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David A. Harpman

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Bureau of Reclamation
Denver Federal Center
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This document describes the interrelationship of hydropower plants with the electricity system, including coal, gas and oil powerplants, emissions, demand side management (DSM) programs and the cost of supplying electricity to meet consumer demand. It also provides documentation for a personal computer based simulation program allowing users to explore the effects of environmental and other restrictions on hydropower plants and the resulting effects on the costs of supplying electricity in an interconnected system, the use of fossil fuels and air emissions. Varying the parameters controlling these plants (fuel costs, etc.) and changing the constraints on the hydropower plants yields detailed information about the physical operation of the system, the costs of meeting demand and the important role of hydropower in the process.

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Exploring the Economic Value of Hydropower in the Interconnected Electricity System

David A. Harpman
Economics Group (86-68270)
Bureau of Reclamation
Technical Service Center
Denver, Colorado 80225

United States Department of the Interior
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ACRONYMS AND ABBREVIATIONS

AF	Acre-feet (of water)
CY	Calender year
kW	Kilowatt
kWh	Kilowatt-hour
kV	Kilovolt
MBTU	Millions of British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NG	Natural gas
USFWS	United States Fish and Wildlife Service
WY	Water year

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PURPOSE AND RATIONALE

The purpose of this interagency effort is to develop a set of quality materials to foster awareness, education and understanding about hydropower and the interconnected electric power system.

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FORWARD

At any given moment, Reclamation is involved in a variety of ongoing environmental studies, water service decisions and legal negotiations, some of which may affect operational flexibility and output at one or more of Reclamation's hydropower facilities. Although they may be intensely involved in the process, members of environmental groups, water users and other stakeholder groups typically have little exposure to hydropower or the interconnected electricity system.

This document is one of the first products of an ongoing interagency effort entitled, *The Economic Value of Hydropower in the Interconnected Electricity System.* The purpose of this effort is to develop a set of instructional materials to help foster awareness, education and understanding about hydropower and the electric power system. This document describes the interconnected electricity system, its components and their operation. It also describes an experiential software program, the ESIM03 model, which allows users to operate a simple interconnected electricity system.

These educational materials were designed for use by Reclamation and client staff, collaborating agency staff and members of the general public with whom we interact. The body of the text is designed for readers with little previous exposure to electric power. More extensive discussions of technical topics are provided in the appendices. We hope this document will provide readers with a better understanding of hydropower and the interconnected electric power system—a prerequisite for balanced and fact-based decision-making.

INTRODUCTION

Electricity cannot be efficiently stored on a large scale using currently available technology. It must be produced as needed. Consequently, when a change in demand occurs—such as when an irrigation pump or central air conditioner is turned on—somewhere in the interconnected power system, the production of electricity must be increased to satisfy this demand.

In 2003, approximately 7 percent (%) of the electricity generated in the United States was produced by hydroelectric powerplants (EIA 2004 page 2). These plants are an invaluable component of the Nation's interconnected electric power system which also consists of fossil fuel, nuclear, solar, wind, and other generation resources. In comparison to other types of generation resources, hydropower plants have exceptionally low costs of operation, are highly reliable, and produce electricity without burning fossil fuels and producing air pollution. In addition, they provide voltage control, system regulation and other ancillary services which help to ensure the reliability and electrical integrity of the system.

Although they play an important role in the electric power system, hydropower plants have some widely recognized environmental effects. Some large hydro facilities have blocked the spawning and migration of anadromous and some native species, eliminated the downstream transport of sediment, fundamentally altered the seasonal hydrograph, affected water chemistry, and changed the downstream temperature regime (Collier, Webb, and Schmidt 1996; Poff et al. 1997; Van Steeter and Pitlick 1998a, 1998b). Furthermore, the operation of these plants, particularly those used to produce peaking power, causes hourly variations in stream flow and elevation, often adversely affecting downstream aquatic and riparian communities (Nilsson, Jansson, and Zinko 1997, Parasiewicz, Schmutz and Moog 1998), and recreation (Welsh and Poe 1998; Bishop et al. 1987; Kearsley, Schmidt, and Warren 1994).

ELECTRICITY TERMS AND UNITS OF MEASURE

When working with electricity, the terms watts, kilowatts and megawatts are commonly encountered. The fundamental unit of electric power measurement is the watt[1]. One watt of electric power flowing continuously for one hour is known as a watt-hour. Residential electricity is typically measured in thousands of watt-hours or kilowatt-hours (kWh). At the bulk generation and transmission level, electricity is generally measured in thousands of kilowatt-hours or megawatt-hours (MWh). Equivalently, one megawatt-hour is also equal to one million watt-hours. Table 1 summarizes these units of measure and their abbreviations.

Table 1. Electricity Units of Measure

Term	Definition	Abbreviation
Watt	Fundamental unit of measure	W
Kilowatt	1000 Watts	kW
Kilowatt-hour	1000 Watt-hours	kWh
Megawatt	1,000,000 Watts	MW
Megawatt-hour	1,000,000 Watt-hours	MWh

The electricity supplied for commercial, industrial and residential use in the United States is of a type known as alternating current (AC). In the United States, Canada and much of Mexico, AC electricity is supplied at 60 Hertz (Hz) or cycles per second. Residential users commonly receive single phase AC electricity at 240/120 volts. Readers with more interest in these details are referred to Appendix 2 which contains a discussion of AC electricity terms and concepts.

[1] The relationship between watts, volts and current is described in Appendix 1.

The electric power industry employs a large number of specialized terms. For convenience, a short glossary containing many of these terms has been provided at the end of this document. Because selected terms such as load, onpeak and offpeak, energy and capacity, are used extensively in this document, a short discussion of these terms is essential to understanding the remainder of the text.

In the language of the utility industry, the demand for electricity is known as "load." Load varies on a second-by-second basis and has characteristic daily, weekly and seasonal patterns. As with other commodities, electric energy is most valuable when it's most in demand—during the day when people are awake and when industry and businesses are operating. This period, when the demand is highest, is called the “onpeak period.” In the West the “onpeak” period is typically defined as the hours from 7:00 a.m. to 11:00 p.m., Monday through Saturday. All other hours are considered to be “offpeak.”

The term “energy” is used to describe generation over a period of time. Energy is typically measured in megawatt-hours (MWh). Another commonly used term is “capacity.” The maximum amount of electricity which can be produced by a powerplant or transmitted by power lines is called capacity. Capacity is typically measured in megawatts (MW). The capacity of most powerplants is determined by their design, size, location and the ambient temperature. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, environmental and other constraints, the amount of water available for release and the design of the facility. Because the capacity at hydropower plants is highly variable, the amount of dependable or marketable capacity is of particular significance.

NERC AND THE WECC REGION

The North American Electric Reliability Council (NERC) was formed following the 1965 Northeast blackout as a voluntary industry organization to promote the reliability and adequacy of the bulk power system. NERC’s members are the eight Regional Reliability Councils whose members are drawn from all segments of the electricity industry. The Western United States and parts of Canada and Mexico (Baja Norte) form the Western Electricity Coordinating Council (WECC) which is one of the North American Electric Reliability Council (NERC) regions. A map of these regions can be found at: http://www.nerc.com/regional/ . The geographic boundaries of these regions were based primarily on their marketing inter-relationships and the degree to which transmission lines allowed for the interchange of energy.

