Tools and Methods for

Integrated Resource Planning

Improving Energy Efficiency and Protecting the Environment

Joel N. Swisher
Gilberto de Martino Jannuzzi
Robert Y. Redlinger

UNEP

UNEP Collaborating Centre on Energy and Environment
Risø National Laboratory
November 1997

UNEP

United Nations Environment Programme

Tools and Methods for Integrated Resource Planning

Improving Energy Efficiency and Protecting the Environment

Joel N. Swisher
Gilberto de Martino Jannuzzi
Robert Y. Redlinger

UNEP Collaborating Centre on Energy and Environment
Risø National Laboratory, Denmark
November 1997

RISØ

TOOLS AND METHODS FOR INTEGRATED RESOURCE PLANNING:
IMPROVING ENERGY EFFICIENCY AND PROTECTING THE ENVIRONMENT

Printed by: Grafisk Service, Risø National Laboratory

Working Paper No. 7
ISBN 87-550-2332-0
ISSN 1025-2258

Joel N. Swisher
Gilberto de Martino Jannuzzi
Robert Y. Redlinger

UNEP Collaborating Centre on Energy and Environment
Risø National Laboratory
P.O. Box 49
DK-4000 Roskilde
Denmark
Tel.: +45 46 32 22 88
Fax.: +45 46 32 19 99

Table of Contents

Foreword

The improvement in the efficiency of energy use ("energy conservation") in the OECD countries after the first oil crisis in 1973 was one of the powerful instruments used to reduce the industrialized countries' dependence on oil imports. As a result, gross domestic product (GDP) continued to grow while energy consumption remained approximately constant in the period 1973-1988. The old cherished idea that economic growth and energy consumption go hand-in-hand was shattered, and the "delinking" of them became the object of many studies and the basis of energy policies in numerous countries.

In this book, Joel Swisher, Gilberto Jannuzzi, and Robert Redlinger have assembled all the necessary information for graduate students and utility managers to learn the techniques for doing their own calculations and analyzing the cost effectiveness of energy conservation measures against supply-side options. The book addresses "tools and methods for integrated resource planning" with particular attention toward improving energy efficiency in developing countries. It discusses IRP (integrated resource planning), DSM (demand-side management), environmental externalities, the competitiveness of renewables, barriers to energy efficiency, and the like. It is not merely a recitation of well-known ideas and proposals, but rather goes into the details of calculating savings, cost-effectiveness, comparing options, etc., with all the algorithms and spreadsheets necessary.

This book will prove very useful to anyone in the energy field interested in looking into the details of calculations and learning how to do it themselves.

Professor José Goldemberg
Universidade de São Paulo, Brazil
August, 1997

Preface

This book resulted from our recognition of the need to have systematic teaching and training materials on energy efficiency, end-use analysis, demand-side management (DSM) and integrated resource planning (IRP). Our objective is to make it possible to give academic courses and professional training workshops in these areas without having to spend valuable time collecting articles, lectures, tables and graphs, as well as preparing examples and exercises, from the many diverse sources available in this field.

This book addresses energy efficiency programs and IRP, exploring their application in the electricity sector. We believe that these methods will provide powerful and practical tools for designing efficient and environmentally-sustainable energy supply and demand-side programs to minimize the economic, environmental and other social costs of electricity conversion and use. Moreover, the principles of IRP can be and already are being applied in other areas such as natural gas, water supply, and even transportation and health services.

It is important to address the present uncertainty regarding the use of IRP as it was initially applied in North America, due to the on-going deregulation of electric power markets in the USA and Canada. The mandatory use of IRP and DSM is declining as more planning functions are being left to the forces of the deregulated market. Also, in Latin America and other emerging markets, there is a clear trend toward deregulation and privatization in power-sector development, both to exploit the efficiency of the private sector and to relieve the debt-ridden public-utility sector of the burden of new investments. These changes may foreclose some options for "traditional" IRP, but open up a range of new possibilities.

First, public authorities can use IRP principles to design programs to encourage end-use efficiency and environmental protection through environmental charges and incentives, non-utility programs, and utility programs applied to the functions remaining in monopoly concessions such as the distribution wires. Second, competitive supply firms can use IRP principles to satisfy customer needs for efficiency and low prices, to comply with present and future environmental restrictions, and to optimize supply and demand-side investments and returns, particularly at the distribution level, where local-area IRP is now being actively practiced. Finally, in those countries where a strong planning function remains in place, IRP provides a way to integrate end-use efficiency and environmental protection into energy development.

This book was written with a certain audience in mind, namely post-graduate students taking courses in the areas of energy and environmental engineering and economics, as well as engineers and planners in electric utilities and other public and private institutions in the energy sector. In developing the exercises, we kept in mind the need to show students how to use relatively simple models to present comparisons between diverse alternatives to meet society's demand for energy services. The electronic spreadsheets are available at the University of Campinas' site on the Internet at http://www.fem.unicamp.br/~jannuzzi/pir-livro1.htm and at the UCCEE Internet site listed below.

We acknowledge the support of the UNEP Collaborating Centre on Energy and Environment (UCCEE), directed by Dr. John Christensen at Risø National Laboratory in Denmark, for making possible our collaboration in the production of this book. For further information about this English version of the book, one can consult UCCEE's site on the Internet at http://www.risoe.dk/sys-ucc/

This book was written simultaneously in English and Portuguese with the collaboration of several colleagues and students. We are pleased to acknowledge the students of the University of Campinas (Unicamp), who served as "guinea pigs" in testing this material and helping to improve its accuracy and utility. In particular, we thank G. Mammana, G. Queiroz, R. Rodrígues, M. Eanes, S. Polidoro, Edmilson, and E. Bezerra of Unicamp, as well as L. Hummel of Stanford University. P. DuPont and S. Udo of the International Institute for Energy Conservation also provided valuable suggestions and material. We especially thank Prof. Gilbert Masters of Stanford University for contributing his class notes, significant parts of which were used in the preparation of Chapters 2 and 3.

This English version uses the following numbering convention throughout. Commas (",") indicate thousands separators, periods (".") indicate decimal places, and currencies are generically presented as dollars ("$"). This book is also available in Portuguese; details can be obtained from the above Internet site at Unicamp.

Joel N. Swisher, Gilberto de Martino Jannuzzi, and Robert Y. Redlinger

Chapter 1. Energy Services and Energy Efficiency

A. Introduction: Why Energy Efficiency?

Economic development requires increased access to commercial energy in developing countries, as increasing urbanization and industrialization both create greater demands for energy. Urban populations demand high levels of transportation (of people and goods) and other energy-using services. Building and operating the urban infrastructure and industrial and commercial facilities all require energy, especially electricity. Rising living standards result in greater demands for energy-consuming services, such as private transportation and home appliances. Moreover, rural electrification is a major priority in many developing nations, where a small supply of electricity can significantly improve living conditions.

A.1. Vulnerability to Energy Costs

The dramatic oil price increases of the 1970s, combined with rising interest rates, ended the era of cheap energy for the developing countries. Suddenly, energy had become a constraint to Third World development, and it continues today to constrain development in two areas: the economy and the environment. The major economic constraints include the foreign exchange demands for imported oil (even with the present low world prices) and the capital demands for building new energy production and distribution facilities.

While consumers in industrialized countries were inconvenienced by the oil shocks, the high oil prices effectively priced many developing countries out of the market, depriving them of the fuel they need for such essential activities as fertilizer production. Although the current world oil market is very soft, this may be a temporary aberration. The prospect of higher oil prices makes the developing countries' energy situation especially precarious.

Energy also places excessive demands on investment capital in developing nations, many of which spend more than 30 percent of their entire development budget on energy. The World Bank devotes about 25 percent of its loan money to energy projects, mostly for electric power generation, and these loans provide leverage for larger commercial loans. Much of this capital does not stay in the borrowing nation's economy, but is devoted to foreign equipment and services. The magnitude of the developing countries' energy loans suggests that energy development has been a significant factor in the Third World debt crisis. Moreover, every dollar spent on a power plant is a dollar that cannot be spent on health, education, sanitation, or agriculture.

A.2. Environmental Impacts

Rapid energy production growth leads to environmental impacts which can also constrain development. Energy production, whether from depletable fossil and nuclear fuels or large-scale exploitation of hydroelectric or biomass resources, leads to many of the most severe environmental impacts faced by developing and industrialized nations alike. These include air pollution, radioactive waste, siltation of river basins, deforestation and soil erosion, etc.

In the past, environmental issues have been considered secondary to economic growth in developing and industrialized nations. Recently, however, both local and global environmental impacts have been identified as a potential constraint to development. According to the World Commission on Environment and Development, "...related changes have locked the global economy and ecology together in new ways. We have in the past been concerned about the impacts of economic growth upon the environment. We are now forced to concern ourselves with the impacts of ecological stress - degradation of soils, water regimes, atmosphere, and forests - upon our economic prospects" (WCED, 1987).

As the Framework Convention on Climate Change (FCCC) goes into effect, some 20 industrialized countries have made commitments to stabilize or reduce future carbon emissions. To accomplish the stated goal of the FCCC, which is to stabilize greenhouse gas (GHG) concentrations in the atmosphere, global carbon emissions would have to be reduced by 60 percent or more from present levels (IPCC 1990). This would require much more drastic reductions by the industrialized countries, and emissions from developing countries would eventually have to be limited as well.

To achieve the existing reduction targets, not to mention those necessary to stabilize the atmosphere, technological changes will be necessary to reduce the fossil fuel intensity of most countries' energy systems (supply-side measures) and to improve the efficiency with which fuels and electricity are used (demand-side measures). The possible policy instruments with which to stimulate these changes are many. At the international level, most discussion has centered on various forms of carbon emission taxes and to some extent on tradable emission offsets or permits.

At the national level, where most real energy policy changes would have to be implemented, other policy mechanisms, which use regulation or a mix of regulation and financial incentives, are common. Some of these mechanisms are already in widespread use, while some are more innovative and have only recently been applied to energy technologies. They include energy performance standards, technology procurement programs, and utility demand-side management, as well as familiar development and demonstration activities. To a large degree, these types of programs are designed to capture the potential end-use energy-efficiency improvements.

Thus, one of the principal reasons for pursuing energy-efficiency improvements is that energy consumption leads to pervasive externalities, ranging from local pollution and global greenhouse gases to energy and nuclear security risks, that are not reflected in energy supply costs and planning efforts. By mitigating these problems with technical improvements that are cost-effective relative to new energy supplies, innovative energy-efficiency programs appear to offer a "win-win" solution. Moreover, it appears that such cost-effective technical opportunities are also abundant in developing countries (US OTA 1992).

A.3. The Need for Energy Efficiency

Beginning in the 1970s, disaggregated modeling of energy systems led to the general observation that many cost-effective technical improvements in energy end-use efficiency were becoming available. These results suggested that economic growth could be maintained in conjunction with significantly slower growth in energy supply and reductions in the related environmental impacts. Although it is clear that growth in energy supply is still required in developing countries, this growth can be de-coupled from GNP growth.

At the same time, perhaps the most convincing advantage of energy efficiency is that it is often less expensive than energy production. Investing in efficient energy end-use technology can require major capital expenditures, as efficient systems and equipment are usually, though not always, more expensive than the less efficient technology they replace. However, the cost of saving a kWh is generally cheaper than producing the equivalent amount of energy supply. In many applications, the cost of efficiency is a small fraction of energy production costs.

In addition, the indivisibility, or “lumpiness,” of energy production investments can be a handicap to developing countries, which must borrow capital and pay interest for several years before an energy facility is completed and producing an economic return. Efficiency investments, on the other hand, tend to be incremental, with short lead times. Thus, efficiency measures can be in place and saving enough energy and money to repay their costs before a power station can even be built. This is an important benefit when one considers the contribution of energy-related loans to the Third World debt crisis.

Even when the apparent costs of energy efficiency are much less than those of new energy supplies, investments in efficiency and renewables are more difficult to finance than conventional energy supplies. A simple but essential feature of this relationship is that the people who produce energy resources and those who use them are two entirely different groups, with vastly different investment priorities and access to capital. Many efficiency measures that would pay for themselves in two years or less, yielding a 40% or greater return on investment, do not appear financially beneficial to the energy users who make the investment decisions.

This “gap” suggests a role for policy measures focused on stimulating innovation and investments in energy-efficiency improvement. Such policies include accelerating technology development and demonstration, stimulating product demand via procurement policies, applying efficiency standards to information-poor sectors, encouraging utility demand-side management (“DSM,” i.e., involvement by the utility to influence changes in customers’ energy-using behavior, sometimes including use of financial incentives) programs, and in general finding ways to create markets for energy savings, thus stimulating further innovation. Efforts to implement many such measures are already underway in some industrialized countries, and this policy area is evolving rapidly.

Policy mechanisms to increase energy-efficiency investments, including DSM, have also begun to be implemented in developing countries and the formerly planned economies of Eastern Europe and the former Soviet Union. From a technological perspective, these countries are generally less energy-efficient than Western industrialized countries and therefore present great opportunities for efficiency improvement.

Although developing countries use much less energy per capita than industrialized countries, they can still benefit from the economic savings and environmental advantages of energy-efficiency by following a course of development that adopts efficient technology in the early stages. This approach would avoid repeating the industrialized countries’ energy-intensive and polluting development path, and it would capture energy-efficiency opportunities at the least expensive point, when new equipment and facilities are first put into service.

Despite the many difficulties, DSM and other innovative approaches to energy efficiency have appeared in some developing countries and formerly planned economies. Energy efficiency centers in Poland, the Czech and Slovak republics and Russia were opened in 1991, and recently a similar center opened in China. These centers have encouraged the adoption of least-cost energy planning to include energy-efficiency measures, developed information programs and energy-efficiency legislation, and catalyzed private-sector investments and joint ventures in energy-efficiency projects. Other successful energy efficiency centers have been set up in Pakistan and Korea, among others.

The Electricity Generating Authority of Thailand (EGAT), which is having difficulty keeping up with its customers' explosive demand growth, has committed to a five-year DSM program, partly financed by the Global Environment Facility (GEF). The program is expected to reduce peak demand by 160 MW and serve as a pilot for more ambitious DSM implementation in the future.

In Brazil, the government and the national electric supply utility Eletrobras began a national electricity efficiency program, Procel, in 1985. During its initial years, Procel was involved with research projects, demonstrations, information programs and some direct installation of energy-saving measures such as efficient street lamps. More recently, some Brazilian utilities have begun to finance energy savings through DSM programs, such as a major lighting energy efficiency program in São Paulo and Manaus.

A.4. The Need for a New Planning Context

The planning and policy context in which these types of energy-efficiency initiatives have been most effectively implemented is called *integrated resources planning (IRP). IRP is the combined development of electricity supplies and demand-side management (DSM) options to provide energy services at minimum cost, including environmental and social costs*. As suggested by the name and as defined earlier, *demand-side management* programs involve a systematic effort to manage the timing or amount of electricity demanded by customers.

Although the existing literature on DSM and IRP is considerable, there are no teaching/training materials designed for audiences located in developing countries on these issues. Over the past years information has become available on end-use analysis in some developing countries, as energy efficiency conservation programs have been implemented with varying degrees of success.

The objective of this book, *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, is to take a hands-on approach to understanding and using the tools of end-use energy analysis in the context of IRP, especially in developing countries and economies in transition. This book is targeted to students of post-graduate courses in energy planning and to people working in electricity utilities.

The book reviews the theoretical framework for end-use energy analysis, the basic methodologies currently being used in designing strategies to integrate supply options with demand-side options, and tools to account for the economic, environmental and other social costs of energy conversion and use. The remainder of this chapter presents the principal definitions involved in energy systems and IRP. Chapter 2 introduces the methodology for creating future scenarios of energy end-use demand for application in the IRP process. Chapter 3 discusses the role of efficiency, renewable energy sources, and the programs and policies that can be used to implement these options in the context of IRP. Chapter 4 presents the principles of electric utility planning and the methods for integrating the supply-side options together with DSM to solve IRP problems. Throughout the book, we highlight realistic examples and case studies, providing a practical, hands-on approach to solving problems related to energy planning in developing countries. Examples and exercises, suitable for computer spreadsheet solution and drawn from the authors' experience in developing countries, accompany each chapter.

B. Basics of the Energy System

B.1. Energy Sources, Carriers and Uses

The energy system can be divided into three levels: a) production and conversion from energy sources into energy carriers, b) storage and distribution of energy carriers, and c) consumption of the energy carriers. Each level includes a complex network of activities with the objective of extracting energy from the sources and delivering it to the point of consumption.

Energy sources are the forms in which energy is found stored in nature. The various sources are processed and converted into *energy carriers* that, in turn, are stored or distributed to the final consumers. Depending on the activities in the consuming sectors, energy is used to operate machines, motors, lights and appliances, to transport people and goods, to produce goods and services, etc. These diverse functions are called *end-uses of energy*. Table 1.1 provides an overview of these terms and functions.

Table 1.1. The energy system.

Sources	**Oil**	**Coal**	**Natural Gas**	**Sun**	**Biomass**
Extraction Treatment	oil well	coal mine	cleaning		agroforestry agriculture
Conversion Technology	refinery	power plant		photovoltaic cell	
Energy Carriers	gasoline, diesel, etc.	electricity	methane	electricity	ethanol, methanol
Distribution	oil derivates distribution system	electricity grid	gas grid	electricity grid / local use	truck, pipeline
End-Use Technologies	automobile	motors	cooking stove	light bulbs	automobile
Energy Services	transportation	drivepower	cooking	lighting	transportation

Sources of energy can be classified as primary or secondary sources, and as renewable or depletable sources. *Primary sources* originate from natural processes; these include petroleum, coal, natural gas, etc. Generally, primary energy needs to be transformed into *secondary (or delivered) energy*, such as electricity or gasoline, in order to supply the final-energy carrier.

The classification of energy sources as renewable or depletable can be controversial. In principle, no source can be considered absolutely inexhaustible. However, energy sources are considered to be *renewable sources* if their use by humanity does not cause a significant variation in their potential, and if their replacement in the short term is relatively certain. For example, solar energy is considered renewable although it originates from fusion reactions that are irreversible.

Similarly, energy sources are considered to be *depletable sources* if their natural replacement would take many centuries or millennia under unique conditions, such as for petroleum, and their artificial replacement is absolutely infeasible, involving processes with energy expenditures equal to or greater than the quantity of energy obtained or with prohibitive costs.

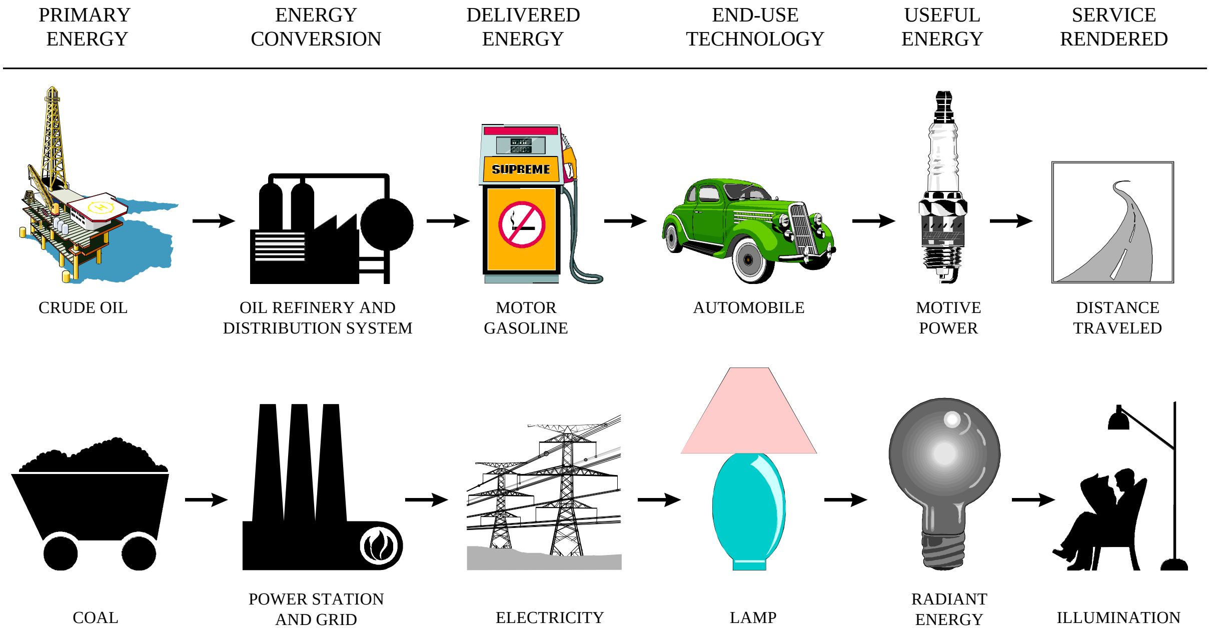


Figure 1.1. The energy flow.
Source: Scientific American (1990).

Final energy includes any form of energy, primary or secondary, that is available to the consumer, discounting storage and distribution losses. This energy is converted at the point of end-use to useful energy. *Useful energy* is the energy form that is really demanded by the consumer for heat, light or mechanical motion. The amount of useful energy delivered from a given amount of final energy depends on the efficiency of the end-use technology.

Figure 1.1 shows the energy conversion chain. Primary energy exists in a crude form, say, a fossil fuel, that is extracted from a sedimentary repository. After undergoing transformation (or conversion), it becomes delivered energy which is made available to the consumer, who then converts it into useful forms and finally into energy services, which are the desired end.

Useful energy reaches the consumer by providing some type of energy service. *Energy services* include, for example, cooking, illumination, thermal comfort, food refrigeration, transportation, material production and product manufacturing. While we generally discuss energy end-use efficiency (including in this book) with regard to the conversion from final to useful energy, it is actually the quantity and quality of energy services that determine whether the consumers' needs are met. For example, a relatively efficient air-conditioner can reduce the electricity demand of an office building, but a well-designed building could provide the same energy service of thermal comfort with no air-conditioning at all. Figure 1.2 illustrates the effect of improvements in end-use efficiency in reducing energy input requirements while maintaining the same level of service output (work).

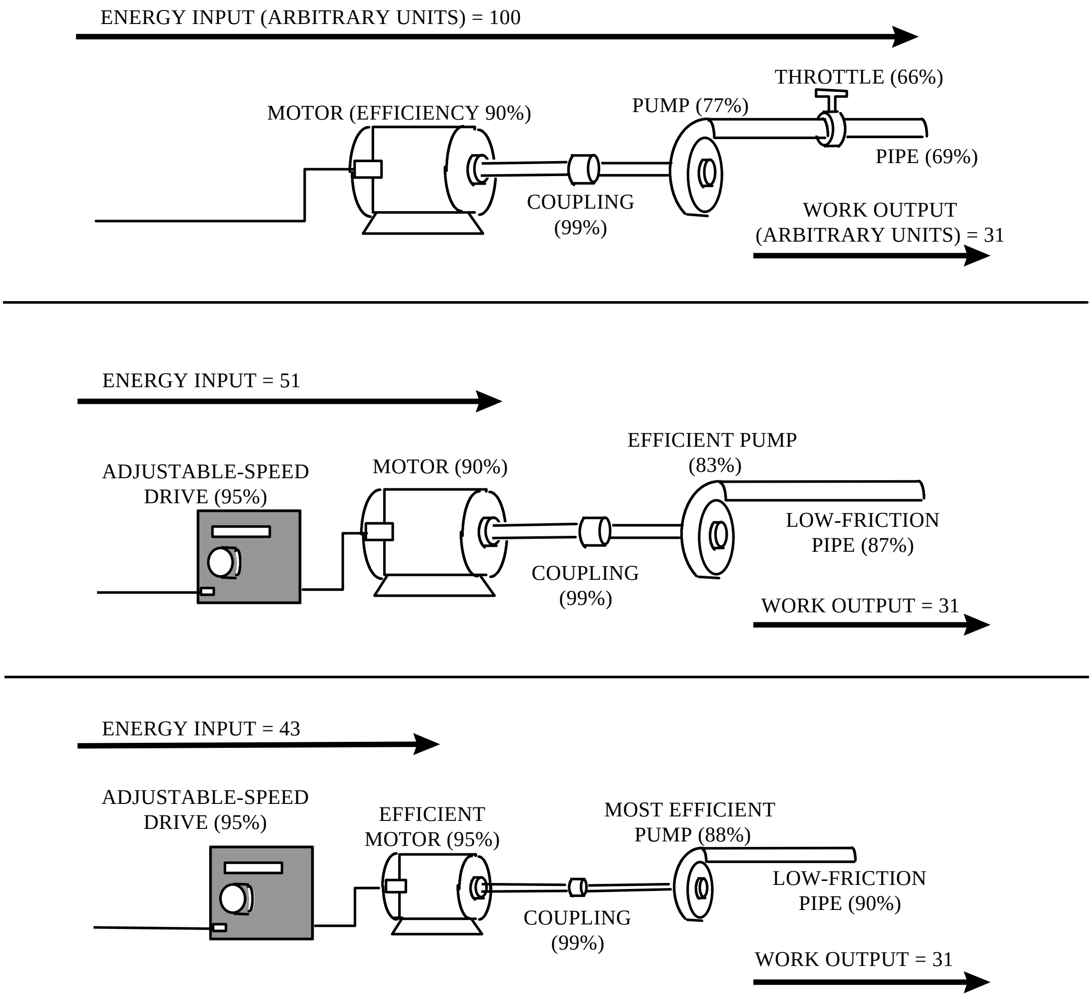


Figure 1.2. End-use efficiency measures can raise the efficiency of a typical motor-pump system from 31% (top diagram) to 72% (31/43, bottom diagram) and can pay for themselves in two or three years (or less counting maintenance-cost savings). An electronically controlled adjustable-speed drive (middle) eliminates the need for throttle-control and the resulting energy loss. A more efficient and properly-sized motor and pump, as well as larger and better pipes, can save even more (bottom).
Source: Scientific American (1990).

B.2. The Human Dimension of Energy

Energy can be viewed by society in various ways, depending on the level of decision-making and the inherent needs of different societal groups. Energy can be treated as a commodity, a social need, or an ecological or strategic resource. Apart from technical aspects, energy decision-making is very much influenced by the way it is perceived.

The view of energy as a *commodity* is presented by certain sectors of the economy which are composed of energy companies that are concerned mostly with the production and sale of these products. The viewpoint reflects a collection of values based on the *buyer-price-seller* relationship and excludes other aspects outside such commercial transactions. Large consumers such as electricity-intensive industries also tend to share this view.

The *ecological view* emerged in the 1970s when the oil crises caused some industrialized countries to use more coal and nuclear power as energy sources. Several accidents raised the issue of nuclear safety and security, generally increasing awareness of environmental impacts. The broad introduction of the concepts of environmental pollution and renewable resources led to the appearance of public interest groups concerned with maintaining their right to a clean environment. These groups were sensitive to the effects of the installation of nuclear, fossil-fuel, and hydroelectric stations with major environmental impacts, and despite not participating directly in the commercial energy trade, they were able to influence energy policy decisions.

Energy can also be understood as a *necessity of modern society*, as its services are now considered as basic as the provision of water and transportation infrastructure. In many countries there are measures to socialize its use, through subsidies on fuels used by low-income groups or rural electrification programs, for example. Maintaining the access of certain disadvantaged consumer groups to modern energy services is seen by some sectors as a top societal priority.

The *strategic aspect* has been determined according to the geographic location of certain energy sources and their current political orientation, which has caused many countries to invest in domestic sources or to search for more secure alternatives, despite the potentially high costs. Energy has become an issue of national security and has contributed decisively to some countries' support for military intervention in producing regions, evidenced by the Persian Gulf war in 1991.

In the case of developing countries, the most important agents in energy decisions have been national governments, which have also been primarily responsible for national economic decisions. In general, electricity sector debt started to rise in the late 1960s and early 1970s when revenues from electricity sales became increasingly insufficient to finance much of the new investments needed each year. Beginning around that time, revenues decreased to the point that, by the mid-1980s, they were insufficient in many countries to service the outstanding debt, which had to be covered by new loans. In most of Latin America, the energy sector played a large role in the debt crisis of the 1980s.

In Brazil, it is possible to identify three main priorities among the national economic goals in recent years, and to show their influence on energy-policy decisions:

- *Strategic Development.* As in many developing countries, energy has been seen by the Brazilian government as a strategic element to promote economic growth through industrialization and manufactured exports. There is also concern about creating new jobs and stimulating industry, which are associated with the expansion of energy production capacity. The infrastructure to provide inexpensive energy was an important part of Brazil's industrial development strategy. The industrial sector has had preferential prices for fuels and electricity, and some industries, such as mineral exporters, still pay energy prices that are far below the real costs of energy.

- *Social Equity and Access to Energy.* The supply of energy services to the population has also been a concern to the Brazilian government. Several electric utilities had in the past, and some still have, electrification programs and special tariffs for rural areas and low-income urban districts. The price of liquid petroleum gas (LPG) has been controlled in Brazil and has decreased in real terms over time. These factors help explain the increase in the share of households using electricity and LPG (including piped gas) from 38% and 18%, respectively, to 85% and 82% in 1990. This situation is typical of many developing countries.

The concern with the reduction of regional income disparities is reflected in the equalization of energy prices to the consumer. Prices are identical throughout the entire country, even though there are significant differences regarding the market and the actual cost of production and delivery. This type of energy policy is consistent with the concern about territorial integration held by the previous military governments of Brazil. However, similar policies are shared by developing and industrialized countries alike.

Regional differences in consumption have been reduced, but this has not been reflected at the production level. For example, ethanol fuel produced in the state of São Paulo is sold throughout Brazil at the same price. This approach discourages both the development of regional fuel sources and the implementation of energy conservation policies based on true market (i.e., increased) energy prices. More recently, however, this approach has begun to be revised, and there is now a tendency toward increased regional differences in energy prices in Brazil and elsewhere.

- *External Political and Financial Pressure.* In Brazil and most developing countries, the present view of energy has been influenced by important external events such as the oil price shocks and the financial pressures resulting from accumulated external debt. The oil price increases during the 1970s led to major efforts to reduce the dependence on this fuel, for example through the channeling of investments toward domestic exploration and the national production and use of hydroelectricity. Fuel substitution programs were initiated during that time, such as the National Alcohol Program (Proalcool), to increase the domestic production of fuel as a strategic commodity. Though results were mixed, these energy production programs in Brazil were among the most successful of the energy supply programs initiated worldwide in the 1970s, as many others failed completely.

  Problems with guaranteeing a profitable return on new investments also contributed to the difficulty in obtaining further loans, and those that were made by multilateral banks required increased investments in energy conservation and environmental protection. A share of these resources in Brazil were devoted to the National Program for Electricity Conservation (Procel). Procel thus had an external origin, and the energy planning authorities had to incorporate this new component in their projections of energy demand and preparation of policies. Procel is now an important component of Brazil's electricity planning and development capacity.

B.3. Energy Balance Accounting

Energy balance and energy matrix. An energy balance is an accounting system that describes the flow of energy through an economy (regional, state or national) during a given period, usually a calendar year. This combination of information is constructed from the most complete available sources of official energy statistics on production, conversion and consumption, as well as exports of energy carriers.

The main objective of an energy balance is to provide information for the planning of investments in different sectors of the energy system. It should also present indications of where to direct investments in research and development for more efficient energy use.

The energy balance consists of a matrix, also called an energy matrix, in which all forms of energy, their conversions, losses, and uses in a given period are registered in the same unit of measurement. An energy balance can be presented in various forms, each with its own conventions and purposes. The most common form includes columns, with quantities of energy sources or carriers used, and rows with data on the conversions and uses.

Units and conversion. There are a variety of physical quantities in which energy stocks and flows are usually expressed, and these quantities are not necessarily compatible with each other. For example, gasoline and ethanol are usually measured in *liters*, electricity in *kilowatt-hours* (kWh), coal in *tons*, crude petroleum in *barrels*, etc.

It is necessary to express different energy forms according to the same unit of measurement. The thermal energy content of each fuel is the form used for accounting of energy quantities, which can be expressed as *calories* (cal), *joules* (J), *tons of oil equivalent* (TOE), *tons of coal equivalent* (TCE), or *terawatt-hours* (TWh). Conversion factors between these units of measurement are provided in Appendix 1.

The thermal content or heating-value of a fuel is measured with a calorimeter and can be expressed as higher heating-value (HHV), which includes the amount of heat released by condensation of the water vapor formed during combustion, or the lower heating-value (LHV) which excludes this water vaporization latent heat from the heating value.

The HHV is the quantity used to estimate the amount of energy available to the user. In most North and South American countries, the HHV is used for the necessary conversions in the national energy accounts and energy balance tables. In Europe, the LHV is more often used.

Expression of the thermal content of a fuel provides a useful unit of measure, but it is very helpful to also indicate the value in SI units. This is especially the case when using TOE or TCE, because the heat content value of TOE and TCE vary from country to country (see Appendix 1).

The name “balance” refers to the fact that the quantities of primary energy produced must be equal to the quantities consumed, after accounting for changes in stocks, imports and exports, and the share used for conversion into secondary energy carriers, including losses:

$$P + I - X = L + C_f + C_{ne} + DS \qquad [Eq.\ 1.1]$$

where: P = total energy produced
I = imports
X = exports
L = losses and consumption within the energy conversion sector
C_f = total energy use in the final consumption sectors (residential, industrial, etc.)
C_{ne} = non-energy consumption (e.g. natural gas as a petrochemical feedstock)
DS = net change in stocks (positive DS means an increase in stocks).

The matrix is then filled for each type of energy carrier in use. The elements *P*, *I* and *X* refer to the primary energy sector, *L* refers to the conversion of primary energy sources to secondary energy carriers, including the production of petroleum derivatives, electricity, ethanol, etc., and the resulting losses. C_f refers to the final energy consumption sectors, which can be disaggregated into subsectors and then broken down according to the type of end-use, such as illumination, motive power, space conditioning, water heating, process heat, etc. C_{ne} refers to consumption of energy products for non-energy-related uses such as the use of oil products as a feedstock to produce chemical fertilizers. An example of an energy balance by the International Energy Agency (IEA) is provided in Table 1.2.

Table 1.2. Energy balance example. (Source: IEA, 1995)

Thailand Energy Balance, 1993 (Thousand TOE)

	Coal	Crude Oil	Petroleum Products	Gas	Nuclear	Hydro/ Other	Electricity	Heat	Total
Indigenous Production	4514	3948		8395		319			17175
Import	664	16425	9115				55		26259
Export		-685	-368				-4		-1057
International Marine Bunkers			-812						-812
Stock Changes	65	-304	-729						-969
TPES	5242	19383	7205	8395	0	319	51	0	40595
Returns and Transfers		-977	986						10
Statistical Differences	254		-47						207
Public Electricity	-2964		-4172	-7795		-319	5453		-9797
Autoproducers of Electricity									0
CHP Plants									0
District Heating									0
Gas Works									0
Petroleum Refineries		-18355	16892						-1463
Coal Transformation									0
Liquefaction									0
Other Transformation									0
Own Use			-34	-294			-220		-548
Distribution Losses							-444		-444
TFC	2532	51	20830	306	0	0	4840	0	28560
Industry Sector	*2532*	*51*	*3539*	*306*	*0*	*0*	*1860*	*0*	*8289*
Iron and Steel			69				172		241
Chemical		51	271	184			336		842
Non-Ferrous Metals									0
Non-Metallic Minerals	1467		933	11			293		2703
Transport Equipment									0
Machinery			300				238		539
Mining and Quarrying			43						43
Food and Tobacco	101		583				313		997
Paper, Pulp, and Printing			145				52		197
Wood and Wood Products			71				44		114
Construction			183						183
Textile and Leather			553				357		910
Non-specified Industry	965		388	111			55		1520
Transport Sector	*0*	*0*	*14236*	*0*	*0*	*0*	*0*	*0*	*14236*
Air			2423						2423
Road			11429						11429
Rail			120						120
Internal Navigation			264						264
Non-specified Transport									0
Other Sectors	*0*	*0*	*2715*	*0*	*0*	*0*	*2980*	*0*	*5695*
Agriculture			1628				11		1640
Public/Commerce							1890		1890
Residential			1086				1026		2113
Non-specified Other							52		52
Non-Energy Use			340						340

An energy balance can also be expressed in terms of useful energy, aggregating data regarding the efficiency of final energy use. In order to calculate this efficiency, it is necessary to distinguish two steps in the process of final energy use. The first step occurs when energy is transformed into a final energy carrier, and the second step refers to the way in which this energy carrier is exploited to produce goods or provide services. For example, diesel fuel can be used to produce steam in a boiler, with an efficiency of 60%, and the steam produced will be distributed to other pieces of equipment where its energy will be used. This second step can have a new efficiency related to the way in which the steam system is designed and operated. Often it is possible to increase the efficiency of this phase without major investments. An energy balance in terms of useful energy requires detailed data regarding the end-use technologies and how they are used.

Table 1.3. Examples of conversion efficiency from final energy to useful energy in end-use equipment.

Sector - End-use		**Final Energy**										
		electric	natural gas	LPG	wood	solar	diesel	coal	baggasse	ethanol	gasoline	charcoal
Resid	Cooking	45-80%	50%	30-50%	10-20%							
	Water Heating	95%	80%			40%						
Comm	Lighting -incand. -fluores.	 5-8% 20-30%										
Indust	Motive Power	90-95%					32%					
	Steam Boiler		70-75%		45%		65-73%	60%	30%			45%
Transport		70%	22%				24-35%			33%	18-25%	

More recently, discussions regarding the possibility of global climate change, resulting from the emission of carbon dioxide from combustion of fossil fuels, have led to the use of an energy balance in terms of the tons of carbon released in the energy production and consumption sectors.

Some factors of carbon emissions by fuel source are provided in Table 1.4.

Table 1.4. Carbon emissions by fuel source

Fuel	Emission rate (kg-C/GJ)
Coal	23.8
Fuel oil	20.0
Diesel oil	19.7
Gasoline	18.9
Butane	16.8
Propane	16.3
Ethane	15.5
Methane	13.1

Source: Greenhouse and Global Climate Change. Committee on Energy and National Resources. US Senate. US Printing Office (1988).

Exercise 1.1) A certain industrial process requires the use of 1 ton of steam. The industrial facility is currently generating this steam using a steam generator which operates at 80% efficiency, using fuel oil at a rate of 65.78 kg/hour. The steam could also be produced with alternate fuels other than fuel oil, and with steam generators of different efficiencies. Considering the following three combinations of fuel and technologies, calculate the required energy input for each in order to meet the 1 ton of steam requirement.

a.) natural gas, steam generator with 88% efficiency.
b.) firewood, steam generator with 70% efficiency.
c.) electricity, steam generator with 95% efficiency.

Note: use the energy content of fuels listed in Appendix 1.

In doing this exercise, think about the relationship between *useful* energy (i.e., 1 ton of steam) and *delivered* energy (i.e., 65.78 kg/hr) as discussed in Section B.1.

Exercise 1.2) Consider the lighting technologies and their efficiency (in terms of lumens/watt) shown in Table 1.5:

Table 1.5. Common lighting technologies, power consumption, and efficiency.

Lighting Technologies	**Most Common Commercial Types**	
	Lumens/Watt	**Watts**
incandescent conventional	10 14	25, 60 100
incandescent halogen	12 22	10 100
incandescent efficient	13 14	54 90
fluorescent conventional	67 67	20 40
fluorescent efficient	90 90	16 32
fluorescent (compact)	57 65	5 13

Source: Jannuzzi (1991). Conservação de Energia, Meio Ambiente e Desenvolvimento.

Assuming that you want to replace inefficient technologies, find at least four cases where it is possible to use a more efficient technology that maintains, as closely as possible, the same level of energy service (lumen output).

Assuming a 3 hour daily usage for each replacement, calculate the annual energy savings.

C. Energy Services and Electricity Supply

C.1. Energy as a Commodity

In the early 1970s projections were being made for energy demand based on macroeconomic forecasting that essentially extrapolated past energy-economy relationships into the future. These projections indicated very high energy demand growth and typically led to plans for large expansion of energy supply capacity, especially for nuclear and coal-fired electricity generation. However, energy demand did not develop accordingly, stimulating work to understand the underlying reasons.

A major observation of this work was that the energy *service* markets do not work as assumed in the models used, and that the projections based on these models therefore do not reflect reality. Subsequent studies formed the basis of the bottom-up approach to energy analysis, which involves disaggregated modeling of the systems that deliver energy services. This approach considers both energy supply and end-use (demand-side) alternatives and the costs of those alternatives. Accordingly, the focus of bottom-up analysis is on measures that provide energy services rather than energy simply as a commodity. This is a broader view than the conventional approach to analyzing the energy sector, which encompasses energy supply only.

This work led to the general observations that many of the energy-intensive goods and services were reaching saturation in industrialized countries, and that many technical improvements in energy end-use efficiency were becoming available. These results suggested that economic growth and material welfare could be maintained with significantly less energy supply and environmental impact than the existing projections indicated.

During the following decade, nearly every country in the Organization for Economic Cooperation and Development (OECD) revised its energy-demand projections drastically downward. More recently, the potential for efficient energy use as a development strategy has become widely recognized in developing countries (Geller 1990). Meanwhile, bottom-up analysis became a commonly-used method in demand forecasting and in government agencies' and electric utilities' energy-efficiency program planning.

C.2. Objectives of Bottom-Up Analysis

The principal objective of bottom-up analysis is to create a quantitative description of the technological structure of energy conversion and use. It begins with an estimate of the demand for energy services, such as comfort and mobility, and from this foundation builds future scenarios using different combinations of technologies for energy demand and supply. Demand scenarios are based on quantitative physical data that identify alternative end-use technologies and evaluate their performance and costs. This physical description provides the analytic framework for comparing technologies, their performance and costs, and policy measures to influence their rate of development and use.

Scenario analysis is one way of comparing alternative combinations of technological options to provide the same level of energy *services*. This level of energy services must then be met through a combination of efficiency improvements, relative to the specified baseline average, and supply resources. It is essential to define a *baseline scenario* as the starting point in the analysis of energy-efficiency improvements and to avoid double-counting of measures (see Chapter 2).

The *baseline scenario* for future levels of energy service demand is often treated outside the energy analysis, for example by adopting official government projections of energy services growth and basic structure of the future economy. However, a bottom-up perspective can reveal insights regarding the prospects for saturation in the demand of some energy-intensive products or changes in consumption patterns. Such changes influence the composition and quantity of energy services embodied in a given level of economic activity, for example the demand for material-intensive, and thus energy-intensive products (Williams et al 1987).

In addition to identifying technological potentials, bottom-up analysis can help describe the market limitations and barriers, such as equipment turnover rates and capital requirements, which constrain the rate of energy-efficiency implementation. Without policy changes, market distortions and institutional barriers will hinder the achievement of the identified potentials. Thus, alternative scenarios should be perceived as achievable under the presumption that markets are reformed and policies are designed to remove the barriers.

C.3. Structure of Electricity Supply: Load-Duration Curve

The process of IRP considers actions on both the supply and demand-side of the electricity system. This requires matching the structure of electricity supply with the structure of the demand. Because it is difficult and expensive to store electricity, there must be a precise match between power production and the demand profile during the day. The IRP process must therefore account for market characteristics (e.g., technologies, consumer behavior, etc.) as part of the electric system in terms of its daily operation and future expansion. Below we present some forms of information that are traditionally used in electric system expansion planning, and in Chapter 4 we introduce additional concepts relevant to the IRP process.

Electric demand typically varies considerably during the course of the day and the year. There are usually a few hours of peak demand each day, for example when commercial and residential uses overlap in late afternoon, and several hours of low demand during the night and early morning. In addition, there is usually a season of relatively high demand, due to the seasonality of weather-driven end-uses such as air conditioning.

The magnitude of the total demand in each hour of the year can be analyzed according to its frequency of occurrence. The cumulative frequency distribution of load levels is shown in the utility's *load-duration curve* (Figure 1.3). The load-duration curve sorts the utility's hourly demand by decreasing size according to the fraction of the year during which a given level is exceeded. It typically shows a few hours of very high peak demand, and then a gradual reduction of the load level as the cumulative frequency increases.

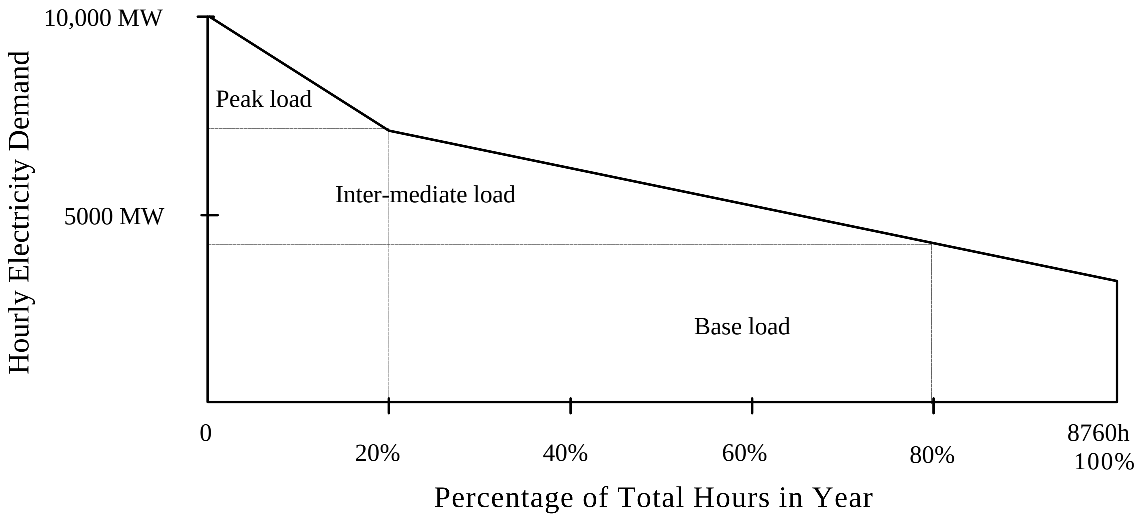


Figure 1.3. Sample load-duration curve.

A *load duration curve* can be divided into three levels, which indicate the different operating categories of the required supply resources. On a load-duration curve, the minimum load is the single lowest level of demand the utility must meet, and this defines the load that is met 100% of the time. Generating plants that run nearly all the time (>80% of the time) to meet this minimum constant load are base-load resources. Intermediate load is the level of demand that occurs between about 20% and 80% of the time, and plants that run for this fraction of the year are intermediate-load resources. Peak load is the level that is exceeded less than about 20% of the year, and maximum load is the single highest demand level of the year. Plants that only run during these hours of maximum demand are peak-load resources.

The frequency of use of an electricity plant affect both its operation and its economic performance. Some plants are appropriate for load-following operation, varying their output with the level of demand, and such plants are well suited to intermediate and peak load applications. In other plants, it can be difficult and expensive to change the level output quickly, and these plants are more appropriate for base load applications. In addition, plants with low fuel and variable operating costs are more economic as base-load plants, even if their capital costs are high, because of their long operating time. Plants with low capital costs, on the other hand, are economic as peak-load plants, regardless of their operating costs, because they are run for relatively few hours during the year.

Frequently it is necessary to develop daily load curves and to make future projections of electric demand for the purpose of system capacity expansion planning. Chapter 4 addresses this topic in detail within the context of integrating supply and demand-side options. Figure 1.4 illustrates an example of a daily load curve and shows a peak load that occurs in the evening. In Chapter 4 we describe the relationship between the load profile and the total energy demand, in the form of the *load factor* and the *load-duration curve*.

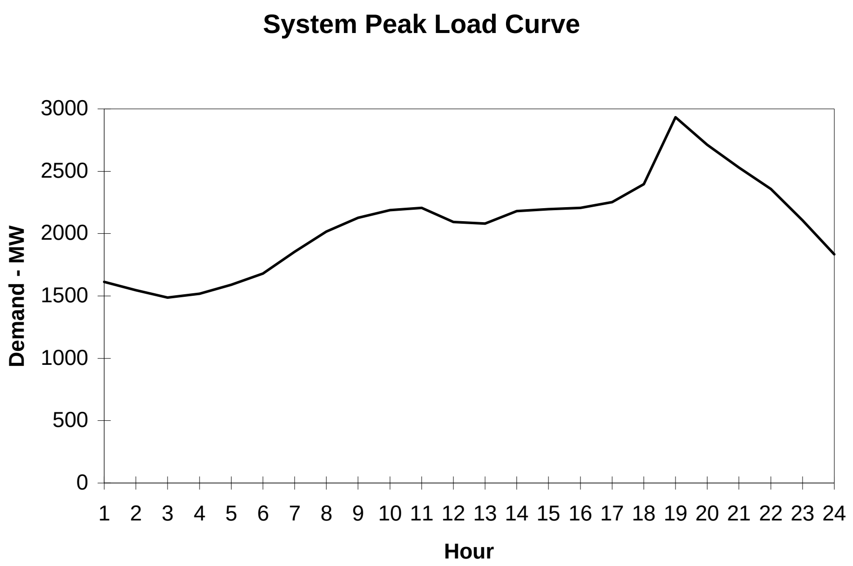


Figure 1.4. Sample system load curve for a Brazilian utility

D. What is Integrated Resource Planning?

D.1. IRP and the Traditional Power-Planning Approach

The complex nature of modern electricity planning, which must satisfy multiple economic, social and environmental objectives, requires the application of a planning process that integrates these often-conflicting objectives and considers the widest possible range of traditional and alternative energy resources. In describing the design and evaluation of an integrated resource planning (IRP) process, we hope to demonstrate useful methods to integrate energy efficiency options and environmental aspects into electricity planning.

Traditional electricity planning has sought to expand supply resources to meet anticipated demand growth with very high reliability, and to minimize the economic cost of this expansion (see Figure 1.5). These criteria, aided until recently by improving economies of scale in electric generation, led to a nearly-universal strategy of rapid capacity expansion and promotion of demand growth, with little consideration of the necessity or efficiency of energy use. More recently, however, increasing supply costs and environmental constraints have reduced or removed these incentives, and the concept of "least-cost" utility planning has begun to be completely redefined in some countries.

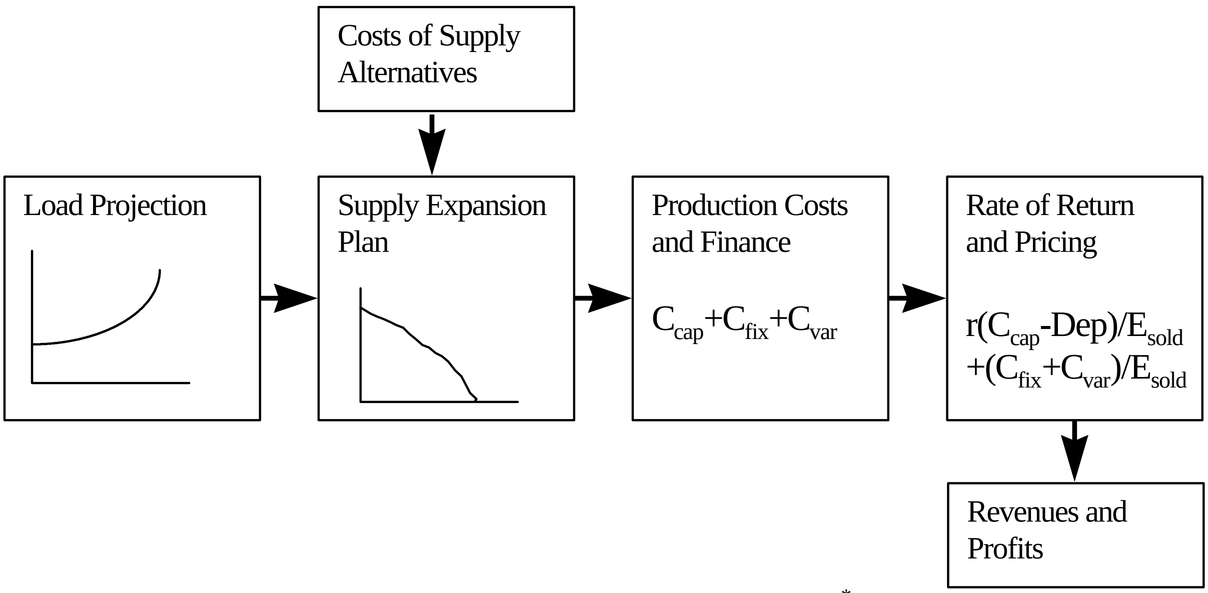


Figure 1.5. The traditional "least cost" electric planning model.[*]

Rather than least-cost supply expansion, modern utility planning is evolving toward IRP (see Figure 1.6). This means integrating a broader range of technological options, including technologies for energy efficiency and load control on the "demand-side," as well as decentralized and non-utility generating sources, into the mix of potential resources. Also, it means integrating a broader range of cost components, including environmental and other social costs, into the evaluation and selection of potential technical resources.

---

[*] Production costs are the sum of capital costs (C_{cap}) and fixed and variable operating costs (C_{fix} and C_{var}, respectively). Traditional planning guarantees full recovery of these costs, plus a fixed return (r) on capital investment, adjusted to account for depreciation (Dep), and spread over the total energy sales (E_{sold}). This model helps explain utilities' propensity to over-build in both nationalized systems and regulated monopolies.

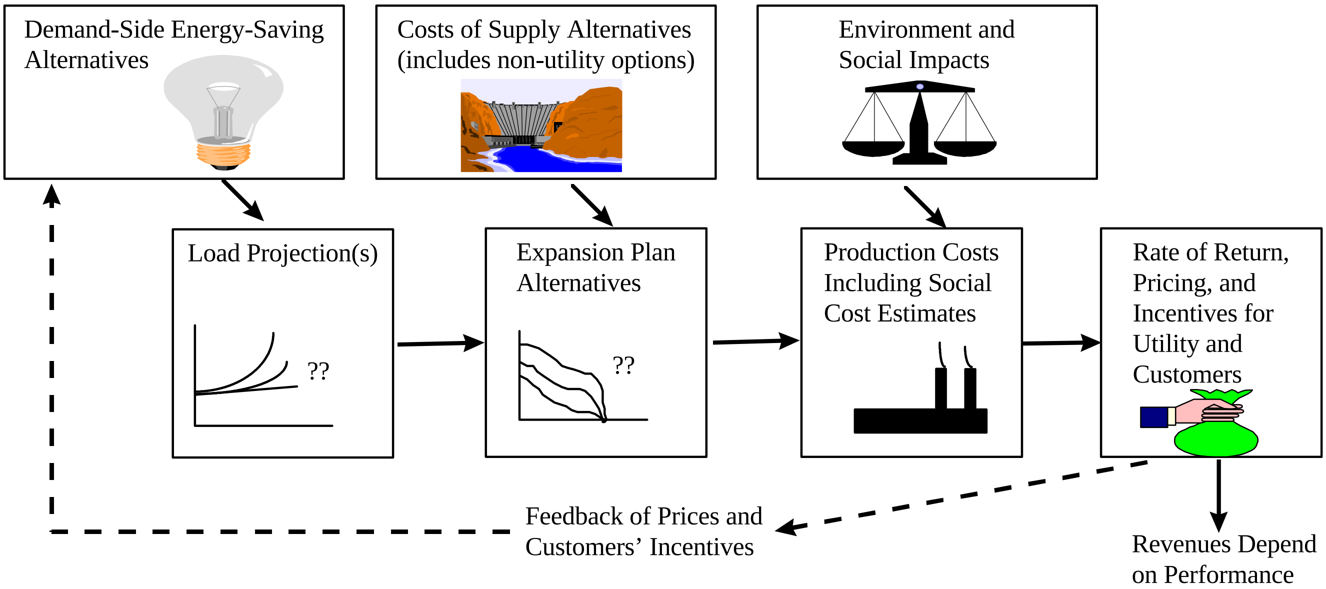


Figure 1.6. An integrated "least-cost" electric production cost and load model.

The expected result of the market and non-market changes brought about by IRP is to create a more favorable economic environment for the development and application of efficient end-use technologies and cleaner and less centralized supply technologies, including renewable sources. IRP means that these options will be considered, and the inclusion of environmental costs means that they will appear relatively attractive compared to traditional supply options.

The difficulty with implementing such changes in a market economy is that the value of environmental quality is not traded in the market, since it is a common social good, and that the benefits of energy efficiency technologies are not fully captured by the market, because of various market distortions and institutional barriers that have been extensively documented (Fisher and Rothkopf, 1989). Thus, planning and regulation has been used to correct these problems and to provide incentives to move the market toward cleaner and more efficient energy technology. Higher electricity prices are often needed to implement the plans and resource allocations resulting from IRP, but price measures are not a sufficient solution in a market with imperfect competition and incomplete information.

D.2. Outline of an IRP Process

IRP is the combined development of electricity supplies and energy-efficiency improvements, including DSM options, to provide energy services at minimum cost, including environmental and social costs. The implementation of IRP generally requires:

1) collection of reliable data on electricity end-use demand patterns and technical alternatives for improving their energy-efficiency or load profiles (treating demand in terms of energy services, rather than strictly kWh),
2) definition and projection of future energy-service demand scenarios,
3) calculation of the costs and electric-load impacts of the demand-side alternatives,
4) comparison of their costs with the economic costs and environmental impacts of conventional and alternative electricity supply options,

5) design of an integrated supply and demand-side plan that satisfies the least-cost criteria in terms of economic costs and environmental impacts, and
6) implementation of the least-cost strategy.

The first two steps are covered in Chapter 2. The planning horizon is defined in terms of its timing and geographic parameters, and the goals for the IRP process are established. Total electricity demand is disaggregated by sector, end-use, and technology, with as much resolution as possible given available data. Based on these end-use demand break-downs and existing electric demand forecasts, disaggregated projections of future levels of energy-service growth can be made.

In the third step, covered in Chapter 3, technologies for improving energy end-use efficiency or influencing load shapes are identified. The technical and economic performance of these alternatives are estimated, compared, and ranked according to cost-effectiveness. Based on these results, DSM programs and other energy-efficiency strategies are analyzed in terms of their total costs and rates of market penetration over time.

In the fourth step, covered in Chapter 4, production-cost analysis of the performance of existing and new electric supply alternatives is used to rank these alternatives according to marginal cost values. The results are compared to the marginal costs of demand-side options, including environmental costs to the extent possible. The two sets of options (supply-side and demand-side) are then compared and combined to produce the “integrated” least-cost electricity plan.

The final two steps (implementation issues) are beyond the scope of the present work, although the relevant issues are brought up at various points throughout the following chapters. The integrated electricity plan must be subjected to further policy studies, financial evaluation, sensitivity analysis, and implementation planning before the final plan is completed. The incorporation of these issues may re-order the ranking of the integrated plan somewhat, or exclude certain resources from the plan. In general, however, this step can be seen as “fine-tuning” of the IRP results to account for specific issues and options inherent in the local or national setting.

D.3. IRP Options

IRP explicitly addresses the full range of options for investments to expand the provision of *energy services.* This section presents some of the principal actions that are commonly considered in an IRP process.

Integrating DSM Programs and System Loss Reduction with Supply Expansion

A key element of the IRP process is thus to bring the economic evaluation of energy efficiency into an equal basis with supply expansion. In North America, active provincial and state-level regulation of vertically integrated utilities has made this kind of evaluation a routine aspect of utility business. The close regulatory oversight by state-level public utility commissions (PUCs) has stimulated the widespread application of utility DSM programs to reduce electricity demand while still meeting customer energy-service needs.

Energy-efficiency investments are evaluated in an IRP process using the same discount rate used for making supply-side investments, as long as customer energy-service needs are met. Planners rank by cost all energy supply and end-use technologies, processes, and programs that could provide the energy services, and select them beginning with the least-cost opportunities. The reason that IRP requires a government or energy-supply entity able to choose, on a relatively equal basis, between financing energy efficiency or paying the marginal costs of new electricity is that successful implementation of end-use efficiency measures requires that their adoption not depend solely on the customers' present economic criteria. The implicit discount rates applied by energy-users to energy-efficiency investments range from 20% to 200%, compared to utility discount rates of 6-10% (Ruderman et al 1987). Thus, one cannot expect that emission taxes and energy price increases, although a necessary measure in many cases where energy is subsidized, will lead to societally optimal investment in energy-efficient technologies. The need for other measures to help implement energy efficiency is the justification for direct government policy measures and utility programs such as DSM, and for their evaluation against supply-side options in an IRP process.

One example of the application of an IRP process is the Northwest (US) Power Planning Council (NWPPC). Every five years, the Council produces 20-year demand forecasts and electricity-resource plans. The NWPPC has made two important changes in the region's energy planning process. First, energy forecasts now explicitly consider the uncertainty of demand. Second, energy efficiency improvements are now treated as part of the electricity-supply resource. The plans account for new and existing electricity-supply resources, energy-efficiency opportunities already captured by consumers and by the Council's and other programs, and future energy-efficiency potential. Estimates of future energy-efficiency potential take into account the achievable market penetration over time and the administrative costs and uncertainties associated with the programs' implementation. The most recent plan identifies as its lowest cost resource the immediate acquisition of energy savings sufficient to meet all the new demand in forecasts based on low and medium rates of economic growth (high growth requires additional generating resources) (NWPPC 1991).

The implementation of energy-efficiency measures via DSM is the most common change resulting from the use of IRP. However, the planning framework is designed to accommodate load management options, supply-side efficiency improvements, non-utility sources, and conventional electric generation and distribution options. Such planning methods could help promote energy efficient technologies and alternative supply options in the developing world as well. IRP may be particularly appropriate for developing countries, where there are often severe capital constraints and an untapped potential for demand reduction. Environmental considerations are now playing a larger role in planning decisions in these countries as well, and these concerns can also be captured in the IRP framework.

Integrating Private Producers and Cogeneration with Utility Generation

Recent years have seen a drastic shift away from the construction of large central power stations by electric utilities. This has been the result of two trends, which are somewhat opposed to one another. The first trend is the widespread adoption of DSM in the U.S. and Canada, especially in states and provinces with ambitious environmental agendas. Such regulatory oversight is not present in other countries, which have nevertheless encouraged varying degrees of energy efficiency through information, pricing, regulation and other policy measures.

The second trend in numerous countries, in both the industrialized and developing parts of the world, is toward deregulation in the electricity sector. Even in the US, where regulatory influence at the state level has remained strong, the Public Utilities Regulatory Policy Act (PURPA) legislation has stimulated the widespread introduction of smaller, independent power producers (IPPs) into the electric supply industry. This change is leading to the advent of competition for supplying utility power and a more general deregulation of the power sector.

In many other countries, the emphasis is clearly on the deregulation and/or privatization of the power sector, with little direct consideration of the implications for energy efficiency and DSM. The assumptions behind the deregulation trend are firmly grounded in economic theory (Anderson 1993). The basic expectations are that private ownership gives stronger performance incentives than public ownership, that regulation is inherently costly and inefficient because it reduces choices available in the market, and that competition increases innovation by rewarding more efficient performance. Implementation, however, is often based more on ideology than realistic analysis.

These trends are also partly the result of technological factors. The powerful economies of scale that reduced generating costs steadily until about 1970 focused utility planning methods and decisions on large central generation (see Hyman 1988). However, these economies of scale in generation technology have been eroded severely. Decentralized options, including DSM technologies for energy efficiency and load management, as well as smaller-scale gas-fired and renewable generation technologies, especially those involving the cogeneration of heat and power, have now become cost-effective alternatives. The trend toward deregulation will tend to accentuate the advantages of decentralized resources by shortening the time-horizon for planning and increasing the risk of large stranded investments in supply capacity (Wiel 1994).

In developing countries, the high rate of growth in the demand for electric service will still require expansion of the central generating capacity. However, the potential for cost-effective introduction of smaller-scale sources, including cogeneration and other non-utility sources, is expected to be significant in many countries. A further goal of IRP is thus to allow the evaluation of such sources on an equal basis with central supply expansion.

Integrating Environmental Impacts and Risks with Cost Analysis

As mentioned above, environmental concerns are one of the primary factors motivating the application of IRP. One of the principal reasons for pursuing energy-efficiency improvements is that energy consumption leads to pervasive externalities, ranging from local pollution and global greenhouse gases to energy and nuclear security risks, that are not reflected in energy supply costs and planning efforts. For example, concerns over the environmental impacts of large hydropower development have influenced system planning in countries as diverse as Canada, India, China and Brazil.

Environmental issues are likely to be even more important in the future as concerns over the regional and global environment, including the potential threat of global climate change, become increasingly serious. The production and use of electricity is generally one of the largest sources of both local and global environmental emissions in most countries. By mitigating these problems with technical improvements that are cost-effective relative to new energy supplies, innovative energy-efficiency initiatives such as DSM programs appear to offer a “win-win” solution.

The costs of environmental emissions from electricity supply are part of the costs avoided through selection of DSM and renewable supply sources. The environmental costs can be quantified either as emission charges actually paid by the utility, or they can be proxy values used to prioritize and select DSM and supply options in the IRP process. Experience in North America with such proxy values has been that they have little effect on DSM activity, even under a regulated planning structure (Hashem et al 1994). Under a deregulated structure, environmental costs would have to be actually paid by the utility in order to have any effect on resource-selection priorities.

Regardless of how environmental costs are captured, and which technologies are chosen to mitigate such costs, it is an important goal of IRP to evaluate environmental and social costs as one of the criteria for determining how the demand for energy services should be met. The technological options for reducing environmental effects include energy-efficiency via DSM and other programs, fuel switching on either the supply or demand-side, cleaner and especially renewable supply sources, adding emission control equipment to power stations, and offsetting emissions by reducing other sources. Including environmental costs in the IRP process makes it possible to weigh the possible environmental benefits of these options against their economic costs.

Integrating the Public ‘Total Resource’ Perspective with the Utility Perspective

In most countries, a reliable supply of electricity is considered an essential public service. Indeed, the expansion of this service to all citizens is a key component in the infrastructure planning of most developing countries, just as it was to the industrialized countries earlier in this century. Because of this public service aspect, and because of the “natural monopoly” afforded by the strong economies of scale in transmission and (until recently) generation of electricity, electric power planning has generally been conducted with wider social welfare objectives than just the narrow interests of the electric supply companies. In some countries, this has been accomplished via nationalized utilities. In other countries, private utilities have operated under a “regulatory compact” that granted them monopoly status and guaranteed earnings in exchange for the obligation to serve all customers at equitable rates. In the US, this concept has been refined to include environmental goals in response to a recognition that guaranteed earnings tend to encourage utilities to over-invest in supply capacity.

Today, as the era of utility nationalization gives way to privatization, and as deregulation removes major elements of the “regulatory compact,” the public service perspective can be preserved through IRP. By selecting technologies and programs to minimize the total cost of electric service, and by including environmental and social costs in the cost criteria, IRP makes it possible to design a plan for electric supply and demand-side options to meet electricity demands without wasting economic or natural resources. Private utilities that are required to pay environmental costs and are rewarded for energy savings will respond to these incentives by making investments that are consistent with the public interest.

In many developing countries, government is mainly responsible for managing the energy sector, so it must be the agent to adopt an integrated approach to energy planning. To do so, most governments would need to shift their traditional power-development focus from the rate of supply expansion to the efficiency with which all investment resources are used. The economic and environmental advantages of supply and demand-side efficiency improvement under IRP would eventually accelerate movement towards transparent regulatory regimes in which utilities will not only enjoy autonomy in their operations but will also be responsible for meeting efficiency and environmental goals set by the society. If governments continue to mix the policy-making role with direct management of energy-supply industries, they can still be made accountable for IRP by donors, creditors, environmentalists and consumers.

D.4. Who Carries Out the IRP Analysis?

The concept of IRP developed from the North American context of private utility monopolies, regulated at the state or provincial level. The utilities were pushed by their regulatory commissions to adopt IRP in order to identify and capture the potential for cost-effective energy-efficiency improvements. The efficiency measures are implemented by the utilities through DSM programs.

Thus, IRP and DSM have come to be seen as utility activities, and they are identified with the North American context of regulated private utilities (a context that itself is changing). Most countries, however, have very different utility structures from the model in which IRP developed. Some countries have national electricity authorities. Others have large private utilities but with less regulatory oversight than in the North American model. Still others have many small local distribution companies buying from a national supply company, and some of these countries are beginning to introduce competition in the power sector.

In these other cases, it can be difficult to create incentives for the utilities to engage in IRP and to implement energy-efficiency through utility-sponsored DSM programs. Some countries in both developing and industrialized countries have begun to experiment with new models of IRP and DSM, but these efforts have not been very ambitious to date. At the same time, there are many other types of policies and programs to implement energy-efficiency improvements, including information campaigns, price incentives, regulatory standards, procurement policies, etc. Such instruments are usually applied by government agencies.

How do these efforts fit with IRP and utility DSM, and how does IRP work in a country with no incentives for utility DSM? In this book, we take a relatively general and inclusive view of IRP. We address all types of energy-efficiency programs, as well as load management and fuel-switching, and provide tools to compare the costs and benefits of these programs to electricity supply expansion. Thus, we try to give a comprehensive view of IRP, in which the optimum mix of resources for supplying energy services can be identified. We acknowledge that these tools will not always be applied in such a comprehensive way, but the IRP approach and the tools provided here should help to improve energy planning decisions even when only a partial set of solutions can be considered.

Where utilities conduct IRP and where utility DSM is an option, we would expect that the IRP analysis would be used by the utility planners, as in the North American model. Where this is not the case, but where the government has an interest in promoting energy efficiency to achieve environmental and economic goals, the IRP analysis could be used by the energy or environment ministry to prioritize programs and policy options. Such options can include those to be implemented through utilities, perhaps as a condition for the approval of power supply projects. This approach may become increasingly relevant as governments attempt to fulfill commitments to reduce emissions of carbon dioxide and other power-sector emissions.

IRP should be distinguished somewhat from the concepts of "integrated national energy planning" (INEP) that were introduced in developing countries around 1980. INEP is a hierarchical approach to integrating energy supply and demand sectors with national economic planning, pricing, and management (Munasinghe 1990a). Because such planning efforts become so comprehensive and so interconnected with other national economic and political priorities, INEP processes have not been widely implemented and have not been shown to make a great deal of difference in energy planning and investment decisions.

Although IRP, as described above, is more inclusive and comprehensive than traditional utility supply planning, it stops far short of the degree of centralization called for in INEP. The concepts of IRP are applicable at the national level as well as at the level of regional or municipal power systems. For small countries, the national level and the utility system may be the same, in which case national IRP makes good sense. In addition, although IRP can and often does include pricing measures, it is not concerned with influencing broader national macro-economic relationships that affect the energy sector. IRP focuses on optimizing or at least improving decisions about direct investments in energy supply and end-use technology.

In larger countries, IRP analysis can be conducted at the national level and/or the local level, but many measures are best delivered through relatively decentralized structures. The present trend toward power sector deregulation in many countries is unlikely to lead to the type of regulatory structure in which IRP developed in North America. However, the principles and methods of IRP remain valid in a deregulated market, where they are best applied at the local level. Indeed, local IRP is now being implemented by distribution utilities in several countries.

D.5. IRP in the Context of Deregulation

Due to the on-going deregulation of electric power markets in the U.S. and Canada, the mandatory use of IRP and DSM is declining as more planning functions are being left to the forces of the deregulated market. In parts of Latin America and other emerging markets, there is also a trend toward deregulation and privatization in power-sector development, both to exploit the efficiency of the private sector and to relieve the debt-ridden public-utility sector of the burden of new investments.

These changes may help to foreclose some options for "traditional" IRP, as originally introduced in North America. However, in spite of the increasing restructuring of the power industry, the state and/or monopoly utilities still play a central role in much of the developing world. Moreover, the international deregulation process may open up a range of new possibilities to apply the principles, if not the full process, of IRP.

For example, the increasing reliance on power purchased from independent power producers (IPPs) in Indonesia, the Philippines, and elsewhere in Southeast Asia does not mean that the state utilities have surrendered their fundamental monopoly. In fact, their situation is similar to that of the U.S. in the 1980s when the PURPA legislation mandated that the (monopoly) utilities buy power from IPPs. Although "traditional" IRP may be increasingly irrelevant in countries such as the U.K., this will not be the case in many developing countries for many years, if ever. In those countries where a planning function remains in place, IRP can provide a way to integrate end-use efficiency and environmental protection into energy development.

In addition, there are several ways in which the principles of IRP will continue to be relevant for application even in completely deregulated power systems. For example, competitive supply firms can use IRP principles to satisfy customer needs for efficiency and low prices, to comply with present and future environmental restrictions, and to optimize supply and demand-side investments and returns, particularly at the distribution level, where local-area IRP is now being actively practiced in North America and elsewhere.

The relevance of IRP to environmental planning and compliance is critical. Public authorities can use IRP principles to design programs to encourage end-use efficiency and environmental protection through environmental charges and incentives, non-utility programs, and utility programs applied to the functions remaining in monopoly concessions such as the distribution wires. Again, the principles of IRP will continue to be relevant to environmental protection in deregulated power markets, even if the process of "traditional" IRP is dissolved.

Further Reading:

Anderson, D., 1993. "Energy-Efficiency and the Economics of Pollution Abatement," Annual Review of Energy and the Environment, vol. 18, pp. 291-318.

EPRI 1990. "Efficient Electricity Use. Estimates of Maximum Energy Savings," Electric Power Research Institute, EPRI/CU-6746.

Chapter 2. The Technological Structure of Energy Demand Projections and Scenarios

Energy and peak load projections play an important role in IRP, because they help to evaluate the need for new resources. Disaggregated projections will help to determine which DSM and efficiency programs are worth pursuing and when, as well as in which sectors and end-uses they should be implemented.

Projections help quantify the potential resources available through "conserved" energy. This potential, as explained in Chapter 1, is the difference between the existing, or baseline, scenario's energy efficiency and a higher efficiency scenario. The baseline can be based on a so-called "frozen efficiency" scenario (which is simply a projection of energy-service growth with no efficiency improvements), or it can include expected changes in energy efficiency, as will be seen later in this chapter.

Demand projections within the IRP framework are in fact *energy services* projections which take into consideration the *technological basis* that provide energy services (e.g., the type of lighting fixture, type of motors) in the projected year, as well as the *socio-economic factors* that determine the required levels of *energy services*.

A. Models to Analyze and Forecast Energy Demand

Several methods can be used to create energy and demand projections. The two main approaches currently being used by most utilities and planning agencies are essentially based on either econometric or end-use (engineering-oriented) models. The main difference between these two approaches is the level of aggregation of the input data. Econometric models are more aggregated and essentially base their projections on price and income (or other parameters of economic activity) factors and their relationship to energy demand.

A.1. Econometric Models

Econometric models have the advantage of requiring less data than engineering-oriented models and have a good theoretical statistical base. Usually they are used for a whole class of customers and do not take into account the technological structure of their energy consumption. Thus, they have a more aggregate nature than the engineering-oriented end-use approach.

The most common type of econometric equation used in energy studies is based on the Cobb-Douglas production function:

$$E = aY^{a} P^{-b} \qquad \textit{[Eq. 2.1]}$$

Where:
E = the energy demand,
Y = income,
P = energy price,

a = coefficient,
α = income elasticity of energy demand,
β = price elasticity of energy demand.

Income and price elasticities indicate how the demand for energy changes as result of changes in prices and incomes in econometric models. Income elasticities are defined as:

$$\alpha = \frac{\Delta E / E}{\Delta Y / Y} = \frac{\%\ Change\ in\ E}{\%\ Change\ in\ Y} \qquad [Eq.\ 2.2]$$

Where:
α is the income elasticity of energy demand,
E is the demand for energy,
Y is the income (GDP).

The price elasticity β of energy demand is defined similarly in relation to the price of energy paid by consumers:

$$\beta = \frac{\Delta E / E}{\Delta P / P} = \frac{\%\ Change\ in\ E}{\%\ Change\ in\ P} \qquad [Eq.\ 2.3]$$

Where:
β is the price elasticity of energy demand,
E is the demand for energy,
P is the price of energy.

The econometric approach utilizes past data to statistically estimate (by means of regression analysis, for example) the parameters a, α, and β of Equation 2.1. Econometric models were widely used in energy demand projections up to the 1970s. They are still important tools to understand the aggregate nature of energy demand and its determinants. However, the fundamental assumption of this model is that the relationship between income, price, and demand which existed in the past will continue to hold in the future. The more fundamental structure of energy demand is not analyzed, and the model's predictive capability breaks down if this fundamental structure changes. There is increasing evidence showing that this relationship between energy, income, and prices may vary significantly in the future when important changes in the technological structure of energy demand, consumer behavior, etc. are taking place.

One application of econometric modeling that is useful for energy-efficiency projections, however, is the projection of baseline energy-service growth. If the technological structure of energy demand remains constant, including the end-use efficiency, then the projected growth in energy consumption is identical to the growth in energy services. This type of projection is also referred to as a "frozen-efficiency" scenario.

A.2. The End-Use Model

End-use projection models (or engineering models) are much more detailed than econometric models, though their analytical formulation can be quite simple. The end-use approach is very well-suited to the purposes of energy-efficiency projections because it is possible to explicitly consider changes in technology and service levels.

Energy demand for each activity is the product of two factors: the level of activity (the energy service) and the energy intensity (energy use per unit of energy service). In addition, the total national or sectoral energy demand is influenced by the breakdown of the different activities that make up the composition, or *structure* of energy demand. Most bottom-up energy analysis holds the mix of energy services and activities (and thus the structure of energy demand) constant across different scenarios but not constant over time.

Given constant structure, the level of activity depends on factors such as population, income and economic output. The level of energy intensity depends on the energy efficiency, including both technological and operational aspects. A summation of the products of these two factors over all activities gives the total energy demand.

$$Energy\,use = \sum_{i=1}^{i=n} Q_i \cdot I_i \qquad \textit{[Eq. 2.4]}$$

Where:
Q_i = quantity of energy service i,
I_i = intensity of energy use for energy service i

The intensity I_i can be reduced by changing technology to improve efficiency, without affecting the level of energy services. Energy use can also be reduced by reducing the usage (hours/year) of a given end-use device (kW), thus reducing the annual energy use (MWh). If this reduction is achieved by reducing waste or unnecessary usage, for example through improved control technology, it can be considered an efficiency improvement (reduction in I_i). However, if the reduction comes from the consumer simply taking less advantage of the end-use, for example by reducing lighting levels or shower temperature, then the resulting savings should really be considered as a reduction in the level of energy services (reduction in Q_i). Generally, bottom-up analysis in the context of IRP assumes that such reductions in energy services are not made, or else they are made in all scenarios and thus not treated as net energy savings.

The quantity of energy services Q_i depends on several factors, including the population, the share using the end-use service, and the extent of use of each service.

$$Q_i = N_i \cdot P_i \cdot M_i \qquad \textit{[Eq. 2.5]}$$

Where:
Q_i = quantity of energy service i,
N_i = number of customers eligible for end-use i,
P_i = penetration (total units/total customers) of end-use service i (can be > 100%),
M_i = magnitude or extent of use of end-use service i.

The population parameter N_i can be the number of households, commercial premises, or industrial customers. A variety of definitions can be used: for example, rather than defining the size of the commercial sector in terms of the number of commercial premises, one could use the total amount of commercial floorspace to define the sector. The key requirement is that the definition of N_i must be consistent with the units in the denominator of the penetration variable P_i.

The P_i value is simply the share of eligible customers that use a given electric end-use service (gas and other fuel-using end-uses must be counted separately). For space heating and cooling end-uses, and for commercial buildings in general, the penetration parameter is typically defined as per-square-meter of building floor area where the end-use service is applied.

For residential appliances, the penetration is simply the number or fraction of appliances per household. This parameter captures the penetration of appliances such as electric cooking stoves or washing machines, or it can be the count of devices that are more numerous, such as lamps and televisions. Some appliances such as TVs and refrigerators can approach a saturation level beyond which penetration is not expected to increase; however, it should not be assumed that this value is 100%, because some households can and do install more than one TV, giving an average penetration greater than 100%.

The form of the magnitude parameter M_i depends on the end-use. For industrial end-uses, it is typically simply the number or tons of a given product. For commercial end-uses, M_i indicates the amount and level of the service provided, for example the average lumens per square meter (lux) of lighting, which can be influenced by changing either the illumination level or the hours of lighting used, or simply the number of hours at a given lux level.

For residential appliances, M_i indicates the frequency of use (number of showers or kg of clothes washed) or the fraction of maximum use (hours of lighting or television) for a given end-use. For heating and cooling end-uses, M_i may indicate the indoor-outdoor temperature difference (ΔT) overcome by the space-conditioning system, weighted according to the number of hours a given ΔT applies. This parameter is measured in degree-days per square meter of conditioned space, and is measured separately for the heating and cooling seasons.

Therefore, the level of energy service depends on the economic activity of the consumer class considered, its patterns of energy usage, and in some cases the information on the penetration levels of energy services within that consumer class. The intensity of energy use is the indicator of the technical efficiency to deliver one unit of energy service being considered for that consumer class. Exercise 1.2 showed several lighting technologies that provide equivalent amounts of lumen output with different efficiencies.

Following are two examples of the concepts outlined above.

Residential example:

In a community of 100 homes (N_i), 80% (P_i) own a TV. The average TV consumes 200 W (I_i) of electricity and is turned on for an average of 2 hours per day (M_i).

