generation mix (loading order), given characteristics of existing generating units (e.g., the types and amount of capacity, fuel type, cost of fuel, hourly load).

■ financial simulation module (yes, no); i.e., the model's ability to provide primary financial statements (i.e., the income statement, balance sheet, and flow-of-funds statements) and calculate important financial ratios (i.e., interest coverage ratio, present value of revenue requirements).

■ treatment of uncertainty (yes, no); i.e., the model's capability to provide ranges for forecasts or expected values of important outputs.

The degree of complexity of a planning model--and user unfriendliness--is related to the manner in which each of these characteristics is treated. A model that has capabilities to:

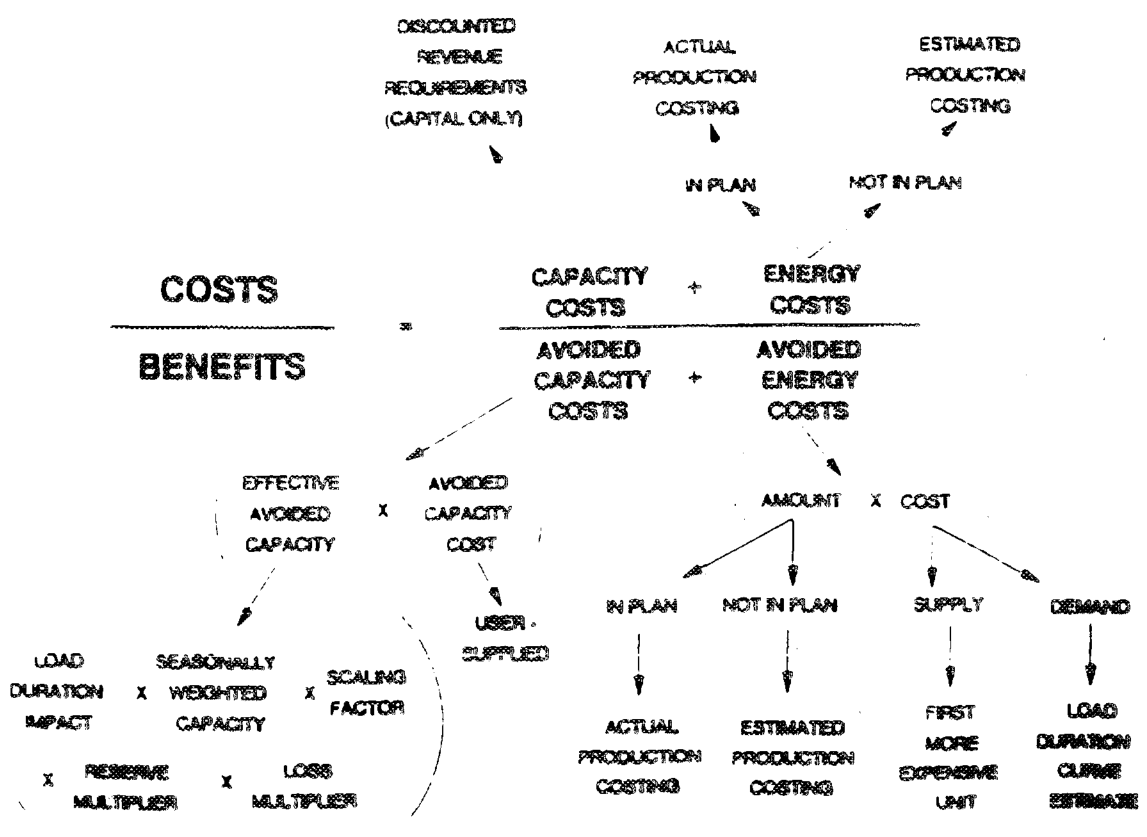
- select an optimal mix of resources,
- characterize demand for 8,760 hours in every year of the planning horizon,
- determine the variable costs of employing supply-side resources,
- simulate the financial performance of the utility, and
- include uncertainties in resource selection

tends to be very large and complex with significant data requirements. Selection of a model for any purpose, of course, depends on the uses to which the model is to be put.

SAFEPLAN was selected because it satisfied the requirements of this study. The model facilitates developing multiple plans, minimizing data requirements.

In Figure 4, we show how cost-benefit ratios are calculated for any DSM or supply resource in SafePlan. The costs of a project are the sum of capacity and energy costs. Capacity costs are the present value of the time stream of construction expenditures provided for each candidate resource. They are applicable only for those projects that take multiple periods to construct. In the WAPA simulations discussed below, the only project that is multiperiod is the combustion turbine. We assume that it takes three years to construct with a 20-20-60 apportionment of the construction costs. The assumed discount rate is 10 percent.

Figure 4
Calculation of Cost-Benefit Ratios in SafePlan



Actual energy costs for a project are determined by economic dispatch in the production costing model. For resources not included in the current plan, energy costs are estimated from units that were included in the dispatch. The capacity utilization factor of the next more expensive unit in the dispatch is used to determine the amount of energy assigned to the project. If a candidate resource is more expensive than the last unit, it is assigned the capacity utilization factor of the last unit. To determine energy costs, these running rates are multiplied by the variable costs of the candidate resources provided by the user. For that combustion turbine, we assumed a fixed O&M cost of $2.00 per kilowatt of installed capacity. The fuel cost is scenario-based and discussed in detail below.

Calculating the two avoided cost components is more complex. Avoided capacity costs are the product of a user-supplied avoided capacity value (in this case, a combustion turbine) and effective avoided capacity. The latter is the product of several factors as shown in Figure 4 and is important in determining the capacity contribution of DSM resources. That is, because DSM resources reduce capacity requirements, they also reduce corresponding reserve requirements. In our simulations, we assume that WAPA requires a 33 percent reserve margin because of its inability to purchase power from neighboring utilities. Therefore, from Figure 4, the reserve multiplier is 1.33 for an DSM resource: a kilowatt of supply capacity is worth 1.33 kW if obtained from a DSM program. Similarly, avoiding construction of one kW of capacity through a DSM program reduces technical losses of transmitting and distributing electricity. We assume a 15 percent loss factor; therefore, from Figure 4, the loss multiplier is 1.15.

Avoided energy costs are estimated as the cost of supplying energy with other resources in the plan. They are the weighted average of the costs of units that have available generation and are more expensive than the candidate resource. Each candidate resource, therefore, has a unique avoided cost. For avoided energy costs of supply resources, the "first more expensive unit" in Figure 4 is the utilization-weighted average cost of under-utilized, more expensive units. The avoided energy costs of candidate DSM resources are estimated using their effects on the load duration curve.