The Energy Policy Act of 2005 authorized the creation of a self-regulatory electric reliability organization (ERO) that spans North America. The Federal Energy Regulatory Commission (FERC) provides oversight within the United States. The Energy Policy Act makes compliance with NERC and regional reliability standards mandatory and enforceable.

COMPONENTS OF THE ELECTRIC POWER SYSTEM

The interconnected electricity system is made up of three components. These three components are the generation resources[2], the transmission and distribution system, and the loads. Operating jointly and simultaneously, these three components comprise the electric power system and their interdependencies are responsible for the nature of its operation.

Generation Resources

Electricity needs in the United States are met by a variety of different kinds of powerplants. In general, these powerplants can be classified into two broad groups; thermal and non-thermal plants as illustrated in Figure 1. A thermal power plant is a power-generating plant which uses heat to produce energy. Such plants may burn fossil fuels, use solar concentrators, harness a naturally occurring heat source or use nuclear energy to produce the necessary thermal energy. In contrast, non-thermal powerplants harness the energy from wind, water, solar radiation, wave action or other sources to generate electricity.

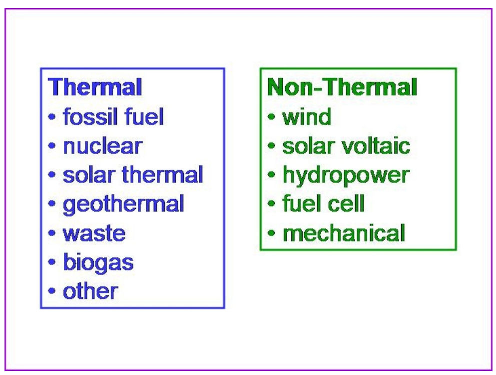

Figure 1. Powerplants can be broadly classified into thermal and non-thermal plant types.

As illustrated in Figure 2, in the United States, the predominant generation source is coal fired thermal powerplants which, on an average basis, provide approximately 49 % of the electricity generated. Nuclear powerplants are the second-most important generation resource, providing approximately 20 % of the nation's electricity needs. Natural gas combined cycle combustion turbine (NGCCCT) and natural gas combustion turbine (NGCT) plants together provide another

[2] Generation resources (powerplants) are sometimes referred to as supply side resources.

17 % of the country's electricity. Hydropower plants produce about 7 %. The remainder of the electricity is produced by oil-fired and renewable resource generation resources such as wind, solar and geothermal plants.

The generation resources in the interconnected system are large and sometimes prominent features of the landscape. Even so, many electricity users have had little personal contact with them and the majority of the public has only a limited understanding of how they work. Appendices 4 through 8 provide short descriptions of selected types of powerplants and diagrams illustrating their major features. The electricity production at the thermal plants is determined by the type of fuel they use, the energy (heat) content of those fuels and the plant's ability to convert those fuels into electricity (referred to in the industry as the "heat rate"). Appendix 9 contains a short overview of selected fuel types and their energy content.

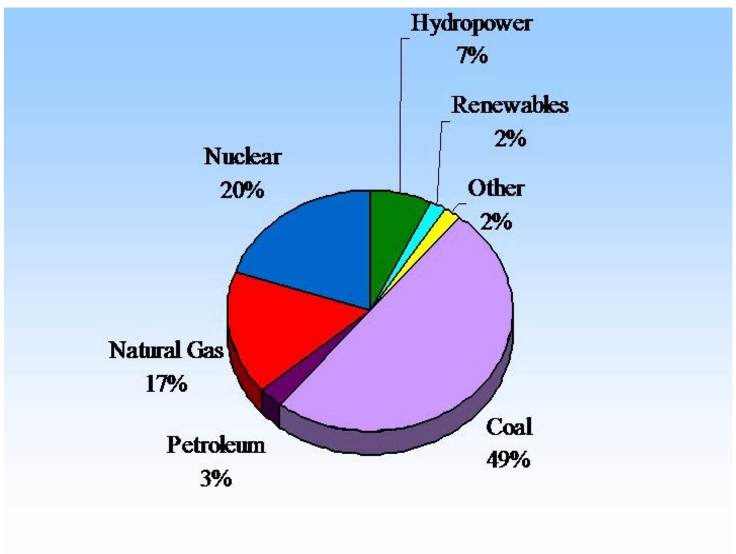

Figure 2. U.S. generation in 2003 by source (EIA 2004 page 2).

Transmission and Distribution System

The transmission and distribution system is a vast and complex system which allows the delivery of electric energy produced by the generators, across long distances to the ultimate points of final demand. The *transmission system* is comprised of a large network of high voltage power lines, relays, capacitors, circuit breakers, switches, transformers, reactors and monitoring equipment. Its purpose is to convey high voltage electricity efficiently from one location to another location.

The *distribution system* consists of low(er) voltage power lines (typically 69 kV or less), transformers, circuit breakers, switches and monitoring equipment. The purpose of the distribution system is to connect to bulk high voltage delivery points, reduce the electricity to a lower voltage for final use, and convey that low(er) voltage electricity to the final consumer. Elements of the electricity distribution system are ubiquitous in our daily lives. The relatively cheap reliable electricity service we take for granted in the United States depends on the often overlooked sub-stations, switch yards and transformer banks which are all around us. A superb description of the power grid including electricity transmission and distribution systems and their components can be found on the "How Stuff Works" website (http://travel.howstuffworks.com/power.htm).

Load

The (aggregate) demand for electricity or load is made up of three primary components: commercial, residential and industrial load. On a national basis, commercial and residential loads each comprise about 33% of the load. Industrial uses comprise about 28% of the total use and the balance is made up by various miscellaneous uses such as transportation (EIA 2004 p. 4).

Load is shaped by human activities and human interactions with natural forces, predominantly the weather. As noted previously, load varies on a second-by-second basis but has predictable daily, weekly and seasonal patterns.

Daily Load Pattern. Figure 3 illustrates the characteristic hourly pattern of load for typical weekdays in the summer and the winter. The vertical (purple) lines in the figure demarcate the onpeak period of the day (0700 to 2300 hours). In the summer, the hourly pattern of load is significantly influenced by air conditioning needs. In the very early morning (0100 hours), the temperature is relatively low, many people are sleeping and there is little business or industrial activity. Around 0500 hours, load begins to rise as residents begin their daily activities, the temperature starts to increase, and commercial and industrial entities commence operations. As the temperature rises, the use of electricity by air conditioning units increase. By late afternoon (1700 hours), temperatures have increased markedly, personal, business and commercial activities are at their height, and electricity use reaches its maximum. In the evening, people return home, businesses and industries close for the day and the temperatures begin to fall. By around 2000 hours, falling temperatures and reduced human activities result in a drastic decline in the demand for electricity.

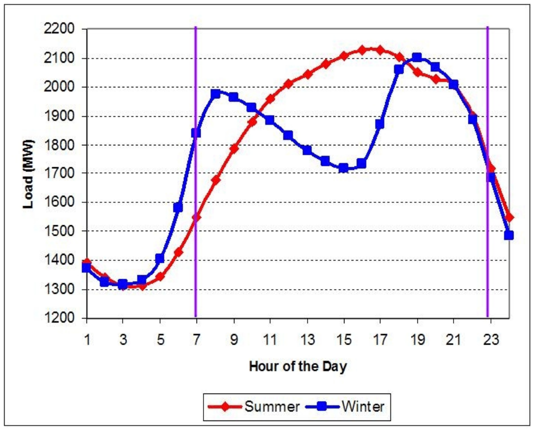

Figure 3. Hourly load pattern for summer and winter weekdays.