Therefore, on an annual basis, $Q_i = N_i \cdot P_i \cdot M_i$ = 100 homes · 80% · 2 hr/day · 365 days/yr = 58,400 home-hr/yr.

The community's annual TV energy use = $Q_i \cdot I_i$
= 58,400 home-hr/yr · 200 W/home = 11,680 kWh/yr.

Commercial example:

A store contains 1000 square meters of floor space (N_i), 90% (P_i) of which is lit by fluorescent lighting. Each 15 square meters of floor area contains four 40W fluorescent bulbs, each of which provides a lighting output of 67 lumens/W. The lights are turned on for an average of 8 hours per day.

On an annual basis, the service level M_i could then be calculated as follows:

M_i = 67 lumens/W · 40W/bulb · 4 bulbs/15m^2 · 8 hr/day · 365 days/yr
= 2,086,827 (lumen-hr)/(m^2-yr).

In other words, on a per-square-meter basis, the store is lit by 2,086,827 lumen-hours per year.

Therefore, $Q_i = N_i \cdot P_i \cdot M_i$ = 1000 m^2 · 90% · 2,086,827 lumen-hr/m^2-yr
= 1.878 x 10^9 lumen-hr/yr of fluorescent light.

Since the fluorescent light produces 67 lumens of light per watt, the intensity (I_i) is 1/67, or 0.0149 W/lumen.

Therefore, the store's total annual fluorescent light energy use is:
1.878 x 10^9 lumen-hr/yr · 0.0149 W/lumen = 28,000 kWh/yr.

B. Projections of End-Use Energy Demand

End-use models make projections for each important end-use, using as input variables information on the level of energy service required and the technical efficiency needed to deliver one unit of that service. For example, suppose we want to project the amount of annual MWh that will be required to provide illumination in the office building sector. We can have the number of square meters illuminated at a given level (e.g., 400 lux) as a measure of the sector's activity level over time; and as a 'technical efficiency' parameter we can have the annual amount of kWh/m^2 consumed. What we need to project is the expected future amount of square meters and the efficiency factor: the amount of kWh needed to provide the required level of illuminance of the tasks performed in an office. Usually, the efficiency factor varies across different scenarios, while the projection of square meters (the energy service, or activity level) is constant across all scenarios.

B.1. Baseline Projections of Energy Services

The level of energy services assumed in a set of end-use energy scenarios is usually based on those described by the baseline scenario. The types of projections we are mostly concerned with require detailed information on trends of electricity use by consumer class, end-uses, and technologies. A good set of information in the base year, containing data on current end-use efficiencies, is necessary. The growth of energy services, such as the square meters of illuminated building space, is then projected into the future as part of the baseline scenario.

Sometimes we combine econometric and end-use models. These engineering/economic models include the econometric relation of the specific activity level of the particular sector with the rest of the economy, and yet they allow for the explicit consideration of technological improvements for each energy end-use considered for that sector. In our current office illumination example, the projection of office square meters could be linked by an econometric expression to future commercial sector GDP growth. The projection is then made in two stages: first the econometric projection of floor area (square meters), then the end-use projection of the required energy to service the projected floor area.

For our office illumination example, then:

$$Area = a \cdot GDP^{g} \qquad \textit{[Eq. 2.6]}$$

Where:
a, g = coefficients,
$Area$ = m^2 of building floor area (= N in Eq. 2.5).

Assuming that penetration P (from Eq. 2.5) is 100%, lighting energy service would be:

$$Q_{light} = Area \cdot M_{light} \qquad \textit{[Eq. 2.7]}$$

Where:
M_{light} = hours of lighting use at a given illumination level.

Lighting energy use (E_{light}) would be:

$$E_{light} = Q_{light} \cdot I_{light} = Area \cdot M_{light} \cdot I_{light} \qquad \textit{[Eq. 2.8]}$$

Where:
I_{light} is the energy intensity or “power density” (W/m^2).

Note that in this current example of Office Lighting, the terms in equations 2.7 and 2.8 are defined slightly differently than in the Store Lighting example presented in Section A.2. on the previous page. In the Section A.2. example, M was characterized in terms of (lumens/m^2)·(hr/yr); and I was characterized as W/lumen. Multiplying $M \times I$ resulted in units of (W/m^2)·(hr/yr). In the current Office Lighting example, M is characterized in terms of hr/yr, and I is characterized as W/m^2. However, multiplying $M \times I$ again results in units of (W/m^2)·(hr/yr). Both are in fact correct. In other words, the equation terms can be defined flexibly as long as consistency is maintained within the equations.

Next, we present the specific equation definitions for projecting end-use energy demand within the residential, commercial, and industrial sectors. As discussed above, the specific definitions of the equation terms can be somewhat flexible and will depend upon data availability and the specific objectives of the planning effort.

B.2. Residential Sector End-Use Energy Projections

Total residential energy use is the sum of the energy demanded by residential services such as lighting, space heating (or cooling), refrigeration, television use, water heating, etc.

$$E_R = \sum_{i=1}^{i=n} E_{R_i} \qquad \textit{[Eq. 2.9]}$$

Where:
E_R = residential energy use
i = end-use

Each end-use can have a specific expression following the general format (Eq. 2.4):

$$E = \sum_{i=1}^{i=n} Q_i \cdot I_i = \sum_{i=1}^{i=n} \left(N_i \cdot P_i \cdot M_i \right) \cdot I_i \qquad \textit{[Eq. 2.4, 2.5]}$$

For the residential sector one can define the energy consumption in each end-use using the following projection equation:

$$E_{R_i} = N_i \cdot P_i \cdot M_i \cdot I_i \qquad \textit{[Eq. 2.10]}$$

Where:
E_{Ri} = residential energy consumption for end-use i,
N_i = the total number of households with end-use i,
P_i = the penetration levels of appliances for end-use i,
M_i = the number of hours, degree-days or frequency of use for energy service i,
I_i = the intensity of the end-use i.

In this equation we express the required level of energy services (Q) given by the product of N by P by M as outlined in Section A.2.

Projecting the level of N and P into the future while maintaining M and I at current levels would provide a frozen-efficiency scenario; or decreasing M and I over time could reflect an assumption of implementation of efficiency measures.

As residential energy services requirements vary across income classes, Eq. 2.9 can also be derived for each income class. In this case, the total residential energy demand would be given as:

$$E_R = \sum_{i,j=1}^{n,m} E_{R_{i,j}} \qquad \textit{[Eq. 2.11]}$$

Where:
i = end-use,
j = income class.

In other words, the general equations elaborated in Eq. 2.9 and 2.11 can be formulated at any appropriate level of detail: by end-use only, or by both end-use and income level, or by end-use, income level, and type of home construction (single-family home vs. apartment), etc. The analyst must balance the benefits of additional levels of detail against the cost and difficulty of obtaining the additional detail.

B.3. Commercial and Services Sector End-Use Energy Projections

Commercial and service activities take place essentially in buildings, so it is useful to disaggregate commercial sector energy demand by the type of economic activity and building type. Typically, commercial sector end-use energy consumption is defined on a per-floorspace basis in terms of kWh/m^2. The definition of the commercial floor area (in m^2) must be consistent, and it may be necessary to reconcile statistical/commercial values with technical/architectural values to account for different accounting of corridors and storage areas, for example.

$$E_C = \sum_{i,j=1}^{n,m} E_{C_{i,j}} \qquad \textit{[Eq. 2.12]}$$

Where:
E_c = commercial energy use
i = end-use,
j = market segment (building type: offices, hotels, hospitals, etc.).

We will re-define Eq. 2.4 in order to make the terms more compatible with the data presented in Exercise 2.7 at the end of this chapter:

$$Energy\,use = \sum_{i=1}^{i=n} Q_i \cdot I_i \qquad \textit{[Eq. 2.4]}$$

I_i is now defined in terms of the average installed wattage per square meter of floorspace for end-use i. Note that different types of buildings or functional areas in buildings could have different energy service levels and thus different intensities.

Here we identify the quantity of energy services Q as being:

$$Q_{i,j} = A_{i,j} \cdot P_{i,j} \cdot M_{i,j} \qquad \textit{[Eq. 2.13]}$$

Where:
A = the total floorspace area of market segment j (or building type j),

P = the percentage of total floorspace area in market segment j served by end-use i,
M = the number of hours, degree-days or frequency of use for energy service i in segment j.

Greater economic activity will influence the growth rate of the commercial and service sector building floorspace area, the penetration of air conditioning, the annual number of hours of appliance use, etc. In this equation technical improvements are represented by reduced wattage per square meter.

B.4. Industrial End-Use Energy Projections

$$E_I = \sum_{i,j=1}^{n,m} E_{I_{i,j}} \qquad \text{[Eq. 2.14]}$$

Where:
E_I = industrial energy use
i = end-use,
j = industrial market segment (e.g., steel production, food processing, pulp & paper, etc.)

We will again re-define Eq. 2.4 in order to be more convenient to be used with the data presented in Exercise 2.7 at the back of this chapter:

$$Energy\, use = \sum_{i=1}^{i=n} Q_i \cdot I_i \qquad \text{[Eq. 2.4]}$$

I_i = the intensity of end-use i.

Here we identify the quantity of energy services Q_i as being:

$$Q_{i,j} = N_{i,j} \cdot P_{i,j} \cdot M_{i,j} \qquad \text{[Eq. 2.15]}$$

Where:
N = the total number of facilities in industrial market segment j,
P = the penetration levels of appliances for end-use i in market segment j,
M = the number of tons of product j requiring energy end-use service i.

B.5. Load Curve

Electricity demand is not uniform throughout the day or year. Several electricity end-uses are related to the time-of-day, such as lighting and cooking. The hours of the day during which the highest demand occurs is known as the peak period. During the year there is also a particular day when electricity demand is at its yearly peak. This yearly peak is typically both climate- and time-related. Some regions face their *peak demand* during the hottest days of summer, when air-conditioning is mostly responsible for the increased electricity demand. In other areas, residential lighting and other evening uses of electricity may be the main drivers of peak demand.

Figure 2.1 provides an example of a total daily load curve for the residential sector and the contribution of refrigeration, lighting and the category “other uses.” Note that some end-uses, such as refrigeration, have basically constant demand throughout the day, while others such as lighting vary significantly by time-of-day.

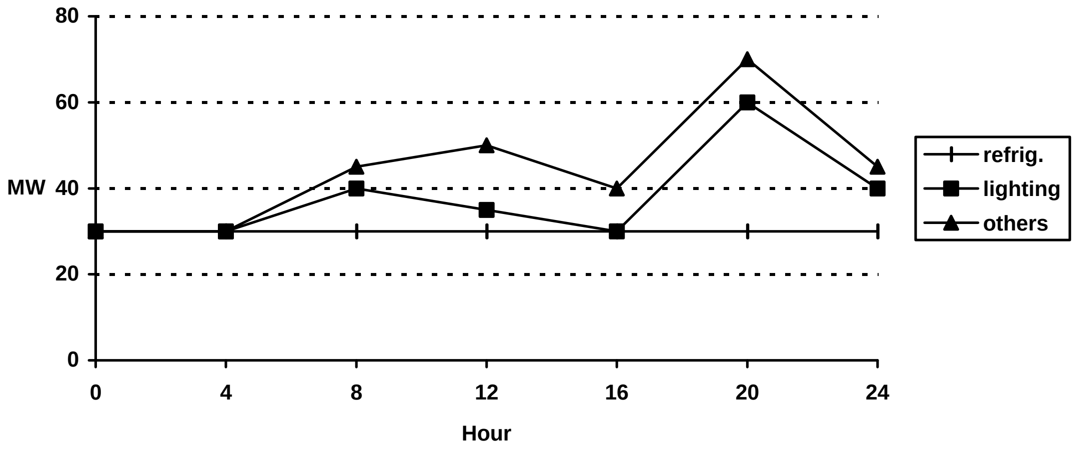


Figure 2.1. Illustration of a residential load curve by different end-uses.

Projections are typically made for electrical energy (kWh) on an annual basis, but it is also important to project the future load profile (daily or annual) to reflect the daily and seasonal fluctuations in demand. Special attention should be paid to projections of the maximum annual peak demand, because this will define the total capacity required to meet demand at all times and avoid power outages. Peak demand is of particular interest to utilities because their capital requirements for building new generation capacity are normally driven by peak demand considerations. One aspect of demand-side management (DSM) involves ways to change the shape of the load curve, as will be seen in Chapter 3. Typically, utilities will strive to avoid the concentration of demand during peak hours of the day and will try to spread this demand throughout the day (or night). This is possible with some end-uses and can sometimes be considerably cheaper than building additional generation capacity to meet the peak demand.

In Chapter 4 we discuss how to link annual energy consumption with load profiles, by means of a *load factor* and a *load duration curve*. The ratio of the annual average hourly demand to the maximum peak demand is the utility's load factor, which is a measure of the variability of the load. The load factor is expressed by the relation between total energy consumed and peak demand, as given by the following equation:

$$\textit{Load factor} = \frac{\textit{energy consumed (MWh/yr)}}{\textit{peak demand (MW)} \cdot \textit{8760 hr/yr}} \qquad \textit{[Eq. 2.16]}$$

B.6. Data Requirements of End-Use Models

Equations used in the end-use projection approach require a breakdown by sectors, activities and end-uses. The estimation of end-use breakdowns is important to determine which end-uses are most relevant. Once these are known their magnitude is quantified more accurately to evaluate the opportunities for energy efficiency improvement. Table 2.1 illustrates one such possible breakdown.

Table 2.1. Example of information required by end-use models.

Consumer class	**End-use**	**Technologies/measures**
Industrial Sector	Power	conventional motor efficient motor VSD + motor better sizing of motors and tasks
	Lighting	incandescent fluorescent + electromag. ballast fluorescent + electronic ballast mercury vapor reflexive fixture improved lighting design daylighting
Residential Sector	Lighting	incandescent compact fluorescent fluorescent (elect., electromag.) fixtures improved lighting design daylighting
	Cooling	ventilation, fans air conditioner natural ventilation passive cooling
	Space heating	gas, electric, central heating
	Refrigeration	efficient refrigeration
	Water heating	solar gas
Commercial Services Sector	Lighting	incandescent fluorescent + electromag. ballast fluorescent + electronic ballast mercury vapor reflexive fixture improved lighting design daylighting occupancy sensors
	Cooling	ventilation, fans air conditioner natural ventilation passive cooling
	Refrigeration	efficient refrigeration
	Water heating	heat pump water heaters gas
	Space heating	gas, electric, central heating

Estimates of end-use equipment saturation and energy use can be made on the basis of aggregate indicators of major end-use categories, for example information on appliance sales. Where comprehensive information of this type is not available, one might try to use existing information from other countries with similar socio-economic development characteristics to make estimates of end-use saturation and energy consumption.

Alternatively, a more reliable analysis is performed by a bottom-up approach, which includes extensive questionnaire-based surveys, billing data analysis, energy audits, and measurements. End-use projection models are very data intensive. Usually we start working with a base year for which we have a detailed breakdown of the consumer classes and main end-uses.

Table 2.2 and Figure 2.2 provide selected residential appliance saturation information. Saturation information is often available and is useful to estimate energy breakdown by uses.

Table 2.2. Percent of households with selected end-use technologies.

City	Number of Households	Incand Light	Fluor. Light	TV b/w	TV color	Refrig	Elec H_2O Heat	Air Cond	Clothes Wash
Beijing ('90)	2416918	88%	93%	42%	77%	87%	1%	2%	84%
Manila ('90)	1520913	85%	88%	41%	55%	93%			
Pune ('90)	323194	86%	84%	40%	38%	40%	41%	2%	8%
Thailand* ('90)	1446262	57%	98%			82%	5%	15%	20%
Nanning ('90)	286533					54%		0%	76%
Hong Kong ('90)	1030928			2%	98%	98%	17%	51%	89%
Manaus ('92)	201000	98%	60%	30%	84%	84%	61%	50%	13%

** Weighted average values for Bangkok, Chieng Mai, and Ayutthaya.*
Source: Sathaye et al. (1991), Jannuzzi et al. (1995).

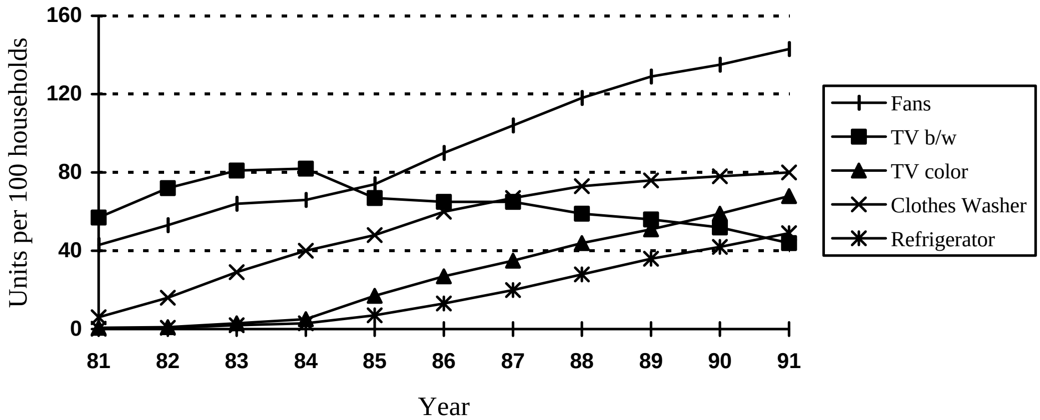


Figure 2.2. The trend of China's urban (1981-1991) ownership of appliances.
Source: Liu (1993).

Exercise 2.1) Assuming the following annual consumption values for appliances listed in Table 2.3, estimate the annual electricity use breakdown for lighting, TV, refrigerator use, water heating, air conditioning and washing machine, for the cities listed in Table 2.2.

Compare the results and discuss possible sources of errors in this procedure.

Table 2.3. Annual consumption per household for appliances.

End-use	(kWh/year)
Incandescent Lighting	15
Fluorescent Lighting	26
Television	174
Refrigerator	763
Electric Water Heater	431
Air Conditioner	1115
Clothes Washer	265

Source: Jannuzzi et. al. (1995).

The electricity end-use structure may vary significantly across countries and regions. Table 2.4 illustrates the breakdown of electricity consumption by major sectors and end-uses in six countries at varying stages of development.

Table 2.4. End-uses, percentages of total national consumption in Industry-Mining-Agriculture, Residential, and Commercial sectors.

End-Use	India	Thailand	Chile	Canada	Argentina	Brazil
Industry, Mining, Agriculture						
Motors & Pumps	80	73	85	85	75	49
Lighting	6	3	7	10	7	2
Refrigeration	2		3		3	
Process Heat	2		3		3	10
Direct Heat		11				32
Electrochemical	8		2		12	7
Others	2	13		5		
Total	100	100	100	100	100	100
Residential						
Refrigeration	13	21	25		29	32
Lighting	28	21	30		30	23
Water Heating			3			26
Air Cond. & Evap. Coolers	11	5	1		2	3
Television	4	9	8		8	8
Cooking		17	3			1
Ironing			8		8	
Space Heating			7		3	
Ventilation-Fans	34		5		5	
Clothes Washing			5		7	
Others	10	26	5		8	7
Total	100	100	100	100	100	100
Commercial						
Lighting	60	31	50	38	53	44
Motors			10	30	10	
Refrigeration		47	12	9	12	17
Equipment			8	7	10	8
Space Heating			8	14	3	
Water Heating			2	2		
Air conditioning	32		5		7	20
Others	8	22	5		5	11
Total	100	100	100	100	100	100

Source: Arrieta (1993), Dutt & Tanides (1994)

Exercise 2.2) If you need to do an energy efficiency program for all countries listed in Table 2.4, with which end-uses you would work? Why?

If you need to do a specific energy efficiency program for each one of these countries, would you choose some different end-uses by sector? Why this change?

Now, choose two end-uses by sector of your country and explain why you would choose these to do an energy efficiency program.

Household surveys indicate that differences in electricity consumption among households increase with income. Place of residence (urban/rural) is also an important determinant. The structure of electricity by end-uses across different income classes is shown in Figure 2.3. Some end-uses including electricity use in showers and TV, appear to saturate with increasing income. Others, including lighting and refrigeration do not.

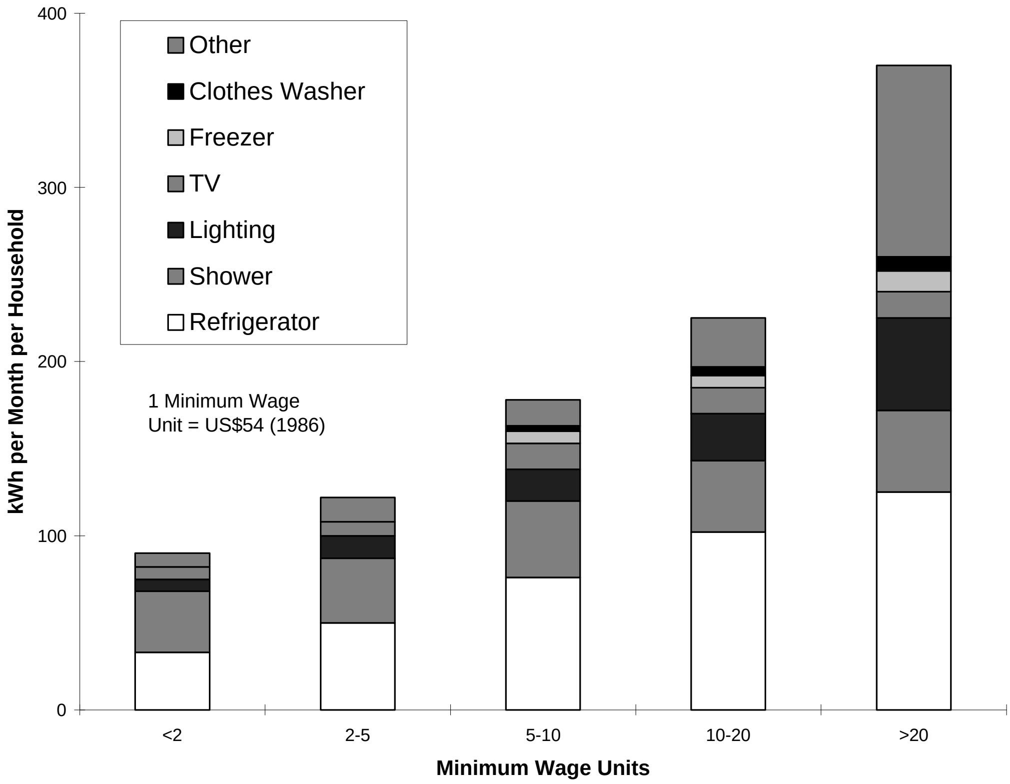


Figure 2.3. Breakdown of household electricity use by end-use and income class.
Source: Jannuzzi (1991).
Note: Refrigeration, illumination, and "other uses" have higher consumption rates as we move from low-income to high-income households.

B.7. Estimation of End-Use Breakdown

Energy consumption estimates by end-use are generally not available from utility load data. If bottom-up data, such as surveys, billing data, energy audits and measurements, are available, they can be used to estimate end-use breakdowns. Otherwise, a simpler approach is to try to estimate energy consumption from equipment sales data.

Residential Refrigerator Example

To illustrate this concept, we will take the example of residential refrigerators. Assume that the average refrigerator has a life of 20 years, consumes 500 kWh of energy per year, and that 100 refrigerators are sold per year.

Part a.) If one were to assume that the market is fully saturated with refrigerators and that the total market size of refrigerators is therefore not growing from year-to-year, then that would mean that all 100 refrigerators sold per year are replacements of existing refrigerators.

We can also assume that the annual replacement rate of the refrigerators is equal to 1/lifetime of the refrigerator. In other words, with a refrigerator lifetime of 20 years, 1/20 of the total existing refrigerator market must be replaced each year.

From the above two paragraphs, we can therefore assume that the 100 refrigerators sold per year represent 1/20 of the total refrigerator market; so the total refrigerator market would be equal to 100 ÷ (1/20) = 2000 refrigerators.

Total annual refrigerator consumption would then be:
(2000 refrigerators) · (500 kWh/yr per refrigerator) = 1 million kWh/yr.

Therefore, given the highly simplifying assumption that all refrigerator sales were to replace existing refrigerators, we were able to calculate the total annual consumption of the refrigerator end-use.

Part b.) Next, assume that the refrigerator market is not fully saturated, but is in fact growing slowly. Say, for example, that of the 100 refrigerators sold in a year, 95 are replacements of existing refrigerators, and 5 represent an expansion of the total refrigerator market size.

For the existing refrigerators, the replacement rate of 1/20 per year would still hold. Therefore, the *existing* refrigerator market size must now be 95 ÷ (1/20) = 1900 refrigerators. The *total* refrigerator market size would include both the existing refrigerator market (1900 refrigerators) and the newly expanded portion of the market (5 refrigerators), and would therefore be 1905 refrigerators.

In this case, the total annual refrigerator consumption would then be:
(1905 refrigerators) · (500 kWh/yr per refrigerator) = 952,500 kWh/yr, still fairly close to the 1 million kWh/yr result obtained in *part a.)* above.

Therefore, as long as the market size is expanding only slowly, annual equipment sales data can be used to obtain a fairly good approximation of annual energy use.

Part c.) Now, assume that the refrigerator market size is expanding rapidly, and that of the 100 refrigerators sold in a year, only 25 are replacements of existing refrigerators, while 75 represent an expansion of the total refrigerator market.

Again, for existing refrigerators, the replacement rate of 1/20 per year would still hold; the existing refrigerator market would now be 25 ÷ (1/20) = 500 refrigerators. The total market size would then be 500 + 75 = 575 refrigerators; and total annual refrigerator energy consumption would be (575 refrigerators) · (500 kWh/yr per refrigerator) = 287,500 kWh/yr.

The result in *part c.)* now shows a total annual energy consumption well below those obtained in *parts a.) and b.)* above. Nevertheless, if one can make a reasonable estimate as to what percent of annual equipment sales represent replacements of existing equipment, then one can develop an estimate of the total end-use energy consumption. The assumption that all equipment sales are for replacement of existing equipment (i.e., the *part a.* scenario) results in an upper-bound estimate of possible energy consumption for the given end-use.

The calculations performed above can be summarized in the equations that follow, with the following definitions:

S = annual equipment sales (units/year),
R = replacement of existing equipment (units/year),
MG = amount of market growth per year (i.e., increase in equipment in market) (units/yr),
EM = size of existing market (i.e., existing equipment currently used in market) (units),
L = lifetime of equipment (years),
UEC = unit energy consumption (i.e., annual energy use per unit of equipment) (kWh/yr-unit)

$$S = R + MG \qquad \text{[Eq. 2.17]}$$

$$R = \frac{EM}{L} \qquad \text{[Eq. 2.18]}$$

Combining Eq. 2.17 and 2.18,

$$S = \frac{EM}{L} + MG \qquad \text{[Eq. 2.19]}$$

or, rearranging the terms in Eq. 2.19,

$$EM = L \cdot (S - MG) \qquad \text{[Eq. 2.20]}$$

$$\textit{Total Annual Energy Consumption} = \left[EM + \left(MG \cdot 1\ yr\right)\right] \cdot UEC \qquad \text{[Eq. 2.21]}$$

Combining Eq. 2.20 and 2.21,

$$\textit{Total Annual Energy Consumption} = \left[L\left(S - MG\right) + \left(MG \cdot 1\ yr\right)\right] \cdot UEC \qquad \text{[Eq. 2.22]}$$

Therefore, using Eq. 2.22 for *Part c.)* of the example on the previous page, total annual energy consumption = [(20 yrs) · (100 units/yr - 75 units/yr) + (75 units/yr) · (1 yr)] · (500 kWh/yr-unit) = 287,500 kWh/yr.

Lighting Example

Next, we will examine lighting energy use in Mexico (Dutt, 1992). Table 2.5 shows lamp sales by category from 1985 to 1989. Each lamp sold either replaces a lamp that burnt out or goes into a new lamp point or fixture. Since lamp sales do not show a rapid increase this may suggest that most of the lamps replaced existing ones. For the present calculation, we assume that all were in fact replacement lamps and that the overall market for lamps did not increase during the study period.

This assumption of zero market growth gives an upper limit estimate of lamp energy consumption, as outlined in the previous *Residential Refrigerators Example*. For appliances that are increasing in annual sales, such as freezers and air conditioners, the existing stock would be lower, and annual energy use would be overestimated by assuming that all equipment is replacing already-existing equipment. In such a case, a more precise vintage model should be used.

Table 2.5. Lamp sales (millions of units) in Mexico by all manufacturers.

Lamp type	1985	1986	1987	1988	1989	Average
Incandescent						
up to 100W	140	118.5	147	121.5	138	133
150-1500 W	2.9	2.3	2.2	1.7	2.0	2.22
Fluorescent						
20 & 40 W	3.8	3.3	3.8	3.5	3.7	3.62
39, 55&75W	9.7	9.1	11.3	9.7	11.6	10.28
Others	1.3	1.4	1.4	1.3	1.3	1.34
Total	14.8	13.8	16.5	14.5	16.6	15.24

Source: Dutt (1992).

For lamp sales data we consider the average annual sales, 1985-89, as shown in the last column of Table 2.5 and additional information from the manufacturers regarding the magnitude of sales according to lamp power, as shown in Table 2.6.

If we assume that all lamps are replacements of existing lamps (i.e., no market growth), then Eq. 2.22 becomes simplified to the following:

$$\textit{Total Annual Energy Consumption} = L \cdot S \cdot UEC \qquad \text{[Eq. 2.23]}$$

For 25 W incandescent lamps in Table 2.6, we can then assume that life (L) = 1 year, sales (S) = 6,650,000 units per year, and UEC = (25 W) · (1000 hr/yr-unit) = 25 kWh/yr-unit. Total annual 25 W bulb energy consumption then equals 0.166 TWh/yr.

For 20 and 40 W (30 W average) fluorescent lamps in Table 2.6, the equipment life is 12000 hours. Let us assume that the lamps are operated for 3000 hours per year, resulting in a life of 4 years. Then, L = 4 years, S = 3,620,000 units per year, and UEC = (30 W) · (3000 hr/yr-unit). Total annual 20 and 40 W bulb energy consumption then equals 1.303 TWh/yr.

Implied annual energy consumption in Mexico is calculated in Table 2.6 for each lamp type.

Table 2.6. Estimate of energy consumption for principal lamp types, Mexico (85-89)

Lamp type and power (W)	Life (hours)	Average annual sales (1000s)	Electricity consumption (TWh/yr)
Incandescent			
25	1000	6650	0.166
40	1000	13300	0.532
60	1000	39900	2.394
75	1000	19950	1.496
100	1000	53200	5.320
100-1500 (avg. 200)	1000	2200	0.440
SubTotal			10.348
Fluorescent			
20, 40 (avg. 30)	12000*	3620	1.303
39, 55, 75 (avg. 56.33)	12000*	10280	6.949
Others (avg. 30)	12000*	1340	0.482
SubTotal			8.734

* *Assume 3000 hours operation per year.*

Note that the data in Table 2.6 do not include the energy consumed by ballasts of the fluorescent lamps. If we assume that the ballasts add 20% to the consumption of the fluorescent lamps, the total energy consumption would be as shown in Table 2.7.

Table 2.7. Electricity consumption by lamp type, including ballasts, in Mexico (85-89).

Lamp type	Incandescent	Fluorescent
Consumption (TWh/yr)	10.348	10.481

Source: Dutt (1992).

Exercise 2.3) We illustrated the method using data from Mexico. Table 2.8 shows some residential end-use sales from 1985 to 1989 in Brazil. Estimate the energy consumption by residential end-use from sales data (assuming the refrigerator life = 35000 hours and the air conditioner life = 2400 hours, and the refrigerator average power = 210 W and the air conditioner average power = 1415 W).

Table 2.8. Residential end-use sales (thousands of units) in Brazil by all manufacturers, 1985-89

End-use	1985	1986	1987	1988	1989	Average
Refrigerator	1689	1963	1907	1651	1931	1828
Air conditioner	265	397	475	424	481	408

Source: COPPE/UFRJ and ELETROBRÁS (1991).

How reliable is your estimate? Make a list of possible sources of errors and uncertainties. Compare these results with the example of lighting energy use.

C. Scenario-Based Projections Framework

We use scenario analysis to compare options to provide a given level of *energy services*. One problem with bottom-up models is that they are not complete models; rather they rely on baseline projections of economic structure and growth (i.e. a macroeconomic, or top-down, model) to project demand for energy services. Usually we begin with one socio-economic scenario that provides projections of population, structure and economic growth for a particular region or country from the present until a target year. Sometimes we can work with more than one socio-economic scenario, such as a high economic growth and a low economic growth scenario. This allows us to perform sensitivity analyses on the socio-economic parameters which can have a major impact on energy demand.

At least two end-use scenarios are needed: a baseline scenario and an efficient scenario which considers improvements in end-use efficiencies. It is possible to include some efficiency improvements in the baseline scenario as well if one assumes that some improvements will happen naturally without any specific market intervention to stimulate such improvements. If the baseline scenario does not include any improvements in end-use efficiencies, thus maintaining constant the current levels of energy efficiency, then this is called a *frozen-efficiency scenario*.

The efficient scenario can be derived for one end-use measure, or a set of improvements in several end-uses and sectors. There are several kinds of efficient scenarios, including the technical potential scenario, the economic potential scenario, and the market potential scenario. These are discussed on the following pages. Other types of scenario definitions can involve the level of energy-service growth, the supply-side strategy, or other parameters.

C.1. Baseline Growth Projection Scenario

To simplify the definition of the baseline, and to relate it to well-known quantities, we usually characterize energy services provided as if the average energy intensity for each activity would not change after the base year. This "frozen efficiency" scenario is not a true scenario at all, because even if no active efficiency improvement efforts are made in the future, energy intensities will generally decline somewhat simply as a result of older, less efficient equipment being taken out of service and being replaced by newer models. Rather, energy use at "frozen efficiency" simply indicates energy service growth, indexed to the present level of energy services and energy consumption.

Thus, the so-called frozen efficiency scenario can be used to project energy service growth in the future. The level of energy services can be difficult to define, because energy services can be measured in several different units, such as lumen-hours of lighting, degree-day-square meters of space-heated or air-conditioned building area, tons of product manufactured, etc. Some energy services, such as cooking or electronic entertainment or office tasks, can be difficult to define in a quantitative way at all. Indexing these ambiguous quantities to measured present energy consumption in a frozen efficiency scenario simplifies the problem of scenario-building.

The baseline scenario usually assumes that present trends are maintained with regard to energy use, equipment penetration (of efficient vs. less-efficient models), etc., that would be expected with no policy change. In countries where IRP is not a common practice, this scenario may well coincide with the official forecast. The main problem with using an official forecast as the baseline scenario is that it may not provide sufficient detail with which to develop an end-use breakdown or determine baseline end-use efficiencies.

The most basic approach to developing a baseline end-use scenario is the static frozen efficiency scenario in which energy intensity is held constant throughout the analysis from the base year until the projected target year. A slightly more complex approach, known as the dynamic frozen efficiency scenario (or frozen "new model" scenario), allows replacement of retired equipment with new (more efficient) models on the market, but does not allow for introduction of new technologies which did not already exist in the marketplace in the base year. In the dynamic frozen efficiency scenario, average energy intensity might be reduced over time, for example, to the level of the average intensity of new equipment available in the base year.

C.2. Technical Potential Scenario

This scenario considers all the possible technical improvements in all equipment, buildings and processes that can be introduced in the projected year. This potential can be characterized in two versions: the hypothetical savings that could be achieved if all systems could be converted instantaneously, or the savings that could be achieved if retiring systems were replaced with more efficient ones.

It is also possible to distinguish a *theoretical energy-efficiency potential*, which can be defined according to thermodynamic limits. For example, if all of the energy used by an electric lamp were converted to light rather than heat, the lamp efficacy (a measure of energy efficiency) would be several times higher than the best lamps now available, and more than ten times higher than conventional incandescent lamps. Similarly, heating and cooling efficiency limits can be determined from thermodynamic efficiency limits for a heat pump operating between given indoor and outdoor temperatures. Even these limits might not be rigid. For example, if a building shell is designed to minimize unwanted heat gains and losses and to admit daylight, passive solar heat and natural cooling, the purchased energy for these energy services can be reduced to zero. While theoretical efficiency limits exist, they are inherently equipment-specific.

The *technical energy-efficiency potential* can be defined as the improvement in end-use energy efficiency that could result if the most efficient technologies known today were to attain 100% market saturation during one lifetime of the technologies (10-20 years) (EPRI 1990). Clearly, this definition is also technology-specific, as building or system design improvements can often reduce energy needs more than equipment improvements alone. In practice, the technical efficiency potential is always changing, as new technologies become available. Because the present availability of “known” technologies depends on their being at least cost-effective enough to be worth introducing, the technical potential can be difficult to distinguish from the economic efficiency potential.

C.3. Economic Potential Scenarios

This type of scenario considers only those alternatives that are cost-effective. The demand-side alternatives are screened, and the scenario includes only those measures that satisfy a given threshold of cost-effectiveness. This threshold tests whether a given measure is considered profitable to society, consumers, the utility, or another agency performing the IRP. Costs of competing supply-side alternatives are taken into account, and environmental and other external costs can be included.

Thus, the *economic energy-efficiency potential* is the energy efficiency improvement that would result from maximum use of cost-effective technologies. It is a function of the selected cost-effectiveness threshold, based on payback time, internal rate-of-return, or cost of saved energy (see Appendix 3). More ambitious efficiency gains can usually be identified as the cost ceiling is raised. Based on this concept, it has become common to depict this potential in the form of marginal cost curves (sometimes called “supply curves” of saved energy).

Figure 2.4 shows a sample cost curve for energy-efficiency potential in the Swedish service sector. The horizontal axis shows the fraction of lighting energy that can be saved at a given marginal cost, in four different years. The baseline for these savings is the consumption resulting when all new and replacement equipment installed after 1990 has the same average efficiency as in 1990. This base consumption value increases with time. At a given marginal cost level, the energy savings include the effects of all the efficiency measures with a cost of saved energy less than that marginal cost level. For example, in the year 2000, a 20% reduction in commercial lighting energy use could be obtained at a cost of SEK 0.20/kWh or less. These cost curves show the efficiency potential in a given year at a given cost level, but they do not indicate how much of that potential can be achieved in a real program or would be achieved without the program.

Note that some savings identified in Figure 2.4 are available at negative cost, as maintenance cost savings can compensate for the initial technology costs. On the other end of the scale, energy-saving potential at relatively high marginal costs may be underestimated in such end-use analysis. These studies are based on engineering analysis of measures that are likely to be implemented in the near term, which often exclude measures that do not appear cost-effective under current economic conditions. This explains the steep increase in marginal costs at high levels of energy savings in Figure 2.4, which would probably show greater savings at the higher costs levels if more information on such measures were available.

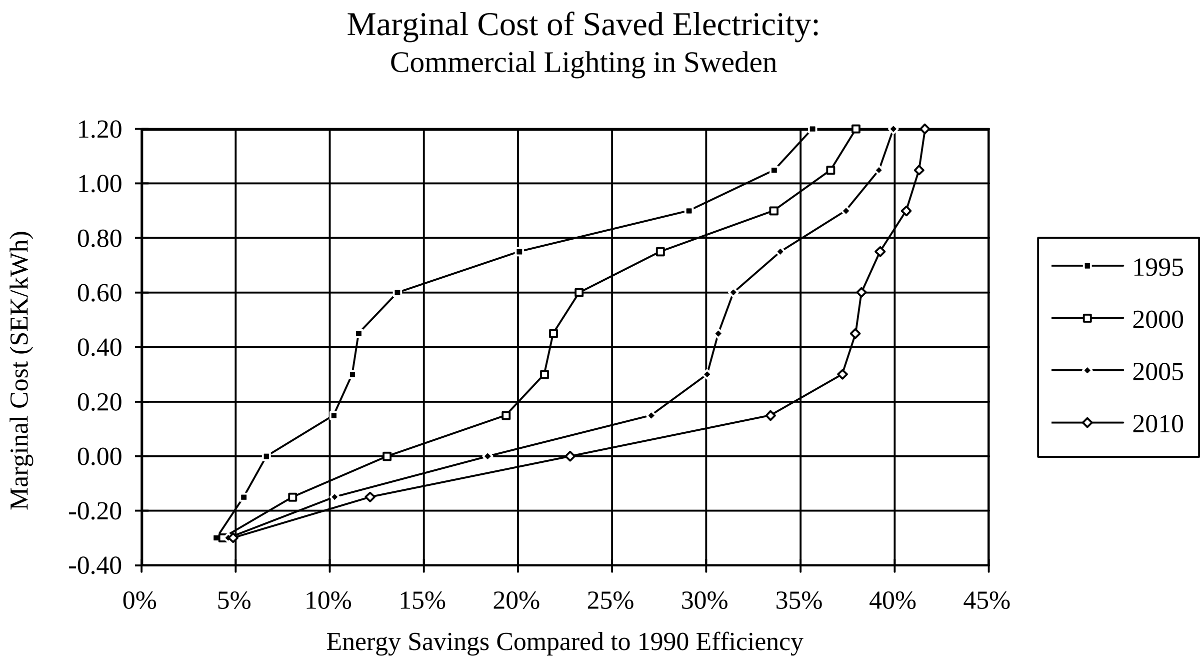


Figure 2.4. Marginal cost curves for lighting energy efficiency in Sweden's service sector.
Source: Swisher et al 1994.
Note: Energy savings in a given year are measured from the projected consumption, assuming all equipment installed after 1990 has the same average efficiency as that installed in 1990, and expressed as a percentage of the projected consumption. Cost units are in Swedish krona (SEK) per kWh. 7 SEK = 1 US$.

C.4. Market Potential Scenarios

Not all cost-effective measures can be successfully implemented via DSM and other energy-efficiency programs. Although the replacement of incandescent bulbs with compact fluorescent bulbs (CFLs) can be cost effective, not all customers may want to install them at home, for example. So, the *market potential* scenario will capture the perceived amount of savings that will be effectively implemented.

In addition to technology costs, energy-efficiency measures are further constrained by administrative costs and the technical and institutional feasibility of the measures. For example the more efficient technology might not be appropriate for some applications, regardless of cost, or it might have functional or aesthetic limitations, such as CFLs that cannot be used in dimming circuits or rooms with small decorative lighting fixtures.

Reaching the full market potential takes time, and 100% market penetration cannot be reached in most cases. Even with strong incentives, new technologies take time to capture a large market share, and programs to retrofit existing facilities are limited by the resources of the implementing agency to serve the full population of eligible customers.

Thus, the *achievable market potential* includes an increasing fraction of the total market potential over time. This potential is a function of the time allowed, the type of programs and institutions involved, and the technical-economic cost-effectiveness threshold. The achievable market scenario will capture the efficiency improvements available through real programs, subject to the rate of turnover of existing buildings and equipment and the existing market penetration limits over time.

Figure 2.5 provides a summary of the various energy scenarios described above.

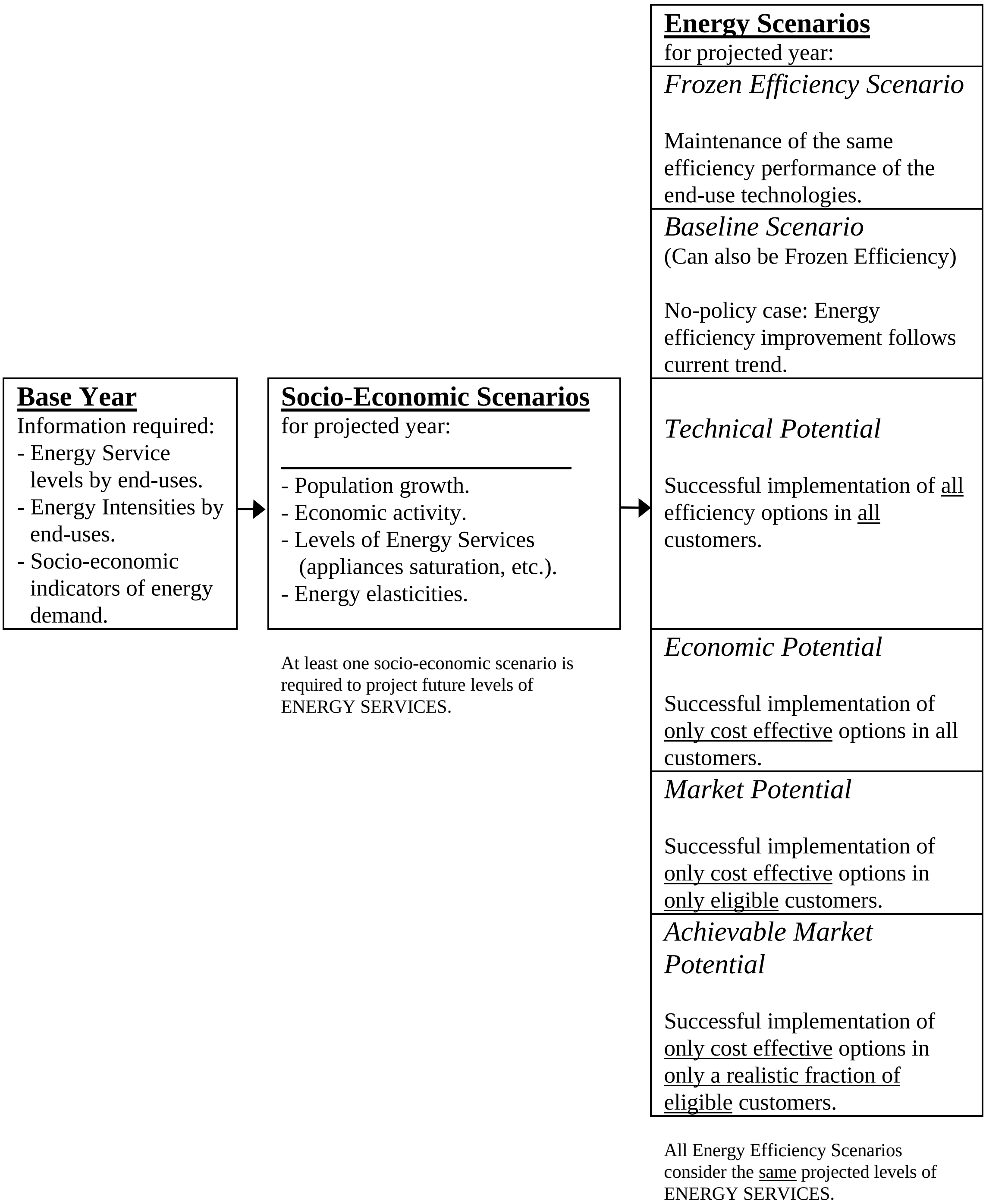


Figure 2.5. The steps used in projecting energy demand efficiency scenarios.

D. Costs of Energy Scenarios

Each scenario describing an estimated projected energy demand will require corresponding investments in new energy supply (generation, transmission, distribution) and/or the implementation of DSM or efficiency programs.

The flow chart presented in Figure 2.6 illustrates a projection exercise where energy production costs (US$/kWh) are associated with the total electricity demanded in the Frozen Efficiency Scenario. The Efficient Scenario (in fact an economic potential scenario) includes these costs but also incorporates the costs incurred with conserving electricity via efficiency and DSM programs. In Chapter 3 we look into closer detail about program costs, and Appendix 3 shows how to estimate the cost of conserving electricity.

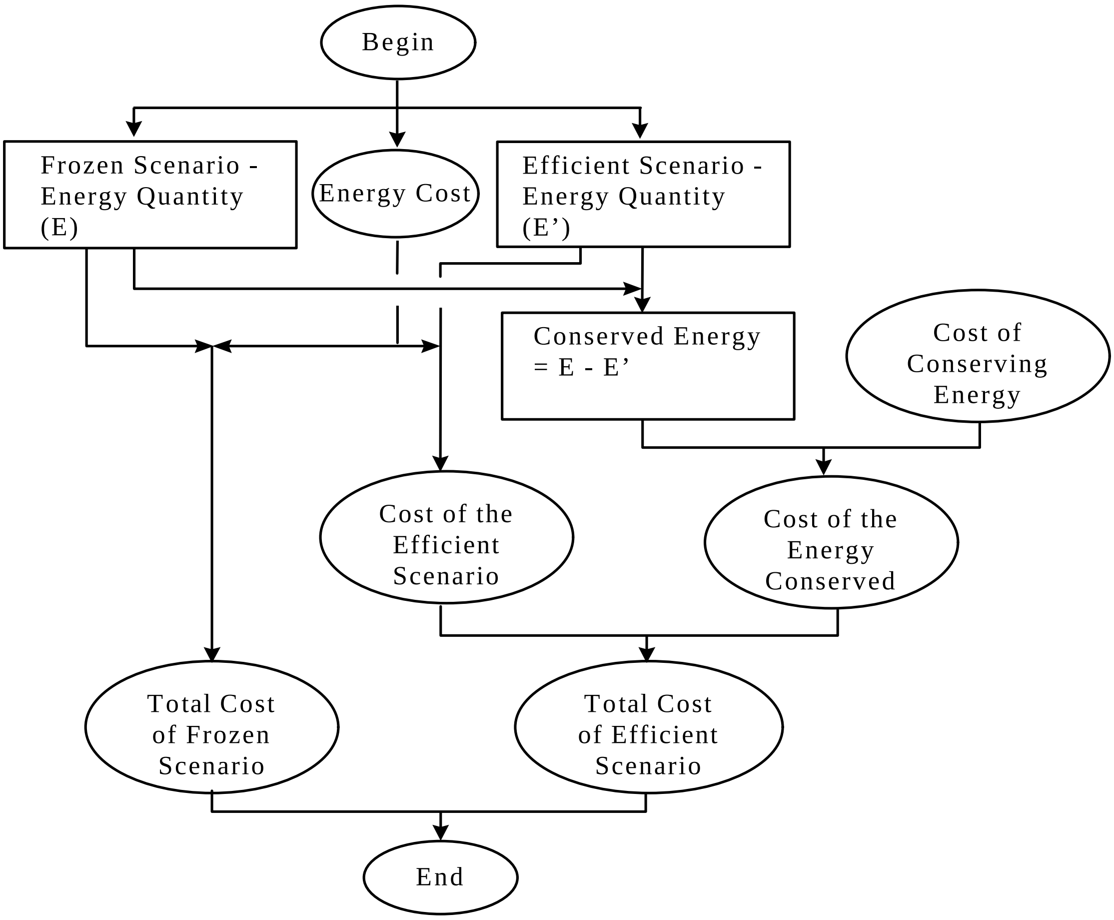


Figure 2.6. Flow chart of energy cost calculations.

Calculating the relative costs and benefits of energy efficiency requires an understanding of the principles of engineering economy, in particular the ideas of discount rates and present worth. Typically, energy efficiency scenarios involve various streams of costs and savings (negative costs) incurred over many years. In order to compare these scenarios, it is necessary to convert the streams of cash flows into values such as *present worth* (or *present value*), which expresses, as a single value in a single year, the equivalent value of an entire cash flow stream. This conversion of cash flows into present worth values is done through the use of the discount rate. Please refer to Appendix 3 for detailed explanations of these concepts.

The following example uses the information provided in Appendix 3 to illustrate the process of calculating the cost-effectiveness of an energy-efficiency investment.

Example:

Part a.) A 10,000 m^2 hotel in a warm tropical climate plans to install a new air conditioning system. A standard baseline system would have a capital cost of $60,000 and would annually consume 500,000 kWh/yr of electricity over the course of its 15 year lifetime. An efficient system with the same cooling capacity has a capital cost of $75,000 and consumes 437,000 kWh/yr of electricity, also over a 15 year lifetime. If the hotel pays $0.07/kWh for its electricity and evaluates its investments based on a discount rate of 30% per year, would it be cost-effective for the hotel to install an efficient air conditioning system rather than the standard system?

To answer this question, we must compare the cash flows of the two scenarios on an equivalent basis, giving appropriate weight to the higher capital cost and lower operating cost of the high-efficiency system. The annual operating costs of the baseline system would be 500,000 kWh/yr · $0.07/kWh = $35,000/yr. Similarly, the annual costs of the efficient system would be $30,590/yr.

We can use Equations A3-7, A3-8, and A3-9 in Appendix 3 to calculate the present worth life cycle cost of the two scenarios:

$$LCC = Cc + \frac{A}{CRF_{t,r}} - \frac{SV}{(1+r)^t} \qquad [A3\text{-}8, A3\text{-}9]$$

where:
LCC = life cycle cost (present worth $),
Cc = initial capital cost (capital, labor, administrative cost),
A = uniform annual costs ($/yr),
SV = salvage value (value of equipment at end of useful life),
r = discount rate,
t = equipment lifetime (years), and

$$CRF = Capital\ Recovery\ Factor = \frac{r}{\left[1-(1+r)^{-t}\right]} \qquad [A3\text{-}7]$$

With an *r* of 30% (i.e., 0.3) and *t* of 15 years, *CRF* can be calculated to be 0.30598/yr. Then, assuming a salvage value of zero (i.e., equipment is worthless at the end of its life), the life cycle cost of the baseline equipment would be $60,000 + ($35,000/yr ÷ 0.30598/yr) = $174,387. Similarly, the life cycle cost of the efficient equipment would be $174,974.

Therefore, the total life cycle cost of the efficient equipment is slightly higher than the life cycle cost of the baseline equipment; so the efficient equipment is not a cost-effective investment for the hotel. This is primarily due to the fact that the hotel is using quite a high discount rate (30%), indicating that the hotel is requiring a very rapid payback on its investment in energy efficiency.

Part b.) Now, suppose that the utility is faced with the necessity of either building new electricity supply capacity or reducing electricity demand. Its long range marginal costs, reflecting the cost of building new generation capacity, are $0.11/kWh. Also, the utility has transmission and distribution (T&D) losses of 10%, meaning that any reduction in energy consumption would also save an additional 10% in reduced T&D losses. If the utility has a discount rate of 12%/year, what would be the impact on the utility if it were to subsidize the hotel's purchase of the more efficient air conditioning system in order to help reduce the need to build new electricity supply capacity?

Suppose that the utility agreed to pay the entire $15,000 incremental cost of the more efficient air conditioning system. Then, in addition to this capital cost, the utility would face revenue losses of (500,000 kWh/yr - 437,000 kWh/yr) · $0.07/kWh = $4410/yr from reduced electricity sales. On the other hand, the utility would be able to avoid its marginal cost of the energy saved and an additional 10% in reduced T&D losses = [(500,000 kWh/yr - 437,000 kWh/yr) · $0.11/kWh] · 1.10 = $7623/yr. Lastly, with a discount rate of 12% (*CRF* = 0.14682) compared to the hotel's discount rate of 30%, the utility does not require as rapid a payback on its investment as does the hotel.

Therefore, the life cycle cost of this investment for the utility would be:

$15,000 + [($4410/yr - $7623/yr) ÷ 0.14682] = -$6883. Therefore, with a negative total life cycle cost, the investment would be cost-effective for the utility.

Exercises:

For the following three exercises, assume that the utility uses a 12% discount rate, and the consumer uses a 60% discount rate to evaluate the measure costs. Marginal electricity production costs are 0.15 US$/kWh, and average consumer tariffs are 0.09 US$/kWh. Consider that the utility wants to compare demand-side investments with a hydroelectric plant and has a 15% loss in transmission and distribution.

Exercise 2.4) A residential consumer has a refrigerator that costs US$ 800 and consumes 600 kWh/year during a lifetime of 25 years. Another refrigerator is available which costs 10% more and consumes 425 kWh/year also during a 25 year lifetime. Is the replacement of the less efficient unit with the more efficient model economically attractive to the residential consumer? If the utility subsidizes the replacement does it lose money?

Exercise 2.5) An industrial consumer has a kit with two conventional fluorescent lamps (40W each) and one ballast that costs US$ 20 per kit and has 1920 hours of yearly usage during a lifetime of 5 years. Another available kit has two efficient fluorescent lamps (32W each) and one ballast, costs 20% more per kit, and has the same 1920 hour yearly usage also during a 5 year lifetime. Is the replacement economically attractive to the industrial consumer? If the utility subsidizes the replacement does it lose money? Does this replacement maintain the same level of energy service (lumen output, see exercise 1.2)?

Exercise 2.6) A school has a conventional incandescent lamp (100W) that costs US$ 1 and has 1920 hours of yearly usage during a lifetime of one year. Another available kit has two conventional fluorescent lamps (20W each) and one ballast, costs US$ 15 per kit, and has the same 1920 hour yearly usage during a 5-year lifetime. Is the replacement economically attractive to this school? If the utility subsidizes the replacement does it lose money? Does this replacement maintain the same level of energy service (lumen output, see exercise 1.2)?

E. Screening of Demand Side Options: DSM Cost Effectiveness

The scenarios described in Section C allow for specific consideration of the demand-side options that will compete with supply options. We also need cost-effectiveness criteria to choose which of the options we want to include in the IRP plan. Different parties will have different criteria by which they will judge the cost-effectiveness of a demand-side option. For example, the utility (or other implementing agency), the consumer (participating in a DSM program or not), and the society as a whole, will all have separate objectives for a DSM program. Therefore, the IRP plan should state clearly what were the criteria used to select the demand-side options and the sensitivity of the results to the input assumptions (Hirst, 1992).

To illustrate the process of choosing the demand-side options that will be considered in an IRP plan, we present the criteria developed by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) in a process called the *California Collaborative*. A joint publication of the CEC and the CPUC called the *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs* (December 1987), lays out the definitions and computational procedures for determining DSM cost effectiveness. They define five different benefit-cost tests: the Participant Test, the Ratepayer Impact Measure Test (RIM), the Total Resource Cost (TRC) Test, the Societal Test, and the Utility Cost Test.

As stated in *An Energy Efficiency Blueprint for California* (California Collaborative, 1990), the goal of utilities' resource planning and investment is to minimize the cost to customers of reliable energy services. With DSM being considered an energy resource on equal footing with supply-side alternatives, it is important to have suitable indicators as to how cost effective DSM measures actually are. Unfortunately, cost-effectiveness is largely in the eyes of the beholder; that is, the most cost effective DSM strategy for utility shareholders may be different from the best strategy as seen by utility customers. In fact, utility customers can also see things differently depending on whether the customer is someone who takes advantage of the utility's conservation incentives, or is someone who either cannot benefit from the measure, or chooses not to participate. Such a nonparticipant might say, for example, “I already insulated my attic on my own without any help from the utility, and now you're offering my neighbors a rebate if they will do it...that isn't fair.”

The following descriptions of the various tests are abstracted from the CEC’s *manual* and the California Collaborative's *Blueprint*.

E.1. Participant Test

The Participant Test measures the difference between the quantifiable costs incurred by a participant in a DSM program and the subsequent benefits received by that participant.

The benefits of participation include the reduction in the customer’s utility bills, any incentives paid by the utility or other third party, and any federal, state, or local tax credits received. The costs to a customer include all out-of-pocket expenses incurred by the customer as a result of participating in the program, such as the cost of equipment purchased as well as any ongoing operation and maintenance costs.

From the participant's perspective, a program is cost effective if the present value of the benefits exceeds the present value of costs. This cost effectiveness can be expressed in several ways, such as a net present value (NPV) that is greater than zero, or as a benefit-cost ratio (BCR) that is greater than one. One difficulty with the Participant Test is picking the appropriate discount rate to use for costs and benefits that appear in the future.

The Participant Test is a very weak one. It is unlikely that a DSM program would be very successful if participants in the program lose money.

E.2. Ratepayer Impact Measure (RIM) Test (also the Nonparticipants Test)

The Ratepayer Impact Measure (RIM) Test is primarily a measure of what happens to utility *rates* (i.e. the cent/kWh or $/GJ prices that customers pay) caused by a DSM program. If DSM causes utility rates to go up, nonparticipants who do not change their energy usage will see increases in their bills. Participants, on the other hand, encountering the same rate increases may see still their total utility bills go down since they are using less energy (in fact, they *will* go down if the DSM measure passes the Participant Test).

Utility rates will go up if the benefits to the utility are less than the costs incurred by the utility in implementing the program. The *benefits* calculated in the RIM Test are the savings that the utility realizes by avoiding energy supply costs. These <u>avoided costs</u> are the marginal costs of the supply resource replaced by DSM or other measures. They include the reduction of transmission, distribution, generation, and capacity costs for periods when the load has been reduced (assuming the purpose of the DSM program is to reduce loads). The *costs* calculated in the RIM Test include DSM program costs (incentives paid to the participants, program administrative costs), and decreases in utility revenues.

For a DSM program to be cost-effective using the RIM Test, utility rates must not increase as a result of the program. That is, nonparticipants must not see any increase in their utility bills. While this is sometimes described as the "no losers" test, a true no-losers test would allow rates to go up *as long as the increase in rates with DSM is less than the increase in rates that would occur without DSM*. That is, without DSM the utility might have to build a new power plant raising everyone's rates by say 0.001US$/kWh. If DSM raises rates by less than 0.001US$/kWh, while delivering the same energy services, then the nonparticipant cannot legitimately complain.

It is helpful to illustrate the essence of the RIM Test with an example. Suppose we start with a utility operating at point A in Figure 2.7. The slope of the line from the origin to point A is the average price before DSM that must be charged for a kWh of electricity in order for the utility to generate needed revenues. For the first example, suppose that the marginal (avoided) cost of electricity is very high, as indicated by the steep slope of the revenue curve. If a DSM program could reduce energy demand at no cost, then the utility could operate at point B. DSM, however, is not free, which means the utility must collect revenues to cover DSM as well as electricity generation costs, putting it at point C. At point C, the price that the utility must charge for a kWh of electricity (given by the slope shown) is less than it had to charge before DSM. Everyone wins in this scenario--even the nonparticipant--since rates go down.

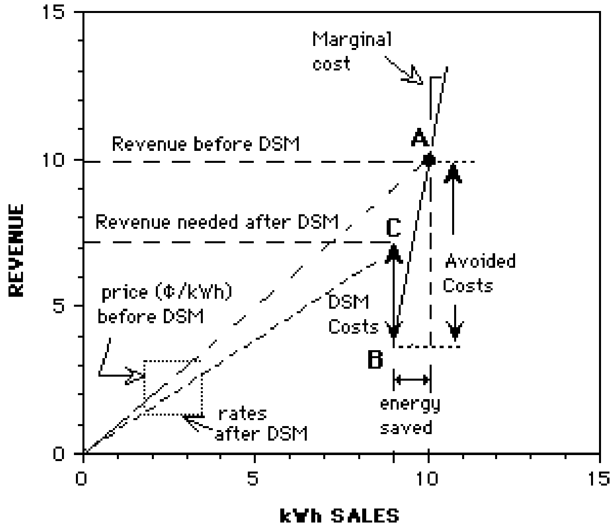


Figure 2.7. A hypothetical example illustrating the RIM Test when marginal costs are high. If the DSM program moves the utility from point A to point C, electricity rates go down for everyone--so even nonparticipants see reduced energy bills.

Generalizing this example yields the following: the RIM Test will be satisfied, meaning that customers will *not* see their utility rates rise, as long as the cost to save a kilowatt-hour is less than the difference between the marginal cost of electricity and the average cost (i.e., rates).

In the above example, it was assumed that the marginal cost of electricity was greater than the average cost. If that is not the case, that is, marginal costs are less than average cost, then any reduction in electricity consumption will increase rates even if DSM is free. This is illustrated in Figure 2.8. Saving electricity moves the utility from point A to point B. Notice that total <u>revenue requirements</u> for the utility are lower at point B, but *rates* need to go up (the slope from the origin to B). This illustrates an important point. The *average bill* for all customers in Figure 2.8 is decreased after DSM, but since *rates* went up, nonparticipating customers will see their bills go up. Thus anytime average costs are higher than marginal costs, the DSM program will not pass the RIM Test; the RIM Test is quite strict.

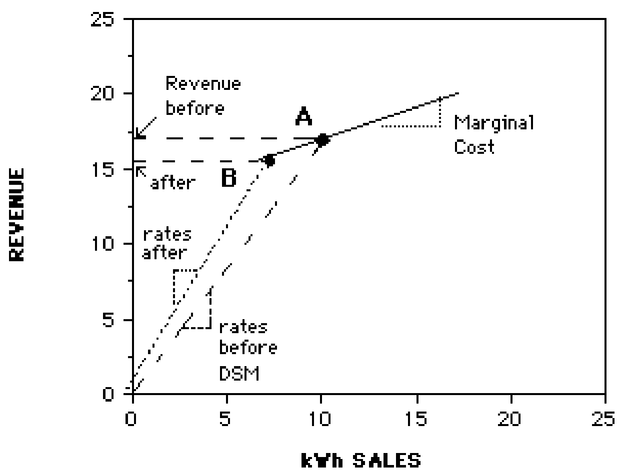


Figure 2.8. When marginal costs are less than average costs, any reduction in sales (from A to B) causes rates to increase, even if DSM is free. Notice, however, in this case the average utility bill is less at point B than at point A, even though rates have increased.

E.3. Total Resource Cost (TRC) Test

The Total Resource Cost (TRC) Test (also called the All Ratepayers Test) compares the total costs of a DSM program (including costs incurred by the utility and the participant) and the avoided costs of energy supply. From this perspective, a program is cost effective if the benefits, that is the total avoided supply costs, exceed the total costs incurred by the utility and the customer. *The TRC Test is the most commonly used measure* of DSM cost effectiveness since it provides an indication of whether the totality of costs, to utility and ratepayer, is being reduced.

In a sense, the TRC Test is a summation of the Participant Test and the Ratepayer Impact Measure Test. That is, benefits are still the total avoided supply costs, but costs are now the sum of the costs incurred by the customer and by the utility. For example, suppose a utility's compact fluorescent (CFL) rebate program costs the utility 0.03US$ to save a kWh. Suppose the customer buys a CFL and amortizes the net lamp cost (retail cost minus the rebate) over the life of the bulb, with the result being that the customer invests 0.02US$ for each 1 kWh saved. Total costs, as measured in the TRC Test, are therefore 0.05US$/kWh. If the utility avoids more than 0.05US$/kWh in costs of transmission, distribution, and generation, then the Total Resource Cost Test is satisfied.

Notice that a DSM measure can pass the RIM Test yet still fail the TRC Test (Figure 2.9). Conversely, a DSM measure can fail the RIM Test, yet pass the TRC Test (Figure 2.10). In other words, neither is inherently more strict, although it is much more common that DSM programs pass the TRC and not the RIM Test (Figure 2.10) than vice versa.

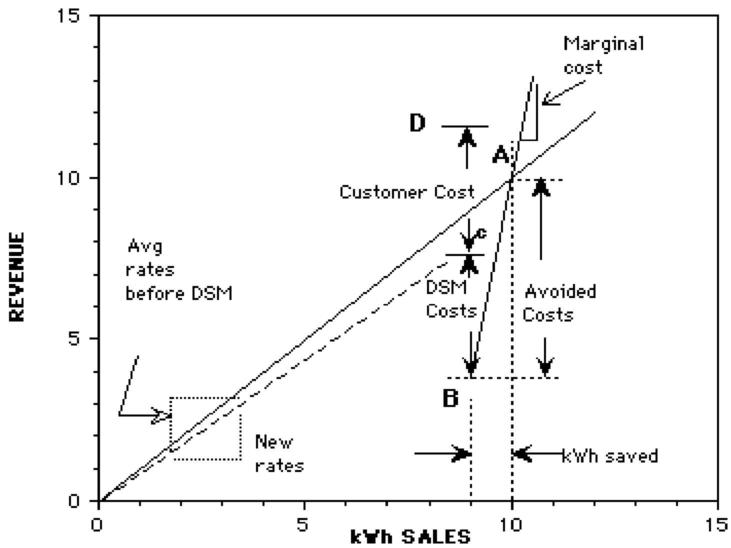


Figure 2.9. Showing an example of a case that fails the TRC Test (point D is higher than point A), yet passes the RIM Test (the new rates after DSM are lower than the old rates).

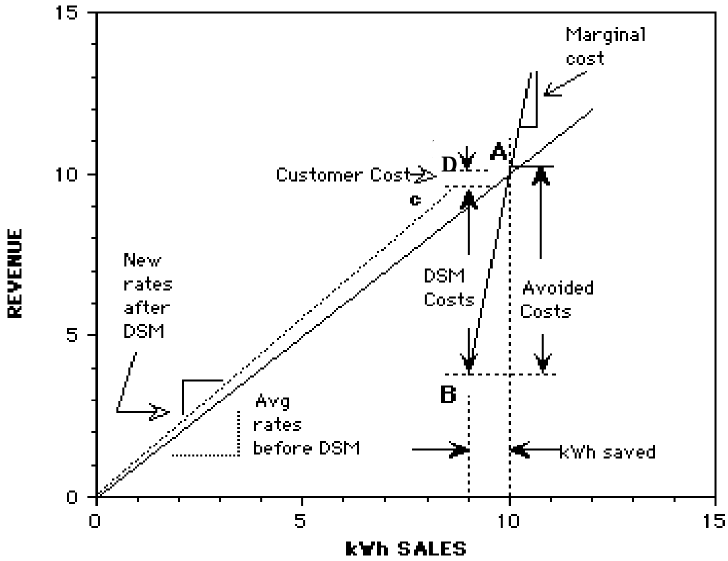


Figure 2.10. An example of a DSM program that passes the TRC Test (point D is lower than point A), but which fails the RIM Test (rates after DSM are higher than rates before DSM).

E.4. Societal Test

The Societal Test is a variant on the Total Resource Cost Test, the difference being that it can include quantified effects of externalities (such as environmental costs) in the measure of costs and benefits.

E.5. Utility Cost Test

The Utility Cost Test is another comparison of costs and benefits. In this case, as in most, the benefits are the result of avoided costs (fuel, operating, and capacity costs) saved by conservation. The costs are utility costs associated with running the DSM program (rebates and administrative costs). This test differs from the TRC Test by counting only utility costs and excluding customer costs.

When benefits exceed costs, the Utility Cost Test is satisfied, indicating that total revenue requirements of the utility drop so the *average* customer bill is lower. Even though total utility revenues drop, actual $/kWh rates may be higher after DSM (if the program fails the RIM Test); so nonparticipants' bills may go up even if the average customer bill goes down. The Utility Cost Test is easier to satisfy than the TRC Test. In fact, the examples in Figures 2.9 and 2.10 both satisfy the Utility Cost Test (while only Figure 2.10 satisfies the TRC Test).

E.6. Summary of DSM Cost Effectiveness Tests

Table 2.9 provides a summary of the cost-effectiveness tests described above. The three most important tests are the Ratepayer Impact Measure (RIM), the Total Resource Cost (TRC), and the Utility Cost Test.

The RIM Test essentially examines whether utility rates go up or down after the DSM measure is in place. For a DSM measure to pass the RIM Test, rates must not go up so that even nonparticipants have no increase in utility bills. To pass the RIM Test, marginal costs must be greater than average costs, and the difference between the two (the utility's net loss on marginal supply, given constant rates) is the maximum amount that can be spent implementing DSM.

The TRC Test basically asks whether society in general is better off with this DSM measure. That is, the TRC Test is satisfied if the total cost of conservation (incurred by the utility that implements DSM and by customers who spend their own money to purchase the device) is less than the benefits associated with reducing demand on the utility energy supply system. While average utility bills go down, *rates* may go up so nonparticipants may have higher bills. The TRC Test is the most commonly used measure of DSM cost effectiveness.

The Utility Cost Test simply asks whether the utility saves more money in avoided costs than it spends on its DSM program. Average bills go down if the program passes the Utility Cost Test. Nonparticipants, however, may see higher bills; and by the time customers pay for their efficiency devices and the utility pays for its DSM program, society may actually spend more on energy services than before, in spite of DSM satisfying this test.

Table 2.9. Elements of the primary economic tests used to assess the benefits and costs of utility DSM program from different perspectives.

Perspective	Benefits	Costs
Participant	Incentives from utility and others, plus reduction in electricity bill	Participants' direct cost of participation
Rate Impact Measure	Avoided supply costs (production, transmission, and distribution) based on energy and load reductions.	Utility program costs (including incentives to participants) plus net lost utility revenues caused by reduced sales.
Utility (revenue requirements)	Same as above.	Utility program costs (including incentives to participants).
Total Resource Cost	Same as above.	Total program costs to both participants and the utility (excluding incentives).
Societal	Same as above plus externality benefits, such as reduced pollution.	Same as above.

Source: California Energy Commission (1987).

E.7. Environmental Externalities

An important purpose of IRP is to treat DSM as a resource along with traditional supply-side resources, and then to choose the lowest-cost combination of these resources to meet projected energy-service needs (see chapter 1). Avoided costs that are saved by investing in DSM may include more than just the savings associated with not having to build and operate power plants. For example, the non-monetary cost of the environmental impacts of supply-side resources, known as *externalities*, can also be considered an avoided cost. An example is given in chapter 4.

Several European countries capture environmental externalities to some extent by imposing emission charges on fossil fuel use, although in some cases electric utilities are exempted from these charges. In the US, several states have adopted rules or policies to incorporate environmental externalities. The methods used to account for externalities vary widely from state to state, both in the way the values are estimated and they way they are used.

Externalities can be captured in either a qualitative procedure or as a quantitative cost value. External cost values can either be emission charges actually paid by the utility, or they can be proxy values used to prioritize and select DSM and supply options in the IRP process. Under a deregulated or non-regulated structure, environmental costs have to be actually paid by the utility in order to affect demand via higher rates. This is one reason that emission charges are used in Europe.

Some US states (e.g., Minnesota) treat externalities in a *qualitative* way, merely giving preference to cleaner energy sources without attempting to quantify the amount of preference. Others (e.g., Vermont) use a *percentage adder* that increases the cost of supply-side resources or decreases the cost of demand-side resources by some percent. Other states (e.g., New York State) include actual dollar estimates of environmental externalities in determining the avoided cost benefit of DSM resources eligible for shared-savings incentives (Eto, et al, 1992). However, each of the US cases uses externalities only as proxy values to determine resource selection preferences; they are not actually paid out by the utilities.

Several analytic methods have been used to estimate the economic value of environmental externalities. The range of methods includes:

Most qualitative:

- Subjective value assignments
- Ranking/weighting schemes
- Marginal costs of impact mitigation
- Implied demand for environmental amenities
- Direct calculation of damage costs

Most quantitative:

Value Assignments: The most widely used and most easily understood method of incorporating environmental externalities is through the subjective assignment of values for the environmental costs or benefits of certain technologies. This method has the least analytic validity; however, the absence of adequate data and cause-effect models make it difficult to justify the cost of using the more detailed methods. Values assigned to environmental externalities by this simple method are generally justified as conservative, minimum values. Thus, if they are lower than the actual value, at least they represent an improvement over the implicit assignment of a zero value.

Ranking and Weighting Schemes: This method is meant to clarify the criteria for technology choice and to assign relative values to these criteria, including such difficult to quantify criteria as environmental impact and social equity. In one such scheme, opinions on energy planning criteria were sampled from a variety of interest groups in Germany and compiled into a hierarchy for evaluation of relative levels of concern over each criterion and identification of areas of consensus between the different groups (Keeney, 1987). Although this approach directly addresses the public reaction to energy planning decisions, the process of weighting the different values can be as complex and difficult as the more quantitative methods described below.

Marginal Costs of Mitigation: One can argue that if existing regulations indicate society's choice for the optimal (i.e., most cost-justified) level of pollution emissions, then the marginal cost of pollution control with these environmental regulations indicates the marginal value of pollution (the so-called revealed preference). In other words, suppose that an existing power plant currently meets NO_x emission standards of 0.12 kg/MWh in a given region, and that controlling one additional kg of NO_x beyond these standards would require installation of additional equipment which has a levelized cost of 0.004 US$/kWh over its lifetime. This marginal control cost of 0.004 US$/kWh would then be considered the environmental externality value under this valuation method.

Since emissions are generally controlled in order to comply with existing regulations, and exceeding these regulations may often require different and more expensive technology, current costs of mitigation do not necessarily reflect the costs of further mitigation. However, the most expensive measures now used in certain areas would indicate the incremental costs in other areas which have not yet employed such measures. These costs can be readily quantified for many technologies, and often the technologies that would be used to further reduce emissions are already known and their costs can be estimated.

Implied Demand: It is difficult to directly estimate the value of environmental quality, and thus the cost of pollution. One approach is to use statistical analysis of consumer choices to estimate the implied demand function for certain environmental amenities. This method has been applied to the estimation of the value of recreational resources such as lakes and reservoirs, based on what consumers pay in travel costs to use the resources. For example, if the average recreational fisherman spends $100 on travel expenses (car, fuel, etc.) to go fishing at a lake on a weekend, then one can assume that the personal enjoyment that the average fisherman receives from this activity is worth at least the $100 which he has spent to reach the lake. If this lake becomes polluted and can no longer be used for fishing, one might calculate that the damage was worth at least $100 multiplied by the number of fishing trips taken at the lake per year. However, it is difficult to identify such a market proxy that would indicate what people are willing to pay to avoid the effect of pollutants emitted into the air or water.

Direct Calculation: The most detailed and comprehensive approach, and also the most difficult, is to estimate directly the health costs and other impacts of pollution in monetary terms. To determine health-related costs, this method requires estimating the transport of pollutants from source to recipient, the health response to the different pollutants, and the economic value of illnesses and premature deaths. Property and crop damage from sulfur emissions, ozone and other photochemical pollutants is equally complex to value, and ecological impacts from acid precipitation and greenhouse gases are even more difficult. An important issue often overlooked in environmental and health risk studies is that the value of the damage should include, not only the cost of what is lost, but also the amount that the public would pay to avoid the damage. This value, which may be considerably higher than the damage cost alone, is more truly comparable to the market value of the economic goods produced at the expense of the environmental impact.

One study used a simple model to attribute environmental health effects in Germany to different pollutants in order to estimate the environmental cost of power production. The results of this study suggested an environmental cost of US$0.02-0.03/kWh for fossil fuel plants and $0.05-0.06/kWh for nuclear plants (Hohmeyer, 1988). Most direct estimates of environmental costs have been presented as a lower bound, because it is difficult to be comprehensive in evaluating all the relevant impacts and costs.

E.8. Non-Monetary Benefits of Energy Efficiency

Technologies to improve energy end-use efficiency often offer benefits in addition to the provision of energy services equivalent to a supply-side source, and the environmental benefits described above. These additional benefits can accrue at either the societal level or at the level of the individual consumer or firm. For the consumer, these benefits can be categorized as (Mills and Rosenfeld 1994):

-improved indoor environment, comfort, health and safety (e.g., from better lighting)
-reduced noise from better insulation
-labor and time savings (improved productivity) from efficient lighting
-water savings and waste reduction from more efficient appliances
-down-sizing or elimination of certain end-use equipment (through reduced loads)
-improved process control
-increased amenity or convenience

At the societal (regional, national or global) level, non-monetary benefits of energy efficiency benefits can be categorized as:

-energy security through reduced imports
-national security through reduced flow of radioactive and fissionable materials
-job creation and local economic development
-reduced strain on capital markets
-improved international competitiveness of domestic business
-enhanced position of efficient domestic products in export markets

In principal, these benefits could be monetized and applied to energy cost comparisons, as suggested above with regard to environmental externalities. In practice, however, such issues are treated only qualitatively, if at all.

Further reading:
B. Chateau, B. Lapillonne, 1982. "Energy Demand: Facts and Trends," Springer-Verlag, Wien.

F. Exercise on Frozen Efficiency Scenario: Electricity Demand Projections for Brakimpur

Brakimpur Integrated Resources Planning Project

Background

Brakimpur has a population of roughly 10.5 million and average per capita income of US$3413 per year. It is situated in the tropics between latitudes 5º and 30º S. The semi-arid climate and location combine to give a high level of solar radiation; the annual average over the country is 20 MJ/m^2-D, and the windspeed averages 4 m/s in the Southeast, reaching 8 m/s in some zones of the Northeast of the country.

In the Base Year the energy consumption was 1,883 GWh, about 6.5 million tons-of-oil-equivalent (TOE)/year. The country has sizable fuel (coal, biomass, etc.) reserves used primarily for process heating and electric power generation.

The economy has reasonably well-developed industrial, commercial, and mining sectors, and 40% of petroleum products are imported. Figure 2-11 shows the allocation of Brakimpur's final energy end-use consumption.

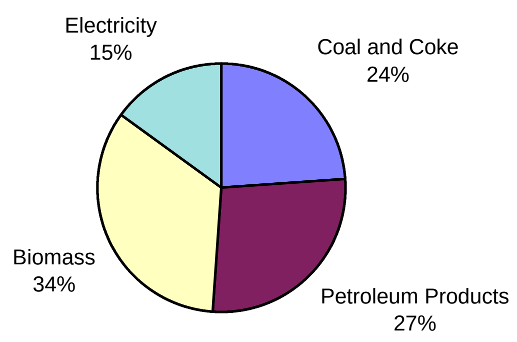


Figure 2.11. Breakdown of Brakimpur total energy consumption - base year

Brakimpur is a country with the following existing electricity supply capacity and future capacity expansion options:

Table 2.10. Brakimpur electricity plan.