5.2. FIVE SCENARIOS

In Table 7, we provide the growth in fuel prices, the growth in peak load, and the treatment of environmental externalities for five scenarios that were simulated in the study. For each of the five scenarios, the assumed values of two important variables did not change: the system load factors and the capacity cost of the avoided generating unit (i.e., the combustion turbine). The system load factor is defined in a manner similar to the conservation load factor defined in Tables 5, 6, and 7: it is the ratio of average load (i.e., kWh generated divided by 8,760 hours) to peak load. The capacity cost of the avoided generating unit is important. In determining the cost-effectiveness of different resource options, it determines the avoided capacity costs of the benefits of employing a resource (see Figure 4). Throughout this study, we use a combustion turbine as the avoided unit. That combustion turbine costs $400 per kW (1992 dollars) and, therefore, has an annual cost of $30/kW.[2] The fuel costs for this avoided unit, of course, are the same ones used for existing units.

Table 7
Definition of Scenarios for Model Simulations
St. Thomas and St. Croix

Scenario	Fuel Prices (%/Year)	Peak Load (% Growth)	Externalities (Scenario)
No Fuel Price Increases[a]	0	2.3	None
EIA Fuel Price Forecasts[b]	2.0	2.3	None
High Fuel Price Increases[c]	4.0	2.3	None
High Load Growth[d]	2.0	3.3	None
Environmental Externalities[e]	2.0	2.3	15% Adder

[a]Assumes that real fuel prices do not increase over the forecast period.

[b]Assumes that fuel prices increase at the fossil fuel rate increase projected by the Energy Information Administration (EIA).

[c]Assumes that fuel prices increase at two times the rate of growth forecasted by EIA.

[d]Assumes that peak load grows at one percentage point higher rate of growth than that projected by WAPA.

[e]Includes 15% additional cost for environmental externalities, increasing the cost of producing electricity using fossil fuel generating units.

The five scenarios were devised to look at the effects of three factors on resource selection: (1) the cost of fuel prices for generating electricity, (2) the projected growth in electric load, and (3) the effect of accounting for externalities in resource selection. The base scenario is the the second one: fuel prices increase at the real rate of 2.0 percent per year, electric load for both St. Thomas and St. Croix grows at WAPA's forecasted rate (2.3 percent per year on average), and environmental externalities are not considered.

The major feature of the first scenario is that the real price of No. 2 and No. 6 fuel

[2]This annual charge can be viewed as delaying the construction of a combustion turbine for one year indefinitely into the future. Therefore, it is the difference between the net present value of revenue requirements for a combustion turbine placed in operation this year and that same unit placed in operation next year. To see the importance of this value in determining the cost-effectiveness of resources under consideration, a 600-MW coal plant at $1,600 per kilowatt has an annual capacity cost of $120/kW.

for generating electricity does not increase. Peak load growth over the next 20 years is that provided by WAPA (U.S. Energy Information Administration, 1991). Characteristics of DSM programs for this scenario are provided in Tables 5 through 7.

In the second scenario, we look at the effect of rising fuel prices on the cost-effectiveness of different resources. Therefore, we use the Energy Information Administration's forecast of fossil fuel price increases over the 20-year planning horizon. Under this forecast, the prices of these fuels grow at the annual rate of 2.0 percent over the planning horizon. For the third scenario, we examine very high fuel price growth rates, doubling EIA's forecast to a 4.0 percent annual rate over the 20-year horizon.

In the fourth scenario, we keep EIA's fuel price forecasts, but increase WAPA's projected load growth figures. For St. Thomas, we use an annual average load growth of 2.3 percent for the summer peak from 66.0 MW in June 1992 to 97.8 MW in June 2012 and 2.3 percent for the winter peak from 59.7 MW in February 1993 to 92.1 MW in February 2013. These growth rates were used for the first three scenarios. In the fourth scenario, we increase St. Thomas' 20-year summer peak growth to 121.4 MW (3.3 percent average annual growth) and the winter peak to 114.8 MW (also a 3.3 percent average annual growth). The average annual percentage increases for St. Croix are similar. Summer peak load is 74.2 MW in September 2012. The corresponding amount for the winter peak in December is 71.7.

The fifth scenario addresses the question of environmental externalities. Here, we add environmental costs to the operating costs of existing and future fossil fuel plants. Rather than quantifying the cost of each of the effluents, we use a 'percentage adder' of 15 percent. As discussed in Section 1.2.3, the adder approach is one of three used by electric utilities. The 15 percent is one that has been used in Wisconsin (Wisconsin Electric Power Company, 1988). The effect of including environmental externalities, of course, is to increase the operating cost of fossil units, making them relatively more unattractive in the resource selection process in comparison with alternatives that do not use fossil fuels.

5.3. SIMULATION RESULTS

5.3.1. Five Scenarios

In Table 8, we provide the cost:benefit ratios of the DSM measures that were calculated in SafePlan.[3] Several conclusions emerge from the data in the table.

First, although the DSM measures were defined similarly for each of the islands (see Tables 5 through 7), their cost-effectiveness differs on St. Thomas and St. Croix. The reasons, of course, are due to differences in the operating characteristics of the two islands.

Second, cost-effectiveness varies across scenarios. For example, the residential

[3]For details of the calculation, see the discussion in Section 5.1 in the context of Figure 4.

Table 8
Cost-Benefit Ratios for DSM Programs from Model Simulations

Area/Measures[a]	Modeling Simulation Scenario				
	No Fuel Increases	EIA Fuel Increases	High Fuel Increases	High Load Growth	Environmental Externalities
St. Thomas					
Residential Water Heating	0.90	0.69	0.52	0.71	0.61
Residential Cooling	0.22	0.17	0.13	0.18	0.15
Residential Retrofit	0.58	0.45	0.34	0.47	0.40
Residential New Construction	1.22	0.92	0.69	0.96	0.82
Commercial Air Conditioning	1.01	0.78	0.59	0.82	0.69
Commercial Lighting	0.43	0.33	0.25	0.35	0.29
Industrial Lighting	0.43	0.33	0.25	0.35	0.29
Load Management	0.32	0.24	0.18	0.25	0.22
St. Croix					
Residential Water Heating	0.96	0.72	0.53	0.76	0.64
Residential Cooling	0.19	0.14	0.11	0.15	0.13
Residential Retrofit	0.48	0.36	0.27	0.38	0.32
Residential New Construction	1.01	0.75	0.55	0.79	0.66
Commercial Air Conditioning	0.83	0.62	0.46	0.66	0.55
Commercial Lighting	0.35	0.26	0.19	0.28	0.24
Industrial Lighting	0.35	0.26	0.19	0.28	0.24
Load Management	0.31	0.23	0.17	0.24	0.21

[a]The DSM measures are defined in Tables 5-7.

cooling DSM measure on St. Thomas is clearly cost-ineffective under the 'no fuel increases' scenario--i.e., a cost:benefit ratio of 1.28. However, as fuel prices are assumed to increase--i.e., as the cost of providing electricity from a combustion turbine increases--the residential cooling option becomes more attractive. It is a borderline option under the 'EIA fuel increases' scenario (cost:benefit of 0.99) and clearly cost-effective under the 'high fuel increases' scenario. Similar arguments can be made for other DSM measures under different scenarios.