In the winter, the hourly pattern of load is shaped by heating requirements. In the very early morning (0100 hours), many people are sleeping and there is little business or industrial activity. Around 0500 hours, load begins to rise as residents begin their daily activities by turning up the heat, making coffee and cooking breakfast. Load rises to an initial peak during this time. When they leave for work, they turn down or turn off the heat in their residences. Temperatures rise to their maximums during the middle of the day, decreasing the use of electricity for heating purposes. Load declines from the initial peak. In the late afternoon and early evening, the temperatures begin to fall, people return home from work, turn up the heat and start cooking dinner. Their aggregate activities cause the load to rise again resulting in a second peak, which is characteristic of the winter season. By around 2000 hours, people begin to reduce their activities and turn down the heat in their homes. As a result, there is again a marked decline in load.

Weekly Load Pattern. The pattern of human activities during the week results in a characteristic load pattern at that time-scale. Hourly load during a typical summer week is illustrated in Figure 4. As shown in this figure, peak use and the pattern of use are very similar Monday through Friday. The load on a Saturday is often, but not always, less than the load on a typical weekday. As illustrated in Figure 4, there is typically less human activity on Sunday than there is during the other days of the week. As a result, Sunday peak load is lower and all Sunday hours are typically considered to be "off-peak." Additional weekly load patterns for typical weeks during the fall, winter and spring seasons can be found in Appendix 3.

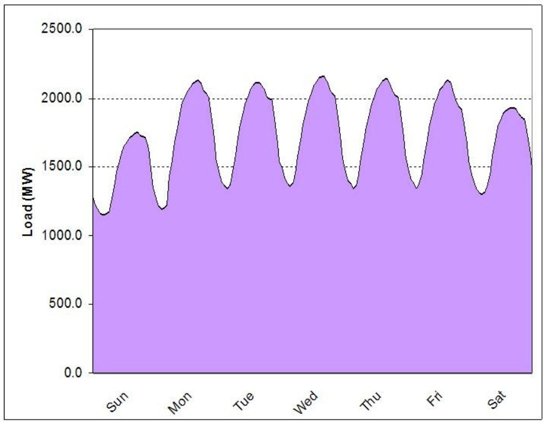

Figure 4. Representative hourly load for a week in the summer; Sunday through Saturday.

Seasonal Load Pattern. There is also a characteristic pattern of load across the seasons of the year. The seasonal load pattern for the WECC region of the United States is illustrated in Figure 5. As shown, the maximum load typically occurs in the summer months due to air conditioning requirements. Load is also high in the winter months in response to heating needs. Load in the spring and fall is typically less than in the winter and summer. Collectively, the spring and fall months are sometimes referred to as "shoulder months" and the winter and summer months as the "peak months."

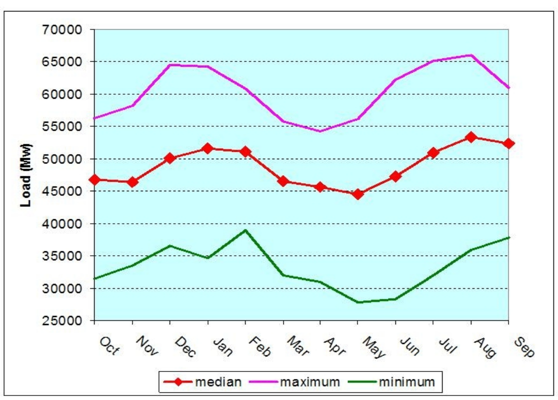

Figure 5. Seasonal load pattern in the Western (WECC) Region of the United States.

Implications for Power System. The large variation in load has an important implication for the electrical generation system. In particular, it greatly influences the amount of generation capacity required and, therefore, the capital cost of the system. This can be readily illustrated by two extreme cases. First, assume the demand for electricity is constant and is 1.0 MW at all times. This would imply (ignoring security and reliability concerns) that a utility could supply this demand by building a 1.0-MW powerplant and operating it continuously. For a month (30 days), this would imply generation of 1.0 MW for 720 hours (hr) which would generate 720 MWh of electricity. Now assume the demand for electricity is more variable. Assume it is 1 MW for 1 hour of the month and 0.5 MW for the rest of the hours in the month. In this case, the costs of constructing a 1-MW powerplant must also be incurred, but the plant generates only 360.5 MWh of energy (1 MW*1 hr + 0.5 MW*719 hrs), approximately 50% of its potential output. The highly variable nature of the demand for electricity results in the following observable characteristics of the electrical power system: (1) some powerplants are idle for part, or all, of the day or season, and, (2) the capital costs of electricity production are typically a significant proportion of the total costs.

OPERATIONAL TERMS

This section of the document introduces several terms and concepts which are central to understanding the nature, behavior and operation of the interconnected power system.

Baseload Power

A commonly encountered term related to load is "baseload." The baseload is the minimum load component which must be met on a continuous basis. In Figure 4, the baseload component is the area below the lowest level of demand or about 1200 MW. Described another way, at least 1200 MW must be supplied at all times to satisfy demand. The baseload component of total load is frequently met by certain types of powerplants such as coal and nuclear plants which can operate continuously and efficiently at high output levels. These plants are often referred to as baseload powerplants or baseload generating resources.

Load Following

As described earlier, the demand for electricity changes rapidly across time potentially causing imbalances between the demand for electricity (load) and the supply. Powerplants which are able to rapidly respond to load changes can be used to correct these imbalances. This process is called "load following."

INTRODUCTION TO POWERPLANT COSTS

The cost of constructing and operating different types of powerplants is of considerable interest to investors and to individuals in many disciplines including engineers, planners, economists, system managers, regulators and others. Powerplant costs are a potentially confusing topic and there are a number of specialized terms associated with this subject.

Powerplant costs can be broadly classified into two categories: investment costs and operation costs. Equivalently, economists employ the terms fixed costs and variable costs. The fixed costs of a powerplant are those expenditures which would need to be incurred whether or not the powerplant was ever used to generate electricity. Fixed costs include both the initial investment required to construct a powerplant and the fixed operation and maintenance (O&M) costs. Fixed O&M costs include all expenditures necessary to maintain the powerplant for use and to keep it ready for operation. Labor is an example of a fixed O&M cost. The variable or operation costs of a powerplant are those costs which change in relation to the generation level of the powerplant. Fuel costs are obviously a variable cost since more fuel is required at higher output levels. Operation or variable O&M costs also vary with output level and include expenditures for such things as cooling system operations and lubrication.

The electric power industry employs a slightly different nomenclature to describe costs. The industry uses the terms "capacity cost" and "energy cost." This industry cost nomenclature is related to the cost terms previously introduced, as shown in Text Box 1. The capacity cost is the investment and fixed O&M cost prorated over the life of the plant on the basis of installed capacity. The energy cost is the fuel and variable O&M cost prorated over the amount of energy produced by the plant.

I. Capacity Cost ($/KW)
   a. plant investment cost
   b. fixed O&M

II. Energy Cost ($/MWh)
   a. variable O&M
   b. fuel cost

Text Box 1. Power industry cost terms and their classification.