Power Source	Number	Capacity (MW)	Capacity Factor	Emissions tSO_2/GWh	Emissions tNO_x/GWh	Cost US$/kWh
Existing						
- Hydro	3	1200	0.50			0.020
- Gas	3	600	0.50		6	0.040
- Coal	3	420	0.75	5.0	11	0.030
Retrofit						
- Coal		400	0.75	0.5	12	0.048
New						
- Gas		200	0.75		5	0.055
- Coal		200	0.75	5.0	10	0.053
- Coal with Scrubbers		200	0.75	0.5	11	0.067
- Wind Farm		500	0.30			0.067
- Combustion Turbines		50	0.15		7	0.095

Table 2.11. Brakimpur GDP structure and projected growth.

	Base Year Year X	Projected Year Year X + 10	Annual Growth Rate (%/yr)
Population	10.5 million		3.0
GDP	US$33 billion		5.65
Structure of GDP	20% agriculture	10% agriculture	
	50% industry	40% industry	
	30% commerce & service	50% commerce & service	

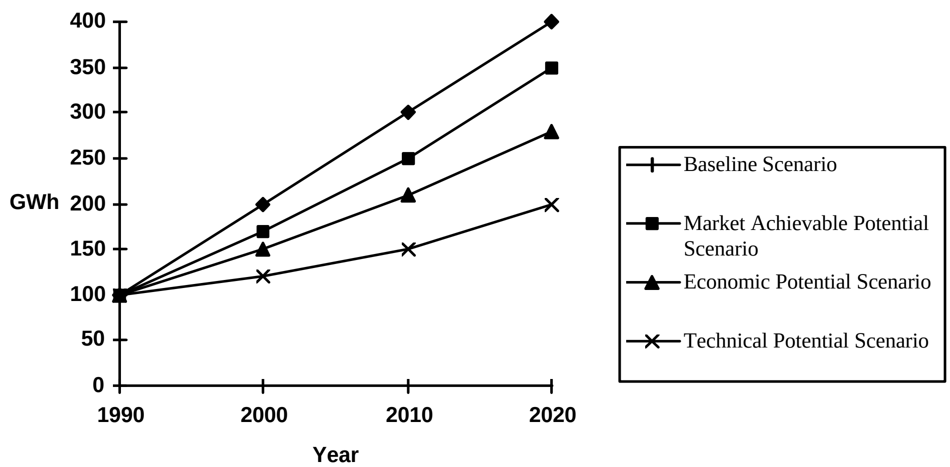


Figure 2.12. Four scenarios of electricity consumption in Brakimpur based on different levels of assumed implementation of energy efficiency.

1. Objectives

The purpose of this exercise is to allow the reader to apply some of the concepts developed in this chapter.

The main objectives are:
a. To learn a simple approach for assessing energy consumption.
b. To work with and analyze approximate energy consumption projections.
c. To develop a frozen efficiency scenario.

2. Spreadsheet

We suggest a computer spreadsheet to organize and calculate the relevant information for the base year and projected year.

As an example, a working spreadsheet is provided in Table 2.12 with some initial data of the Residential Sector of Brakimpur. The reader should adapt this data to better reflect the conditions of his or her country, inserting and interpreting the necessary information.

To make it easier to understand, we have adopted a graphical representation which differentiates between input and output data as follows:

Normal Font =	Data Input (Table A, B, C, D and F) (reader data input)
Bold Font =	Data Output (Table E and G) (results of operations and calculations)

3. Spreadsheet Structure

Table A, B, C, D and **E** = Base Year X:

Table A - Socio-economic indicators of energy demand:

A1 = population
A2 = number of people per household
A3 = percent distribution of households by income class (income class defined by number of minimum wage units earned per household)
N = number of households by income class (N = A3 x A1/A2)

Table B, C, D and **E** have:

Rows: The rows indicate the end-uses suggested in this exercise. They include incandescent lamps, fluorescent lamps, clothes irons, televisions, clothes washing machines, air conditioners, freezers, refrigerators, fans, water heaters and "other".

Columns: The columns indicate the income classes suggested in this exercise.

Table B - Appliance ownership by income class (P = %)

Table C - Average intensity per appliance (I = watts)

Table D - Appliance usage (M = hours/year)

Table E - End-use total household energy consumption by income class:
(E = N x P x M x I = MWh/year)

Table F and **G** = Projected Year (X + 10) (i.e., 10 years after base year X)
Assume only population growth and changes in income distribution, and no change in P, M and I (i.e., the same appliance ownership, usage and efficiency performance in the projected year as in the base year).

Table F - Socio-economic indicators of energy demand in projected year (X+10):

A'1 = population (year X+10)
A'2 = number of people per household (year X+10)
A'3 = percent distribution of households by income class (year X+10)
$\mathbf{N_{X+10}}$ = number of households by income class (N = A'3 x A'1/A'2)

Table G - End-use total household energy consumption (MWh/yr) by income class in projected year (X+10):
***(E_{X+10} = N_{X+10} x P x M x I = MWh/year)* with:**

Rows: The rows indicate the end-uses suggested in this exercise.
Columns: The columns indicate the income classes suggested in this exercise.

4. Worksheet diagram

The residential portion of this exercise will use the worksheet shown in Table 2.12.

Table 2.12. Brakimpur residential sector end-use energy projection

Brakimpur Residential Sector
Base Year X

Table A - Socio-economic indicators of energy demand

A1 - population		10500000
A2 - people/household		4.18
A3 - Income Classes		total
(Minimum Wage Units)		**N**
0-2	15%	**376794**
2-5	32%	**803828**
5-10	28%	**703349**
+10	25%	**627990**
TOTAL	100%	2511962

Table B - Brakimpur: Appliance ownership by income class (P=%)

end-use	*0-2*	*2-5*	*5-10*	*10+*
LAMP_INC	100%	200%	400%	700%
LAMP_FLU	100%	100%	250%	300%
IRON	80%	81%	85%	85%
TV	65%	70%	85%	112%
CLTH WASH	0%	4%	15%	31%
AIR_COND.	0%	20%	70%	95%
FREEZER	0%	6%	20%	35%
REFRIG.	70%	79%	83%	100%
FAN	71%	71%	78%	78%
WATER HTR	9%	80%	60%	70%
OTHERS	50%	100%	150%	200%

Table C - Brakimpur: Average intensity per appliance (I=watts)

end use	*0-2*	*2-5*	*5-10*	*10+*
LAMP_INC	60	60	60	100
LAMP_FLU	20	20	20	20
IRON	2300	2300	2300	2300
TV	100	100	100	100
CLTH WASH	600	600	600	600
AIR_COND.	350	350	400	400
FREEZER	700	700	700	800
REFRIG.	230	230	230	230
FAN	200	200	200	200
WATER HTR	2500	2500	2500	3000
OTHERS	60	60	60	100

Table D - Brakimpur: Appliance usage (M=hours/year)

end use	*0-2*	*2-5*	*5-10*	*10+*
LAMP_INC	3330	3000	2500	1000
LAMP_FLU	1250	1250	1250	1500
IRON	13	22	43	52
TV	1500	1500	1900	2000
CLTH WASH	0	0	833	833
AIR_COND.	2000	2000	3000	4500
FREEZER	1286	1286	1286	1500
REFRIG.	2609	3043	3478	3913
FAN	1000	1500	1750	2500
WATER HTR	120	120	200	200
OTHERS	667	1000	3000	2400

Table E - Brakimpur: End-Use Total Households Energy Consumption by Income Class: E = N * P * M * I (MWh/year)

end use	*0-2*	*2-5*	*5-10*	*10+*	*Total*
LAMP_INC	**75283**	**289378**	**422010**	**439593**	**1226264**
LAMP_FLU	**9420**	**20096**	**43959**	**56519**	**129994**
IRON	**9013**	**32946**	**59127**	**63842**	**164927**
TV	**36737**	**84402**	**113591**	**140670**	**375400**
CLTH WASH	**0**	**0**	**52730**	**97300**	**150030**
AIR_COND.	**0**	**112536**	**590813**	**1073864**	**1777213**
FREEZER	**0**	**43416**	**126631**	**263756**	**433803**
REFRIG.	**158272**	**444447**	**466989**	**565185**	**1634893**
FAN	**53505**	**171215**	**192014**	**244916**	**661651**
WATER HTR	**10173**	**192919**	**211005**	**263756**	**677853**
OTHERS	**7540**	**48230**	**189904**	**301435**	**547109**
Total	**359944**	**1439584**	**2468774**	**3510836**	**7779137**

Table F - Socio-Economic Scenario for projected year (X+10)

- Only Population Growth and change in income distribution; no change in P, M, or I

			avg. annual growth rate
A'1 - population		14111122	3.00%
A'2 - people/household		4.0	-0.44%
A'3 -Income Classes		total	
(Minimum Wage Units)		$\mathbf{N_{x+10}}$	
0-2	13%	**458611**	
2-5	27%	**952501**	
5-10	30%	**1058334**	
+10	30%	**1058334**	
TOTAL	100%	3527780	

Table G -Frozen Efficiency Scenario (MWh/year)
Brakimpur: End-Use Total Households Energy Consumption by Income Class
Unchanged efficiency and usage (M and I): $E_{X+10} = N_{X+10} * P * M * I$

end use	*0-2*	*2-5*	*5-10*	*10+*	*Total*
LAMP_INC	**91631**	**342900**	**635000**	**740834**	**1810365**
LAMP_FLU	**11465**	**23813**	**66146**	**95250**	**196674**
IRON	**10970**	**39039**	**88969**	**107590**	**246568**
TV	**44715**	**100013**	**170921**	**237067**	**552715**
CLTH WASH	**0**	**0**	**79343**	**163976**	**243319**
AIR_COND.	**0**	**133350**	**889001**	**1809751**	**2832102**
FREEZER	**0**	**51446**	**190542**	**444500**	**686489**
REFRIG.	**192639**	**526650**	**702681**	**952490**	**2374461**
FAN	**65123**	**202883**	**288925**	**412750**	**969681**
WATER HTR	**12383**	**228600**	**317500**	**444500**	**1002983**
OTHERS	**9177**	**57150**	**285750**	**508000**	**860077**
Total	**438102**	**1705844**	**3714780**	**5916710**	**11775436**

5. Steps

Step 1: Build or retrieve the spreadsheet. A printed copy of this spreadsheet is attached. We recommend that you rebuild the spreadsheet.

Step 2: Complete the Table A with the following data:
- A1 = population
- A2 = number of people per household
- A3 = percent distribution of households by income class
- **N** (number of households by income class) is calculated based on A1, A2, and A3.

Step 3: Complete Tables B, C and D with the following data:
- (B) Appliance ownership by income class
- (C) Average energy intensity per appliance
- (D) Appliance usage

Step 4: Table **E** should calculate
- (**E**) End-use total household energy consumption by income class

Step 5: Complete Table F
- A'1 = population in year X+10
- A'2 = number of people per household in year X+10
- A'3 = percent distribution of households by income class in year X+10
- $\mathbf{N_{X+10}}$ (number of households by income class in year X+10) is calculated based on A'1, A'2, and A'3.

Step 6: Table **G** should calculate the Frozen Efficiency Scenario:
- End-use total households energy consumption by income classes.

6. Questions

a. Observing Table E, which are the end-uses with the largest MWh consumption? Which are the end-uses with the lowest consumption? Discuss some reasons that could explain the differences observed.

b. Which end-uses are interesting to do a conservation plan?

c. Calculate Table G with no changes in income distribution. Explain what happens.

d. If you were going to select an option for conservation in two end-uses, what would be your decision? Why?

e. Consider an appliance ownership change. How could this affect the energy consumption of each end-use? Make a hypothesis, describe it and make the necessary changes in the spreadsheet.

7. Commercial Sector

Now, we can do the same for the Commercial sector, changing the N (number of households) to A (commercial area in square meters):

The Commercial sector is responsible for 15% of the country's electricity consumption. The most important market segments of the sector are the following:

1. Small commerce
2. Shopping centers
3. Hotels
4. Bank
5. Schools

The end-uses identified with the Commercial sector are:

- Illumination
- Air conditioning
- Electric cooking
- Refrigeration
- Equipment

Next, we present the base year electricity consumption for the various segments and end-uses.

Table 2.13. Base year commercial consumption by market segment and end-use (MWh)

Segment\End-Use	Illumination	Air conditioning	Electric cooking	Refrigeration	Equipment	TOTAL
Small commerce	121,880	1,925	825	55,440	3,025	**183,095**
Shopping center	660,000	70,000	18,000	403,200	50,000	**1,201,200**
Hotels	154,000	177,188	788	176,400	5,250	**513,625**
Banks	93,750	5,625	274	50,400	3,125	**153,174**
Schools	1,470,000	382,813	7,875	352,800	70,000	**2,283,488**
TOTAL	**2,499,630**	**637,550**	**27,761**	**1,038,240**	**131,400**	**4,334,581**
Percent contribution by end-use	**57%**	**15%**	**1%**	**24%**	**3%**	**100%**

For the base year the total consumption of electricity in the Commercial sector was 4,335 GWh, and the end-use with the greatest consumption was illumination, with 57%. Refrigeration also had an important share with 24%, followed by air conditioning with 15%, equipment with 3% and, finally, electric cooking with just 1%.

The consumption of electricity in the base year by the Commercial sector depends strongly on the number of premises in each market segment. The electricity consumption of a market segment can be estimated with the following relationship:

$$E_{ij} = P_{ij} \times A_{ij} \times M_{ij} \times I_{ij}$$

for each market segment **i** and each end-use **j**, and where:

E_{ij} = energy consumption of end use **j** in market segment **i**
P_{ij} = penetration (% of total surface area) of end use **j** in market segment **i**

A_{ij} = total area of each market segment
M_{ij} = total number of annual hours of use for each end-use
I_{ij} = energy intensity, i.e., power consumed per unit of area by each end-use.

Total commercial sector energy consumption would be obtained by summing the E_{ij} terms for each market segment and end-use.

For the base year, $E_{ij(X)}$ is known, as presented in Table 2.13. All other parameters (P_{ij}, A_{ij}, M_{ij}, I_{ij}) must be adjusted such that they match the known $E_{ij(x)}$ when multiplied together. Once the base year parameters have been quantified, it is possible to project the consumption of energy in a future year, for example, the year (X+10) (i.e., 10 years after the base year).

8. Projections of the Demand for Electricity in the Commercial Sector

At the most basic level, an energy projection scenario may assume that current trends are maintained with respect to energy intensity, equipment penetration (efficient vs. non-efficient), etc. In countries where IRP is not in practice, this scenario may well coincide with the official forecast.

For such a scenario where P_{ij}, M_{ij}, and I_{ij} are not expected to change between year X and year X+10, The consumption of electricity for the projected year (X+10) can be written as follows:

$$\boldsymbol{E_{ij(X+10)} = P_{ij} \times A_{ij(X+10)} \times M_{ij} \times I_{ij} = E_{ij(X)} \times A_{ij(X+10)} / A_{ij(X)}}$$

In other words, in the above equation, only the floorspace area of each market segment is expected to change with time. The projected floor area is calculated based on the rate of growth for each market segment.

Table 2.14. Projected floorspace area for by market segment in year X+10.

Market Segment	Growth Rate (% /yr)	Base Year Floor Area (m^2)	**Projected Area (m^2) in Year X+10**
Small commerce	12.0%	55,000	170,822
Shopping center	10.0%	40,000	103,750
Hotels	8.0%	35,000	75,562
Banks	12.0%	25,000	77,646
Schools	10.0%	350,000	907,810
TOTAL	-	505,000	1,335,590

Based on the projected floorspace are provided in Table 2.14, estimate the consumption of electricity in the projected year (X+10) (Frozen Efficiency Scenario) assuming values for P, M and I:

9. Questions

a. Observing the results you have projected, which are the commercial market segments with the largest MWh consumption? Which are the commercial market segments with the lowest consumption? Discuss some reasons that could explain the differences observed.

b. Which end-uses are interesting in terms of implementing a conservation plan?

c. If you were going to select an option for conservation in two end-uses, what would be your decision? Why?

10. Industrial Sector

Now, we can do the same for the Industrial Sector. Here we want to pay particular attention to one important end-use: the use of electricity in motors.

11. Spreadsheet Structure

Table A, B, C, **D**, E, F, G and **H** = Base Year X:

Table A - Consumption Projection by Industrial Market Segment:

I = intensity (watts per US$)
GDP = in million US$
M = yearly work hours by market segment
$\boldsymbol{E_X}$ = $GDP_X \times I \times M$ (MWh base year)
$\boldsymbol{E_{X+10}}$ = $GDP_{X+10} \times I \times M$ (MWh projected year X+10),
$GDP_{X+10} = GDP_X \times (1+G)^{10}$,
G = annual GDP growth rate (% per year)

Table B - Consumption (C%) by end-use of electricity by industrial market segment

Table C - Distribution (D%) of motor types (nominal horsepower) by industrial market segment

Table D - Total industrial market segments' energy consumption by motor type:
$E_{X,motor\ type} = E_X \times C \times D = MWh$ in base year X

We can also develop the motor electricity consumption breakdown in another way:

Table E - Intensity (I' = watts per motor by motor type)

Table F - Usage (M' = yearly hours usage per motor by motor type)

Table G - Number of motors by motor type (N)

Table H - Total industrial market segments' energy consumption by motor type:
$E_{X,motor\ type} = N_X \times I \times M = MWh$ in base year X.

Note that the results of the energy consumption breakdown developed in Table H are the same as those developed in Table D.

Table I = Projected Year X+10.

Using the results of Table H, we can now project electricity consumption in year X+10 as follows:

Table I - Total industrial market segments' energy consumption by motor type in projected year X+10:

$$\boldsymbol{E_{X+10,motor\ type} = N_{X+10} \times I \times M = MWh} \textbf{ in projected year X+10,}$$

$$\boldsymbol{N_{X+10} = N_X \times (1+G)^{10},}$$

$$\boldsymbol{G} \textbf{ = annual GDP growth rate}$$

12. Worksheet diagram

Table 2.15 demonstrates the development of Table A through Table D in the Brakimpur industrial sector exercise.

Table 2.15. Brakimpur industrial sector electricity consumption by motors, Sheet 1

Table A - Electricity Consumption Projection by Industrial Market Segment: $\mathbf{E_{X+10} = GDP_{X+10} \times I \times M}$

	I (Watt/US$)	GDP_X (10^6 US$)	M (hours/year)	E_X **(MWh)**	G (GDP Growth Rate)	E_{X+10} **(MWh)**
Metallurgy	0.52	510	4,320	1153699	0.82%	1252440
Electrical/Electronics	0.05	18,837	4,320	3682237	6.91%	7182964
Wood	0.82	560	1,920	883592	3.86%	1290133
Chemical	0.21	1,105	8,640	1961945	2.54%	2520084
Textiles	0.56	396	4,320	956626	3.69%	1374091
Food&Beverages	0.31	875	6,480	1774128	1.01%	1961332
Transport	0.31	623	6,480	1248492	3.43%	1748533
Others	0.38	10,150	1,920	7365125	4.19%	11105592
Total		33056		19025844		28435169

Table B - Consumption by end-use of electricity by industrial market segment (C=%)

Market Segment	Motor	Process Heat	Direct Heat	Electrochemical	Illumination	Others	Total
Metallurgy	1	0	98	0	0	1	100
Electrical/Electronics	98	0	0	0	2	0	100
Wood	95	0	0	0	5	0	100
Chemical	79	5	4	9	3	0	100
Textiles	89	4	1	0	5	1	100
Food&Beverages	6	77	16	0	1	0	100
Transport	80	10	5	0	5	0	100
Others	58	1	39	0	2	0	100

Table C - Distribution of motor types (nominal horsepower) by industrial market segment (D=%)

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others
Motor Hp<= 10	13	25	15	12	12	10	5	13
10<Motor Hp<=40	25	35	33	35	35	19	25	25
40<Motor Hp<=100	23	40	30	25	25	40	18	23
100<Motor Hp<=200	27	0	12	13	13	19	27	24
200<Motor Hp<=300	12	0	10	15	15	12	25	15
Total	100	100	100	100	100	100	100	100

Table **D** - Total industrial market segments' energy consumption by motor type

$E_{X,motor\ type} = E_X \times C \times D = MWh$ in base year X

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others	Total
Motor Hp<= 10	1500	902148	125912	185992	102168	10645	49940	555330	1933635
10<Motor Hp<=40	2884	1263007	277006	542478	297989	20225	249698	1067943	3721231
40<Motor Hp<=100	2654	1443437	251824	387484	212849	42579	179783	982508	3503117
100<Motor Hp<=200	3115	0	100729	201492	110682	20225	269674	1025225	1731143
200<Motor Hp<=300	1384	0	83941	232490	127710	12774	249698	640766	1348764
Total	11537	3608592	839412	1549936	851397	106448	998794	4271773	12237889

Percent of total E_X consumed by motors = 64.32%

Table 2.16 demonstrates the development of Table E through Table I in the Brakimpur industrial sector exercise. Note that Table I was developed using the results of Table H. Table I could also have been developed using the results of Table D as well.

Table 2.16. Brakimpur industrial sector electricity consumption by motors, Sheet 2

Table E - Intensity (I'= watts per motor)

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others
Motor Hp<= 10	2580	2686	2576	2466	2466	2575	2466	2208
10<Motor Hp<=40	15507	16007	14353	13064	15455	15826	13062	15088
40<Motor Hp<=100	50066	46918	44161	46376	44167	47521	46341	46920
100<Motor Hp<=200	105952	0	97154	97151	99177	97706	97127	99370
200<Motor Hp<=300	197777	0	167147	169121	167598	166325	167358	169336

Table F - Annual usage by motor type (M'=hours/year)

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others
Motor Hp<= 10	3800	5700	1500	4200	3200	3500	3900	3700
10<Motor Hp<=40	6000	6300	2000	5000	5300	3000	6000	4900
40<Motor Hp<=100	5300	3500	1800	5600	4800	3200	5300	5000
100<Motor Hp<=200	4200	0	1800	6800	6000	4500	4500	5100
200<Motor Hp<=300	3500	0	1800	5900	6000	4800	4000	5500

Table G - Number of motors by motor type in year X (N_X)

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others
Motor Hp<= 10	153	58916	32586	17961	12949	1181	5193	67975
10<Motor Hp<=40	31	12524	9650	8305	3638	426	3186	14445
40<Motor Hp<=100	10	8790	3168	1492	1004	280	732	4188
100<Motor Hp<=200	7	0	576	305	186	46	617	2023
200<Motor Hp<=300	2	0	279	233	127	16	373	688

Table **H** - Total industrial market segments' energy consumption by motor type

$E_{X,\text{motor type}} = N_X \times I \times M$ = MWh in base year X

Horsepower (Hp)	Metallurgy	Electrical/Electron	Wood	Chemical	Textiles	Food&Beverag	Transport	Others	Total
Motor Hp<= 10	1500	902016	125912	186026	102183	10644	49943	555329	1933552
10<Motor Hp<=40	2884	1262972	277013	542483	297994	20226	249693	1067936	3721200
40<Motor Hp<=100	2653	1443432	251824	387481	212850	42579	179785	982505	3503108
100<Motor Hp<=200	3115	0	100729	201491	110682	20225	269673	1025230	1731145
200<Motor Hp<=300	1384	0	83941	232491	127710	12774	249698	640767	1348765
Total	11537	3608420	839419	1549971	851418	106447	998792	4271767	12237771

Table I - Frozen Scenario

$\mathbf{E_{X+10,\text{motor type}} = N_{X+10} \times I \times M}$ **= MWh in year X+10**

Horsepower (Hp)	**Metallurgy**	**Electrical/Electro**	**Wood**	**Chemical**	**Textiles**	**Food&Bevera**	**Transport**	**Others**	**Total**
Motor Hp<= 10	**1628**	**1759568**	**183845**	**238947**	**146775**	**11767**	**69946**	**837359**	**3249835**
10<Motor Hp<=40	**3131**	**2463687**	**404467**	**696809**	**428037**	**22360**	**349699**	**1610300**	**5978490**
40<Motor Hp<=100	**2881**	**2815713**	**367688**	**497712**	**305736**	**47072**	**251791**	**1481482**	**5770074**
100<Motor Hp<=200	**3382**	**0**	**147075**	**258812**	**158982**	**22359**	**377682**	**1545905**	**2514197**
200<Motor Hp<=300	**1503**	**0**	**122563**	**298630**	**183441**	**14122**	**349706**	**966189**	**1936154**
TOTAL	**12525**	**7038968**	**1225637**	**1990910**	**1222971**	**117679**	**1398824**	**6441235**	**19448749**

Percent of total E_{X+10} consumed by motors = 68.40%

13. Questions

a. Observing Table A, which are the industrial market segments with the largest MWh consumption? Which are the industrial market segments with the lowest consumption? Discuss some reasons that could explain the differences observed.

b. Which motor types would be economically interesting for doing a conservation plan?

c. Is there any difference in Tables D and H? Explain what happens with the different equations.

d. Consider a motor type substitution. How could this affect the energy consumption of each industrial market segment? Make a hypothesis, describe it and make the necessary changes in the spreadsheet.

Chapter 3: Renewables, Energy-Efficiency Programs, and Demand-Side Management (DSM)

The introduction of measures that favor more efficient or renewable energy technologies do not happen as a natural result from an Integrated Resource Plan, or because we have demonstrated their economic feasibility. They require significant changes in consumer behavior and changes in ways energy companies and consumers make their investment decisions. It is necessary to have a strategic plan in order to promote the required behavioral change and the effective implementation of energy efficiency measures. These strategies imply the elaboration of *programs,* which are a series of coordinated actions targeting specific ends. Programs represent collections of demand-side measures and the policy instruments that are used to implement them in a systematic way. They imply additional costs, time, and uncertainties for demand-side options which must be accounted for when screening these options in an IRP process.

There are several types of programs: programs with the objective of disseminating information on efficient technologies, programs to replace light bulbs and others types of equipment, programs that introduce energy performance standards, etc. Some programs are implemented by utilities, some by governments, and some by other organizations.

Programs are required because very often it is recognized (and especially so in developing countries) that market mechanisms alone are not sufficient to achieve a socially desirable level of energy efficiency. Programs will deliberately intervene in the energy consumer market with instruments other than energy prices (but may also include pricing policy) in order to promote the introduction of energy efficient measures and technologies.

Therefore an Integrated Resource Plan will also include the task of considering costs, timing, and impacts of programs on savings in demand capacity and electricity use. At a more detailed level it will also include the design, implementation and evaluation of programs. At the end of this chapter we include some quantitative exercises which try to incorporate the costs and the potential effects of programs on projected future energy demand scenarios. Although it is a difficult task to estimate precisely the costs, timing and the effects of programs on energy savings, the exercises provided present simple ways of accounting for these parameters so that a more rigorous analysis for screening demand-side options can be performed.

We begin by discussing the main barriers found when implementing energy-efficient and DSM measures, and then describe the main program types that can be implemented by utilities, government and non-governmental agencies.

A. Barriers to Energy Efficiency and Renewables

A.1. Information

Lack of information is usually the first barrier encountered. Lack of or imperfect knowledge on the part of consumers, vendors, manufacturers and policy makers may hamper the introduction of efficiency measures or the use of renewables in situations where they make technical and economic sense.

Consumers are frequently unaware of practices and technologies available to conserve energy. They may be operating their electrical equipment incorrectly or wastefully. For example, residential consumers might place their air conditioner in direct sunlight, which will increase its electricity consumption. Industrial customers might make the wrong specifications for a new electrical motor for their site because they are not properly instructed on making this type of decision.

Information is also required for retail sellers and vendors. They are in close contact with the potential buyers of new equipment and should be able to advise the customer on the best products regarding efficiency as well as other attributes. However, very often they cannot because the retailers and vendors are neglected in information campaigns.

Also manufacturers may need technical assistance if new standards are required for energy consuming equipment. Developers, architects, and facilities managers often have misconceptions about new or unfamiliar technologies. They too are an important target audience for information programs.

Continuous education and good information dissemination are always necessary to keep consumers up-to-date on the recent technologies and ways of using energy more efficiently that become available.

A.2. Institutional and Legal Barriers

These barriers frequently start within the agencies in charge of the country's or region's energy planning. The traditional planning mind set tends to associate greater credibility with highly centralized power production centers and does not favor investments in energy conservation measures or decentralized options of electricity production.

IRP is a more complex planning method and needs an appropriate institutional setting in order to be conceived and implemented. Frequently, planning agencies lack the personnel with good knowledge of the behavior of the energy market and how to implement policies to alter existing trends of energy consumption and their evolution. At the same time the personnel need to understand the several existing options on the supply side as well. Decisions are reached after comparing the capital and operating costs of a number of alternatives, often taking into account several projections of future energy prices, load growth, and interest rates. These tasks require technical skills and tools so that the potential for energy-efficient and DSM measures are properly evaluated and the instruments to implement them conceived.

Legal barriers frequently limit the scope of the planning activities of the energy companies. For example, the electricity companies are usually legally defined as being responsible for supplying electricity only, and are required to make investments only in the power sector. This will limit their consideration of fuel substitution alternatives, for example.

Legal accounting procedures impede utilities from considering investments in their customers' facilities as part of the utility investment, and therefore such investments cannot be taken into consideration when rates are calculated, for example. Institutional and legal barriers impede rates that allow utilities to recover the costs of DSM programs. For example the cost of a DSM program could be treated as an operating cost which allows the full cost to be recovered during the year of expense; or another approach is to have the cost of DSM programs treated as an asset in the utility "rate base," in which case the cost of a program is paid over time with an associated rate of return. Profits also need to be decoupled from increased sales; utilities should not be penalized for lower revenues from successful DSM programs which increase the level of energy services provided to their customers.

These barriers are very strong and impede the elaboration of an IRP that will be put into practice.

A.3. Financial Barriers

Many consumers will not make investments in energy efficiency because they lack capital to buy new energy-efficient equipment or make the required retrofit in their installations. A certain measure might be very cost effective, with fast pay-back, but it will not be implemented unless the consumer can meet the up-front capital costs.

Capital is not the only restraining financial factor: a customer may have capital, but energy-efficiency might not be his priority for investment. For instance, a consumer considering the purchase of a new refrigerator might prefer a less efficient model if it is available in the color he prefers. An industrial customer may prefer to spend capital on a new line of products rather than consider a retrofit in existing installations.

Sometimes the person who pays the energy bill is not the one responsible for the selection and purchase of energy-using equipment. This is especially the case for buildings, where architects, builders, and landlords select building designs and equipment, but where buyers and tenants pay the energy bills.

Different types of consumers will have different ways of estimating the economic returns on their investments in energy efficiency, as will be seen below. Programs can address these specific issues by offering loans at attractive interest rates in order to have investments in energy efficient measures considered a priority by each relevant agent.

A.4. Technological Barriers and Infrastructure

Several opportunities to produce and to conserve energy depend on new technologies which might not be available in some countries or regions. Product availability is important in order to create a sustained market for the technologies being introduced. These products can be imported, but ongoing technical support needs to be available locally; otherwise lack of maintenance and support will also constitute a barrier for success in implementing the demand-side option.

The quality of the equipment being locally produced (or imported) is also important to guarantee the good performance of the electrical system as a whole. For example, it is important not only to produce electronic ballasts for fluorescent lamps because they consume less energy compared to electromagnetic ones, but it is also important to make sure that they are produced with good power factors.

Many new and efficient technologies incorporate electronic components which rely on good quality power to operate. Voltage fluctuations and frequent power failures will shorten the equipment's designed lifetime and thereby jeopardize the measure's economic and technical merit as a demand-side alternative. Some countries have several different service voltage levels in their territory (110, 127, 220V, etc.), which may constitute a barrier for creating a market for such new technologies.

A.5. Energy Prices and Rate Making

Electric rates (tariffs) in many instances have been a barrier to attracting consumers to invest in energy efficiency. In many countries tariffs are administratively set by government agencies which may have a broad range of criteria to consider. The results are very often that the tariffs do not reflect the marginal costs of producing electricity. Rates are often based on average electricity costs, which very poorly match actual electricity costs. For example, very few consumers pay higher rates for on-peak service, even though the cost to the utility of providing this energy is substantially higher than the average cost.

Another practice is the use of subsidies across consumers and across regions. These measures very often impede the utilization of regional resources to produce electricity and impede the introduction of efficiency programs in the most promising areas.

Traditional rate making encourages sales of kWh (for an electric utility), and discourages efficiency measures. To understand this process consider the simplified graph of (non-fuel) revenue requirements versus energy sales in Figure 3.1.

Notice in this (hypothetical) example there is a *fixed* annual *revenue requirement* (see Chapter 4) of $30 million needed to recover capital costs of equipment and earn allowable profits, plus an additional amount (the *short-term marginal cost*, or *variable* cost) of 0.01US$/kWh which depends on how many kWh are generated. (These fixed plus variable costs, by the way, are associated with power production from *existing* resources only; the capital costs of new generating capacity would be included only in *long-run* marginal costs.) In a general rate case, the utility estimates the total annual sales of kWh, along with the revenue required to meet its non-fuel expenses. The ratio of the two establishes the tariff that should be charged for electricity to cover non-fuel costs. In this example, if sales are estimated to be 1 billion kWh/yr then revenues of $40 million would be needed. The ratio of the two is an average rate of 0.04US$/kWh, which is what the utility would be allowed to charge until the next general rate case is heard.

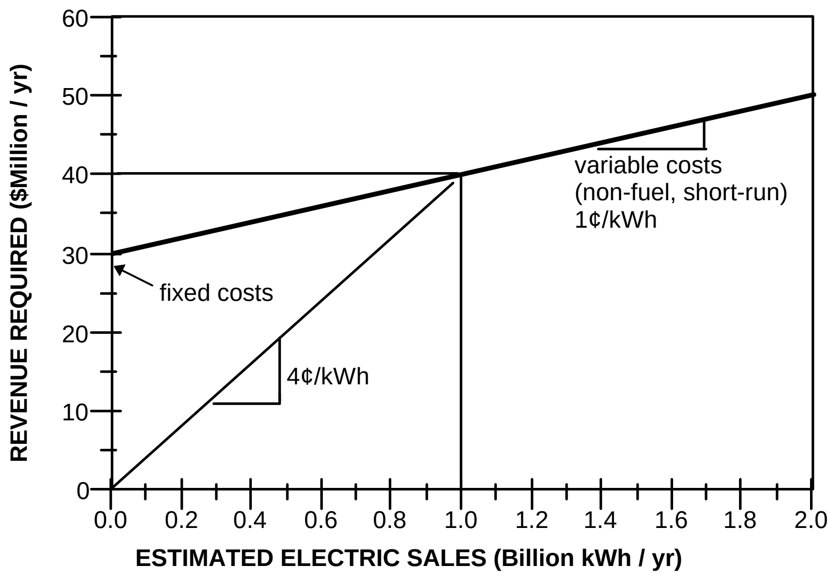


Figure 3.1. In this example, estimated annual sales of 1 billion kWh would require $40 million in revenues, so (non-fuel) rates would be 0.04US$/kWh.

Consider now the perverse incentives that encourage the utility to sell more kWh than the estimated amount shown in Figure 3.1. Having established a price of 0.04US$/kWh for all electricity sales, any sales beyond the estimated 1 billion kWh would yield revenues to the utility of 0.04US$ for each extra kWh sold. Since each extra kWh generated has a marginal cost to the utility of only 0.01US$/kWh, there will be a net 0.03US$ profit for each extra kWh that can be sold. Any extra cost of fuel to run the generators a bit longer is simply passed on to the ratepayers, so that component of utility cost is unaffected by this argument.

Notice that the example utility loses money if it sells less than 1 million kWh. Generating one less kWh reduces costs by 0.01US$, but reduces revenue by 0.04US$. In other words, this quite standard practice of estimating electricity sales and required revenues as a way to establish the base rate not only encourages additional kWh sales, it strongly discourages conservation that would reduce kWh sales.

A.6. Diversity of Actors and Expectations

The making of an IRP and more specifically of DSM programs needs to consider the diversity of actors involved and the different perceptions with regards to costs and benefits, risks and uncertainties of each DSM measure. The evaluation of the economic attractiveness and the convenience (or inconvenience) of implementing a given measure depends on the perspective and criteria of each agent.

We consider three different parties involved in energy-related investments: the energy sector (or energy company), the consumer, and the society (which includes energy consumers, non consumers, and the energy sector). Each of these agents take into account the following factors when considering an investment in energy efficiency measures:

- discount rate used to evaluate benefits and costs resultant from the measure
- future evolution of energy costs and prices
- perception of risks and uncertainties involved by adopting the measures

Most utilities, large consumers and the government[1] have access to low-cost capital, which is not the case for the majority of consumers. Government or utilities can afford to make longer term investments, have longer pay-back periods, and spread the risks of individual investments across a broad range of many diffuse actions.

The power sector tends to assume a lower discount rate compared to an energy consumer, which reflects its greater access to capital. A perception of greater future risks will also be reflected in the rates used to discount future costs and benefits. Different actors may apply different discount rates to their stream of costs and benefits. A lower discount rate for utilities, for example, will make many investments in efficiency cost effective, but that is not necessarily true for consumers.

Table 3.1 provides examples of the different discount rates typically used by different segments of society.

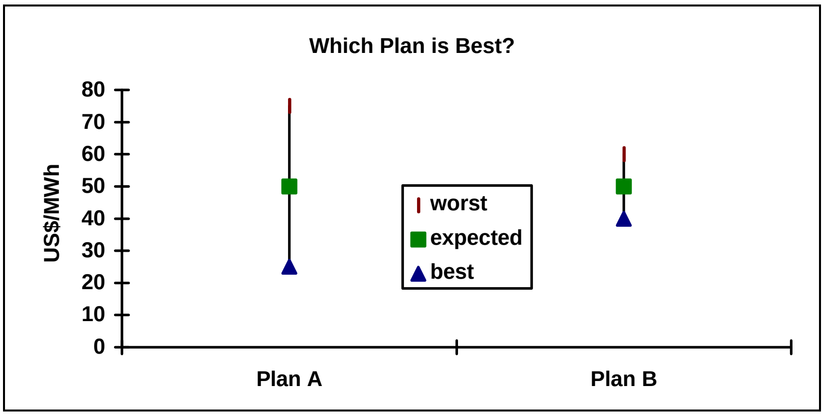
Table 3.1. Examples of different implicit real discount rates used in investment decisions by various agencies in energy projects

	Discount Rate (%)
Governments	4-12
World Bank	10
Public utility (USA, Sweden)	6-8
Public utility (Brazil,Thailand)	10-12
Industry	15-20
Residential household	35-70*

*See Ruderman, et al, 1987.

[1] Throughout this text we use the government as the representative of the society's perceptions.

Example: Compare the risks of two alternative projects a utility might consider in the figure below. Plan A is a low cost capacity, high fuel cost facility (e.g., gas combustion turbine). Plan B represents a wind or hydro facility, which has just the opposite characteristics. Which Plan is best?



Both projects have the same expected cost over the life of the plant. However, because fuel prices for Plan A are very uncertain, they have a significantly wider cost range than the potential fuel price variation for Plan B. While there is a chance that Plan A will have very high fuel prices, it is also possible that the fuel price will fall very low. Plan B, with a smaller and more predictable price range, offers the lower overall cost risk.

The risk associated with Plan A is obvious - that fuel costs will be high. The risk associated with Plan B, on the other hand is much less apparent.

At first one would guess that customers and utilities both would prefer the greater fuel price certainty associated with Plan B. After all, it is well known that fuel costs are a key uncertainty facing utilities, and therefore an opportunity to predict these costs with relative accuracy should be attractive to all stakeholders. However this is not the case. While customers would likely opt for the reduced price volatility of Plan B, more frequently than not utilities choose Plan A. There are three reasons for this preference:

1. If gas prices end up at the low end of the scale and the utility has selected Plan B, then the utility can lose customers to other fuels.

2. If the utility has selected Plan A, it is very likely to have the company of other utilities who are making similar decisions. This means that the risk associated with exposure to high fuel costs is similarly shared and thus minimized.

3. Fuel clause provisions mean that volatile fuel costs are not really a high risk for utilities. Commissions rarely disallow fuel cost increases and when they do, it is never based upon the argument that a plant which burns a particular fuel should not have been built the first place. By being reasonably confident that high fuel prices can be passed on to the customers, Plan A is, in fact, a low risk for the utility even though it is a high risk for customers.

Box 3.1. Comparison of investment opportunities and risks in electricity generating plants by utility and customers.

Exercises:

In Section D of Chapter 2, we examined the concept of discount rates and their influence on cost-effectiveness. We now return again to the concepts of discounting in the following exercises. Please refer to Appendix 3 for more in-depth discussions of discounting and the economics of energy conservation.

Exercise 3.1) Calculate the implicit discount rate for the following agents for an investment in an energy efficient compressor considering: a) the consumer wants a pay-back of 2.5 years, b) the utility a pay-back of 10 years c) the government wants a pay-back of 20 years. Assume a 15 year lifetime for the compressor and the cost of the compressor as US$ 100.

Exercise 3.2) Is there any relationship between the calculated IRR and the given paybacks?

Exercise 3.3) Identify for your region the main existing barriers to the introduction of IRP methods giving examples.

Exercise 3.4) Given the lighting data in the table below, and using the internal rates of return calculated in Exercise 3.1, calculate the maximum price at which lamp model B would still be cost-effective compared to lamp model A for consumers, utilities and government.

	Lamp model A	**Lamp model B**
Lifetime	1 year	5 years
Power	100 W	20 W
Price	$ 1.00	$ X (for each agent)
Usage (hours/year)	1000 hrs	1000 hrs
Residual Value	0	0

Energy price: $80.00 / MWh
Note: consider also the price of lamp replacement.

Further reading:

Levine, M.D., E. Hirst, J.G. Koomey, J.E. McMahon, A.H. Sanstad. 1994. "Energy Efficiency, Market Failures, and Government Policy." Pre-print. Lawrence Berkeley Laboratory LBL-35376, Oak Ridge National Laboratory ORNL/CON-383

Howarth, R. B. and B.Andersson. 1993. "Market Barriers to Energy Efficiency," Energy Economics, October.

Reddy A.K.N. 1991. Barriers to improvements in energy efficiency. Energy Policy 19(7):953-61.

Geller, H., S. Nadel. 1994. "Market Transformation Strategies to Promote End-Use Efficiency." Annual Review of Energy and Environment 19:301-46.

B. Energy Pricing

The pricing structure adopted by the electric power industry typically requires different consumers to pay different prices for the energy used. This is partly because the utility's cost of serving different customers varies based on geography, time-of-day, customer size, etc. However, particularly in developing countries, the pricing system is often used as an instrument of economic or social policy to compensate for unequal wealth distribution or to promote and stimulate specific sectors of the economy. Sometimes as a result of such policy objectives, the variation between the lowest and highest tariff can reach as high 1000%, with the consequence that the average energy price charged may not be sufficient to assure the necessary rate of return to finance the maintenance and expansion of the electricity system in the future. Utilities and governments must be careful to properly price energy services to a.)

ensure that tariffs are sufficient to ensure the financial viability of the utility, and b.) send appropriate price signals to consumers not to over-use energy.

Energy prices vary over time and depend on customer demand, fuel market conditions, the specific technology involved in energy production, and other random or stochastic phenomena (such as weather). It is important to understand how customers react to energy price changes. This reaction is measured in terms of price elasticity, as discussed briefly in Chapter 2, Section A. In some cases electricity price rises may cause customers to switch to other fuels (such as natural gas), or in other cases induce them to use electricity more efficiently.

Energy pricing can be a very effective tool for influencing people's energy-consuming behavior, but this effectiveness will depend on the degree to which customers' demand is sensitive to price changes. This section discusses various pricing mechanisms which can and have been used.

This section also discusses, in great detail, the rate making methods which have been used in the United States to compensate utilities for lost revenues from energy efficiency programs and to thus make energy efficiency more attractive for utilities. Subsequent sections then discuss the concept of fuel switching.

B.1. Block Tariffs

The common pricing mechanisms include block tariff structures, where the price per kWh increases as consumption increases, thus allowing low-income customers to obtain a small "lifeline" amount of electricity very cheaply, while wealthier customers with higher consumption pay more. This mechanism is often applied in the residential sector, and it assumes that high-income households with higher consumption levels will subsidize lower-income households.

B.2. Marginal Cost Pricing

The role of prices in a market economy are threefold: 1) to allocate resources efficiently to productive activities, 2) to give consumers accurate signals regarding the value of different goods and services, and 3) to raise sufficient revenues to cover the costs of producing goods and services. In the context of the power sector, electricity prices should raise revenues for the utility, signal consumers to demand the appropriate quantity of electricity compared to other goods and services, and indicate to utility planners the amount of resources to allocate to each facet of the provision of electricity services.

Straightforward economic analysis demonstrates that these three goals are most readily accomplished by pricing according to long-run marginal cost (LRMC). Equating the price of a good with the marginal cost of the different sources for that good is a standard optimality condition in microeconomic analysis. In the case of a capital-intensive good such as electricity, we distinguish between the short-run marginal cost (SRMC), which is the cost of producing the next unit of electricity without expanding the total production capacity, and the LRMC, which is the cost of providing for increased future production over a time horizon that allows for capacity expansion and optimization (see Chapter 4).

The relationship between LRMC, SRMC, and system demand are shown in an idealized way in Figure 3.2. A certain amount of utility costs, and thus required revenue, can be attributed to recovery of existing investments and other fixed costs, regardless of demand. As demand increases, revenue requirements increase according to the variable costs of operating existing capacity, which indicate the SRMC. At some point demand is such that existing capacity is inadequate and must be expanded. Electric supply resources tend to be “lumpy” investments that are only feasible in discrete size increments, thus the discontinuities in Figure 3.2, which correspond to the costs of incremental increases in capacity. At the point where capacity must increase, the marginal cost (slope) is infinite, but the required investment cannot be attributed entirely to the marginal increase in demand. Rather, the LRMC, which includes the revenue requirements for capacity expansion, is “smoothed” across several increments in demand, as shown in Figure 3.2.

Theoretically, selling electricity at the LRMC will produce optimal results because the utility will receive enough revenues to cover the cost of the marginal resource needed to supply the amount of electricity that consumers are willing to buy. To both fully utilize capacity and avoid unneeded capacity expansion due to peak demand growth, the LRMC approach should distinguish between consumption that increases the need for capacity and that which does not. This difference can be categorized according to customer categories, time-of-use, or geographic location, depending on which factors tend to drive the need for capacity expansion.

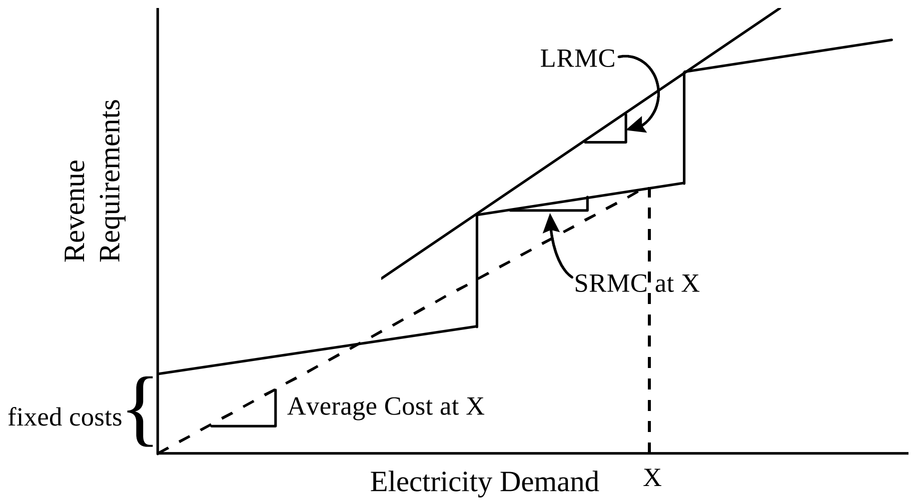


Figure 3.2. Effect of capacity expansion on marginal costs

The most common approach to allocating the LRMC among consumers is to distinguish between consumption during times of peak demand, which drives the need for capacity expansion, and off-peak consumption. The off-peak price is simply the SRMC, which indicates the cost of providing energy without any capacity cost. (The composition of capacity cost and its contribution to LRMC is explained in Chapter 4). The SRMC value may vary seasonally, for example in a hydroelectric system where the energy cost is very low during the wet season. The on-peak price includes the SRMC, or energy cost, and a capacity-related increment that makes the total price equal to LRMC. The capacity cost can be charged according to the total kWh consumption during on-peak hours, or it can be based on the maximum kW demand during those hours. The combination of these values can change hourly over the entire year, depending on the dynamics of the customers' and the utility system's demand profile.

A pure LRMC-based price structure should also include a fixed customer charge to cover the fixed costs that do not depend on the consumption level. In addition, the price should include the value of environmental impacts and other externalities, thus sending the proper signal to consumers of the full societal cost of electricity use.

In practice, neither these refinements nor even the basic criteria for LRMC pricing are used routinely. Instead, prices are mostly based on historical average costs, which include fixed and variable (SRMC) components, as shown in Figure 3.2. There are several reasons for this divergence from economic theory, some technical and some political.

The technical reasons relate to the fact that electric supply investments tend to be "lumpy." If the LRMC is decreasing over time, as was true for most of the period before 1970, the LRMC is less than the average cost. Pricing according to this low LRMC value would make it difficult to raise sufficient revenue to operate and expand the system during a time when increasing electrification was seen as essential. Significant economies of scale and declining LRMC meant that it made sense to treat electric supply as a "natural monopoly" in most countries. In such a system, average-cost pricing more securely ensures cost recovery when LRMC decreases.

In the 1970s and 1980s, high fuel costs and interest rates caused the LRMC of electricity to increase in most countries. At that point, though LRMC-based pricing would have sent an economically correct signal to consumers regarding the future value of electricity, it would also have resulted in a substantial transfer of wealth from consumers to electricity producers. This was generally rejected on both equity and political grounds. Today, it appears that the LRMC of electricity supply is again decreasing, and utilities are already concerned about potential difficulty in recovering the fixed costs of their existing capacity.

The political reasons for avoiding LRMC-based pricing are that it can lead to large differences in prices among customers, and that it can make electric service unaffordable to low-income consumers. Historically, electricity has been seen as an essential component in infrastructure development that helped to integrate rural and remote areas into a country. Although these areas are relatively expensive to serve, it would not be politically acceptable to allow prices to reflect such differences. In some developing countries, electricity is subsidized to the point where utilities are not able to cover their costs, creating an obvious obstacle to efficient system operation and expansion.

B.3. Demand Charges, Time-of-Use, and Seasonal Pricing

A direct application of marginal cost electricity pricing can be found in the tariff system known as time-of-use and demand charges, in which tariffs vary by time-of-day and the relative cost of providing electricity service at different times.

Tariffs can vary between peak hours (normally from 6 pm to 9 or 10 pm) and off-peak hours and between wet season and dry season (important in a hydroelectric system). Some customers pay two types of tariffs: one for the energy consumed (kWh) and another for the maximum demand (kW) contracted. Electricity prices are higher during certain periods of the day or year[2]. The consumer is thus induced to modify his consumption patterns through operational and technological changes to keep his bills low.

This pricing mechanism can be used, therefore, to promote changes in the load curve in the electrical system. This also helps to create better conditions for the penetration of more efficient appliances as well. The following two exercises provide useful practice in examining different tariff schedules and their impact on energy-consuming behavior.

Exercise 3.5) Electricity tariffs can be important instruments for changing customers' electricity consumption profile to save energy and peak capacity. Consider the case of an imaginary textile factory that can choose from the 3 different tariff schedules shown below. The factory operates 20 days per month, and its total costs consist of only labor and energy, with energy consumption and labor costs shown below. Calculate the factory's total monthly operating costs for each of the 3 tariffs. Which tariff is most cost-effective for the factory?

I. Tariff schedules (US$/MWh)				
A. Single tariff	B. Block tariff		C. Time of use (T.O.U.) tariff	
	Consumption kWh/month	US$/MWh	Period	US$/MWh
80	0-1000	65	22:00 - 08:00	35
	1000-1500	75	08:00 - 12:00	85
	over 1500	95	12:00 - 18:00	78
			18:00 - 22:00	90

Staff Category	**Number of Staff by Category**	**Salary (US$/month) Working Hours: 08:00 - 20:00**
Worker A	4	500
Worker B	5	300
Worker C	3	1000
Worker D	5	300

The factory has 2 machines (nominal capacity of 100000 W each) each operating for 8 hours/day, resulting in the following total daily load profile for the factory:

Period	**Energy Consumption (W hr per hr)**
08:00 - 12:00 hrs	203000
12:00 - 14:00 hrs	2000
14:00 - 18:00 hrs	203000
18:00 - 20:00 hrs	1200
20:00 - 08:00 hrs	1000

Exercise 3.6) Based on the above tariff schedules, the factory decides to consider shifting all of its textile production to night time, while maintaining total monthly production at the current level and continuing to operate 8 hours per day for 20 days per month. This would shift the factory's load profile to the following:

[2] In Brazil, demand tariffs are five times more expensive during peak hours than off-peak, and 10% more expensive during the dry season for high voltage industrial customers.

Period	Energy Consumption (W hr per hr)
22:00 - 02:00 hrs	203000
02:00 - 04:00 hrs	2000
04:00 - 08:00 hrs	203000
08:00 - 10:00 hrs	1200
10:00 - 22:00 hrs	1000

However, in order to shift production to night time, the factory must pay higher wages to its workers. Labor costs for the night time production schedule would be as follows:

Staff Category	Number of Staff by Category	Salary (US$/month) Working Hours: 22:00 - 10:00
Worker A	4	610
Worker B	5	380
Worker C	3	1100
Worker D	5	360

Calculate the factory's monthly operating costs under the night time production schedule. Will this option save the factory money?

B.4. Green Pricing and Tax Benefits to Renewables

Green pricing refers to the concept where customers voluntarily agree to pay a little more (typically 5 to 10% of the existing tariff) in order to support the development and use of renewable energy sources which may cost slightly more than conventional sources. This is a new approach based on the idea people who are concerned about the environment and the externalities of conventional energy should be willing to pay more for their energy to ensure that it is derived from clean sources.

As deregulation in the worldwide electricity industry proceeds and customers become more able to choose their electricity supplier similarly to how they choose to purchase other market-traded goods, the green pricing approach is likely to become more common as specialty "green" energy companies develop to serve this market niche. Such companies have already been established in the United Kingdom, for example, where electricity market deregulation has been moving rapidly.

Tax incentives can also be used to make renewable resources more competitive with conventional resources. For example, tax benefits for wind energy were the primary mechanism used (with mixed results) in California in the 1980s to initially stimulate the creation of the wind energy industry there, and India is currently relying heavily on tax credits for similar purposes. However, tax credits must be carefully structured in such a way as to ensure that the resulting power plants are operational and efficient, and that investment decisions are not overly distorted by tax considerations.

C. Electricity Tariffs and Energy-Efficiency Program Costs

Traditional rate-making strongly discourages energy conservation by encouraging utilities to maximize profits by selling as much energy as possible. Mechanisms that address this bias by eliminating the link between energy sales and utility profits are referred to as *decoupling*.

When a utility encourages its customers to conserve energy by offering incentives (information, rebates, etc.), it incurs costs that need to be fully and promptly recovered. Just as utilities recover supply-side investments, with a profit, by putting them into the rate base, rate-basing of efficiency and DSM programs is considered by many to be best way of letting supply-side and demand-side options compete by offering comparable returns for the utility.

There is some disagreement as to whether utilities should be allowed to earn profits on their DSM expenditures. Allowing rate-basing of DSM provides a strong profit incentive for utilities to invest in DSM but increases the cost of conservation. Treating DSM expenditures as “expensable” operating costs which can only be recovered by the utility without additional profit would reduce the cost of DSM but would eliminate much of a utility’s incentive to pursue DSM.

Sections C.1 to C.5 below discuss in detail several ways of introducing DSM and energy efficiency programs and alternate rate-making mechanisms.

C.1. Decoupling: California’s Electric Revenue Adjustment Mechanism

To counter the disincentives incurred under traditional rate making, the *decoupling* of energy sales from utility revenues is essential if DSM is to fulfill its promise. California decoupled its revenues from sales for natural gas in 1978. Later, in 1982, California began to decouple its electric utilities using a revenue recovery program called the *Electric Revenue Adjustment Mechanism* (ERAM). Other states are beginning to adopt similar revenue decoupling mechanisms. An excellent presentation of ERAM is provided in Marnay and Comnes (1992), and this section is based on their work.

The essence of ERAM is fairly simple. The utility is allowed to keep only the base revenues authorized in its general rate case. Any excess revenues, or deficiencies in revenues, in a given year are held in a balancing account. That account, including interest, is cleared each year using an adder (which can be positive or negative) that gets rolled into the following year’s rates. The following example (Table 3.2) illustrates the calculation. For simplicity we are ignoring any interest earned or owed on the ERAM balancing account, though in reality that would be included.

Consider the data in Table 3.2, Year 1, which continues the simple utility illustrated in Figure 3.1. The first entry, \$300 million, represents the utility’s assets that are “*rate based*” (this is a very small utility). The public utilities commission (PUC) allows these assets to earn a rate of return, in this case 10%/yr (Line 3, \$30 million/yr). Line 4 shows forecasted kWh sales for the year, 1 billion kWh for Year 1. Multiplying forecasted sales by the (non-fuel) operational costs (Line 5, 0.01US\$/kWh) gives revenue requirements for non-fuel related operational costs (Line 6, \$10 million). Line 7 shows total authorized rate-based revenues (\$30 million return on investment + \$10 million operational costs = \$40 million). Authorized base rate revenues are then adjusted by any amount in the ERAM balancing account from the previous year (in year 1 this is $0), giving total authorized revenues (Line 9, $40 million). Dividing total authorized revenues by forecasted kWh sales gives the effective base-rate that the utility can charge its customers that year ($40 million ÷ 1 billion kWh = $0.04/kWh shown on Line 10).

Table 3.2. Illustrating decoupling using ERAM
(see Marnay and Comnes in Regulatory Incentives for DSM, ACEEE, 1992, for more detail).

CALIFORNIA ERAM EXAMPLE					
(not including interest on ERAM account)	YEAR 1	YEAR 2	YEAR 3		NOTES
(1) Rate Base ($ million = $M)	$ 300	$ 300	$ 300		
(2) Authorized rate of return	10%	10%	10%		
(3) Amortized rate-based revenue ($M)	$ 30	$ 30	$ 30		(1) x (2)
(4) Forecasted sales (million kWh)	1000	1100	1000		
(5) Operating costs (US$/kWh)	0.01	0.01	0.01		
(6) Forecasted non-fuel costs ($M)	$ 10	$ 11	$ 10		(4) x (5) ÷ 100
(7) Authorized base-rate revenue ($M)	$ 40	$ 41	$ 40		(3) + (6)
(8) ERAM Balance from previous year	$ 0	$ 4	$ -3.4		prev (13)
(9) Total authorized revenue ($M)	$ 40	$ 37	$ 43.4		(7) - (8)
(10) Effective Base Rate (US$/kWh)	0.0400	0.0336	0.0434		(9) x 100 ÷ (4)
(11) Actual Sales (million kWh)	1100	1000	1100		
(12) Revenues collected ($M)	$ 44	$ 33.6	$ 47.7		(10) x (11) ÷ 100
(13) Extra revenue collected ($M): goes into next year's ERAM balance (Line 8)	$ 4.0	$ -3.4	$ 4.3		(12) - (9)

In year 1, actual sales (1.1 billion kWh, Line 11) are above the forecasted sales (1.0 billion kWh, Line 4) so the utility collects an extra $4 million ($44 M - $40 M = $4 M, Line 13) beyond its authorized $40 million. That extra revenue collected goes into an interest bearing ERAM balancing account, to be returned (if positive), or collected (if negative) in the following year (Line 8). In this example, the effect of interest on the ERAM account has been neglected.

In this example, Year 1's actual kWh sales are greater than forecasted sales, thereby yielding extra revenues which are returned in Year 2. In Year 2, actual kWh sales are less than forecasted, and not enough revenues are collected. That deficit in revenue from Year 2 is collected in Year 3, and so on. The overall effect of ERAM is thus the removal of incentives to sell more kWh, and the removal of disincentives to conserve kWh.

Let us close this section on decoupling with a few final comments. While ERAM has been well accepted in California, it is not the only method of decoupling (see, for example, the description of Revenue-per-Customer decoupling in Moskovitz and Swofford). Also, while decoupling is a necessary condition for DSM by reducing the utility's bias against conservation, neither does ERAM reward the utility for investing in energy efficiency; the utility can still only make money by selling kWh. For a utility to be truly interested in DSM, more than just ERAM is generally necessary: the utility must be able to make a profit on its investment in DSM, just as the utility can profit from its supply-side investments. Lastly, there is a potential down-side to ERAM: if ERAM ensures that the utility earns the same sum of money regardless of kWh sales or any other performance benchmark, then the utility may lose its incentive to operate in a way which maximizes performance or customer value. The key with decoupling is therefore to reduce the utility's bias against conservation while still providing incentive mechanisms to ensure that the utility is well-run and provides value to its customers.

C.2. Recovering Program Costs: Ratebasing vs. Expensing of DSM Costs

There are two methods for utilities to recover supply-side or demand-side program costs: they can be *expensed* , or *ratebased*. Costs that are expensed are recovered in the year in which the expenditure is made. Costs that are ratebased are recovered over time, with a rate of return (i.e., profit). Utility investments in generation, transmission, and distribution systems are generally ratebased, while DSM costs have tended to be expensed.

There are a number of reasons why ratebasing DSM costs, rather than expensing them, is often considered desirable by the energy conservation community (see, for example, Reid 1992).

1. Costs that are ratebased earn profits for the utility through an authorized rate of return on investment. As shown in Table 3.1, these rates of return may be in the 6-12% (real) range. Expensed items do not obtain this profit level. The costs of expensed items are simply passed on to customers with no markup. Therefore, if DSM costs are expensed, then utilities are unable to earn a profit on these DSM activities.

2. Since the full costs of an expensed item are recovered in the year in which they are incurred, there may be sudden, and irregular annual increases in utility rates charged to their customers. This "rate shock" may tend to discourage large DSM expenditures. When costs are amortized over time, rates change more slowly, which reduces customer complaints and decreases the likelihood that large customers will withdraw from the utility system.

3. As utility generation, transmission, and distribution investments are depreciated over time, their book value declines. This causes a reduction in the remaining rate base of the utility, which has negative psychological implications for investors, who would rather see a utility's rate base grow than decline. If investor confidence erodes, the market value of the utility's stock shares may decline, and the cost of capital may increase. Thus, if DSM is treated as an annual expense rather than being put into the rate base, a regulated utility must build more production capacity in order to maintain rate-base growth and attract investors.

C.3. DSM Incentives

By decoupling utility revenues from sales, and by ratebasing DSM expenditures, supply-side and demand-side investments can compete on a more equal basis. It can be argued that DSM needs more than that, however, if it is to fulfill its potential of delivering energy services at the lowest cost. For example, as shown in Figure 3.3, California utility expenditures in electricity conservation got off to a good start in the early 1980s after ERAM decoupling commenced; but without further DSM incentives, it took only a few years before utility management apparently lost interest and expenditures began to rapidly decline. (A new nuclear power plant coming on line in those years must also have contributed to diminished utility interest in DSM.)

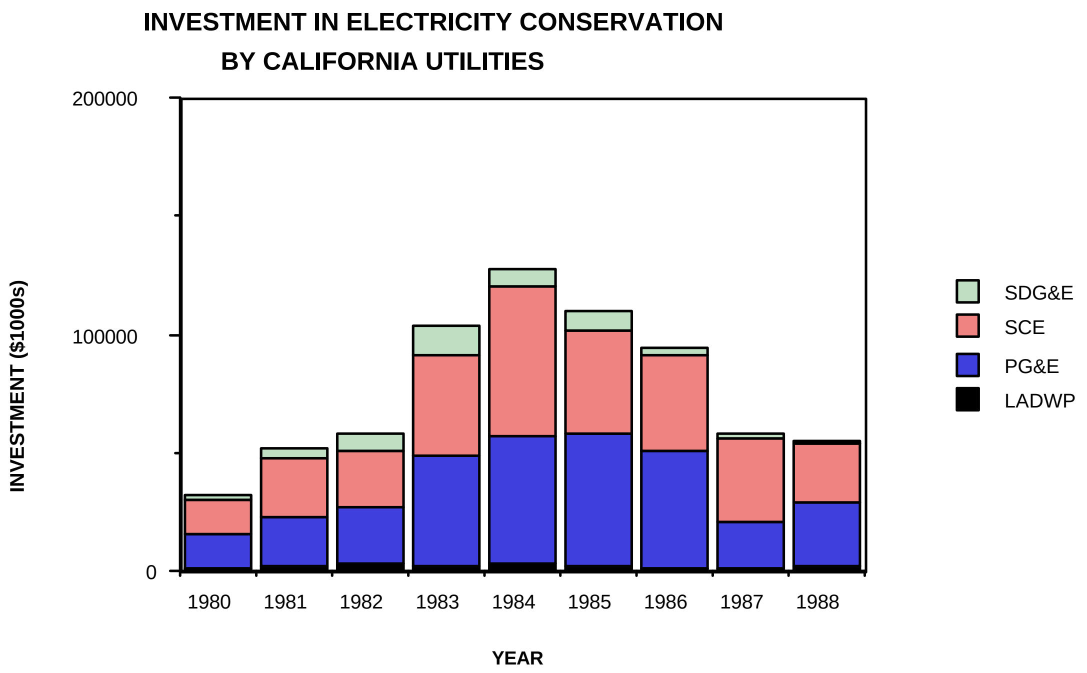


Figure 3.3. Without DSM incentives, utility expenditures in electricity conservation declined dramatically in the late 1980s. (Calwell and Cavanagh, 1989)

Figure 3.3 shows clearly the decline of utility interest in DSM in the late 1980s. ERAM decoupling was in place, but without DSM incentives, utilities were heading back toward supply-side, business-as-usual, thinking. All that changed in California in 1990, with DSM activity heading back up again. Pacific Gas & Electric (PG&E) alone, for example, spent roughly $200 million per year on DSM in 1993, which is four times as much as it spent in 1984 (the peak year in the 1980s), and seven times as much as it spent in 1988. And then, after a burst of DSM activities in the early 1990s, the pattern of DSM activity has again begun to repeat the decline of the late 1980s. What happened? Why the sudden interest in DSM? And why has this interest deteriorated again in the mid-1990s?

C.4. The California Collaborative and Further Restructuring

Citing evidence of the decline in utility interest in conservation, such as that shown in Figure 3.3, environmental advocacy groups convinced the California Public Utilities Commission (CPUC) to hold a special hearing in 1989 on the future of DSM in California. The hearing resulted in the creation of the *California Collaborative* consisting of representatives from fifteen utilities, major industries, regulatory agencies, consumer interests, and environmental organizations. The collaborative was challenged by the CPUC to come up with a detailed plan that would expand utility DSM programs by creating specific and detailed performance-based incentives. The collaborative process itself was as extraordinary as the resulting programs that it created. Rather than fighting each other in adversarial proceedings, this diverse group of institutions and individuals used a collaborative process that led to consensus on a number of important, key issues. The Collaborative produced a report in 1990 called *An Energy Efficiency Blueprint for California* that led in 1990 and 1991 to the CPUC's approval of an array of utility Customer Energy Efficiency (CEE) incentives. As a result of this, utilities could provide financial incentives to customers to pursue energy efficiency and were authorized to earn handsome profits through this process.

After CEE incentives were introduced, California utility conservation practices changed dramatically. For example, PG&E's earlier policy of advocating energy consumption growth was totally transformed, so that their 1991 Annual Report reported that "PG&E (has) established a major corporate goal...to improve the environment by leading efforts to increase energy efficiency..." Moreover, they went on to state that PG&E had actually added $45 million to their earnings by encouraging their customers to use less energy. Their 1992 Annual Report went on to characterize their business strategy as "...emphasizes meeting growth in electric demand through improved customer energy efficiency (CEE) and renewables. Efficiency is the most cost-effective way to meet our customers' growing electric needs..." This aggressive energy conservation policy led to increased financial strength for the utility. Earnings per share were up 15% in 1992 compared with 1991. The way in which PG&E was able to increase its profits through DSM is described in Section C.5 below.

Energy efficiency had become mainstream in California. In *The 1992-93 California Energy Plan*, for example, Governor Pete Wilson challenged the CPUC to ensure that "at least" three-fourths of California's needs for new electricity supply by 2001 should come from improvements in energy efficiency. In February 1993, another CPUC hearing was held to ascertain how well DSM programs were working. Representatives from every investor-owned utility in California spoke with enthusiasm about their programs. The hearing recommended that the CPUC "stay the course."

Then, in April 1994, the CPUC changed direction completely. The Commission proposed a restructuring plan, which was largely adopted in December 1995, to pursue lower electricity rates in the state based on competitive market principles. The plan included instituting open access to power supply services, at both the wholesale and retail levels, and the functional separation or "unbundling" of the generation, transmission and distribution operations of the vertically-integrated utilities. The CPUC decision will consolidate the operation of the state's transmission network in an independent system (or grid) operator (ISO). The ISO will be responsible for operating the network, purchasing network support services, and creating information necessary for the financial market to both hedge price risks and to trade available transmission capacity.

The CPUC expects that competitive pressures will drive electricity suppliers to reduce their rates in order to retain existing customers and attract new ones to take long-term contracts. Moreover, the CPUC does not intend for utilities to pursue energy-efficiency activities that it believes the competitive market could provide. Unfortunately, DSM will be discouraged by both the rate-minimizing strategy driven by retail competition, and by the sales-maximizing strategy driven by the need to cover fixed costs. The result of electric industry restructuring in other countries has also typically been to reduce investment in DSM.

The CPUC restructuring decision recommends a two-track approach to DSM, such that customer-specific energy efficiency projects would not receive funding from ratepayers, but would instead rely on "market-driven" funding mechanisms (Track 1), with continued funding for activities designed to transform the energy efficiency market and that would not naturally be provided by a competitive market (Track 2). There would be a non-bypassable surcharge applied to all retail electric bills to fund such energy efficiency activities. The utilities' reaction has been to curtail many of their DSM programs.

However, though electric industry restructuring has, at least in the short term, reduced utility DSM activity, it is by no means clear that restructuring will necessarily reduce energy efficiency activity in the long run. In the new competitive market place, it is envisioned that energy efficiency services will be one of the competitive strategies used by utilities and other energy service providers to distinguish their services from other competitors and to thus retain customers. In addition, even in the competitive retail environment, distribution utilities will still find that in distribution-constrained areas, it can be more cost-effective for utilities to encourage demand reduction than to invest in additional distribution substation capacity.

The long-term impacts of restructuring on energy-efficiency in the U.S. will continue to unfold for many years and are impossible to predict at this time. Other countries will face very different changes depending on the types of electric industry restructuring being undertaken. Nevertheless, DSM programs are still continuing in the U.S. and continue to offer many lessons for what can be achieved in developing countries as well.

Let us look now at the mechanism which was adopted by Pacific Gas & Electric to allow them to profit from DSM investments and which led to PG&E’s significant increase in DSM activity in the early 1990s.

C.5. PG&E’s Shared Savings Program

Interestingly, California’s utilities have not all chosen the same types of incentives for receiving compensation for DSM activities. While there are a number of different approaches being taken by utilities across the country, one of the most popular mechanisms is based on tying the utility’s earnings incentive to the amount of money actually being saved by conservation. Commonly known as *shared savings* programs (because the utility and the ratepayers share the benefits of saving energy through the utility’s DSM investment) such mechanisms are being used by PG&E and San Diego Gas and Electric in California, and in New England by Narragansett Electric in Rhode Island and Granite State Electric in New Hampshire, among others. To keep this section concise, we shall focus on PG&E’s shared-savings approach as our main example. For other examples, and more detailed explanations, the 1992 book *Regulatory Incentives for Demand-Side Management*, by the American Council for an Energy-Efficient Economy (ACEEE) is an invaluable reference.

Utility shared-savings programs are based on the following simple equation:

Net Savings ($) = Avoided Cost ($) - Program Cost ($) *[Eq. 3.1]*

where:

Avoided Cost ($) = Load Reduction (kW or kWh) x Avoided Supply Cost ($/kW or $/kWh), *[Eq. 3.2]*

and

Program Cost = Utility Efficiency Program Cost (administration, rebates, etc.) *[Eq. 3.3]*

In PG&E’s shared savings program, only the money spent by the utility itself is included in the Program Cost, i.e., they use the utility cost test (see Chapter 2) for defining Program Cost.

Some utilities, however, use the total resource cost (TRC), which includes the money that the customer spends on conservation.

In PG&E's shared savings program, the utility's shareholders are allowed to keep 15% of the Net Savings as their incentive to invest in DSM *provided that certain targets for energy savings are exceeded*. The remaining 85% of the Net Savings benefit the ratepayers as a whole through reduced costs of utility energy generation (see Chapter 4 for a more detailed discussion of utility supply costs). Ratepayers who take advantage of the rebate also save on their electric bills since they are using less electricity. Figure 3.4 illustrates these concepts. Here, a hypothetical DSM program successfully avoids $200 million of investment in energy supply through an investment of $100 million in DSM. Therefore, the DSM program yields a net savings of $100 million, of which the ratepayers receive $85 million in lower electricity bills, and utility shareholders receive $15 million.

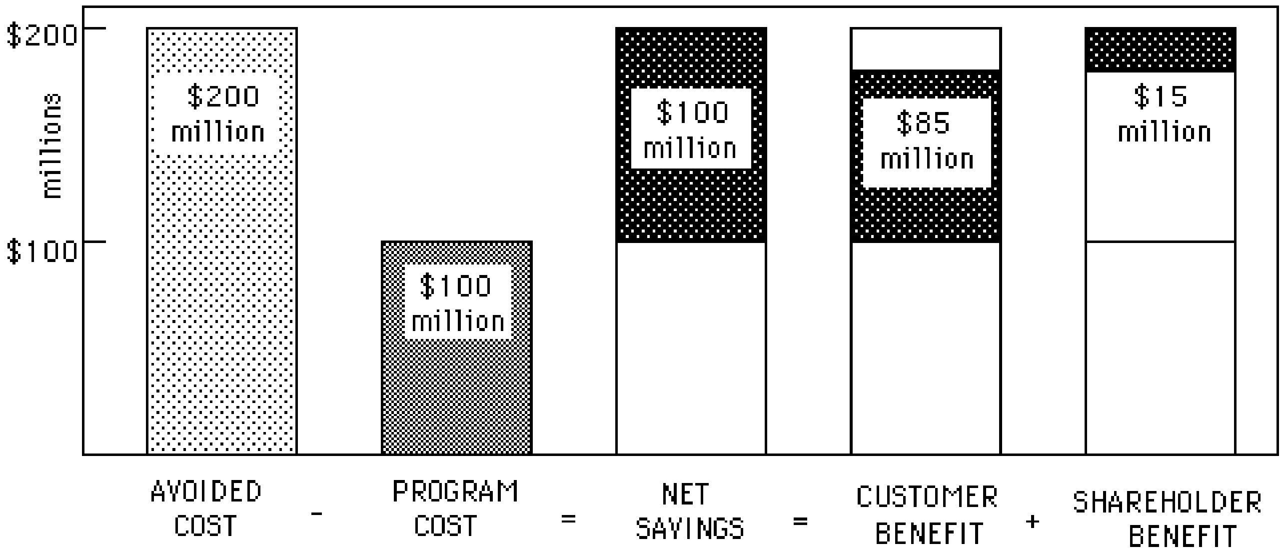


Figure 3.4. Illustrating PG&E's shared savings approach, which allows 15% of net savings to be given to shareholders.

While PG&E stockholders reap a 15% reward for conservation that exceeds a pre-established performance threshold, there is also a 15% *penalty* that is applied to the shortfall if savings drop below a separate minimum threshold. Performance is measured by program participation, not by program energy savings.

Example:

> Suppose PG&E offers a $5 rebate on 18-watt compact fluorescent lightbulbs (CFLs) that produce as much light as 75-watt incandescent bulbs, and which last 10,000 hours. Suppose it costs PG&E an additional $1 per CFL to administer the program. Also suppose PG&E's (avoided) marginal cost of electricity is 0.04US$/kWh.
>
> Find the allowed earnings for PG&E's shareholders if 1 million customers take advantage of the rebate.

The Avoided Cost to PG&E would be:

$$(75 - 18) \text{ watts/CFL} \cdot 10{,}000 \text{ hrs} \cdot 0.04\$/\text{kWh} \cdot 1 \times 10^6 \text{ CFLs} \cdot 10^{-3} \text{ kW/W} = \$22.8 \text{ million}$$

The Program Cost would be (\$5 + \$1)/CFL · 1 x 10^6 CFLs = \$6 million

The Net Savings would be \$22.8 - \$6 million = \$16.8 million

The Shareholder Benefit would be 15% · \$16.8 million = \$2.52 million

Net Savings to ratepayers would be 85% · \$16.8 million = \$14.28 million

It is interesting to note that PG&E expenses its Program Costs, rather than ratebasing them. This allows immediate cost recovery, which helps assure the utility that they will get their money back even if the PUC suddenly changes its mind about DSM (which now seems to have happened). As mentioned earlier, however, ratebasing is often thought to be a more attractive method of cost recovery, assuming a stable regulatory climate, since a rate of return on the investment would be earned. In the above example, however, one could certainly argue that a \$2.52 million benefit to shareholders generated from a \$6 million investment is plenty of reward even without ratebasing of program costs.

Total Resource and Societal Cost

Another way to illustrate the advantage of DSM is from the perspective of society as a whole (see Chapter 2). For example, we can write the following relationships:

Total Resource Cost = Program Costs + Customer Costs *[Eq. 3.4]*

and

Net Benefit = Avoided Cost - Total Resource Cost *[Eq. 3.5]*

Example:

Continue the PG&E Shared Savings CFL example above to find the net benefit to society of this program. Assume that compact fluorescents cost \$15 at the local hardware store (\$10 after the rebate).

The cost to the utility and its customers is (again, assuming 1 million CFLs are purchased):

Total Resource Cost = Program Cost + Customer Cost
= \$6 million + \$2.52 million + 10^6 CFLs · (\$15 - \$5) = \$18.52 million

And, the benefit to society is:

Net Benefit = Avoided Cost - Total Resource Cost
= \$22.8 million - \$18.52 million = \$4.28 million

Societal cost in some calculations includes an added component for environmental benefits of reducing energy consumption. That is, externalities could (should) be included in the cost of each energy option under consideration (see Chapter 2).

$$Societal\ Cost = Total\ Resource\ Cost + External\ Cost \qquad [Eq.\ 3.6]$$

Further reading:

Nadel S., M. W. Reed, D. R. Wolcott, 1994 (eds). Regulatory Incentives for Demand-Side Management. ACEEE, Washington DC.

D. Renewables and Energy Substitution Programs

D.1. Electricity vs. Gas

One option for saving primary energy and reducing costs and emissions is fuel switching on the demand-side, by changing from electric end-uses to other fuels such as gas, or vice versa. The primary energy savings and emission benefits of fuel switching depend on a number of factors, including the fuel and heat rate (efficiency) of the marginal unit of electricity production, the efficiency of the gas end-use technology, and the efficiency or coefficient of performance (COP) of the electric end-use technology. In regions that have a strong reliance on coal as a utility fuel, switching from electricity to gas can often reduce total emissions of CO_2 and SO_2, among others.

We can analyze the relative performance of gas and electric end-uses according to their annual energy use, emissions and costs:

$$E = Load / Eff \qquad [Eq.\ 3.7]$$

$$ER = E \cdot \Delta ER/\Delta E = Load / Eff \cdot \Delta ER/\Delta E \qquad [Eq.\ 3.8]$$

$$AC = C_{cap} \cdot crf + E \cdot C_{fuel} \qquad [Eq.\ 3.9]$$

where:
E = annual energy use (MWh/yr),
Load = annual useful energy load (MWh/yr),
Eff = efficiency of end-use technology,
ER = annual emission rate (ton/yr),
DER/DE = emission intensity of fuel or electricity (ton/MWh),
AC = annual cost of service ($/yr),
C_{cap} = capital cost of end-use technology ($),
crf = capital recovery factor (yr^{-1}),
C_{fuel} = unit cost of fuel or electricity ($/MWh).

Example:

Compare the energy use, carbon emissions, and costs of switching from electric to gas-fired water heating in houses with the following characteristics. A customer's useful energy need for water heating is 3.5 MWh per year. The electric heater is 90% efficient and costs $200, while the gas unit is 65% efficient and costs $400. For the utility, the marginal electric supply for a year-round use such as water heating produces 0.18 tons of carbon per MWh. Gas-fired end-uses, on the other hand, produce 14 kg-carbon per GJ, or 0.05 tC/MWh equivalent. Gas costs \$5/GJ, or \$18/MWh, and electricity costs \$65/MWh.

The lifetime of both heaters is 15 years and the discount rate is 6 percent, which gives a crf of 0.10.