Third, the commercial and industrial lighting measures and the load management programs on the two islands are the clearly the most cost-effective DSM measures. Under the worst-case scenario for DSM measures--i.e., no increases in the real price of No. 2 and No. 6 fuel--those three measures are almost the only cost-effective measures on St. Croix (the residential water heating measure is the exception) and the three most cost-effective on St. Thomas. As restrictive fuel-price and load-growth assumptions are relaxed, these three measures become even more attractive from the standpoint of resource acquisition. The cost-effectiveness of these three measures is generally consistent with that which is found in the experiences of other utilities.

In Table 9, we summarize the simulation results for St. Thomas and St. Croix for the five scenarios. The dollar values are the present value of the costs of satisfying WAPA's electric load from 1993 to 2012 with cost-effective DSM programs included in the analysis and with cost-effective DSM programs excluded. In the 'without DSM' simulations, we use only a 22-MW combustion turbine to satisfy WAPA's projected load. In the 'with DSM' simulations, we implement cost-effective DSM programs in 1993 (i.e., based on the ratios in Table 8) until all eight programs are exhausted or capacity and energy requirements are met--whichever comes first. Any remaining load requirements are met by constructing combustion turbines.

The results in Table 9 show that including cost-effective DSM programs to satisfy future load requirements has a significant impact on the cost of providing electricity services, irrespective of the assumptions made about fuel price growth, load growth, and environmental externalities. Put simply, this means that, under all scenarios, the cost of conserved energy for the cost-effective measures is less than WAPA's avoided cost of power. The avoided cost, of course, is based on simulations of the system using SafePlan. The cost savings are greater on St. Thomas because there are more electric customers and electricity consumption is larger on these islands than St. Croix and, therefore, the potential for DSM programs is greater. The largest amount of savings are associated with a higher assumed load growth ('high load growth' scenario) because more cost-effective DSM programs can be implemented with higher levels of load growth. From Table 9, the difference between present value of costs without DSM measures and the value of costs with DSM measures is $163.6 million over the 20-year planning horizon.

The energy savings resulting from implementing DSM measures and their contributions to capacity under the five scenarios are presented in Table 10. One of the main reasons for the decline in the percentage contribution of DSM measures from 2002 to 2012 is the assumption that the initial savings in many DSM measures declines over the 20-year planning period after the life of the energy-efficient durable expires. The assumption is that WAPA runs DSM programs to capture the initial market. It does not

Table 9
Cost Savings from Running DSM Programs
St. Thomas and St. Croix
(In Millions of 1992 Dollars)

Scenario	Total Plan Cost[a]		
	St. Thomas	St.Croix	Total
No Fuel Price Increases			
Without DSM	663.7	238.4	902.1
With DSM	612.1	210.0	822.1
Savings	51.6	28.4	80.0
EIA Fuel Price Forecasts			
Without DSM	795.7	284.4	1,080.1
With DSM	723.6	261.7	985.3
Savings	72.1	22.7	94.8
High Fuel Price Increases			
Without DSM	980.6	348.9	1,329.5
With DSM	878.2	318.4	1,196.6
Savings	102.4	30.5	132.9
High Load Growth			
Without DSM	924.5	321.5	1,246.0
With DSM	785.2	297.2	1,082.4
Savings	139.3	24.3	163.6
Environmental Externalities			
Without DSM	900.6	320.6	1,221.2
With DSM	817.3	294.6	1,111.9
Savings	83.3	26.0	109.3

[a]The net present value of the incremental cost of servicing electric load over the 20-year planning horizon.

Table 10
Energy and Capacity Contributions of DSM Programs
St. Thomas and St. Croix
2002 and 2012
(In Percentages)

Scenario/ Region	Energy[a]		Capacity[a]	
	2002	2012	2002	2012
No Fuel Price Increases				
St. Thomas	9.4	5.6	100.0	53.5
St. Croix	6.9	3.6	100.0	100.0
Total	8.5	4.8	100.0	65.1
EIA Fuel Price Increases				
St. Thomas	10.2	6.5	100.0	55.6
St. Croix	6.9	3.6	100.0	100.0
Total	8.9	5.4	100.0	66.3
High Fuel Price Increases				
St. Thomas	10.2	6.5	100.0	55.6
St. Croix	6.9	3.6	100.0	100.0
Total	8.9	5.4	100.0	66.3
High Load Growth				
St. Thomas	9.0	5.1	100.0	38.1
St. Croix	11.8	7.3	100.0	50.9
Total	10.0	5.9	100.0	43.1
Environmental Externalities				
St. Thomas	9.7	6.5	100.0	55.6
St. Croix	6.9	3.6	100.0	100.0
Total	8.7	5.4	100.0	66.3

[a]The portion of total energy and capacity accounted for by DSM programs.

run programs over the 20-year planning horizon. The savings for each of the DSM measures on each of the islands is provided in detail in Appendix A.

The results in Table 10 are consistent with the cost savings provided in Table 9. For example, the largest amount of energy savings comes under the high load growth scenario where cost-effective DSM programs have a better opportunity to be adopted because of higher energy and capacity requirements. Again, the results in Table 10 understate the energy savings and capacity contributions of DSM programs because many expected cost-effective DSM programs were not defined.[4]

5.3.2. Wind Generation as a Resource Option

Wind as an electric generating resource option was not compared with a combustion turbine and DSM measures in all of the simulations. One of the primary reasons was data limitations. Ideal wind generation sites were not determined at the time of running of the simulations. Those sites are crucial for cost determination because of the high cost of land in the USVI relative to other regions where the data has been gathered on wind generation.

However, based on experiences elsewhere, the parameters of a wind generating resource were quantified and varied to look at the potential for wind as a future generating option. The wind resource under consideration was 250 kW with a total installed capacity cost of $253,250. Net annual energy from the turbines is 438 MWh. It has a fixed O&M cost of $8.00/kW and 0.7 ¢/kWh variable O&M cost. A wind turbine with 125 kW capacity is assumed to require 0.75 acres of land. The capacity factor of the plant is 20 percent. The plant has a 20-year life.