Fixed or capacity costs are primarily of importance in planning and long-run decision-making. In contrast, the variable or energy costs of a powerplant are pertinent to decisions about whether to operate the powerplant and when to operate it. This decision is often called the "dispatch decision" in the electric power industry. Appendix 10 contains a further discussion of fixed and variable costs along with a comparison of representative costs for different types of generation resources.

POWERPLANT OPERATION COSTS

The focus of this section of the document is on powerplant operation costs. For existing in-service powerplants, operation costs are relevant to decisions about when to use the plant to generate electricity. The costs of operating a powerplant consist of the variable operation and maintenance (O&M) costs and the fuel costs. Operation costs differ by plant type, design, altitude, ambient temperature and fuel quality. Although there are many factors which influence the costs of operation, there are relatively clear-cut differences between different types of generators which influence their number, size, use and role in the electric power system.

Table 2. Representative Plant Operation Costs (2003$)

Plant Type	Variable O&M ($/MWh)	Avg. Fuel Cost ($/MWh)
Coal	4.09	10.59[3]
NGCT	2.80	49.04[3]
NGCCCT	1.77	40.25[3]
Nuclear	0.44	4.53[4]
Hydropower	4.80	none

Source: Unless otherwise specified, all data are from EIA (2005a) Table 38 p. 67. Coal refers to "scrubbed" coal plants; NGCT, NGCCCT and Nuclear refer to "advanced" plant types, and hydropower refers to "conventional" hydropower plants.

[3] Calculated (4/13/2005) using the fuel heat content assumptions and heat rate curves in the ESIM03 model. See filename=calc_avg_fuelcost.xls for fuel costs per unit and other details.

[4] Calculated from EIA (2005a) Table 38 and EIA (2005b) Figure 72 data (2004 price used).

Table 2 illustrates the operation costs for selected generation resources. As shown in this table, hydropower plants have the lowest operation costs followed by nuclear and coal plants. Operation costs are much higher for natural gas combustion turbine (NGCT) and natural gas combined cycle combustion turbine (NGCCCT) plants. The subset of plants which can be used for supplying peaking power are found in the shaded (yellow) rows of the table. Hydropower plants have the lowest operation cost for this subset of plants. Appendix 10 contains a more extensive exposition on the capital and operation costs of generators.

ENGINEERING CHARACTERISTICS OF GENERATORS

The different types and designs of powerplants have distinct operational modes and abilities. These are referred to as, "engineering characteristics" (Graves and Murphy 1997). The engineering characteristics of powerplants help to determine their physical siting (location) requirements and the role they play in the interconnected electricity system. Some knowledge about powerplant characteristics and their operational limitations is a useful first-step in towards understanding the coordinated operation of the electricity system. Table 3 presents a summary of the engineering characteristics for selected generation technologies.

Responsiveness

For purposes of this document, the ability of a powerplant to change output level is termed its responsiveness. The responsiveness of different types of powerplants is shaped by the design, vintage, technology and nature of the plant. The shaded (yellow) portions of Table 3 highlight powerplants which have rapid response capabilities . Of these, natural gas combustion turbines (NGCT), natural gas combined cycle combustion turbine (NGCCCT) and hydropower plants are very responsive. This subset of plants can be used to provide generation when the load is rapidly changing (load following) and during onpeak periods. Because they can be quickly started and are very responsive, they are also used to provide reserve generation in case of an unforeseen outage in another powerplant or transmission line. The other types of powerplants in the table, such as coal and nuclear plants, cannot change their output levels very rapidly and are primarily used to provide baseload power.

Table 3. Engineering Characteristics of Selected Generators

Plant Type	Responsiveness[5]	Availability[6]
Coal	Relatively fast for small output changes (e.g. 10% in 10 minutes), significantly longer for larger changes, hours from 0 to 100% output	87.35%
NGCT	Fast: 0 to 100% output in 2 to 3 minutes.	93.76%
NGCCCT	CT cycle: Fast: 0 to 100% output in 2 to 3 minutes. Steam cycle: relatively fast for small changes (10% in 10 minutes), longer for larger changes, hours from 0 to 100% output.	89.95%
Nuclear	Safety and operational concerns dictate very slow changes in output	87.10%
Hydropower	Very fast: 0 to 100% output in 90 seconds (spinning) to 2-3 minutes (not spinning)	88.64%

Availability

Powerplants are large, complex mechanical devices. They require routine or scheduled maintenance on a periodic basis. They are also subject to unscheduled outages, termed "forced outages." As a consequence, powerplants cannot be counted on to operate 100 % of the time. The last column of Table 3 provides some comparable availabilities for different generation technologies. As shown in Table 3, hydropower plants, which have fewer mechanical systems to fail, are the relatively reliable. Nuclear powerplants, which have the most complex mechanical systems, are somewhat less reliable.

[5] Constructed from Graves and Murphy (1997) and professional judgement.
[6] North American Electricity Reliability Council (2005).

COORDINATED SYSTEM POWERPLANT OPERATIONS

As shown in Tables 2 and 3, as well as Appendix 10, powerplants have varying engineering capabilities and differing operational costs. One consequence of this is they are used for different purposes and play different roles within the interconnected power system. Looking only at the operation costs in Table 3, it might be imagined that hydropower, coal and nuclear power plants would be used to provide all of the electricity used in the country. Hydropower plants don't provide a larger share of our electricity needs because there are a very limited number of sites suitable for the construction of new hydropower plants. Further, the amount of water available at those sites for power generation is limited. Coal plants do provide nearly 50% of our electricity needs. Although they are very efficient producers of baseload energy, their engineering characteristics, primarily low responsiveness, precludes using them for supplying peaking power, load following and generation reserves. The same is true for nuclear powerplants. Although they are relatively inexpensive to operate, they have very limited ability to change output levels.

Due to their varying capabilities and costs, a mix of different powerplants is required to ensure the demand for electricity is met on a reliable basis. Each type of plant in the interconnected electricity system is operated somewhat differently to exploit its engineering capabilities and, at the same time, to minimize the costs of meeting load. When expressed in mathematical terms, the optimal operation of the hydropower plants and thermal plants in a system is called the "optimal hydro-thermal dispatch" problem. The solution to this mathematical problem is the least-cost method of operating the interconnected system. The process of solving the optimal hydro-thermal dispatch problem yields information about two important auxiliary variables. These two auxiliary variables are gamma (γ), the marginal value of water used for hydropower generation, and lambda (λ), the marginal cost of operating the thermal system. Appendix 13 contains a description of the optimal hydro-thermal dispatch problem.

Figure 6 illustrates the economic dispatch of a simple interconnected system consisting of a hydropower plant, an oil-fired steam plant, a coal plant, a NGCT and an NGCCCT plant during a typical summer week. As shown in the figure, the coal plant is operated to produce baseload power. It operates continuously during all hours of the week at a level of output at, or near, its capacity. If there were a nuclear plant in this system, it would be operated in a similar fashion. The NGCCCT plant is not only an efficient producer of baseload energy but is also capable of rapid changes in output. The NGCCCT plant operates continuously during the week. It produces baseload power but also increases its output significantly during the onpeak hours. The NGCT plant is relatively expensive to operate but is highly responsive. This plant is used primarily to produce power during the onpeak periods of the day. During the offpeak periods, it is kept in reserve in case one of the other powerplants experiences a forced outage, there is transmission line failure, or another component in the interconnected system fails. The oil-fired steam plant is the most expensive of the fossil fuel plants to operate. It is operated sparingly during the onpeak hours. The oil-fired steam plant is also operated at a very low level during other hours of the day as a reserve or backup so it can increase its output quickly in the event of an outage at another powerplant or failure of a transmission line.