For the gas-fired heater:
E_{gas} = 3.5 MWh/yr ÷ 0.65 efficiency = 5.4 MWh/yr
ER_{gas} = 5.4 MWh/yr · 0.05 tC/MWh = 0.27 tC/yr
AC_{gas} = (\$400 · 0.10/yr) + (5.4 MWh/yr · \$18/MWh) = \$137/yr

For the electric heater:
$E_{electric}$ = 3.5 MWh/yr ÷ 0.9 efficiency = 3.9 MWh/yr
$ER_{electric}$ = 3.9 MWh/yr · 0.18 tC/MWh = 0.70 tC/yr
$AC_{electric}$ = (\$200 · 0.10/yr) + (3.9 MWh/yr · \$65/MWh) = \$273/yr

Thus, the annual cost savings are 273-137 = \$136, and the annual emissions savings are 0.70-0.27 = 0.43 tC, for switching from electric to gas water heaters. If electricity has a primary energy value of three units (i.e., the conversion efficiency from primary fuel to electricity is 33%) compared to gas, then the primary energy savings are 3(3.9 MWh/yr) - 5.4 MWh/yr = 6.3 MWh per year. Normalized according to the reduction in electricity use, the emission savings are 0.43tC/yr ÷ 3.9 MWh/yr = 0.11 tC/MWh. Excluding the cost of purchased electricity, the cost of saved electricity is [(\$400 · 0.10/yr) + (5.4 MWh/yr · \$18/MWh) - (\$200 · 0.10/yr)] ÷ 3.9 MWh/yr = \$30/MWh.[3] This value is much less than the price of electricity (\$65/MWh), and probably less than the long-run marginal cost of production (\$30/MWh might be close to the short-run marginal cost).

The following exercise will provide you with practice in performing similar calculations for an electric heat pump water heater, which uses the refrigeration cycle to heat water by extracting heat from the ambient air.

Exercise 3.7) The above example showed the benefits of switching from electric resistance to gas-fired water heating. Electric heat pumps, on the other hand, can achieve high enough efficiencies to out-perform gas technologies in some cases. If a heat pump water heater has an electric end-use efficiency of 2.1, a capital cost of \$900, and a lifetime of 15 years, analyze the energy, emissions, and cost performance of a heat pump water heater compared to the gas-fired replacement considered above in the same utility service territory.

D.2. Electricity vs. Solar

Despite the presence of sunlight in all areas of the earth, the use of solar energy is most viable in the low latitude regions, between the tropics of Cancer and Capricorn. The substitution of electricity with solar energy can be done for some specific end-uses. Lighting, space heating and water heating are the most important end-uses that show cost-effective opportunities to substitute solar energy for electricity.

[3] The cost of saved energy is the sum of net annualized capital costs of the efficiency measure and its net increase in operating costs (can be negative), divided by the annual energy savings (see Appendix 3). In a fuel switching program, the energy cost of the energy carrier being "saved" (electricity in this case) is not included in the cost-of-saved-energy calculation, but the energy cost of the energy carrier being switched to (i.e., gas in this case) is included.

Of course, it is necessary to analyze each particular case to determine the costs and benefits of replacing electricity. Though solar energy is essentially free once the equipment to harness the energy is in place, the high initial capital costs of solar equipment often mean that solar energy is not cost-effective in spite of its low operating cost. Careful analysis is therefore essential.

Daylighting is one way to improve building design and materials in order to introduce more solar light into rooms, thus saving electricity. Good architecture can also take advantage of sunlight to bring more heat into buildings in cold climates.

Solar water heating can often be attractive, particularly in tropical countries with high insolation levels. The following exercise examines the cost-effectiveness of replacing an electric water heating system with solar.

Exercise 3.8) Calculate the cost-effectiveness (benefit/cost ratios) for the utility and for the customer of replacing an electric water heater with a solar water pre-heater considering the equipment characteristics below, an electric transmission and distribution loss rate of 15%, and the following discount rates: a) utility discount rate = 12%; b) customer discount rate = 35%. The marginal cost of electricity production for the utility is $0.07/kWh, and the average tariff charged to the customer is $0.09/kWh.

	Electric Water Heating	**Solar Water Pre-Heating**
Life (years)	20	20
Installed Cost (US$)	141	433
Average consumption (kWh/year)	632.0	126.4

Further reading:

Scientific American, Special Issue: Energy for Planet Earth, Sep. 1990, Vol. 263, No. 3.

Energy Technology - Sources, Systems and Frontier Conversion. Tokio Ohta. Pergamon, 1994.

Solar Power Plants - Fundamentals, Technology, Systems, Economics. C.-J. Winter, R. L. Sizmann, L.L. Vant-Hull (Eds.). Springer-Verlag, 1991.

Renewable Energy, T. Johansson, H. Kelly, A. Reddy, R. Williams (Eds.). Island Press, 1992.

D.3. Cogeneration

Cogeneration refers to processes for the combined production of heat and power[4], which allows the sequential use of the energy released from combustion of a fuel. Cogeneration can be used in systems where the primary movers are steam turbines, gas turbines, and internal combustion engines.

From an energy perspective, the attraction of cogeneration is the potentially high overall conversion efficiency, on the order of 75-90%, much higher than can be achieved by independent systems for heat and power. In this sense, cogeneration can be considered an

[4] Combined heat and power (CHP) is the more common term used in Europe for cogeneration technology.

energy-efficiency technology. From the perspective of the electricity system, cogeneration in the industrial and commercial sectors is an option for decentralized electric generation.

Cogeneration has been widely known and used since the beginning of this century. It was utilized at the beginning of industrial electrification, especially in the energy-intensive industries, as a way to meet industries' dual need for both electricity and heat, mostly in the form of steam. Over time, until the mid-1970s, cogeneration decreased in importance, along with most other decentralized sources of electricity, to an extent dependent on the particular conditions in each country.

Cogeneration regained importance during the 1980s with the deregulation of the power-sector in a number of countries and the adoption of policies for the long-term rationalization of energy use. Today cogeneration is a priority in the context of energy policies that aim to minimize environmental impacts.

Cogeneration is a process of energy conversion that varies in terms of:

- the forms of energy available: electricity or mechanical power, process steam or absorption cooling,
- whether electric power is consumed by the cogenerating firm or sold to other consumers via the electricity grid,
- whether the cogeneration system is owned by a power consumer, an independent power producer or a utility,
- the scale of the system: from a few kW to many MW.

The same principle of combined production of heat and power can be applied in three different concepts. The first concept is associated with the operation of thermal power stations, where the heat rejected from the thermodynamic power cycle is recovered and used in the form of a heat flow, such as for space heating. Such cogeneration plants sometimes sell low-pressure steam to industrial plants.

In this first concept, the amount of heat produced is significant and may partly or completely meet the heating needs of neighboring communities. This type of cogeneration system is referred to as a thermal network or district heating. Another form of district heating can be found in waste incineration facilities, also using the waste heat from incineration to provide heat to the community..

There are many district heating systems in Europe, especially in Eastern Europe, Germany, Austria and Scandinavia. The pattern of post-war reconstruction, climate conditions, state action in infrastructure planning, and the practice of decentralization with greater autonomy for local communities, are factors that explain the importance of this form of cogeneration. District heating facilities are generally developed and operated under strong influence by the public sector.

The second concept for implementation of cogeneration is in industrial plants. The power produced can meet part or all of the plant's internal needs, and any surplus power can be sold to the local utility grid. The thermal energy flows are used as process heat.

The technical and economic feasibility of cogeneration in industrial plants is improved if the thermal energy demand is relatively large and constant. Such conditions are prevalent in the chemical industry, oil refineries, large-scale steel and other metallurgical plants, pulp and paper mills, and large food-processing plants. Cogeneration is also attractive in processes that produce a by-product that can be used for fuel. Two examples are pulp mills, which burn the black liquor, and sugar mills, which use the bagasse.

The third concept is cogeneration in the commercial sector. Because all of a commercial building's heat and power demand is met by one integrated system, such configurations are called "integrated energy systems" or "total energy systems." Of the three cogeneration concepts, this one is the most recently developed, both from the market perspective as well as in terms of the technology itself.

As in the case of industrial cogeneration, the amount of power produced in a commercial building's cogeneration system can be less than, equal to, or greater than the local demand. The heat obtained from the system is generally used for heating large volumes of water destined for a variety of uses, including absorption cooling. Integrated energy systems are found in schools, universities, hotels, hospitals, multifamily housing, recreation centers, research centers, supermarkets, banks, and waste-treatment facilities.

The limitations of cogeneration technology in the commercial sector are associated with inherent sectional characteristics such as low power requirements, short hours of operation, and seasonal thermal loads. These aspects almost always result in a relatively fragile condition regarding economic feasibility. The economic viability of cogeneration in the commercial sector has been enhanced in some places by a reduction in investment costs through subsidies.

The development of cogeneration has been significant in two quite different cases, both associated to a certain degree with the decentralization of the energy system. The first case is in regions where district heating systems were important historically, and consequently where the technology of cogeneration fit naturally into existing local energy planning. Prominent examples of countries in this first group are Germany, Denmark, and Finland.

The second case is in countries where cogeneration never had a tradition, or fell from importance between 1950 and 1980, and where diverse problems associated with national and regional energy planning more recently allowed the return of cogeneration mainly in the industrial and commercial sectors. In the second group are the U.S., Italy, and Japan. It is interesting to note that the importance of cogeneration also varies in different countries between the three concepts. For example, in Germany cogeneration is important in industry and in district heating systems, while in Denmark it is only important with respect to district heating. In the U.S., where cogeneration had the largest recent "boom," cogeneration gained importance during the 1980s in the industrial sector and to a lesser extent in the commercial sector. In Italy, on the other hand, all three concepts have been valuable, but particularly in industry.

A fundamental question regarding cogeneration concerns the existence of mechanisms to provide economic leverage. Incentives usually take the form of tax credits, accelerated depreciation, and extension of favourable credit terms. A recent form of incentive has been direct or indirect government participation in the formation of investment societies.

Promotional organizations have also played an important role in carrying out pre-feasibility studies, preparing projects, and in dissemination of information regarding successfully implemented projects, as a marketing instrument.

The following section looks in greater detail at one particular type of cogeneration: district heating.

Further reading:

Brun, M.J., La Cogénération dans le Monde. Institut Français de L'Energie, Paris, 1989.

Horlock, J.H.. Cogeneration: Combined Heat and Power - Thermodynamics and Economics. Pergamon Press, 1987.

Hu, S.D.. Cogeneration, Reston Publishing Co., Reston, USA, 1985.

Marecki, J.. Combined Heat & Power: Generating Systems, Peter Peregrinus Ltd., London, U.K., 1988.

Orlando, J.A.. Cogeneration Planner's Handbook. Fairmont Press, 1991.

Payne, J.R.. Cogeneration in the Cane Sugar Industry, Elsevier, Amsterdam, 1991.

D.4. District Heating

District heating is the supply of thermal energy for space heating, water heating and process heating at multiple sites from a central source. It can be used in industry, commercial buildings, and both single-family and multifamily housing, although the most common application is for space and water heating in multifamily residential buildings. District heating is widely used in northern and eastern Europe, including the former USSR, and to a lesser extent in North America, Japan, and China.

One of the main requirements for feasibility of district heating is a high spatial density of population or heat demands, because the long-range transport of thermal energy tends to be expensive and inefficient compared to the transport of raw fuels or electricity. Although the lack of a space heating demand in most tropical countries limits the relevance of district heating, there too locations and applications do exist where it may be appropriate.

District heating is an alternative to the direct use of fuel or electricity for end-uses that require medium- to low-temperature heat, especially space heating. It is entirely feasible to produce the thermal energy for district heating via cogeneration, utilizing the waste heat from the production of electricity in thermal plants. Thus, district heating can be both competitive and complementary to electricity as an energy carrier.

To take an IRP perspective on the analysis of district heating, we must consider the technical performance and costs for both the central supplier and the customer. The analysis of the relative performance of electricity and district heat is similar to that provided earlier in Section D.1, Electricity vs. Gas:

$$AC = C_{cap} \cdot crf + E \cdot C_{fuel} \qquad [Eq.\ 3.7]$$

$$ER = E \cdot \Delta ER/\Delta E = Load\ /\ Eff \cdot \Delta ER/\Delta E \qquad [Eq.\ 3.8]$$

$$AC = C_{cap} \cdot crf + E \cdot C_{fuel} \qquad [Eq.\ 3.9]$$

where:
E = annual energy use (MWh/yr)
Load = annual useful energy load (MWh/yr)
Eff = efficiency of end-use technology
ER = annual emission rate (ton/yr)
DER/DE = emission intensity of electricity or heat source (ton/MWh)
AC = annual cost of service ($/yr)
C_{cap} = capital cost of end-use technology ($)
crf = capital recovery factor (yr^{-1})
C_{fuel} = unit cost of electricity or heat ($/MWh)

Example:

Calculate the annual energy use, carbon emissions, and costs of providing space heat via cogenerated district heating in houses with the following characteristics. A customer's useful energy need for space heating is 20 MWh per year. Heating equipment and connection to the district heating system cost $3000 per household, and the district heating system operates at 80% efficiency. The lifetime of the heating system is 24 years, and the discount rate is 6 percent, which gives a crf of 0.08.

The marginal electric supply produces 0.18 tC/MWh when it produces only electricity, and 0.20 tC/MWh of electricity when it is cogenerating. In the cogeneration mode, the ratio of electricity to heat production, α, is 2.

The operating cost of district heating is $12/MWh, based on the additional capital investment in the cogeneration plants (see below) and the heat distribution system.

In order to get the net emission rate for the district heat, we need to deduct the emissions that would result through electricity production alone from the total emissions of the cogeneration plant. This can be calculated as follows. In an electric-only mode, the plant would produce 0.18 tC while generating 1 MWh. In a cogeneration mode, the plant would continue to generate 1 MWh but would produce 0.20 tC. The additional 0.02 tC is being produced in order to generate 0.5 MWh of heat. Therefore, the emission rate of the heating process alone would be 0.02tC/0.5MWh or 0.04 tC/MWh.

Mathematically, this can be expressed as follows:

$$(\Delta ER/\Delta E)_{heat} \cdot E_{heat} + (\Delta ER/\Delta E)_{elec} \cdot E_{elec} = (\Delta ER/\Delta E)_{cogen} \cdot E_{elec} \qquad [Eq.\ 3.10]$$

or

$$(\Delta ER/\Delta E)_{heat} = \left[(\Delta ER/\Delta E)_{cogen} - (\Delta ER/\Delta E)_{elec}\right] \cdot \left(E_{elec} / E_{heat} \right) \qquad [Eq.\ 3.11]$$

so

$$(\Delta ER/\Delta E)_{heat} = \left[(\Delta ER/\Delta E)_{cogen} - (\Delta ER/\Delta E)_{elec}\right] \cdot a \qquad \textit{[Eq. 3.12]}$$

Therefore, $(DER/DE)_{heat}$ = (0.20 tC/MWh - 0.18 tC/MWh) · 2
= 0.04 tC/MWh

Then,

E_{heat} = 20 MWh/yr ÷ 0.8 efficiency = 25 MWh/yr = the annual heating energy consumed per household.

ER_{heat} = 25 MWh/yr · 0.04 tC/MWh = 1 tC/yr = annual carbon emissions per household from cogenerated district heat.

AC_{heat} = ($3000 · 0.08/yr) + (25 MWh/yr · $12/MWh) = $540/yr = annual cost per household for heating with cogenerated district heat.

Exercise 3.9) Compare the above results for cogenerated district heat with the following:

a.) Heating is provided through electric space heat at each individual household. The electric heating system costs $1000 per household for capital costs and has an operating cost of $65/MWh (the retail cost of electricity). The electric heating system has an end-use efficiency of 95%. In this case, the electric power plant is operating in a non-cogenerating mode and therefore emits 0.18 tC/MWh.

b.) Heating is provided through district heat which comes from a gas-fired dedicated heating plant (not cogenerated). Capital equipment costs and connection charges to the district heating system cost $3000 per household, and the operating cost of the system is $30/MWh. The district heating system has an efficiency of 80%, and the dedicated gas heat plant produces 14 kg of carbon per GJ, or 0.05 tC/MWh equivalent.

The lifetime of both the electric and dedicated gas district heating systems is 24 years, and the discount rate is 6 percent, which gives a CRF of 0.08.

E. Government Programs

Government agencies are capable of leading a variety of initiatives for implementing conservation or energy efficiency programs, as well as the introduction of renewable energy. These options include public information campaigns, labeling of energy equipment, standards for buildings and appliances, technology procurement, government sponsored RD&D (research, development and demonstration), and financial and fiscal mechanisms. Some of these options are highlighted in Table 3.3.

The types of programs described in the following sections are all options which have been implemented in different countries. The acceptability of programs will depend on several factors including economics, cultural norms, and current environmental or social values. Some programs must remain voluntary while others can be enforced through legislation, but all programs must be flexible and adaptable in their initial years.

Table 3.3. Examples of programmatic options for stimulating energy efficiency.

	Performance Standards	Technology Procurement	Demand-Side Management
Description	Regulation to prohibit sales of non-qualifying products and systems	Competitive solicitation for collective purchase of qualifying technology	Typically utility-run programs to improve customer energy-efficiency and load factor
Examples	US CAFE (corporate average fuel economy) & appliance standards, buildings standards in Sweden, etc.	Swedish (Nutek) *teknik upphandling*, US SERP ("golden carrot" super-efficient refrigerator program)	DSM programs in many US states and Canada, Brazil, Mexico, Thailand
Main agents	Government agencies	Government, utilities	Electric and gas utilities
End-use areas	Appliances, vehicles, lighting, building systems	Appliances, lamps, building components	Heating and cooling units, lighting, building systems
Product market status	Mature products	Proven prototype	Products with low share of market
Barriers reduced	Information, consumer criteria, seller risk	(Manufacturers') risk of product introduction	Information, consumer selection criteria
Costs	Administration, analysis, testing and compliance	Initial incentive, administration	Administration, on-going incentives (rebates, etc.)
Strengths	Clear, reliable, fair, often low administration cost	Low cost, stimulates business development	Flexible, include retrofits, can transform markets
Weaknesses	Does not stimulate new technology, can hurt competition	Slow, uncertain rate of product adoption	Costs, measurement, free riders, non-participants
Variations	Fleet standards, voluntary industry standards	Cooperative (Energy Star, Green Lights) programs	Producer incentives, energy-service companies

E.1. Information and Labeling

Information programs can be developed by government agencies or by energy companies. These programs have their main focus on disseminating information on energy conservation measures or more efficient technologies. Examples of information programs include ongoing appliance performance labeling programs in several countries. Evaluations have shown that information programs alone are generally insufficient to stimulate significant changes in technology, although they can complement and amplify other program approaches (Nadel et al 1994). The following can all be broadly classified as information programs:

- educational programs targeting schools at various levels,
- seminars and workshops for selected audience,
- training programs,
- public marketing (radio, TV, printed media),
- performance labeling of specific products
- dissemination through brochures and leaflets to a specific customer class.

The costs of these programs vary a great deal according to their geographical coverage and use of electronic media. The efficacy of these initiatives is also very debatable, especially with regards to their persistence. Even consumers who respond to the information program tend to return to their previous habits as energy efficiency loses its priority. Information programs work better when attached to other initiatives (such as pricing) and other programs such as rebates, energy audits, or performance standards and labeling, for example. Otherwise only the most innovative and proactive consumers tend to make the necessary investments in efficiency.

Some information programs have greater impacts and longer lasting effects. This is the case when energy efficiency issues are covered in the educational curricula of architects and engineers, for example. Information programs which are targeted to a specific audience and have the objective of giving technical and managerial information also tend to be more effective and long lasting. This is the case for large industrial and commercial customers. Most of them have an energy or utilities department within the corporation, and they can have a significant influence on the introduction of energy efficiency measures if this becomes a priority within their corporation.

Labeling is an activity usually done in cooperation with appliance manufacturers and consists of submitting their products to a set of performance tests to evaluate appliance energy efficiency. The labels are usually given by an independent organization (a government agency, laboratory, energy company, or an environmental NGO) that has the objective of informing the purchaser of the estimated annual energy consumption of a particular piece of equipment. Some labels include a scale that ranks the appliance in relation to others in the market. This allows the consumer to include energy performance as an additional criterion when deciding on the purchase of an appliance.

E.2. Standards and Regulation

Depending on the country a standard can be understood as a code, guideline, norm, law, protocol, recommendation, criterion, or rule. Standards can be introduced for new appliances, materials, and buildings. The main objective is to have a regulating system which ensures that these new products will have lower consumption levels than the ones they will be replacing over time. These standards can be voluntary during a certain period, and after that they tend to become compulsory.

There are many examples of successful introduction of energy standards (see Box 3.2). Standards are useful in situations where energy efficiency improvement cannot be achieved otherwise. Building energy standards are a good example of this because building designers and contractors are generally not the ones who will use the finished building and pay its utility bills. Although buildings have a long lifetime, energy maintenance costs are often considered irrelevant during the project design and construction phase because the builders and designers seek to minimize up-front costs.

Energy consumption testing and labeling of refrigerators were introduced in Brazil in 1987 by PROCEL (the Brazilian National Electricity Conservation Program). The results appeared shortly afterwards with a 10% improvement in most models sold. Some models with higher consumption changed their efficiency drastically in order to be more competitive with other similarly sized models. Other appliances are being included in the PROCEL labeling program such as freezers, electric showers and air conditioners.

US appliance energy-performance standards began with state-level standards in California and were first adopted at the national level in 1987, for application in 1990 to residential refrigerators, freezers, water heaters, furnaces and air-conditioners. The national standards were strengthened in 1993, and further tightening is being discussed. The standards have had a major impact, for example reducing the energy use of new refrigerators and freezers by as much as 60 percent at low cost to consumers, less than $0.03/kWh saved including administrative overhead (McMahon et al 1990). There is no evidence that these efficiency improvements would have occurred in the absence of the standards.

In addition, energy performance standards have been extended to some classes of lamps, motors, plumbing fixtures and air-conditioning equipment. Meanwhile, many US states and municipalities have adopted building energy standards, and California has a particularly sophisticated code that combines prescriptive measures with performance-based compliance options. Building codes that extend to lighting and air-handling efficiency are also used in several states including California and are being developed at the national level.

Elsewhere, Sweden has some of the strictest building thermal standards in the world, and as a result Swedish housing is among the most comfortable and energy-efficient despite the severe climate. Although Danish building energy-efficiency at one time lagged far behind that of Sweden, the strengthening of thermal standards and investments in building retrofits have made Danish buildings nearly comparable in energy efficiency to those in Sweden (Schipper and Johnson 1993).

An international survey identified approximately 30 countries that have mandatory building energy efficiency standards in place, and another 15 where such standards are presently proposed or voluntary (Janda and Busch 1994). Most of the mandatory standards are found in industrialized countries, although several developing countries, particularly in Southeast Asia, have at least proposed or voluntary standards. Many of the standards are derived from those developed in other countries, such as the US or Germany, and adapted to the local climate and building practice. The development of standards is generally hindered, especially in developing countries, by a lack of data on energy consumption and building practices, lack of compliance verification and enforcement procedures, and lack of performance testing and development facilities.

Other examples of energy-efficiency standards include the US Corporate Average Fuel Economy (CAFE) standards, which doubled automobile fuel efficiency in less than ten years. Most improvements were achieved through technical efficiency and design, with little reduction in interior space or safety (Ross 1989). These improvements are sometimes attributed to price increases during the 1970s, but it seems curious that the average fuel economy values exactly met the targets in most years. Statistical analysis of the manufacturers' fuel-economy progress shows that the CAFE standards were the primary cause for the improvements (Greene 1990).

Box 3.2. Examples of energy labeling and performance standards

There are two basic types of energy-efficiency standards: *prescriptive standards*, and *performance standards* . Prescriptive standards mandate that a certain technology or system configuration be used for a specified purpose. For example, a prescriptive standard might oblige the use of fluorescent lighting in lobby areas of commercial buildings (frequently on during the daytime). Performance standards require a certain level of overall energy performance for an appliance or building without specifying how this performance is to be achieved. For example, a performance standard could allow a maximum wattage of 10 W/m^2 for lighting in corridor areas of commercial buildings (see Table 3.4 for examples of actual lighting standards). In this case the project designer can choose between various technologies and daylighting. Generally, prescriptive standards are simpler and are used to govern the efficiency of various types of components and stand-alone equipment.

Performance standards are more flexible and are used to govern the overall system efficiency of, for example, a building or functional areas within a building. These standards are more complex and generally impose greater requirements for compliance and verification. Prescriptive component standards are also advantageous for improving the energy performance of equipment replacements in existing buildings and facilities (Atkinson et al 1993). In new buildings, however, system performance standards are appropriate to allow designers flexibility to exploit system interactions that provide better overall energy efficiency with lower cost and greater comfort than achieved by simply following component standards.

Table 3.4. Building energy codes: upper limits for installed lighting capacity in commercial buildings. Source: National Building Codes.

W/m^2	Indonesia	Jamaica
Offices	15	17
Classrooms	15	18
Auditoriums	25	-
Super Markets	20	-
Hotel Rooms	17	13
Common Areas	20	11
Hospitals (common areas)	15	19
Storage Places	5	3
Restaurants	10	14

The development of standards is a public process and should involve a number of professional organizations, industries' associations, and energy companies, as well as public agencies. It also requires the existence of certified laboratories that can periodically test the appliances being manufactured or imported. Other significant expenses incurred in this type of program include the development of test procedures for measuring efficiencies, technical analysis to provide an engineering and economic basis for the standard levels selected, administrative costs associated with public hearings, publication of laws and supporting technical documents, and general management of the program.

Stricter energy standards will imply additional costs to consumers as well. They will have to pay more for the acquisition of new appliances which incorporate the new features. These standards are set by government agencies together with manufacturers so that a time lag can be introduced and the market for these products can be created. A combination of other programs such as loans, rebates, and information can also be used in conjunction with the standards to create a market for these products and help minimize the impact on consumers' budgets. Can energy-efficiency standards be economically efficient, even though they impose additional regulations on consumer behavior? The high engineering benefit/cost ratios and low administrative costs of existing programs suggest that they can indeed. Engineering cost analysis of refrigerators and freezers in Scandinavia indicates that an energy-consumption level somewhat less than today's best-available models can be achieved with consumer life-cycle costs no higher than the average new model on the market today (Pedersen 1992).

The key advantage of standards is that they overcome information barriers in diffuse markets such as home appliances, and they reduce the risk to vendors of stocking and selling energy-efficient products. To the consumer, standards overcome the uncertainty and invisibility of energy efficiency improvements. To vendors, standards convey the essential information that yes, customers will buy efficient products. While such regulations suggest that consumer choice is reduced, in fact, there is just as much chance that producers will introduce additional models that surpass the standards, and this has been the case in the US.

It is difficult to evaluate the economic impact of mandating technically feasible higher efficiency levels beyond those achievable with available present models, but it is likely that both purchase price and life-cycle cost would increase, based on present engineering data. However, it is also quite possible that after more than 5-10 years of development, manufacturers would find less expensive ways to produce energy-efficient products than those presently available. Anecdotal results from the US suggest that the actual costs to manufacturers of complying with the 1993 appliance efficiency standards were less than estimated in engineering analyses supporting the development of the standards.

E.3. The Effects of Standards Over Time

Energy efficiency standards may be an effective way to remove energy-wasting products from the market and capture a large share of the least expensive energy-saving potential, but this will depend on how the stock of the particular technology changes over time.

Figure 3.5 illustrates the case of improving energy use in the refrigerator stock over time in Sweden. If mandated by standards, the efficiency levels of today's best models could be the norm as soon as 2002, many years before this level would be reached without policy intervention (Swisher 1994). These levels of efficiency are technically feasible, and their economic cost is not likely to be significant.

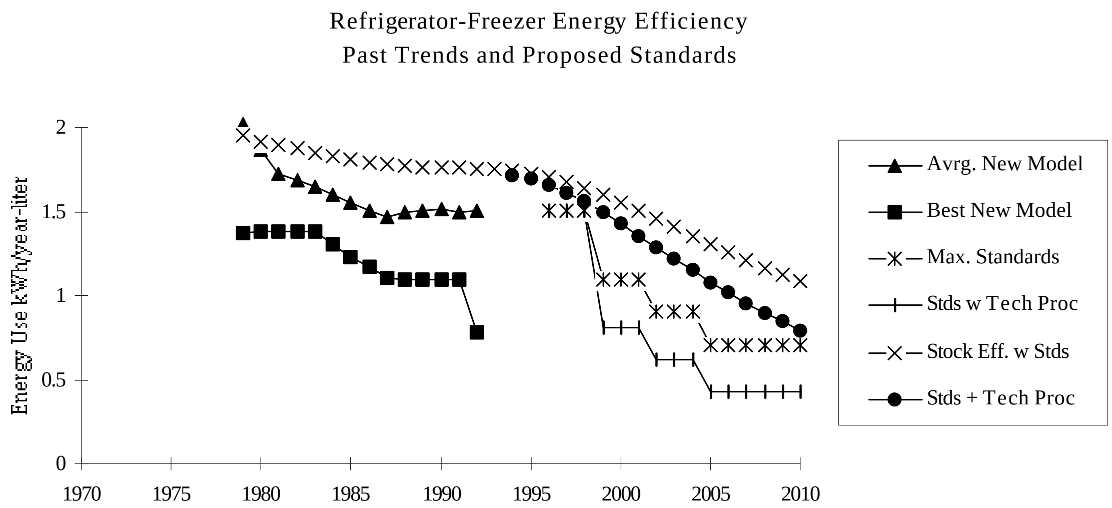


Figure 3.5. Historical trends and energy-efficiency standards analyzed for refrigerator-freezers in Sweden. Energy use is normalized per adjusted liter of refrigerator volume, with freezer volume counted as 2.1 units of refrigerator volume. Past trends show best-available, average new-model, and average stock efficiency. Average stock efficiency is projected into the future based on two sets of standards: with and without technology procurement (Swisher 1994).

Figure 3.5 highlights the dramatic improvements in performance levels that are achievable technologically, and such technology appears likely to be cost-effective. However, the average stock energy consumption will still not be reduced to very efficient levels until after 2010 because many less efficient models will still be in service in the meantime (see Figure

3.5). In other words, the rate of energy-efficiency improvement through standards is limited by the rate of turnover of existing equipment. It is also subject to market penetration constraints, as there is little incentive for appliance producers to develop and introduce new models with efficiencies greater than that required by the standards.

In developing countries, appliance penetration is much lower than in the Swedish example provided above. In such a case, the impact of stricter performance standards can be much more rapid. In other words, in a developed country with a large stock of existing equipment, rapid societal energy efficiency improvement would be achieved only through replacement of this existing stock; but in developing countries with small existing stock, significant societal efficiency improvements can be more readily achieved concentrating solely on new equipment.

Exercise 3.10) Suppose that in Brakimpur, there are only two types of refrigerators: Model A (800 kWh/yr; old model from the 1960s) and Model B (400 kWh/yr; a new model not yet introduced in the market). Consider that in the Base Year X there are 2,110,550 Model A refrigerators in use and that their lifetime is 25 years, after which they would have to be replaced by a new refrigerator. Every year there are 50,000 new households in Brakimpur that each add one additional new refrigerator to the market. The distribution by age of Model A refrigerators in use is indicated in the following table:

Model A Refrigerator Age (years)	**Percentage Distribution**	**Number of Refrigerators**
20-25	23%	485,427
15-20	23%	485,427
10-15	18%	379,899
5-10	18%	379,899
0-5	18%	379,899

The Model B refrigerator was developed as part of a governmental program to reduce energy consumption and will compete with Model A in the coming years. Model B is identical to Model A in all characteristics except for energy consumption.

You will have to consider the following factors when the new Model B is launched:

- 5% of users will spontaneously replace their Model A with Model B regardless of their refrigerator's current age;
- The substitution rate for the obsolete models, and the decision to purchase the new Model B, will depend on the efforts that you, as a government manager, dedicate to the DSM program. In other words you can choose the between the following two plans:
- Plan 1: high adoption rate for Model B (60%) resulting from high investments in advertising campaigns and subsidies;
- Plan 2: low adoption rate (30%) for Model B resulting from low investments in advertising campaigns and subsidies

For both Plan 1 and Plan 2, plot the number of refrigerators of each type and the annual total refrigerator electricity consumption over the next 25 years in Brakimpur.

E.4. Technology Procurement

Large organizations, especially government agencies, can help create a market for new efficient equipment by ordering in large quantities. These orders can specify performance standards, and several manufacturers can often be induced to meet these specifications based on the large potential order. Programs in which organizations commit to purchase a certain minimum number of products in exchange for manufacturers meeting stipulated performance criteria are known as technology procurement programs.

Technology procurement and related programs are appropriate when technologies are available but have yet to be introduced as commercial products. In such cases, the risks are high for producers introducing a new product without knowing if customers will buy it. Overcoming this type of risk is the most important effect of technology procurement programs. For products with clear cost-effective side-benefits such as power-managed computers that can be expected to “sell themselves” once introduced, an initial technology procurement program may be sufficient to ensure their successful long-term adoption in the market. Other products may need an additional mechanism to further increase their initial market penetration. This function can be achieved by standards as described earlier, or by other types of incentives such as those provided by utility DSM programs.

Sweden and the USA have both had significant success with technology procurement programs. Examples of these are provided in Box 3.3.

E.5. Financial and Fiscal Mechanisms

National banks can have special credit lines for loans dedicated to the purchase of energy efficiency products. In the case of Brazil, the National Development Bank has established special lines of credit to finance energy conservation projects. However, successful marketing is a critical component of such programs for ensuring consumer interest.

The United States has had some successes with special mortgage advantages for people buying energy-efficient residential homes. The federal housing lending markets of “Fannie Mae” (FNMA), “Freddie Mac” (FHLMC), and the Department of Housing and Urban Development have special provisions for underwriting qualifying energy efficient homes. In Phoenix Arizona, the key feature of the Salt River Project utility’s successful Climate Crafted Home Program has been the Home Stretch Mortgage, which uses the Fannie Mae and Freddie Mac provisions to allow home buyers to factor in their utility bill savings when qualifying for a home mortgage. The utility, which certifies homes built to certain levels of energy efficiency, has been able to stimulate consumer interest in energy efficiency not by touting the monthly savings which customers would see on their utility bills (which were not of great interest to the customers), but rather by appealing to customers’ desire to purchase more expensive homes and by helping them to qualify for such homes through energy efficiency (Barker 1993). Such programs require close cooperation with lenders and builders.

An innovative energy-efficiency policy intervention is public technology procurement (teknik upphandling), which has been developed in Sweden by NUTEK, the technology and industrial development ministry.

This process combines government incentives with guaranteed orders from organized buying groups (such as apartment managers) in a competitive solicitation for improved energy-efficient products (Westling 1991). Manufacturers are invited to enter prototype models with certain features, including a specified minimum energy efficiency, and the entries are judged according to their efficiency and how well they satisfy the other requirements (Nilsson 1992). The winner(s) receives incentive payments and a guaranteed initial order sufficient to begin production of the new model, thus removing a large part of the risk of introducing new energy-efficient models in their product line.

This process was successfully completed in 1991 for refrigerator-freezers, with the winning model's energy use 30 percent below the previous best available and 50 percent below the average in the market (Nilsson 1992). Although the winning model entered the market with nearly a 50 percent price premium, within one year the price premium was reduced to about 10 percent and a competing firm offered a new model with energy use comparable to the winner and a price close to other models on the market (Nutek 1993).

The procurement process has also been applied in Sweden to high-performance windows, high-frequency lighting ballasts, computer displays that turn off automatically, and most recently to washing machines tailored for use in small households. The winning window products have about three times the thermal resistance of conventional glazing products, and these improved products are now entering the market both in Europe and North America.

NUTEK has recently conducted a successful public technology procurement for automatic shut-off computer monitors (Lewald and Bowie 1993). There are large potential energy-efficiency improvements in computers and other office equipment that can be achieved at very low incremental cost. The automatic shut-off monitors and other energy-efficient office-equipment products are expected to gain a large market share in the next generations of office-equipment technology (Dandridge et al 1993), with energy savings of more than 50 percent compared to current equipment models. These savings can take place quickly because of the fast turnover of electronic equipment. The improvements are driven by the rapid technical advances in this area, leaving little need for additional programs to further accelerate the market penetration of efficient products once they have been introduced.

A similar US program, Energy Star by the Environmental Protection Agency (EPA), is expected to move the computer market from zero to nearly 100% power-managed desktop computers in 4 years, at essentially no cost. This voluntary program, which certifies power-managed computers and efficient peripheral equipment with the "Energy Star" label, nevertheless achieves efficiency improvements that would probably not have happened as soon without EPA involvement with the computer manufacturers.

The Energy Star program grew from the EPA's "Green Lights" program, a voluntary corporate lighting energy-efficiency program. Already hundreds of large commercial firms, representing several percent of the national commercial floorspace stock, have joined the program and committed to lighting energy-efficiency retrofits covering 90% of their floor area. The demand generated by this program should have a significant effect in terms of moving the lighting equipment industry in the direction of greater energy efficiency.

The Super Efficient, or "Golden Carrot," Refrigerator Program in the US is a variation on the Swedish technology procurement program. In this case, several large utilities created a pooled incentive, which was offered to manufacturers as the prize in a competition to develop a highly-efficient CFC-free refrigerator-freezer. The incentive will be paid as each unit of the winning model is delivered in the utilities' service areas. The program will also be expanded to clothes-washers and air-conditioners. The technical progress stimulated by this program might make it possible to further tighten the fridge-freezer energy-efficiency standards by 1998, a move that would probably not have been possible without the program.

The effect of technology procurement and related "technology push" approaches is to accelerate energy-efficiency gains by raising the performance of the high-efficiency end of the market, which serves to accelerate energy-saving potential earlier in time and is particularly effective in combination with energy performance standards. Standards eliminate the least efficient models from the market, but their energy-saving impact is limited by presently available technology because they cannot improve the high-efficiency end of the market. It is therefore possible that, without a "technology push" mechanism such as the technology procurement process, development of new products with further energy-efficiency improvements would not occur. The introduction of new models at the high-efficiency end of the market pulls the average efficiency upward, even without the imposition of energy efficiency standards, but their overall market impact can be amplified by presence of progressive standards to remove less efficient products (Swisher 1994).

Box 3.3. Examples of technology procurement programs.

Exercise 3.11) Explain the advantages of a Technology Procurement Program for a company that will introduce a new product in the market. What kind of information should the company consider in order to decide if a Technology Procurement Program will guarantee the success of its new product?

Exercise 3.12) What are the risks of a Technology Procurement Program?

F. Demand-Side Management (DSM) Strategies

Demand-Side Management programs involve a systematic effort to manage the timing or amount of electricity demanded by customers. DSM programs are developed and implemented within a certain geographical area, usually by the utility that serves the area, although in some countries government agencies have also taken action in DSM efforts. The first requirement of a DSM program is an assessment of the future evolution of the utility load profile and demand for energy, as covered in the end-use forecasting discussion in Chapter 2.

DSM strategies consider initiatives aiming to change the shape of the load curve or the total area under the load curve (the integral of the load curve gives the total energy consumed), or can be a combination of both goals. Figure 3.6 describes the classical DSM strategies. Electrical utilities can design programs combining two or more of the load shape strategies, modifying the load profiles of their customers and/or total energy demanded.

The situation presented in Figure 3.6A represents the objective of reducing the peak of the load curve. It can be achieved by raising tariffs during peak-hours, for example. Reducing the peak does not necessarily decrease overall energy consumption, as shown in Figure 3.6C. It is possible to shift certain amounts of energy consumed during peak-hours to other periods, for example using thermal energy storage.

Figures 3.6B and 3.6E illustrate the objective of increasing electricity sales. In the first case efforts are made to direct load growth toward specific periods, and the second case promotes general load growth. In some cases, increased electricity use can result from fuel-switching that reduces direct fuel use, so electric load growth does not necessarily (though usually) increase total primary energy consumption.

Figure 3.6F represents a situation where a utility has the possibility to create a flexible load curve that can accommodate customers’ demand and the utility’s operational characteristics. For example, in a hydroelectric system during the dry-season the utility is interested in reducing electricity demand, but during the wet-season it has the opposite situation. Direct load control is one technology used for this purpose.

Figure 3.6D presents the case where energy conservation, through improved end-use efficiency, is the main objective of the DSM effort.

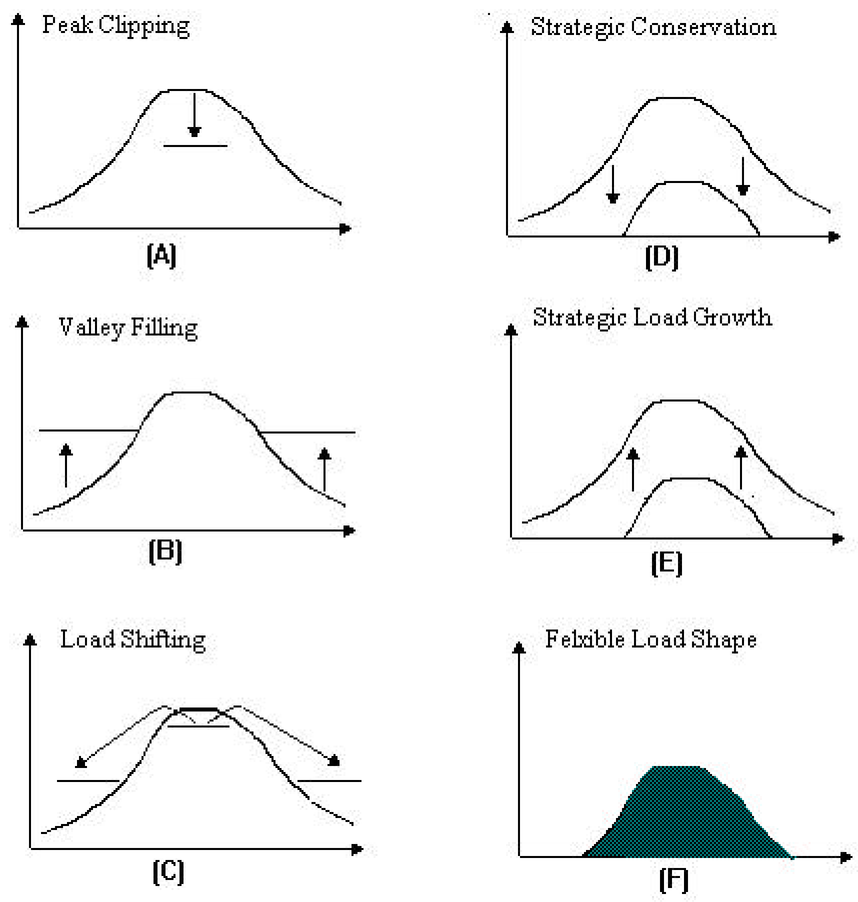


Figure 3.6. DSM load shape objectives (EPRI 1990)

F.1. Load Management

Load management programs include measures which aim to make better use of the existing installed electrical capacity, or to defer or obviate the need for new capacity. Therefore, the primary objective of load management is to modify the load profile, not to save energy. Load management is not meant to save the fuel used in thermal plants to generate electricity. Total energy consumption may remain constant or even increase. The six diagrams displayed in Figure 3.6 illustrate the changes that can be deliberately introduced into utilities' load profiles.

To determine the most appropriate load management program, it is critical to understand the structure of the utility's load profile by consumer class and end use technology. Figure 3.7 shows the example of a Brazilian utility. From the figure, the residential class is clearly the one responsible for the increase in the evening peak. Two end-uses were important for the formation of this peak: lighting and electric water heating. In some countries electric cooking and air conditioning also contribute to such an evening peak.

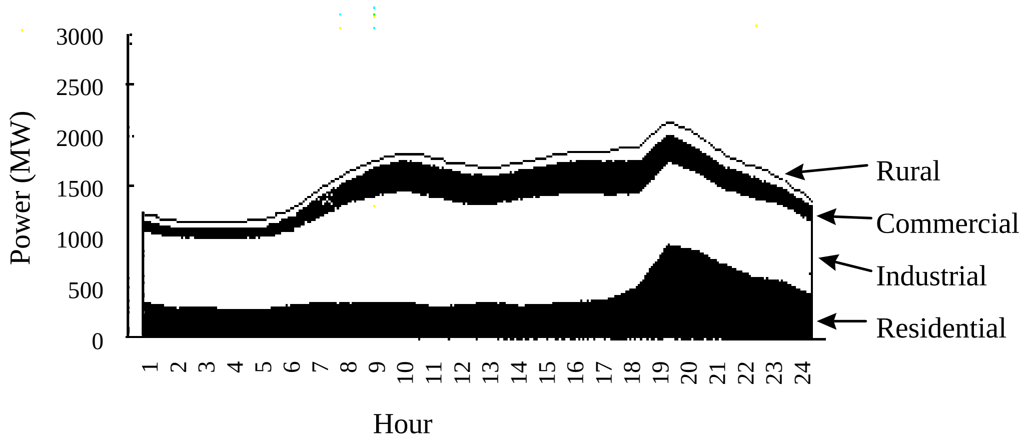


Figure 3.7. Example of utility load profile
Source: Jannuzzi et al, 1994.

Load management can be accomplished by means of changing the tariff structure, direct load control, or by the introduction of specific technologies. As seen earlier in this chapter in Section B.2, special tariffs for peak hours can result in peak clipping or load shifting. Direct load control can be achieved by means of installing demand limiters in consumers' premises or by introducing demand measurements and contracts. Programs introducing specific technologies can also change the load pattern. This is the case with the replacement of on-demand electrical water heaters by thermal heat storage water heaters in residences.

F.2. Investments in Energy Efficiency

Energy efficiency is one specific type of demand-side management objective, highlighted in Figure 3.6D, where efforts are made to decrease the energy consumption of a particular end-use. The goal is to reduce energy consumption often in conjunction with reducing peak demand growth, and therefore these programs save both capacity and fuel (for thermal plants). There are several types of programs that can address this:

a.) Audits and Information

Energy audits, especially in the industrial and commercial sectors, have been one of the most widely practiced programs in several countries. Audits can be performed as a utility or government program, and consist of visits and interviews with energy customers.

Audits are necessary when detailed information is required on end-use technologies and how they are operated by the customer. This information is frequently used to feed computer models that evaluate customer's energy-savings opportunities due to changes in tariff structure, technology or equipment usage.

Audits have a relatively low cost and may help gather information on consumer behavior which is helpful to evaluate information campaigns. They are, however, also time-intensive and require qualified (or trained) labor; so they are best-suited where detailed customer-specific information is necessary, usually for complex facilities. Physical measurements on-site greatly help in developing precision in the energy savings estimates.

b.) Incentives and Loans

Financial incentives range from low-interest and deferred-payment loans to subsidies and rebates for the purchase of energy efficient equipment. Loan programs have generally not been very successful, as relatively low numbers of customers are typically willing to take on debt in order to save energy (Nadel et al 1990, Larsen et al 1993). Rebate programs have been more successful and are best applied to fully saturated equipment markets such as refrigerators or lighting, where the rebates would not be likely to increase the total number of units installed. Rebates may not be suitable, for example, to room air-conditioners, where there is a danger that the rebates would induce people to buy air conditioners who would not otherwise own them. Although more reliable than loan programs, rebate programs still do not provide the utility with any direct control over the level of energy or peak demand savings, and these programs sometimes suffer from high administrative costs, especially in the residential sector.

Prior to financing specific measures, a detailed technology evaluation must be carried out.

c.) Direct Installation / Energy Service Company

Direct installation programs involve actual installation of equipment by the utility or a utility representative. They are more expensive, but they have the potential to be simpler and therefore more cost-effective than incentive (rebate) programs.

Direct installation programs avoid the problem of consumers' lack of information, and they are particularly attractive for difficult sectors such as rental housing and offices. Such programs have greater consumer participation rates than incentive programs. For example, more than 90% participation was achieved in residential retrofit programs in Hood River, Oregon in the mid-1980s and more recently in Espanola, Ontario (Goeltz and Hirst 1986, Sharpe et al 1993). In the commercial sector, the New England Electric System's (NEES) lighting retrofit program provides both financing and comprehensive training to electrical contractors for advanced lighting systems, thus increasing the ability of the contractors to apply efficient technology in their work outside the DSM program as well (Miller et al 1992).

Direct installation programs are often implemented by contracting with an Energy Service Company (ESCO). An ESCO is a company whose primary objective is to provide energy management activities. They can function as companies that commercialize or lease energy-efficient equipment, or act as energy consultants providing audits, tariff negotiations, and retrofitting services. Often ESCOs provide conservation measures (like financing, purchasing, and installing new equipment) and receive payment for this service in the form of a share of the energy bill savings achieved by the customer. This payment mechanism is know as "shared savings," where the customer and the ESCO share the benefits of the savings achieved through energy efficiency. ESCOs are often referred to as "performance contractors" because the payments they receive are directly tied to the energy savings performance of the measures they implement.

Several ESCOs are partly owned by electric utilities seeking to add a new dimension of customized energy services to their portfolio of business activities. The ESCO has been a response to the trend toward a more competitive market-oriented utility industry, and is a concrete example of the possibility of improving the efficiency of the energy market within the context of new restructured markets. Also, in a situation where competition is driving down marginal profits from new electricity supply, provision of energy services through ESCOs may provide new possibilities for utilities to increase profits.

ESCOs can of course also be independent from electric utilities. Some of the major ESCOs in the United States are owned by building energy controls equipment companies and heating/ventilation/air conditioning equipment companies.

d.) Equipment Supplier / Vendor Programs

A utility DSM program can also interact directly with equipment suppliers. This is the approach being used by some US utilities who, for example, have given financial incentives to compact fluorescent lamp (CFL) manufacturers to reduce their prices instead of giving the incentives to customers.

Market transformation programs such as the Super Efficient Refrigerator Program have also worked directly with equipment suppliers, providing incentives to manufacturers to develop more efficient products at reasonable cost (see Boxes 3.3, 3.4).

One example of utility demand-side management is British Columbia Hydro's efficient industrial motors program, which used both customer and distributor rebates to increase the market share of efficient motors from 4% to 64% in 3 years, at a cost of \$0.012/kWh saved (Nelson and Ternes 1993). BC Hydro has reduced its rebate payments twice after transforming the market, and they are now applied only to even higher performance levels. Because vendors tend to stock just one line of motors, this transformation has made the efficient motors the norm, making further utility expenditures for future energy savings unnecessary. Free riders (see Box 3.6 for definition of free riders) were estimated at about 10% initially, but now there are many times more "free drivers," who purchase the efficient equipment without receiving rebates.. Comparable results were achieved in a similar program at Ontario Hydro.

The Super Efficient Refrigerator Program in the US is aimed explicitly at market transformation. Similarly, a consortium of US gas utilities are providing support for the commercialization of a gas heat pump, which will improve the efficiency of gas-fired home heating to more than 100 percent. The utilities will pay incentives directly to the selected manufacturer, in order to buy down the retail price, and will be repaid from this model's sales after a certain level of sales have been reached (Geller and Nadel 1994).

The Model Conservation Standards in the US were developed by the Bonneville Power Administration (BPA) and the Northwest Power Planning Council (NWPPC) to encourage builders to improve the energy efficiency of new houses and to make such improvements sufficiently acceptable to builders to allow the adoption of stronger mandatory building codes in the region, thus moving from incentives to consensus standards. BPA and NWPPC also collaborated with building manufacturers, paying rebates for the first four years, to get a commitment of 90% compliance with the voluntary standard. The cost of saved energy for the program, from 1983-2003, is estimated at \$0.03/kWh, plus about \$0.005 for implementation costs (Geller and Nadel 1994).

The US EPA is assembling a consortium of utilities and NGOs to pay manufacturers incentives to buy down the cost of integral CFLs, together with public education programs, which over time can be expected to increase consumer awareness of CFLs as a household energy- and money-saving measure. Although information programs are rarely sufficient to change consumer purchasing habits, they can complement and amplify incentive programs. A study of utility CFL promotional campaigns in Sweden found that participants were willing to accept almost twice as long a payback time for CFLs as non-participants (Bülow-Hübe and Ankarljung 1991).

Box 3.4. Some examples of utility and non-utility DSM programs

Though DSM has been most widely practiced in North America, other countries have also accumulated significant DSM experience. Box 3.5 provides some international perspectives on DSM.

Recently, North American DSM programs have begun to evolve away from general information and rebate programs, which are common but have been criticized for high costs and low participation rates, to more targeted programs that better respond to customers' needs and produce more reliable energy savings (Nadel 1992). In addition, more attention is being paid to capturing long-term efficiency improvements by influencing equipment manufacturers and building designers to offer more energy-efficient products.

In Europe, DSM has not developed as quickly as in North America, partly because vertical utility integration is not as common. A more common utility model is municipal distribution utilities that buy their power from larger (often nationalized) generation utilities. In Scandinavia, for example, the few fully-vertically integrated utilities, such as Oslo Energi and Stockholm Energi, may be broken up as a result of the deregulatory policies now taking effect. Moreover, the regulatory intervention that made DSM possible in North America is not apparent in Europe, where utilities operate more independently of government oversight. Nevertheless, energy suppliers in some countries, such as Denmark and the Netherlands, have become more active in IRP and are encouraging energy efficiency.

In Sweden, Vattenfall AB, the largest electric generator and wholesaler and formerly the national power board, recently completed *Uppdrag 2000*, (project 2000) a field study of energy efficiency options. The study produced the first detailed statistical picture of energy in the Swedish service sector and evaluated the potential cost and performance of a wide range of energy-saving measures (Hedenström et al 1992). The *Uppdrag 2000* results suggest savings potential in the buildings sector of about 10-15 percent based on retrofit measures that could be implemented immediately (Hedenström 1991). While the achievable energy efficiency potential is not as great as some studies of technical potential suggest, Vattenfall's results are an underestimate because they ignore the longer-term efficiency potential in new buildings and replacement equipment. The efficiency measures identified under *Uppdrag 2000* are not presently being carried out, partly due to the continuing surplus of electric supply in Sweden. Presumably, these measures could be implemented later when supply constraints appear, or to defend the utility's market under the threat of new supply competition (Swisher et al 1994).

In both Sweden and New Zealand, the former state electric power boards have been corporatized, with the eventual aim of privatization. For the time being, this situation is the worst of both worlds for DSM: the new corporate monopoly faces neither competitive market pressure nor public oversight via binding regulation. These organizations' business strategies thus become a matter of positioning themselves to defend and perhaps increase their market position in case of real competition being introduced in the future.

One hopeful possibility is that the utility might use DSM as a tool to defend its market share against new competition by making their service more attractive and economical to the customer. Rather than reducing customers' *rates* to respond to competition, the utility can thus reduce their *bills,* including perhaps maintenance and other fuel costs, making continued service from the utility relatively attractive compared to the competition. Although the utility could recover only part of its costs and lost revenues from the DSM, the lost revenues must be compared to the alternative case where customers are lost to the competition, taking *all* of their revenues with them (Swisher and Hedenström 1993).

Box 3.5. DSM international experience

F.3. Thailand's DSM Program

In 1991, Thailand became the first Asian country to formally approve a countrywide demand-side management plan. The Thai DSM programs got under way in late 1993, and the DSM Office now has a staff of 100 who are developing residential, commercial, and industrial energy-efficiency programs. Beginning in 1992, Thailand also initiated a national energy conservation law, supplemented by a US$80 million annual fund, separate from the DSM effort, to finance investments in energy efficiency throughout the economy. This section provides a brief overview of the Thai DSM programs.

The utility-sponsored DSM effort in Thailand was spurred by a 1990 directive by the National Energy Policy Committee to the three state-owed electric utilities to develop a DSM Master

Plan by mid-1991. Thailand has a state-owned generating utility, the Electricity Generating Authority of Thailand (EGAT), and two state-run distribution utilities, the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA). With assistance from the International Institute for Energy Conservation (IIEC), the three utilities developed and submitted a plan which was approved by the government in November 1991. The five-year plan called for an investment of US$189 million to achieve a peak demand reduction of 225 MW and energy savings of 1080 GWh/yr at a cost-of-saved-energy of less than half of the utilities' long-run marginal supply cost. The table below shows the program descriptions and current savings targets for the Thai DSM effort.

The DSM programs offer a cost-effective alternative to investment in new power plant capacity. The average cost of the Thai DSM programs will be an estimated US$0.017/kWh and US$792/kW of avoided peak power, compared to the utility's long-run marginal cost of US$0.043/kWh, and the utility's cost of new capacity of US$1500/kW. While the DSM programs are ambitious by any terms, the savings will offset only a small fraction of projected future demand. EGAT has a plan to invest a total of $36 billion in power plant construction during the period 1991 to 2006. By comparison, EGAT is planning to invest US$190 million in its five-year pilot DSM program between 1993 and 1998.

The Thai DSM programs evolved significantly during the early stages of implementation. The original DSM Master Plan called for a broad range of programs that were based on DSM experience in North America, and relied on a combination of incentives and program marketing to spur a shift toward more energy-efficient products. The majority of DSM programs implemented in North America during the 1980s provided rebates to the customer and not to the manufacturer. The Thai approach has been to seek voluntary agreements with manufacturers and to supplement these agreements with nationwide advertising campaigns and incentives for customers where necessary. In an effort to stimulate more cost-effective market transformation, the Thai DSM Master Plan relied on a combination of customer rebates and incentives for manufacturers.

The lighting efficiency program perhaps best represents the spirit of the Thai DSM philosophy. In September 1993, EGAT negotiated a voluntary agreement with the five major manufacturers of fluorescent lamps in Thailand. Under the agreement, all local lamp production would be shifted to the energy-efficient, "thin tube" (T-8) lamps. By mid-1995, all of the manufacturers had shifted to production of thin tubes. The startling thing about the voluntary agreement with the lighting manufacturers is how *different* it is from the traditional methods of government-imposed and utility-sponsored energy-efficiency programs. It relies largely on a public-private partnership to develop win-win situations where it is in the interest of the manufacturers to produce and aggressively market high-efficiency equipment.

Table 3.5. Summary of Thai DSM programs and savings targets (1993-1998)

Program		**Description**	**Peak MW Savings**	**Energy Savings**
Cross-Sectoral Programs				
Thin-tube (T8) Lighting	9/93	Voluntary shift to production of 36W and 18W Lamps	159 MW	1528 GWh/yr
Low-loss ballasts[a]	1996	Mass procurement of low-loss (<6W) magnetic ballasts to support the Green Buildings program		
Residential Programs				
Refrigerators	9/94	Voluntary testing and labeling	36 MW	315 GWh/yr
Air conditioners[b]	9/95	Voluntary testing and labeling		
Compact Fluorescent lamps[c]	1996	1.5 million lamps offered at reduced prices through mass procurement		
Low-income lighting	1996	Direct replacement at no cost to customer		
Commercial Programs				
Green Buildings	9/95	Zero-interest financing of energy-efficient equipment. Paid back over 3-5 years.	48 MW	1378 GWh/yr
New Buildings and Thermal Storage				--
Industrial Programs				
Motor systems	3/96	Zero-interest financing of energy-efficient motors. Motor efficiency testing lab and motor rewinding efficiency program.	41 MW	460 GWh/yr
Industrial ESCO	1997	Pilot program to develop turn-key energy services for industry.		
Load Control Program				
Direct load control	1997	Direct load control and standby generator operation.		--

[a] Estimated savings for low-loss ballasts program (84 MW and 499 GWh/yr) not included in 1993-1998 total.
[b] A/C market potential not estimated at this time. Technical potential is 350 MW and 1,022 GWh/yr
[c] CFL market potential not estimated at this time. Technical potential is 62 MW and 170 GWh/yr

Source: P. du Pont, P. Amranand, Y. Lemoine, 1997. "Lessons Learned in the Implementation of Energy-Efficiency Programs in Thailand," Energy Policy, in press.

F.4. Evaluation of DSM Programs

Evaluation is the systematic measurement of the operation and performance of programs and depends on objective measurements. Evaluation uses social-science research methods and technical data (Hirst and Reed 1992). This is an important component of any DSM program, because it verifies the response of customers to different types and levels of incentives and information. This information is necessary to better design DSM programs and make them more cost-effective. There are two types of evaluations: *process* and *impact* evaluation.

a.) Process Evaluation

A process evaluation is concerned primarily with the operational aspects of the DSM program. It investigates how well a program has performed, compares the intended objectives with what really occurred, and studies the perceptions of those involved in the program. It analyses the potential barriers to more effective implementation, what parts of the program went well, and what could be improved. This type of evaluation is qualitative, based on interviews, and focuses on program operations. It provides ideas for improved operation, design of new programs, causes of a program's results, and also documents the history of a program.

b.) Impact Evaluation

Impact evaluation examines the program results in terms of energy saved and load reductions. Costs and benefits, participation rates, and customer acceptance are also evaluated. The impact evaluation approach is more quantitative than in the process evaluation and may use advanced statistical analyses (Hirst and Reed 1992). The results obtained from this type of evaluation are useful for new program design, and load and energy projections. We will concentrate here on this type of evaluation.

The cost-benefit ratio of DSM programs depends on the achievable market penetration over time and the administrative costs and uncertainties associated with implementation.

Estimating Savings from DSM Programs

An important step in evaluating any DSM program is to estimate the amount of potential savings it can achieve (pre-evaluation), and once it has been launched, to estimate the actual savings achieved through the program (post-evaluation). The evaluation methods include:

- measurement pre- and post-program: whole building metering, end use metering
- analysis of customer billing data
- engineering analysis: uses physical models based on weather data, customer surveys, facility and equipment inventories and operating patterns
- questionnaires and surveys
- statistical modeling - uses statistical techniques to evaluate changes through billing data, demographic characteristics, and economic variables.

Engineering analysis is generally the simplest and least expensive approach to impact analysis. This involves information about the technical characteristics of end-use equipment and data on customer participation in the program. The limitation of this approach is that it does not capture changes in customer behavior, for example to increase comfort in an efficiently air-conditioned building. More sophisticated engineering methods include the use of simulation models to estimate program impacts.

Direct measurements to determine the evolution of the load profile involves instrumentation and collection of data by individual end-use or by building as a whole. This allows the quantification of energy use before and after the addition of the conservation measure, or simultaneously in participants and non-participants. For correct interpretation of the results, this method requires the analysis of a control group (of non-participants). This method offers greater precision in verifying impacts, but it is more expensive and difficult to implement, due to the need for installation of monitoring equipment and the collection and analysis of large amounts of data. Cost limits the number of end-uses that can be measured, and statistical sampling data are used to select the customers to be monitored.

Statistical analysis of energy bills and customer data is a low-cost approach that allows the use of large samples or even the entire population of customers. This approach is commonly used in the residential sector, where customer characteristics are relatively uniform. Greater precision can be obtained with analysis before and after the implementation of efficiency measures, normalizing for the effects of weather, demographic and economic variations.

The correlation of customer data on end-use equipment ownership and socioeconomic information can be used to generalize estimates of program impact. In this case, data are obtained through sampling involving program participants and non-participants.

Cost Components of DSM Programs

<u>Direct costs</u>: include costs directly associated with the efficiency measure. For example, in a rebate program it will include the amount of capital spent by the utility to subsidize the purchase of new equipment. This cost component includes the financial incentive paid by the utility for the materials and installations needed to acquire the conservation resource.

<u>Indirect costs</u>: include both fixed and variable costs for managing the program. Let us take the example of a rebate program again: indirect costs will include costs of an information campaign, utility staff salaries, and costs of evaluating or monitoring the program results. Some of these costs are fixed, while others will vary depending on the duration of the program, like staff salaries, for example.

Total program cost per kWh saved depends on the measure lifetime and the discount rate used. It also depends on the estimated amount of saved kWh on an annual basis. Hirst, 1991, indicates that a utility conservation program's performance depends on two factors: participation in the program and the net savings of the program. The net savings of the program are:

$$\textit{Net program savings} = \textit{avoided supply costs} - \textit{total program costs} \qquad [\textit{Eq. 3.13}]$$

The cost component of a program can be indicated by the total cost of saved energy:

$$\textit{Program CSE} = (\textit{Ccap} + \textit{Cind}) \cdot \textit{crf} / D \qquad [\textit{Eq. 3.14}]$$

where: *CSE* = cost of saved energy ($/kWh)
Ccap = capital cost of end-use technology
Cind = indirect costs of DSM program
crf = capital recovery factor
D = DSM or conservation program annual kWh savings

Box 3.6 discusses some other cost factors to be considered regarding DSM programs. They include the issue of "free riders" as well as transaction costs.

Technical progress causes improvements in energy efficiency even without DSM programs. This means that there are customers who will take advantage of utility-sponsored incentives even though they would have invested in efficiency measures anyway even if the incentives were not available, i.e., there will be "free riders." Although free riders do not impose additional costs on society (except administration costs), the utility must still pay both the incentives and the program administration cost for the free riders' participation. Evaluations of North American DSM programs report free rider fractions from less than 10 percent to more than 50 percent of program participants, depending on the type of program; and experience has shown that programs can be designed to avoid excessive free-ridership (Nadel et al 1990).

When a utility tries to capture the lowest-cost efficiency measures, which are generally found in new and replacement equipment rather than retrofits of existing buildings and equipment, there tends to be a high fraction of free riders, which increase utility costs. However, such measures in new buildings and replacements of burnt-out equipment are one-time opportunities that are lost or become much more expensive if they are not exploited when the equipment is first installed. Capturing this inexpensive "lost opportunity" energy-efficiency resource should therefore be a high priority, despite the risk of free-riders. Some of this "lost opportunity" resource can be effectively captured through energy performance standards, such as for end-uses like household appliances and service-sector lighting. Even relatively modest standards help to capture many low-cost "lost opportunity" resources. This allows utility DSM planners to set thresholds for incentives that exceed the standard by some degree, requiring more elaborate measures where fewer free riders are likely (Swisher et al 1994).

In addition to free-riders, significant transaction costs exist for many energy-efficiency options. It is sometimes argued that these costs are high and, in fact, the reason why energy efficient technologies have not already been adopted more by the markets (Sutherland 1991). In some studies of technical potential, transaction costs have implicitly been assumed to be zero (Lovins and Lovins 1991). In fact such transaction costs and limitations do exist and can be measured and explicitly included in bottom-up analysis. However, penetration limits and implementation costs vary widely with the technology and type of program applied.

Transaction costs can be estimated both in terms of consumers' "search cost," the time and trouble it takes to acquire more efficient products, and actual administrative costs of energy-efficiency programs. At the low end of program costs, the procurement of energy-efficient and environmentally sound refrigerator/freezers promoted by the Swedish government reduced energy use in new models by 30 percent with an estimated transaction cost of about $300,000, or less than $0.001/kWh (Nilsson 1992). The $50 million spent by the US government on appliance standards amount to even lower costs per saved kWh (Levine et al 1994). For US utility DSM programs, administrative costs add on average 10-30 percent to the technology costs (Berry 1989, Nadel et al 1993). These costs tend to decrease with increasing participation rates, which reduce the importance of fixed program costs, up to very high participation rates where decreasing returns drive costs upward.

Consumer transaction costs for acquiring energy efficiency are more difficult to estimate, but they appear to be in the same range of 15-30% of technology costs (Bjorkqvist and Wene 1993). This is significant but still does not explain the consumer payback "gap" shown by the very high implicit discount rates of consumers. This gap must be explained by the other barriers described earlier. Assuming that most energy-efficiency measures include transaction costs on either the consumer or the program side, or perhaps a mix of both, it seems that a conservative estimate of the additional cost is about 30% of the technology cost, although many programs can be implemented with lower administrative cost and with little effort by the consumer. While transaction costs are a real cost that should be included in DSM planning, they cannot explain the barriers to energy-efficiency investment, nor do they indicate that such barriers represent irreducible costs and are thus economically efficient. Other factors can also induce the consumer to conserve energy independently from a program such as changes in energy prices, changes in income or economic activity. When evaluating the program results we should take steps to separate those savings attributed to the program from the others.

The costs of DSM programs very widely and are somewhat larger than the simple technology costs, as discussed above. Most programs report costs of saved energy of $0.02/kWh or less (Nadel et al 1990). Generally, the programs with high rates of free-riders involve measures that are highly cost-effective and therefore have very low technology costs. Some critics point out the uncertainty in these costs and argue that DSM programs are much more expensive than claimed by utilities (Joskow and Marron 1993). However, they ignore uncertainties that could reduce such costs, such as free-drivers that adopt energy-efficiency without participating in DSM programs (Hirst and Reed 1991).

Box 3.6. Costs and benefits of DSM programs

Exercise 3.13) Prepare a table (spreadsheet) like the one in Table 3.6 to calculate the total utility cost, annual kWh savings, and cost of saved energy of a program which conserves energy through rebates from the utility to consumers who buy efficient lamps. Note that the participation level varies based on the rebate level. Do the numbers in the table below appear realistic for your geographical area? What other costs might you include?

Table 3.6. Sample program costs for efficient lamp rebate program

Lamps Rebate Program - Total Cost Estimation			
Number of Households	30,000		
Number of Lamps/Household	2		
Annual kWh Savings per Lamp	124		
Lifetime of Bulb (years)	5		
Lamp Market Price (per lamp)	$13		
Lamp Rebate (%)	40%		
Participation (%) (Based on Rebate)	35%		
Lamp Final Price to Household (per lamp)	$8		
Lamp Cost to Utility (per lamp)	$5		
Total Number of Lamps Adopted Through Program	21,000		
	Lamp	Net	
Program Participation Schedule:	Rebate	Participation	
Net Program Participation Level by Rebate Level	(%)	(%)	
	0.0%	0%	
	10.0%	5%	
	20.0%	13%	
	30.0%	23%	
	40.0%	35%	
	50.0%	48%	
	60.0%	61%	
	70.0%	73%	
	80.0%	81%	
	90.0%	88%	
	100.0%	93%	
	Unit Cost	Subtotal	Total
A. Program Fixed Cost			**$85,000**
Program Project & Negotiation		$5,000	
Marketing		$60,000	
Advertising Production	$10,000		
Campaign	$50,000		
Staff Allocated to Program (total)		$15,000	
Staff Training		$3,000	
Operating Costs (installation)		$2,000	
B. Program Variable Cost			**$109,200**
Lamp Cost to Utility			$109,200
Total Utility Cost			**$194,200**
Utility Discount Rate	10%		
Utility Capital Recovery Factor	0.263797		
Equivalent Annual Utility Program Cost	$51,229	/yr	
Total Annual kWh Saved	**2,604,000**	**kWh/yr**	
Program Cost of Saved Energy	**$0.020**	**/kWh**	

Exercise 3.14) Using Table 3.6, calculate the total utility program cost, total annual kWh saved, and the cost of saved energy (CSE) which would result from varying the rebate level between 0% and 100% (i.e., 0%, 10%, 20%, ...90%, 100%). What rebate level provides the lowest CSE?

Note, however, that minimum CSE is not always the main decision criterion. Suppose that all DSM with a CSE of less than $25/MWh is found to be cost-effective compared to the alternative supply-side option. In that case, what rebate level should be provided to achieve the maximum cost-effective energy savings?

Are these results reasonable? Should some of the program fixed costs in fact be variable costs which vary based on the participation level?

G. Exercise on Implementation Strategies for Energy Efficiency and DSM Programs

1. Objectives

The purpose of this exercise is to allow the reader to apply some concepts developed in this chapter and contemplate some of the difficulties related to the elaboration, implementation and follow-up of the IRP strategies.

The main objectives are:
a. To learn a simple approach for assessing costs and savings of program and policy options.
b. To assess the approximate costs and savings of ten potential programs and policies.
c. To develop a simple least-cost plan.

2. Strategies and Programs

Ten potential DSM program types are to be analyzed. They are as follows:

1. A design assistance program for commercial new construction, under which an association or center would provide technical assistance to architects and engineers designing new buildings.

2. A mandatory energy code for new commercial buildings.

3. Industrial audits, offered by an Energy Conservation Center.

4. Rebates for industrial efficiency improvements.

5. A refrigerator labeling program under which all refrigerators would be tested for their energy consumption and a label providing this information would be attached to each model sold.

6. Refrigerator efficiency standards under which the electricity use of all new refrigerators would be required to be below a specific value.

7. Rebates for commercial (business) efficiency improvements.

8. A commercial lighting installation program under which commercial facilities would receive a free lighting assessment and free installation of high efficiency lighting equipment.

9. A commercial storage cooling technical assistance and incentive program.

10. An industrial energy manager program under which a sponsoring agency provides training for industrial energy managers and guarantees that the money saved in efficiency improvements will pay the salary of the manager. If the value of energy savings does not pay the salary of the manager, the sponsoring agency pays the difference.

The variety of programs and the information necessary for this kind of evaluation are wide and depend on each case. These programs involve: information for different agents, direct financing to equipment, equipment installation, indirect financing, and development and implementation of mandatory codes.

3. Spreadsheet

We suggest a computer spreadsheet to organize and compare information for each of the ten DSM strategies/programs listed above.

As an example, a working spreadsheet is provided in Table 3.6 with some initial data for each of the ten programs. The reader should adapt this data to better reflect the conditions of his or her country, inserting and interpreting the necessary information. Each program is expected to have a program duration of ten years.

To make it easier to understand, we have adopted a graphical representation which differentiates between columns of input and output data through the font of the column number as follows:

Normal Font =	Data Input Column (reader data input)
Bold Font =	**Data Output Column** (results of operations and calculations)

4. Spreadsheet Structure:

Rows: Each line indicates one of the programs/strategies suggested in this exercise. The discount rate should be selected to reflect the investment criteria of the appropriate agency as discussed earlier in this chapter. See Table 3.1 for examples of possible discount rates.

Columns:

(A) **#** : number of program (1-10).

(B) **Program**: name of each program.

(C) **Eligible Population**: indicates the population (number of persons, companies, etc.) eligible to participate in the program. This is the maximum potential market for each program, considering the total program period of 10 years.

(D) **Unit**: indicates the unit of eligible population corresponding to Column C.

(E) **Annual Consumption, MWh/Unit**: indicates the annual energy consumption of each population unit.

(F) Participation Rate: indicates the percentage of the eligible population that will participate in the program.

(G) Number of Participants in the Program: indicates the number of participating units. This is calculated through the following formula: (G) = (C) * (F).

(H) Savings Due to Program (%): percentage of annual MWh consumption in Column E which will be saved by program adopters. This indicates the savings accruing to each participating unit.

(I) Annual Potential MWh Savings per Unit: the amount of energy that will be conserved by each unit participating in the program. This is calculated as: (I) = (E) * (H).

(J) Total Annual Potential MWh Savings: considering the estimated number of participating units and the estimated savings per unit, the spreadsheet should calculate the potential annual MWh savings during the 10 year program duration. Remember that we are simplifying the analysis by considering the annual average consumption. The formula is:
(J) = (G) * (I).

(K) Peak/Average Demand Ratio: this is a data input and should reflect the relation between the peak energy demand and the average energy demand for the average participating unit.

(L) Annual MW Savings: this should calculate the annual peak savings over the course of the ten year program duration as a result of the adopted measure. This will be directly related to the new energy supply capacity avoided through the DSM program. The formula is: (L) = [(J) * (K)]/ [24 hours/day * 365 days/year].

(M) Total Utility Cost or Government Cost of Program Per Participating Unit: this is the total estimated program cost per participating unit summed over the 10 year program duration. Note that this information is not always available and may require estimation.

(N) Total Annual Cost of Program: this is the annual cost per participating unit (during the 10 year program duration) multiplied by the number of participating units. The formula is: (N) = [(G) * ((M) / 10)].

(O) Total $ Cost per Avoided MW: this column should calculate the total cost of each MW of peak capacity conserved. The formula is: (O) = (G) * (M) / (L)

(P) Measure Life (Years): lifetime of each measure. Notice that the measure life is not necessarily equal to the program/policy duration. This is important in the calculation of Column (Q).

(Q) Cost $/MWh: this column should calculate the program's cost per MWh saved, considering the discount rate, the measure lifetime, and the program duration. Remember that a program's duration could be shorter than the duration of its energy savings, and this should be considered in the financial analysis.

5. Worksheet Diagram

The suggested worksheet for this exercise is shown in Table 3.6.

Table 3.6. Sample DSM energy savings, participation, and cost calculations

#	Program	Eligible Popul-ation	Unit	Annual Consump MWh per Unit	Particip. Rate	Number of Particip. in Program [C*F]	Savings Due to Program (%)	Annual Potential MWh Savings per Unit [E*H]	Total Annual Potential MWh Savings [G*I]	Peak/Avg Demand Ratio	Annual MW Savings J*K/(24*365)	Total Utility or Govt. Cost per Particip Unit	Total Annual Cost of Program [G*M]/10yr	Total $ Cost per Avoided MW [G*M/L]	Meas. Life (Yrs)	Level. Cost $/MWh
(A)	(B)	(C)	(D)	(E)	(F)	**(G)**	(H)	**(I)**	**(J)**	(K)	**(L)**	(M)	**(N)**	**(O)**	(P)	**(Q)**
1	Information Program	2677	New Buildings	674	10%	268	10%	67	18043	1.15	2.37	67500	1806975	7628693	30	65.28
2	Mandatory Code	2677	New Buildings	674	80%	2142	20%	135	288688	1.15	37.90	13500	2891160	762869	30	6.53
3	Industrial Audit	6500	Factories	1005	16%	1040	3%	30	31356	1.1	3.94	56853	5912712	15016803	10	188.57
4	Industrial Audit & Incentive	6500	Factories	1005	30%	1950	14%	141	274365	1.1	34.45	270000	52650000	15282031	10	191.90
5	Refrigerator Labeling	3545200	Refrig.	0.649	50%	1772600	15%	0	172563	1.5	29.55	38	6735880	2279610	10	39.03
6	Mandatory Code	3545200	Refrig.	0.649	90%	3190680	30%	0	621225	1.5	106.37	30	9572040	899846	10	15.41
7	Commercial Rebate	180638	Commerc Customer	24.8	10%	18064	7%	2	31359	1.4	5.01	3375	6096533	12164664	10	194.41
8	Commercial Lamps	180638	Commerc Customer	24.8	50%	90319	10%	2	223991	1.7	43.47	16200	146316780	33660342	20	471.46
9	Commercial Refrigerator	2677	New Commerc.	674	30%	803	32%	216	173213	1.15	22.74	229222	18408819	8095668	20	76.71
10	Energy Manager	689	Large Industrial	7974	50%	345	8%	638	219763	1.1	27.60	45225	1558001	564578	10	7.09
															Discount Rate	10%

6. Steps

Step 1: Build or retrieve the spreadsheet. We recommend that you rebuild the spreadsheet.

Step 2: Complete the columns with the following data:
- (C) Eligible population (consider the period of 10 years)
- (D) Units
- (E) Annual consumption, MWh/unit
- (F) Participation rate
- (H) Savings due to program

Step 3: The spreadsheet should calculate:
- (G) Number of participants in the program - this will be the number of participants over the **ten year** program duration. (G) = (C) * (F)
- (I) Annual potential MWh savings/unit. (I) = (E) * (H)

Step 4: The spreadsheet should next calculate:
- (J) Total annual potential MWh savings. (J) = (G) * (I)

Step 5: Using the result in Column (J) and the data input in Column (K):
- (K) Peak/average demand ratio (input data),
  the spreadsheet should calculate the annual coincident peak demand savings (MW) in Column (L), using the following formula:

$$(L)\ Annual\ MW\ Savings = \frac{(J)\ Annual\ MWh\ Savings \cdot (K)\ Peak/Average\ Demand\ Ratio}{24\ hours/day \cdot 365\ days/year}$$

Step 6: Input data in Column (M):

- (M) Total utility or government cost per participating unit, and then calculate:
- (N) Total annual cost of program, using the following formula:

$$(N)\ Annual\ Cost\ of\ Program = \frac{(G)\ Number\ of\ Participants \cdot (M)\ Total\ Cost\ per\ Participant}{10\ Year\ Program\ Duration}$$

Step 7: Calculate Column (O):

- (O) Total $ cost per avoided MW, using the following formula:

$$(O)\ Total\ Cost\ per\ Avoided\ MW = \frac{(G)\ Number\ of\ Participants \cdot (M)\ Total\ Cost\ per\ Participant}{(L)\ Annual\ MW\ Savings}$$

Step 8: Using the results of

- (J) Total annual potential MWh savings
- (N) Total annual cost of the program
- (P) Measure life in years (data input)

The spreadsheet should calculate the levelized cost using the following formula:

$$(Q)\ Levelized\ Cost\ \$/MWh = \frac{@PMT\left\{\left[@PV((N),\ Discount\ Rate,\ 10\ yr)\right],Discount\ Rate,\ (P)\right\}}{(J)}$$

In other words, the 10 years of annual program costs are converted to a present value, and then annualized again over the measure life; and this value is divided by the annual MWh savings.[5]

7. Questions:

a. Observing Columns (J) and (L), which are the programs/policies with the largest MWh and MW savings? Which are the programs/policies with the lowest savings? Discuss some reasons that could explain the differences observed.

b. Which programs/policies have the lowest cost per kWh? Which programs/policies have the highest cost per kWh? How does the cost of these programs and policies compare to the cost per kWh of electricity from a new gas or coal generating plant in Brakimpur (see Table 2.10)? Do these numbers seem reasonable?

[5] Note that in calculating the levelized cost, the program costs were levelized, but the energy savings were not levelized. In fact, the annual energy savings should be levelized as well. In this particular example, because each program's energy savings are constant from year to year, whether the energy savings are levelized or not does not impact the result. However, if the energy savings vary from year-to-year, then one would have to levelize the energy savings in order to obtain the correct $/MWh levelized cost.

c. Calculate the maximum MWh and MW savings that could be achieved if all 10 programs and policies are implemented.

d. If you were to choose to implement two programs from the ten suggested here, considering the barriers, problems and advantages of programs and policies discussed in this chapter, which two programs would you choose? Why?

e. Consider an energy price increase of 40%. How might this affect the cost and results of each program? Make some hypotheses, describe them, and make the necessary changes in the spreadsheet.