The cost:benefit ratio for this wind system on St. Thomas was simulated to be 0.66 under the base scenario (EIA fuel price increases). Doubling the capital cost makes the system cost ineffective: 1.27 cost:benefit ratio. Doubling the O&M cost, but holding capital cost constant results in a 0.71 ratio. Doubling both the capital and operating cost components, of course, results in a 1.32 cost:benefit ratio.

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[4] See the starred entries in Tables 5 through 7 for details of the DSM measures that were not considered in the simulations because of data limitations.

6. RECOMMENDATIONS

In this study, we suggested some alternatives to constructing and operating combustion turbine electric generating plants to satisfy future electric energy and load requirements in the USVI. The economic attractiveness of the suggested alternatives was based on a rigorous comparison of their costs and benefits.

The key point to remember is that IRP is not a one-time study. Rather, it is a continuing process, the exact procedures of which for a given utility evolve over time. Although undertaken with the cooperation and assistance of WAPA staff, this assessment was largely conducted at ORNL. It should be viewed as the springboard for IRP activities, not an end in itself. Three types of activities should be pursued to develop WAPA's capability to properly compare DSM and supply resources:

- Familiarization with IRP,
- Information gathering,
- Resource comparison.

6.1. FAMILIARIZATION WITH IRP

It would be beneficial to have two separate levels of familiarization: one at the executive level and the other for staff members of WAPA and other government agencies. The executive presentation should last a maximum of one-half day and should include an overview of the two components of the IRP process--least-cost planning and demand-side planning--and how they are used together as an analytical tool. The benefits to the USVI from achieving lower-cost electricity services should be identified, and their prospective magnitudes presented so that decisionmakers can understand the potential contribution IRP could make to achieving their goals. The presentation should also include a discussion of the social costing of resources. It should also include the experience of other utilities with IRP: motivation for IRP, reporting requirements, the extent of usage, and the benefits obtained from its use. Ideally, there would be several speakers at the session, representing research, utility, and regulatory experiences.

Once the IRP process is adopted, there should be an intensive series of sessions on detailed aspects of its implementation. These sessions should be attended by the practitioners and their managers, rather than executives. This portion of the training would last no more than one week, and again include both utility and regulatory perspectives. The IRP familiarization would ideally be organized around five topics:

- Least-cost planning

This session would discuss conceptual and pragmatic issues in analyzing the optimal mix of supply resources.

- Demand-side management

This session would cover three areas: (1) methods to develop DSM programs, including data requirements; (2) the process of implementing DSM programs; and (3) the process of evaluating DSM programs.

- Social costing of resources

The environmental (and other) externality debate is introduced in this session. The discussion includes the types of approaches that can be used to incorporate externalities into decisionmaking, along with the experiences of electric firms in other parts of the world.

- Integrated resource planning

This portion will cover two areas: (1) existing models to compare DSM and supply resources and (2) important factors to consider when comparing them, including differences in their financial, economic, and reliability characteristics.

- Conservation Technologies

This portion of the training would introduce the engineering aspects of energy-efficiency improvements, including the types of off-the-shelf technologies that are currently available and the energy savings likely to result from their use.

6.2. INFORMATION GATHERING

In Section 4, we pointed out the types of data needed to implement the IRP process and data requirements for designing, implementing, and evaluating DSM programs. In fact, a good starting point in understanding the types of data needed is the information provided in Tables 5, 6, and 7 of Section 4, especially the program assumptions provided in the footnotes to those tables.

Ideally, data are needed on electricity consumption by end use (e.g., lighting, refrigeration). Data are also needed on the customer base of the programs. How many potential customers will particpate in a commercial lighting program? A residential solar water heating program? Data is also required on the resource base for renewable supply options. Besides quantities, many other types of information are required. Many of them relate to the institutional structure of the USVI. For example, information on the possibility of using different financing mechanisms for DSM programs is required. The ownership of the housing stock must also be considered (e.g., public vs. private housing). These types of data, however, are not routinely collected by government agencies in the USVI or WAPA.

Several methods can be used to collect the type of information required to implement an IRP process. First, customers can be metered to accurately quantify end-use consumption. The on-going metering in the renewable energy district in Frederiksted should provide important information here. Lacking funds or time to meter, another method is a survey of electricity customers on their consumption patterns and durable ownership. Finally, a controlled experiment in the form of a pilot program has been used extensively by many mainland utilities. The information obtained from the pilot is then used to develop a program for the entire island.

6.3. RESOURCE INTEGRATION

The third activity is the heart of the process: resource comparison. The activity involves procuring and adapting a model to systematically assess the different financial, economic, and reliability dimensions of DSM and supply resources. The outcome of the process is a plan or strategy for employing resources in the future. There should be a short-term action plan produced which requires the immediate attention of WAPA and other policymakers. The second output of the process is a long-term integrated resource plan spanning a 15- to 20-year period. This plan provides a resource road map for policymakers.

Changing conditions external to WAPA (e.g., changing fuel input prices, electricity demand growth rates, and the costs of financing) suggest that IRP is not a one-time study, but rather a continuing *process*. An appreciable change in any one of these variables can alter the relative cost-effectiveness of resources. Recognizing the dynamics of this process, another recommendation is that IRP be institutionalized at WAPA. One method is to have regular plan updates. For example, a common practice with utilities on the mainland is to perform a full-scale, integrated resource plan every three years. However, in the intervening two years, the utilities are required to update the plan based on changing external circumstances.

Because IRP is a continuing process, we also recommend that changes be made in the organizational structure of WAPA to accommodate the process. One approach used on the mainland is to organize around the IRP process using a team concept, drawing upon appropriate staff from all departments within the utility. The center of the process, an integration team, takes input from a demand-side team and a supply-side team. The integration team is ultimately responsible for developing the integrated plan.

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APPENDIX A

TECHNICAL DSM PROGRAMS

A.1. RESIDENTIAL TIME-OF-RETIREMENT PROGRAM

Residential Water Heating Program--St. Thomas

		Participation			Total MWh Savings	Total Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	25	458	458	777	448	448		0.15
1994	2	50	915	1,373	2,331	897	897	448	0.44
1995	3	75	1,373	2,745	4,662	1,345	1,345	897	0.89
1996	4	75	1,373	4,118	6,992	1,345	1,345	1,345	1.33
1997	5	75	1,373	5,491	9,323	1,345	1,345	1,345	1.77
1998	6	75	1,373	6,863	11,654	1,345	1,345	1,345	2.22
1999	7	75	1,373	8,236	13,985	1,345	1,345	1,345	2.66
2000	8	75	1,373	9,609	16,316	1,345	1,345	1,345	3.10
2001	9	75	0	9,609	16,316	0	0	1,345	3.10
2002	10	75	0	9,609	16,316	0	0	0	3.10
2003	11	75	0	9,609	16,316	0	0	0	3.10
2004	12	75	0	9,609	16,316	0	0	0	3.10
2005	13	75	0	9,609	16,316	0	0	0	3.10
2006	14	75	0	9,609	16,316	0	0	0	3.10
2007	15	75	0	9,609	16,316	0	0	0	3.10
2008	16	75	0	9,609	16,316	0	0	0	3.10
2009	17	75	0	9,609	16,316	0	0	0	3.10
2010	18	75	0	9,609	16,316	0	0	0	3.10
2011	19	75	0	9,609	16,316	0	0	0	3.10
2012	20	75	0	9,609	16,316	0	0	0	3.10
								0	