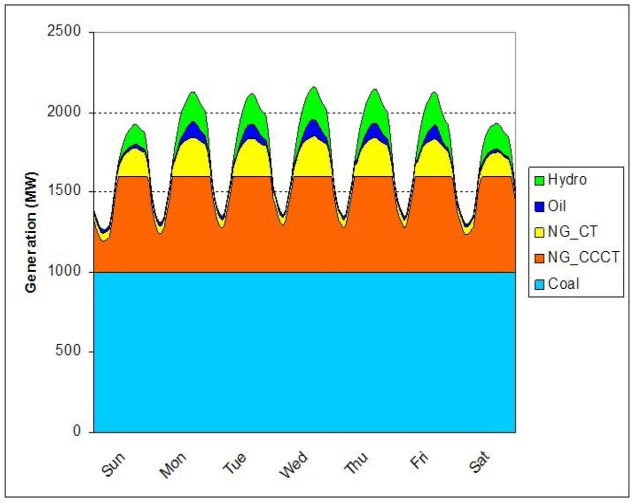

Figure 6. Coordinated power system operations for a representative week. Source: ESIM03 model output.

Although least expensive of all of the plants to operate, the hydropower plant has a limited water supply. In order to minimize the total cost of operating the interconnected system, and in the absence of environmental, water delivery or other operational considerations associated with the dam and reservoir, the hydropower plant is operated primarily during the onpeak hours when it generates to its full capability. If additional water were available, the hydropower plant would initially be used to generate additional energy during the onpeak hours and, if the supply of water were large enough, to generate more electricity during the offpeak hours as well.

EMISSIONS

Fossil fuel plants emit varying amounts of different compounds into the atmosphere when they are operating. Of particular concern are their emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x) and mercury (Hg). Some of these emissions, such as Hg, are produced in trace amounts and some, particularly the products of the combustion process like carbon dioxide (CO_2), are produced in significant volumes. The quantity of these compounds released by powerplants varies depending on the design of the plant, its location, the type and quality of the fuel used, the generation level, the plant's efficiency, the ambient conditions and the control technologies installed at the plant.

The effects of these emissions on human health and the environment have been amply documented. In the United States, significant reductions in emissions have been achieved through regulatory and incentive programs. Even so, there is continuing concern about the deleterious effects of air emissions. Federal, state and local entities continue to be at the forefront of new and more effective approaches for curtailing powerplant emissions.

The hourly dispatch of powerplants in the interconnected electricity system can and does effect aggregate emissions. The nature of selected pollutants, their relationship to powerplants, and their hourly operations are discussed in further detail in Appendix 11. Table 4 provides a representative summary of emissions per megawatt-hour from different types of powerplants.

Table 4. Representative Emission Output Rates by Generator Type

Plant Type	Carbon Dioxide CO_2 (lbs/MWh)	Sulphur Dioxide SO_2 (lbs/MWh)	Nitrous Oxides NO_x (lbs/MWh)	Mercury Hg (lbs/MWh)
Coal	2,474.40	0.86	3.56	1.78e-05
NGCT	2,377.40	0.53	8.07	na
NGCCCT	999.21	0.01	0.30	na
Oil Fired Steam	2,748.81	8.37	3.57	na
Hydropower	0.00	0.00	0.00	0.00
Nuclear	0.00	0.00	0.00	0.00
Source: Representative plants selected from the eGrid database (EPA 2003).				

As shown in Table 4, coal, oil and natural gas powerplants produce significant quantities of CO_2, one of several gasses known to contribute to the greenhouse effect. In general, NGCCCT plants produce less CO_2 per MWh of electricity produced than do NGCT plants. This is primarily due to their greater efficiency (higher heat rate). Residual fuel oil has a higher sulfur content than coal and natural gas. Consequently, oil fired powerplants are a significant emitter of SO_2. The high relative cost of fuel oil along with their relatively high SO_2 emission have made oil-fired plants a less attractive generation resource. NO_x is formed during high temperature combustion processes. On the basis of their output levels, NGCT plants emit far greater amounts of NO_x than most other types of fossil fuel plants. This reflects the high combustion temperatures inherent in combustion turbines used as a peaking resource. Although there is mercury in all fossil fuels, the highest concentrations occur in coal and only trace amounts are found in natural gas and oil. Data for Hg emissions are available only for coal plants at the present time.

ECONOMIC VALUE OF ELECTRIC POWER

Demand

The value of electricity is determined by the forces of supply and demand in the same manner as other commodities. Elasticity is a term used by economists to measure the responsiveness of demand to price changes. Economic studies have found the demand for electricity is quite inelastic. Translating this into common terms, at a particular instant in time the demand for electricity does not change very much when the price of electricity changes. As a result, the demand for electricity at a particular time is sometimes viewed as fixed or given (the demand function has a very steep slope). Figure 7 illustrates the demand for electricity at a particular point in time. Appendix 12 provides an overview of economic demand theory, the concept of elasticity, and documents elasticity of demand estimates obtained in a number of empirical studies.

Supply

Economists and engineers are often interested in the "marginal" or incremental cost of operating the interconnected power system. The marginal cost of operation is the cost of generating the next increment of electricity. For purposes of this document, it is convenient to think of the term marginal as referring to a 1-MW change in generation.

A supply function traces out the marginal cost of providing electricity for various levels of output. The marginal cost of generation depends on the mix of plants which are in service or on-line, their engineering characteristics, and their operation costs. For a given interconnected system, a supply function can be constructed by repeatedly solving the optimal hydro-thermal dispatch problem. Because different generation technologies have different upper and lower output limits, engineering characteristics, fuels and output efficiencies, the resulting marginal cost schedule is often discontinuous. An example supply function for the simple interconnected system characterized by the ESIM03 model is shown in Figure 7. The supply function in this figure has four distinct segments. These correspond to each of the fossil-fuel plants in the system. The first segment, up to an output level of 1,200 MW, results from operation of the coal-fired plant. The second segment, from 1,200 to 1,700 MW, results from the operation of the NGCCCT plant. The third and forth segments reflect the operation of the NGCT and oil-fired plants respectively.

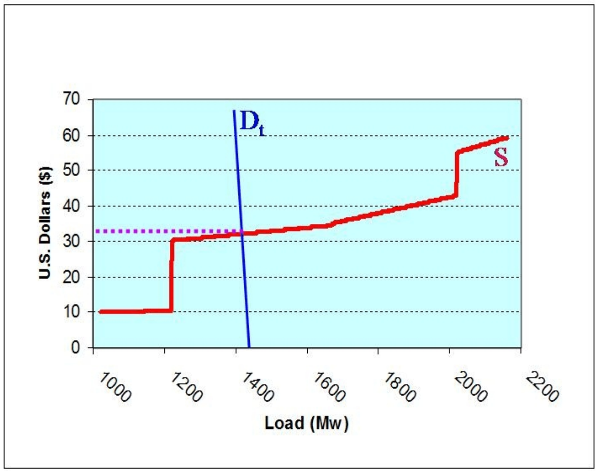

Figure 7. Demand and supply for electricity. The marginal cost where the curves intersect is system lambda (λ).