Chapter 4: Integrating the Options on the Supply and Demand Sides

As explained in Chapter 1, an integrated resource planning (IRP) process brings together, on a common basis of comparison, programs for energy efficiency and load management with options for electricity supply, including both utility and non-utility sources. Ideally, the basis of comparison should have a societal perspective and should include environmental and social costs. This chapter explains how IRP can be used to bring new elements such as energy efficiency programs and environmental constraints into electricity supply planning.

A. Fundamentals of Electric Power Planning

It is useful to begin with a brief description of the type of planning process into which IRP would be "integrated," and to define some of the terms that will be used throughout the rest of this chapter. As shown previously in Figure 1.5, the traditional electric planning model includes:

1. Projections of demand growth
2. Expansion planning to determine available resources and when they are needed
3. Production-cost analysis to rank supply-options by cost
4. Calculation of required revenues and rates

The principal goal of traditional power planning is to meet the projected demand for electricity at the least-cost. This goal is modified in the IRP context to meet the demand for *energy services*, which allows for the inclusion of DSM and energy efficiency programs as discussed in Chapter 3. In other words, under IRP, if it is cheaper to meet the demand for energy services by improving energy efficiency rather than by building additional supply capacity, then the energy efficiency resource would be selected.

In both traditional utility planning and in IRP, expansion planning analysis is used to determine the least-cost plan for increasing the power supply *capacity*. The main cost criterion in expansion planning is the *revenue requirements*, which must be sufficient to cover all utility costs and an acceptable return to investors. Although sunk costs of past investments contribute to revenue requirements, they cannot be reversed, so the planning process should concentrate on being forward-looking to minimize future investments.

These future investments should be discounted to their *present worth* to reflect the time value of money (see Appendix 3), and they should be compared according to their *long-run marginal costs*. Because different resources are available in different (and often quite large) size-increments, the marginal costs are usually normalized for comparison on the basis of the marginal cost of energy ($/kWh) or marginal cost of capacity ($/kW). The ratio between the marginal costs of energy and capacity depends on the extent to which a resource runs at full capacity, reflected by the *capacity factor*. This is related to the *load factor*, which measures the variability of demand and can be estimated from the *load-duration curve*. All of these concepts are applicable in both traditional planning and IRP processes.

Knowing the marginal costs as a function of capacity factor or load factor, the planner can screen the potential supply options to determine the least-cost expansion plan that meets the projected demand. Of course, this plan must be periodically reviewed and updated as more information about demand growth and supply resources and costs becomes available. In addition to the conventional thermal and hydroelectric power supply options, the IRP process described in this Chapter can include options such as *DSM*, supply-side *loss reductions*, *cogeneration* of heat and power, and intermittent *renewable resources* (solar, wind, etc.). The fundamental comparison between these options is generally made on the basis of the (long-run) *marginal cost of energy*, although other measures will be presented as well.

While the long-run marginal cost governs the planning of new resources, the choice of which existing resources to operate, or dispatch, at a given time depends on *short-run marginal costs* (variable costs for fuel, operations and maintenance). A traditional *economic dispatch* strategy ranks supply resources by variable costs to determine the *dispatch order*. The most expensive source operating at a given time is the *marginal resource*, and this varies with the system load. Another approach is *environmental dispatch*, which considers the emissions from available sources and ranks them according to a combination of cost and emission rates, depending on how the pollution is valued. In IRP, the environmental impacts can also be used to rank new supply resources according to the *cost of avoided emissions*, or by adding *emission charges* or *externality values* to the economic cost values.

To establish electricity rates (tariffs) requires the summation of present revenue requirements and the allocation of these costs to the electricity sales in each customer category. In traditional power planning, the least-cost plan should also have the lowest tariffs. In IRP, however, the extensive use of DSM can increase tariffs while decreasing total costs, as indicated by the total resource cost (TRC) explained in Chapter 2. In other words, with a cost-effective DSM plan, electricity *rates* might increase on a per-kWh basis, but electricity *bills* should decline because the reduction in energy consumption would more than compensate for the increase in the per-kWh price. All of the concepts introduced here are explained more fully in the following sections.

B. Least-Cost Planning Criteria

In an IRP process, resource options are evaluated based on the following fundamental criterion: to *provide energy services at the least total cost*, in which the total cost includes the costs of electricity generation, transmission, distribution, environmental emissions, and other societal costs. Each alternative combination of resources should be evaluated using the same IRP criteria, and each should provide at least the same level of *energy services*, including end-use convenience and supply reliability, as the baseline case, as defined in Chapter 1.

The resource planning goal can be formalized as an optimization problem which can be tackled either through formal optimization models or using a range of simpler techniques. The following equations summarize the IRP optimization process:

Minimize Total Costs: $C_S\ (E,R)\ +\ C_D\ (D)\ +\ C_P\ (E,D,R)$ *[Eq. 4.1]*

Subject to: $E\ +\ D\ =\ ES$ *[Eq. 4.2]*

Where:

E	=	Electricity sold to consumers
D	=	DSM electricity savings
R	=	Required emission reduction
$C_S(E,R)$	=	Cost of electricity supply (includes capital and O&M costs and is a function of electricity sales *E;* also includes the cost of pollution control equipment to meet legal environmental standards and is thus also a function of *R*)
$C_D(D)$	=	Cost of DSM programs (is a function of the size of DSM programs *D*)
$C_P(E,D,R)$	=	Cost of pollutant emissions, i.e., the value of the environmental damage to society caused by electric power production (is a function of the amount of electricity sales *E*, the level of DSM programs *D*, and the required level of emission controls *R*)
ES	=	Level of energy services demanded by electric customers.

Note that the cost of electricity supply includes the cost of pollution control equipment required to meet environmental regulations. For example, if the cost of generating, transmitting, and distributing electricity is $50/MWh, but pollution control equipment costs another $10/MWh, then the total cost of electricity supply would be $60/MWh. The cost of the pollution control equipment is then said to be *internalized* into the electricity price. However, even after installing the pollution control equipment, there would still be some residual pollution which is released into the environment and causes damage to society. This cost, which is not borne by the power plant but rather by society as a whole, is known as an *externality*. The value of this externality, typically ignored in conventional planning, is captured in the IRP equation above by the C_P term.

The constraint on this cost-minimization problem is simply that the same total quantity of energy services must be met, whether by producing electric energy or by saving energy via DSM or other efficiency programs. This criterion does not mean that energy services are constant over time; indeed they can be expected to increase. Nor does it mean that the baseline level of demand for energy services is a fixed trend that is known with certainty; rather, there may be a range of different baseline scenarios, for example reflecting different rates of future economic growth. The IRP criterion simply requires that, for each baseline scenario of expected energy service demand, the defined level of energy services should be met by all alternatives to that baseline scenario.

Using this criterion, we can describe and evaluate electricity supply and demand-side alternatives. Having already analyzed the energy efficiency and DSM options as discussed in Chapter 3, our next task is to evaluate the costs of supply-side options, including unconventional sources. We can then estimate the environmental impacts of different options and, if possible, their effect on supply costs. Finally, we rank the options according to cost and construct integrated resource scenarios. These scenarios combine supply and demand-side options, together with implementation programs and operating plans, to arrive at an integrated least-cost plan, or a set of plans based on a sensitivity analysis of important assumptions.

C. Electricity Production Costs

The basic goal of electricity supply economics is to estimate the production costs of electric power, based on the least-cost mix of available generating options. IRP is not unique in trying to minimize costs, but it does introduce new criteria and new options, such as DSM and non-utility supply, that are not part of the traditional utility planning process.

C.1. Utility Revenue Requirements

The standard procedure for capital budgeting and cost analysis for electric utilities is the *net revenue requirements* method. Revenue requirements are the expected revenues that would provide a minimum acceptable return to investors. Revenue requirements include all of a utility's cost of service including fuel, operating and maintenance (O&M) expenses, capital depreciation, taxes, interest, and additionally costs of DSM, non-utility energy purchases, etc. In equation 4.1, revenue requirements would be defined as $C_S + C_D$.

These costs are projected over the planning period, which should be at least as long as the longest-lived investment option, and discounted to obtain a *present worth* that can be compared across different investment scenarios.[1] The basic planning criterion is to minimize this *present worth* of utility *revenue requirements*. Conventional planning applies this criterion to supply options only, while IRP includes DSM options into revenue requirements and also includes environmental costs if possible. In other words, in a conventional planning process, equation 4.1 would try to minimize just C_S, while in IRP, equation 4.1 tries to minimize $C_S + C_D + C_P$.

Note that we have defined revenue requirements in the IRP context as $C_S + C_D$ in the above paragraphs, but the total costs which we are trying to minimize are defined by $C_S + C_D + C_P$. The reason C_P has not been included in utility revenue requirements is that the cost of the environmental damage caused by pollution from power production has traditionally been borne by the society in general and not by the utility. However, if it were the case that the utility had to pay for the societal cost of pollution (through a pollution tax, for example), then C_P would become part of the utility's revenue requirements. In that case, revenue requirements could be redefined as $C_S + C_D + C_P$.

The present worth of revenue requirements is a criterion for choosing among alternatives that provide an equivalent level of service. Traditionally, the level of service has been defined by the quantity and reliability of electric energy. In the IRP framework, the definition of services is expanded to include energy services at the end-use level, which allows the consideration of DSM options.

---

[1] The revenue requirements method is slightly different from the present worth rule that is typically used for corporate budgeting, in which the net present worth of projected revenues minus projected costs must be positive, after discounting at a threshold rate that reflects the *risk-adjusted* cost-of-capital. In a public utility, the revenue requirements are assumed to only balance the costs, giving a net present worth of zero, when discounted at the *utility's* cost-of-capital, which is generally set by government regulation to be sufficient to attract investors. Similarly, if we imagine electricity production in a perfectly competitive market, the competition should drive the producers' returns down to the point where revenues only balance costs, based on the *market-based* cost-of-capital. In either case, the revenue requirements method will indicate the least-cost strategy for providing electricity services.

The value to minimize is thus:

$$PW(RR) = RR_0 + \sum_{t=1}^{t=n} \frac{RR_t}{(1+r)^t} \qquad [Eq.\ 4.3]$$

Where:

$PW(RR)$ = present worth of revenue requirements
RR_0 = revenue requirements from expenditures until year 0
RR_t = revenue requirements from expenditures in the year t
r = discount rate = weighted-average cost-of-capital (WACC)
n = number of years in the planning period

The value for RR_0 represents the current revenue requirements remaining (sunk costs) due to investments in previous years; they reflect the capital costs of existing generation, transmission, and distribution facilities which have not yet been fully depreciated. The revenue requirements from a future given year RR_t are the sum of investments, expenses and taxes:

$$RR_t = I_t + Ex_t + T_t \qquad [Eq.\ 4.4]$$

Where:

I_t = capital investment expenditures in the year t
Ex_t = operating expenses in the year t
T_t = taxes in the year t

Investments I_t include the capital costs of generation, transmission and distribution facilities:

$$I_t = Cg_t + Ct_t + Cd_t \qquad [Eq.\ 4.5]$$

Where:

Cg_t = capital investment in generation in the year t
Ct_t = capital investment in transmission in the year t
Cd_t = capital investment in distribution in the year t

Expenses Ex_t include fuel costs and both fixed and variable operation and maintenance costs. Variable costs, such as fuel costs, depend on the amount of energy generated from a given plant. Fixed costs, on the other hand, are usually expressed as constant annual values, independent of the amount of energy generated. Therefore:

$$Ex_t = Cfuel_t + Cvar_t + Cfix_t \qquad [Eq.\ 4.6]$$

Where:

$Cfuel_t$ = fuel expenses in the year t
$Cvar_t$ = variable operation and maintenance costs in the year t
$Cfix_t$ = fixed operation and maintenance costs in the year t

Regarding taxes T_t , they will be ignored for the remainder of this chapter for the sake of simplicity. However, Appendix 4 discusses taxes in more detail and shows a simple method for incorporating taxes into revenue requirement calculations. We can assume that taxes vary proportionally with investments, and that taxes and investments can therefore be combined into one term, as outlined in Appendix 4:

$$PW(I_t) + PW(T_t) = PW(I^*_t) \qquad \text{[Eq. 4.7]}$$

Where:

$PW(I_t)$ = present worth of capital investments in year t
$PW(T_t)$ = present worth of taxes in year t
$PW(I^*_t)$ = present worth of capital investments in year t including taxes

Therefore, the explicit tax term can be removed from equation 4.4, which can be rewritten as:

$$RR_t = I^*_t + Ex_t, \qquad \text{[Eq. 4.8]}$$

in which I^*_t incorporates taxes as a given fraction of investment expenditures.

The following example provides a simplified illustration of the calculation of utility revenue requirements.

Example:

An electric utility expansion plan for the period 1995-2005 includes investments in supply capacity (generation, transmission, and distribution) of $7 million in 1997, $2 million in 1999, and $1 million in 2001. The annual operating costs (fuel, fixed O&M, and variable O&M) remain constant at $1 million per year during the entire period. What is the present worth (at the beginning of 1995) of the revenue requirements for this plan? Use an annual discount rate of 6%/year. Assume no RR_0, and assume that taxes are included in the investment figures.

First, we sum the cost components to determine the annual revenue requirements. Then we take the present worth (at 6%) of each annual value. The sum of the present worth series is the total present worth of the revenue requirements, $15.92 million.

Year	Capital Investment	Operating Expenses	Annual Revenue Requirement	Present Worth of Annual Revenue Requirements
1995	0	1	1	0.94
1996	0	1	1	0.89
1997	7	1	8	6.72
1998	0	1	1	0.79
1999	2	1	3	2.24
2000	0	1	1	0.70
2001	1	1	2	1.33
2002	0	1	1	0.63
2003	0	1	1	0.59
2004	0	1	1	0.56
2005	0	1	1	0.53
Total Present Worth of RR in Beginning of 1995:				15.92

Note that we have assumed that all expenditures occur at the *end* of each year, and that the present worth is calculated at the *beginning* of 1995. Therefore, for example, the 1995 expenditure of $1 million is divided by (1+r) or 1.06 to obtain its value of $0.94 million at the beginning of the year. If we had assumed that the $1 million expenditure had occurred at the beginning of 1995, then the present worth of the 1995 expenditure would have been the full $1 million. Therefore, assumptions about when expenditures are incurred do impact the present worth calculations.

The $15.92 million revenue requirements can be expressed in a variety of ways, such as an equivalent annualized value using the capital recovery factor described in Appendix 3:

$$CRF = Capital\ Recovery\ Factor = A/P = \frac{r}{\left[1-(1+r)^{-t}\right]} \qquad [A3\text{-}7]$$

With r = 0.06 and t = 11 years, CRF = 0.127. Since $A = PW \cdot CRF$, A = $2.02 million. So, the $15.92 million present worth of the revenue requirements could also be expressed as an annual revenue requirement of $2.02 million.

C.2. Marginal Energy and Capacity Costs

A cost minimization analysis, following equations 4.1 and 4.2, would tell us that the least-cost combination of different resources is one where the marginal cost of each resource is equal (assuming diminishing returns to scale). As the total supply is increased, this marginal cost threshold increases and indicates how much of each resource should be included in the least-cost mix. In practice, where energy supply and DSM resources are available in finite amounts, this means that the least-cost mix can be found by ranking the available resources in order of marginal cost and selecting those with the lowest marginal costs. Resources of increasing marginal cost are added until the total supply satisfies the total projected demand. If, in the process of expanding total supply to meet projected demand, the projected tariff changes enough that projected demand changes, then the projected total supply would in turn have to change as well. The projection of future required capacity is therefore an iterative process between demand and supply projections.

Figure 4.1 graphically illustrates how the optimum mix of energy supply and energy savings (e.g., DSM) occurs at the point where the marginal cost of adding an extra unit of energy supply equals the marginal cost of adding an extra unit of energy savings.

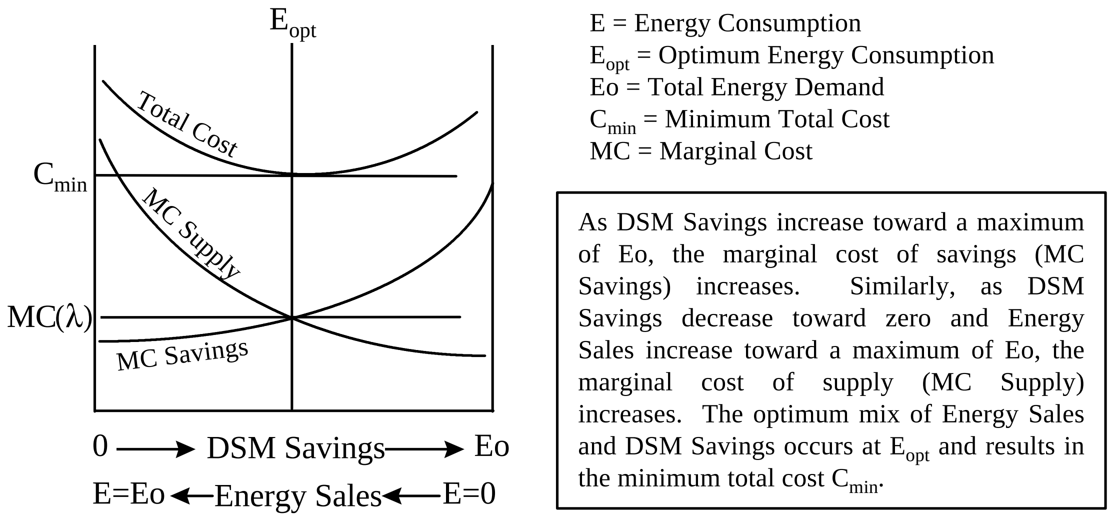


Figure 4.1. The least-cost combination of energy supply and DSM savings is at the level where the marginal cost of increasing either resource is equal. In an actual IRP analysis, multiple options of both types would be considered and evaluated in this framework.

A utility's marginal costs provide the economic basis of comparison against which a DSM program or independent supply resource must be evaluated. The <u>long-run</u> marginal cost value must include both the one-time cost-terms related to the production *capacity* and the recurring cost-terms that relate to the amount of *energy* produced (i.e., the <u>short-run</u> marginal cost). The <u>long-run</u> marginal cost should be used to compare new resources for future planning. A simple expression for the long-run marginal cost (MC), is:

$$MC = (MCC \cdot \Delta kW) + (MEC \cdot \Delta kWh/crf) \qquad [Eq.\ 4.9]$$

Where:

- *MC* = long-run marginal cost
- *MCC* = marginal capacity cost (depends on system expansion plan)
- *dkW* = marginal increment in capacity (depends on coincidence of peak demand)
- *MEC* = marginal energy cost (depends on system expansion plan and dispatching)
- *dkWh* = marginal increment in annual energy use (depends on annual load profile)
- *crf* = capital recovery factor (depends on discount rate and amortization time)[2]

In other words, the benefits of an energy efficiency program would be defined by the sum of the program's impact on energy use and its impact on future supply capacity additions. The energy and capacity terms in equation 4.9 can be related to incremental changes in electric demand, either increases from growth in energy services or decreases from energy efficiency or load management programs. As explained in Chapters 2 and 3, the effects of such programs vary according to the technology used and the load profile of the energy end-use.

[2] crf = capital recovery factor = annuity value / present value = $r / [1-(1+r)^{-t}]$ {Units: $year^{-1}$ }

The increment in annual energy use, δkWh, caused by an energy efficiency program could result from a constant energy reduction over the entire year (e.g., from refrigerators which operate 24-hours per day), or it could be the sum of hourly changes in energy use which vary daily and/or seasonally (e.g., lighting or air conditioning).

The marginal increment in capacity δkW is the effect of an energy efficiency or load management program on the utility's peak demand, which occurs only during certain hours of the year and which drives the need for new supply capacity. The value of δkW therefore depends on the timing of the changes in end-use demand and the degree to which these demand impacts coincide with the utility's peak demand. If a program has its full effect during peak demand hours, then δkW is equal to the program's maximum demand reduction. Otherwise, δkW would be a lower value. An extreme case would be that the program has no effect during peak hours, and then δkW would be zero.

The cost terms in equation 4.9 can be related to the cost definitions given in equations 4.8 and 4.6 by observing that all investment costs, including tax effects, are part of the capacity cost, along with the fixed operating costs. Thus, I^*_t and $Cfix_t$ are components of MCC[3]. The remaining expenses for fuel and variable operating costs are proportional to the energy produced. Thus, $Cfuel_t$ and $Cvar_t$ are components of MEC.

In practice, each of the cost terms in equation 4.9 is evaluated for each hour of the year, and the results are summed to estimate the full marginal costs. The two cost terms in equation 4.9 are usually determined by *production-cost models* that determine system capacity requirements and minimize variable operating costs (including fuel) by the optimal dispatch of generating sources, subject to accepted system reliability criteria.

A common generation reliability criterion is the maximum annual *loss-of-load probability* (LOLP), which can be derived using production cost-models and provides a measure of the statistical likelihood that the energy demand cannot be met by the supply system.[4] A simpler criterion for supply reliability is simply the excess supply capacity, or *reserve margin*, which can be estimated without complex analysis and production-cost models.[5]

---

[3] Note that capital and fixed operating costs are part of the marginal cost of supply capacity that has not yet been built. In a sense, this is a variable cost with regard to future supply levels. Once the capacity is built, these fixed costs are sunk and are no longer part of the utility's marginal costs.

[4] A common measure of the reliability of a power generation system is the *loss-of-load probability* (LOLP), which is the probability that system demand will exceed capacity during a given period. This probability value is based on the estimated probability that one or more generating resources will be out-of-service at a given time, combined with the probability distribution of the system demand. The LOLP is determined by running *production-cost models* that simulate the operation of the power supply system, treating each supply resource as having a certain probability of unplanned outages.

[5] Distribution systems have separate reliability criteria. A common way to determine distribution system reliability is to use two contingency security criteria (Crane and Roy 1992). The normal criterion is that forecasted loads can be met without overloading any facility in the system, and the emergency criterion is that the failure of any facility can be compensated by other facilities without exceeding their emergency capacity for a limited time.

a.) Marginal Energy Cost

Hourly marginal energy costs depend on which generation plants are dispatched at a given time. These values can be derived directly from production-cost models and should be adjusted upward to account for transmission and distribution losses.

Fundamentally, the hourly marginal energy cost represents the quantity (Δ Total System Energy Cost) ÷ (Δ Total System Energy) in each hour. This can best be illustrated by a simple example:

Example:

> Suppose that in a given utility system, there are only two power plants: a 200 MW coal plant with an energy cost of \$0.03/kWh, and a 50 MW gas plant with an energy cost of \$0.04/kWh. Suppose that in hour *h*, both plants are operating at full capacity. Then, the total energy generated in that hour would be (200 MW + 50 MW) · (1 hr) = 250 MWh; and the total system energy cost would be (\$0.03/kWh · 200 MWh + \$0.04 · 50 MWh) = \$8000. Suppose then, that total energy consumption in that hour is reduced by 1 MWh. In that case, because the gas plant is more expensive to operate, the gas plant's production (rather than the coal plant's) would be reduced by 1 MWh in that hour. In other words, the total energy generated in that hour would now be (200 MW + 49 MW) · (1 hr) = 249 MWh; and the total system energy cost would be (\$0.03/kWh · 200 MWh + \$0.04 · 49 MWh) = \$7960.
>
> The system marginal energy cost in that hour would be (\$8000 - \$7960) ÷ (250 MWh - 249 MWh) = \$0.04/MWh. So we see that the system marginal energy cost is equivalent to the energy cost of the gas plant, i.e., the most expensive operating plant in that hour.
>
> Now suppose that the demand in hour *h* is still 249 MWh, but in addition to the above coal and gas plants, the utility system also contains a 50 MW diesel plant with an energy cost of \$0.08/kWh. Now what would the system's marginal energy cost be in hour *h*?
>
> The system marginal energy cost would still be \$0.04/kWh. The diesel plant's \$0.08/kWh cost would not affect the marginal energy cost because the diesel plant would not be required to operate at the 249 MWh energy demand level. On the other hand, if in the following hour (*h+1*) the demand is 280 MWh, then the diesel plant would be required to operate, so the marginal energy cost in hour *h+1* would be \$0.08/kWh.

Therefore, the marginal energy cost can be derived from a production cost model by looking at the hourly changes that occur in the total system energy cost and the total system energy consumption. This can be represented algebraically as the difference between scenarios A and B as follows:

$$MEC = \sum_{h=1}^{h=8760} \frac{\left[TEC_{(h)}\right]_A - \left[TEC_{(h)}\right]_B}{\left[E_{gen(h)}\right]_A - \left[E_{gen(h)}\right]_B} \qquad \text{[Eq. 4.10]}$$

Where:

MEC = marginal energy cost {units = \$/kWh}
$TEC_{(h)}$ = total system energy cost (fuel and variable costs) in hour *h* {units = \$}
$E_{gen(h)}$ = total electricity generated in hour *h* {units = kWh}

Example:

Suppose that Scenario A in equation 4.10 represents an Energy Efficiency scenario, and Scenario B represents the Baseline scenario. For Scenario A, if we add up the hourly system energy cost (i.e., hourly fuel and variable O&M costs) for the year, the total equals $10 million, corresponding to a total yearly generation of 200,000 MWh. In Scenario B, the yearly total system energy cost equals $12 million, corresponding to a total generation of 235,000 MWh. Then MEC = ($10 million - $12 million) ÷ (200,000 MWh - 235,000 MWh) = $0.057/kWh. This MEC value, showing the change in total system energy costs divided by the change in total electricity generated, represents the value of each kWh saved through the Energy Efficiency program in Scenario A.

Another more simplified way to visualize the system's marginal energy cost is as an average of the fuel plus variable costs of each hour's marginal supply source. Ignoring transmission losses for the moment, the yearly system marginal energy cost could then be presented as follows:[6]

$$MEC = \frac{1}{8760} \cdot \sum_{h=1}^{h=8760} \frac{C_{en(h)}}{\Delta kWh} \qquad \textit{[Eq. 4.11]}$$

and

$$C_{en(h)} = \left[C_{fuel(h)} + C_{var(h)} \right] \qquad \textit{[Eq. 4.12]}$$

Where:

MEC = marginal energy cost {units = $/kWh}

$C_{en(h)}$ = cost of producing energy with marginal supply source in hour h {units = $}

$C_{fuel(h)}$ = fuel cost in hour h of marginal supply source without system losses {units = $}

$C_{var(h)}$ = variable costs in hour h of marginal supply source without system losses {units = $}

$DkWh$ = increment of energy produced by marginal supply source in hour h {units = kWh}

Example:

Suppose that in a given utility system, the year's 8760 hours are divided evenly (2920 hours each) into off-peak, intermediate, and on-peak periods. Assume that in the off-peak period, the marginal supply resource is a coal-fired plant, with costs (fuel + variable) of $0.03 for each kWh it generates. The marginal resource in the intermediate period is represented by a gas-fired plant with fuel plus variable costs of $0.04/kWh; and in the peak period the marginal resource is a diesel generator with fuel plus variable costs of $0.08/kWh. Ignoring transmission and distribution losses, what is the yearly system marginal energy cost?

---

[6] This simplified approach assumes that changes in energy demand (due to an energy efficiency program, for example) occur uniformly throughout the year, leading the annual marginal cost to be a straight average of each hour's marginal cost. In reality, changes in energy demand vary in magnitude over the day and year, so annual marginal costs should ideally reflect this variation and should weight different hours' marginal costs accordingly. However, this would require knowing beforehand the magnitude and timing of the changes in energy demand.

The yearly marginal energy cost would be calculated using equation 4.11 such that:
MEC = [($0.03/kWh) · (2920 hr/yr) / (8760 hr/yr)] + [($0.04/kWh) · (2920 hr/yr) / (8760 hr/yr)] + [($0.08/kWh) · (2920 hr/yr) / (8760 hr/yr)] = $0.05/yr.

As mentioned earlier, marginal costs should account for transmission and distribution (T&D) losses. In other words, in order to consume 1 kWh of electricity, the generator must produce more than 1 kWh because a fraction of the electricity will be lost in the T&D system. Therefore, if consumption changes by 1 kWh, the actual change in generation would be greater than 1 kWh. If we incorporate T&D losses, equation 4.11 becomes modified as follows:

$$MEC = \frac{1}{8760} \cdot \sum_{h=1}^{h=8760} \frac{C_{en(h)}}{\Delta kWh \cdot \left(1 - F_{loss(h)}\right)} \qquad \text{[Eq. 4.13a]}$$

and $$F_{loss(h)} = \frac{E_{gen(h)} - E_{sold(h)}}{E_{gen(h)}} \qquad \text{[Eq. 4.13b]}$$

Where:

$F_{loss(h)}$ = fraction of electricity generated in hour h that is lost
$E_{gen(h)}$ = total system electricity generated in hour h
$E_{sold(h)}$ = total system electricity demand (sales) in hour h

Example:

Suppose that the marginal energy cost is $0.05/kWh, ignoring T&D losses. If the total electricity sales = 1000 kWh but the total electricity generated = 1100 kWh, then F_{loss} = (1100-1000)/1100 = 0.09091. So, including T&D losses, MEC = $0.05/kWh ÷ (1-0.09091) = $0.055/kWh.

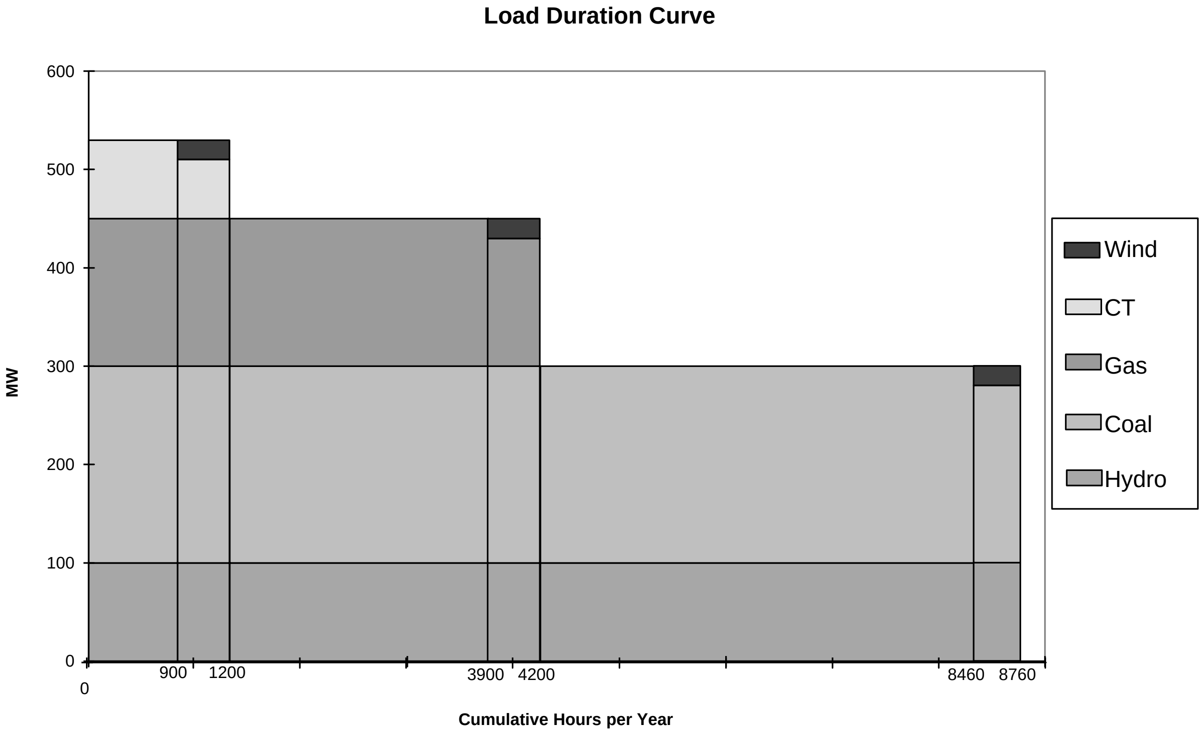
Equations 4.9 through 4.13 can be used directly when marginal energy costs do not vary much from year to year. If they are relatively variable, for example if significant changes are expected in the utility's future fuel mix, then each annual value of MEC must be estimated and discounted to a present worth, rather than using a uniform annual value with the crf.

Exercise 4.1) Using the table below, we can calculate the marginal energy cost of the coal-fired plant as follows: C_{fuel} = (10 GJ/MWh) · (1 $/GJ) / 1000 kWh/MWh = 0.01 $/kWh, C_{var} = 0.02 $/kWh, and MEC = 0.01 + 0.02 = 0.03 $/kWh.

Plant Type	Capacity (MW)	Heat Rate (GJ/MWh)	Fuel Cost ($/GJ)	Variable Cost ($/kWh)	Dispatch Position
Hydro	100	n/a	0	0.020	Baseload
Gas	150	12	2	0.016	Intermediate
Coal	200	10	1	0.020	Baseload
Comb. Turb. (CT)	80	15	2	0.023	Peaking
Wind	20	n/a	0	0.010	Must Run

Similarly, calculate the MEC values for the other resources listed, and the annual MEC for the system. Assume that peaking plants operate for 1200 hours/year, intermediate plants operate during those hours and an additional 3000 hours/year, baseload plants operate all 8760 hours/year, and that must-run plants operate for 900 hours evenly spread during each of the three dispatch periods. System peak demand is 530 MW. Ignore transmission and distribution losses for now. Remember, the marginal resource during a given dispatch period is the one with the highest energy cost.

In performing calculations like these, it is helpful to visualize the operation of the system through a load duration curve as shown below. The load duration curve graphically illustrates the total number of hours that each plant operates and the total electricity generated by each plant.



Exercise 4.2) In Exercise 4.1, if T&D losses are 10% during peak hours (when the CT plant is operating), 9% during intermediate hours (when the gas plant is operating but not the CT plant), and 8% during off-peak hours (when neither the gas nor CT plants are operating), then what is the annual MEC for the system including T&D losses?

b.) Marginal Capacity Cost

The marginal capacity cost (MCC) depends on the size and time-proximity of required new investments in generation and transmission capacity expansion. The schedule of planned investments can be taken from the utility *expansion plan*, which gives the required timing and mix of power stations to produce sufficient electricity (including reserve margins) for various intervals of time during the year. Baseload plants are needed to meet the minimum constant load, while peak-load plants need only run during a few peak-demand hours, and intermediate-load plants are needed during many but not all hours of the year. In addition, the distribution expansion plan includes the required timing and mix of investments in poles, conductors, substations, etc.

A supply *expansion plan* is developed using the following steps:[7]

1. subtract present load and expected retirements of supply capacity from present supply capacity to determine current excess capacity (beyond the required reserve margin),
2. divide excess capacity by the forecasted annual load growth to determine the time when present capacity will be exceeded,
3. identify available supply resources to meet the future needs, and
4. prepare a least-cost capacity-expansion plan to satisfy the forecasted load growth using available resources under accepted engineering reliability criteria.

The schedule of these investments provides the cost data from which the marginal costs can be estimated. Economically meaningful estimates of MCC require a costing method that captures the time-specific nature of supply-capacity investments, which are inherently "lumpy," in that they come in only a limited range of discrete sizes. Baseload generating stations are usually of the scale of several hundred MW, while peakload stations are typically sized in the tens of MW. Distribution equipment is also lumpy. Transformers, for example, typically have 10, 25, 37.5, 100, 176, 250, 333 or 500 kVA capacity (Pansini 1992).

Because supply capacity investments are lumpy, it is difficult to identify one increment of capacity as the marginal unit, because it is unlikely that such a unit will have the same size and operating schedule as the marginal change in load that is under consideration. Instead, it is more likely that a change in load will require the delay or acceleration of a particular investment or set of investments.

The appropriate costing method uses a present-worth approach, which determines the value of deferring an expansion plan for a given time period (see Orans 1989). The need for imminent expansion tends to increase the marginal capacity costs, because costs have a greater discounted present value if they occur sooner rather than later. Thus, marginal capacity costs are time-specific, although they are not location-specific, except to the extent that local load profiles are different (for example, due to a different climate) from the rest of the system.

Marginal capacity costs *(MCC)* fundamentally reflect the quantity (Δ Total System Capacity Cost) ÷ (Δ Total System Coincident Peak Demand). Let us illustrate this concept with the following example:

Example:

> Scenario A represents an Energy Efficiency scenario, and Scenario B represents the Baseline scenario. In a given year, Scenario A requires $80 million for capital investment and fixed O&M costs. In the same year, Scenario B requires $90 million for capital investment and fixed O&M. Scenario A has a coincident peak demand in that year of 215 MW, while Scenario B's coincident peak demand is 240 MW. The marginal capacity cost is then represented by ($80 million - $90 million) ÷ (215 MW - 240 MW) = $400/kW per year. This MCC represents the value of each kW of coincident peak demand reduced through the Energy Efficiency scenario in that year.

This can be represented by the following equation:

[7] In this chapter we will generally assume that these four steps have already been accomplished, and the utility's least-cost central-supply expansion plan is already given. The IRP process involves *adding* demand-side and other alternatives to this existing plan.

$$MCC = \sum_{t=0}^{t=n} \frac{I^*_{A(t)} + Cfix_{A(t)} - I^*_{B(t)} - Cfix_{B(t)}}{\Delta kW \cdot (1+r)^t} \qquad \text{[Eq. 4.14]}$$

Where:

- $I^*_{A(t)}$ = investment in year t for supply capacity in case A {units = $}
- $I^*_{B(t)}$ = investment in year t for supply capacity in baseline case B {units = $}
- $Cfix_{A(t)}$ = fixed operation and maintenance costs in the year t for case A {units = $}
- $Cfix_{B(t)}$ = fixed operation and maintenance costs in the year t for case B {units = $}
- dkW = coincident peak demand in case A minus coincident peak demand in case B {units = kW}
- r = utility's weighted-average cost of capital

However, in order to develop scenarios such as those presented in the example above, one needs not only a detailed utility capacity expansion plan, but also a detailed estimation of the magnitude and timing of the energy efficiency impacts, which are difficult to estimate in advance. A simpler method of estimating marginal capacity costs is therefore provided below.

The marginal capacity cost, often called the *avoided* capacity cost in the context of DSM, represents the economic benefit of avoiding a certain investment in capital equipment. As suggested above, this does not typically mean canceling plans to build a power plant outright, but rather *deferring* construction of the plant. The marginal capacity cost *(MCC)*, for a discrete increment of capacity can therefore be defined as follows:

$$MCC = \sum_{t=0}^{t=n} \frac{I^*_{(t)} + Cfix_{(t)}}{kW_{cap} \cdot (1+r)^t} \qquad \text{[Eq. 4.15]}$$

Where:

- $I^*_{(t)}$ = investment in year t for supply capacity {units = $}
- $Cfix_{(t)}$ = fixed operation and maintenance costs in the year t {units = $}
- kW_{cap} = generation capacity of marginal supply unit {units = kW}
- r = utility's weighted-average cost of capital

Example:

Calculate the MCC and the annualized MCC value for the wind generation plant from the list of resources below. The lead time indicates how long it takes to complete a plant, and assume that the total cost is evenly distributed to each year of the lead time. Use a discount rate of 6%/year, and assume that each of the plants would be built to begin operation in five years (i.e., no costs are yet sunk).

Plant Type	Capacity (MW)	Lifetime (years)	Lead Time (years)	Capital Cost ($million)	Fixed Cost ($million/year)	Dispatch Position
Hydro	100	50	2	110	0.5	Baseload
Gas	150	30	3	210	3.4	Intermediate
Coal	200	30	5	300	5.0	Baseload
Comb. Turb.	80	20	1	40	2.1	Peaking
Wind	20	20	2	28	0.5	Must Run

We calculate the MCC values as present worths at the beginning of year 5 when the plant begins operation. For wind, the lead time is two years, so half the capital cost ($14 million) is incurred during the year before operation (end of year 3) and the other half at the end of year 4. The present worth in year 0 is thus $14/(1.06)^3 + 14/(1.06)^4$ = $22.8 million. The present value of this cost at the beginning of year 5 is $22.8 \cdot (1.06)^4$ = $28.9 million. Note that, because of the lead time, the total cost in the year when the plant enters service is higher than the simple capital cost.

The crf is 0.087 (20 year lifetime, 6%). The present value of the fixed cost is the annual fixed cost divided by the crf, or $0.5 million ÷ 0.087 = $5.7 million. The total present value of MCC at the beginning of year 5 is thus $28.9 million + $5.7 million = $34.6 million, or $1730/kW. To get the annualized MCC value, multiply by the crf: 1730 · 0.087 = $151/kW/year.

Please use the table in the above example to complete the following exercise.

Exercise 4.3) Calculate the MCC and annualized MCC values for the other resources listed in the above table.

As you can see in the above example, the MCC of a project will be affected by the timing of the investment in the project. In other words, if a project is accelerated or deferred, this will change the MCC. So, an Energy Efficiency case, "case A," might add the same units of capacity as the baseline "case B," but as a result of energy efficiency improvements in case A, some supply capacity units might be built at a later time. Delaying a capital investment provides a cost saving, because of the time value of money (discounting).

In the example of the wind energy plant above, the annualized MCC equals $151/kW/year. This means that for each year that construction of the wind plant can be deferred through energy efficiency, the deferral will be worth $151/kW in that year. This means that if the wind plant could be deferred for 20 years (its full economic life), the present value of those deferrals would sum up to $1730/kW, or the full capital cost of the plant.

A one-year deferral value equals the difference between the present worth of the expansion plan and the present worth of the expansion plan deferred one year, adjusted for inflation and technological progress. If an energy efficiency program can reduce the baseline demand by more than one year's load growth, the length of the deferral is determined by the ratio of the load reduction to the baseline load growth. The value of capacity investments to serve s years of load growth, or the value of deferring new capacity for s years, can be expressed by modifying equation 4.15 as follows:

$$MCC = \sum_{t=0}^{t=n} \left[\frac{I^*_{(t)} + Cfix_{(t)}}{(1+r)^t} - \frac{\left[I^*_{(t)} + Cfix_{(t)} \right] \cdot (1+f)^s}{(1+r)^{t+s}} \right] \bigg/ kW_{cap} \qquad [Eq.\ 4.16]$$

Where:

$I^*_{(t)}$ = investment in year t for supply capacity {units = $}
$Cfix_{(t)}$ = fixed operation and maintenance costs in the year t {units = $}
kW_{cap} = generation capacity of marginal supply unit {units = kW}
r = utility's weighted-average cost of capital
f = technology-specific inflation rate net of technological progress
s = years of deferral = dkW ÷ (annual load growth)

Because of the lumpy nature of investments in supply capacity, the expansion plan must allow for the addition of new resources before their entire capacity is needed (see Figure 4.2). The planner may have to choose, for example, between a large power station that will cause excess capacity for several years and several smaller plants timed to come on-line after shorter time intervals. In addition, the lead time required to build new facilities means that investments must be made in advance of the year in which the facilities enter service, increasing the present-worth capital cost of the facilities.

The MCC value tends to increase as new capacity begins construction, and then falls after its completion when the costs are sunk (see Figure 4.2). This time variation arises because the present-worth approach is forward-looking, i.e., it ignores past investments and applies a high value to imminent investments needed to prevent an approaching capacity shortage. Once an investment is in place and its cost is sunk, the resulting excess capacity pushes future investments farther away on the planning time-horizon; so the marginal capacity cost can then fall to almost zero following the construction of a large new power plant which creates significant excess capacity.

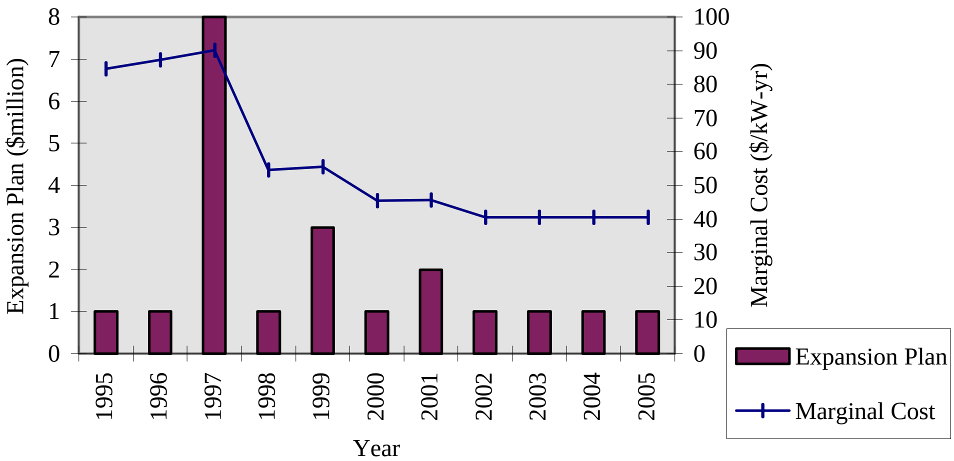


Figure 4.2. Typical time-distribution of capacity investments and marginal capacity costs

The marginal capacity cost can be allocated to each hour of the year according to the hourly contribution to the annual loss-of-load probability (LOLP) (Vardi 1977).

$$C_{cap(h)} = \frac{MCC \cdot \Delta kW \cdot P_{(h)}}{LOLP} \qquad \text{[Eq. 4.17]}$$

Where:

$C_{cap(h)}$ = marginal capacity cost allocated to hour h {units = \$}
MCC = annual marginal capacity cost {units = \$/kW}
DkW = increment of marginal capacity {units = kW}
$LOLP$ = total annual loss-of-load probability
$P_{(h)}$ = contribution of hour h to the annual LOLP

Using this hourly marginal capacity cost in conjunction with the hourly marginal energy costs contained in Equation 4.11, the overall system marginal cost can be calculated for any hour of the year.

c.) Other Marginal Cost Indicators

So far in this section, we have discussed ways of calculating marginal energy costs (MEC) and marginal capacity costs (MCC) in order to be able to calculate the overall long-run marginal cost (MC) presented in equation 4.9:

$$MC = (MCC \cdot \Delta kW) + (MEC \cdot \Delta kWh/crf) \qquad [Eq.\ 4.9]$$

Here, we will outline some other methods of presenting marginal costs. MC, calculated using equation 4.9, can be normalized to give estimates of the marginal cost per unit of energy, which can be used to compare alternative measures such as energy efficiency or DSM programs. In such a comparison, the marginal supply cost is treated as the *avoided cost*, i.e., the marginal cost that is avoided by substituting energy efficiency improvements, cogeneration or other measures in place of the incremental energy supply resources in the existing expansion plan.

The marginal cost of energy (MCOE) is the annualized value of MC, divided by the increment of annual energy produced; and this value has the standard electricity-cost units of \$/kWh. The capital recovery factor with which MC is annualized is based on the weighted-average cost-of-capital (WACC) (see Appendix 4) as the discount rate and the number of years in the planning period as the amortization time.

$$MCOE = \frac{MC \cdot crf}{\Delta kWh} \qquad [Eq.\ 4.18]$$

The marginal cost values can also be normalized to give estimates of the marginal cost per unit of supply capacity.

$$MCOC = \frac{MC}{\Delta kW} \qquad [Eq.\ 4.19]$$

C.3. Capacity Factor and Load Factor

Calculation of MCOE and MCOC involves conversions between energy (kWh) values and capacity (kW) values. The value of MCOC for a specific increment of supply capacity depends on the number of hours per year that the capacity is used. The extent to which a generating plant is operated during the year is indicated by its *capacity factor (CF)*, which is simply the ratio of its average production to its peak production, or its total production to its potential production if operated constantly at full capacity.

$$CF = \frac{kWh/yr\ electricity\ produced}{(kW\ peak\ capacity) \cdot (8760\ hr/yr)} \qquad [Eq.\ 4.20]$$

Example:

What is the annual electricity produced by a 20 MW geothermal station with a capacity factor of 0.80, and by a 50 MW combustion turbine (CT) with a capacity factor of 0.30?

Equation 4.20 can be re-written as kWh/yr = kW peak capacity · 8760 hr/yr · CF. Thus,
Geothermal: 20MW · 8760hr/yr · 0.80 = 140,160 MWh/yr
Combustion turbine: 50MW · 8760hr/yr · 0.30 = 131,400 MWh/yr

By substituting the expression for MC from equation 4.9 into equations 4.18 (MCOE) and 4.19 (MCOC), and substituting equation 4.20 into the resulting expressions for kWh/kW, we can obtain the following alternate definitions of MCOE and MCOC:

$$MCOE = \frac{MCC \cdot crf}{8760 \cdot CF} + MEC \qquad \text{[Eq. 4.21]}$$

$$MCOC = MCC + \frac{8760 \cdot CF \cdot MEC}{crf} \qquad \text{[Eq. 4.22]}$$

Exercise 4.4) Calculate the MCOE for generating stations with the costs and capacity factors shown below. Note that $C_{fuel(t)}$ and $C_{var(t)}$ are components of MEC and that $I^*_{(t)}$ and $C_{fix(t)}$ are components of MCC, which is shown below in annualized form. By providing the annualized MCC values (MCC · crf), we make it unnecessary to know the economic life of each plant in order determine the crf value for each power source.

Power Source	Capacity (MW)	Capacity Factor	Variable Cost ($/kWh)	Marginal Capacity Cost ($/kW-yr)
Hydro Existing	1200	0.50	0.020	0
Gas Existing	600	0.50	0.040	0
Coal Existing	420	0.75	0.030	0
Coal Retrofit	400	0.75	0.040	50
New Gas	200	0.75	0.035	130
New Coal	200	0.75	0.030	150
New Coal w/Scrubbers	200	0.75	0.040	180
Wind Farm	500	0.30	0.010	150
Combustion Turbines	50	0.20	0.055	70

As shown in Figure 4.3, the annual supply costs, and thus the MC and MCOC values, increase as the capacity factor increases. Of course, the MCOE would actually decrease with increasing capacity factor because the capital and fixed costs are spread over more kWh of energy production. The capacity factor is not something that is inherent in the design of a power station; it depends on how the plant is used according to its place in the expansion plan and the dispatch ranking. Therefore, the value of MCOC applies only to a specific increment in a specific expansion plan. In order to compare supply resources directly, the capacity cost is often expressed simply according to MCC, values that are independent of operating hours or capacity factor. Such an estimate of capacity cost alone assumes a CF value of 0.

The ratio of the annual average hourly demand to the maximum peak demand is the utility's *load factor (LF)*, which is a measure of the variability of the load. A constant demand would give a load factor of 1, while a variable demand with a sharp peak would have a low load factor. Expressed graphically, the load factor is the ratio of the area under the load-duration curve (total annual energy demand) to the area of the rectangle with a width of 8760 hours and a height equal to the peak demand (as if the demand were constant at this level). This is expressed algebraically as follows:

$$LF = \frac{kWh/yr\ electricity\ consumed}{(kW\ peak\ demand) \cdot (8760hr/yr)} \qquad [Eq.\ 4.23]$$

Example:

What is the load factor for an end-use that has the following daily profile, 365 days per year? What is the total annual energy use?

Hour	**Demand (MW)**	**Consumption (MWh/day)**
Midnight-6am	1.0	6
6am-Noon	3.0	18
12-3pm	4.0	12
3-4pm	5.0	5
4-8pm	4.5	18
8pm-Midnight	2.5	<u>10</u>
Total		69

Total energy consumption = 365 days/year · 69 MWh/day = 25,185 MWh

Peak demand = 5.0 MW. Therefore, LF = 25,185 MWh / (5 MW · 8760 hr/yr) = 0.575

Exercise 4.5) What is the load factor for the electricity demand described by the load-duration curve in Figure 4.4? What is the total annual energy use?

A load factor can be calculated for the entire system, for customer classes, or for individual end-uses, and the value depends on the time-profile of the load considered. This is analogous to the capacity factor, which depends on the amount of time and the level of output at which a supply resource or the supply system as a whole is operated.

D. Supply System Integration

D.1. Supply Resource Screening

Figure 4.3 illustrates some of the production-cost parameters of different types of supply resources. The sample set of resources will be used in the examples of IRP analysis later in this chapter.

The cost values are the MCOC annualized by multiplying by the crf. Some plants, such as combustion turbines (CTs), have low capital costs but high fuel and variable operating costs, and these plants are used only for peakload power. Other plants, such as central coal and hydroelectric plants, have higher capital costs but lower fuel and variable operating costs, and such plants are used to provide baseload power. The higher initial costs are justified by the economy of running these plants most of the time. The existing plants including the hydro plant listed in Figure 4.3 have the lowest costs because their capital costs are already sunk, and only fixed and variable operating costs, or incremental costs of retrofit measures, should be counted.

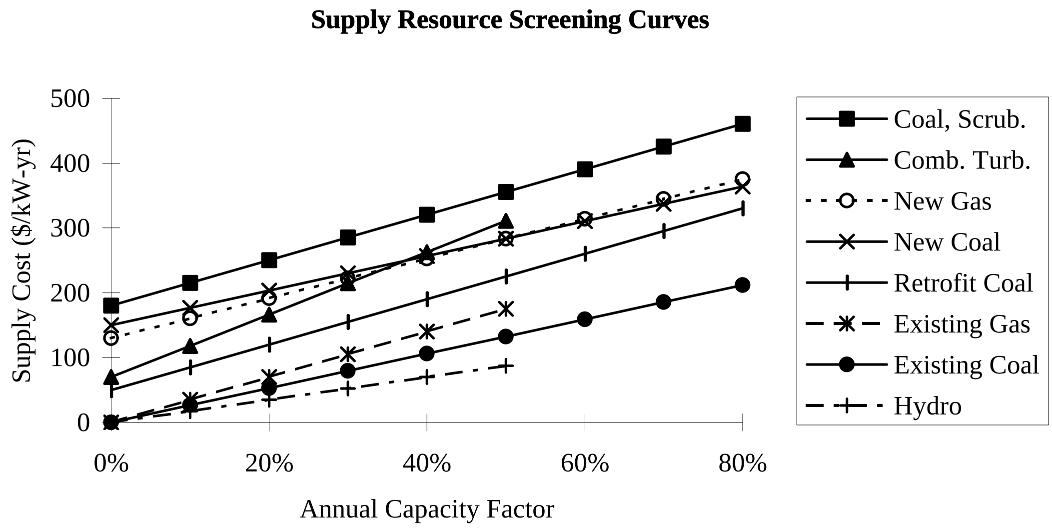


Figure 4.3. Annual supply costs for plants operated for different numbers of hours per year

The least-cost supply resource depends on the capacity factor that is needed to meet the incremental demand for new capacity. Of the new plants, the least expensive resources are the coal plant (without scrubbers) for baseload, the gas plants for intermediate-load (capacity factor [CF] between 35% and 50%), and the combustion turbines for peaking. Over time, a mix of low-CF peaking plants, medium-CF intermediate-load plants and high-CF baseload plants will be needed. The least-cost combination will therefore depend on the frequency of different levels of demand during the year, as shown by the utility's *load-duration curve*, illustrated in Figure 4.4.

The use of the load-duration curve can be illustrated by taking the cost values from Figure 4.3 and determining how much capacity of the three types would be the least cost supply mix. For new capacity, for a capacity factor of 50% or more, baseload coal plants are the least expensive. This corresponds to a demand of 5700 MW of baseload capacity, which are operated as much as possible due to their low variable costs. For a capacity factor of 35% or less, combustion-turbine peaking plants are the least expensive. This corresponds to a demand of more than 6500 MW, up to a maximum of 10,000 MW, requiring 3500 MW of peakload capacity that are operated only during a limited number of hours. For the 15% of the time when the load is between 5700 MW and 6500 MW, the least-cost resource at the corresponding capacity factor is the intermediate-load gas-fired plants, which should have a total capacity of 800 MW and are operated whenever the load exceeds the capacity of the baseload plants.

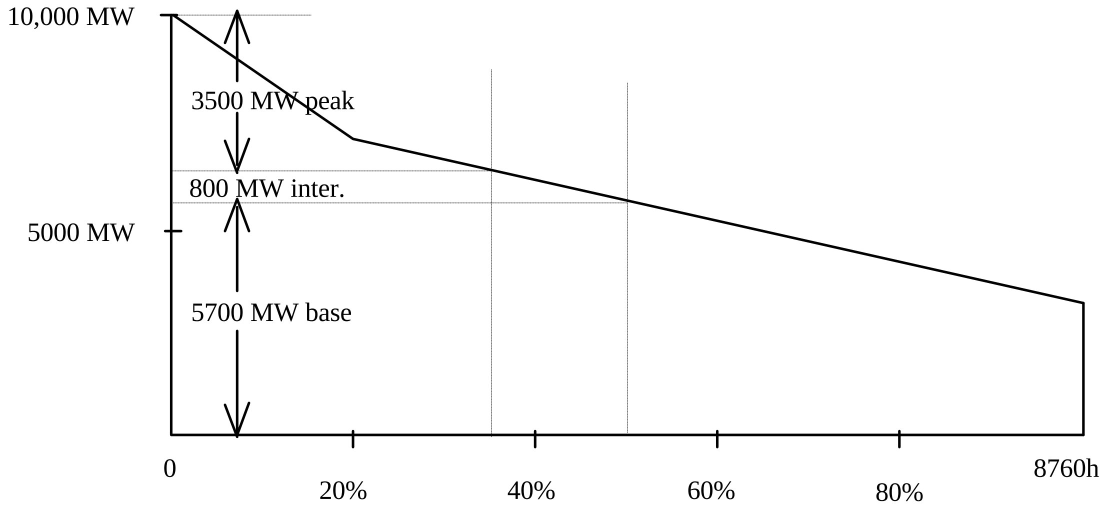


Figure 4.4. Sample load-duration curve

The example illustrated in Figure 4.4 assumes that all capacity consists of new additions of thermal capacity. The situation is more complicated when one considers existing capacity and hydro resources. Such analysis requires complex iterative calculations that are beyond the scope of the present discussion. However, we can illustrate the conceptual approach with a simplified example, shown in Figure 4.5, also based on the load-duration curve. In this case existing baseload coal and intermediate-load gas-fired capacity are shown by rectangles indicating those resources' total capacity and maximum capacity factor. The area of each rectangle is the plants' annual energy production.

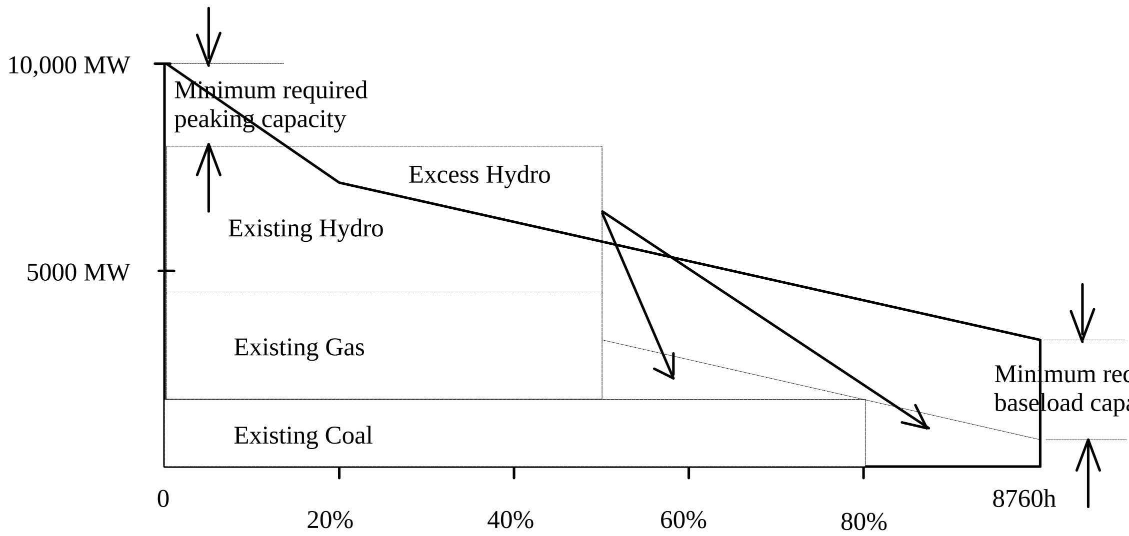


Figure 4.5. Sample load-duration curve including existing capacity

Hydro capacity is shown by an additional rectangle in Figure 4.5, such that the total energy production from hydro surpasses the demand for intermediate-load supply. Although the total hydro capacity is fixed, we can assume that it is possible to reduce the average hydro output and increase the operating hours, as if this resource had a lower capacity and higher capacity factor. This is possible because the total annual output of the hydro resource is determined by the annual amount of water captured and stored in reservoirs, regardless of the power capacity.

Figure 4.5 shows an approximate analysis of the use of the hydro resource. The excess hydroelectric energy is shifted to provide additional baseload, indicated by moving an equivalent area (representing energy) from above the demand curve to the lower right section under the curve. Without this addition, the baseload requirement would be about 4000 MW (5700MW as above less about 1700 MW of existing coal). However, the excess hydro resource reduces this requirement to about 2500 MW. In addition, about 2000 MW of peak load capacity are still needed.

Real electric supply planning is more complex than the simple process illustrated above using the load-duration curve. The loads are variable and difficult to predict, and supply resources may not be available at all times. These uncertainties are reasons for maintaining a reserve margin, such that total supply capacity, at the generation, transmission and distribution levels, almost always exceeds the maximum expected demand. One way of thinking about the use of the load-duration curve as illustrated above is to assume that the demand levels shown include the reserve margin needed to ensure that a given level of demand can be met with adequate reliability.

In practice, supply resources such as generating plants are lumpy investments that come in discreet and often large sizes. Thus, one can never add exactly the correct amount of baseload, intermediate- and peakload capacity as required each year. Instead, a real utility expansion plan must select individual types of plants in discreet sizes to begin service in specific years in order to meet present and anticipated (but uncertain) future demand. Thus, the selection of these plants must maintain a balance between the different types of plants, according to the pattern of load growth and retirements of existing plants, in order to achieve the least-cost resource mix.

The criterion for determining when and how much supply capacity should be added is generally the system peak demand, except for distribution capacity which is driven by local area peaks (see Appendix 5). As long as the total generating and transmission capacity is sufficient, it is assumed that the generating plants can be run at a high enough capacity factor to meet the total energy demand, i.e.,

$$\textit{Annual electricity produced} > \textit{Annual electricity consumed} \qquad \text{[Eq. 4.24a]}$$

Substituting the definitions of capacity factor (CF) and load factor (LF) from equations 4.20 and 4.23:

$$CF_{system} \times \textit{kW peak capacity} > LF_{system} \times \textit{kW peak demand} \qquad \text{[Eq. 4.24b]}$$

If peak capacity is approximately equal to peak demand plus reserve margin:

$$CF_{system} \cdot (1 + \textit{reserve margin}) > LF_{system} \qquad \text{[Eq. 4.24c]}$$

As Figure 4.5 shows, hydroelectric resources can add to the flexibility of system operation, because the potential energy stored in hydro reservoirs allows this resource to be dispatched as either intermediate or baseload. Systems with a large share of hydroelectric generating capacity, however, are more complex. The capacity-factor criterion given above may not be sufficient to ensure that the total energy requirement is met. Because hydro plants are limited in the total amount of water they can capture during a year, they are an *energy-limited resource*, in contrast to a strictly *capacity-limited resource* such as a thermal plant. A hydro-dominated system can therefore also be energy limited. If so, the maximum capacity factor may be such that the inequality of equation 4.24 is not satisfied, and additional generating capacity is needed to meet the energy demand.

As shown in Figure 4.3, the variable operating costs of hydroelectric plants are typically very low. Thus, one would expect such plants to be operated as baseload capacity and run as much of the time as possible. However, the water that feeds the hydroelectric plants may not be available in uniform quantities during the year. If there is a pronounced wet season, more water may accumulate than can be stored, in which case it must be used to generate power or spilled from the reservoir. Providing enough storage capacity to store all wet-season precipitation for the dry season may be expensive and also inefficient, as evaporation losses would increase. Instead, the operation of hydroelectric capacity typically follows to some degree the availability of rainfall (or melting snow). In this way, hydro resources are somewhat similar to intermittent renewable resources, especially those with partial storage such as some solar-thermal power technologies.

This timing of the maximum hydroelectric output may or may not correspond to the time of peak demand. The impact on the supply system can be simply analyzed by treating the hydroelectric output as a negative load that reduces the load that must be met by thermal plants (Figure 4.6a and 4.6b). This approach requires matching the hourly hydroelectric output with the loads for the corresponding hours. If the peak demand is in the wet season, the remaining load is relatively uniform (high load factor) and can be met with thermal plants running at a high capacity factor as illustrated in Figure 4.6a. If the peak demand is in the dry season, however, the load remaining for thermal plants would be large in the dry season and small in the wet season (low load factor), indicating a low capacity factor for some of the thermal plants as illustrated in Figure 4.6b.

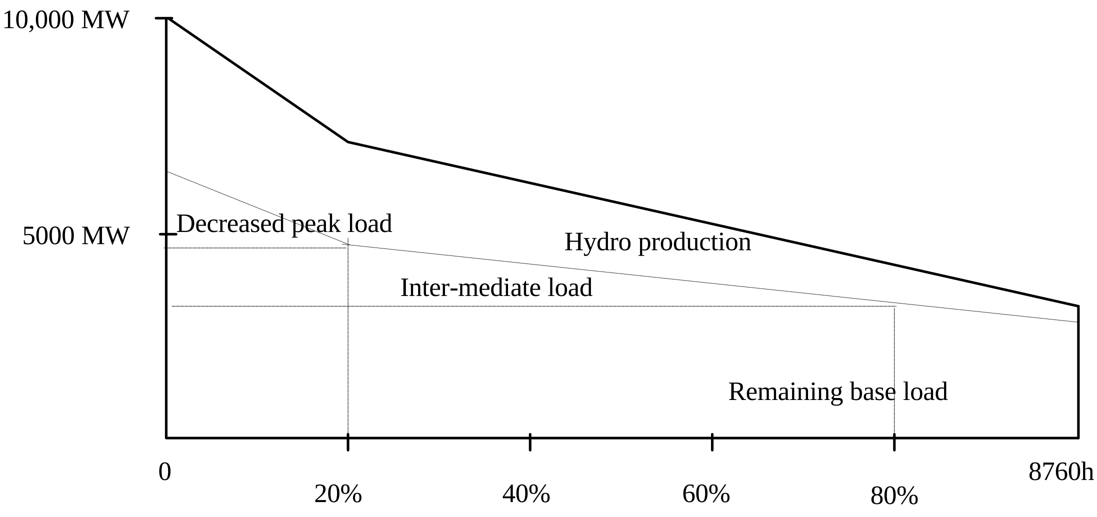


Figure 4.6a. Load-duration curve for a hydro-dominated system (wet season peak)

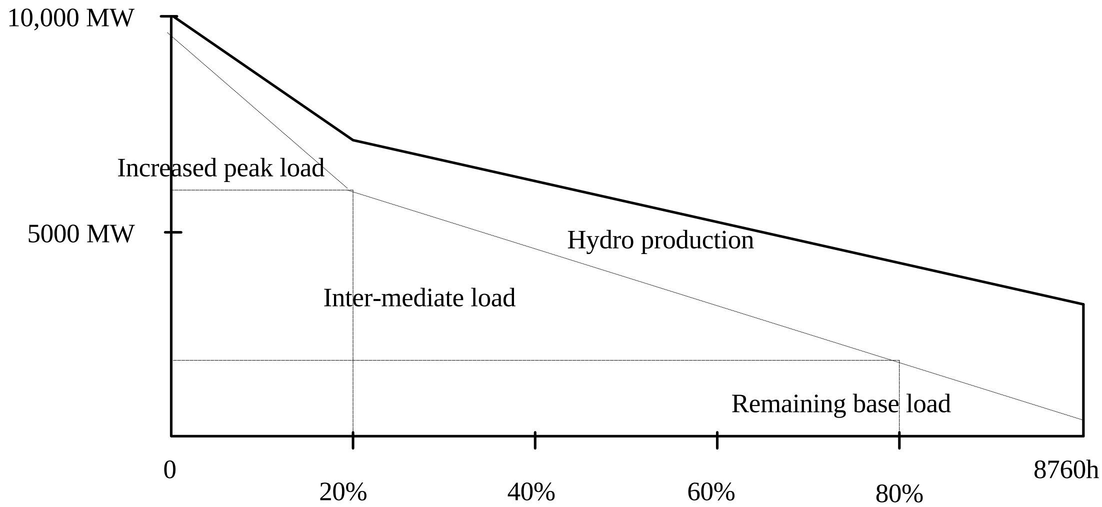


Figure 4.6b. Load-duration curve for a hydro-dominated system (dry season peak)

Most of the present discussion on electric supply options is focused on generation planning, and we shall not go into transmission planning in detail. Rather complex network-flow models are used to design transmission systems, and this topic is beyond the scope of the present discussion. We will simply assume that capacity requirements and investment costs for bulk transmission facilities are approximately proportional to total generating capacity, and that these costs can thus be treated in the same manner as generation costs.

We approximate the effect of transmission system energy losses on system-level generation planning by using the loss factor described earlier. We assume that this loss factor value applies uniformly to the electric energy generated, a great simplification because losses are in fact related non-linearly to system demand.

Distribution and local transmission requirements, on the other hand, depend more on local area demand levels, which may not correspond very closely to system-level demand or supply parameters. The analysis of distribution networks is another complex task that is beyond the scope of this chapter, but we do try to indicate where this information can be used to develop area-specific cost estimates for planning purposes, as explained in Appendix 5.

D.2. Dispatch Strategies

The information in Figure 4.3, which summarizes some of the key relationships between marginal supply cost components (defined in equation 4.9), can be used to identify which supply resources should be selected to satisfy a utility's expansion plan. Once the plants are in service, however, the capital costs are sunk and it is only fuel and other operating costs that determine how existing plants should be used. The order in which plants are selected for use, or *dispatched*, is generally according to the lowest variable cost, including fuel. This is called *economic dispatch*.

Hydroelectric stations and other renewable sources generally have very low variable costs and should therefore be operated as much of the time as possible. However, as stated above, there are constraints on when and how much these resources are available, and they are most simply treated as negative loads based on their availability and output. The remaining demand must be met by dispatching thermal stations, generally on an economic criterion.

For planning purposes it is simplest to treat variable costs as being constant per kWh for a given plant type, independent of the plant's output. In practice, however, a thermal plant's efficiency and therefore its fuel and operating costs depend on the level of generation output. Economic theory indicates that the least-cost combination of resources is the one that equalizes the marginal costs of different resources. Under *economic dispatch*, generating plants are dispatched at the same short-run marginal cost, or *system lambda* (λ).[8]

There are other short-term constraints on dispatching decisions, such as the rates at which plants can be brought into service and at which their output can be increased or decreased. Some plants may have minimum levels of output below which they cannot be operated reliably. Generally, baseload plants are those with low variable costs and less flexible operating parameters, while peaking plants have higher variable costs but are better for *load-following*, i.e., they can be operated at changing levels of output with greater flexibility. Hydroelectric capacity is relatively flexible with regard to load following, subject to energy constraints based on the seasonal variations in water availability.

One approach to reducing the environmental impact of power production is to alter the dispatch order to give higher priority to cleaner, although perhaps more expensive, sources. This approach, called *environmental dispatch*, is usually achieved by adding a component to a plant's variable operating cost in proportion to the plant's emissions. This cost increment can either be a real emission charge that is paid, or it can be an artificial “adder” that is used to guide dispatch decisions toward lower-emission sources (see section E of Chapter 4 on environmental cost analysis).

Depending on the mix of resources available and the range of emission and cost parameters, *environmental dispatch* can decrease emissions significantly, although at higher cost. For some types of emissions that are time-sensitive, such as local pollutants that have infrequent episodes of peak concentration, environmental dispatch during these times can provide important benefits at little additional cost. This strategy is always subject to the operating flexibility and *load-following* ability of the supply resources available in a utility's system.

D.3. Supply-Side Loss Reduction

In addition to improving end-use efficiency via DSM and other programs, IRP can improve efficiency on the supply side of the electricity meter as well. One option is to reduce the rate of losses from the transmission and distribution (T&D) system. In developing countries, T&D losses are typically around 15-25% of generation, with some cases exceeding 35%, compared to a typical value in industrialized countries of 7-8%.

T&D losses can be categorized as *technical* or *non-technical* losses. *Non-technical* losses, or commercial losses, result from theft of electricity through unauthorized connections, tampering with meter reading, metering errors, etc. Although such losses cost the utility revenue, customers still benefit from the use of the electricity. *Technical* losses refer to

[8] The problem of optimizing power system dispatch is typically solved mathematically using the technique of Lagrange multipliers, which produce a series of constants that allow the governing equations to simultaneously balance. The multipliers indicate the marginal costs under different conditions (hourly loads) and are represented by the Greek letter lambda (λ). Thus, each of the set of marginal cost values is referred to as a *system lambda*.

energy that is dissipated through the various elements of the T&D system (transformers, feeders, etc.). These losses are especially serious because the utility has incurred the economic and environmental cost of producing electricity, yet this product does not benefit any customers nor provide revenues.

Technical losses consist of feeder losses, which vary with current and therefore load (including reactive load), and transformer losses, which are less dependent on load levels:

$$F_{loss(h)} = F_{fl(h)} + F_{tl(h)} \qquad [4\text{-}25]$$

where:

$F_{loss(h)}$ = total technical loss factor
$F_{fl(h)}$ = feeder loss factor
$F_{tl(h)}$ = transformer loss factor

Transformer losses can be characterized as:

$$F_{tl(h)} = \frac{P_{tl}}{E_{gen(h)}} \qquad [4\text{-}26]$$

where:

P_{tl} = hourly transformer loss rate (kW)
$E_{gen(h)}$ = total system electricity generated in hour h (kWh/hour)

The main objective of loss reduction is to reduce the feeder losses, which increase non-linearly with increasing loads. In an individual line, losses are proportional to the product of the feeder-line resistance and the square of the current through that line (a consequence of Ohm's law):

$$P_{floss(h)} = (I_{f(h)}^{\;2} \cdot R_f) \qquad [4\text{-}27]$$

where:

$P_{floss(h)}$ = feeder loss rate (kW)
$I_{f(h)}$ = current in the distribution feeder (amperes)
R_f = electrical resistance of feeder line (kilo-ohms)

In a complete distribution system, even a simple one with only radial connections, the loss rate is a more complex function of several parameters for each line in the system, including the feeder-line resistance, the current and supply voltage level, the voltage drop in the line, and the power factor of the load. This can be written as follows:

$$F_{fl(h)} = f\,(V, I_{f(h)}, R_f, DV_{(h)}, PF) \qquad [4\text{-}28]$$

where:

V = supply voltage (V)
$DV_{(h)}$ = distribution voltage drop (V)
PF = power factor

The *power factor* is the ratio of real power supplied (kW) to the apparent power (kVA) and is equal to the cosine of the phase-angle between the supply voltage and current. This is a measure of the reactive load on the system: an entirely active load (e.g., an electric resistance heater) has a power factor of 1, while reactive loads such as inductive motors tend to reduce the power factor. Although a reactive load does not impose an additional loss directly, it requires more current to supply a given real power level, and the higher current causes an increase in losses. Thus, a power factor close to 1 improves system efficiency.

Generally, the annual rate of feeder losses ($F_{fl(h)\ average}$) is about 2/3 that of the loss rate during hours of peak demand ($F_{fl(h)\ peak}$), although this ratio depends somewhat on the load factor and other parameters as well. Thus, as an approximation:

$$F_{fl(h)\ average} = \frac{\sum_{h=1}^{8760}\left(F_{fl(h)} \cdot E_{gen(h)}\right)}{\sum_{h=1}^{8760} E_{gen(h)}} \approx \frac{F_{fl(h)\ peak}}{1.5} \qquad [4\text{-}29]$$

The annual loss rate (F_{loss}) is the sum of the hourly losses divided by the total energy generated:

$$F_{loss} = \frac{\sum_{h=1}^{8760}\left(F_{loss(h)} \cdot E_{gen(h)}\right)}{\sum_{h=1}^{8760} E_{gen(h)}} \qquad [4\text{-}30a]$$

Substituting Eq. 4-25:

$$F_{loss} = \frac{\sum_{h=1}^{8760}\left(\left[F_{fl(h)} + F_{tl(h)}\right] \cdot E_{gen(h)}\right)}{\sum_{h=1}^{8760} E_{gen(h)}} \qquad [4\text{-}30b]$$

Next, substituting Eq. 4-26 and the first part of Eq. 4-29:

$$F_{loss} = \frac{8760 \cdot P_{tl}}{\sum_{h=1}^{8760} E_{gen(h)}} + F_{fl(h)\ average} \qquad [4\text{-}30c]$$

Lastly, substituting Eq. 4-20 and the second part of Eq. 4-29:

$$F_{loss} \approx \frac{P_{tl}}{CF \cdot kW\ peak\ capacity} + \frac{F_{fl(h)\ peak}}{1.5} \qquad [4\text{-}30d]$$

Although a detailed analysis of distribution system performance is beyond the scope of this book, we can observe the important sources of grid losses. Because losses increase with the voltage drop (*DV*) and decrease with the supply voltage level, it is not surprising that long-distance transmission uses high voltage levels and that the majority of system losses occur at the low-voltage end of the distribution system. Losses can be decreased by using higher-voltage distribution and by reducing the voltage drops in the distribution system (which also improves reliability).

Because losses increase with current, the loss rate tends to increase at times of peak demand, generally about 50% above the average loss rate (Eq. 4.29). This tendency suggests that load management measures, which reduce peak demand, can reduce losses as well as the need for supply capacity. In addition, load management to improve the load factor can help to somewhat reduce the transformer losses.

Because line losses are proportional to distribution line resistance, losses can be reduced by decreasing the length and/or the resistivity of feeder lines. Length can be reduced by locating transformers closer to loads, and resistivity can be reduced by using higher capacity conductors.

Losses can also be reduced by decreasing reactive loads and increasing the power factor to a value close to 1. Although reactive loads do not increase energy demand directly, they do increase losses. Thus, power factor correction using capacitors at distribution sub-stations (to balance reactive loads) can improve reliability and save energy.

Example:

The Brakimpur Electric Company, a distribution utility, had losses in its distribution grid of 20% annually. Transformer losses were estimated at 4% per year. The utility invested $800,000 to upgrade the system, reducing the transformer losses to 3% and increasing the number of transformers and locating them nearer the loads. The peak feeder loss rate was reduced to 9%.

What is the total annual loss rate after the upgrade program? What is the marginal cost of the electricity saved by the loss reduction measures? Assume a 5% discount rate and 25 year lifetime (crf = 0.07). The peak capacity of the generation system is 10 MW, and the capacity factor is 0.6.

Of the 20% annual losses, 4% were transformer losses, so the remaining 16% represent the average feeder losses. Thus, the initial peak feeder loss rate was approximately 1.5 · 16% = 24% (equation 4-29).

After the upgrade, the peak feeder loss rate is reduced to 9%, so the average feeder losses are 9% ÷ 1.5 = 6% (equation 4-29). The new total annual loss rate is thus 6% + 3% = 9%.

The annualized cost of the program is (0.07) · ($800,000) = $56,000/yr.

The energy saved is represented by the increase in energy that is available to customers after the upgrade. This is the difference in the loss rates multiplied by the total energy supplied from the generation system.

The total electricity supply is calculated from the peak capacity of 10 MW. The original energy supply was (10 MW) · (8760 hr/yr) · (0.6) = 52 GWh, and correcting for losses, the total sales were (52 GWh) · (1 - 0.20) = 41.6 GWh.

With the upgraded system, the available electricity supply rises to (52 GWh) · (1 - 0.09) = 47.3 GWh. Thus, the incremental energy supplied is 47.3 - 41.6 = 5.7 GWh per year. At a cost of $56,000 per year, this corresponds to a cost of saved electricity of $56,000/yr ÷ 5.7 million kWh/yr = $0.01/kWh.

D.4. Cogeneration

Although simple in principle, cogeneration is a complex technology to incorporate into a production process or an energy system, because of the multiple functions performed and the diverse interests that can be affected. The successful diffusion of this technology depends on various factors, including political, economic, environmental, strategic and institutional aspects of the structure of the energy system and the interests of the actors involved, which are decisive in the definition of a favorable setting for cogeneration.

The role of the electric utilities is decisive. Except for the possibility of "wheeling" (in which case cogenerators could sell power directly to third party users through the utility's transmission system) electric utilities have the distinction of being the only option for buying electricity produced by cogeneration, and at the same time, the only option for selling energy to cogenerators, when the cogenerators' facilities are not operating. In an environment that is not adequately regulated for the development of cogeneration, this type of market, that is both monopoly and monopsony, gives the utilities a special power to suppress the development of cogeneration simply by refusing to buy self-generated power or by establishing unfavorable conditions regarding the tariff levels, the contractual conditions or the technical requirements.