Customer Base	1,830	per year (1/8*14642)	5,991	5,446	---Net Present Value
Cost/Cust.	$980	($850 + 15% administration fee)			
Savings/Cust.	1,698	kWh		545	---$000 Savings
CLF	0.6			13,091	---Avg. MWh Savings
				4.2	---CCE

Residential Water Heating Program--St. Croix

		Participation			Total	Total	CCE		Total
		%	New	Total	MWh Savings	Cost ($000)	Current	Deferred	MW Savings
1993	1	25	425	414	703	417	417		0.13
1994	2	50	850	1,264	2,147	833	833	417	0.41
1995	3	75	1,275	2,539	4,312	1,250	1,250	833	0.82
1996	4	75	1,275	3,815	6,477	1,250	1,250	1,250	1.23
1997	5	75	1,275	5,090	8,643	1,250	1,250	1,250	1.64
1998	6	75	1,275	6,365	10,808	1,250	1,250	1,250	2.06
1999	7	75	1,275	7,641	12,974	1,250	1,250	1,250	2.47
2000	8	75	1,275	8,916	15,139	1,250	1,250	1,250	2.88
2001	9	75	0	8,916	15,139	0	0	1,250	2.88
2002	10	75	0	8,916	15,139	0	0	0	2.88
2003	11	75	0	8,916	15,139	0	0	0	2.88
2004	12	75	0	8,916	15,139	0	0	0	2.88
2005	13	75	0	8,916	15,139	0	0	0	2.88
2006	14	75	0	8,916	15,139	0	0	0	2.88
2007	15	75	0	8,916	15,139	0	0	0	2.88
2008	16	75	0	8,916	15,139	0	0	0	2.88
2009	17	75	0	8,916	15,139	0	0	0	2.88
2010	18	75	0	8,916	15,139	0	0	0	2.88
2011	19	75	0	8,916	15,139	0	0	0	2.88
2012	20	75	0	8,916	15,139	0	0	0	2.88
								0	

Customer Base	1,700	per year (1/8*13603)	5,566	5,060	---Net Present Value
Cost/Cust.	$980	($850 + 15% Administration Fee)			
Savings/Cust.	1,698	kWh		506	---$000 Savings
CLF	0.6			12,144	---Avg. MWh Savings
				4.2	---CCE

Residential Cooling Program--St. Thomas

		Participation			Total MWh Savings	Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	20	78	78	31	5	5		0.01
1994	2	40	156	234	94	10	10	5	0.03
1995	3	50	195	429	172	12	12	10	0.05
1996	4	50	195	625	250	12	12	12	0.07
1997	5	50	195	820	328	12	12	12	0.09
1998	6	50	195	1,015	406	12	12	12	0.12
1999	7	50	195	1,210	484	12	12	12	0.14
2000	8	50	195	1,405	562	12	12	12	0.16
2001	9	50	195	1,601	640	12	12	12	0.18
2002	10	50	195	1,796	718	12	12	12	0.21
2003	11	0	0	1,796	703	0	0	12	0.20
2004	12	0	0	1,796	671	0	0	0	0.19
2005	13	0	0	1,796	632	0	0	0	0.18
2006	14	0	0	1,796	593	0	0	0	0.17
2007	15	0	0	1,796	554	0	0	0	0.16
2008	16	0	0	1,796	515	0	0	0	0.15
2009	17	0	0	1,796	476	0	0	0	0.14
2010	18	0	0	1,796	437	0	0	0	0.12
2011	19	0	0	1,796	398	0	0	0	0.11
2012	20	0	0	1,796	359	0	0	0	0.10
								0	
							68	62 ---Net Present Value	

Customer Base	390 (3,904*1/10 deprec. per year)
Cost/Cust.	$64
Savings/Cust.	400 kWh
CLF	0.4

6 ---$000 Savings

451 ---Avg. MWh Savings

1.4 ---CCE

Residential Cooling Program--St. Croix

		Participation			Total MWh	Cost	CCE		Total MW
		%	New	Total	Savings	($000)	Current	Deferred	Savings
1993	1	20	73	73	29	5	5		0.01
1994	2	40	145	218	87	9	9	5	0.02
1995	3	50	181	399	160	12	12	9	0.05
1996	4	50	181	580	232	12	12	12	0.07
1997	5	50	181	762	305	12	12	12	0.09
1998	6	50	181	943	377	12	12	12	0.11
1999	7	50	181	1,124	450	12	12	12	0.13
2000	8	50	181	1,306	522	12	12	12	0.15
2001	9	50	181	1,487	595	12	12	12	0.17
2002	10	50	181	1,668	667	12	12	12	0.19
2003	11	0	0	1,668	653	0	0	12	0.19
2004	12	0	0	1,668	624	0	0	0	0.18
2005	13	0	0	1,668	588	0	0	0	0.17
2006	14	0	0	1,668	551	0	0	0	0.16
2007	15	0	0	1,668	515	0	0	0	0.15
2008	16	0	0	1,668	479	0	0	0	0.14
2009	17	0	0	1,668	442	0	0	0	0.13
2010	18	0	0	1,668	406	0	0	0	0.12
2011	19	0	0	1,668	370	0	0	0	0.11
2012	20	0	0	1,668	334	0	0	0	0.10
								0	

Customer Base	363 (3,627*1/10 deprec. per year)	63	57	---Net Present Value
Cost/Cust.	$64			
Savings/Cust.	400 kWh		6	---$000 Savings
CLF	0.4		419	---Avg. MWh Savings
			1.4	---CCE