System Lambda (λ)

The intersection of the demand and supply functions, illustrated in Figure 7, yields the economic value of electricity for that particular instant in time. The corresponding marginal cost is described by a specialized term. In the electric power industry, it is known as system lambda (λ). The term "system lambda (λ)" originates from the mathematical specification of the optimal hydro-thermal dispatch problem. As explained previously, lambda is an auxiliary variable in that problem (see Appendix 13). System lambda is interpreted as the marginal cost of operating a given interconnected system at a particular location and point in time. The use of this term implies a specific load, mix of on-line plants and fuel costs. The magnitude of system lambda, for a specific point in time, indicates how much it would cost to generate an additional unit of electricity or how much would be saved if one less unit of electricity was generated.

System lambda (λ) is not only a mathematical and conceptual measure of marginal cost—it is also a real-world measure. The Federal Energy Regulatory Commission (FERC) requires hourly system lambda to be reported by the area control operator of each electricity system with a peak load greater than 200 MW. Examples of system lambda can be found in the data reported by these utilities as part of their FERC Form 714 filings.

ECONOMIC VALUE OF HYDROPOWER

The marginal cost of operating a thermal system is relatively easily established. The economic value of (very) small changes in the output of the thermal component of the system is system lambda. For non-thermal plants, such as solar, wind and hydropower plants, the marginal costs of operation are very low, since there are no fuel costs. The value of operating these plants in the interconnected system is given by the system-wide cost savings which result. This is called "avoided cost."

The economic value of operating an existing hydropower plant is measured by the avoided cost of doing so. The avoided cost is the savings realized by supplying electricity from a low-cost hydropower source rather than a higher-cost thermal source. These savings arise, in part, because the cost of operating a hydropower plant is relatively low in comparison to thermal units. Referring back to Table 2, the variable cost of operating a typical hydropower plant in 2003 was $4.80 per MWh. In contrast, the variable cost of operating a typical coal plant was $14.59 per MWh, and the variable cost of operating a typical natural gas turbine unit was approximately $51.84 per MWh.

The economic value of operating an existing hydropower plant varies considerably with time of day. The variable cost of meeting demand varies on a second by second basis depending on the load, the mix of plants being operated to meet load, and their output levels. As discussed previously, during offpeak periods, demand is typically satisfied with lower-cost coal and nuclear units. During onpeak periods, the additional load is met with more expensive sources such as natural gas turbine units. Consequently, the economic value of hydropower is greatest during the hours when the demand for electricity, and the variable cost of meeting demand, is the highest.

If the marginal cost of purchasing an additional megawatt-hour of electricity from a least cost source were observable in the market, the economic value of producing hydroelectricity could be readily determined. For example, assume that the cost of purchasing a megawatt-hour of electricity, from the least cost source was $30.00 in a particular hour, and the cost of producing a megawatt of hydroelectricity was $6.00. Then, the avoided cost or economic value of producing an additional megawatt-hour of hydropower at that time would be ($30.00-$6.00) or $24.00.

VALUE OF WATER USED FOR PRODUCING HYDROPOWER

In a very real sense, water is the "fuel" used by a hydropower plant to produce electricity. Establishing the marginal value of water used in hydropower production is a relatively complicated undertaking.

The marginal value of water in the production of hydropower is represented by the Greek letter gamma (γ) in the widely used text by Wood and Wollenberg (1996) and also used in this document. Like system lambda (λ), which we have encountered previously, gamma (γ) is one of the auxiliary variables in the optimal hydro-thermal dispatch problem. The specification of this problem and the role of gamma in its solution are described in Appendix 13. The marginal value of water is determined by the increment in generation produced by an additional unit of water and the marginal value of that generation (λ). Since the marginal value of the generation produced (λ) is time specific, gamma is also a time specific measure.

The marginal value of water can be positive, negative or zero. All other factors the same, the marginal value of water (γ) is higher during onpeak hours and lower during offpeak periods. Gamma is typically higher at low levels of release and declines as releases increase (again recall that gamma is a marginal value). The marginal value of water declines to zero at powerplant capacity. Gamma becomes negative as total releases increase beyond turbine capacity. This occurs because the elevation of the tailwater increases, causing head and generation to fall. Appendix 14 provides further technical details as well as a discussion of gamma (γ) and how it is determined.

DEMAND SIDE MANAGEMENT (DSM)

Demand side management (DSM) is a term used to describe programs designed to conserve electricity. As we have seen, load varies instant-by-instant and is considerably higher during the onpeak hours of the day. The cost of providing for load during the onpeak hours is higher than it is at other times because more expensive generation resources, such as NGCT and NGCCCT plants must be operated. To the extent that electricity can be conserved and the peak demand reduced, cost savings can result.

DSM programs span a large range, from those programs which focus on the direct conservation of energy, to those which provide incentives to conserve. Appendix 15 provides a further explanation of DSM and three common DSM measures. These are conservation, interruptible supply and onpeak pricing. In general DSM programs affect the hourly demand for electricity. Operationally, either the demand is reduced, or the load is spread more evenly across the day. These reductions in load can reduce the amount of electricity which must be provided, decrease the need to operate the most expensive generation resources, and may postpone the need to construct new and replacement powerplants in the system.

HYDROLOGY BASICS

The amount and timing of inflows can have a substantial effect on the operation of a hydropower facility. Reservoirs are filled by waters which flow into them. In aggregate, these are referred to as “inflows.” Inflows are often, but not always, derived from water flowing down streams and rivers which empty into the reservoir. To the extent that inflows arise from natural or uncontrolled watersheds, their magnitude and timing is uncertain.

The amount of water stored in a reservoir is not a static quantity. In addition to variable inflows, stored water may be diminished by evaporation or increased by precipitation falling on the surface of the reservoir. Evaporation can be a significant source of storage loss particularly when the reservoir surface area is large and there are long periods of wind and high temperatures. Precipitation can add significantly to storage in locations where the surface area of the reservoir is large and precipitation in the form of rainfall or snowfall is high. The volume of water contained in a reservoir can also be affected by bank storage. Bank storage is the net water movement into or out of the banks of the reservoir. Bank storage can be operationally significant depending on the nature of the soils and the geology of the site.

The total release from a hydropower reservoir is made up of two components; releases from the turbines (turbine release) and bypasses, also known as spills. Turbine releases rotate the blades of the turbines, turn the generators and produce electricity. Spills are made from outlet works such as spillways, overflow valves, jet-tubes, etc. These releases bypass the turbines and *do not* produce any electricity. From the hydropower production standpoint, spills are considered undesirable and wasteful since they represent water that passes through the dam without producing hydropower. Appendix 16 contains a further discussion of these basic hydrology concepts and their mathematical underpinnings.

RESERVOIR BASICS

Operation of a reservoir and hydropower plant is a complex endeavor. A given storage reservoir has a finite maximum storage volume which must be considered in the decision process. Although there are exceptions of course, typically, storage reservoirs are relatively small in proportion to the annual water yield from the watershed where they are located. In many circumstances, there is little or no year-to-year carryover storage. The volume of water stored in the reservoir at any given point in time can be measured and is known to the operator. The amount and timing of future inflow and the nature of future conditions in the electric power markets are uncertain.