At least at first, utilities tend to discourage cogeneration as an alternative for system expansion at the first hint of management problems, revenue losses, or loss of control of their business. From a long-term perspective, however, utilities tend to understand that cogeneration can contribute to a reduction in their marginal costs, as well as an increase in reserve capacity. Beyond the specific interests of the entrepreneurs and the electric sector, cogeneration is a technical option that can benefit society through its potential advantages with respect to energy efficiency and environment.

D.5. Intermittent Renewable Resources

Some renewable resources, such as solar power and especially wind power, are not *dispatchable* in the way that thermal and hydro plants are. Rather, the *availability* of these types of capacity at times of peak demand depends on the probability of their operating during these times. If the peak demand occurs during the windy season, there is a high probability that wind power can meet some of the peak demand. However, the probability that the wind capacity will operate at full power during the peak hours is less than for a thermal plant. The situation is similar with solar power, except that solar thermal energy can be stored and thus be more reliably available and somewhat *dispatchable*. In addition, it is possible that the solar energy resource is more predictably coincident with times of peak demand from weather-driven loads such as air-conditioning.

Because these intermittent supply resources are not fully dispatchable, they cannot be directly compared with thermal capacity on the basis of their capacity factor, for example using the "screening curves" shown in Figure 4.3. Such a comparison assumes that the supply source is available when needed during times of peak demand and that, if run at a lower capacity factor than its maximum, its operation can conform to peak demand. Intermittent renewable sources do not fully meet these criteria and should not be compared using “screening curves.”

Thus, the maximum output of these resources cannot be assumed to be available with sufficient reliability that they can be considered in calculating the system’s reserve margin. The concept of *capacity value*, the capacity that can be assumed to contribute to system peak capacity and reserve margin, will be discussed later in this chapter.

E. Environmental and Social Cost Analysis

One of the principal goals of IRP is to include a broader range of evaluation criteria in the selection of resources and technologies with which to meet the demand for energy services. One of the most important aspects of this broader analysis is to account for environmental impacts and to weigh these impacts against the costs of relatively clean options such as DSM and renewable sources. The following discussion focuses on environmental impacts, especially emissions to the air, but the techniques described can also be applied to other types of non-monetary social costs.

E.1. Environmental Impacts of Electricity Production

The electric power sector creates many different types of environmental impacts, the majority of which occur in the process of generating electricity. The various impacts can be classified as follows:

Land Use: The large amounts of land committed to electric generation and transmission increasingly make these facilities difficult or controversial to site. There is often a visual impact of the facility itself, and some types of facilities discourage residential or commercial use in the surrounding area. For example, people may be concerned about the magnetic fields created by high-voltage transmission lines, or about the possibility of accidents at nuclear generation plants.

Coal mining, which provides the majority of fuel for the electric utility industry in countries as diverse as China and the U.S., also has severe impacts on land use, especially in areas where surface mining is predominant. There has been increasing concern in recent years about the need to reclaim land that has been mined.

Other land impacts include the areas flooded to provide hydroelectric storage reservoirs. These areas can include pristine river valleys of high scenic and recreational value, although the reservoir may also provide a new recreational resource of significant value. The areas inundated depend on the flow, the design storage capacity and the steepness of the watershed. In some projects, such as the Balbina dam in Brazil, this land area approaches one hectare per kW of generating capacity.

Waste Disposal: Electricity generation produces many different types of wastes which must be handled safely. The large volumes of ash created by coal combustion, and the sludge waste from air pollution control equipment, create a problem of disposing of solid and liquid wastes, some of which are radioactive and highly toxic. Despite extensive research and demonstration programs, the long-term disposal of radioactive wastes from nuclear power plants remains unresolved. Proposed test sites have been the subject of intense technical and political debate, and more recently repositories built for the disposal of military nuclear wastes have been removed from operation because of unresolved environmental and safety issues.

Cooling: All coal and nuclear power plants, and some gas and oil-fired plants as well, use Rankine-cycle steam turbines to convert thermal energy into electric power. These cycles require large quantities of cooling to maintain efficient operating conditions, usually about 2 MW (thermal) for each 1 MW (electrical) in nuclear plants, and somewhat less in fossil plants.[9]

Because the heat capacity of air is too low to effectively remove this heat, large quantities of cooling water must be provided. In fact, electricity generation is the second largest use of water in the U.S., after agriculture. Water can either remove heat by evaporation, consuming about 3 m^3 per MWh, or by discharging warmer water into the environment. This thermal pollution can be a problem because higher temperatures lower the dissolved oxygen content of water, which is especially dangerous to aquatic life in water bodies already polluted by other means.

Air Emissions: The most serious impacts of electric generation, in countries where it is predominantly fossil fuel-based, are the emissions of various trace gases into the atmosphere as by-products of combustion. Meeting air pollution regulations has been the largest cause of environmental expenditures by utilities and is likely to be the most important environmental constraint on utility operation in the future.

Some emissions result from impurities in the fuel, such as particulates and sulfur dioxide from coal; some come from the air used in the combustion process, such as oxides of nitrogen; and some are the inherent end-product of hydrocarbon combustion, such as carbon dioxide and water vapor, although the latter is seldom a concern.

To date, utility regulations and expenditures have focused on reducing the rates of emission of particulates, sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). Particulates include both the visible and microscopic dust particles emitted from the combustion process, especially when the fuel is coal or diesel oil. Although larger particulates create a visual impact by creating haze and reducing visibility, the smaller microscopic particulates are a greater health hazard because they readily enter people's lungs. The most common method for removing small particulates is the electrostatic precipitator, and this technology is being used increasingly world-wide.

SO_2 is a corrosive gas that is a direct hazard to human health at high concentration, especially in the presence of high particulate concentrations. Also, SO_2 undergoes reactions in the atmosphere that produce sulfuric acid, which is deposited over large distances downwind from the original source. SO_2 is removed from coal-fired plant emissions through various processes. The conventional wet scrubber technology mixes a pulverized limestone slurry

[9] In a hypothetical example, a nuclear plant might operate at 34% efficiency. This means that for each unit of electric output, three units of heat are generated by the reactor, and two units must be removed by the cooling system. In a fossil plant, the efficiency might be 40%, while 10% of the heat produced is removed with the combustion products through the exhaust stack, while 50% (a little more than one unit of heat per unit of electricity) must be removed by the cooling system.

with the flue gases to absorb about 90 percent of the SO_2; however, they are expensive and consume about 5 percent of the plant's electric output, and they produce large quantities of waste sludge.

Other technologies include regenerative scrubbers, which recover the sulfur for other commercial uses, and dry scrubbers using lime as a sorbent to remove 40 to 60 percent of the SO_2, but at lower cost than wet scrubbers. In fluidized bed combustion, pulverized coal or biomass plant emissions are mixed with limestone and fluidized by up-flowing combustion air, such that the limestone reacts with SO_2 during combustion to form a dry by-product, reducing emissions by 90 percent.

NO_x emitted from power plants include mostly NO and some NO_2. Additional NO_2 is formed in the atmosphere, reducing visibility, together with other secondary by-products such as N_2O, nitric acid, and peroxyacetyl nitrate (PAN), an eye irritant. NO_x react with small concentrations of hydrocarbons in the presence of sunlight to form ozone, which damages plants and materials, and other constituents of photochemical smog.

Nitric acid, like sulfuric acid, can be deposited far from the original pollution source. These two pollutants lower the pH of rain, fog, and snow, and this acid precipitation threatens fresh-water life and weakens forest health both directly and through increased leaching of hazardous minerals such as aluminium. Emission regulations to control both dry deposition and acid precipitation, including trans-boundary deposition, have been intensely debated both in Europe and in the U.S.

NO_x emissions are controlled by modifying the combustion process or by post-combustion controls. Accurate control of combustion air to minimize excess air can reduce NO_x emissions by 15 to 50 percent, and new low-NO_x burners, which use multi-stage combustion, can provide 40 to 60 percent reductions. Post-combustion technologies include urea injection to reduce 35 to 75 percent of flue gas NO_x to nitrogen and water, and selective catalytic reduction, which accomplishes 80 to 90 percent NO_x removal by mixing the flue gas with ammonia in the presence of a vanadium catalyst.

<u>Greenhouse Gases</u>: Although not currently regulated under any national-level policies, the increasing atmospheric emissions of carbon dioxide have raised concerns about the potential threat of global climate change. The principal source of CO_2 is fossil fuel combustion, and electric utilities contribute about one-third of global CO_2 emissions. Coal burning utilities produce the most emissions because coal produces roughly 24 kg of carbon per GJ energy, compared to approximately 20 kg/GJ for oil and 14 kg/GJ for natural gas.

Under the United Nations Framework Convention on Climate Change (FCCC), industrialized countries are making voluntary commitments to stabilize or reduce future carbon emissions. To stabilize the CO_2 concentration in the atmosphere, emissions from developing countries would eventually have to be limited as well. As a result, numerous national and multilateral efforts are underway to identify emission reduction options and develop national strategies in developing countries.

Energy-efficiency and non-fossil generation technologies are key components of such a strategy. Because industrialized countries are responsible for most of the existing climate-change threat, and because they have the most resources, the FCCC provides for emission reduction measures in developing countries to be funded by industrialized countries. This process of joint implementation (JI) could become an important source of support for clean energy options, and IRP provides an ideal framework for prioritizing these options.

E.2. Emissions Accounting and Environmental Impacts

To relate environmental impacts, on ecosystems and/or human health, to emissions from the operation of electric power stations requires a chain of analytic techniques and models:

- Emissions are related to concentration and deposition by transport processes;
- Concentration and deposition are related to dosage by exposure relationships;
- Damage is related to dosage according to dose/response relationships.

As an example, emissions from a source of SO_2 must be analyzed to determine how the pollutants, and by-products formed by atmospheric reactions, are transported, resulting in a pattern of local airborne concentration or deposition on land. A given concentration causes human exposure depending on the relationship between where it occurs and where and how people spend their time, while deposition causes exposure to plant and animal species depending on where they are located and come in contact with the pollutant. Exposures lead to health damage or ecological impacts according to the sensitivity of the individuals exposed (age, diet and other parameters) or of the ecosystem (nutrition, chemical buffering, etc.).

This full chain of analytic steps is beyond the scope of this chapter. The key point is that methods and models exist to translate emissions into impacts and (at least in theory) to environmental and social cost values. In the context of IRP, this means that potential energy supply or demand-side options can be compared on the basis of environmental as well as economic costs. Even if the environmental costs cannot reliably be monetized, such costs can be assumed to be proportional to emissions, such that we can rank different measures according to their emission values.

The analysis of environmental costs, whether monetized or not, requires a consistent accounting of emission rates. For an electric utility system, demand analysis and forecasting, together with supply-side analysis and production-cost modeling, provide scenarios for the installation and operation of generating stations and other facilities. Each kWh of electricity produced can be linked to rates of emissions, for each pollutant of concern, by an *emission factor*. The *emission factor* is the ratio of emissions to energy produced or fuel consumed, and it is denominated in units of tons per unit energy, for example tons of SO_2 per GWh.

The *emission factor* coefficients can be stored in a database and multiplied by the energy quantities (such as GWh from different electricity sources) to determine the total emission rates for scenarios under consideration in an IRP process. Usually, the direct emissions from power stations are the primary concern, but it is also possible to account for indirect effects, such as emissions produced upstream in the fuel chain. Both the direct and indirect *emission factor* coefficients are incorporated into packaged environmental accounting models such as the Environmental Data Base, which is part of the widely-used LEAP model (SEI 1993).

E.3. Externality Values

Ideally, the costs imposed on society by environmental impacts from electricity supply should be considered part of the supply cost (see chapters 1 and 2). The inclusion of such environmental *externality* costs would allow one to make a direct economic comparison between conventional technologies and cleaner but otherwise more expensive alternatives. Because DSM options and renewable supply sources tend to produce very low emissions, including environmental costs in an IRP analysis tend to make these options appear more favorable by increasing the conventional supply costs that can be avoided.

For a given generation-fuel source, emissions are essentially proportional to the amount of electric energy generated, represented by the *emission factor*. Marginal environmental costs therefore tend to supplement the marginal energy cost (MEC), rather than the capacity costs; and including such environmental costs would tend to favor DSM measures with significant energy savings (δkWh), rather than load management options that reduce peak demand. The values of MEC and the resulting marginal cost of energy (MCOE) can be augmented to include environmental costs and other *externalities* according to:

$$MEC_{ex} = MEC + \sum_i \left[C_{em(i)} \cdot F_{em(i)} \right] \qquad \textit{[Eq. 4.31]}$$

and

$$MCOE_{ex} = MCOE + \sum_i \left[C_{em(i)} \cdot F_{em(i)} \right] \qquad \textit{[Eq. 4.32]}$$

Where:

MEC_{ex} = marginal energy cost including environmental externalities
MEC = marginal energy cost not including externalities
$C_{em(i)}$ = external cost of emissions for impact *i* (e.g., \$/kg)
$F_{em(i)}$ = emission factor for impact *i* (e.g., kg/MWh)
$MCOE_{ex}$ = marginal cost of energy including environmental externalities
$MCOE$ = marginal cost of energy not including environmental externalities

These environmental costs can either be emission charges actually paid by the utility, or they can be proxy values used to prioritize and select DSM and supply options in the IRP process. Experience in North America with such proxy values has been that they in fact have little effect on DSM activity, even under a regulated planning structure (Hashem et al 1994).

E.4. Costs of Emission Reductions

A useful way to prioritize options to reduce emissions, without the use of environmental externality values, is to analyze and rank the incremental cost of the emission reduction resulting from each option. This approach is similar to the marginal cost (MCOE) ranking of supply and DSM measures, which is a central technique in the IRP process. To determine the costs of emission reductions, it is always necessary to define a baseline from which the reductions can be measured. The cost of avoided emissions can be defined as follows:

$$CAE = (MCOE_A - MCOE_B) / (MER_B - MER_A) \qquad \textit{[Eq. 4.33]}$$

Where:

CAE = cost of avoided emissions
$MCOE_A$ = marginal cost of energy for option A
$MCOE_B$ = marginal cost of energy for baseline option B
MER_B = marginal emission rate for baseline option B
MER_A = marginal emission rate for option A

Example:

What is the CAE for NO_x for 1) a new gas plant to replace an existing coal plant? 2) a wind farm to replace the coal plant, 3) a wind farm to replace the gas plant? Use these data:

Source	**MCOE ($/kWh)**	**Emission rate (tNO_x/GWh)**
Existing coal	0.030	11
New gas	0.055	5
Wind farm	0.067	0

1) For the gas plant as option A and the coal plant as the baseline B:
CAE = ($0.055/kWh - $0.030/kWh) · ($10^6$ kWh/GWh) ÷ (11 ton/GWh - 5 ton/GWh) = $4167/ton

2) For the wind farm as option A and the coal plant as the baseline B:
CAE = ($0.067/kWh - $0.030/kWh) · ($10^6$ kWh/GWh) ÷ (11 ton/GWh - 0 ton/GWh) = $3364/ton

3) For the wind farm as option A and the gas plant as the baseline B:
CAE = ($0.067/kWh - $0.055/kWh) · ($10^6$ kWh/GWh) ÷ (5 tons/GWh - 0 ton/GWh) = $2400/ton

The results of this type of analysis are the incremental costs of emission reductions, compared to the utility's base case expansion plan. In the IRP framework, DSM costs are combined with utility marginal supply costs (the *avoided costs*) and potential emission reductions to determine the cost, from the utility's viewpoint, of DSM as an emission reduction strategy.

In evaluating the CAE of various levels of DSM implementation, the utility's avoided costs may vary. As DSM is implemented to a greater degree, it may obviate the need for some amount of marginal supply (the utility's most expensive resource). This helps make DSM attractive to the utility. Once the most expensive resources have been removed or deferred, however, the avoided costs (for the remaining supply resources) are reduced, increasing the incremental cost of emission reductions via additional DSM measures.

F. Integrating Energy Demand and Supply

Production-cost analysis of the performance of existing and new electric supply alternatives allows us to rank these alternatives according to marginal cost, including environmental and social costs to the extent possible. The next step is to compare these results to the marginal costs of the demand-side options covered in the previous chapter. The two sets of options can then be combined to produce the “integrated” least-cost electricity plan. As discussed earlier, the plan is “integrated” in the sense that, unlike traditional least-cost planning, it includes demand-side options, non-utility supply options, as well as the environmental costs and other societal impacts of all the options considered.

According to the Northwest Power Planning Council in the United States, the process of developing an integrated least-cost energy plan can be summarized as the following steps (NWPPC, 1991):

1. Develop scenarios of energy-service (not kWh) growth over time, and sensitivity analysis;
2. Assess the size, timing, costs and risks of energy supply and energy efficiency options;
3. Rank the options by marginal costs to develop integrated energy-service “supply curves;”
4. Evaluate environmental and economic risks and reorder options to include policy issues;
5. Develop plans to implement energy savings and integrate with supply resources.

One of the basic assumptions of IRP is that the benefit of electricity service should be measured in terms of the *energy services* provided, not simply the amount of energy sold. Thus, the scenarios are based on projections of the growth in energy services (step 1), and the need to maintain the required level of energy services regardless of which combination of DSM and supply resources are used to meet the demand for energy services. As in the case of energy-efficiency and DSM scenarios, the integrated energy scenarios begin with baseline projections of energy service demand growth. This is discussed further below.

The second step according to the NWPPC is the assessment of an “integrated” set of options, including utility and non-utility energy supply sources as well as energy efficiency and load management options. This assessment is the key information required to develop an integrated plan and has been covered in detail in the previous section and chapter.

The remainder of this chapter covers the ranking of both supply and demand-side options according to their marginal costs (step 3), which allows us to develop an integrated marginal cost function, or “supply curve,” for providing electric services in a given future year. The resources available and their relative ranking depend on the existing resources, the new options considered, the time horizon, the economic and energy-service growth rate, the discount rate and other economic parameters, the use of environmental or other external cost values, and other factors.

The last two steps in the NWPPC outline involve subjecting the integrated electricity plan to further policy studies, financial evaluation, sensitivity analysis and implementation planning before a final plan can be completed. The incorporation of these issues may re-order the ranking of the integrated plan somewhat, or exclude certain resources from the plan. These steps are beyond the scope of the present work, although the relevant issues have been brought up and discussed at various points throughout the preceding chapters.

F.1. Defining Scenarios and Baselines

As discussed in Chapter 1, scenario analysis is one way to compare alternative combinations of technological options to provide the same level of energy services. The scenarios can be defined and differentiated according to 1) the level of projected energy service growth (e.g., high, medium, low), 2) the degree of implementation of energy-efficiency improvements (e.g., efficiency standards scenario, DSM scenario, etc.), and 3) the energy supply strategy applied (e.g., least-cost, least-emissions, high renewables, etc.).

One or more baseline scenarios serve as the starting point in the analysis of energy-efficiency improvements. As described in Chapter 2 Section C.1, other scenarios can describe various levels of improved energy efficiency, meeting the same level of energy-service demand. A starting point might be a scenario that reflects a marginal cost threshold of zero for energy efficiency measures. This threshold might represent existing trends in energy-efficiency improvement, which would be expected with no policy change or new utility programs (see Figure 4.7, scenario 2). These criteria, for example, can be used to describe a *reference scenario*. Other scenarios might include greater efficiency improvement at higher cost.

Additional scenarios might reflect increasing penetration of energy-efficient technologies through DSM or other programs, or different choices of supply resources. From the possible scenarios, one should be able to identify a least-cost scenario which combines the most cost-effective supply and demand options, where increasing the electric supply would cost more than increasing savings through energy efficiency, and vice versa (see Figure 4.7). With a complex range of options, linear optimization models can be used to help identify the least-cost energy system. Other scenarios might illustrate cases where research and development makes new supply or energy-efficiency options available, and these penetrate the market significantly enough to change the energy supply mix, emissions and costs.

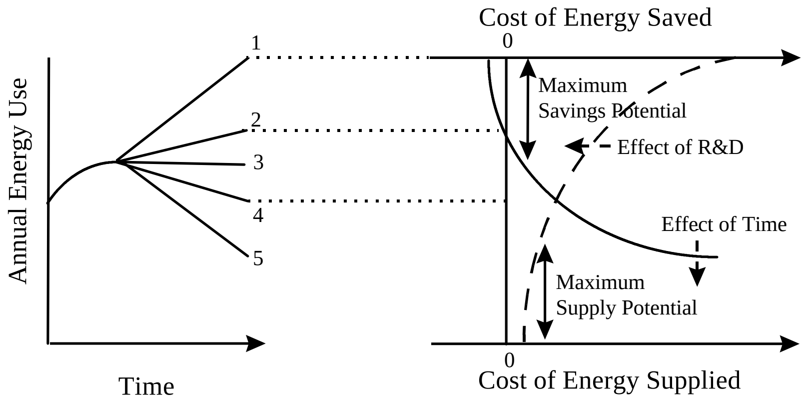


Figure 4.7. The relationship between energy demand scenarios and marginal costs. The left-hand graph illustrates the development of energy use up to the base year of the study, and shows five scenarios with different levels of energy demand for the end year of the study. Note that all values apply to a given year. The upper half of the right-hand side of the figure illustrates the energy efficiency supply curve. This is constructed from the level of base-year frozen efficiencies. It starts with negative cost measures, that is measures that will reduce the costs of obtaining the energy services. Energy service demand that is not met by end-use energy efficiency measures must be met by supply options, the costs of which are shown by the energy supply curve in the bottom half of the right-hand figure.

F.2. Combining DSM and Supply Resource Options

The goal of IRP is to meet energy-service demand with a combination of available resources that minimizes total revenue requirements. The basic method for the selection of supply and demand-side energy resources in an integrated plan is to combine the marginal cost curves for each type of resource into an integrated marginal cost curve, which should then provide a ranking of the cost-effectiveness of all types of available resources. For a given level of energy service demand, the least-cost plan exploits the lowest marginal-cost options up to the point where their total energy and power capacity meets the demand (see Figure 4.7). In practice, some utilities have conducted their IRP process in a sequential manner, first optimizing either the supply or demand-side resource selection and then adjusting the results to include the other type of resources. However, simultaneous integration of all resources has been shown to be a more effective way to identify least-cost solutions (Hill 1991).

There are many complications in determining the integrated marginal cost function and the resulting least-cost solution. Two of the most important types of complications are those resulting from interactions between options and those caused by the time-dynamics of energy demand and supply systems. IRP should consider both the dynamics of energy-efficiency penetration as well as the lead-times and carrying costs for supply options. End-use technologies should also be carefully integrated with the supply plan, for example to be sure that peak electric demands are met and that the timing of resource acquisition is planned to maintain adequate supplies over time. Finally, the IRP process should include the selection of appropriate implementation programs, including government policies and utility programs, to achieve the needed energy savings (see Chapter 3).

Interactions between options can lead to both positive and negative feedbacks. On the demand side, for example, replacing incandescent lighting with fluorescent lighting in commercial buildings tends to magnify lighting energy savings by also reducing cooling loads (positive interaction). Building shell improvements can cut energy needs for heating, ventilation and air conditioning (HVAC) by 50%, as can HVAC system efficiency improvements. These two measures adopted together, however, can reduce space-conditioning needs by only 70-80%, not by 100%, which would be the sum of the measures' individual savings (negative interaction). On the supply side, the presence of existing hydro resources can influence the dispatch priority and therefore the capacity factor and marginal costs of some potential new resources (positive or negative interaction).

F.3. Ranking the Resource Options by Marginal Cost

Table 4.1. Sample set of resources and their performance parameters

Power Source	Capacity (MW)	Capacity Factor	Annual GWh	Variable Cost $/kWh	Marginal Capacity Cost $/kW-yr	Emissions tSO_2/GWh	Emissions tNO_x/GWh
Hydro	1200	0.50	5256	0.020	0	0.0	0
Existing Gas	600	0.50	2628	0.040	0	0.0	6
Existing Coal	420	0.75	2759	0.030	0	5.0	11
Retrofit Coal	400	0.75	2628	0.040	50	0.5	12
New Gas	200	0.75	1314	0.035	130	0.0	5
New Coal	200	0.75	1314	0.030	150	5.0	10
New Coal w/ Scrubbers	200	0.75	1314	0.040	180	0.5	11
DSM 1	375	0.40	1314	-0.001	100	0.0	0
DSM 2	750	0.20	1314	-0.001	100	0.0	0
Wind Farm	500	0.30	1314	0.010	150	0.0	0
Combustion Turbines	50	0.20	88	0.055	70	0.0	7
Load Management	100	-0.05	-44		50	0.0	0

A simplified example of a set of electricity supply and DSM resources is given in Table 4.1. The table shows the maximum power capacity, annual capacity factor, and energy production for each resource. In addition, the marginal cost parameters are given, as well as the emission rates for two pollutants. The variable cost parameter includes the fuel and other variable costs for producing an incremental kWh of electricity (i.e., the MEC). The marginal capacity cost parameter includes the annualized capital costs as well as the fixed annual operating costs for an incremental kW of capacity (i.e., the annualized MCC).

The list of resources includes new supply and DSM options as well as existing power stations. We assume here that all existing resources will stay in service at least through the full duration of the planning horizon, and that new resources are needed only to meet the demand for new energy services. In practice, it is also possible that some existing resources would be retired and need replacement during the planning period, or that refurbishing older plants to extend their life could be one of the resource options, with their corresponding cost and performance parameters (similar to the retrofit coal plant shown in Table 4.1).

The *marginal* capacity-cost value is practically zero for plants that have already been built, in which case the capital costs are sunk and the fixed operating costs must be paid regardless of how much the plant is dispatched (this is a simplification; in practice some fixed costs could be avoided if the plant is retired from service). It is important to note, however, that these costs do still exist and are still part of the utility's total revenue requirements, which must be recovered from the electricity rates charged to customers. While rates are generally based on *average* costs, the selection of new resources is based on *marginal* costs.

In addition to a range of existing and potential new supply resources, three DSM options are given in Table 4.1: two energy-efficiency programs and a load management program.[10] The performance parameters for these options are somewhat different from the supply-side options. Because the energy-efficiency programs are not *dispatchable*, their "capacity factor" is not truly comparable to those of the supply options, it is simply the load factor of the demand that would be reduced. Their variable costs are based on the *total resource cost* (TRC) definition, and they are negative because of the potential to reduce customer maintenance costs in the course of improving energy efficiency. *Lost revenues* are not counted as a DSM cost under the TRC definition (see Chapter 2, Section E). For the load management option, the annual energy contribution and "capacity factor" are negative, because this option consumes a small amount of energy while reducing the peak load.

The marginal costs of the sample set of resources are shown in Table 4.2. The first column shows the marginal cost of electricity (MCOE), which is the sum of the annual variable and fixed costs including the annualized capital costs, normalized per kWh of energy produced or saved. This was derived earlier by substituting equations 4.18 and 4.20 into equation 4.9, and is reviewed below.

$$MC = (MCC \cdot \Delta kW) + (MEC \cdot \Delta kWh/crf) \qquad \text{[Eq. 4.9]}$$

$$MCOE = \frac{MC \cdot crf}{\Delta kWh} \qquad \text{[Eq. 4.18]}$$

[10] The DSM programs given in this example are larger and fewer in number than most real programs, in order to simplify the calculations. To achieve an impact as large as that shown in the example, it would normally be necessary to aggregate a number of smaller programs, each with its own costs and impacts. For example the IRP presented by the Northwest Power Planning Council in their 1991 plan called for 12 distinct DSM options and one supply option with a marginal cost of less than $0.06/kWh (NWPPC 1991).

Thus, $MCOE = \dfrac{MCC \cdot crf \cdot \Delta kW}{\Delta kWh} + MEC$

$$CF = \frac{(\Delta)kWh/yr\ electricity\ produced}{(\Delta)(kW\ peak\ capacity) \cdot (8760\ hr/yr)} \qquad [Eq.\ 4.20]$$

So, $MCOE = \dfrac{MCC \cdot crf}{8760 \cdot CF} + MEC$ *[Eq. 4.21]*

Table 4.2. Marginal cost parameters for sample set of resources

Power Source	MCOE* $/kWh	Cost of Saved SO_2 ($/ton)		Cost of Saved NO_x ($/ton)		
		vs new coal	vs existing coal	vs new coal	vs existing coal	vs existing gas
Hydro	0.020					
Existing Gas	0.040					
Existing Coal	0.030					
Retrofit Coal	0.048		3913			
New Gas	0.055	391	4957	391	4131	14787
New Coal	0.053					
New Coal with Scrubbers	0.067	3237	8311			
DSM 1	0.028	-5059	-491	-2529	-220	-2100
DSM 2	0.056	649	5216	325	2371	2680
Wind Farm	0.067	2849	7416	1425	3371	4513
Combustion Turbines	0.095	8420	12992	14037	16240	

* MCOE = Marginal Cost of Energy. See equations 4.18 and 4.21 for definition of MCOE.

> ***Exercise 4.6)*** Make a table showing the variable cost (given), marginal cost of energy, and revenue requirements for each of the resources shown in Table 4.1. For the existing hydro, coal and gas plants, assume that the sunk capacity and other fixed costs have a present value of $350 million for each plant. Also assume that the existing hydro plant, coal plant, and gas plant have remaining lifetimes of 13 years, 17 years, and 12 years, respectively. Use a discount rate of 6% per year.

Looking at the MCOE in Table 4.2, the least expensive resources are the existing supply resources, which have zero capital costs because those costs are already sunk, and the DSM 1 option, which has negligible variable costs. The most expensive resources include combustion turbines with their high fuel costs, the wind farm with high capital costs and low capacity factor, and the new coal plant fitted with expensive scrubbers to remove SO_2 emissions. Although the retrofit coal-fired plant already exists, the capital cost of adding emission-removal equipment increases its marginal capacity cost.

The remaining columns in Table 4.2 show the marginal costs of reducing emissions, of both SO_2 and NO_x. The cost of reduced emissions must be relative to a baseline option, i.e., some resource that is in the existing plan and that produces the type of emissions to be reduced. Both new and existing coal-fired plants emit SO_2, and NO_x is emitted by these coal plants as well as by the gas-fired plants. Thus, replacing coal-fired plants with alternative options can reduce SO_2 emissions, while replacing either coal- or gas-fired plants can reduce NO_x.

For alternative options with lower emissions, the difference in marginal cost per kWh divided by the difference in emissions per kWh gives the cost of avoided emissions (CAE, equation 4.33). The DSM options and the new gas-fired plant have the lowest CAE values due to their low capital costs. The DSM 1 option actually has a negative CAE, because its total marginal cost is less than that of the existing fossil fuel-fired plants. It is more expensive to reduce emissions compared to the existing coal plant than compared to the new coal plant, because the two plants have similar emission rates and the new plant has significantly higher marginal costs (i.e., $MCOE_B$ in equation 4.33).

> ***Exercise 4.7)*** Calculate the CAE values for reducing SO_2 emissions through each of the new and retrofit resources listed in Table 4.1. For a baseline, use 1) new coal plant and 2) existing coal plant.

The least-cost combination of these resources is given in Table 4.3, together with their resulting capacity and energy contributions, marginal costs, and emissions. This list of resources is determined by:

1. ranking the sample resources in order of marginal cost, and
2. selecting the least expensive resources up to the point that their total energy and capacity is sufficient to meet the projected demand.

In the example, the demand is 13,000 GWh per year, with a peak demand of 2600 MW and a load factor of 57% (equation 4.23). The existing plants, the DSM 1 option, and the new coal plant (without scrubbers) have the lowest marginal costs. When the new coal plant is added to the list, the total energy and capacity exceed the projected demand. The marginal cost is that of the new coal plant, \$0.053/kWh, but the average cost is only \$0.03/kWh, due to the less expensive DSM and existing supply options.

Table 4.3. Performance summary for least-cost combination of sample resources

System Requirement: 13,000 GWh/yr, 2600 MW (57% load factor)						
Least-Cost System	Capacity (MW)	MCOE (\$/kWh)	Variable Cost (\$/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of SO_2)	Emissions (tons of NO_x)
Hydro	1200	0.020	0.020	5256	0	0
DSM 1	375	0.028	-0.001	1314	0	0
Existing Coal	420	0.030	0.030	2759	13797	30353
Existing Gas	600	0.040	0.040	2357	0	14140
New Coal	200	0.053	0.030	1314	6570	13140
Total	2795	0.030 (avg)		13000	20367	57633

Note that the *dispatch order*, or the priority for operating each unit of capacity, depends on the variable cost, rather than total marginal cost which governs the choice of new capacity (and which includes the capital and other fixed costs of new resources). Thus, the plants with the lowest variable costs would be operated as much as possible. The DSM 1 option is not *dispatchable*, so it must be treated as a reduction in the projected load.

Under *economic dispatch*, the low variable-cost hydro plant would normally be operated in a pattern that maximizes its output, subject to maintaining its necessary reservoir level. The daily pattern of operation for the hydro plant could be load-following, i.e., responding to variations in demand. The coal plants would generally be dispatched as base-load and run as much as possible, due to their low variable costs. Because the total demand is exceeded, the gas plant, with the highest variable cost, would be operated at less than full capacity, as an intermediate or peakload resource and providing additional reserve margin. Thus, its annual output would be less than the maximum value shown in Table 4.1.

For comparison, Table 4.4 shows the non-integrated system, i.e., the least-cost combination of supply resources only, according to the conventional planning approach. The difference between the two solutions is that the integrated plan includes the DSM 1 option, while the non-integrated plan simply adds a second unit of new coal capacity. Although the marginal cost of the non-integrated plan is the same as that of the integrated plan, the non-integrated plan's average cost is \$0.33/kWh, about 10% higher. Emissions of SO_2 are increased by more than 30%, and NO_x by more than 20%.

Table 4.4. Performance summary for least-cost combination of supply-only resources

Non-Integrated System	Capacity (MW)	MCOE (\$/kWh)	Variable Cost (\$/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of SO_2)	Emissions (tons of NO_x)
Hydro	1200	0.020	0.020	5256	0	0
New Coal 1	200	0.053	0.030	1314	6570	13140
Existing Coal	420	0.030	0.030	2759	13797	30353
Existing Gas	600	0.040	0.040	2357	0	14140
New Coal 2	200	0.053	0.030	1314	6570	13140
Total	2620	0.033 (avg)		13000	26937	70773

F.4. Ranking Emission Reduction Measures by Cost of Avoided Emissions

IRP should include additional criteria besides economic costs, as discussed in Chapter 1. The following examples address the problem of reducing emissions of air pollutants using the approach described above. By definition, reducing emissions below those from the least-cost plan increases system costs. However, reducing emissions from a sub-optimal baseline such as the non-integrated plan shown in Table 4.4 to the integrated least-cost plan shown in Table 4.3 can reduce costs as well.

In the following cases, the least-cost emission-reduction measures are identified, based on a ranking of their CAE values (equation 4.33). The least-cost system, given a constraint of 30% reductions in SO_2 emissions compared to the (integrated) base case (i.e., SO_2 reduced from 20,000 tons/year to <14,000), is shown in Table 4.5. Starting from the least-cost system of Table 4.3 as a base case, modifications are made by selecting the option with the lowest CAE for SO_2. This results in the new coal plant in Table 4.3 being replaced by the new gas plant in Table 4.5.

Table 4.5. Performance summary for least-cost system with 30% SO_2 reduction

Least-Cost System -30% SO_2	Capacity (MW)	MCOE ($/kWh)	Variable Cost ($/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of SO_2)
Hydro	1200	0.020	0.020	5256	0
DSM 1	375	0.028	-0.001	1314	0
Existing Coal	420	0.030	0.030	2759	13797
Existing Gas	600	0.040	0.040	2357	0
New Gas	200	0.055	0.035	1314	0
Total	2795	0.030 (avg)		13000	13797

Because the capacity and annual output of the new gas and new coal plants are comparable, the gas plant can directly substitute for the coal plant in the plan in Table 4.5. The result is that demand is met with more than 30% less emissions and only slightly higher costs. As in the base case, under an *economic dispatch* priority, the existing gas plant has the highest variable cost and would be operated at less than full capacity. However, if the dispatch priority is changed to *environmental dispatch*, the plant with the highest emission rate, in this case the existing coal plant, would be the marginal plant and would be operated at less than full capacity.

The corresponding results for a 90% SO_2 emission reduction (down to <2000 ton/year) are shown in Table 4.6. To reduce emissions by 90%, the first step is again to replace the new coal plant with the new gas plant. The next cheapest measure shown in Table 4.2 is DSM option 2 replacing the new coal plant, but that option cannot be selected because the new coal plant has already been replaced by the new gas plant. The next option must be chosen from those that can replace the existing coal plant. These options include the retrofit coal plant, which can only replace the existing coal plant (by the definition of a retrofit), and this measure has a lower marginal CAE than DSM option 2, the next cheapest available option. Note that, although the retrofit coal plant has a lower marginal cost than the new gas plant, this is a more expensive emission reduction measure because it replaces a much cheaper option, the existing coal plant. In this case, the retrofit coal plant is the marginal plant, based on either the economic dispatch or the environmental dispatch criteria. The addition of this expensive measure leads to a significant increase (about 12%) in the overall system costs.

Table 4.6. Performance summary for least-cost system with 90% SO_2 reduction

Least-Cost System -90% SO_2	Capacity (MW)	MCOE ($/kWh)	Variable Cost ($/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of SO_2)
Hydro	1200	0.020	0.020	5256	0
DSM 1	375	0.028	-0.001	1314	0
Existing Gas	600	0.040	0.040	2628	0
Retrofit Coal	400	0.048	0.040	2488	1244
New Gas	200	0.055	0.035	1314	0
Total	2775	0.034 (avg)		13000	1244

Similar results are shown in Tables 4.7 and 4.8 for reductions of NO_x emissions by 20 and 60%, respectively, compared to the Table 4.3 least cost case. However, because the NO_x emission rates are not as easily reduced by switching from coal to gas, the least-cost approach to NO_x emission reductions is different from that for SO_2 emissions. Table 4.2 shows that the least-cost NO_x emission reduction option is to replace the new coal plant with the DSM 2 option, rather than with the new gas plant. This option alone reduces NO_x emissions by more than 20% (from 59,000 tons/year in Table 4.3 to 46,000 tons/year in Table 4.7) and meets the projected demand with slightly higher costs. In the case of 20% NO_x reductions, as in the case of 30% SO_2 reductions, the existing gas plant is the marginal plant under economic dispatch, and the existing coal becomes the marginal plant under environmental dispatch.

Table 4.7. Performance summary for least-cost system with 20% NO_x reduction

Least-Cost System -20% NO_x	Capacity (MW)	MCOE ($/kWh)	Variable Cost ($/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of NO_x)
Hydro	1200	0.020	0.020	5256	0
DSM 1	375	0.028	-0.001	1314	0
Existing Coal	420	0.030	0.030	2759	30353
Existing Gas	600	0.040	0.040	2357	14140
DSM 2	750	0.056	-0.001	1314	0
Total	3345	0.030 (avg)		13000	44493

Let us now examine the 60% NO_x reduction in Table 4.8. With the new coal plant already removed from the options considered, the next lowest cost option in terms of CAE, compared to the existing coal plant, would be the wind farm. Because the wind farm does not produce enough energy to completely replace the coal plant, we must continue to the next option, which is the new gas plant. Together these two options can replace the existing coal plant in terms of capacity and annual output, and the emission reductions surpass 60% (down to 22,000 tons/year). This solution means that existing capacity, with its costs already sunk, would be shut down and replaced by the two new generating sources.

Table 4.8. Performance summary for least-cost system with 60% NO_x reduction

Least-Cost System -60% NO_x	Capacity (MW)	MCOE ($/kWh)	Variable Cost ($/kWh)	Electricity Generated (GWh/yr)	Emissions (tons of NO_x)
Hydro	1200	0.020	0.020	5256	0
DSM 1	375	0.028	-0.001	1314	0
Existing Gas	600	0.040	0.040	2488	14928
New Gas	200	0.055	0.035	1314	6570
DSM 2	750	0.056	-0.001	1314	0
Wind farm	500	0.067	0.010	1314	0
Total	3625	0.037 (avg)		13000	21498

As a result, overall costs are increased by more than 20% in Table 4.8 compared to Table 4.3. For 60% NO_x reductions, as in the case of 90% SO_2 reductions, the existing gas plant is the marginal plant under both economic dispatch and emissions dispatch criteria. Note that the total capacity in these two cases is higher than in the base case. This indicates that some plant, such as the hydro plant, would at times be operated at relatively low capacity factor, closely following the daily pattern of load fluctuations.

Note that the results shown above for reducing NO_x emissions are similar to what one would find for CO_2 emissions. The relative emission factors are similar for the two pollutants, as natural gas emits about 60% as much CO_2 per unit of energy as coal (compared to about 50% for NO_x shown above), and the DSM and renewable sources have negligible emissions of both NO_x and CO_2. Thus, the least-cost plan to reduce CO_2 emissions by 20% or 60% would be the same as that shown in Tables 4.7 and 4.8, respectively. On the other hand, if 20% NO_x emission reductions were already mandated through local environmental regulations, then the case in Table 4.7 would become the baseline from which to begin CO_2 reductions.

F.5. Including Emission Charges in Marginal Cost Estimates

Another approach to the analysis and planning of least-cost emission reductions is to apply monetary values to the emissions and use the resulting values to determine the resource mix with the lowest total cost, including the emission charges (equations 4.31 and 4.32). As discussed earlier, the emission charges can be taxes that the utility would pay in proportion to their actual emissions, or they can simply be proxy values or “adders” that are included in the IRP analysis to account for the environmental goals of the planning procedure.

Table 4.9 shows the total marginal costs of the sample set of options, including emission charges based on two levels of SO_2 charges, two levels of NO_x charges and one combined SO_2 and NO_x charge schedule. With emission charges high enough to achieve the reductions analyzed above (Tables 4.5 to 4.8), the results with emission charges should be the same in terms of the resource options selected. For example, an emission charge of \$600/tSO_2 causes the cost of the new coal plant to surpass that of the new gas plant. Thus, the gas plant would replace the coal plant in the plan, leading to the 30% SO_2 emission reduction shown in Table 4.5.

Table 4.9. Marginal cost values including emission charges

Power Source	MCOE* (\$/kWh)	MCOE (\$/kWh) @ \$600/tSO_2	MCOE (\$/kWh) @ \$4500/tSO_2	MCOE (\$/kWh) @ \$600/tNO_x	MCOE (\$/kWh) @ \$4500/tNO_x	MCOE (\$/kWh) @ \$3000/tSO_2 & \$2000/tNO_x
Hydro	0.020	0.020	0.020	0.020	0.020	0.020
Existing Gas	0.040	0.040	0.040	0.044	0.067	0.052
Existing Coal	0.030	0.033	0.053	0.037	0.080	0.067
Retrofit Coal	0.048	0.048	0.050	0.055	0.102	0.073
New Gas	0.055	0.055	0.055	0.058	0.077	0.065
New Coal	0.053	0.056	0.075	0.059	0.098	0.088
New Coal w/ Scrubbers	0.067	0.068	0.070	0.074	0.117	0.091
DSM 1	0.028	0.028	0.028	0.028	0.028	0.028
DSM 2	0.056	0.056	0.056	0.056	0.056	0.056
Wind farm	0.067	0.067	0.067	0.067	0.067	0.067
Combustion Turbines	0.095	0.095	0.095	0.099	0.126	0.109

* MCOE = Marginal Cost of Energy. See equations 4.18 and 4.21 for definition of MCOE.

Exercise 4.8) Recalculate the variable cost, marginal cost and revenue requirements for each resource in Table 4.1, using an emission charge of 1) \$600/tSO_2 and 2) \$600/tNO_x.

With this approach, there could be a different approach to dispatch, as one could incorporate the environmental charges into the economic dispatch criterion. However, an emission charge of $600/t$SO_2$ does not cause the variable cost of the existing coal plant to surpass that of the existing gas plant. (For these existing plants, the variable costs account for practically all of the marginal cost.). Thus, the coal plant would still be dispatched ahead of the gas plant according to economic dispatch criteria that include the $600/t$SO_2$ emission charge. Table 4.9 shows that if the charge is raised to $4500/t$SO_2$, the retrofit coal plant becomes cheaper than the existing coal plant, the same result shown in Table 4.6 for the least-cost plan to reduce SO_2 emissions by 90%.

Similar results are obtained for NO_x emission reductions. Table 4.9 shows that an emission charge of $600/t$NO_x$ causes the cost of both the new coal plant and the new gas plant to surpass that of the DSM-2 option. Thus, the DSM option would be preferred in the plan, leading to 20% emission reductions as shown in Table 4.7. If the charge is $4500/t$NO_x$, the wind farm and the new gas plant become cheaper than the existing coal plant, the same result as shown in Table 4.8 for the least-cost plan to reduce NO_x emissions by 60%.

The emission charges shown in Table 4.9 were selected to achieve the same reductions as those shown in Tables 4.5 to 4.8. Different charges would result in different solutions and higher or lower emission levels. For example, a combined SO_2 and NO_x charge schedule is shown in Table 4.9, and the solution for this case is essentially the same (in terms of power plant selection) as in the case of 60% NO_x reductions shown in Table 4.8.

With the combined SO_2 and NO_x emission charges included, the existing coal plant has about the same total marginal cost value as the wind farm. The combination of the windfarm and the new gas plant provide about the same quantity of energy as the existing coal plant at slightly less cost (including emission charges). Even with these large emission charges, the marginal cost difference is small, but the difference in terms of NO_x and especially SO_2 emissions is dramatic. Of course, without the emission charges, the existing coal plant would be much less expensive than these new plants.

F.6. Constructing Emission Reduction Cost Curves

The above examples are simple enough that the least-cost system could be identified manually. If the list of resources were much longer and more complex, for example involving steps of operation of a power plant (between its minimum and its maximum capacity factor) or many individual DSM options, a more automated approach might be used. A simple ranking approach can be used, or more complex optimization models could be applied, with the objective function being to minimize total costs as in equations 4.1 and 4.2. Such models can also be used to find solutions under other criteria, for example reducing emissions to a given level while minimizing total costs. In such a case, an optimization model, given the same input data, should give the same sort of results as those shown in the above examples based on the simple manual methods given here.

One difficulty with optimization models is that it can be difficult to make them construct scenarios that are sub-optimal according to a specific criterion such as the least-cost system. For example, the emission-reduction cases analyzed above would require the imposition of additional constraints on an optimization model, or the application of an emission charge or "shadow price" to force the model to find a low-emission scenario as optimal. The theory behind optimization techniques indicates that, at an optimal point, the marginal effects of any of the possible changes should be equal. In economic terms, the marginal costs of the different types of measures, for example to provide energy services or reduce emissions, should be equal for a set of measures to be the least-cost solution.

If the specific externality criteria, such as the quantity of emissions allowed or the level of emission charges, have yet to be determined, construction of a marginal cost curve (of, for example, emission reductions) can help analyze what might be an appropriate emissions charge or what level of emission reductions can be achieved at what cost. The marginal cost curve for emission reductions would plot each emission reduction option's marginal costs on the vertical axis and its amount of emission reductions achieved on the horizontal axis, such as those shown in Figure 4.8. The options are plotted in order of increasing marginal cost to show the cost of emission reductions increasing as the level of emission reductions increases.

For example, if we look at the curve entitled "NO_x - dynamic base" in Figure 4.8, this curve suggests that approximately 40% emission reductions can be achieved at a marginal cost of zero, and roughly 70% emission reductions can be achieved at a marginal cost of around \$3000/ton. Marginal cost curves can therefore provide a clear graphical illustration of the trade-offs between emission reductions and costs.

Optimization models can be used to create such cost curves if they can be incrementally constrained to produce a series of solutions with different levels of emissions. At each emissions level, the "optimal" solution can be compared in terms of system costs to determine the marginal cost of achieving that emission level. Similar results can also be obtained using the simple methods shown above, based on the ranking of measures according to their required CAE values.

Equation 4.33 indicates that the CAE is based on differences, in terms of both costs and emissions, between a reduction option (A) and a baseline case (B). This means that the CAE can change depending on what option is considered to be the marginal baseline resource that is being replaced. For example, in calculating the CAE for NO_x emission reductions in Table 4.2, we compared the costs of DSM, new gas plants and wind farms against those of the marginal resource, but the CAE values were dependent on whether the baseline marginal resource was a new coal plant, an existing coal plant, or an existing gas plant. When we consider a plan that requires multiple measures to achieve a reduction target, we cannot use the same baseline for every successive measure. Rather, the *marginal* CAE of each emission reduction measure depends on the order in which the measures are considered, because the baseline can change as one progresses through the list of measures.

If the first (least-cost) measure replaces the marginal resource that was used as the baseline, then the next measure must be evaluated against the resource that it would replace, i.e., a different baseline, which affects the second measure's *marginal* CAE. For example, looking at NO_x reductions in Table 4.2, if the new coal plant is the marginal baseline resource, then replacing the new coal plant with a new gas plant would result in a CAE of \$391/tNO_x. But if the new coal plant is already being replaced by other measures with a lower CAE (such as the DSM 1 option with a CAE of -\$2529/tNO_x), then the new gas plant would have to be compared against a different baseline, i.e., the existing coal plant, against which it has a much higher *marginal* CAE of \$4131/tNO_x. If even further reductions are needed after the existing coal plant has been replaced, then in Table 4.2 the existing gas plant becomes the baseline, against which the new gas plant's *marginal* CAE increases to almost $15,000/t$NO_x$.

Example:

Calculate the marginal CAE values for reducing NO_x emissions, based on: 1.) the dynamic case (i.e., the baseline marginal resource changing), beginning with the non-integrated (supply-only) plan of Table 4.4; and 2.) the static case (i.e., constant baseline marginal resource), with the new coal plant as the "marginal" resource.

Cost of Avoided Emissions: NO_x						
Power Source	MCOE ($/kWh)	Annual GWh	CAE: static base ($/ton)	CAE: dynamic base ($/ton)		
			vs new coal (1314 GWh/yr)	vs new coal (1314 GWh/yr)	vs existing coal (2759 GWh/yr)	vs existing gas (2628 GWh/yr)
DSM 1	0.028	1314	-2529	-2529		
DSM 2	0.056	1314	325	325		
New Gas	0.055	1314	391		4131	14787
Wind farm	0.067	1314	1425		3371	
Combustion Turbines	0.095	88	14037			

The static case simply involves the values for the CAE vs. new coal, and these numbers can be taken directly from Table 4.2. In the dynamic case, the first two measures, DSM 1 and DSM 2, can also be compared to the new coal plants (remember, in the "supply-only" plan in Table 4.4 there are two new coal plants which can be replaced) and these two DSM measures are sufficient to replace both new coal plants, eliminating the new coal plants as the "marginal" resource. Now, the existing coal plant becomes the new marginal baseline resource, and the next cheapest option is the wind farm vs. existing coal. The wind farm does not produce enough energy to replace the existing coal plant, so the existing coal plant remains at the margin. The next option is the new gas plant, which is also compared against the existing coal plant. Together, the wind farm and the new gas plant produce roughly sufficient energy to replace the existing coal plant. Therefore, the existing gas plant finally becomes the baseline marginal resource; and the new gas plant is compared against the existing gas plant as the final option for reducing NO_x.

Given the resources outlined in Table 4.2, Figure 4.8 plots the marginal emission reduction cost curves for SO_2 and NO_x and compares the results of using a static baseline vs. a dynamic baseline. Remember, the dynamic baseline provides the more complete solution.

Exercise 4.9) Calculate the static and dynamic marginal CAE values for SO_2 emissions. In the static case, assume that the new coal plant is the marginal baseline resource. In the dynamic case, assume that the non-integrated (supply-only) plan of Table 4.4 is the baseline scenario.

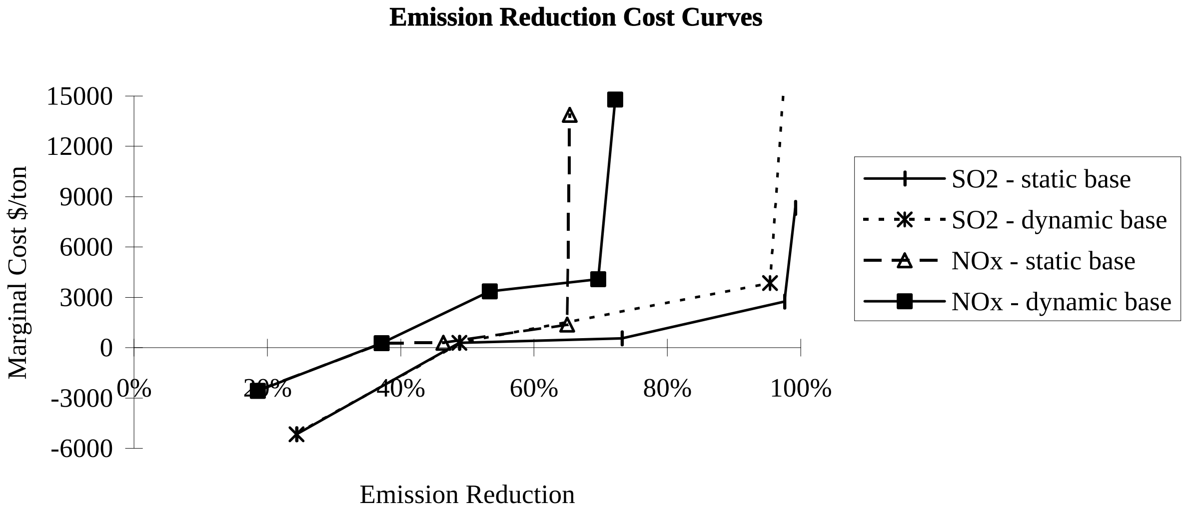


Figure 4.8. Marginal emission reduction cost curves based on static and dynamic baselines

F.7. Estimating Impacts on Electricity Rates

Throughout the presentation of this analysis, we approach costs according to the *total resource cost* definition (see Chapter 2 Section E for definition). This approach is designed to minimize system costs, but it does not necessarily minimize electric rates (tariffs). As discussed in Chapter 2 Section E, DSM measures can reduce the utility's sales and revenues by more than they reduce costs, thus increasing rates. Such measures are cost-effective according to the *total resource cost* definition but fail the *rate impact measure* of cost-effectiveness, which focuses on rates rather than total costs.

The key concept in using the total resource cost definition is the treatment of *energy services*, as defined in Chapter 2 Section A, as the relevant product, rather than the energy-commodity measure of kWh generated and sold. Doing the analysis on the basis of energy services makes it possible to compare energy supplied and energy saved on a common basis, provided of course that they both deliver the same level of service and reliability. Nevertheless, from the utility's standpoint, energy savings are not sold in the same way as electricity. Ideally, the costs and lost revenues associated with energy savings should be recovered from the same customers, or at least the same customer class, as where the savings occur. This is often not the case, and instead the costs may be recovered from the general rate base via slightly higher rates.

Although rates for different customers vary and can involve complex formulas, the average utility rate is simply the value that allows the utility to recover its total costs from its sales, i.e., the average cost of electricity.

Average rate = (total annual cost) / (kWh/yr electricity sold) *[Eq. 4.34a]*

$$= \left[PW_{RR} \cdot crf \right] \Big/ \sum_{h=1}^{h=8760} E_{sold(h)} \qquad \text{[Eq. 4.34b]}$$

Where:

$PW(RR)$ = present worth of revenue requirements
crf = capital recovery factor (See Eq. A3-7 in Appendix 3)
$E_{sold(h)}$ = total system electricity demand (sales) in hour h

Substituting equations 4.3 through 4.7 into the above expression yields the following:

$$Average\ rate = \frac{crf \cdot \left[RR_0 + \dfrac{\sum_{t=0}^{t=n} \left[I_t^* + Cfuel_t + Cvar_t + Cfix_t \right]}{(1+r)^t} \right]}{\sum_{h=1}^{h=8760} E_{sold(h)}} \qquad [Eq.\ 4.35]$$

For each resource, the contribution to total cost (revenue requirements) is composed of the energy terms $Cfuel_t$ and $Cvar_t$ and the capacity terms I^*_t and $Cfix_t$. These same terms make up the marginal costs for each incremental resource (equations 4.11 through 4.16). The marginal costs of a given year's expansion plan can be summed and added to the sunk capital and other fixed costs at that time to provide an estimate of the total cost. Therefore:

$$Total\ annual\ cost = crf \cdot \left[RR_0 + \sum_{j=1}^{j=n} MC_j \right] \qquad [Eq.\ 4.36]$$

Where:
MC_j = marginal cost of supply or DSM resource j of n

And substituting MCOE for MC using equation 4-18,

$$MCOE = \frac{MC \cdot crf}{\Delta kWh} \qquad [Eq.\ 4.18]$$

the average rate can be re-written as follows:

$$Average\ rate = \left[crf \cdot RR_0 + \sum_{j=1}^{j=n} \left[MCOE_j \cdot \Delta kWh_j \right] \right] \Big/ \sum_{h=1}^{h=8760} E_{sold(h)} \qquad [Eq.\ 4.37]$$

Where:

$MCOE_j$ = marginal cost of supply or DSM resource j of n
$dkWh_j$ = increment in annual energy supply or savings from resource j of n

The effect of the resource plans from Tables 4.3 to 4.8 on average rates, average costs, and system marginal costs are compared in Table 4.10. Average rates represent system revenue requirements (including marginal costs for all selected supply and DSM resources plus the sunk capital and other fixed costs of existing plants) divided by sales (excluding DSM savings), assuming that DSM costs and lost revenues are allocated to the general rate base. A more equitable approach would be to allocate DSM costs and lost revenues to participating customers; however this is difficult in practice. Most existing rate structures contain other built-in distortions and inequities as well.

Average costs are based on the same revenue requirement (the numerator in Eq. 4.37), but this cost value is divided by the total of both annual energy supply and energy savings from DSM, rather than just the energy supply (E_{sold}). This sum represents the *energy services* that are provided by the combination of kWh supplied and DSM (kWh saved). The cases with a substantial amount of DSM savings thus have an average cost that is significantly less than the average rate.

For example, the results in Table 4.10 show that, although the integrated least-cost plan (Case 1) requires average rates 10% higher than average costs, these rates are only 5% more than the rates in the non-integrated plan (Case 0), while the average costs of the integrated plan are 5% *less* than in the non-integrated plan. Case 3 (90% SO_2 reduction) and Case 4 (20% NO_x reduction) show significantly higher rates. However, the average costs for Case 3 are only 3% higher than for the non-integrated plan, and Case 4 costs are just marginally greater than the least-cost plan. Case 5 (60% NO_x reduction) has higher costs and rates.

Table 4.10. Comparison of rates and costs for sample electric resource plans

	Average Rate* ($/kWh)	**Average Cost* ($/kWh)**	**Marginal Cost ($/kWh)**
Case 0. Non-integrated plan (new coal)	0.041	0.041	0.053
Case 1. Least-cost plan (new coal)	0.043	0.039	0.053
Case 2. 30% SO_2 reduction (new gas)	0.043	0.039	0.055
Case 3. 90% SO_2 reduction (new gas)	0.047	0.042	0.055
Case 4. 20% NO_x reduction (DSM 2)	0.049	0.039	0.056
Case 5. 60% NO_x reduction (wind farm)	0.057	0.045	0.067

**note: average costs and rates include $1050 million in sunk capital and other fixed costs for existing capacity*

These results also show the important effects of DSM programs in terms of reduced costs despite increased rates. The least cost integrated plan (Case 1 in Table 4.10) has lower average costs than the non-integrated supply-only plan (Case 0 in Table 4.10). In other words, the inclusion of low-cost DSM in Case 1 reduces the cost of providing energy services compared to the supply-only Case 0. However, because Case 1 involves the sale of fewer kWh of electricity (due to DSM) than Case 0, total utility revenue requirements must be apportioned over a smaller kWh sales base, so the $/kWh average rate (tariff) for Case 1 becomes higher than in Case 0. In other words, the total cost of providing energy services declines, but average $/kWh rates increase. However, it is important to distinguish between customer *rates* (tariffs) and customers' actual electricity *bills*. In spite of the fact that rates in Case 1 are higher than in Case 0, the average customer's electricity bill will decline in Case 1 because his electricity consumption will decline (through DSM) sufficiently to compensate for the increase in rates.

Perhaps this can be most easily demonstrated through the following simple example:

Example:

> Suppose an electric utility has 1 million customers who each consume an average of 8000 kWh/yr before any DSM is implemented. Without any DSM, the utility's total annual revenue requirements are \$800 million/yr. Therefore, if the utility pursues a supply-only plan, then the average rate which it must charge its customers would be \$800 million/yr ÷ (8000 kWh/yr · 1 million customers) = \$0.10/kWh. The average customer's annual electricity bill would be 8000 kWh/yr · \$0.10/kWh = \$800/yr.
>
> If the utility pursues DSM, then under its integrated least-cost plan, the 1 million customers' average consumption drops to 7000 kWh/yr, and the utility's revenue requirements drop to \$720 million/yr. The average *rate* then rises to \$720 million/yr ÷ (7000 kWh/yr · 1 million customers) = \$0.103/kWh, but the average customer's electricity *bill* drops to 7000 kWh/yr · \$0.103/kWh = \$721/yr. In terms of the average cost of energy services, the utility is still providing 8000 kWh-worth of energy services per customer for only \$720 million/yr, so the average cost drops to \$720 million/yr ÷ (8000 kWh/yr · 1 million customers) = \$0.090/kWh
>
> The rise in *rates* from \$0.10/kWh to \$0.103/kWh, and the drop in *average bills* from \$800/yr to \$721/yr mask some important differences between customers, however. Customers who do not participate in the DSM program would continue to consume 8000 kWh/yr but would be paying \$0.103/kWh, so their annual bills would in fact increase to \$824/yr, while those customers participating in the DSM programs would see their bills drop to below the \$721/yr average.

These changes in costs and rates can be best understood in the context of the cost-effectiveness tests described in Chapter 2, Section E. The fact that the utility's total revenue requirements drop and that average bills decrease indicates that the DSM program passes the Utility Cost Test. However, the fact that average rates increase indicates that the DSM program fails the Rate Impact Measure (RIM) Test (i.e, has a RIM benefit/cost ratio of < 1.0). The Utility Cost Test and the RIM Test are identical except that the RIM Test includes lost revenues from reduced electricity sales as a cost, while the Utility Cost Test does not.

As described in Chapter 2, the RIM benefit/cost test is defined as follows:

$$\mathit{RIM}\quad \frac{\mathit{Benefits}}{\mathit{Costs}} = \frac{\mathit{Avoided\ Supply\ Costs\ \{based\ on\ Marginal\ Costs\}}}{\mathit{Lost\ Revenues\ \{based\ on\ Average\ Costs\}} + \mathit{DSM\ Program\ Costs}}$$

Therefore, if average costs (which typically define rates) are higher than marginal costs, then a DSM program will always fail the RIM test even if the program is cost-effective for the utility and for society as a whole. Cost-effectiveness for society in general is typically defined by the TRC Test or Societal Test (please refer to Chapter 2, Section E).

F.8. Accounting for Intermittent Supply Resources

The analysis methods presented above focus on providing enough energy, in the form of generated power and/or DSM savings, to meet the projected total annual requirements (13 TWh in the above examples). Electric planning must also address the supply capacity to meet peak demands. In the examples given above, the total capacity was in each case sufficient to meet the projected peak demand (2600 MW). There are potential complications, however, that can change this result and require additional resources to meet peak demands. Some of these potential complications are discussed below.

Changes on the demand side can alter the load factor and increase the peak demand relative to average demand. For example, a space-heating DSM program might reduce total energy consumption without reducing the (summer) peak load driven by air-conditioning. In this case, peak-load supply capacity must be built to keep up with the summer peak, regardless of the savings from the DSM program.

Also, the peak output of a generating plant, or the peak savings from a DSM program, might not coincide with the timing of the peak demand, or may not be available at that time. For fully dispatchable generating resources, such as the coal and gas plants in the above examples, it is assumed that they are available at full capacity during times of peak demand. This may not be the case, however, for some resources. As discussed earlier, the dispatching of hydroelectric capacity is complex, and the availability of hydro capacity to meet daily and seasonal load fluctuations depends on the climatic seasons and the size of the hydroelectric reservoirs. As long as sufficient stored water is in the reservoirs, hydro plants can also be assumed to be fully dispatchable.

Also as discussed earlier, renewable resources such as solar power and wind power, are not as dispatchable as thermal and hydro plants. Moreover, most energy-efficiency programs are not dispatchable at all. The load reduced by DSM options do not necessarily correspond to the peak demand times that determine the utility' supply-capacity requirements. Thus, the value of the DSM resource, in terms of peak capacity, is not the same as a supply-side resource with an equivalent capacity factor. The *capacity value* of the DSM may be less.

Also, the "capacity factor" of a DSM option is not comparable to those of the supply options described by the "screening curves" shown in Figure 4.3. Rather, it is simply the load factor of the load that would be reduced. The load factor of an end-use affected by DSM (except for dispatchable load management options like thermal storage and direct load control) is not comparable to the capacity factor of a dispatchable power plant. The hours-of-use which give the load factor for a DSM option may or may not correspond to the system or local peak demand times when the utility needs capacity, nor is it dispatchable in this sense.

These complications in the timing and availability of DSM and intermittent sources has lead to extensive analysis to determine the *capacity value* of these resources, in terms of the share of their maximum output that can be considered in calculating the system's reserve margin. The *capacity value* is the capacity that can be expected to be available at times of peak demand with approximately the same reliability as a conventional thermal plant. This type of analysis is beyond the scope of this book; however, we can illustrate how the concept might be used.

Table 4.11 shows a possible result of analyzing the capacity value for some of the resources in the sample set from the examples given above. As the thermal plants are expected to be available whenever they are required, they are defined to have 100% capacity credit. The other non-thermal resources are evaluated relative to this value. The load management option is assumed to be designed specifically to reduce peak demand and thus receives 100% capacity credit. The DSM options are evaluated on the basis of the load reductions achieved, relative to the maximum reduction, during times of peak demand. The load for DSM-1 is relatively coincident with the peak, giving 67% capacity credit, and DSM-2 is less so, with only 33%. The wind farm, as discussed earlier, is a complicated case and would depend heavily on local wind characteristics, but we assume in Table 4.11 that about 40% of its output can be expected to be available during peak hours.[11]

Table 4.11. Examples of capacity credits for selected resources

	Capacity (MW)	Capacity Credit	Capacity Value (MW)
Hydro	1200	100%	1200
New Gas	200	100%	200
New Coal	200	100%	200
DSM 1	375	67%	250
DSM 2	750	33%	250
Wind Farm	500	40%	200
Load Management	100	100%	100
Combustion Turbine	50	100%	50

Hydro plants are energy-constrained (based on water availability in the reservoir) rather than capacity-constrained. A reservoir-based hydro plant should be able to generate at its full nominal capacity at any given time, giving it a 100% capacity credit. However, in some cases, environmental restrictions (such as protection of spawning fish) may limit water releases from the dam and prevent the hydro plant from operating at full capacity during certain times or seasons. In such a case, a hydro plant would not receive a full 100% capacity credit. Similarly, a run-of-river hydro plant's capacity credit will be dependent on how well the system peak demand coincides with the high water flow season. For the purposes of Table 4.11, we have assumed a hydro capacity credit of 100%.

Applying the new capacity values of Table 4.11 to the capacity calculations of Tables 4.3 to 4.8, the revised capacity totals are shown in Table 4.12. The revised capacity totals are in the range of 2620-2720 MW, rather than the original range of 2620-3625 MW. Although the wind farm and the DSM options reduce the system's capacity value compared to its nominal capacity, each case still has sufficient capacity to meet the projected peak demand.

Table 4.12. Total capacity of sample electric resource plans with revised capacity values

	Original Total Capacity (MW)	Total Capacity with Revised Capacity Values (MW)
Case 0. Non-integrated plan (new coal)	2620	2620
Case 1. Least-cost plan " "	2795	2670
Case 2. 30% SO_2 reduction (new gas)	2795	2670
Case 3. 90% SO_2 reduction " "	2775	2650
Case 4. 20% NO_x reduction (DSM 2)	3345	2720
Case 5. 60% NO_x reduction (wind farm)	3625	2700

[11] Let us briefly review the difference between the capacity factor and the capacity credit. The capacity factor represents the fraction of a power plant's nominal capacity which is being utilized on average during the year. If a plant has a capacity of 100 MW but on average generates 50 MW each hour during the year (i.e., its total annual generation equals 50 MW · 8760 hr/yr = 438,000 MWh/yr), then its capacity factor would be 50%. The capacity credit represents the fraction of the power plant's nominal capacity which is likely to be available at the time of system peak demand. If our 100 MW plant is fully dispatchable, then we can rely on it to be available during the peak demand, so its capacity credit would be 100% even though its capacity factor is only 50%.

Example:

Suppose that the projected peak demand of 2600 MW is determined to have insufficient reserve margin, and that 10% more capacity (i.e., a total of 2860 MW) must be provided to maintain adequate system reliability. This means that the plans shown in Tables 4.3 to 4.8 require 140-240 MW of additional capacity to meet the requirement, although the total annual energy demand is already satisfied.

What is the least-cost capacity addition to meet this requirement?

The additional reliability requirement calls for capacity with a low capacity factor and, most importantly, low cost per kW. Fuel and other variable costs, and emission rates, are less important because the capacity will be used relatively infrequently. The option with the lowest capacity cost is the 100 MW load management option. Although this option actually consumes energy, the total net energy production still meets the annual demand.

The further additional 40-140 MW of capacity would be provided by the more expensive combustion turbines. Although these units produce relatively expensive electricity, at low capacity factors they are actually less expensive than other plants with higher capacity costs, as shown in Figure 4.3. Their emission rate may also be relatively high, but only for a few hours per year. However, if extreme pollution episodes during times of peak electric demand is an important environmental constraint, such "peaking" plants should be selected with caution.

Exercise 4.10) Assume that the (integrated) least-cost plan shown in Table 4.3 requires additional resources consisting of the 100 MW load management program and 50 MW of combustion turbines. Re-calculate the system marginal costs, revenue requirements and average rates with these resources included.

Further reading:

Charles River Associates, 1986. "Capital Budgeting for Utilities: The Revenue Requirements Method," Electric Power Research Institute, EPRI/EA-4879.

Dutt, G., 1993. *Energy End Use*, Asian Development Bank, Manila.

Hill, L.J., 1991. "Comparison of Methods to Integrate DSM and Supply Resources in Electric Utility Planning," ORNL/CON-341, Oak Ridge, Tennessee, December.

Hohmeyer, O.H., 1988. *The Social Costs of Energy Consumption*, Springer Verlag, Berlin.

Johansson, T.B., H. Kelly, A.K.N. Reddy and R.H. Williams, (eds.) 1992. *Renewable Energy Sources for Fuels and Electricity*, Island Press, Washington.

Johansson, T.B. and Swisher, J.N., 1993. "Perspectives on Bottom-Up Analysis of Costs of Carbon Dioxide Emission Reductions," *OECD International Conference on the Economics of Climate Change*, Paris, June.

Munasinghe, M., 1990. *Electric Power Economics*, Butterworths, London.

Northwest Power Planning Council (NWPPC), 1991. “Northwest Conservation and Electric Power Plan,” NWPPC, Portland, Oregon.

Orans, R., C.K. Woo, J. Swisher, 1992. *Targeting DSM for Transmission and Distribution Benefits,* Electric Power Research Institute, EPRI TR-100487.

Swisher, J., and Johnson, K., 1992. “Cost and Performance Comparison of DSM Measures and Supply Changes to Reduce Utility Carbon Emissions,” *ACEEE Summer Study on Energy Efficiency in Buildings*, Monterey, CA, September.

G. Exercise on Energy Technical and Economical Efficiency Scenario Comprising the Electricity Demand Projections for Brakimpur.

Brakimpur Integrated Resources Planning Project

This exercise is a continuation of the Brakimpur exercise contained at the back of Chapter 2 but draws on the additional concepts studied in Chapter 4. In this current exercise, we continue the analysis of energy demand and build two DSM options; and then we develop a simplified integrated resource plan which allows Brakimpur to meet its future energy service requirements in a manner which considers both economic and environmental priorities.

The New Electricity Plan of Brakimpur is shown in Table 4.13. Table 4.13 represents the result of the exercise you are about to undertake.

Table 4.13. Brakimpur new electricity plan.

Power Source	Number	Capacity (MW)	Capacity Factor	Energy (GWh/yr)	Emissions tSO_2 per GWh	tNO_x per GWh	tSO_2 per yr	tNO_x per yr	MCOE US$/kWh
Existing									
- Hydro	3	1200	0.50	15768					0.020
- Gas	3	600	0.50	7884		6		47304	0.040
- Coal	3	420	0.75	8278	5	11	41391	91060	0.030
EXISTING TOTAL				**31930**			**41391**	**138364**	
Retrofit									
- Coal	1	400	0.75	2628	0.5	12	1314	31536	0.048
New									
- Gas	3	200	0.75	3942		5		19710	0.055
- Coal	3	200	0.75	3942	5	10	19710	39420	0.053
- Coal with Scrubbers		200	0.75	0	0.5	11			0.067
- Wind Farm	1	500	0.30	1314					0.067
- Combustion Turbines		50	0.20	0		7			0.095
DSM1									0.030
DSM2	1			9711					0.035
TOTAL				**53467**			**62415**	**229030**	

1. Objectives

The purpose of this exercise is to allow the reader to apply the concepts developed in this chapter.

The main objective is to develop a technical and economic Efficiency Scenario for the Projected Year (X+10) and to then create an IRP resource expansion plan.

2. Spreadsheet

We suggest a computer spreadsheet to organize and calculate the relevant information for each scenario.

As an example, there is a working spreadsheet with some initial data for the Residential Sector of Brakimpur. Preferably, the reader should adapt this data to better reflect the conditions of his or her country, inserting and interpreting the necessary information.

To make it easier to understand, we have adopted a graphical representation which differentiates input and output data as following:

Normal Font = Data Input (Table A, B, C, and D)
(readers' data input, close to their reality)

Bold Font = **Data Output** (Table E, F and G)
(results on operations and calculations)

3. Spreadsheet Structure

Table A - Socioeconomic indicators of energy demand:
A'1 = population in year X+10
A'2 = number of people per household in year X+10
A'3 = percent distribution of households by income class in year X+10
$\mathbf{N_{X+10}}$ = number of households by income class in year X+10

Table B, C, and D have:

Rows: The rows indicate the end-uses suggested in this exercise.
Columns: The columns indicate the income classes suggested in this exercise.

Table B - New appliance ownership by income class (P_{X+10} = %)

Table C - New average intensity per appliance (I_{X+10} = watts)

Table D - New appliance usage (M_{X+10} = hours/year)

Table E - Brakimpur Technical Scenario: New end-use total household energy consumption by income class:
$\mathbf{E_{X+10} = N_{X+10} \cdot P_{X+10} \cdot M_{X+10} \cdot I_{X+10}}$ **= MWh/year**

Table **F** and **G** = DSM1 and DSM2 Scenarios

Table **F** - DSM1: Economic Scenario assuming implementation of only those DSM measures with costs of saved energy lower than US$30/MWh (i.e., no change in P and no change in water heating).

Table **G** - DSM2: Economic Scenario assuming implementation of only those DSM measures with costs of saved energy lower than US$35/MWh (i.e., no change in P).

4. Worksheet diagram

To show the necessary information and calculations, complete the following worksheet:

5. Steps

Step 1: Build or retrieve the spreadsheet. A printed copy of this spreadsheet is attached. We recommend that you rebuild the spreadsheet.

Step 2: Complete Table A with the following data:
- A'1 = population in year X+10
- A'2 = number of people per household in year X+10
- A'3 = percent distribution of households by income class in year X+10
- $\mathbf{N_{X+10}}$ (number of households by income class in year X+10 is calculated based on N_{X+10} = A'3·A'1/A'2)

Step 3: Complete the Table B, C and D with the following data:
- (B) New appliance ownership by income classes
- (C) New average intensity per appliance
- (D) New appliance usage

Step 4: The Table **E** should calculate the Brakimpur Technical Scenario
- (**E**) New end-use total household energy consumption by income classes

Step 5: The Table **F** and **G** should calculate the Economic Efficiency Scenario.
- (**F**) DSM1.
- (**G**) DSM2.

Table 4.14. Brakimpur residential sector: Technical Scenario

Brakimpur Residential Sector
Year X+10

Table A - Socio-Economic Indicators of Energy Demand

A'1 - population: 14111122 (from Chapter 2
A'2 - people/household: 4 Exercise)

A'3 - Income Classes (Minimum Wage Units)		Total N_{X+10}
0-2	13%	**458611**
2-5	27%	**952501**
5-10	30%	**1058334**
>10	30%	**1058334**
TOTAL	100%	**3527780**

Table B - Brakimpur: Appliance Ownership
Replace Incandescent Lamps with Fluorescent Lamps
LAMP_INC reduced to 350% in (5-10) and to 600% in (10+)
LAMP_FLU increased to 300% in (5-10) and to 400% in (10+)

Appliance ownership by income class (P_{X+10} =%)

end-use	0-2	2-5	5-10	10+
LAMP_INC	100%	200%	350%	600%
LAMP_FLU	100%	100%	300%	400%
IRON	80%	81%	85%	85%
TV	65%	70%	85%	112%
CLTH WASH	0%	4%	15%	31%
AIR_COND.	0%	20%	70%	95%
FREEZER	0%	6%	20%	35%
REFRIG.	70%	79%	83%	100%
FAN	71%	71%	78%	78%
WATER HTR	9%	80%	60%	70%
OTHERS	50%	100%	150%	200%

Table C - Brakimpur: Energy Intensity

Reduction in average intensity per appliance since Year X:

LAMP_INC	25.00%
WATER HTR	4.50%
REFRIG.	24.00%
AIR_COND.	24.00%

New average intensity per appliance (I_{X+10} =watts):

end use	0-2	2-5	5-10	10+
LAMP_INC	45	45	45	75
LAMP_FLU	20	20	20	20
IRON	2300	2300	2300	2300
TV	100	100	100	100
CLTH WASH	600	600	600	600
AIR_COND.	266	266	304	304
FREEZER	700	700	700	800
REFRIG.	174.8	174.8	174.8	174.8
FAN	200	200	200	200
WATER HTR	2387.5	2387.5	2387.5	2865
OTHERS	60	60	60	100

Table D - Brakimpur: Appliance Usage

Reduction in average usage per appliance since Year X:
WATER HTR 4.50%

New Appliance Usage (M_{X+10} =hours/year) :

end use	0-2	2-5	5-10	10+
LAMP_INC	3330	3000	2500	1000
LAMP_FLU	1250	1250	1250	1500
IRON	13	22	43	52
TV	1500	1500	1900	2000
CLTH WASH	0	0	833	833
AIR_COND.	2000	2000	3000	4500
FREEZER	1286	1286	1286	1500
REFRIG.	2609	3043	3478	3913
FAN	1000	1500	1750	2500
WATER HTR	114.6	114.6	191	191
OTHERS	667	1000	3000	2400

Table E - Brakimpur Technical Scenario: New End-Use Total Household Energy Consumption by Income Class
$E_{X+10} = N_{X+10} * P_{X+10} * I_{X+10} * M_{X+10}$ (MWh/year)

end use	0-2	2-5	5-10	10+	Total
LAMP_INC	**68723**	**257175**	**416719**	**476250**	**1218868**
LAMP_FLU	**11465**	**23813**	**79375**	**127000**	**241653**
IRON	**10970**	**39039**	**88969**	**107590**	**246568**
TV	**44715**	**100013**	**170921**	**237067**	**552715**
CLTH WASH	**0**	**0**	**79343**	**163976**	**243319**
AIR_COND.	**0**	**101346**	**675641**	**1375411**	**2152398**
FREEZER	**0**	**51446**	**190542**	**444500**	**686489**
REFRIG.	**146406**	**400254**	**534038**	**723893**	**1804590**
FAN	**65123**	**202883**	**288925**	**412750**	**969681**
WATER HTR	**11293**	**208489**	**289568**	**405395**	**914746**
OTHERS	**9177**	**57150**	**285750**	**508000**	**860077**
Total	**367871**	**1441608**	**3099792**	**4981834**	**9891105**

Table 4.15. Brakimpur residential sector: Economic Scenarios

DSM Options from Tables B, C, and D:		*Cost of DSM Options (US$/MWh)*
Reduce P(LAMP_INC), Increase P(LAMP_FLU) as in Table B:		44
Reduction in M(WATER HTR) as in Table D by:	4.50%	31
Reduction in I(LAMP_INC) as in Table C by:	25.00%	27
Reduction in I(REFRIG) as in Table C by:	24.00%	29
Reduction in I(AIR_COND.) as in Table C by:	24.00%	27
Reduction in I(WATER HTR) as in Table C by:	4.50%	27

Table F - Brakimpur DSM1 (Economic Scenario 1) Results
Only implement DSM options costing less than US$30/MWh

end use	0-2	2-5	5-10	10+	Total
LAMP_INC	**68723**	**257175**	**476250**	**555625**	**1357774**
LAMP_FLU	**11465**	**23813**	**66146**	**95250**	**196674**
IRON	**11007**	**38576**	**89958**	**107950**	**247491**
TV	**44715**	**100013**	**170921**	**237067**	**552715**
WATER MA.	**0**	**0**	**79375**	**164042**	**243417**
AIR_COND.	**0**	**101346**	**675641**	**1375411**	**2152398**
FREEZER	**0**	**51435**	**190500**	**444500**	**686436**
REFRIG.	**146389**	**400317**	**534078**	**723901**	**1804684**
FAN	**65123**	**202883**	**288925**	**412750**	**969681**
WATER HE.	**11825**	**218313**	**303213**	**424498**	**957849**
OTHERS	**9172**	**57150**	**285750**	**508000**	**860073**
Total	**368419**	**1451021**	**3160757**	**5048995**	**10029191**

Table G - Brakimpur DSM2 (Economic Scenario 2) Results
Only implement DSM options costing less than US$35/MWh

end use	0-2	2-5	5-10	10+	Total
LAMP_INC	**68723**	**257175**	**476250**	**555625**	**1357774**
LAMP_FLU	**11465**	**23813**	**66146**	**95250**	**196674**
IRON	**11007**	**38576**	**89958**	**107950**	**247491**
TV	**44715**	**100013**	**170921**	**237067**	**552715**
WATER MA.	**0**	**0**	**79375**	**164042**	**243417**
AIR_COND.	**0**	**101346**	**675641**	**1375411**	**2152398**
FREEZER	**0**	**51435**	**190500**	**444500**	**686436**
REFRIG.	**146389**	**400317**	**534078**	**723901**	**1804684**
FAN	**65123**	**202883**	**288925**	**412750**	**969681**
WATER HE.	**11293**	**208489**	**289568**	**405395**	**914746**
OTHERS	**9172**	**57150**	**285750**	**508000**	**860073**
Total	**367887**	**1441196**	**3147113**	**5029892**	**9986088**

6. Questions

a. Compare the Brakimpur Frozen Efficiency Scenario in Table G of Table 2.12 (Chapter 2) with the Technical Scenario in Table E of Table 4.14. Which are the end-uses with the largest MWh saved? Which are the end-uses with the least MWh saved? Discuss some reasons that could explain the differences observed.

b. How much is the total residential energy saved in the Technical Scenario compared to the Frozen Efficiency Scenario?

c. If you were going to select an option for conservation in two end-uses in the Technical Scenario, what would be your decision? Why?

d. How much is the total residential energy saved in the Economic Scenarios DSM1 and DSM2 compared to the Frozen Efficiency Scenario?