A.2. RESIDENTIAL RETROFIT PROGRAM

Residential Retrofit Program--St. Thomas

		Participation			Total MWh Savings	Total Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	4	781	781	419	171	171		0.12
1994	2	6	390	1,171	629	86	86	171	0.18
1995	3	8	390	1,562	839	86	86	86	0.24
1996	4	12	781	2,343	1,258	171	171	86	0.36
1997	5	18	1,171	3,514	1,887	257	257	171	0.54
1998	6	24	1,171	4,685	2,516	257	257	257	0.72
1999	7	32	1,562	6,247	3,355	342	342	257	0.96
2000	8	44	2,343	8,590	4,613	513	513	342	1.32
2001	9	58	2,733	11,323	6,080	599	599	513	1.74
2002	10	60	390	11,713	6,290	86	86	599	1.80
2003	11	0	0	0	6,080	0	0	86	1.74
2004	12	0	0	0	5,976	0	0	0	1.71
2005	13	0	0	0	5,871	0	0	0	1.68
2006	14	0	0	0	5,661	0	0	0	1.62
2007	15	0	0	0	5,347	0	0	0	1.53
2008	16	0	0	0	5,032	0	0	0	1.44
2009	17	0	0	0	4,613	0	0	0	1.32
2010	18	0	0	0	3,984	0	0	0	1.14
2011	19	0	0	0	3,250	0	0	0	0.93
2012	20	0	0	0	3,145	0	0	0	0.90
								0	

Customer Base 19,522 Total Number of Customers — 1,413 1,284 ---Net Present Value

Cost/Cust. $219

Savings/Cust. 537 kWh — 128 ---$000 Savings

CLF 0.4 — 3,842 ---Avg. MWh Savings

3.3 ---CCE (c/kWh)

Residential Retrofit Program--St. Croix

		Participation			Total MWh Savings	Total Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	4	725	725	390	159	159		0.11
1994	2	6	363	1,088	584	79	79	159	0.17
1995	3	8	363	1,451	779	79	79	79	0.22
1996	4	12	725	2,176	1,169	159	159	79	0.33
1997	5	18	1,088	3,265	1,753	238	238	159	0.50
1998	6	24	1,088	4,353	2,337	238	238	238	0.67
1999	7	32	1,451	5,804	3,117	318	318	238	0.89
2000	8	44	2,176	7,980	4,285	477	477	318	1.22
2001	9	58	2,539	10,519	5,649	556	556	477	1.61
2002	10	60	363	10,882	5,844	79	79	556	1.67
2003	11	0	0	0	5,649	0	0	79	1.61
2004	12	0	0	0	5,552	0	0	0	1.58
2005	13	0	0	0	5,454	0	0	0	1.56
2006	14	0	0	0	5,260	0	0	0	1.50
2007	15	0	0	0	4,967	0	0	0	1.42
2008	16	0	0	0	4,675	0	0	0	1.33
2009	17	0	0	0	4,286	0	0	0	1.22
2010	18	0	0	0	3,701	0	0	0	1.06
2011	19	0	0	0	3,020	0	0	0	0.86
2012	20	0	0	0	2,922	0	0	0	0.83
								0	

Customer Base	18,137	Total Number of Customers	1,313	1,193	---Net Present Value
Cost/Cust.	$219				
Savings/Cust.	537	kWh		119	---$000 Savings
				3,570	---Avg. MWh Savings
CLF	0.4			3.3	---CCE (c/kWh)

A.3. COMMERCIAL/INDUSTRIAL TIME-OF-RETIREMENT PROGRAM

Commercial-Industrial Air Conditioning Program--St. Thomas

		Participation			Total MWh	Cost	CCE		Total MW
		%	New	Total	Savings	($000)	Current	Deferred	Savings
1993	1	25	97	97	49	34	34		0.01
1994	2	50	195	292	146	68	68	34	0.04
1995	3	75	292	584	292	103	103	68	0.08
1996	4	75	292	875	438	103	103	103	0.12
1997	5	75	292	1,167	584	103	103	103	0.17
1998	6	75	292	1,459	729	103	103	103	0.21
1999	7	75	292	1,751	875	103	103	103	0.25
2000	8	75	292	2,042	1,021	103	103	103	0.29
2001	9	75	292	2,334	1,167	103	103	103	0.33
2002	10	75	292	2,626	1,313	103	103	103	0.37
2003	11	0	0	2,626	1,289	0	0	103	0.37
2004	12	0	0	2,626	1,240	0	0	0	0.35
2005	13	0	0	2,626	1,167	0	0	0	0.33
2006	14	0	0	2,626	1,094	0	0	0	0.31
2007	15	0	0	2,626	1,021	0	0	0	0.29
2008	16	0	0	2,626	948	0	0	0	0.27
2009	17	0	0	2,626	875	0	0	0	0.25
2010	18	0	0	2,626	802	0	0	0	0.23
2011	19	0	0	2,626	729	0	0	0	0.21
2012	20	0	0	2,626	656	0	0	0	0.19
								0	

Customer Base	389	(3,890*1/10 per year)	540	491	---Net Present Value
Cost/Cust.	$352				
Savings/Cust.	500	kWh		49	---$000 Savings
CLF	0.4			822	---Avg. MWh Savings
				6.0	---CCE (c/kWh)

Commercial-Industrial Air Conditioning Program--St. Croix

		Participation			Total MWh	Cost	CCE		Total MW
		%	New	Total	Savings	($000)	Current	Deferred	Savings
1993	1	25	79	79	40	28	28		0.01
1994	2	50	159	238	119	56	56	28	0.03
1995	3	75	238	477	238	84	84	56	0.07
1996	4	75	238	715	357	84	84	84	0.10
1997	5	75	238	953	477	84	84	84	0.14
1998	6	75	238	1,191	596	84	84	84	0.17
1999	7	75	238	1,430	715	84	84	84	0.20
2000	8	75	238	1,668	834	84	84	84	0.24
2001	9	75	238	1,906	953	84	84	84	0.27
2002	10	75	238	2,144	1,072	84	84	84	0.31
2003	11	0	0	0	1,052	0	0	84	0.30
2004	12	0	0	0	1,012	0	0	0	0.29
2005	13	0	0	0	953	0	0	0	0.27
2006	14	0	0	0	893	0	0	0	0.25
2007	15	0	0	0	834	0	0	0	0.24
2008	16	0	0	0	774	0	0	0	0.22
2009	17	0	0	0	715	0	0	0	0.20
2010	18	0	0	0	655	0	0	0	0.19
2011	19	0	0	0	595	0	0	0	0.17
2012	20	0	0	0	536	0	0	0	0.15
								0	

Customer Base 318 (3,177*1/10 per year) 441 401 ---Net Present Value
Cost/Cust. $352
Savings/Cust. 500 kWh 40 ---$000 Savings

CLF 0.4 671 ---Avg. MWh Savings

6.0 ---CCE (c/kWh)