A typical storage reservoir has a "live" pool and a "dead" pool. The dead pool is that portion of the reservoir below the elevation of the outlet works. The volume of water stored in the dead pool cannot be evacuated from the reservoir. The live pool is that portion of a reservoir's storage capacity above the elevation of the outlet works.

The amount of "active" storage at a particular reservoir depends on the topography of the site and the design of the plant. Generally, active storage is defined as the volume of water which can be retained in the reservoir and then released through the generators and/or outlet structures *under normal circumstances*. Typically, but not always, the lower elevation limit of the active storage pool is dependent on the elevation of the penstocks plus the minimum required level of penstock submergence. Some level of minimum penstock submergence is necessary to avoid entrainment of air in the turbines and consequent equipment damage. The upper limit of the active storage pool is often the level of the dam crest minus some amount of freeboard space. "Inactive" storage is that part of the reservoir pool which is not released from the reservoir *under normal circumstances.* Depending on the particulars of the facility and the site, inactive storage can be a substantial portion of total storage. The active and inactive storage pools for a hypothetical reservoir are illustrated in Figure 8.

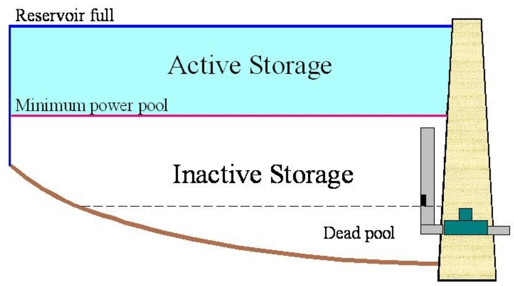

Figure 8. Active and inactive storage in a typical reservoir.

Reservoirs are often designed and constructed for multiple purposes including flood control, recreation, agricultural water storage, municipal and industrial (M&I) use, fish and wildlife enhancement purposes, hydropower generation and a variety of other reasons. Reservoir operation is an intricate balancing of these different and often conflicting water uses. From the hydropower perspective, the problem is how much water to release from storage in a given period to produce hydropower, while simultaneously meeting these other purposes, and how much water to retain in storage until later. If the manager releases too much water now, and it is not replenished by inflow, the reservoir elevation is reduced and there is less water available for generation and other uses later. If the manager releases too little water now, and there is a substantial amount of inflow, the reservoir may be unable to contain the inflow and a "spill" will result[7].

To reiterate, water that is spilled or bypasses the turbines does not produce any hydropower. To the extent these spills can be prevented, they represent hydropower that could be generated at some future time, but isn't. In addition, spilled water is unavailable for future release and use by all other reservoir purposes. Consequently, reservoir managers will go to great lengths to avoid unnecessary spills. When large inflows are anticipated, additional turbine releases may be made to partially evacuate the reservoir and create additional storage space. These measures can prevent or minimize unnecessary spills.

In drought periods or periods when low inflows are anticipated, operators of hydropower plants may choose to curtail releases as long as higher priority purposes are not adversely affected. A reduction in near-term releases preserves water in storage for generation and other purposes later and maintains a higher reservoir elevation.

[7] Releases which go over the spillway are often referred to as "uncontrolled spills." Releases made through structures over which there is management control are referred to as "controlled spills."

To the extent possible, the operation of hydropower plants reflects current and expected electricity market conditions. When high demand periods (like peak months) are anticipated, prices are generally higher and it is advantageous to release more water and generate more hydropower. During periods of reduced electricity demand (for example during shoulder months), the value of electricity is relatively lower and it is less desirable to use limited water resources for the production of hydropower. Insofar as the pattern of inflows and the storage capability of the reservoir allows, and it is consistent with other reservoir purposes, the pattern of releases (and generation) at a hydropower plant tends to follow anticipated conditions in the electricity market.

RELEASE, HEAD AND GENERATION

At a hydropower plant, electricity is produced by the force of falling water. A schematic drawing of a hydropower plant and a typical generator are provided in Appendix 8. As described and illustrated in considerable detail in that appendix, water falls through the penstocks into the turbines. The force of the water against the blades of the turbine rotates a large shaft. This shaft turns the rotor within the generator and produces electricity.

The amount of electricity produced depends on the amount of water released and the vertical distance the water falls. This vertical distance is called “head.” The head at any point in time is measured by the difference between the water surface elevation of the reservoir and the elevation of the tailwater below the dam. For any given instant in time, the elevation of the reservoir is fixed and known. The elevation of the tailwater increases as the total amount of water released is increased. As illustrated in Figure 9, the higher the reservoir elevation, the greater the head and generation. For any given release, lower reservoir elevations result in lower levels of head and lower generation levels. The mathematical relationship between the release, head and generation is described in Appendix 17.

Due to engineering constraints inherent in the design of the turbines, generators, and other equipment, the maximum power generation capability or capacity is limited. As releases increase, the amount of electricity generated increases. When the maximum generation capability is reached, further releases cause an increase in the tailwater elevation without any addition to generation. As illustrated in Figure 9, releases beyond the maximum release capability of the turbines generally cause a decline in generation. This concept and the mathematics which underlies it are illustrated further in Appendix 17.

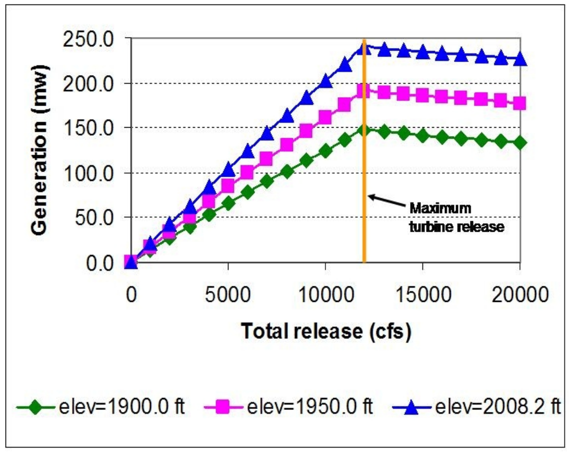

Figure 9. Hydropower generation is greater when reservoir elevations are higher. Releases above powerplant capacity (12,000 cfs in this case) cause a decline in head and generation.

STRATEGY FOR HOURLY OPERATION OF HYDROPOWER PLANTS

Typically, the storage water available for hydropower generation is limited. For a given period of time, the problem facing the owner of the hydropower plant is when to use this limited water to generate electricity and obtain the highest return. In the absence of any other consideration, a prudent operator would choose to use limited water resources to generate hydropower when it is the most valuable—primarily during the onpeak hours. Figure 10 illustrates a weekly pattern of hydropower generation (and release) which might result during the summer.

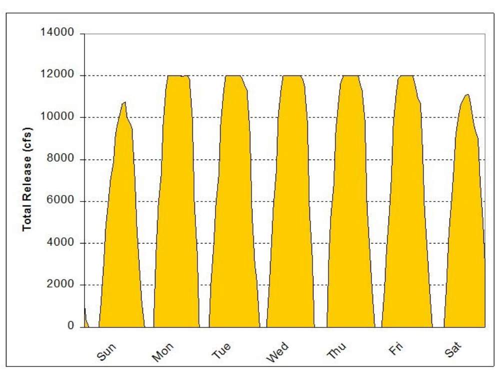

Figure 10. Example of unconstrained hydropower plant operation during a typical summer week.