7. Commercial Sector

Now, we can do the same for the Commercial Sector, changing the N (number of households) to A (commercial sector area in square meters):

In Table 4.16, we present the projected year (X+10) electricity consumption for the various segments and end-uses based on a Frozen Efficiency Scenario.

Table 4.16. Projected year (X+10) electricity consumption by market segment and end-use in the commercial sector (MWh): Frozen Efficiency Scenario

Segment\End-Use	Illumination	Air Conditioning	Electric Cooking	Refrigeration	Equipment	TOTAL MWh
Small commerce	378,542	5,979	2,562	172,189	9,395	568,666
Shopping center	1,711,875	181,563	46,688	1,045,800	129,688	3,115,613
Hotels	332,473	382,534	1,701	380,832	11,334	1,108,875
Banks	291,173	17,470	851	156,534	9,706	475,734
Schools	3,812,802	992,918	20,426	915,072	181,562	5,922,781
TOTAL MWh	6,526,864	1,580,464	72,228	2,670,428	341,685	11,191,668

The consumption of electricity in the projected year by the commercial sector depends strongly on the number of premises in each market segment. The consumption of electricity in the commercial sector can be calculated according to the following relationship:

$$\boldsymbol{E_{ij(X+10)} = P_{ij(X+10)} \times A_{ij(X+10)} \times M_{ij(X+10)} \times I_{ij(X+10)}}$$

for each market segment **i** and each end-use **j**, and where:

$E_{ij(X+10)}$ = energy consumption of end use **j** in market segment **i**
$P_{ij(X+10)}$ = penetration (% of total surface area) of end use **j** in market segment **i**
$A_{ij(X+10)}$ = total area of each market segment
$M_{ij(X+10)}$ = total number of annual hours of use for each end-use
$I_{ij(X+10)}$ = energy intensity, i.e., power consumed per unit of area by each end-use.

Total commercial sector energy consumption would be obtained by summing the E_{ij} terms for each market segment and end-use.

8. Projections of the Electricity Demand for the Commercial Sector

For an energy conservation scenario, the new consumption of electricity for the projected year (X+10) could be written using the following relationship:

$$\boldsymbol{Econs_{ij(X+10)} = Efroz_{ij(X+10)} \times (1 - p_{ij(X+10)})}$$

for each market segment **i** and end-use **j** and where:

$Econs_{ij(X+10)}$ =	energy consumption of end-use **j** in market segment **i** under a conservation scenario
$Efroz_{ij(X+10)}$ =	energy consumption of end-use **j** in market segment **i** under a frozen efficiency scenario
$p_{ij(X+10)}$ =	conservation potential (%) of end use **j** in market segment **i**

Now estimate the consumption of electricity in the projected year (X+10) for both a Technical Efficiency Scenario and an Economic Potential Scenario with DSM options, assuming a 40% conservation potential for illumination that costs US$19/MWh, a 21% conservation potential for air-conditioners that costs US$12/MWh, and a 15% conservation potential for refrigeration that costs only US$4/MWh. Use the same cost-effectiveness criteria as in the residential sector's DSM1 and DSM2 scenarios for choosing which DSM options to implement in the Economic Potential Scenario.

9. Questions

a. Compare your results with ours, that is, 7,848,461 MWh/yr for the Technical scenario as well as for the DSM1 and DSM2 Economic scenarios. Why do we have the same values for all three scenarios?

b. Observing the results you have projected, which are the commercial market segments with the largest MWh consumption? How does DSM impact this? Which are the commercial market segments with the lowest consumption? Discuss some reasons that could explain the differences observed.

10. Industrial Sector

Now, we will briefly look at the Industrial Sector The basic ideas are the same as for the residential and commercial sectors.

In the Chapter 2 Brakimpur exercise, we looked primarily at one important end-use: the use of electricity in motors.

For our current exercise, we will assume that we have the following two conservation options: (i) lowest cost measures for all end-uses except motors, and (ii) replacement of standard motors with efficient motors.

We will assume that the conservation potential for these two options in year X+10 is:

(i) 1,684,856 MWh at a cost of US$15/MWh, and

(ii) 2,893,284 MWh at a cost of US$33/MWh.

Therefore, for the industrial sector, the DSM1 Economic Potential Scenario would incorporate only option (i) because option (ii) costs more than US$30/MWh, but the DSM2 Economic Potential Scenario would incorporate both options (i) and (ii).

11. Integrating the Supply and Demand Side Options

Table 4.17 summarizes the potential MWh savings in the Technical, DSM1, and DSM2 scenarios for each sector.

Table 4.17. MWh saved in different sectors and scenarios.

Sector \ Scenario	Technical	Economic	
		DSM1	DSM2
Residential	1,884,331	1,746,245	1,789,348
Commercial	3,343,207	3,343,207	3,343,207
Industrial	4,578,140	1,684,856	4,578,140
Total	9,805,678	6,774,308	9,710,695

In year X+10, in the absence of any DSM programs (i.e., in the case of the Frozen Efficiency scenario), the total expected electricity demand in Brakimpur is 51,402,273 MWh, as shown in Table 4.18. Given that the total electricity generation potential is only 31,930,200 MWh in the base year X, Brakimpur would face a deficit of 19,472,073 MWh in year X+10 if no new additional capacity is made available.

Therefore, we must develop a capacity expansion plan which recommends which new supply capacity and DSM programs should be implemented between the base year X and the projected year X+10.

Let us assume that the following conditions are placed on the new resource plan:

- Resources should be chosen based on their marginal cost of energy (MCOE). In the absence of other constraints, the cheapest options should be chosen.
- The reserve margin in terms of available energy should be a minimum of 4% of total MWh energy demand.
- Emissions of SO_2 and NO_x per kWh should not increase between year X and year X+10.
- The Brakimpur government has made a commitment to meet a minimum of 2% of total electricity demand through wind energy.

Based on these conditions and the available resources as shown Table 4.13, we have chosen to implement the following new options: 1 retrofit coal plant, 3 new gas plants, 3 new coal plants, 1 new wind farm, and DSM2. For simplicity, we have assumed that the retrofit coal plant does not replace an existing coal plant but simply adds additional (cleaner) capacity to it. We have also assumed that only 1 coal plant can be retrofitted.

The resulting new resource plan's characteristics are summarized in Table 4.18, and the energy produced by each plant type is shown in Table 4.13. Note that we have treated DSM2 like a supply-side resource and equal to other supply-side resources. This is one of the primary objectives of IRP.

Table 4.18. Base year X and year X+10 electricity demand, and electricity system characteristics

	Year X	**Year X+10**
Residential (MWh)	7,779,137	11,775,436
Commercial (MWh)	4,334,581	11,191,668
Industrial (MWh)	19,025,844	28,435,169
Total Demand (MWh)	31,139,562	51,402,273
Energy Available (MWh)	31,930,200	53,466,895
Reserve Margin (MWh)	790,638	2,064,622
Reserve Margin (%)	2.54%	4.02%
SO_2 tons per GWh	1.30	1.17
NO_x tons per GWh	4.33	4.28
% of Energy from Coal	26%	28%
% of Energy from Gas	25%	22%
% of Energy from Hydro	49%	29%
% of Energy from DSM	0%	18%
% of Energy from Wind	0%	2%

13. Questions

a. Does our resource plan meet the conditions/restrictions placed on the resource selection in the previous page?

b. Can you recreate our resource plan? Do you agree with our selection of resources? Why or why not? Why did we choose the resources we chose?

c. Our resource plan contains a number of simplifications. Can you name some of them?

Appendix 1. Conversion Factors

Heating Value (Lower Heating Value, or Net Calorific Value) of Some Fuels

Fuel	GJ/metric ton	MJ/m^3
LPG	49.35	
Kerosene	46.05	
Diesel oil	45.46	
Fuel oil	43.24	
Natural gas		41.23
Gasoline	38.87	
Ethanol	29.68	
Charcoal	29.46	
Coal	28.46	
Piped gas (Town or City gas)		17.50
Wood fuel	10.56	

Source: Brasil, Ministerio de Minas e Energia, 1995

Important Conversion Factors

	Joule	Kilowatt-hour	Kilo calorie
1 J	1	2.778×10^{-7}	2.388×10^{-4}
1 kWh	3.6×10^{6}	1	860
1 kcal	4186.8	1.163×10^{-3}	1
1 TOE (IEA)[1]	4.1868×10^{10}	11630	10^{7}
1 TOE (Brazil)[1]	4.5×10^{10}	12510	1.0755×10^{7}

Source: International Energy Agency (IEA), 1995, except Brazil TOE conversions: from Brasil, Ministerio de Minas e Energia, 1995

Decimal Multipliers

Multiplier	Abbreviation	Meaning
kilo	k	10^{3}
mega	M	10^{6}
giga	G	10^{9}
tera	T	10^{12}
peta	P	10^{15}
exa	E	10^{18}

[1] Note, every country's oil products have different calorific values, resulting in different conversion factors for each country between TOE and other units of measurement, like joules, kilowatt-hours, and kilo-calories. We present two separate TOE conversions here to illustrate this point. The IEA value is an international average, while the Brazil value applies specifically to just one country, Brazil. In carrying out analyses for specific countries, country-specific TOE values should be used to the greatest extent possible.

Appendix 2. Glossary of Utility Planning and Demand-Side Management Terms

Absorbent. A material which, due to an affinity for certain substances, extracts one or more such substances from a liquid or gaseous medium with which it contacts and which changes physically or chemically, or both, during the process. Calcium chloride is an example of a solid absorbent, while solutions of lithium chloride, lithium bromide, and ethylene glycol's are liquid absorbents.

Absorption. A process of attracting and holding moisture in which the desiccant material undergoes a chemical change. For example, table salt (a desiccant) changes from a solid to a liquid as it absorbs moisture.

Achievable Potential. An estimate of energy savings based on the assumptions that all energy-efficient options will be adopted to the extent that it is cost-effective and possible through utility DSM programs.

Adiabatic Process. A thermodynamic process in which no heat is extracted or added to the system.

Administrative Costs. In the context of DSM, costs incurred by a utility for program planning, design, marketing, implementation, and evaluation. They include labor-related costs, office supplies and expenses, data processing, and other such costs. They exclude costs of marketing materials and advertising, purchases of equipment for specific programs, and rebates or other incentives.

AFUE- Annual Fuel Utilization Efficiency. AFUE, used to measure the efficiency of gas-fired heating furnaces, is the ratio of heat delivered to heat input during a year under specified conditions.

Agricultural Sector. Non-residential customers engaged in the production of crops and livestock, forestry, fishing, hunting or trapping.

Air Change. A measure of the rate at which the air in a building is replaced by outside air from infiltration and ventilation; usually described as air changes per hour.

Air Conditioner, Room. A room air conditioner is a factory-made encased assembly designed as a unit for mounting in a window, through a wall, or as a console. It is designed for free delivery of conditioned air to an enclosed space without ducts.

Air Conditioner, Unitary. A rotary air conditioner consists of one or more factory-made assemblies which normally include an evaporator or cooling coil, a compressor and condenser combination, and may include a heating function as well; where each equipment is provided in more than one assembly, the separated assemblies are designed to be used together.

Air Conditioning. The process of treating air so as to control simultaneously its temperature, humidity, cleanliness, and distribution to meet the requirements of the conditioned space.

Air Conditioning Hours. The number of hours in a 24-hour period in which the temperature exceeded 75^{o}F.

Air Conditioning System, Central Fan. A mechanical indirect system of heating, ventilating or air conditioning in which the air is treated or handled by equipment located outside the rooms served, usually at a central location, and conveyed to and from the rooms by means of a fan and a system of distributing ducts.

Air Conditioning System, Year Round. One which ventilates, heats, and humidifies in winter, and cools and dehumidifies in summer the spaces under construction, and provides the desired degree of air motion and cleanliness. The system includes the following equipment, whether it is located within the structure served or external to it: the refrigeration system and the heat generating system; any piping systems used to convey the heating and cooling media to suitable heat transfer surfaces; pumps, accessories, automatic controls, and interrelated electrical work. The heat transfer portions of the system generally include, as required, preheaters, fan systems of distributing ducts, piping, and necessary means of manual or automatic control.

Air Diffuser. A circular, square, or rectangular air distribution outlet, generally located in the ceiling and comprised of deflecting members discharging supply air in various directions and planes, and arranged to promote mixing of primary air with secondary room air.

Alternative Rate Programs. Special rate structure or discount on the customer's electric bill, generally in return for participation in programs aimed at cutting peak demands.

Ampere. The rate of flow of electric current through a conductor.

Annual Effects. Electricity use and demand effects caused by a program's activities in the current year.

Annual Energy Effects. The estimated change in energy use on an average annual basis associated with participation in a program or installation of an efficiency measure. (Note: California collaborative defines this in terms of '"the first full year after the installation of a measure" to avoid ambiguity about what year to use).

Annual Participation. The number of participants who are enrolled in a particular program for a given year.

Appliance Saturation. The number of each of the specific types of household appliances connected to a utility's lines, divided by the total number of residential customers.

ASHRAE. The American Society of Heating, Refrigeration and Air Conditioning Engineers.

ASHRAE 90-75. ASHRAE standard for energy conservation in new building design.

Attrition. Any pattern of customers dropping out of ongoing program (e.g., interruptible rate).

Audit. Analysis of a home, building or industrial process by an energy engineer to determine ways the customer can improve their energy efficiency.

Automatic Meter Reading System (AMRS). A system capable of reading a meter (watt hour, demand, gas, water or any other type of meter), preparing and conditioning the data and transmitting the accumulated information for the meter location to a central data accumulation device. The communications link may be radio, telephone line, power line carrier, direct cable, or a combination thereof. The data accumulation device will in most cases be a computer.

Availability. The ratio of the maximum output of a supply resource to its rated capacity, a measure of reliability.

Avoided Cost. The incremental cost that a utility would incur to produce or purchase an amount of power equivalent to that saved by a DSM measure.

Ballast. One component of a fluorescent fixture or compact fluorescent lamp which controls the voltage and current to the lamp.

Ballast Factor. The fractional loss of task illuminance due to use of a ballast other than the standard one.

Base Load Generation. Those generating facilities within a utility system which are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs.

Base Load Unit/Station. Units or plants which are designed for nearly continuous operation at or near full capacity to provide all or part of the base load. An electric generation station normally operated to meet all, or part, of the minimum load demand of a power company's system over a given amount of time.

Base Market. The set of customers or technologies against which participation in a program is measured.

Bench Marking. A process for achieving superior performance through rigorous measurement and comparison of operating practices and philosophies in companies recognized as "best-in-class", to identify and incorporate the best practices and to surpass the best-in-class performers.

Benefit-Cost Ratio. The ratio of the value of a DSM measure's energy savings to its installed cost. The energy savings value is based on the utility's avoided cost.

Bidding Program. The utility's issuance of a Request for Proposal (RFP) to acquire demand-side resources. Potential bidders may include energy service companies, installation contractors, material suppliers, customers, and other utilities.

Bill Credit. An incentive in the form of a reduction in a customer's electricity bill.

Blower Door. A diagnostic tool used to test air infiltration rates by either pressurizing or depressurizing the building.

Boiler. A device where hot water or steam is generated, usually by burning fuel or using electricity.

Booster Water Heater. Hot water from a primary system is raised to a higher temperature for a particular task (i.e., dishwasher rinse).

Btu - British Thermal Unit. The amount of energy required to raise the temperature of one pound of pure water by one degree Fahrenheit. One Btu is equal to 3.413 Watt hours, 778 ft-lb. and 252 calories.

Btuh Heat Loss. The amount (in Btu per hour) of heat that escapes, from warmer to colder areas, through walls, ceilings, floors, windows, doors by infiltration in one hour's time.

Building Envelope. The walls, doors, windows, and roof that separates the inside of a building from the outside.

Capacity. Usable output of a system or system component in which only losses occurring in the system or component are charged against it.

Capacity, Condensing Unit. Refrigerating effect in Btuh produced by the difference in total enthalpy between refrigerant liquid leaving the unit and the total enthalpy of the refrigerant vapor entering it. Generally measured in ton or Btuh.

Capacity Credit. The fraction of a supply source’s rated capacity that is expected to be available at times of peak demand with the same reliability as a conventional thermal plant.

Capacity, Electric Supply. The maximum quantity of electrical output for which a supply system or component is rated.

Capacity Factor. The ratio of the average operating capacity of an electric power generating unit for a period of time to the capacity rating of the unit during that period.

Capacity-Limited Resource. A supply resource (e.g., thermal) of which the energy output is limited by the rated capacity, regardless of how much energy is available.

Capacity, Refrigerating. The term refrigerating capacity is used to denote the rate of heat removal from a medium or space to be cooled at stated conditions; refrigerating effect is used to denote heat transfer to or from the refrigerant itself in a refrigerating system.

Capacity Value. The contribution of a supply resource to the maximum capacity of the system, a measure of reliability and predictability of a resource.

Capitalized. Equipment or other costs that are considered capital investments to be used over a multi-year period and therefore eligible for inclusion in rate base.

Cash Incentive. An incentive in the form of a rebate or cash payment.

CCF. One hundred cubic feet of natural gas, with a thermal content of 100,000 Btu or one therm.

Central Air Conditioner. A consumer appliance rated below 65,000 Btu/hour that is powered by single phase electric current. It consists of a compressor and an air-cooled condenser assembly and an evaporator or cooling coil; designed to provide air cooling, dehumidifying, circulation, and cleaning. The air is treated by equipment at one of more central locations outside the spaces served and conveyed to and from these spaces by means of fans and pumps through ducts and pipes.

Central Heating System. A system in which heat is supplied to all areas of a building from a central plant through a network of ducts or pipes.

Central Water Heater. Hot water generated in one location and piped to points of use. May require recirculating to maintain required temperature at points of use.

CFM (cubic feet per minute). A measure of air flow rate.

CGS. A system of units and measurements comprised of centimeter-gram-second.

Chiller. A device where water is cooled (to 40-50^{0}F) for later use in cooling air.

Circuit. A conductor or a system of conductors through which an electric current flows.

Clothes Washer. A consumer product designed to clean clothes, utilizing a water solution of soap and/or detergent and mechanical agitation or other movement, and can be one of the following classes: automatic clothes washers, semi-automatic clothes washers, and other clothes washers.

Coefficient of Performance, Heat Pump. Ratio of heating effect produced to the energy supplied, where the heating effect and energy supplied are expressed in the same thermal units.

Coefficient of Performance, Refrigerating Unit. Ratio of the refrigeration produced to the work supplied, where refrigeration and work supplied are expressed in the same thermal units.

Coils. Finned-tube heat exchanger which heats/cools air flowing over the outside of the tubes by hot/cold water flowing inside the tubes.

Coincident Demand. A customer's demand at the time of a utility's system peak demand.

Coincident Peak. Customer's demand at the time of the utility's system peak.

Cold Deck. The portion of the duct containing the chilled water coil or DX coil. Generally parallel with a bypass deck or hot deck.

Collector Efficiency. For solar collectors, the output (energy collected) divided by the input (the solar energy falling on the collector surface) within a specified period of time.

Commercial Sector. A group of nonresidential customers that provide services, including retail, wholesale, finance, insurance, and public administration.

Competitive Bidding. A competitive procurement process for selecting some portion of future electric generating capacity that may include: the publication of a Request for Proposal (RFP) by an electric utility for the purchase of electric generating capacity, electric energy, and/or demand-side management products and services; the submission of bids offering to provide such products and services by multiple would-be suppliers; and the selection by the electric utility of one or more winning bids subject to appropriate oversight by a state regulatory body.

Compression Chiller. A refrigeration device which uses mechanical energy input to produce chilled water.

Compressor. A device that increases the pressure of a refrigerant.

Condenser. A vessel or arrangement of pipe or tubing in which a vapor is liquefied by removal of heat.

Condenser, Air-Cooled Refrigerant. A condenser cooled by natural or forced circulation of atmospheric air through it. In refrigeration systems, the component that rejects heat.

Condensing Unit. A component of a central air conditioner which is designed to remove the heat absorbed by the refrigerant and to transfer it to the outside environment, and which consists of an outdoor coil, compressor(s), and air moving device.

Conductance, Thermal. The time rate of heat flow through a body per unit area from one of its bounding surfaces to the other for a unit temperature difference between the two surfaces, under steady conditions. The term is applied to specific bodies or constructions as used, either homogeneous or heterogeneous.

Connected Lighting Load. The power in watts required by lights when all fixtures are fully on throughout the building.

Connection Charge. An amount to be paid by a customer in a lump sum, or in installations, for connecting the customer's facilities to the supplier's facilities.

Conservation. The protection, improvement, and use of natural resources according to principles that will assure their highest economic or social benefits.

Conservation Cost Adjustment (CCA). A means of billing customers to accrue funds to pay for the costs of load management programs as set forth under the Public Utility Regulatory Policies Act of 1978 (PURPA). Utilities defer the cost of building expensive generating capacity by encouraging customers to use energy more efficiently. One means is encouraging customers to purchase energy-efficient appliances and *machinery* to replace less efficient devices. A common example is when a utility advertises that it will pay customers to convert from electric resistance heat to heat pumps. The greater efficiency of the heat pumps reduces peak demand. Applied over large numbers of customers, the lowered demand allows the utility to avoid expensive construction of energy supply units, which more than pays for the cost of the advertising and the rebates.

Conservation Program. A DSM program that attempts to reduce a customer's energy (kWh) consumption over most or all hours of the day.

Constant Air Volume System. An air conditioning system of the reheat, recool, dual duct or multi-zone type which has fixed air flow rate.

Contingency Security Criteria. Reliability criteria based on a given number of component failures being compensated by other facilities without losing the ability to meet forecasted loads.

Control Group. A group of customers who did not participate in a program, who are used to isolate program effects from other factors such as natural conservation.

Convection. Transfer of heat by movement of fluid.

Conventional Cooking Top. A class of kitchen ranges and ovens which is a household cooking appliance consisting of a horizontal surface containing one or more surface units which include either a gas flame or electric resistance heating.

Conventional Oven. A class of kitchen ranges and ovens which is a household cooking appliance consisting of one or more compartments intended for the cooking or heating of food by means of either a gas flame or electric resistance heating. It does not include portable or countertop ovens which use electric resistance heating for the cooking or heating of food and are designed for an electrical supply of approximately 120 volts.

Conventional Range. A class of kitchen ranges and ovens witch is a household cooking appliance consisting of a conventional cooking top and one or more conventional ovens.

Cooling, Evaporative. Involves adiabatic heat exchange between air and a water spray or wetted surface. The water assumes the wet-bulb temperature of the air, which remains constant during its traverse of the exchanger.

Cooling-Degree Day. An indicator of cooling needs in a given geographical area. The difference between the mean temperature of any day and a base temperature when the mean temperature is greater than the base temperature, with each degree above that temperature equaling one cooling-degree day. For example, if the base temperature is 50^{o}F and the mean temperature for a specific day is 78^{o}F, 28 cooling-degree days to a 50^{o}F base would be accrued.

COP - Coefficient of Performance. The scientifically accepted measure of the heating or cooling performance of any refrigeration machine - heat pump, air conditioner, or refrigerator. It is determined through ARI standardized laboratory testing and provides an indication of steady-state performance. The COP is defined as:

$$\text{COP} = \frac{\text{Heating or (cooling) provided by the system, in Btu}}{\text{Energy consumed by the system, in Btu}}$$

The total heating output of a heat pump includes heat generated by the circulating fan but excludes supplemental resistance heat. Because the COP is a dimensionless measure, the heating and cooling output and energy input must be expressed in the same units. If the output is expressed in Btu, then the system energy consumption, typically expressed in watt hours, must be converted to Btu. This is done by multiplying the denominator by the conversion factor 3.413 Btu /watt-hour.

COP is more commonly used to measure heating performance than cooling performance and varies with source and sink temperature. Good performance is indicated by a high COP. The higher the COP, the higher the equipment efficiency. The COP is equal to the EER divided by 3.413.

COS - Coefficient of Shading. Ratio of solar radiation passing through a specific glazing system to the solar radiation passing through a single layer of double strength.

Cost of Avoided Emissions. The ratio of incremental costs of emission-reducing measures to the incremental quantity of emissions reduced.

Cream Skimming. Installing only the lowest cost or easy-to-install DSM measures while ignoring other cost-effective opportunities.

CU - Coefficient of Utilization. The ratio of light (lumens) from a luminaire received on a work plane, to the lumens emitted by the lamps alone.

Cubic Feet per Minute (CFM). A measure of air flow rate.

Cumulative Effects. The electricity use and demand effects of a program caused by all its participants, from the program's inception through the current year.

Cumulative Participation. The sum of the number of participants from the start of a program through the current year.

Curtailable Electric Service Programs. Programs which are designed to reduce a utility's peak load requirements by offering customers substantial rate discounts when service is interrupted during the utility's peak demand period. Most utility programs are targeted at large commercial and industrial customers who pledge a minimum interruptible load level to be curtailed as directed by the utility during emergency power shortages.

Customer (electric). An individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated.

Customer Charge. An amount to be paid periodically by a customer for electric service often based upon costs incurred for metering, meter reading, billings, etc., exclusive of demand and/or energy consumption.

Customer Class. A group of customers with similar characteristics, such as economic activity or level of electricity use.

Customer Unit. A participating unit that is based on customers, households or buildings, in contract to technology units.

Customer Load Management System. Normally consists of a unidirectional signal system operated by a utility company which upon command from a central control station provides switching signals to turn one or more selected customer appliances off or on in order to improve system load factor by reducing peak load.

Cycle, Carnot. A sequence of reversible processes forming the reversible working cycle of an ideal heat engine of maximum thermal efficiency. It consists of isothermal expansion, adiabatic expansion, isothermal compression, and adiabatic compression to the initial state.

Degree Day. See “Cooling Degree Day” and “Heating Degree Day.”

Dehumidification. (1) condensation of water vapor from air by cooling below the dew point; (2) a compression or absorption device for removing moisture from air.

Dehumidifier. A self-contained, electrically powered, mechanically-refrigerated device designed primarily to decrease the moisture content of the air in an enclosed space; it has a refrigerated surface (evaporator) onto which moisture from the air condenses, a refrigerating system that includes an electric motor, a fan for circulating air, and a drainage arrangement for collecting and /or disposing of the condensate.

Demand. The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment. It is expressed in kilowatts, kilovolt amperes or other suitable unit at a given instant or averaged over any designated period of time. The primary source of “Demand” is the power-consuming equipment of the customers.

> **Annual System Maximum**: The greatest demand on an electric system during a prescribed demand interval in a calendar year.
>
> **Average**: The demand on, or the power output of, an electric system or any of its parts over any interval of time, as determined by dividing the total number of kilowatt hours by the number of hours in the interval.
>
> **Billing**: The demand upon which billing to a customer is based, as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.
>
> **Coincident**: Two or more demands which occur during the same time interval. Typically used to express customer demand which occurs at the time of utility system peak demand.
>
> **Instantaneous Peak**: The demand at the instant of greatest load, usually determined from the readings of indicating meters or graphic meters.
>
> **Integrated**: The demand usually determined by an integrating demand meter or by the integration of a load curve. It is the summation of the continuously varying instantaneous demands during a specified demand interval.
>
> **Maximum**: The greatest demand which occurred during a specified period of time.
>
> **Non-Coincident**: Two or more demands which do not occur during the same time interval. Typically used in the context of “non-coincident peak demand” to express the customer’s peak demand which does not necessarily occur at the time of utility system peak demand.

Demand Charge. That portion of the charge for electric service based upon the electric capacity (kW or kVa) consumed and billed on the basis of billing demand under an applicable rate schedule.

Demand-Side Management (DSM). The planning implementation, and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of DSM include: load management, new uses of electricity, energy conservation, electrification, customer generation adjustments in market share and innovative rates. DSM includes only those activities that involve a deliberate intervention by the utility to alter the load shape. These changes must produce benefits to both the utility and its customers.

> **DSM Objectives**: Defining broad utility DSM mission and objectives, operational objectives, and load shape objectives.
>
> **DSM Alternatives**: Identifying the range of available end uses, technologies, and market implementation techniques.
>
> **DSM Evaluation and Selection**: Identifying and evaluating key customer or market considerations and utility considerations and completing a cost/benefit analysis of these.
>
> **DSM Program Implementation**: Consisting of pilot and full-scale implementation or execution of the marketing plan.
>
> **DSM Program Monitoring**: Measuring the outcomes of program implementation and providing feedback on results.

Department of Energy (DOE). In the USA, established in 1977 by the Department of Energy Organization Act to consolidate the major federal energy function into one cabinet-level department that would formulate a comprehensive, balanced national energy policy.

Desiccant. Any absorbent or absorber, liquid or solid, that will remove water or water vapor from a material. In a refrigeration circuit the desiccant should be insoluble in the refrigerant.

Desiccation. Any process for evaporating water or removing water vapor from a material.

Design Temperature. Outdoor temperature representing extreme weather conditions; used in sizing heating and cooling equipment.

Direct Installation Program. Utility installation of DSM measures within customer's home or business; such programs generally cover low-cost measures, such as water-heater wraps and compact fluorescent lamps.

Dispatch Order. The order of priority in which each unit of generation capacity is selected for operation during a given time interval.

Dispatchability. The ability of the utility to schedule and control, directly or indirectly, manually or automatically, the generating plants and DSM measures.

Dispatching. The operating control of an integrated electric system to:

1. Assign load to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises of falls.
2. Control operations and maintenance of high-voltage lines, substations, and equipment, including the administration of safety procedures.
3. Operate the interconnection.
4. Schedule energy transactions with other interconnected electric utilities.

Diversified Demand. The average load (kW) across a group of customers or end uses.

Diversity. Individual maximum demands in a collection of demands (e.g., electric loads), usually occurring at different intervals. The diversity among customers' demands creates variations among the loads in distribution transformers, feeders, and substations at a given time. A load diversity is the difference between the sum of the maximum of two or more individual loads and the coincident or combined maximum load. It is usually measured in kilowatts.

Diversity Factor. The ratio of the sum of the non-coincident maximum demands of a utility's customers or customer classes to the system peak, or maximum coincident demand, of the utility. If all customers have their demands at the same time, the diversity factor would equal one. If customers maximized their demand at different times, the diversity factor would be greater than one. Generally, a high diversity factor (i.e., much greater than one) indicates that a utility's load curve is relatively flat. Diversity factor is the reciprocal of coincidence factor.

DOE-2.1. A computer program that simulates the energy consumption of commercial buildings.

Domestic Hot Water. Hot water for domestic or commercial purposes other than comfort heating and industrial processes (i.e., hot tap water, showers, etc.).

Double-Bundle Condenser. Condenser (usually in a refrigeration machine) that contains two separate tube bundles allowing rejection of heat either to the cooling tower or to another building system requiring heat input.

Double Glazing. Two panes of glass, usually parallel, with an air space in-between; used to provide increased thermal and/or sound insulation.

Dropouts. Customers who do not continue to participate in a program, typically applicable to direct load control programs.

Dry Bulb Temperature. Temperature of air as indicated by a standard thermometer, as contrasted with wet-bulb temperature dependent upon atmospheric humidity.

Dual Duct System. An air conditioning system in which there are two air ducts (called decks), one of which is heated and the other cooled. Air of the correct temperature for a particular zone is obtained by mixing varying amounts of each stream.

Duct. A passageway made of sheet metal or other suitable material, not necessarily leak-tight, used for conveying air or other gas at low pressures.

Duty Cycling. Periodic cycling off of electrical loads to reduce overall kW demand level and kWh consumption.

Early Replacement. Replacement of equipment before it reaches retirement age (sometimes called retrofit).

Early Retirement. Equipment that is removed before it reaches normal retirement age but is not replaced.

Economic Dispatch. The start-up, shutdown, and allocation of load to individual generating units to effect the most economical production of electricity for customers.

Economic Potential. An estimate of energy savings based on the assumption that all energy efficient options will be adopted and all existing equipment will be replaced with the most efficient whenever it is cost-effective to do so, without regard to market acceptance.

Economizer Cycle. An automatic control strategy which readjusts outside air to take advantage of cooling effect which may be available there. Can be controlled either by temperature alone (temperature control) or by temperature and humidity (enthalpy control).

Edison Electric Institute (EEI). The U.S. association of electric companies. Organized in 1933 and incorporated in 1970, EEI provides a principal forum where electric utility staff exchange information on developments in their business, and maintain liaison between the industry and the federal government. Its officers act as spokesmen for investor-owned electric utility companies on subjects of national interest.

EER - Energy Efficiency Ratio. The ratio of net cooling capacity in Btu/hour to total electric input in watts under a designated operating condition. The EER is typically used to measure the efficiency of room air conditioners. The EER is equal to the COP times 3.413 (the number of Btus in a watt).

EF - Energy Factor. A measure of the efficiency of water heaters, it expresses the ratio of daily heat delivered to daily heat input during a year under specified conditions.

Effect, Chimney. Tendency of air or gas in a duct or other vertical passage to rise when heated due to its lower density compared to that of the surrounding air or gas; in buildings, tendency toward displacement (caused by the difference in temperature) of internal heated air by unheated outside air due to the difference in density of outside and inside air.

Effect, Dehumidifying. Heat removed in reducing the moisture content of air, passing through a dehumidifier, from its entering to its leaving condition.

Effect, Heating, Compressor (heat pump). Rate of heat delivery by the refrigerant assigned to the compressor in a heat pump system. This equals the product of the mass rate of refrigerant flow produced by the compressor and the difference in specific enthalpies of the refrigerant vapor at thermodynamic state leaving the compressor and saturated liquid refrigerant at the pressure of vapor leaving the compressor.

Effect, Humidifying. Latent heat of water vaporization at the average evaporating temperature times the number of pounds of water evaporated per hour in Btuh.

Effect, Refrigerating. Rate of heat removal by a refrigerant in a refrigerating system. This equals the product of the mass rate of refrigerant flow in the system and the difference in specific enthalpies of the refrigerant at two designated points in the system or two designated thermodynamic states of the refrigerant. The term refrigerating effect is used to denote heat transfer to or from the refrigerant itself in a refrigeration system, whereas refrigerating capacity denotes the rate of heat removal from a medium or space to be cooled.

Effect, Refrigerating, Compressor. Rate of heat removal by the refrigerant assigned to the compressor in a refrigerating system. This equals the product of the mass rate of refrigerant flow produced by the compressor and the difference in specific enthalpies of the refrigerant vapor at its thermodynamic state entering the compressor and refrigerant liquid at saturation temperature corresponding to the pressure of the vapor leaving the compressor.

Effect, Refrigerating, Condensing Unit. Rate of heat removal by the refrigerant assigned to the condensing unit in a refrigerating system. This equals the product of the mass rate of refrigerant flow produced by the condensing unit and the difference in the specific enthalpies of the refrigerant vapor entering the unit and the refrigerant liquid leaving the unit.

Effect, Total Cooling. Difference between the total enthalpy of the dry air and water vapor mixture entering a unit per hour and the total enthalpy of the dry air and water vapor (and water) mixture leaving the unit per hour, in watt (Btuh).

Efficacy. The ratio of light from a lamp to the electrical power used, expressed in lumens per watt (LW).

Efficiency, First Law. The amount of energy service delivered by a machine per unit of energy input. For example, if a 400-watt electric motor delivers only 280 watts of mechanical drive power, it has an efficiency of 280/400 = 70%. Under the first law of thermodynamics, this efficiency cannot exceed 100%.

Efficiency, Second Law. An alternative concept of energy efficiency, based on the second law of thermodynamics. The second-law efficiency is defined as the ratio of the theoretical minimum energy that is required to accomplish a given task to the energy actually consumed. In using the second-law efficiency concept, energy consumption must be measured in units that reflect the quality of the energy involved. For example, a water heater with a first-law efficiency of 75% would be compared to an ideal heat pump, operating between the same temperatures as the water heater with a coefficient of performance of 7.5 (750% efficiency). This comparison would give a second-law efficiency of 0.75/7.5 = 10%. While the first-law efficiency gives the impression that only modest improvement is possible, the second-law efficiency indicates a ten-fold potential gain.

Efficient Technologies. State-of-the-art commercially available appliances, equipment, building-shell measures, or industrial processes that improve the end-use efficiency of electricity relative to the existing stock of appliances, equipment, measures, and processes.

Electric Central Furnace. A furnace designed to supply heat through a system of ducts with air as the heating medium, in which heat is generated by one or more electric resistance heating elements and the heated air is circulated by means of a fan or blower.

Electric Clothes Dryer. A cabinet-like appliance designed to dry fabrics in a tumble-type drum with forced air circulation. The heat source is electricity and the drum and blower(s) are driven by an electric motor(s).

Electric Heater. An electric appliance in which heat is generated from electrical energy and dissipated through convection and radiation and includes baseboard electric heaters, ceiling electric heaters, floor electric heaters, portable electric heaters, and wall electric heaters.

Electric Power Research Institute (EPRI). Founded in 1972 in the USA by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution and utilization.

Electric Refrigerator. A cabinet designed for the refrigerated storage of food at temperatures above 32^0F and having a source of refrigeration requiring single phase, alternating current electric energy input only. An electric refrigerator may include a compartment for the freezing and storage of food at temperatures below 32^0F, but does not provide a separate low temperature compartment designed for the storage of food at temperatures below 8^0F.

Electric Refrigerator-Freezer. A cabinet which consists of two or more compartments with at least one of the compartments designed for the refrigerated storage of food at temperatures above 32^0F and with at least one of the compartments designed for the freezing and storage of food at temperatures below 8^0F, which may be adjusted by the user to a temperature of 0^0F or below. The source of refrigeration requires single phase, alternating current electric energy input only.

Electric Space Heating. Space heating of a dwelling or business establishment or other structure using permanently installed electric heating as the principal source of space heating throughout the entire premises.

Electrification. The term describing emerging electric technologies such as electric vehicles, industrial process heating, and automation. These technologies have the potential for increasing productivity, contributing to strategic load growth, or facilitating strategic conservation, peak clipping or load shifting. Examples include robotics and industry automation, microwave heating and drain, and freeze concentration of solutions.

Eligibility Criteria. Standards that describe the customers who can participate in a utility's DSM program.

Eligible Market. The subset of the total market that is allowed to participate in a program based on eligibility criteria.

Emission Factor. The ratio of emissions to energy produced or fuel consumed, denominated in units of tons of emissions per unit of energy.

End-Use Metering. End-use loads are directly measured before and after installation of efficiency measures to identify associated charges.

Energy. The ability or capacity to do work. Energy can be categorized in either stored or transient forms. Stored forms of energy include thermal energy, potential energy, kinetic energy, chemical energy, and nuclear energy. Transient forms include heat and work, mechanical or flow.

> Electric energy, measured in kilowatt hours (kWh) is the time-integral of power. In the English (FPS) system, energy is measured in British thermal units (Btu) or foot-pounds.

Energy Audit. A review of the customer's electricity and/or gas usage often including recommendations to alter the customer's electric demand or reduce energy usage. An audit usually includes a visit to the customer's facility.

Energy Conservation. Refers to the steps that can be taken to reduce energy consumption. It includes encouraging customers to invest in capital improvements (as with improved home insulation or more energy-efficient appliances) and changing energy consumption behavior (e.g., thermostat setback). It is measured by kilowatt-hours or BTUs of energy savings in the past or energy savings potential expected in the future.

Energy Costs. Costs, such as fuel, that are related to and vary with energy production or consumption.

Energy Efficiency Ratio (EER). A figure of merit of air conditioning or refrigeration performance. The relative efficiency of an appliance in converting primary energy (e.g., electricity) to useful work (such as for cooling in the case of air conditioners) at the rated condition. EER (Btu/kWh) is the Btu per hour output provided by the unit, divided by the watts of electrical power input. The larger the EER, the more efficient the unit.

Energy Effects. The changes in aggregate electricity use (kWh/year) for customers that participate in a utility DSM program.

Energy Efficiency Program. DSM program aimed at reducing overall electricity consumption (kWh), often without regard for the daily timing of the program induced savings. Such savings are generally achieved by substituting technically more efficient equipment to produce the same level of end-use services with less electricity.

Energy, Electric. As commonly used in the electric utility industry, electric energy means kilowatt-hours.

> **Off-Peak Energy** is supplied during periods of relatively low system demands as specified by the supplier.
>
> **On-Peak Energy** is supplied during periods of relatively low system demands as specified by the supplier.
>
> **Surplus Energy** is generated power that is beyond the immediate needs of the producing system. This energy is frequently obtained from spinning reserve and sold on an interruptible basis.

Energy-Limited Resource. A supply resource (e.g., hydro) of which the total annual energy output is limited, regardless of how much rated capacity is available.

Energy Productivity. Refers to the productivity of energy as a factor of production and includes the level of economic value produced per unit of energy input. Energy productivity improvements occur when existing energy services (e.g., lighting, heating, cooling, motor drive) are made more efficient and when new energy-using technologies boost economic efficiency (e.g., telecommunications, automation/robotics, information processing).

Energy Services. The physical amenity provided by energy-using equipment, for example cooking, illumination, thermal comfort, food refrigeration, transportation or product manufacturing.

Engine. A device that transforms energy, especially heat energy, into mechanical work. Among the prime movers, those in which the power originates in a piston and cylinder are classified as engines, while those with purely rotative motion are known as turbines.

Engineering Calculations. Calculations of expected changes in energy and loads based on specification of technical performance or efficiency measures and assumptions about operating patterns and conditions. Methods range from simple formulas to complex thermal load simulations.

Enthalpy. A thermodynamic property of a substance defined as the sum of its internal energy plus the quantity Pv/j, where P = pressure of the substance, v = its volume, and j = the mechanical equivalent heat. Formerly called by the obsolescent names total heat and heat content.

Entropy. A measure of the capacity of a system to undergo spontaneous change, thermodynamically specified by the relationship $dS = dQ/T$, where dS is an infinitesimal change in the measure for a system absorbing an infinitesimal quantity of heat (dQ) at absolute temperature (T).

Environmental Dispatch. The selection of generating sources for operation according to a combination of lowest emission rates and fuel and operating costs.

Environmental Protection Agency (EPA). In the USA, a federal agency created in 1970 to permit coordinated and effective governmental action for protection of the environment by the systematic abatement and control of pollution through integration of research, monitoring, standard setting, and enforcement activities.

Erg. A very small unit of energy in the metric system. One erg equals approximately 9.5×10^{-11} Btu.

Evaluation. Systematic measurement of the performance of DSM programs.

Evaporator. A heat exchanger which adds heat to a liquid, changing it to a gaseous state (in a refrigeration system it is the component that absorbs heat).

Exhaust. The air deliberately removed from a room, by a fan or otherwise, usually used to eject air contaminants near the source.

Existing Buildings. All buildings that are in operation as of the beginning of an analysis period or program year.

Expansion Plan. The schedule of planned power-supply investments to produce sufficient electricity (including reserve margins) to meet forecasted future demand.

Expensed Costs. Costs that are treated as current expenses rather than as capital costs; the utility cannot earn a return on expensed costs.

Experiments. Small scale efforts intended to test various concepts and collect information associated with a future DSM program.

Exterior Zones. The portions of a building with significant amounts of exterior wall, windows, roofs or exposed floors. Such zones have heating or cooling needs largely dependent upon weather conditions.

Externality. A social cost that is not captured in conventional market transactions.

Fan Inlet (Vortex) Damper. An air valve placed on the inlet to a fan used to modulate the amount of air, expressed in cubic feet per minute (CFM), delivered by the fan.

Fixed Costs. Costs that do not vary with the number of DSM program participants.

Fixture. A complete lighting unit, including one or more lamps and a means for connection to a power source. Many fixtures also include one or more ballasts, and elements to position and protect lamps and distribute their light.

Flexible Load Shape. Designed to achieve a load shape composed of various components with varying degrees of reliability. In exchange for accepting a lower level of reliability, a customer is typically offered some incentive. A flexible load shape may be achieved through such measures as interruptible loads, pooled or integrated energy management systems, or individual customer load control devices imposing service constraints.

Flue. A passage or channel through which the products of combustion of a domestic fire, boiler, or other furnace are taken to the chimney.

Fluorescent Lamp (tube). A low-pressure mercury electric-discharge lamp in which a fluorescing coating of phosphor transforms ultraviolet energy into visible light.

Foot-Candle. A unit of luminance. One foot-candle equals 1 lumen per square foot.

Forced-Air Furnace. A warm-air furnace equipped with a blower to circulate the air through the furnace and ductwork.

FPS. The British system of units and measurements based on the foot-pound-second system.

Free Driver. A customer who takes the same conservation actions as those customers who participated in a utility program, without participating in the program.

Free Rider. A customer who receives the benefits of participating in a utility program who would have taken the same conservation actions even if there were no program.

Free Service. An incentive in the form of assistance offered by utilities, such as energy audits and maintenance of equipment such as refrigerator or air conditioner tune-up programs.

Freezer. A cabinet designed as a unit for the freezing and storage of food at temperatures of 0^0F or below, and having a source of refrigeration requiring single phase, alternating current electric energy input only.

Fuel Substitution. The conversion of an end-use from one fuel source to another. For example, replacing an electric hot water heater with a gas fired unit.

Full Scale Program. Programs that are available to all eligible customers within the utility's service area.

Furnace. A device utilizing only single-phase electric current or millivoltage DC current in conjunction with either natural gas, propane, or home heating oil, which is designed to be the principal heating source for the living space of a residence and which is not contained within the same cabinet as a central air conditioner whose rates of cooling capacity are above 65,000 BTUs per hour. Every furnace is either an electric central furnace, electric boiler, forced-air central furnace, gravity central furnace, or low pressure steam or hot water boiler. The heat input rate of a furnace is less than 300,000 BTUs per hour for electric boilers and low pressure steam or hot water boilers, and is less than 225,000 BTUs per hour for forced-air central furnaces, gravity central furnaces, and electric central furnaces.

Gas Clothes Dryer. A cabinet-like appliance designed to dry fabrics in a tumble-type drum with forced air circulation. The heat source is gas and the drum and blower(s) are driven by an electric motor(s).

General Information Programs. A utility's efforts to inform customers about DSM options through such mechanisms as brochures, bill inserts, TV and radio ads, and workshops.

Gigawatt (GW). One gigawatt equals 1 billion watts, 1 million kilowatts or 1 thousand megawatts.

Gigawatt hour (GWh). One gigawatt hour equals one billion watt hours.

Gross Participation. The total number of customers who participated in the program and the measures that they adopted under it. For purposes of comparison, it is often useful to state this in terms of a percentage rate of participation.

Gross Program Savings. The difference between customers' energy consumption before and after participating in a utility program.

Gross Square Feet of Conditioned Floor Area. The sum of the enclosed areas of conditioned space on all floors of the building, including basements, mezzanines, and intermediate floor tiers and penthouses, measured from the exterior faces of exterior walls and the centerline of walls separating conditioned and unconditioned spaces of the building.

Heat. The form of energy that is transferred by virtue of a temperature difference.

Heat Engine. A mechanism for converting heat energy into mechanical energy, for example, an internal-combustion engine.

Heat Exchanger. A device specifically designed to transfer heat between two physically separated fluids.

Heat Gain. As applied to HVAC calculations, it is that amount of heat gained by a space from all sources, including people, lights, machines, sunshine, etc. The total heat gain represents the amount of heat that must be removed from a space by an air conditioner to maintain indoor comfort conditions.

Heat, Latent. Change of enthalpy during a change of state, usually expressed in j/kg (Btu per lb.). With pure substances, latent heat is absorbed or rejected at constant temperature at any pressure.

Heat Loss. The sum cooling effect of the building structure when the outdoor temperature is lower than the desired indoor temperature. It represents the amount of heat that must be provided to a space to maintain indoor comfort conditions.

Heat Pipe. A heat pipe is a sealed, static tube in which a refrigerant transfers heat from one end of the device to the opposite end. The device is installed through adjacent walls of inlet and exhaust ducts, with their opposite ends projecting into each air stream. A temperature difference between the ends of the pipe causes the refrigerant to migrate by capillary action to the warmer end where it evaporates and absorbs heat. It then returns to the cooler end, condenses, and gives up the heat.

Heat Pump. An air conditioning unit that reverses itself and can thus be used as a heater. By means of a compressor and reversing valve system, a heat-transfer liquid is pumped between the indoor and outdoor units, moving heat into a building during cold weather and out of it during warm weather. In other words a heat pump is a refrigeration machine which is arranged to either heat or cool a building by using heat from the condenser section or by using cooling from the evaporator section.

Heat Pump, Cooling and Heating. A refrigeration system designed to utilize alternately or simultaneously the heat extracted at a low temperature and the heat rejected at a higher temperature for cooling and heating functions respectively.

Heat, Sensible. Heat which is associated with a change in temperature; specific heat exchange of temperature; in contrast to a heat interchange in which a change of state (latent heat) occurs.

Heat Transfer. Heat can be transferred by three different methods: conduction, convection, and radiation.

> In conduction, the heat must diffuse through solid materials or through stagnant fluids. According to Fourier's law, the amount of heat transferred through conduction is determined by the area perpendicular to the heat flow, the thickness of the material through which the heat flow is occurring, the conductivity of the material, and the temperature differential between the two materials.
>
> In convection, heat transfer occurs through a carrying medium that travels from the hot to cold regions. Usually, this carrying medium is a fluid in steady motion.
>
> In radiation, heat is transferred by means of radiant wave energy.

Heating-Degree Day. An indicator of heating needs in a given geographical area. The difference between the mean temperature of any day and a base temperature when the median temperature is less than the base temperature, with each degree below that temperature equaling one heating-degree day. For example, if the median temperature for a specific day is 35^{o}F and the base is 50^{o}F, 15 heating-degree days to base 50^{o}F would be accrued.

Heating System, High-Pressure Steam. A steam heating system employing steam at pressures above 15 psig.

Heating System, High-Temperature Water. A heating system in which water having supply temperatures above 350ºF is used as a medium to convey heat from a central boiler, through a piping system, to suitable heat-distributing means.

Heating System, Hot Water. A heating system in which water having supply temperatures less than 250ºF is used as a medium to convey heat form a central boiler, through a piping system, to suitable heat-distributing means.

Heating System, Low-Pressure Steam. A steam heating system employing steam at pressures between 0 and 15 psig.

Heating System, Medium-Temperature Water. A heating system in which water having supply temperatures between 250°F and 350°F is used as a medium to convey heat from a central boiler, through a piping system, to suitable heat-distributing means.

Heating System, Steam. A heating system in which heat is transferred from the boiler or other source of heat to the heating units by means of steam at, above, or below atmospheric pressure.

Hertz. The number of cycles of alternating current per second, such as 60 Hz.

HID - High Intensity Discharge. High intensity discharge lighting, including mercury vapor, metal halide, and high-pressure sodium light sources.

Horsepower. A unit of power equaling 746 watts, 42.44 Btu/minute, or 550 foot-pounds of work per second.

Hot Air Furnace. A heating unit enclosed in a casing from which warm air is circulated through the building in ducts by gravity convection or by fans.

Household. A person or group of people sharing a dwelling unit.

HP. Horsepower.

HPS - High-Pressure Sodium Lamp. A high-intensity discharge lamp in which light is produced from sodium gas operating at a partial pressure of about 133 x 10^4 Pa. Clear and diffuse-coated lamps are included.

HSPF - Heating Seasonal Performance Factor. Combines the effects of heat pump heating - under a range of weather conditions assumed to be typical of the location or region - with performance losses due to coil frost, defrost, cycling under part-load conditions, and use of supplemental resistance heat during defrost. As such, it is a measure of "dynamic" rather than steady-state performance.
The HSPF is defined as:

$$HSPF = \frac{\textit{Total heating. provided during season, in Btu}}{\textit{Total}\ \text{energy}\ \textit{consumed by the system, in watt-hours}}$$

Computation of the HSPF requires specification of the building heating load as well as the outdoor temperature distribution for the location. These specifications vary from building to building and location to location.

Humidifier. A consumer product designed to add moisture into the conditioned air, and which falls into one of the following classes: a central system humidifier or room humidifier.

Humidistat. An instrument which measures humidity and controls a device(s) for maintaining a desired humidity.

Humidity. The water vapor content of the air; may be expressed as specific humidity, relative humidity, absolute humidity, saturation coefficient, or mixing ratio.

Humidity, Relative. The ratio of the mole fraction of water vapor present in the air to the mole fraction of water vapor present in saturated air at the same temperature and barometric pressure. Approximately, it equals the ratio of the partial pressure or density of the water vapor in the air to the saturation pressure or density, respectively, of water vapor a the temperature.

HVAC. Heating, Ventilation, and Air Conditioning.

HVAC System. A system that provides either collectively or individually the processes of comfort heating, ventilation and/or cooling within or associated with a building.

Illuminance. Lighting level, measure in footcandles or lux.

Impact Evaluation. Examines the effects of a DSM program, including quantitative documentation of a program's costs and benefits, program participation and measure adoption, performance of DSM technologies, and energy and load impacts.

Incandescence. The self-emission of light energy in the visible spectrum due to the thermal excitation of atoms or molecules.

Incandescent Filament (bulb). A lamp in which light is produced by a filament heated to incandescence by an electric current.

Incentive. An award offered to encourage participation in a DSM program and adoption of recommended measures.

Incentive Program. Awards (either cash or non-cash) to customers, trade allies, or employees to encourage participation in a DSM program and adoption of recommended measures.

Incentive Rate. Some form of reduced commercial or industrial rate generally designed to provide an incentive for targeted businesses to remain in the utility's service territory or to promote business expansion in an economically depressed area of the utility's service territory. Some rates are also targeted at businesses experiencing severe financial difficulties. The rates are usually offered to customers for a fixed period of time.

Incremental Cost. The difference in costs, particularly between that of an efficient technology or measure and the alternative standard technology. In some early retirements and retrofits, the full cost of the efficient technology is considered to be the incremental cost.

Incremental Participation. The number of annual participants in the current year minus the annual participants in the previous year.

Induction. The entrainment of room air by the jet action of a primary air stream discharging from an air outlet.

Induction Unit, Room Air. A factory-made assembly consisting of a cooling coil, or cooling and heating coil, and means for delivering preconditioned air (received under pressure from an external source), mixed with recirculated air by the air-induction process, to the space being conditioned. This device is normally designed for free delivery of air into the space.

Industrial Sector. The group of nonresidential customers that provide products, including construction, mining and manufacturing.

Infiltration. The uncontrolled inward air leakage through cracks and joints in any building element and around windows and doors of a building, caused by the pressure effects of wind and/or the effect of differences in the indoor and outdoor air density.

Innovative Rate. A rate schedule with rate above or below the associated costs of providing service to the customer. A promotional rate establishes a pricing level which permits sales to be made which otherwise would not occur.

Insolation. Solar radiation which is delivered to any place on the surface of the earth directly from the sun; the rate of such radiation per unit of surface.

Instantaneous Technical Potential. An estimate of potential energy savings based on the assumption that all existing appliances, equipment, building-shell measures, and industrial processes are instantly replaced with the most efficient commercially available units.

Insulation. Any material that provides a high resistance to the flow of heat from one surface to another. The different types include blanket or batt, foam, loose fill, or reflective insulation.

Integrated Engineering Statistical Analysis. Engineering-based estimates are used as explanatory variables in regression analysis of whole customer loads. Parameters verify reasonableness of engineering estimates or identify systematic biases.

Integrated Resource Planning. The combined development of electricity supplies and demand-side management (DSM) options to provide energy services at minimum cost, including environmental and social costs.

Intelligent Duty Cyclers. Devices containing both microcomputer-based and radio receiver controlled subcomponents for inhibiting the operation of air conditioning equipment based on site-specific conditions. The intelligent cycler monitors the on- and off-cycle time intervals of a specific air conditioner under normal, pre-control operation and stores these times in memory. When the device receives a signal to exercise control, it does not allow the on-time to exceed or the off-time to drop below those times stored in memory. The utility may also opt to further reduce load by ordering the device to reduce the on-time by some percentage of the stored on-time.

Interactions of Measure Adoption. Propensity of customers to purchase certain combinations of measures. For example, customers buy electronic ballasts and efficient lamps. This affects the savings from each measure.

Interactive Effects. The effect that a change in one end-use's energy consumption has on another end-use's energy consumption. For example, replacing incandescent lamps with compact fluorescents causes a reduction in cooling load.

Interior Zones. The portions of a building which do not have significant amounts of exterior surfaces. Such zones have heating or cooling needs (usually cooling only) largely dependent upon internal loads such as lights.

Interruptible Electric Power. Power made available under agreements which permit curtailment or cessation of delivery by the supplier.

Isentropic. An adjective describing a reversible adiabatic process; a change taking place at constant entropy.

Isothermal. An adjective used to indicate a change taking place at constant temperature.

Joule. A unit of energy in the metric (MKS) system. One joule equals one watt-second or 9.48×10^{-4} Btu.

Lamp. A light source, commonly called a bulb or tube.

Latent Heat. The quantity of heat required to produce a change in state (e.g., from solid to liquid) at an unchanging temperature level.

LCP - Least-Cost Planning. A utility planning method whereby alternative resource mixes, including demand-side options such as conservation and load management, are evaluated along with traditional supply-side options to determine which of them minimizes the overall cost of service. Cost management is used as the criterion for selecting the resource plan for the utility company.

Lighting Area. A room defined by walls and partitions, or an area where a definite usage is planned and is different from the surrounding areas. Under US building standards, if more than 75% of a perimeter is enclosed (floor-to-ceiling), it must be treated as a separate lighting area.

Line Losses. Kilowatt-hours and kilowatts lost in the transmission and distribution lines under specified conditions.

Load Building Programs. A program with the objective of increasing electricity consumption, generally without regard to the timing of the increase.

Load Displacement. The increment of customer load measured in megawatts (MW) that is removed from the total customer load served by the utility and is alternatively served by some form of customer electric power generation.

Load-Duration Curve. A graph showing a utility's hourly demand, sorted by decreasing size, and the amount of time a given level of demand is exceeded during the year.

Load Factor. The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

$$\textit{Load Factor} = \frac{\textit{kWh Supplied in Period}}{\textit{Peak kW in Period x Hours in Period}}$$

Load-Following. The ability of a supply resource to respond to variations in demand.

Load Forecasts. Predicted demand for electric power. A load forecast may be short-term (e.g., 15 minutes) for system operation purposes, long-term (e.g., 5 to 20 years) for generation planning purposes, or for any range in between. Load forecasts may include peak demand (kW), energy (kWh), reactive power (kVAR), and/or load profile. Forecasts may be made of total system load, transmission load, substation/feeder load, individual customers' loads, and/or appliance loads.

Load Management. Economic reduction of electric energy demand during a utility's peak generating periods. Load management differs from conservation in that load management strategies are designed to either reduce or shift demand from on-peak to off-peak , while conservation strategies may primarily reduce usage over the entire 24-hour period. Motivations for initiating load management include the reduction of capital expenditure, circumvention of capacity limitations, provision for economic dispatch, cost of service reduction, system efficiency improvements, or system reliability improvements. Actions may take the form of normal or emergency procedures. Many utilities encourage load management by offering customers a choice of service options with various price incentives.

Load Research. The systematic gathering, recording, and analyzing of data describing utility customers' patterns of energy usage. Types of load research include aggregate load research whereby total electricity usage of a representative sample of customers is recorded and analyzed, end-use load research whereby the energy use of customers' specific end-use equipment is measured and analyzed, and rate load research whereby daily, monthly, and/ or seasonal energy use of a sample of customers is used to develop class load profiles.

Load Shape. The time-of-use pattern of customer electricity use, generally a 24-hour pattern or an annual (8760-hour) pattern.

Load Shape Effects. The estimated changes in energy use at specific times during the year. The time periods usually are the same as those of which avoided costs are calculated.

Load Shedding. The turning off of electrical loads to limit peak electrical demand.

Load Shifting. Involves shifting load from peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, cool storage, and customer load shifts to take advantage of time-of-use or other special rates.

Loss of Load Probability. A measure of the probability that system demand will exceed available capacity during a given period.

Lost Revenues. Utility income that is lost through reduced sales due to a DSM or energy-efficiency program.

Louver. A series of baffles arranged in a geometric pattern that shields a lamp from view at certain angles in order to avoid glare from the bare lamp.

Low-Pressure Sodium Lamp. A discharge lamp in which light is produced from sodium gas operating at a partial pressure of 0.13 to 1.3 Pa.

Lumen (1m). SI unit of luminous flux. Radiometrically, it is determined from the radiant power. Photometrically, it is the luminous flux emitted within a unit solid angle (one steradian) by a point source having a uniform luminous intensity of one candela.

Luminaire. A complete lighting unit consisting of a lamp, or lamps, together with parts designed to distribute the light, to position and protect the lamps, and to connect the lamps to the power supply.

Lux (lx). A quantitative unit for measuring illuminance; the illumination on a surface of one meter square, on which there is a uniformly distributed flux of one lumen.

Marginal Cost. The cost of providing an incremental unit of energy services.

Marginal Cost of Energy. The cost of providing an incremental unit of energy.

Marginal Cost of Capacity. The cost of meeting an incremental unit of peak-demand.

Marginal Resource. The most expensive resource, in terms of short-run marginal (fuel and operating) cost, needed at a given time.

Market Potential. An estimate of energy savings that adjusts the economic potential for the likely acceptance by customers of various energy-saving actions.

Market Research. The systematic gathering, recording, and analysis of data about problems relating to the marketing of goods and services. Also called marketing research, it refers to the process of developing information and analyses about customers. Market research includes various subsidiary types of research such as market analysis (a study of the size, location, nature, and characteristics of a specified market), consumer research (a study of consumer attitudes, behavior, reactions, and preferences for goods or services), sales analysis (a study of sales data), and advertising research (a study of the effectiveness of the advertising of goods and services).

Marketing Costs. All costs directly associated with the preparation and implementation of the strategies designed to encourage participation in a program.

Mass. The quantity of matter in a body as measured by the ratio of the force required to produce a unit of acceleration to the acceleration.

MCF. One thousand cubic feet (<u>NOT</u> 1 million!) of natural gas containing a heat content of 1,000,000 Btu or ten therms (called decatherm).

Measures. Actions taken by a customer to improve the efficiency or modify the timing of electricity use.

Medium, Heating. A solid or fluid, such as water, steam, air or flue gas, used to convey heat from a boiler, furnace, or other heat source, and to deliver it, directly or through a suitable heating device, to a substance or space being heated.

Medium, Refrigerating. A solid or fluid, such as a refrigerant, ice, dry ice, or brine, used to absorb heat, either directly or through a suitable refrigerating device, from a substance or space.

Mercury Lamp. A high-intensity discharge (HID) lamp in which the major portion of the light is produced by mercury operating at a partial pressure in excess of 1.013×10^5 Pa (1 atmosphere). Includes clear, phosphor coated, and self-ballasted lamps.

Metal Halide Lamp. A high-intensity discharge (HID) lamp in which the major portion of the light is produced from metal halides and their products of dissociation - possibly in combination with metallic gases such as mercury. Includes clear and phosphor coated lamps.

Mixing Box. A box containing dampers in the hot or cold air stream, mixing the two and delivering the air to a space at a specified temperature.

MKS - Meter-Kilogram-Second. The metric system of units and measurements using meters, kilogram, and seconds.

Monitoring and Evaluation Costs. The expenditures associated with the collection and analysis of data used to assess program operation and effects.

Multi-Zone System. An air conditioning system which functions like a dual duct system, but the mixing takes place at the air handler. A separate duct, carrying air at the correct temperature, goes to each zone.

Net Program Savings. The estimation of a program's energy and demand savings which are directly attributable to the program.

New Construction. New buildings and facilities that are constructed during the current year or since the inception of a DSM program.

New Construction Program. Programs that affect the design and construction of new residential and commercial buildings and manufacturing facilities; such programs may also include major renovations of existing facilities.

New Participants. Customers who participate in a program during the current year and did not participate in the program during the previous year.

Non-Cash Incentives. Incentives in a form other than rebate or cash payment, may include low-interest loans, reduced equipment costs, bill credits or discounts, merchandise, or free services.

Non-Coincident Demand. Maximum demand of a customer, or customer class, regardless of when it occurs. Generally the non-coincident demand is used as the basis for calculating the demand charge.

Non-Technical Losses. Commercial losses from theft of electricity through unauthorized connections, tampering with meter reading, metering errors, etc.

Non-Utility Costs. Expenses incurred by customers and trade allies associated with participation in a DSM program that are not reimbursed by the utility.

Normal Replacement. Replacement of worn-out (and perhaps obsolete) equipment.

Ohm's Law. In a given circuit, the amount of current in amperes is equal to the pressure in volts divided by the resistance in Ohms.

$$\textit{Current} = \frac{\textit{(Pressure) Volts}}{\textit{(Resistance) Ohms}}$$

Operations and Maintenance Costs. Non-capital, equipment-related costs that continue over the life of the equipment; include fuel costs as well as costs for maintaining and servicing equipment.

Partial Participants. Customers who have installed only some of the DSM program measures recommended for their facility.

Participant. The definition of units used by a utility to measure participation in its DSM programs. Such units include customers or households for residential programs; and customers, floor area, or kW-connected for commercial and industrial customers.

Participant Costs. Costs associated with participation in a DSM program paid by the customer and not reimbursed by the utility.

Payback Period. The time (usually expressed in years) required for the cumulative operational savings of an option (or equipment) to equal the investment cost of that option.

Peak Load. The maximum electrical or thermal load reached during a given period of time.

Perfluorocarbon Tracer Technology. The use of tracer elements to measure the air infiltration rates within residential and commercial buildings. A number of tracers and capillary absorption tubes are placed within the facility. Natural air infiltration forces the migration of tracers to the capillary absorption tubes. After a set period of time the capillary absorption tubes are analyzed using a gas chromatograph. The level of tracer found within the capillary absorption tube is indicative of the building's air infiltration rate.

Performance Factor. The ratio of the useful output capacity of a system to the input required to obtain it. Units of capacity and input need not be consistent.

Plenum. In suspended ceiling construction, the space between the suspended ceiling and the main structure above. Can serve as a distribution area for heating or cooling systems.

Power. The time-rate at which work is performed, measured in Watts or British thermal units per hour (Btu,/hr). Electric power is the product of electric current and electromotive force. In a DC circuit, the current measured in amperes is multiplied by the voltage between the wires to obtain watts. In an AC circuit, where the current and voltage may be out of phase power, this also enters the calculation.

Power Factor. The ratio of actual power being used in a circuit, expressed in watts or kilowatts (kW), to the power which is apparently being drawn from the line, expressed in volt-amperes or kilovolt-amperes.

Present Worth: the equivalent value today of discounted future cash flows.

Process Evaluation. An independent review of a program's design, delivery and implementation.

Production-Cost Model. An analytic tool that simulates utility loads and the operation and economic dispatch of generating sources to help determine system capacity requirements.

Properties, Thermodynamic. Basic qualities used in defining the condition of a substance, such as temperature, pressure, volume, enthalpy, entropy.

Psi. Pounds per square inch. A measure of pressure.

Psig. Pounds per square inch gauge. Measurement of pressure relative to pressure of the surroundings.

Psychrometer. Instrument for measuring relative humidities by means of wet- and dry-bulb temperatures.

Psychrometry. The branch of physics relating to the measurement or determination of atmospheric conditions, particularly regarding the moisture mixed with the air.

R-Value. A measure of thermal resistance, equal to the reciprocal of the U-value (measure of thermal conductance). It has units of Fahrenheit degrees times hours times square feet per Btu.

Radiant Heating System. A system for heating a room or space by means of heated surfaces (such as coils of electricity, hot water, or steam pipes embedded in floors, ceiling, or walls) that provide heat primarily by radiation.

Radiation, Thermal (heat). The transmission of energy by means of electromagnetic waves of very long wavelength. Radiant energy of any wavelength may, when absorbed, become thermal energy and result in an increase in the temperature of the absorbing body.

Radiator. A heating unit exposed to view within the room or space to be heated. A radiator transfers heat by radiation to objects within visible range and, by conduction, to the surrounding air which in turn is circulated by natural convection. The so-called radiator is also a convector, but the term “radiator” has been established by long usage.

Rate Impact Measure (RIM). The cost of a DSM program to a utility, including lost revenues.

Rebate Program. A conservation or load management program where the utility offers a financial incentive for the installation of energy efficient equipment. Rebates can be offered to customers, installers, or dealers. Rebates are typically either per equipment ($/lamp) or energy- or demand-based ($/kWh or $/kW).

Recovery Capacity. The quantity of water that a water heating system can heat from supply temperature to required temperature in one hour. Expressed in gallons per hour.

Reference Scenario. A future scenario based on present trends without any projected policy changes or new utility programs.

Reflectance. The ratio of the light reflected by a surface or medium to the light incident upon it.

Reflector. A device used to direct the light from a source by the process of reflection.

Refrigerant. The fluid used for heat transfer in a refrigerating system, which absorbs heat at a low temperature and a low pressure of the fluid and rejects heat at a higher temperature and a higher pressure of the fluid, usually involving changes of state of the fluid.

Refrigerating System, Absorption-Type. A refrigerating system in which refrigeration is effected by evaporating a refrigerant in a heat exchanger (evaporator), resulting vapor then being absorbed by an absorbent medium from which it is subsequently expelled by heating at a higher partial vapor pressure and condensed by cooling in another heat exchanger (condenser).

Refrigerating System, Compression-Type. A refrigerating system in which the temperature and pressure of gaseous refrigerant are increased by a mechanically operated component. In most cases, the refrigerant undergoes changes of state in the system

Refrigerating System, Direct-Expansion. A refrigerating system in which the evaporator is in direct contact with the refrigerated material or space or is located in air-circulating passages communicating with such spaces.

Refrigerating System, Mechanical. A refrigerating system employing a mechanical compression device to remove the low pressure refrigerant enclosed in the low pressure side and deliver it to the high pressure side of the system.

Refrigerating System, Single-Package. A complete factory-made and factory-tested refrigerating system in a suitable frame or enclosure which is fabricated and shipped in one or more sections and in which no refrigerant-containing parts are connected in the field.

Refrigeration Cycle. A repetitive thermodynamic process in which a refrigerant absorbs heat from a controlled space at a lower temperature and rejects it elsewhere at a higher temperature. The cycle operates by using power input from an external source. The amount of heat rejected is greater than that taken in by the amount of work required to effect the cycle.

Refrigerator, Commercial. A general category referring to any of the many types of refrigerators used commercially. Includes reach-ins, walk-ins, refrigerated display cases, both service and self-service, of all types which are used by business establishments.

Reheat. Adjustment of the set point of a control instrument to a higher or lower value automatically or manually to conserve energy.

Relative Humidity. The ratio of water vapor in the air, expressed as a percentage of the maximum amount that the air could hold at the given temperature.

Reserve Margin. The difference between an electric system's maximum capacity and the expected peak demand.

Retrofit. Modifications made to update existing equipment or structures.

Revenue Requirements. The total amount of money a utility must collect from customers to pay all capital and operating costs, including an acceptable return on investment.

Room Air Conditioner. A device that delivers conditioned air to an enclosed space without the use of ducts; usually mounted in a window or in an opening in a wall, or as a console. Includes a prime source of refrigeration and may include a means for ventilating and heating.

Secondary Measure Adoption. Any measures that customers adopt outside of the program as a direct result of the promotion and incentives. For example, a customer purchases lighting measures beyond the maximum number eligible for a rebate.

SEER - Seasonal Energy Efficiency Ratio. A measure of seasonal cooling efficiency under a range of weather conditions assumed to be typical of the location in question, as well as of performance losses due to cycling under part-load operation. The SEER is defined as:

$$SEER = \frac{\textit{Total cooling provided during cooling season, Btu}}{\textit{Total energy consumed by the system, watt-hours}}$$

As in the case of the HSPF, the SEER is dependent on the cooling load of the specific building and outdoor temperature distribution, and is a measure of "dynamic" rather than steady-state performance.

SEER contrasts with EER, which measures an instantaneous value at design conditions.

Self Selection. The difference between the control group and the participant group as revealed by the participants choosing to participate in a program and the control group choosing not to participate.

Sensible Cooling Load. The cooling load due to sensible heat gains.

Sensible Heat. The heat added to or taken from a body when its temperature is changed.

Setback. The intended depression of the control point by means other than adjustment of the scale setting. An example is thermostat setback.

SIC. Standard Industrial Classification. A system of classification for industry types, used in the USA.

Single-Package Air Conditioner. A combination of apparatus for room cooling complete in one package; usually consists of compressor, evaporator, condenser, fan motor, and air filter. Requires connection to electric line. Also known as self-contained unit.

Snapback Effect. The argument that by undertaking conservation actions, customers perceive a lower (relative) price for energy and, therefore, purchase more of the commodity in terms of comfort or appliance use.

Specular Angle. The angle between the perpendicular to the surface and the reflected ray that is numerically equal to the angle of incidence and that lies in the same plane as the incident ray and the perpendicular, but on the opposite side of the perpendicular to the surface.

SPF - Seasonal Performance Factor. Ratio of the useful energy output of a device to the energy input, averaged over the entire heating season.

Split System Air Conditioner. A system consisting of two or more separate units incorporating the different functions of air conditioning.

Standby Loss. The percentage of the total energy stored in the water which is lost each hour from a storage-type water heater.

Statistical Analysis. Statistical analysis of whole customers' energy or load data to infer changes in consumption associated with adoption of efficient technologies. Methods range from simple before/after comparisons between program and control groups, to applications of parametric statistical models (e.g., regression models).

Storm Window or Other Protective Window Covering. An extra window or sash, usually placed on the outside of an existing window as additional protection against severe weather or to serve as an insulating factor for conversation. Included in this category are protective window coverings such as double-glazed glass, closable shutters, or plastic.

Strategic Conservation. Achieved through utility-stimulated programs directed at reducing end-use consumption especially, but not only, during peak period. Not normally considered load management, the change reflects a modification of load shape involving a reduction in sales as well as a change in the pattern of use. In promoting energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost effectiveness of possible intended utility programs to accelerate or stimulate those actions.

Strategic Load Growth. The increase of end-use consumption during certain periods. The result is a general increase in energy sales beyond the valley filling (defined herein) strategy. Strategic load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development.

Summer Peak. The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30 in the northern hemisphere.

Supply Effects. The direct and indirect effects that the level of program funding has on participation patterns.

Synergism (or Synergistic Effect). A cooperative action of two substances that results in a greater effect than each of the substances could have had acting independently.

System Efficiency, Water Heater. Ratio of the energy (in the form of heated water) delivered at water fixtures, to the energy supplied to the water at the heater. Losses of energy are due to radiation, convection, and conduction from storage tank and piping.

System Lambda (λ). The short-run marginal (fuel and operating) cost of the most expensive resource needed at a given time.

System, One-Pipe. A piping system in which the fluid withdrawn from the supply main passes through a heating or cooling unit and returns to the same supply main.

System, Two-Pipe. A piping system in which the fluid withdrawn from the supply main passes through a heating or cooling unit to a separate return main.

Tankless Water Heater. Water heater which contains little or no storage and which heats water only as required.

Task Lighting. Lighting directed to a specific surface, or area, that provides illumination for visual tasks.

Technical Losses. Energy that is dissipated through the various elements of the transmission and distribution system (transformers, feeders, etc.).

Temperature, Dry-Bulb. The temperature of a gas or mixture of gases indicated by an accurate thermometer after correction for radiation.

Temperature, Wet-Bulb. Thermodynamic wet-bulb temperature is the temperature at which liquid or solid water, by evaporating into air, bring the air to saturation adiabatically at the same temperature. Wet-bulb temperature (without qualification) is the temperature indicated by a wet-bulb psychrometer constructed and used according to specifications.

Therm. A unit of heat, typically associated with natural gas. One therm contains 100,000 Btu and, as there are 1,000 Btu per cubic foot, there are 100 cubic feet of gas per therm.

Thermal Balance Point. A point of outdoor temperature (e.g., 25ºF) at which the heating capacity of a heat pump matches the heating requirements of the building which it heats.

Thermodynamics. The study of energy, its transformations, and its relation to states of matter.

Thermodynamics, Laws Of. Two laws form the basis of classical thermodynamic principles and underlie many of the efficiency concepts discussed elsewhere in this glossary. These laws have been muted in many different ways:

> *The first law:* (1) Energy is neither created nor destroyed. The sum of the energy entering a process (potential, kinetic, thermal, chemical, and electrical) must equal the sum or the energy leaving it, even though the proportions may change. This law implies that the efficiency of an energy conversion process can never exceed 100%. (2) When work is expended in generating heat, the quantity of heat produced is proportional to the work expended; and conversely, when heat is employed in the performance of work the quantity of heat which disappears is proportional to the work done (joule); (3) If a system is caused to change from an initial state to a final state by adiabatic means only, the work done is the same for all adiabatic paths connecting the two states; (4) In any power cycle or refrigeration cycle the net heat absorbed by the working substance is exactly equal to the net work done.
>
> *The second law:* (1) It is impossible for a self-acting machine, unaided by any external agent, to convey heat from a body of lower temperature to one of higher temperature; (2) It is impossible to derive mechanical work from heat taken from a body unless there is available a body of lower temperature into which the residue not so used my be discharged; (3) It is impossible to construct an engine that, operating in a cycle, will produce no effect other than the extraction of heat reservoir and the performance of an equivalent amount of work.

Thermograph. An infrared scan that can be used to detect heat loss due to poor insulation.

Thermostat. An instrument which measures temperature and controls device(s) for maintaining desired temperature.

Three Phase. Three separate sources of alternating current so arranged that the peaks of voltage follow each other in a regular, repeating pattern.

Time-Of-Day Pricing. A rate structure that prices electricity at different rates, reflecting the variations in the utility's costs of providing electricity at different times of the day. With time-of-day rates, higher prices are charged during the time when the electric system experiences its peak demand and marginal (incremental) costs are highest. Time-of-day rates price electricity closer to the cost of providing service, sending 'better' price signals to customers than non time-of-day rates. These price signals encourage efficient consumption, conservation and shifting of load to times of lower system demand.

Time-Of-Season Pricing. Pricing of service during seasons of the year based on the cost of supplying the service during those seasons.

Ton. A measure of useful space cooling and refrigeration capacity equaling 12,000 Btu per hour or 3516 watts. This denotes the heat absorbing capability of a ton of ice as it melts in one hour.

Total Resource Cost (TRC). The total economic cost of a DSM program to the utility and customers.

Tungsten-Halogen Lamp. A compact, incandescent filament lamp with its initial efficacy essentially maintained over the life of the lamp.

Turbine. A rotary engine actuated by the action or impulse or both of a current of fluid (e.g., water or steam) subject to pressure and usually made with a series of curved vanes on a central rotating spindle.

U-Value. The overall heat transmission coefficient, or quantity of heat in Btu conducted per hour through one square foot of a building section (wall, roof, window, floor, etc.) for each degree F of temperature difference between the air on the warm side and the air on the cold side of the building section. Expressed in Btu per hour/square feet/degrees F. It equals the reciprocal of R-value.

Unitary Air Conditioner. Equipment consisting of one or more factory-fabricated assemblies designed to perform the functions of air moving, air cleaning, cooling, and dehumidification; the assemblies usually include a fan, an evaporator, or a cooling coil, and a compressor and condenser in combination; a heating unit may also be included.