A.4. COMMERCIAL/INDUSTRIAL RETROFIT PROGRAM

Commercial Lighting Program--St. Thomas

		Participation			Total MWh Savings	Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	6	233	233	409	123	123		0.12
1994	2	9	117	350	613	61	61	123	0.18
1995	3	12	117	467	818	61	61	61	0.23
1996	4	18	233	700	1,227	123	123	61	0.35
1997	5	27	350	1,050	1,840	184	184	123	0.53
1998	6	36	350	1,400	2,454	184	184	184	0.70
1999	7	48	467	1,867	3,271	245	245	184	0.93
2000	8	66	700	2,567	4,498	368	368	245	1.28
2001	9	87	817	3,384	5,929	429	429	368	1.69
2002	10	90	117	3,501	6,134	61	61	429	1.75
2003	11	0	0	0	5,930	0	0	61	1.69
2004	12	0	0	0	5,827	0	0	0	1.66
2005	13	0	0	0	5,725	0	0	0	1.63
2006	14	0	0	0	5,521	0	0	0	1.58
2007	15	0	0	0	5,214	0	0	0	1.49
2008	16	0	0	0	4,907	0	0	0	1.40
2009	17	0	0	0	4,498	0	0	0	1.28
2010	18	0	0	0	3,885	0	0	0	1.11
2011	19	0	0	0	3,169	0	0	0	0.90
2012	20	0	0	0	3,067	0	0	0	0.88
								0	

Customer Base	3,890	(Total Commercial Customers)	1,014	921 ---Net Present Value
Cost/Cust.	$526	($300/MWh/Yr.)		
Savings/Cust.	1,752	kWh		92 ---$000 Savings
CLF	0.4			3,747 ---Avg. MWh Savings
				2.5 ---CCE

Commercial Lighting Program--St. Croix

		Participation %	Participation New	Participation Total	Total MWh Savings	Cost ($000)	CCE Current	CCE Deferred	Total MW Savings
1993	1	6	191	191	248	74	74		0.07
1994	2	9	95	286	371	37	37	74	0.11
1995	3	12	95	381	495	37	37	37	0.14
1996	4	18	191	572	743	74	74	37	0.21
1997	5	27	286	858	1,114	111	111	74	0.32
1998	6	36	286	1,144	1,486	111	111	111	0.42
1999	7	48	381	1,525	1,981	149	149	111	0.57
2000	8	66	572	2,097	2,724	223	223	149	0.78
2001	9	87	667	2,764	3,590	260	260	223	1.02
2002	10	90	95	2,859	3,714	37	37	260	1.06
2003	11	0	0	0	3,590	0	0	37	1.02
2004	12	0	0	0	3,528	0	0	0	1.01
2005	13	0	0	0	3,466	0	0	0	0.99
2006	14	0	0	0	3,343	0	0	0	0.95
2007	15	0	0	0	3,157	0	0	0	0.90
2008	16	0	0	0	2,971	0	0	0	0.85
2009	17	0	0	0	2,724	0	0	0	0.78
2010	18	0	0	0	2,352	0	0	0	0.67
2011	19	0	0	0	1,919	0	0	0	0.55
2012	20	0	0	0	1,857	0	0	0	0.53
								0	

Customer Base	3,177	(Total Commercial Customers)	614	558 ---Net Present Value
Cost/Cust.	$390	($300/MWh/Yr.)		
Savings/Cust.	1,299	kWh		56 ---$000 Savings
CLF	0.4			2,269 ---Avg. MWh Savings
				2.5 ---CCE

Industrial Lighting Program--St. Thomas

		Participation			Total MWh	Cost	CCE		Total MW
		%	New	Total	Savings	($000)	Current	Deferred	Savings
1993	1	6	27	27	895	269	269		0.26
1994	2	9	13	40	1,343	134	134	269	0.38
1995	3	12	13	53	1,790	134	134	134	0.51
1996	4	18	27	80	2,685	269	269	134	0.77
1997	5	27	40	119	4,028	403	403	269	1.15
1998	6	36	40	159	5,371	403	403	403	1.53
1999	7	48	53	212	7,161	537	537	403	2.04
2000	8	66	80	292	9,847	806	806	537	2.81
2001	9	87	93	385	12,980	940	940	806	3.70
2002	10	90	13	398	13,427	134	134	940	3.83
2003	11	0	0	0	12,979	0	0	134	3.70
2004	12	0	0	0	12,756	0	0	0	3.64
2005	13	0	0	0	12,532	0	0	0	3.58
2006	14	0	0	0	12,084	0	0	0	3.45
2007	15	0	0	0	11,413	0	0	0	3.26
2008	16	0	0	0	10,742	0	0	0	3.07
2009	17	0	0	0	9,846	0	0	0	2.81
2010	18	0	0	0	8,504	0	0	0	2.43
2011	19	0	0	0	6,937	0	0	0	1.98
2012	20	0	0	0	6,713	0	0	0	1.92
								0	

Customer Base	442	(Total Industrial Customers)	2,219	2,017	---Net Present Value
Cost/Cust.	$10,126	($300/MWh/Yr.)			
Savings/Cust.	33,754	(kWh)		202	---$000 Savings
CLF	0.4			8,202	---Avg. MWh Savings
				2.5	---CCE

Industrial Lighting Program--St. Croix

		Participation			Total MWh Savings	Cost ($000)	CCE		Total MW Savings
		%	New	Total			Current	Deferred	
1993	1	6	21	21	452	136	136		0.13
1994	2	9	11	32	679	68	68	136	0.19
1995	3	12	11	42	905	68	68	68	0.26
1996	4	18	21	64	1,357	136	136	68	0.39
1997	5	27	32	96	2,036	204	204	136	0.58
1998	6	36	32	127	2,714	204	204	204	0.77
1999	7	48	42	170	3,619	271	271	204	1.03
2000	8	66	64	234	4,976	407	407	271	1.42
2001	9	87	74	308	6,559	475	475	407	1.87
2002	10	90	11	319	6,786	68	68	475	1.94
2003	11	0	0	0	6,560	0	0	68	1.87
2004	12	0	0	0	6,447	0	0	0	1.84
2005	13	0	0	0	6,334	0	0	0	1.81
2006	14	0	0	0	6,107	0	0	0	1.74
2007	15	0	0	0	5,768	0	0	0	1.65
2008	16	0	0	0	5,429	0	0	0	1.55
2009	17	0	0	0	4,977	0	0	0	1.42
2010	18	0	0	0	4,298	0	0	0	1.23
2011	19	0	0	0	3,506	0	0	0	1.00
2012	20	0	0	0	3,393	0	0	0	0.97
								0	

Customer Base	354	(Total Industrial Customers)	1,121	1,019	---Net Present Value
Cost/Cust.	$6,389	($300/MWh/Yr.)			
Savings/Cust.	21,298	(kWh)		102	---$000 Savings
CLF	0.4			4,145	---Avg. MWh Savings
				2.5	---CCE