Used and Useful. A regulatory specification typically used to determine whether an item of "Plant" may be included in a utility's rate base, on the principle that the plant must be “used and useful” for providing energy to the customer.

Valley Filling. The building of off-peak loads. Valley filling may be partially desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is thermal storage (water heating and/or space heating or cooling) that increase night-time loads and reduce peak period loads.

Variable Air Volume. A method used to cool or heat a space or zone by varying the amount of air delivered to that space as conditions change (versus holding the amount of air constant and changing the air temperature).

Variations by Attributes, Time, and Program Features. Understanding energy and load impacts by these dimensions is critical for extrapolating effects into the future and applying the results for program and integrated resource planning.

VAV - Variable Air Volume. An air conditioning system of the reheat, recool, dual duct or multi-zone type in which the amount of heating or cooling is controlled by changing the air flow rate.

Ventilation. The process of supplying or removing air by natural or mechanical means to or from a space; such air may or may not have been conditioned.

Ventilation Air. That portion of supply air which comes from outside plus any recirculated air that has been treated to maintain the desired quality of air within a designated space.

Volt. The push that moves electric current through a conductor.

Water Heater. An automatically controlled, thermally insulated vessel designed for heating water and storing heated water, which utilizes either oil, gas, or electricity as the fuel or energy source for heating the water, which is designed to produce hot water at a temperature of less than 180^{o}F, and which includes the following products.

(a) "electric water heater" means a water heater which utilizes electricity as the energy source for heating the water, which has a manufacturer's specified energy input rating of 12 kilowatts or less at a voltage no greater than 250 volts, and which has a manufacturer's specified storage capacity of not less than 20 gallons nor more than 120 gallons.

(b) "gas water heater" means a water heater which utilizes gas as the energy source for heating the water, which has a manufacturer's specified energy input rating of 75,000 Btu per hour or less, and which has a manufacturer's specified storage capacity of not less than 20 gallons nor more than 100 gallons.

Watt. A unit of power, named after James Watt, a Scottish engineer. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower, or one joule per second.

Watthour. The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy is commonly sold by the kilowatt-hour (defined herein).

Weatherization. Caulking and weather-stripping to reduce air infiltration.

Wet Bulb Temperature. The temperature reading obtained from a standard thermometer with its bulb encased in a wick saturated with water at air temperature and exposed to air moving at sufficient velocity to bring fresh samples of air successively to the wick. The thermometer reading is dependent on the dry bulb temperature and moisture content of the air.

Winter Peak. The greatest load on an electric system during any prescribed demand interval in the winter (or heating) season, usually between December 1 and March 31 in the northern hemisphere.

Work. In the British foot-pound-second (FPS) system, this is measured in British thermal units. One Btu is equal to 778 foot-pounds, or joules.

Zone. A space or group of spaces within a building with heating and/or cooling requirements sufficiently similar so that comfort conditions can be maintained throughout by a single controlling device.

Appendix 3. Fundamentals of the Economics of Energy Conservation

The Discount Rate

The analysis of most energy conservation and end-use efficiency programs requires the comparison of present investment with future savings. The result of such comparisons depends on the discount rate, which measures the time value of money. The discount rate is essentially the interest rate or rate-of-return which one would demand in order to forego a unit of consumption today in return for a greater amount one year later.

For example, suppose that you possess $20 and that you have two options: a.) you can spend the $20 today, or b.) you can deposit the money in a bank for one year, at which point the bank will pay you back $22 instead of your original $20. If you find these two choices equally attractive, then this indicates that $20 today is worth the same amount to you as $22 ($20 x 1.1) one year later; your discount rate would be 0.1, or 10%. On the other hand, if you decided that you would rather spend the $20 today rather than wait one year to receive $22, then this would indicate that your discount rate is higher than 10%. In other words, the higher the discount rate, the greater the value placed on current consumption compared to future consumption.

The discount rate can be expressed in *nominal* terms that reflect the current value of the currency, including inflation, or it can be expressed in *real* terms that reflect a constant value of the currency, exclusive of inflation. It is usually simpler to use a real discount rate with constant dollars, as opposed to current nominal dollars. For example, to convert between nominal 1996 dollars and constant 1990 dollars:

$$\$\,(1990) = \frac{\$\,(1996)}{(1+f)^6} \qquad [A3\text{-}1]$$

where:
f = annual inflation rate, 1990-1996

The real inflation-corrected discount rate (r_r) can be derived from the nominal discount rate (r_n) as follows:

$$(1+r_r)\cdot(1+f) = 1+r_n$$

$$r_r + r_r f + f = r_n$$

$$r_r = \frac{r_n - f}{1+f} \qquad [A3\text{-}2]$$

where:
r_r = real discount rate,

r_n = nominal discount rate,
f = inflation rate.

For example, if the nominal discount rate is 12% and the inflation rate is 8%, then the real discount rate = (0.12 - 0.08)/(1 + 0.08) = 0.037 = 3.7%.[1]

While it is usually more convenient to use real discount rates, this is not always the case. For example, bank interest rates are always expressed in nominal terms. In fact, one can use either nominal or real values with equal accuracy; the important thing is simply to be consistent.

So what do discount rates really indicate? The time-value of money can depend on factors other than a strict time-preference. In finance theory, the time-value of money is thought to change (to increase) with greater risk and uncertainty. For two investments with the same average expected return, a higher present value is given to the one with less uncertainty (less risk of loss). In some cases, energy efficiency investments may appear risky to the consumer, due to lack of information and resulting uncertainty, and indeed consumers often appear to apply a high discount rate to such investments. For society, however, energy efficiency is a low-risk investment that would normally deserve a low discount rate.

Net Present Worth

Net present worth (NPW), also known as net present value (NPV), is the value today of future cash flows. This is the cash value today that is of equivalent value to a stream of cash flows which occurs in the future. As shown in Figure A3-1, future cash flows (dark bars in the figure) are discounted to determine their present worth (light bars in the figure). As the cash flow moves farther out into the future, its value (in terms of present worth) becomes more heavily discounted.

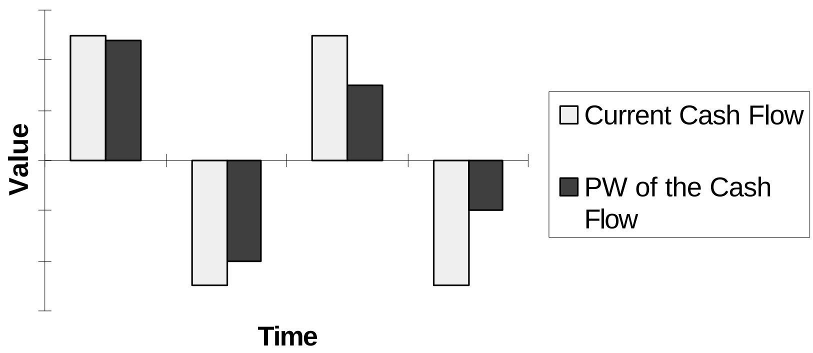


Figure A3-1. Relationship between current and discounted (present worth) cash flows over time.

[1] The value of r must be in terms of 1/year if time is expressed in years, but it is an arbitrary convention to use one-year time increments. r could also be expressed in terms of monthly increments, for example, in which case:
$(1+r_{monthly})^{12} = 1+r_{yearly}$, or

$$r_{monthly} = (1+r_{yearly})^{1/12} - 1 \qquad [A3\text{-}3]$$

For a single future flow *F*, the present worth *P* is defined by:

$$P = F \cdot PWF \qquad [A3\text{-}4]$$

where:
P = present worth in base year,
F = future value in year of occurrence,
PWF = Present Worth Factor = $\dfrac{1}{(1+r)^t}$
r = discount rate,
t = time between P (today) and F.

For example, if a payment of \$500 is made on December 31 in the year 2000 and the discount rate is 5% per year, then the present worth of this payment on 1 January 1997 (4 years earlier) would be:
$\$500 \cdot [1/(1 + 0.05)^4] = \$411.35$

The net present worth of a series of future cash flows is simply the sum of the discounted present worth of each individual cash flow, including both positive (income) and negative (cost) flows. Thus, in Figure A3-1, the net present worth of the series would be the net sum of the lighter bars.

For multiple future flows F_n:

$$P = \sum \left(F_n \cdot PWF_n \right) \qquad [A3\text{-}5]$$

If future flows F_n occur in equal annual amounts $F_n = A$ (where A is a constant annual value for all n), then:

$$P = A \cdot \left[\frac{1}{1+r} + \frac{1}{(1+r)^2} + \frac{1}{(1+r)^3} + ... + \frac{1}{(1+r)^t} \right] = A \cdot \frac{\left[1-(1+r)^{-t} \right]}{r} \qquad [A3\text{-}6]$$

The capital recovery factor (*CRF*) is defined as the ratio between a uniform annual (annuity) value and the present value of the annual stream. This is a very useful quantity for evaluating the performance of energy-efficiency investments that lead to annual energy-cost savings.

$$CRF = Capital\ Recovery\ Factor = A/P = \frac{r}{\left[1-(1+r)^{-t} \right]} \qquad [A3\text{-}7]$$

For example, suppose we invest in a high efficiency air conditioning system with an incremental cost of \$1000. Given an equipment life of 12 years and a discount rate of 9%, what would be the minimum value of annual energy savings at which this investment would be cost-effective?

P = \$1000, t = 12 years, r = 9%. Using Eq. A3-7, $CRF = A/P = 0.13965$.
Therefore, $A = P \cdot CRF$ = \$139.65/yr = the minimum annual savings necessary to justify the investment in the high-efficiency system.

Life Cycle Cost

The life cycle cost (*LCC*) is the total discounted (present worth) cash flow for an investment with future costs during its economic life.

$$LCC=Cc+\sum_{n=1}^{n=t}\left[\frac{C_n}{(1+r)^n}\right]-\frac{SV}{(1+r)^t} \qquad [A3\text{-}8]$$

where:
Cc = Initial Capital Cost (capital, labor, administrative cost),
C_n = Operating Cost (operation + maintenance, fuel, tax and interest) in year n,
SV = Salvage Value (in year t).

For uniform annual costs:
If $C_n = A$ for all n:

$$LCC = Cc+\frac{A}{CRF_{t,r}}-(SV\cdot PWF_{t,r}) \qquad [A3\text{-}9]$$

For example, assume that a piece of equipment costs $1000 to purchase and has an annual operating cost of $100/yr. At the end of 8 years, the equipment is sold for $300. Assuming a discount rate of 7%, $CRF_{8yr,7\%}$ = 0.16747, and $PWF_{8yr,7\%}$ = 0.5820.

The life cycle cost would then be:
LCC = $1000 + ($100/0.16747) - ($300 · 0.5820) = $1423. [2]

[2] Again, the time increment between cash flows can be in increments other than one year. If rather than annual payments A, payments K_L are made in time intervals $L \neq 1$ year:

then instead of $\frac{A}{CRF_{t,r}}$ in Eq. A3-9, we can use $\frac{K_L}{CRF_{t^*,r^*}}$, where $t^* = t/L$, and $r^* = (1+r)^L-1$.

In our example of the equipment with the $1000 capital cost, $100 annual operating cost, $300 salvage value after 8 years, and annual discount rate of 7%, using a time increment of one month would yield the following:

L = 1 month = (1/12) years, t = 8 years, r = 7%. So,
K_L = $100/yr ÷ 12 months/yr = $8.33/month
$t^* = t/L = 8/(1/12) = 96$
$r^* = (1+r)^L-1 = (1+0.07)^{(1/12)} - 1 = 0.005654$

Therefore, our $CRF_{96,\,0.005654} = \frac{r^*}{\left[1-(1+r^*)^{-t^*}\right]} = \frac{0.005654}{\left[1-(1+0.005654)^{-96}\right]} = 0.01353$, so

LCC now becomes $1000 + ($8.33/0.01353) - ($300 · 0.5820) = $1441.

Note the difference in *LCC*s: $1423 when operating cost is assumed to be paid once per year, and $1441 when paid once per month. This difference is due to the timing of the operating cost payments over the course of the year.

Annualized Life Cycle Cost

The annualized life cycle cost (*ALCC*) is the annual uniform cash flow series (annuity) with a net present worth equal to that of the life cycle cost.

$$ALCC = LCC \cdot (A/P)_{t,r} = LCC \cdot CRF_{t,r} \qquad [A3\text{-}10]$$

For our above example, with a life cycle cost of \$1423, life of 8 years, and 7% discount rate, *ALCC* = \$1423 · 0.16747 = \$238/yr.

Economic Figures of Merit: Internal Rate of Return

There are several economic figures of merit that one can use to compare different types of investments. The *LCC* and *ALCC* are possibilities, but they depend strongly on the magnitude of the investments, not just their relative cost-effectiveness. Another figure of merit is the internal rate of return (*IRR*), which is the equivalent discount rate (r) at which the net present worth of present and future cash flows (i.e., the *LCC*), is equal to zero. The higher the *IRR*, the more cost-effective the investment.

Using Eq. A3-5 and setting its value equal to zero:

$$P = \sum\left(F_n \cdot PWF_n\right) = \sum\left[\frac{F_n}{(1+r)^n}\right] = 0 \qquad [A3\text{-}11]$$

With all values of F_n known, we can solve Eq. A3-11 by iteration for r, which represents the *IRR* at the point at which P becomes zero.

For uniform annual savings D over n years resulting from a present capital expenditure Cc,

$$P = 0 = Cc - \frac{D}{CRF_{n,irr}}, \text{ or } CRF_{n,irr} = \frac{D}{Cc} \qquad [A3\text{-}12]$$

This might be thought of as a specialized case of Eq. A3-9. Knowing D and Cc, one can solve Eq. A3-12 for *CRF*, and can then either look up the corresponding *IRR* value in a compound interest table, or use Eq. A3-7 to solve iteratively for *IRR* (i.e., r). Alternatively, most spreadsheet programs and programmable calculators have built-in functions to calculate the *IRR* from any series of cash flow values.

For example, a high efficiency device has an incremental cost of \$500, and saves \$80 annually in energy bills over the course of its 12 year life. Using Eq. A3-12, *CRF* = \$80/yr ÷ \$50 = 0.16/yr, resulting in a corresponding *IRR* of 11.81%

Economic Figures of Merit : Simple Payback

An even simpler but also useful figure of merit is the simple payback (*SPB*), which is the time required for annual savings to sum to an initial cost, without discounting.

$$SPB = \frac{Cc}{D} = \frac{Capital\ Cost}{Annual\ Savings} \qquad [A3\text{-}13]$$

For example, a \$100 investment that saves 1.0 MWh/year, at \$50/MWh, would yield:

SPB = \$100 ÷ \$50/yr = 2 years.

Although the *SPB* ignores both discounting and cash-flows after the pay-back time, for a uniform annual cash flow it is a comparable figure of merit to more complex indicators like the *IRR*. The relationship between *SPB* and *IRR* is most clearly demonstrated through the following specific example:

Example:

Let us assume that an energy efficiency investment has a capital cost of \$100, saves \$20 per year, and has a lifetime *t* of 10 years. The simple payback of the investment would be \$100 ÷ \$20/yr = 5 years.

If the discount rate is 15%, then the present worth of the investment is:

$$PW = -\$100 + \$20 \cdot \left[\frac{1}{1.15} + \frac{1}{(1.15)^2} + \frac{1}{(1.15)^3} + ... + \frac{1}{(1.15)^{10}} \right] = \$0$$

As using a discount rate of 15% yields a present worth of 0, this indicates that the *IRR* for this investment is 15%.

If we calculate the CRF using the 15% *IRR* as the discount rate *r* and the equipment lifetime *t* of 10 years, then

$$CRF = \frac{r}{\left[1-(1+r)^{-t}\right]} = \frac{0.15}{\left[1-(1.15)^{-10}\right]} = 0.2\big/ yr$$

Therefore, $P/A = 1/CRF_{t,irr} = 1 \div 0.2/yr = 5\ years = SPB.$

In other words, calculating the *CRF* with the *IRR* as the discount rate and the full equipment life as the discounting period, the resulting value of the *CRF* is equal to the reciprocal of the simple payback: $SPB = 1/CRF_{t,irr}$ in cases of uniform cash flow. This demonstrates a clear correlation between *SPB* and *IRR*.

Cost of Saved Energy

Another very useful simple measure of economic performance for energy-efficiency measures is the cost of saved energy (*CSE*), which measures the cost of an efficiency measure in the same units as one typically compares energy supply resources, i.e., cost per kWh or per GJ. The cost of saved energy is the sum of net annualized capital costs of an efficiency measure and its net increase (or decrease) in operating costs, divided by the annual energy savings.

$$CSE = \frac{ALCC*}{D} \qquad [A3\text{-}14]$$

where:
CSE = Cost of saved energy (e.g., \$/MWh),
*ALCC** = Modified annualized life cycle cost (e.g., \$/yr) of the efficiency measure: this cost should not include savings from reduced energy consumption,
D = Annual energy savings (e.g., MWh/yr).

A key point with regard to the *CSE* is that if the efficiency improvement is a retrofit to still-usable existing equipment, one should use the total cost of the energy-efficiency measure to calculate the *CSE* (because there would have been zero additional cost without the measure).

But if the efficiency measure replaces other “base-case” new equipment which was to be installed, then one should use only the net additional (incremental) cost of the energy-efficiency measure, because the cost of the “base-case” equipment without the efficiency measure would have been spent regardless. In this case, *CSE* would be defined as follows:

$$CSE = \frac{ALCC*_A - ALCC*_B}{D} \qquad [A3\text{-}15]$$

where:
$ALCC*_A$ = *ALCC** using an energy-efficiency measure,
$ALCC*_B$ = *ALCC** with non-energy-efficient measure (i.e., “base case”),
D = Energy savings from replacing measure B with measure A.

The estimation of the *CSE* can usually be simplified by assuming that the energy savings are a uniform annual series, in which case:

$$CSE = \frac{(CRF \cdot Cc) + Cop}{D} \qquad [A3\text{-}16]$$

where:
CRF = Capital recovery factor (see Equation A3-7),
Cc = Capital cost of measure (\$),
Cop = Operating cost of the measure only (\$/year) (do not include any energy savings),
D = Annual energy savings (MWh/year).

Example: Compact Fluorescent Lamps

Consider the energy savings potential of a compact fluorescent lamp (CFL). This efficient lamp uses 15 watts, lasts for 10,000 hours, and costs $15.00. It replaces an incandescent light bulb (ILB), which uses 75 watts, lasts for 1000 hours (thus we need 10 over the lifetime of one CFL), and costs $0.50 each. If we use the CFL 2000 hours/year, it would last five years and would replace two ILBs per year.

The annual energy savings are 2000 hrs · (75W - 15W) = 120,000 Wh/yr = 120 kWh/yr. Assuming an 8% real discount rate for this analysis, the $CRF_{5yr,8\%}$ is 0.25046. The cost of replacing the two ILBs per year can be thought of as a negative operating cost (i.e., operating cost savings) for the CFL. Thus, the *CSE* can be calculated as follows:

CSE = [(0.25046/yr) · ($15.00) - (2) · ($0.50/yr)] ÷ 120 kWh/yr = $0.023/kWh.

Assuming an average electricity rate of $0.07/kWh, we can calculate the annual cost savings as [(2) · ($0.50/yr) + (120 kWh/yr) · ($0.07/kWh)] = $9.40/yr. Thus, using Equation A3-13, we can calculate the simple payback (*SPB*) as $15.00 ÷ $9.40/yr = 1.6 year, which is much less than the 5 year life of the measure.

We can also calculate the internal rate of return (*IRR*) using Equation A3-12:

$CRF_{5yr,irr} = \frac{D}{Cc} = \frac{\$9.40/yr}{\$15.00}$ = 0.6267/yr. Solving Equation A3-7 iteratively for *r*, we find that the *r* (i.e., *IRR*) value for which *CRF* = 0.6267 is *IRR* = 55.85%.

Cost of Saved Capacity

Another useful figure of merit, particularly for load management programs where the primary objective is to reduce peak demand, and thereby delay the need for supply capacity expansion, rather than energy consumption, is the cost of saved capacity (*CSC*).

$$CSC = \frac{LCC^* \cdot (8760\ hr/yr) \cdot LF}{D} \qquad [A3\text{-}17]$$

where:

CSC = Cost of saved capacity ($/MW),

*LCC** = Modified life cycle cost ($) of the efficiency measure: this cost should <u>not</u> include O&M savings from reduced energy consumption,

D = Annual energy savings (MWh/year), and

$$LF = \frac{kWh/yr\ electricity\ consumed}{(kW\ peak\ demand) \cdot (8760\ hr/yr)} = \frac{average\ energy\ demand}{peak\ demand} \qquad [A3\text{-}18]$$

Note that peak demand credit, and thus credit for capacity reduction, should be adjusted according to the fraction of load in service during hours of system (or local area) peak load.

Appendix 4. Treatment of Taxes in Utility Revenue Requirements

This appendix is meant to clarify the treatment of taxes when calculating utility revenue requirements and provides a more detailed discussion of concepts discussed in Chapter 4, Section C. We will begin with the basic definition of utility revenue requirements provided in Chapter 4, Equation 4.4:

$$RR_t = I_t + Ex_t + T_t \qquad [A4\text{-}1]$$

Where:

- RR_t = revenue requirements from expenditures in year t
- I_t = capital investment expenditures in year t
- Ex_t = operating expenses in year t
- T_t = taxes in year t

In Chapter 4, Equation 4.5, investments I_t were defined as including the capital costs of physical generation, transmission and distribution facilities as follows:

$$I_t = Cg_t + Ct_t + Cd_t \qquad [A4\text{-}2]$$

Where:

- Cg_t = capital investment in generation in year t
- Ct_t = capital investment in transmission in year t
- Cd_t = capital investment in distribution in year t

From a financial perspective, however, the investment component of revenue requirements can alternatively be defined in terms of the financial instruments used to finance the construction of the physical generation, transmission, and distribution facilities. In other words, in any given year, a utility's revenue requirements must include sufficient revenues to cover the following costs associated with its capital investments: a depreciation cost to cover the annual depreciation of its facilities, a debt servicing cost to pay interest on its outstanding debt, and an equity cost of paying a return (such as dividends) to its equity investors. In this sense, investment can be defined as follows:

$$I_t = D_t + i_d B_t + EQ_t \qquad [A4\text{-}3]$$

Where:

- D_t = depreciation allowance in year t
- i_d = interest rate on debt
- B_t = outstanding debt in year t
- EQ_t = equity return in year t

Therefore, equation A4-1 can be re-written as follows:

$$RR_t = D_t + i_d B_t + EQ_t + Ex_t + T_t \qquad [A4\text{-}4]$$

Now, let us look at the composition of the tax term T_t. Tax regulations will of course differ in every country, but we will look at the tax system in the USA as a fairly typical example of an investor-owned utility.

A utility in the USA will pay taxes on its profits, and it will also pay returns to its investors through these profits. Let us assume that the a hypothetical utility's tax rate τ = 40%, and let us further assume that the utility must provide a return on investment of 12% per year to its investors. The 12% return to investors would be paid out of after-tax profits, so the utility would have to earn sufficient pre-tax profits that, after paying the 40% taxes, it would still have a sufficient sum left to pay a 12% return to investors.

Let us call these pre-tax profits the "revenue requirements of equity," or RR_{EQ}. RR_{EQ} represents the pre-tax revenue requirements of the utility with which, after paying taxes, the utility would pay its equity investors. The relationship can be written algebraically as follows:

$$RR_{EQ} = EQ_t + T_t = EQ_t + tRR_{EQ} \qquad [A4\text{-}5]$$

Where:

RR_{EQ} = "revenue requirements of equity"
EQ_t = equity return in year t
T_t = taxes in year t
t = marginal tax rate in year t

Because $T_t = tRR_{EQ}$, RR_{EQ} can be re-written as T_t/t and substituted back into equation A4-5. Therefore, equation A4-5 could be re-written as $T_t/t = EQ_t + T_t$, so

$$T_t = \frac{tEQ_t}{1-t} \qquad [A4\text{-}6]$$

So if, for example, our hypothetical utility is to pay a \$1 million equity return to its investors, then its tax bill (at the 40% tax rate) would be (0.4)·(\$1 million)/(1-0.4) = \$666,667; and its RR_{EQ} would be \$1 million + \$666,667 = \$1.667 million. In other words, the utility would earn \$1.667 million pre-tax profit, of which 40% (\$666,667) would be paid in taxes, and the remaining \$1 million would be paid out to its investors.

Substituting our expression for T_t in equation A4-6 back into equation A4-4, we have:

$$RR_t = D_t + i_d B_t + EQ_t + Ex_t + \left(\frac{t}{1-t}\right)EQ_t \text{, or}$$

$$RR_t = D_t + i_d B_t + \frac{EQ_t}{1-t} + Ex_t \qquad [A4\text{-}7]$$

Equation A4-7 shows that the actual value of taxes does not have to be explicitly determined in order to calculate the revenue requirements defined in equation A4-4. Only the marginal tax rate t is needed, with which taxes can be readily incorporated into the equity return term of equation A4-4.

From equation A4-7, we also see that taxes can be expressed as a function of capital investment. Because capital investment $I_t = D_t + i_d B_t + EQ_t$, the expression $D_t + i_d B_t + \frac{EQ_t}{1-t}$ in equation A4-7 can be considered a variant of I_t which includes taxes and which we will call I^*_t. In other words, if we combine equations A4-3 and A4-6, we see that:

$I_t = D_t + i_d B_t + EQ_t$ and $T_t = \frac{tEQ_t}{1-t}$, so

$I_t + T_t = D_t + i_d B_t + \frac{EQ_t}{1-t} = I^*_t$. Therefore,

$$I^*_t = I_t + T_t \qquad [A4\text{-}8]$$

The point of the above discussion is to highlight that taxes can be considered as a given fraction of capital investment and do not have to be treated explicitly when calculating revenue requirements. We can therefore eliminate the tax term T_t from equation A4-1 and re-write the equation as:

$$RR_t = I^*_t + Ex_t \qquad [A4\text{-}9]$$

Equation A4-9 above is presented as equation 4.8 in Chapter 4.

In terms of calculating the present value of revenue requirements, this is done using the utility's after-tax weighted-average cost-of-capital (WACC), which is calculated as follows (Brealey and Meyers, 1996):

$$r = (1-t)i_d F_{debt} + i_e F_{equity} \qquad [A4\text{-}10]$$

where:

r = discount rate = weighted average cost of capital
t = tax rate
i_d = interest rate on debt
i_e = return on equity
F_{debt} = fraction of debt financing
F_{equity} = fraction of equity financing

Note that the term *(1-t)* is included in the debt portion of equation A4-10 because interest payments are considered a business expense and are tax-deductible, thus reducing the "true" cost of debt capital by the tax rate.

If we assume that i_d, i_e, t, F_{debt}, and F_{equity} are constant during the planning period, then r can be considered a constant discount rate. This allows us to calculate the present value of revenue requirements using equation A4-7 as:

$$PW(RR_t) = PW(D_t) + PW(i_d B_t) + PW\left(\frac{EQ_t}{1-t}\right) + PW(Ex_t)\,, \qquad [A4\text{-}11]$$

and equation A4-8 can be re-written as:

$$PW(I^*_t) = PW(I_t) + PW(T_t)\,, \qquad [A4\text{-}12]$$

which is presented in Chapter 4 as Equation 4.7.

Appendix 5. Area-Specific Marginal Costs

In addition to the system-level energy costs and (generation and transmission) capacity costs described in Chapter 4, the marginal cost (MC) includes the area- and time-specific value of the marginal costs of distribution and local transmission capacity (MDCC). Estimating the MDCC requires the development of the local distribution supply and expansion plan. To develop such a distribution plan, utility planners evaluate each planning area's future load growth and related investments in capacity expansion, which can be used to estimate MDCC values. In the past utilities have had little use for such information, which can be very data-intensive and analytically demanding to obtain. Instead, distribution planning has usually been performed on a rather *ad hoc* basis, and most utilities do not even have their planning areas clearly defined.

Similarly to equation 4.9 in Chapter 4, area-specific marginal costs (ASMC) can be defined by the following equation:

$$ASMC = \frac{MEC \cdot \Delta kWh}{crf} + MCC \cdot \Delta kW_{sys} + MDCC \cdot \Delta kW_{area} \qquad [A5\text{-}1]$$

where: *ASMC* = area-specific marginal cost {units = $}
MEC = marginal energy cost (depends on amount of energy service)
dkWh = incremental annual energy use (depends on annual load profile)
crf = capital recovery factor (depends on discount rate and amortization time)
MCC = marginal system-level capacity cost (generation and transmission only), (depends on system expansion plan)
dkW_{sys} = incremental system-level capacity (depends on system peak demand)
MDCC = marginal distribution capacity cost (depends on local area expansion plan)
dkW_{area} = incremental distribution capacity (depends on area peak demand)

The MDCC varies by area because the method is applied at the local level to individual area-specific distribution supply plans, which can include a wide divergence of distribution investments by area and time. The MDCC is usually allocated to the 60-100 hours per year of maximum area-specific demand, which are the hours that influence the distribution capacity. It is important to note that the need for distribution supply expansion, and thus the MDCC, is driven by the area-specific demand peak, rather than the system-wide peak. These two peaks are often highly coincident, but they can also occur at different times or even different seasons.

The area-specific marginal capacity cost can be allocated to each hour of the year, similarly to that shown in equation 4.17 in Chapter 4:

$$ASC_{cap(h)} = \frac{MCC \cdot \Delta kW_{sys} \cdot P_{(h)}}{LOLP} + \frac{MDCC \cdot \Delta kW_{area} \cdot L_{(h)}}{\sum_{h=1}^{h=100} L_{(h)}} \qquad [A5\text{-}2]$$

where: $ASC_{cap(h)}$ = area-specific capacity cost allocated to hour h {units = $}
$P_{(h)}$ = contribution of hour h to the annual LOLP
$LOLP$ = total annual loss-of-load probability
$L_{(h)}$ = load of hour h, for the 100 hours of highest peak load

Similarly to the definition of the marginal cost of energy defined in equation 4.18 in Chapter 4, summary marginal cost values can also be estimated using area-specific capital cost values:

$$ASCOE = \frac{ASMC \cdot crf}{\Delta kWh} \qquad [A5\text{-}3]$$

where: $ASCOE$ = area-specific cost of energy {units = $/kWh}.

Another issue in comparing capacity costs is that the incremental unit of capacity can be defined in different ways. From the supply side, one kW of capacity corresponds to the maximum output of a generating plant. A unit of transmission capacity, however, depends on the capacity for carrying current at the time of the system peak, while distribution capacity depends on the local peak. On the demand side, the maximum load depends on the usage pattern of a particular type of end-use, which may or may not contribute to the demand on the maximum capacity of either generation, transmission or distribution facilities. For example, the area-specific cost of capacity is related to the local distribution capacity needs, and is therefore expressed in terms of the area-specific peak.

Similarly to equation 4.19 in Chapter 4,

$$ASMCOC = \frac{ASMC}{\Delta kW_{area}} \qquad [A5\text{-}4]$$

where: $ASMCOC$ = area-specific marginal cost of capacity {units = $/kW}.

Similarly, in hour h,

$$ASMC_{(h)} = ASC_{cap(h)} + C_{en(h)} \qquad [A5\text{-}5]$$

where: $ASMC_{(h)}$ = area-specific marginal cost in hour h {units = $}
$ASC_{cap(h)}$ = area-specific capacity cost allocated to hour h
$C_{en(h)}$ = cost of producing energy in hour h.

Appendix 6. Answers to Exercises

1.1

a. 62.70 m^3/hr

b. 307.8 kg/hr

c. 666 kWh/hr

1.2

Conventional fluorescent to efficient fluorescent: 8.76 kWh/yr savings.

Conventional 60 W incandescent to efficient 54 W incandescent: 6.57 kWh/yr savings.

Conventional 25 W incandescent to compact fluorescent 5 W: 21.9 kWh/yr savings.

2.1

Annual MWh Consumption by End-Use								
City	Incand Light	Fluor. Light	TV b/w	TV color	Refrig	Elec H2O Heat	Air Cond	Clothes Wash
Beijing	31903	58441	176628	323819	1604374	10417	53897	538006
Manila	19392	34798	108502	145551	1079225			
Pune	4169	7059	22494	21370	98639	57112	7207	6852
Thailand	12366	36851			904868	31167	241887	76652
Nanning					118057			57708
Hong Kong			3588	175794	770866	75536	586237	243144
Manaus	2955	3136	10492	29378	128825	52845	112058	6924

2.3

Refrigerators: 13.45 TWh/yr if market size not increasing

Air conditioners: 1.39 TWh/yr if market size not increasing. If we assume that half of all units are due to market growth and average operating hours = 300 hr/yr, then total annual consumption = 0.779 TWh/yr

2.4

Not cost-effective for customer, but cost-effective for utility to provide subsidy.

2.5

Cost-effective for both customer and utility. Lighting energy service level improves with efficient kit.

2.6

Cost-effective for both customer and utility. Lighting energy service level improves with efficient kit.

Chapter 2, Brakimpur: Point 6c.

Table F - Socio-Economic Scenario for projected year (X+10)			
- Only Population Growth and change in income distribution; no change in P, M, or I			
			avg. annual growth rate
A'1 - population		14111122	3.00%
A'2 - people/household		4.0	-0.44%
A'3 -Income Classes		total	
(Minimum Wage Units)		**N_{x+10}**	
0-2	15%	**529167**	
2-5	32%	**1128890**	
5-10	28%	**987779**	
+10	25%	**881945**	
TOTAL	100%	3527780	

Table G -Frozen Efficiency Scenario **(MWh/year)**

Brakimpur: End-Use Total Households Energy Consumption by Income Class

Unchanged efficiency and usage (M and I): $E_{X+10} = N_{X+10} * P * M * I$

end use	*0-2*	*2-5*	*5-10*	*+10*	*Total*
LAMP_INC	**105728**	**406400**	**592667**	**617362**	**1722157**
LAMP_FLU	**13229**	**28222**	**61736**	**79375**	**182563**
IRON	**12658**	**46269**	**83038**	**89659**	**231622**
TV	**51594**	**118533**	**159526**	**197556**	**527209**
CLTH WASH	**0**	**0**	**74054**	**136647**	**210701**
AIR_COND.	**0**	**158045**	**829734**	**1508126**	**2495905**
FREEZER	**0**	**60974**	**177840**	**370417**	**609230**
REFRIG.	**222276**	**624178**	**655836**	**793742**	**2296032**
FAN	**75142**	**240454**	**269664**	**343959**	**929217**
WATER HTR	**14288**	**270934**	**296334**	**370417**	**951972**
OTHERS	**10589**	**67733**	**266700**	**423334**	**768356**
Total	**505502**	**2021741**	**3467128**	**4930592**	**10924963**

Chapter 2, Brakimpur: Point 9.
Commercial sector projection:

Year X+10 MWh Energy Consumption Assuming Unchanged P, M, and I Between Year X and X+10							
Market Segment	Illumination	Air conditioning	Electric cooking	Refrigeration	Equipment	TOTAL MWh	TOTAL MWh per m^2 of floor area
Small commerce	378,542	5,979	2,562	172,189	9,395	568,666	3.33
Shopping center	1,711,875	181,563	46,688	1,045,800	129,688	3,115,613	30.03
Hotels	332,473	382,534	1,701	380,832	11,334	1,108,875	14.68
Bank	291,173	17,470	851	156,534	9,706	475,734	6.13
Schools	3,812,802	992,918	20,426	915,072	181,562	5,922,781	6.52
TOTAL MWh	6,526,864	1,580,464	72,228	2,670,428	341,685	11,191,668	8.38

3.1
a. r = 39.735%
b. r = 5.556%
c. r = -3.398%: infinite payback

3.4
If r = 39.735%, then maximum cost-effective price = $15.94.
If r = 5.556%, then $31.79.

3.5
Tariff A.

3.6
Tariff C: $10,604/month. Factory saves money by switching to night time production.

3.7
$E_{electric}$ = 1.2 MWh/yr. At 33% conversion efficiency: 3.6 MWh/yr.
$ER_{electric}$ = 0.22 tC/yr
$AC_{electric}$ = $168/yr
Heat pump has lower energy consumption and lower carbon emissions but is not cost-effective.

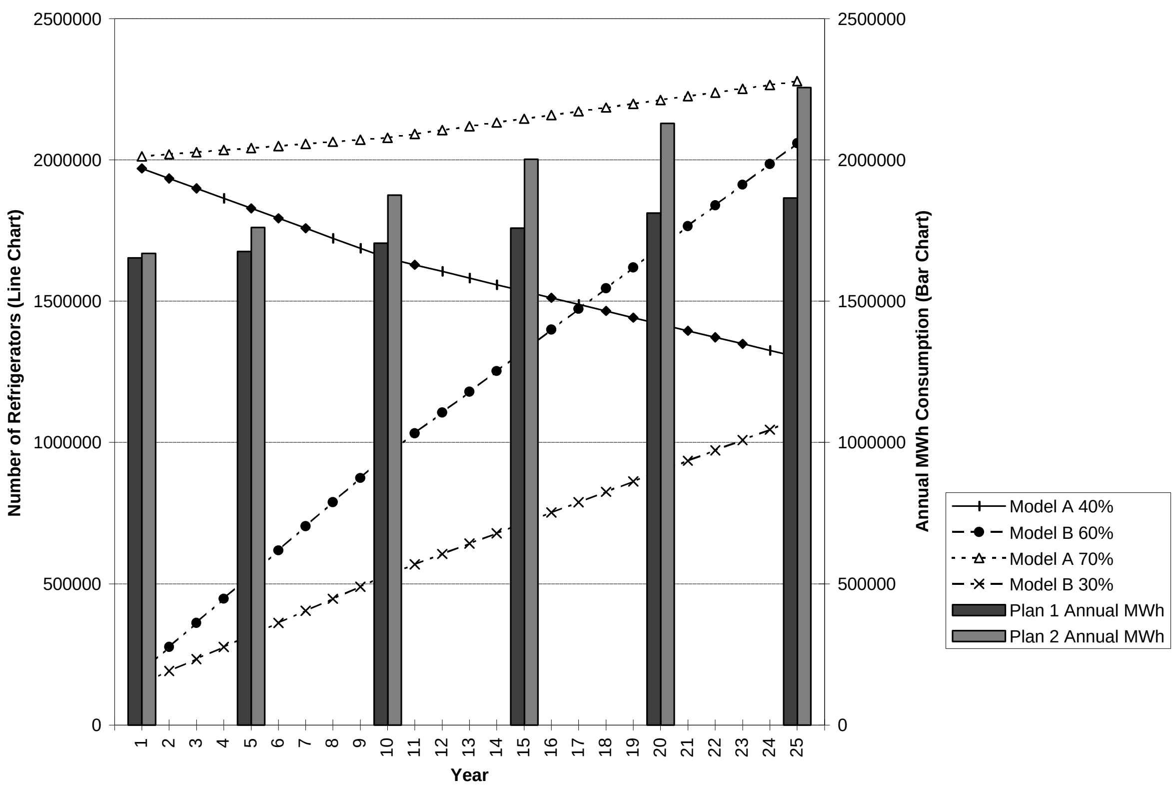
3.8
Utility’s benefit/cost ratio = 1.02.
Customer’s benefit/cost ratio = 0.65.

3.9
Electric heating system: E = 21.05 MWh/yr; AC = $1448/yr per household; annual emissions = 3.79 tC/yr per household.

District heat dedicated gas plant: E = 25.0 MWh/yr; AC = $990/yr per household; annual emissions = 1.25 tC/yr per household.

3.10

	Plan 1			Plan 2		
Year	Model A 40%	Model B 60%	MWh/yr	Model A 70%	Model B 30%	MWh/yr
1	1,969,684	190,866	1,652,094	2,012,353	148,197	1,669,161
2	1,934,345	276,205		2,019,684	190,866	
3	1,899,007	361,543		2,027,015	233,535	
4	1,863,668	446,882		2,034,345	276,205	
5	1,828,330	532,221	1,675,552	2,041,676	318,874	1,760,891
6	1,792,991	617,559		2,049,007	361,543	
7	1,757,652	702,898		2,056,338	404,213	
8	1,722,314	788,237		2,063,668	446,882	
9	1,686,975	873,575		2,070,999	489,551	
10	1,651,636	958,914	1,704,875	2,078,330	532,221	1,875,552
11	1,628,328	1,032,222		2,091,675	568,875	
12	1,605,019	1,105,531		2,105,021	605,529	
13	1,581,711	1,178,839		2,118,367	642,183	
14	1,558,402	1,252,148		2,131,713	678,838	
15	1,535,094	1,325,456	1,758,258	2,145,058	715,492	2,002,243
16	1,511,786	1,398,765		2,158,404	752,146	
17	1,488,477	1,472,073		2,171,750	788,800	
18	1,465,169	1,545,382		2,185,096	825,455	
19	1,441,860	1,618,690		2,198,441	862,109	
20	1,418,552	1,691,999	1,811,641	2,211,787	898,763	2,128,935
21	1,395,243	1,765,307		2,225,133	935,417	
22	1,371,935	1,838,616		2,238,479	972,072	
23	1,348,626	1,911,924		2,251,824	1,008,726	
24	1,325,318	1,985,233		2,265,170	1,045,380	
25	1,302,009	2,058,541	1,865,024	2,278,516	1,082,034	2,255,626



3.14
CSE is lowest for utility at 40% and 50% rebate levels.

Rebate Level	Total Utility Cost	Total Annual kWh Saved (kWh/yr)	Cost of Saved Energy ($/kWh)
0.0%	$85,000	0	-
10.0%	$88,900	372,000	0.063
20.0%	$105,280	967,200	0.029
30.0%	$138,820	1,711,200	0.021
40.0%	$194,200	2,604,000	0.020
50.0%	$272,200	3,571,200	0.020
60.0%	$370,480	4,538,400	0.022
70.0%	$483,580	5,431,200	0.023
80.0%	$590,440	6,026,400	0.026
90.0%	$702,760	6,547,200	0.028
100.0%	$810,400	6,919,200	0.031

4.1
Coal: $0.03/kWh, marginal resource for 4560 hr/yr
Gas: $0.04/kWh, marginal resource for 3000 hr/yr
CT: $0.053/kWh, marginal resource for 1200 hr/yr
Hydro: $0.020/kWh.
Wind: $0.010/kWh.
Annual system marginal cost = $0.0366/kWh.

4.2
$0.0401/kWh

4.3
Hydro:
Present Value of MCC = $121.2 million = $1212/kW.
Annualized MCC = $76/kW/yr.

Gas:
Present Value of MCC = $269.4 million = $1796/kW.
Annualized MCC = $131/kW/yr.

Coal:
Present Value of MCC = $406.7 million = $2034/kW.
Annualized MCC = $148/kW/yr.

CT:
Present Value of MCC = $64.1 million = $801/kW.
Annualized MCC = $70/kW/yr.

4.4

Power Source	Capacity (MW)	Capacity Factor	Variable Cost ($/kWh)	Marginal Capacity Cost ($/kW-yr)	**Marginal Cost of Energy ($/kWh)**
Hydro Existing	1200	0.50	0.020	0	**0.020**
Gas Existing	600	0.50	0.040	0	**0.040**
Coal Existing	420	0.75	0.030	0	**0.030**
Coal Retrofit	400	0.75	0.040	50	**0.048**
New Gas	200	0.75	0.035	130	**0.055**
New Coal	200	0.75	0.030	150	**0.053**
New Coal w/Scrubbers	200	0.75	0.040	180	**0.067**
Wind Farm	500	0.30	0.010	150	**0.067**
Combustion Turbines	50	0.20	0.055	70	**0.095**

4.5

Total annual electricity consumption = approximately 49,932 GWh.
Load Factor = 57%

4.6

Power Source	Capacity (MW)	Capacity Factor	Annual GWh	**Variable Cost $/kWh**	**MCOE $/kWh**	**Revenue Requirements $/kWh**
Hydro	1200	0.50	5256	**0.020**	**0.020**	**0.028**
Existing Gas	600	0.50	2628	**0.040**	**0.040**	**0.056**
Existing Coal	420	0.75	2759	**0.030**	**0.030**	**0.042**
Retrofit Coal	400	0.75	2628	**0.040**	**0.048**	**0.048**
New Gas	200	0.75	1314	**0.035**	**0.055**	**0.055**
New Coal	200	0.75	1314	**0.030**	**0.053**	**0.053**
New Coal w/ Scrubbers	200	0.75	1314	**0.040**	**0.067**	**0.067**
DSM 1	375	0.40	1314	**-0.001**	**0.028**	**0.028**
DSM 2	750	0.20	1314	**-0.001**	**0.056**	**0.056**
Wind Farm	500	0.30	1314	**0.010**	**0.067**	**0.067**
Combustion Turbines	50	0.20	88	**0.055**	**0.095**	**0.095**
Load Mgmt.	100	-0.05	-44			

4.7

Power Source	MCOE $/kWh	Emissions tSO2/GWh	**CAE vs New Coal $/ton**	**CAE vs Exist Coal $/ton**
Hydro	0.02	0	**-6600**	**-2000**
Existing Gas	0.04	0	**-2600**	**2000**
Existing Coal	0.03	5		
Retrofit Coal	0.048	0.5	**-1111**	**4000**
New Gas	0.055	0	**400**	**5000**
New Coal	0.053	5		
New Coal with Scrubbers	0.067	0.5	**3111**	**8222**
DSM 1	0.028	0	**-5000**	**-400**
DSM 2	0.056	0	**600**	**5200**
Wind Farm	0.067	0	**2800**	**7400**
Combustion Turbines	0.095	0	**8400**	**13000**

4.8

	No Emission Charges			$600/tSO2 Emission Charge			$600/tNOx Emission Charge		
Power Source	Variable Cost ($/kWh)	Marginal Cost of Energy ($/kWh)	Revenue Requirements ($/kWh)	Variable Cost ($/kWh)	Marginal Cost of Energy ($/kWh)	Revenue Requirements ($/kWh)	Variable Cost ($/kWh)	Marginal Cost of Energy ($/kWh)	Revenue Requirements ($/kWh)
Hydro	0.0200	0.0200	0.0275	0.0200	0.0200	0.0275	0.0200	0.0200	0.0275
Existing Gas	0.0400	0.0400	0.0559	0.0400	0.0400	0.0559	0.0436	0.0436	0.0595
Existing Coal	0.0300	0.0300	0.0421	0.0330	0.0330	0.0451	0.0366	0.0366	0.0487
Retrofit Coal	0.0400	0.0476	0.0476	0.0403	0.0479	0.0479	0.0472	0.0548	0.0548
New Gas	0.0350	0.0548	0.0548	0.0350	0.0548	0.0548	0.0380	0.0578	0.0578
New Coal	0.0300	0.0528	0.0528	0.0330	0.0558	0.0558	0.0360	0.0588	0.0588
New Coal w/Scrubbers	0.0400	0.0674	0.0674	0.0403	0.0677	0.0677	0.0466	0.0740	0.0740
DSM 1	-0.0010	0.0275	0.0275	-0.0010	0.0275	0.0275	-0.0010	0.0275	0.0275
DSM 2	-0.0010	0.0561	0.0561	-0.0010	0.0561	0.0561	-0.0010	0.0561	0.0561
Wind Farm	0.0100	0.0671	0.0671	0.0100	0.0671	0.0671	0.0100	0.0671	0.0671
Combustion Turbines	0.0550	0.0950	0.0950	0.0550	0.0950	0.0950	0.0592	0.0992	0.0992

4.9

Cost of Avoided Emissions: SO_2					
Power Source	MCOE ($/kWh)	Annual GWh	CAE: static base ($/ton)	CAE: dynamic base ($/ton)	
			vs new coal (1314 GWh/yr)	vs new coal (1314 GWh/yr)	vs existing coal (2759 GWh/yr)
DSM 1	0.028	1314	-5059	-5059	
Retrofit Coal	0.048	2628			3913
New Gas	0.055	1314	391	391	
DSM 2	0.056	1314	649		5216
Wind farm	0.067	1314	2849		7416
Combustion Turbines	0.095	88	8420		12992

4.10

Power Source	Capac. (MW)	CF	Annual GWh	Variable Cost ($/kWh)	Marginal Capacity Cost ($/kW-yr)	Marginal Capacity Cost ($/kWh)	MCOE ($/kWh)	Sunk Capacity Cost ($/kW-yr)	Revenue Requirements ($/kWh)	Revenue Requirements (@13315 GWh/yr) ($million/yr)	Revenue Requirements (@13000 GWh/yr) ($million/yr)
Hydro	1200	0.5	5256	0.0200	0	0	0.0200	33	0.0275	144.7	144.7
DSM 1	375	0.4	1314	-0.0010	100	0.02854	0.0275	0	0.0275	36.2	36.2
Existing Coal	420	0.75	2759	0.0300	0	0	0.0300	80	0.0421	116.2	116.2
Existing Gas	600	0.5	2628	0.0400	0	0	0.0400	70	0.0559	146.9	129.3
New Coal	200	0.75	1314	0.0300	150	0.02283	0.0528	0	0.0528	69.4	69.4
Load Mgmt	100	-0.05	-44	0.0000	50					5.0	5.0
Combustion Turbines	50	0.2	87.6	0.0550	70	0.03995	0.0950	0	0.0950	8.3	8.3
Total	2945		13315							526.6	509.0
							Average Rate ($/kWh):			0.0396	0.0392

For Load Management revenue requirements, $50/kW-yr · 100 MW · 1000 kW/MW = $5.0 million/yr.

Marginal resource = combustion turbine. Marginal cost = 0.0950 $/kWh.

At 13315 GWh/yr, annual revenue requirements = $526.6 million/yr, average rate = $0.0396/kWh

At 13000 GWh/yr, existing gas plant will be marginal resource.
Annual revenue requirements = $509.0 million/yr, average rate = $0.0392/kWh

Brakimpur Chapter 4: Point 6b.
Energy consumption drops 1,884,331 MWh, or 16%.

Brakimpur Chapter 4: Point 6d.
DSM1 savings: 1,746,245 MWh; DSM2 savings: 1,789,348 MWh.

Brakimpur Chapter 4: Point 9.

Segment\End-Use	Illumination	Air Conditioning	Electric Cooking	Refrigeration	Equipment	TOTAL MWh
Small commerce	227,125	4,723	2,562	146,360	9,395	390,166
Shopping center	1,027,125	143,434	46,688	888,930	129,688	2,235,864
Hotels	199,484	302,202	1,701	323,708	11,334	838,428
Banks	174,704	13,802	851	133,054	9,706	332,116
Schools	2,287,681	784,406	20,426	777,812	181,562	4,051,886
TOTAL MWh	3,916,118	1,248,566	72,228	2,269,864	341,685	7,848,461

Bibliography

ACEEE, 1992. “Summer Study on Energy Efficiency in Buildings - Proceedings: Integrated Resource Planning,” American Council for an Energy-Efficient Economy.

ADSMP Program Plan & Implementation Manual / Glossary. “Glossary of Demand-Side Management Terms.”

Akbari, H. et al., 1990. “A review of Existing Commercial Energy Use Intensity and Load-Shape Studies,” Energy Analysis Program, Applied Science Division, Lawrence Berkeley Laboratory, University of California, August.

Anderson, D., 1993. “Energy-Efficiency and the Economics of Pollution Abatement,” Annual Review of Energy and the Environment, vol. 18, pp. 291-318.

Arrieta, Felipe Valdes, 1993. “Saving Energy in Chile: An Assessment of Electricity Use and Potential Efficiency Improvements,” IIEC, May.

Asian Energy News, 1994. “The New Environmental Accouunting: A Status Report,” Volume 4, Number 10, November, pp. 11.

Asian Energy News, 1994. “The New Environmental Accouunting: A Status Report,” Volume 4, Number 12, December, pp. 11.

Asian Energy News, 1994. “The New Environmental Accouunting: A Status Report,” Volume 5, Number 2, February, pp. 11.

Atkinson, B.A., J. McMahon, E. Mills, 1993. “Analysis of Federal Policy Options for Improving US Lighting Energy Efficiency: Commercial and Residential Buildings,” LBL-31469, Lawrence Berkeley Laboratory.

Barker, Ann H., 1993. “Climate Crafted Homes: Using a Branded Product to Promote Energy Efficient New Home Construction,” Proceedings of Second National New Construction Programs for Demand-Side Management Conference, October 24-27.

Barnes, D. F. and Qian, L., 1992. “Urban Interfuel Substitution, Energy use, and Equity in developing Countries: Some Preliminary Results,” The World Bank Industry and Energy Department, PRS, April.

Beck, F. A. and Arasteh, D., 1992. “Improving the Thermal Performance of Vinyl-Framed Windows,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, October.

Berry, L., 1989. “The Administrative Costs of Energy Conservation Programs,” ORNL/CON-294, Oak Ridge National Laboratory.

Besnosik, R. I. et al., 1995. “Technology strategy - Management of technology in the Brazilian power sector,” Science and Public Policy, volume 22, number 1, February, pages 2-8, England.

Bevington, R. and Rosenfeld, A. H., 1990. “Energy for Buildings and Homes,” Scientific American, Vol. 263, Number 3, September, pp. 77-86.

B. J. Novitski, 1993. “Energy Design Software,” Architecture, June, T&P Computers.

Brasil, Ministerio de Minas e Energia, 1995. Balanco Energetico Nacional 1995. Brasilia, 150 pp.

Brealey, Richard A. and Myers, Stewart C., 1996. “Principles of Corporate Finance,” McGraw-Hill, New York.

Brugnoni, M. S. F.; Dutt, G. S. and Tanides, C. G., 1994. “Una Infraestructura hacia el Uso Eficiente de la Energía Eléctrica,” Grupo de Energía y Ambiente (GEA), Depto. de Electrotecnica, Facultad de Ingeniería, Universidad de Buenos Aires, pp.7.

Brun, M.J., 1989. “La Cogénération dans le Monde”. Institut Français de L'Energie, Paris.

Bülow-Hübe, H., T. Ankarljung, 1991, “A Programme Targeted at More Permanent Conversion to Compact Fluorescent Lamps in the Residential Sector,” Proceedings of the 1st European Conference on Energy-Efficient Lighting, Stockholm.

Busch, J. F. J., 1991. “Determining the Value of Conservation to Thailand’s Electric Utility,” IEEE, Lawrence Berkeley Laboratory, University of California, Berkeley, California, pp.7.

California Collaborative, (1990), “An Energy Efficiency Blueprint for California,” January.

California Public Utilities Commission, California Energy Commission, (1987), “Standard Practice Manual: Economic Analysis of Demand-Side Management Programs,” December.

Calwell, C. J., and R. Cavanagh, 1989, “The Decline of Conservation at California Utilities: Causes,”

Charles River Associates, 1986. “Capital Budgeting for Utilities: The Revenue Requirements Method,” Electric Power Research Institute, EPRI/EA-4879.

C.-J. Winter, R. L. Sizmann, L.L., 1991. “Solar Power Plants - Fundamentals, Technology, Systems, Economics,” Vant-Hull (Eds.). Springer-Verlag.

Costs and Remedies, “National Resources Defense Council Special Report,” July.

Cohen, S. D., J. H. Eto, C. A. Goldman, J. Beldock, G. Crandall, “Environmental Externalities; What State Regulators Are Doing,” The Electricity Journal, July, 1990.

Conference Proceedings, 1993. “Investing in Energy Efficiency: The Role of Third Party Financing,” Direcção-geral de Energia, European Commission, International Energy Agency, 28th-29th October, Lisbon, Portugal.

COPPE/UFRJ e ELETROBRÁS, 1991. “Análise da Demanda e Potencial de Conservação de Energia Elétrica no Setor Residencial Brasileiro”.

CPFL e UNICAMP, 1994. “Desenvolvimento de Tecnologia de Pré-Aquecedor Solar de Água para Chuveiros Elétricos de Potência Reduzida,” Etapa 1 - Experiência de Laboratório, Relatório Final, 34 páginas.

Crane, A., and R. Roy, “Competition, Trading and the Reliability of Electric Power Service,” Annual Review of Energy and the Environment, Vol. 17,pp. 161-186.

Dandridge, C., et al, 1993. “Trends in Energy Efficiency in Office Technology,” Proceedings of the 1993 ECEEE Summer Study: The Energy Efficiency Challenge for Europe, Denmark, June.

du Pont, P., P. Amranand, Y. Lemoine, 1997. “Lessons Learned in the Implementation of Energy-Efficiency Programs in Thailand,” *Energy Policy*, in press.

Dutt, Gautam S., y Carlos G. Tanides, 1993. “Potencial de Uso Eficiente de la Energía Eléctrica: una primera aproximación,” Universidad de Buenos Aires. REPORT.

EEnergy Informer, 1995. “The International Newsletter,” Volume 5, Number 4, April, 10 pages.

The Electricity Journal, 1991. “The New Environmental Accouunting: A Status Report,” November, pp. 46-54.

The Electricity Journal, 1992. “Reconsidering DSM,” Volume 5, Number 9, November.

Energy Conservation Committee of the National Association of Regulatory Utility Commissioners (1988), “Statement of Position of the NARUC Energy Conservation Committee on Least Cost Planning Profitability.” July 26.

EPRI 1990. “Efficient Electricity Use. Estimates of Maximum Energy Savings,” Electric Power Research Institute, EPRI/CU-6746.

EPRI, 1994-95. “End-Use News,” Electric Power Research Institute, California, Winter, pp. 8.

ESMAP, 1992. “Ghana - Industrial Energy Efficiency Activity, Phase I,” Volume I: Consultants’ Reports, World Bank, November.

ESMAP, 1992. “Ghana: Industrial Energy Efficiency Activity, Phase I” Volume II: Consultants’ Reports, World Bank, November.

ESMAP, 1992. “Jamaica - Energy Sector Strategy and Investment Planning Study,” Volume I Main Report, World Bank, August.

ESMAP, 1993. “Nepal - Energy Efficiency and Fuel Substitution in Industries: An Agenda for Action,” Activity Completion Report, World Bank, June.

ESPE. “Plan de Uso Eficiente de Energia Electrica para el Ecuador,” Programa de Postgrado en Energia y Medio Ambiente, Escuela Politecnica del Ejercito (ESPE), Ecuador.

Eto, J. et al., 1994. “The Cost and performance of Utility Commercial Lighting Programs,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, May.

Eto, J. H. et al., 1990. “End-Use Load Shape Data Application, Estimation, and Collection: A State-of-the-Art Review,” Applied Science Division, Lawrence Berkeley Laboratory, University of California, June, 21 pages.

Eto, J. H. et al., 1990. “End-Use Load Shape Data Application, Estimation, and Collection: A State-of-the-Art Review,” Applied Science Division, Lawrence Berkeley Laboratory, University of California, June.

Eto, J., A. Destribats, and D. Schultz, (1992), “Sharing the Savings to Promote Energy Efficiency,” in Regulatory Incentives for Demand Side Management, S. Nadel, et al, A.C.E.E.E., 1992.

Eto, J.; Destribats, A.; and Schultz, D., 1992. “Sharing the Savings to Promote Energy Efficiency,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, April, 30 pages.

F. Liu, 1993. “Energy Use and Conservation in China's Residential and Commercial Sectors: Patterns, Problems, and Prospects,” Lawrence Berkeley Laboratory - University of california, July.

Felipe Valdes-Arrieta, 1993. “Saving Energy in Chile: An Assessment of Electricity Use and Potential Efficiency Improvements,” iiec May.

FEMP, 1994. “Federal Energy Management Program - FOCUS,” Vol. 3, No. 4, December, pp. 15.

FEMP, 1995. “Federal Energy Management Program - FOCUS,” Vol. 4, No. 1, February, pp. 12.

Figueroa, M. J. and Sathaye, J., 1993. “Household Energy Use in Urban Venezuela: Implications from Surveys in Maracaibo, Valencia, Mérida, and Barcelona-Puerto La Cruz,” Energy Analysis Program, Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, April.

Fisher A.C. and Rothkopf M.H., 1989. “Market Failure and Energy Policy,” Energy Policy, pp. 397-406, August.

Gadgil, A. J. and Jannuzzi, G. M., 1991. “Conservation potential of compact fluorescent lamps in India and Brazil,” Energy Policy, June, pp. 449-464.

Gautam S. Dutt y Carlos G. Tanides. “Potencial de Uso Eficiente de la Energía Eléctrica: una primera aproximación,” Universidad de Buenos Aires.

Gautam S. Dutt, 1992. “Techniques for End-use electricity analysis and conservation program design and evaluation, A Manual,” Volume A: Technical and Economic End-use Analysis, june.

Geller, H. S. 1991. “Efficient Electricity Use - A Development Strategy for Brazil,” Foreword by José Goldemberg, 164 pages.

Geller, H., S. Nadel. 1994. “Market Transformation Strategies to Promote End-Use Efficiency,” Annual Review of Energy and Environment. 19:301-46.

Geller, H.S., 1990. “Efficient Electricity Use, A Development Strategy for Brazil,” American Council for Energy-Efficient Economy, Washington.

Geller, Howard, 1994. “O uso eficiente de eletricidade - Uma estratégia de desenvolvimento para o Brasil,” INEE, Rio de Janeiro.

Goeltz, R., E. Hirst, 1986. “Residential Retrofit Measures in the Hood River Conservation Project,” ORNL/CON-208, Oak Ridge National Laboratory.

Greene, D.L., 1990. “Cafe or Price?: An Analysis of the Effects of Federal Fuel Economy Regulations and Gasoline Price on New Car MPG, 1978-89,” The Energy Journal, vol. 11, pp. 37-57.

Harris, J. P. et al., 1993. “Energy-efficiency research, development and demonstration - New roles for US states,” Energy Policy, December, pp. 1205-1216.

Hashem, J., E. Haites, D. Vanderhoff. “The Reality: Externaluty Requirement Do Little for DSM,” ACEEE Summer Study on Energy Efficiency in Buildings, Monterrey, CA, September.

Hedenström, C., 1991, “Från Krog till Kontor: Slutrapport från Uppdrag 2000-lokaler,” Vattenfall, Vällingby, Sweden.

Hedenström, C., A. Göransson, U. Lindahl, G. Forsman, 1992. “Lokalerna och Hushållningen,” STIL-studien, Vattenfall, Vällingby, Sweden.

Heinemeier, K. E. and Akbari, H., 1992. “Evaluation of the Use of Energy Management and Control Systems for Remote Building Performance Monitoring,” Energy Analysis Program, Energy and Environment Division, Lawrence Berkeley Laboratory, University of California, Berkeley, April, Published in Proceedings of the ASME.

Helby, P., 1993. “Financing transformation of the energy system - a preliminary presentation of research agenda,” Paper for the conference at Denmark - September 28-29 - Nordic Energy Research Programme: Energy and Society, 7 pages.

Hill, L.J., 1991. “Comparison of Methods to Integrate DSM and Supply Resources in Electric Utility Planning,” ORNL/CON-341, Oak Ridge, Tennessee, December.

Hill, W. W., 1993, “Keeping a Running Score on Weatherization,” Home Energy, March/April.

Hirst, E., 1992, “Effects of Utility DSM Programs on Risk,” ORNL/CON-346, Oak Ridge, Tennessee, May.

Hirst, E., J. Reed, 1991. “Handbook of Evaluation of Utility DSM Programs,” ORNL/CON-336, Oak Ridge National Laboratory.

Horlock, J.H., 1987. “Cogeneration: Combined Heat and Power - Thermodynamics and Economics,” Pergamon Press.

Howarth, R. B. and B.Andersson. 1993. “Market Barriers to Energy Efficiency,” Energy Economics, October.

Hu, S.D., 1985. “Cogeneration,” Reston Publishing Co., Reston, USA.

Huang, Y. J. et al., 1990. “A daylighting Design Tool for Singapore Based on DOE-2.1D Simulations,” Energy Analysis Program, Applied Science Division, Lawrence Berkeley Laboratory, University of California, March.

Huang, Y. J., 1989. “Potentials for and Barriers to Building Energy Conservation in China,” Energy Analysis Program, Energy and Environment Division, Lawrence Berkeley Laboratory, University of California, Berkeley, Presented at The Western Economic Association International Annual Meeting-June-California.

Hyman, L.S., 1988. “America's Electric Utilities: Past, Present and Future,” Arlington, VA, Public Utilities Reports.

IAEEL, 1994. “Sun on Earth,” International Association for Energy-Efficient Lighting, Newsletter 3, Issue No. 8, Vol. 3.

iei, 1994. “Energy for Sustainable Development,” The Journal of the International Energy Initiative, Volume I, N.4, November.

Initiatives, 1994. “80 European Cities Launch Campaign for Sustainability,” The Organization Newsletter of the International Council for Local Environmental Initiatives, No. 7, June, pp. 16.

Initiatives, 1994. “LA21 Model Communities Program Launched in latin America, Asia and the Pacific,” The Organization Newsletter of the International Council for Local Environmental Initiatives, No. 8, October, pp. 16.

Intergovernmental Panel on Climate Change (IPCC) Working Group 1, 1990. “Scientific Assessment of Climate Change,” Geneva, U.N. Environment Programme, June.

International Energy Agency, 1995. Energy Statistics and Balances of Non-OECD Countries 1992 - 1993.

International Institute for Energy Conservation - Asia Office, 1994. “Introduction to Integrated Resource Planning and Demand Side Management,” Presented to Philippine Non-Governmental Organizations’DSM/IRP Workshop, August.

International Resources Group, Ltd., 1993. “Pakistan Household Energy Strategy Study - Energy pricing and Policy for the Household Sector,” Washington, D.C. 20005, August.

Janda, K., J. Busch, 1994. “Worldwide Status of Energy Standards for Buildings,” Energy: the International Journal, vol. 19, pp. 27-44.

Jannuzzi, G. M. and Lee Schipper, 1991. “The structure of electricity demand in the Brazilian household sector,” Energy Policy, November, pp. 879-892.

Jannuzzi, G. M., 1991. “Conservação de Energia, Meio Ambiente e Desenvolvimento,” UNICAMP, Brasil.

Jannuzzi, G. M., M. L. Leonardi, R. C. Parente, A. Braga, 1996. “Pesquisa de Posse de Equipamentos e Hábitos de Consumo de Consumidores Residenciais da Cidade de Manaus.” REPORT (ELETROBRÁS/PNUD).

Joskow, P., D. Marron, 1993. “What Does a Negawatt Really Cost? Evidence from Utility Conservation Programs,” The Energy Journal, Vol. 13, No. 4.

Kahn, E. and Goldman, C., 1991. “The Role of Competitive Forces in Integrated Resource Planning,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, October.

Kahn, E. P., 1990. “Structural Evolution in the Electric Utility Industry,” Public Utilities Fortnightly, Arlington, VA, January 4.

Koomey, J. G. et al., 1991. “The Potential for Electricity Efficiency Improvements in the U.S. Residential Sector,” Energy Analysis Program, Applied Science Division, Lawrence Berkeley Laboratory, University of California, July.

Lang, S. and Huang, Y. J., 1993. “Energy Conservation Standard for Space Heating in Chinese Urban Residential Buildings,” Energy, Vol. 18, No. 8, pp. 871-892.

Larsen, A., L. Nielsen, K. Jørgensen, J. Jordal-Jørgensen, 1993. “Virkemidler og Elbesparelser,” AKF, Copenhagen.

Levine, M. D. et al., 1994. “Energy Efficiency, Market Failures, and Governament Policy,” Energy Analysis Program, Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, March.

Levine, M.D.; Liu, F.; and Sinton, J. E., 1992. “China’s Energy System: Historical Evolution, Current Issues, and Prospects,” Annu. Rev. Energy Environ. 17:405-35, pp. 405-435.

Levine, M.D., E.Hirst, J.G.Koomey, J. E. McMahon, A.H. Sanstad. 1994. “Energy Efficiency, Market Failures, and Government Policy,” Pre-print. Lawrence Berkeley Laboratory LBL-35376, Oak Ridge National Laboratory ORNL/CON-383.

Lewald, A., R. Bowie, 1993. “What Is Happening with the Swedish Technology Procurement Program,” Proceedings of the ECEEE Summer Study: The Energy Efficiency Challenge for Europe, Copenhagen.

Liu F., 1993. “Energy Use and Conservation in China's Residential and Commercial Sectors: Patterns, Problems, and Prospects,” Lawrence Berkeley Laboratory - University of California, July.

Maldonado et al., 1994. “Energia y Equidad,” CEPAL - Comisión Económica para América Latina y el Caribe, 14 de octubre, 49 p.

Maldonado, P.; Lebens, J.; and Castro, H., 1992. “Administracion del Lado de la Demanda en Chile: Posible con el Sistema Regulatorio Presente?,” Traductor Ing. Lionel Dignowity México, D.F., First International Energy Efficiency and DSM Conference, Canada, September.

Marecki, J., 1988. “Combined Heat & Power: Generating Systems,” Peter Peregrinus Ltd., London, U.K.

Marnay, C., and G. A.Comnes (ex CE 176er), “California’s ERAM Experience,” in Regulatory Incentives for Demand Side Management, S. Nadel, et al, A.C.E.E.E., 1992.

McMahon, J., D. Berman, P. Chan, J. Koomey, M. Levine, S. Stoft, 1990. “Impacts of US Appliance Efficiency Standards on Consumers, Manufacturers, Electric Utilities and the Environment,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, ACEEE, Washington.

Meyers, S. and C. Campbell, 1992. “Trends in electricity Demand and Supply in the Developing Countries, 1980-1990,” Lawrence Berkeley Laboratory, University of California, November.

Meyers, S. et al., 1993. “Electric Motor Systems in Developing Countries: Opportunities for Efficiency Improvement,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, August.

Miller, M., W. Blake, S. Dagher, J. Schutte, 1992. “Development of Measured Savings for a Small Commercial/Industrial Lighting Program,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, ACEEE, Washington.

Mills, E. “The New Downstream: Increased End-Use Efficiency and renewable Forms of Energy as Competitive Energy Resources,” The Future of Energy Gases - U.S. Geological Survey Professional Paper 1570, Center for Building Science, Lawrence Berkeley Laboratory, Berkeley, pp. 849-867.

MME, 1994. “Balanço Energético Nacional 1994,” Ministério das Minas e Energia, Ano base 1993, Brasil.

Moskovitz, D., and G. B. Swofford, “Revenue-Per-Customer Decoupling,” in Regulatory Incentives for Demand Side Management, S. Nadel, et al, A.C.E.E.E., 1992.

Munasinghe, M., 1990a. “Energy Analysis and Policy,” Butterworths, London.

Nadel, S., B. Atkinson, J. McMahon, 1993. “A Review of US and Canadian Lighting Programs,” Energy: the International Journal, vol. 18, no. 2, pp. 145-158.

Nadel, S., M. W. Reed, D. R. Wolcott, 1994 (eds). “Regulatory Incentives for Demand-Side Management,” DCEEE, Washington, DC.

Nadel, S., Wolcott, D., Smith, P., Flaim. T., 1990. “A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers”.

National Academy of Science, 1976. “Energy for Rural Development: renewable resources and alternatives technologies for developing countries,” Washington, DC.

Nelson, D., M. Ternes, 1993. “Flipping the Industrial Market: The Move to High Efficiency Motors,” Proceedings: 6th National Demand-Side Management Conference, EPRI TR-102021, Electric Power Research Institute.

News at Seven, 1995. “Energy Efficiency news from the Czech Republic,” Volume 3, Number 2, March.

News at Seven, 1995. “Energy Efficiency news from the Czech Republic,” Volume 3, Number 1, January.

Nilsson, H., 1992. “Market Transformation by Technology Procurement and Demonstration,” Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, ACEEE, Washington.

Northwest Power Planning Council (NWPPC), 1991. “Northwest Conservation and Electric Power Plan,” NWPPC, Portland, Oregon.

Nova Scotia Dept. Mines and Energy, 1979. “Wind Power,” Canada.

Nutek, “Kansliet för effektivare energianvändning,” 1993. Eleffektiv Disk-Tvätt-Kyl-Frys, Stockholm, June.

Ohta, Tokio, 1994. “Energy Technology - Sources, Systems and Frontier Conversion,” Pergamon.

Olade, P.; Aguinaga-Diaz, J. and Carvalho, A. V. J., 1993. “OLADE’s Central American DSM Project: A Model for International Cooperation,” Proceedings of 2nd International, Energy Efficiency and DSM Conference, Stockholm, Sweden, September, pp. 547-555.

Orans, R., 1989. “Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs,” PhD Thesis, Stanford University, Civil Engineering Dept.

Orlando, J.A., 1991. “Cogeneration Planner's Handbook,” Fairmont Press.

Pansini, A., 1992. “Electrical Distribution Engineering,” Fairmont Press, Lilburn, GA.

Papamichael, K. and Beltrán, L., 1993. “Simulating the daylight Performance of Fenestration Systems and Spaces of Arbitrary Complexity: The IDC Method,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, April.

Payne, J.R., 1991. “Cogeneration in the Cane Sugar Industry,” Elsevier, Amsterdam. Kulsum Ahmed, 1994. “Renewable Energy Technologies: A Review of the Status and Costs of Selected Technologies”. World Bank Technical Paper No. 240 - Energy Series.

Pedersen, P.B., 1992. “Engineering Analysis Concerning Energy Efficiency Standards for Refrigerators and Freezers in Denmark,” dk-TEKNIK, Copenhagen.

Plas, R. and Graaff, A. B., 1988. “A Comparison of Lamps for Domestic Lighting in Developing Countries,” The World Bank Industry and Energy Department (PPR), Industry and Energy Department Working Paper - Energy Series paper N.6, June, 59 pages.

PROCEL, 1994. “Programa Nacional de Conservação de Energia Elétrica,” Boletim Publicado pela Eletrobrás, ANO VII, No. 35, Dezembro.

RCG Hagler/Bailly. “Costa Rica: Evaluacion de la Eficiencia del Sector de Energia Electrica,” Oak Ridge National Laboratory, Oficina de Energía, Agencia para la Ciencia y Tecnología, Agencia de los Estados Unidos para el Desarollo Internacional, pp. 173-214.

RCG/Hagler Bailly, Inc. “Resumen Ejecutivo - Antecedentes Y Proposito del Estudio,” Washington, D.C., Traductor México, D.F.

Reddy A.K.N. 1991. “Barriers to improvements in energy efficiency,” Energy Policy 19(7):953-61.

Reid, M. W., “Ratebasing of DSM Expenditures” in Regulatory Incentives for Demand Side Management, S. Nadel, et al, A.C.E.E.E., 1992.

Rosenfeld et al., 1993. “Conserved Energy Supply Curves for U.S. Buildings,” Contemporary Policy Issues, , Vol. XI, January, pp. 45-68.

Rosenfeld, A. H. and Hafemeister, D., 1988. “Energy-efficient Buildings - Energy conservation and economic development can go hand in hand. Efficiently designed homes and offices will slash energy bills, liberate investment capital and avoid the expense of building new power plants,” Scientific American, Vol. 258, No.4, pp. 78-85, April.

Rosenfeld, A. H., 1994. “Past Successes and Future Plans for LBL Technologies in Units of Avoided GW, Cars, and Climate Change Action Plans,” Lawrence Berkeley Laboratory, University of California.

Ross, M., 1989. “Energy and Transportation in the United States,” Annual Review of Energy, vol. 14.

Ruderman, H., M. Levine, J. McMahon, 1987. “The Behavior of the Market for Energy Efficiency in Residential Appliances Including Heating and Cooling Equipment,” The Energy Journal, vol. 8, no. 1, pp. 101-124.

Sabadell, A. J. USAID and Streicher, A. RCG/Hagler Bailly, Inc., 1991. “Administracion de Carga Electrica en paises en Desarollo-Costa Rica a la Vanguardia,” U.S. Agency for International Development, Traductor Ing. Lionel Dignowity, México, D.F.

Sathaye, Jayant A., 1992. “Economics of Improving Efficiency of China’s Electricity Supply and Use: Are Efficiency Investments Cost-effective?,” World Bank - Chinese Ministry of Energy Workshop on Coal Utilization and Energy Efficiency in China, Beijing, 19 pages.

Sathaye, J. and S. Meyers, 1985. “Energy Use in Cities of the Developing Countries,” Lawrence Berkeley Laboratory, University of California, June, pp. 109-133.

Sathaye, Jayant and Stephen Tyler, 1991. “Transitions in Household Energy Use in Urban China, India, The Philippines, Thailand, and Hong Kong,” Annual Review of Energy and Environment., pp. 295-335.

Sathaye, J. et al., 1994. “Economic analysis of Ilumex - A project to promote energy-efficient residential lighting in Mexico,” Energy Policy, February, pp. 163-171.

Schipper, L., 1994. “Energy use and human activity: what’s wrong and what can be done?,” Symposium: Sustainable Consumption, 19-20 January, Oslo, Norway.

Schipper, L., F.X Johnson, 1993. “Energy Use in Sweden: An International Perspective,” LBL-33819, Lawrence Berkeley Laboratory.

Schipper, L.; Meyers, S.; and Howarth, R., 1993. “Energy intensities in OECD countries: an historical analysis,” Int. J. of Global Energy Issues, Vol.5, Nos 2/3/4, pp. 76-89.

Scientific American, 1990. “Special Issue Energy for Planet Earth,” September, Vol. 263, No. 3.

Selkowitz, S. E. and Lampert, C. M, 1989. “Application of Large-Area Chromogenics to Architectural Glazings,” Applied Science Division, Lawrence Berkeley Laboratory, University of California, Berkeley, CA 94720, USA, June.

Sharpe, V., P. D'Angelo, W. Ruhnke, 1993. “Working With Customers: The Espanola Experience,” Proceedings of the Second International Energy Efficiency and DSM Conference, Stockholm.

Steven Nadel - ACEEE, 1994. “Incorporating New Efficiency Standards and Codes in Utility Forecasts,” American Council for an Energy-Efficient Economy, Washington, D.C./Berkeley, California.

Sullivan, R.; Wilde, M.; and Selkowitz, S., 1990. “An Interactive Microcomputer-Based Kiosk Providing Energy Efficient Building Design Information,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, April.

Swisher, J., and K. Johnson, 1992. “Cost and Performance Comparison of DSM Measures and Supply Changes to Reduce Utility Carbon Emissions,” ACEEE Summer Study on Energy Efficiency in Buildings, Monterrey, CA, September.

Swisher, J., 1994. “Dynamics of Appliance Energy Efficiency in Sweden,” Energy: the International Journal, vol. 19, no. 11, pp. 1131-1141.

Swisher, J., C: Hedenström, 1993, “The Role of Energy Efficiency for Utility Planning in a Deregulated Market,” Proceedings of the Second International Energy Efficiency and DSM Conference, Stockholm.

Swisher, J., L. Christiansson and C. Hedenström, 1994. “Dynamics of Energy-Efficient Lighting,” Energy Policy, vol. 22, no. 7, pp.581-594, July.

Teplitz-Sembitzky, W., 1990. “Regulation, Deregulation, or Reregulation-What is Needed in the LDCs Power Sector?,” The World Bank Industry and Energy Department, PRS, July.
[157] The Electricity Journal, 1991. “The Electric Utility as Investment Bank for Energy Efficiency,” May, pp. 30-39.

UNDP and ESMAP, 1987. “Kenya - Coal Conservation, Energy Conservation, and Substitution Action Plan,” Volume I - A report by consultants, World Bank, May.

UNDP and ESMAP, 1987. “Kenya - Coal Conservation, Energy Conservation, and Substitution Action Plan,” Volume II - Appendices, A report by consultants, World Bank, May.

UNDP and ESMAP, 1994. “Philippines: Energy Conservation Study,” World Bank and Philippines Department of Energy, August.

UNEP, 1994. “Climate Change Studies in Africa,” The Newsletter of the UNEP Collaborating Centre on Energy and Environment, No. 6, December, pp. 16.

U.S. Department of Energy (DOE), 1994. “Technology for a Sustainnable Future,” Energy Efficiency and Renewable Energy Working Group, First Order Draft, October 28, 11 pages.

U. S. Energy Association, 1992. “Getting Down to Business: A Strategy for Energy Efficiency in the United States,” p 13.

U.S. Office of Technology Assessment (US OTA), 1992. “Fueling Development: Energy Technologies for Developing Countries,” OTA-E-516, US Govt. Printing Office, Washington.

U.S. Senate, Committee on Energy and National Resources, 1988. “Greenhouse and Global Climate Change.” US Govt. Printing Office.

Vardi, J., 1977. “Variable Load Pricing in the Face of Loss of Load Probability,” Bell Journal of Economics, vol. 8. pp. 270-288.

Warner, J. L. et al., 1992. “Utility and Economic Benefits of Electrochromic Smart Windows,” Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, June.

Westling, H., 1991. “Technology Procurement for Innovation in Swedish Construction,” Byggforskningsrådet, Stockholm.

Wiel, S., 1994. “The Impacts of Power Sector Restructuring on Building Energy Efficiency: The Roles of IRP and DSM,” ACEEE Summer Study on Energy Efficiency in Buildings, Monterrey, CA, September.

Williams, R., Larson, E., Ross, M., 1987. “Materials, Affluence and Energy,” Annual Review of Energy, vol. 12, pp. 99-144.

Williams, R., Larson, E., Ross, M., 1987. “Materials, Affluence and Energy,” Annual Review of Energy, vol. 12, pp. 99-144.

World Commission on Environment and Development (WCED), 1987. “Our Common Future,” New York, Oxford Press.