A.5. COMMERCIAL/INDUSTRIAL LOAD MANAGEMENT PROGRAM

Load Management Program--St. Thomas

		Participation			Total MW Savings	Cost ($000)
		%	New	Total		
1993	1	2	78	78	0.39	39
1994	2	4	78	156	0.78	78
1995	3	7	117	272	1.36	136
1996	4	13	233	506	2.53	253
1997	5	21	311	817	4.08	408
1998	6	29	311	1,128	5.64	564
1999	7	37	311	1,439	7.20	720
2000	8	43	233	1,673	8.36	836
2001	9	47	156	1,828	9.14	914
2002	10	50	117	1,945	9.73	973
2003	11	0	0	1,945	9.73	973
2004	12	0	0	1,945	9.73	973
2005	13	0	0	1,945	9.73	973
2006	14	0	0	1,945	9.73	973
2007	15	0	0	1,945	9.73	973
2008	16	0	0	1,945	9.73	973
2009	17	0	0	1,945	9.73	973
2010	18	0	0	1,945	9.73	973
2011	19	0	0	1,945	9.73	973
2012	20	0	0	1,945	9.73	973

Customer Base	3,890	(Total Commercial Customers)
Cost/Customer	$500	($500/kW/Yr.)
Savings/Cust.	5	kW

Load Management Program--St. Thomas

		Participation			Total MW	Cost
		%	New	Total	Savings	($000)
1993	1	2	64	64	0.32	32
1994	2	4	64	127	0.64	64
1995	3	7	95	222	1.11	111
1996	4	13	191	413	2.07	207
1997	5	21	254	667	3.34	334
1998	6	29	254	921	4.61	461
1999	7	37	254	1,175	5.88	588
2000	8	43	191	1,366	6.83	683
2001	9	47	127	1,493	7.47	747
2002	10	50	95	1,589	7.94	794
2003	11	0	0	1,589	7.95	795
2004	12	0	0	1,589	7.95	795
2005	13	0	0	1,589	7.95	795
2006	14	0	0	1,589	7.95	795
2007	15	0	0	1,589	7.95	795
2008	16	0	0	1,589	7.95	795
2009	17	0	0	1,589	7.95	795
2010	18	0	0	1,589	7.95	795
2011	19	0	0	1,589	7.95	795
2012	20	0	0	1,589	7.95	795

Customer Base	3,177	(Total Commercial Customers)
Cost/Customer	$500	($500/kW/Yr.)
Savings/Cust.	5	kW

A.6. NEW CONSTRUCTION PROGRAM

Residential New Construction Program--St. Thomas

		Note: Total	New Homes	Participation %	Participation New	Participation Total	Total MWh Savings	Total Cost ($000)	CCE Current	CCE Deferred	Total MW Savings
1993	1	19,815	146	25	37	37	78	50	50		0.02
1994	2	20,112	149	50	74	111	236	102	102	50	0.05
1995	3	20,414	151	75	113	224	477	155	155	102	0.11
1996	4	20,720	153	75	115	339	721	157	157	155	0.16
1997	5	21,031	155	75	117	455	969	159	159	157	0.22
1998	6	21,346	158	75	118	574	1,221	162	162	159	0.28
1999	7	21,666	160	75	120	694	1,476	164	164	162	0.34
2000	8	21,991	162	75	122	816	1,736	167	167	164	0.40
2001	9	22,321	165	75	124	939	1,999	169	169	167	0.46
2002	10	22,656	167	75	126	1,065	2,266	172	172	169	0.52
2003	11	22,996	170	75	127	1,192	2,537	174	174	172	0.58
2004	12	23,341	172	75	129	1,322	2,812	177	177	174	0.64
2005	13	23,691	175	75	131	1,453	3,092	180	180	177	0.71
2006	14	24,046	178	75	133	1,586	3,375	182	182	180	0.77
2007	15	24,407	180	75	135	1,721	3,663	185	185	182	0.84
2008	16	24,773	183	75	137	1,859	3,955	188	188	185	0.90
2009	17	25,145	186	75	139	1,998	4,252	191	191	188	0.97
2010	18	25,522	189	75	141	2,139	4,553	193	193	191	1.04
2011	19	25,905	191	75	144	2,283	4,858	196	196	193	1.11
2012	20	26,293	194	75	146	2,429	5,168	199	199	196	1.18
										199	

Customer Base — One-half Historical Annual Growth — 1,280 — 1,164 ---Net Present Value

Cost/Cust. $1,368

Savings/Cust. 2,128 (kWh) — 116 ---$000 Savings

CLF 0.5 — 2,472 ---Avg. MWh Savings

4.7 ---CCE

Residential New Construction Program--St. Croix

		Note: Total	New Homes	Participation %	Participation New	Participation Total	Total MWh Savings	Total Cost ($000)	CCE Current	CCE Deferred	Total MW Savings
1993	1	18,500	181	25	45	45	96	62	62		0.02
1994	2	18,870	185	50	92	138	293	127	127	62	0.07
1995	3	19,247	189	75	142	279	594	194	194	127	0.14
1996	4	19,632	192	75	144	424	901	197	197	194	0.21
1997	5	20,025	196	75	147	571	1,215	201	201	197	0.28
1998	6	20,425	200	75	150	721	1,534	205	205	201	0.35
1999	7	20,834	204	75	153	874	1,860	210	210	205	0.42
2000	8	21,250	208	75	156	1,030	2,193	214	214	210	0.50
2001	9	21,675	213	75	159	1,190	2,532	218	218	214	0.58
2002	10	22,109	217	75	163	1,352	2,878	222	222	218	0.66
2003	11	22,551	221	75	166	1,518	3,231	227	227	222	0.74
2004	12	23,002	226	75	169	1,687	3,591	231	231	227	0.82
2005	13	23,462	230	75	173	1,860	3,958	236	236	231	0.90
2006	14	23,931	235	75	176	2,036	4,332	241	241	236	0.99
2007	15	24,410	239	75	179	2,215	4,714	246	246	241	1.08
2008	16	24,898	244	75	183	2,398	5,104	250	250	246	1.17
2009	17	25,396	249	75	187	2,585	5,501	255	255	250	1.26
2010	18	25,904	254	75	190	2,776	5,907	261	261	255	1.35
2011	19	26,422	259	75	194	2,970	6,320	266	266	261	1.44
2012	20	26,951	264	75	198	3,168	6,742	271	271	266	1.54
										271	

Customer Base	One-half Historical Annual Growth	1,647	1,497 ---Net Present Value
Cost/Cust.	$1,368		
Savings/Cust.	2,128 (kWh)		150 ---$000 Savings
CLF	0.5		3,175 ---Avg. MWh Savings
			4.7 ---CCE

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