As shown in Figure 10, in the absence of any other considerations, the rational powerplant operator would choose to operate the plant primarily during the onpeak hours and would operate the plant less intensively during the offpeak hours, if at all. The resulting generation and release pattern varies on an hourly basis.

HYDROPOWER OPERATIONS AND AQUATIC RESOURCES

Unconstrained operation of peaking hydropower plants results in the optimal operation from the standpoint of the interconnected electricity system. Not surprisingly, the ensuing pattern of release may have adverse effects on the downstream aquatic and riparian habitat. Referring to Figure 10, note that releases are nil during some of the offpeak hours. Although such a strategy preserves storage water for use during high value periods, to the extent the downstream biota are dependent on some level of minimum release, this would certainly be problematic. For the example illustrated in Figure 10, releases are increased rapidly and have a wide range (0 to 12,000 cfs) during onpeak periods. Depending on the downstream topography, these changes in release can result in large fluctuations in tailwater elevation which can also be detrimental to downstream aquatic and riparian resources.

The pattern of release shown in Figure 10 is, or was, a relatively common occurrence at some large hydropower plants. For example, peaking operations at Hell's Canyon Dam on the Snake River can cause fluctuations in the elevation of the river below the dam of as much as 9.3 feet per day (Idaho Power Company 1997). Historical operations at Glen Canyon Dam on the Colorado River have been shown to cause 7 to 12 foot fluctuations per day in the elevation of the river below the dam (Bureau of Reclamation 1994, Appendix D). These hourly variations in stream flow and elevation have been shown to adversely affect downstream aquatic and riparian communities (Nilsson, Jansson, and Zinko 1997, Parasiewicz, Schmutz and Moog 1998), and recreation (Welsh and Poe 1998; Bishop et al. 1987; Kearsley, Schmidt, and Warren 1994).

ENVIRONMENTAL CONSTRAINTS ON HYDROPOWER PLANTS

In an effort to mitigate the impacts of hydropower operations on both reservoir and downstream riparian and aquatic resources, a variety of restrictive constraints have been employed. Text Box 2 lists 6 common types of constraints which have been applied to operations at hydropower plants.

- Maximum release limitations
- Minimum release limitations
- Ramprate restrictions
- Reservoir fluctuation limits
- Tailwater fluctuation limits
- Limitations on daily release changes

Text Box 2. Selected constraints on hydropower operations.

The constraint measures shown have been applied both singly and in combination at different sites. The goal of these constraints is to moderate the fluctuations in reservoir elevations and release downstream of the hydropower plant. Constraints on maximum releases have been used at some sites and are generally seasonal in their application. They are generally employed in combination with constraints on minimum releases in order to moderate the range of release fluctuations. However, these constraints also reduce fluctuations in reservoir elevations. The use of minimum flow constraints is quite common. Minimum release constraints are often used to protect fish redds (nests) during the spawning and incubation periods and, in general, to ensure that some minimum level of aquatic habitat is maintained. “Ramprate” is a term used to describe the change in release from one hour to the next. Ramprates are typically, but not always, measured by the change in cubic feet per second per hour (cfs/hr). Restrictions on ramprates are sometimes employed to moderate the rate at which releases can be ramped up or ramped down. Judicious application of such constraints can help to stabilize downstream aquatic environments as well as reduce fluctuations in reservoir elevations.

In cases where operation of a hydropower plant causes undesirable changes in reservoir elevation levels, direct constraints on fluctuations in reservoir elevations have been imposed. These constraints have been used to facilitate recreational access, maintain fish populations and stabilize the near-shore environment in the storage reservoir. By their nature, these limitations also decrease possible fluctuations in release rates. In yet other cases, constraints on tailwater fluctuations have been employed. These can facilitate recreational use, maintain downstream navigability and improve conditions in the downstream aquatic and riparian habitat. Constraints on the daily changes in release are less frequently encountered. Where present, such constraints can limit, for example, 24-hour changes in release, to some specified value. Maximum daily change constraints are somewhat unique in that they are a “relative” constraint which can float upward or downward in relation to the minimum or maximum release in the preceding 24-hour period.

The institution of operational constraints such as those described can help to mitigate the effects of hydropower operations on both reservoir and downstream ecosystems. However, these constraints can adversely modify hourly hydropower operations, reduce the value of the output from the plant and increase the cost of operating the interconnected electricity system.

ABOUT THE ESIM03 PROGRAM

The ESIM03 program is a fully executable program designed for use on all Windows 98, NT and XP platforms. It is coded in Borland's Delphi 7.10, a rapid application development (RAD) framework. This program is relatively compact, portable and free of any licensing restrictions which might affect distribution or use by the public.

PURPOSE OF ESIM03 PROGRAM

The ESIM03 program is very much an educational software product. It is designed for ease of use and to illustrate a variety of electric system concepts. The ESIM03 model simulates the least cost dispatch of a representative interconnected electricity system for one week on an hourly basis. The representative electricity system represented in the model consists of a hydropower plant, a natural gas combined cycle combustion turbine (NGCCCT) plant, a natural gas combustion turbine (NGCT) plant, a coal plant and an oil fired steam plant. These plants are operated to satisfy the demand for electricity at a minimum cost. The easy to use model interface allows the user to quickly change the value of many input parameters including the weekly water release volume, reservoir inflows, starting reservoir elevations and electricity demand (load) patterns as well as to impose a number of environmental constraints. Following a simulation, the clear numerical and graphical output allows the user to see and understand the hourly effects on the interconnected power system.

ASSUMPTIONS AND SIMPLIFICATIONS

A number of assumptions and simplifications have been made to operationalize the ESIM03 software package and allow it to be distributed for educational use. Like any model, the ESIM03 program is a simplification of the real world. It cannot and was not designed to fully portray all of the intricacies inherent in the operation of an actual interconnected electricity system. In addition, this software was designed for educational purposes, an important aspect of which is that it is free of licensing restrictions and readily usable by stakeholder groups. To satisfy these and other requirements, a number of assumptions and simplifications have been made. These are described more fully in Appendix 18.

INSTALLING THE ESIM03 PROGRAM

The ESIM03 program and its required data files are contained in a single ZIP file. This ZIP file should be copied to a separate directory on your local hard disk. Once you have copied the ZIP file to a directory on your hard disk, it must be unpacked using PKUNZIP or a similar product such as WINZIP before the program can be used. Warning—do not simply drag the ZIP file to your desktop and UNzip it or try to UNzip the file over the network! This will cause erratic and difficult to diagnose program behaviors.

Contents of the ZIP File

After the ZIP file containing the ESIM03 program and its required data files have been UNZIPPED, the files shown in Text Box 3 should appear.

```
eps_sim03.exe              the software application
eps03_fallload.txt         fall hourly load file
eps03_springload.txt       spring hourly load file
eps03_winterload.txt       winter hourly load file
eps03_summerload.txt       summer hourly load file
h4inflow01.txt             "increasing" hourly inflow file
h4inflow02.txt             "constant" hourly inflow file
h4inflow03.txt             "high peak" hourly inflow file
h4inflow04.txt             "declining" hourly inflow file
h4inflow05.txt             "medium peak" hourly inflow file
h4inflow06.txt             "high constant" hourly inflow file
h4inflow07.txt             "high increasing" hourly inflow file
```

Text Box 3. The program and data files contained in the ZIP file. All files shown are required for proper operation of the ESIM03 program.

Please use Windows Explorer to verify that all of these files are present in the directory. In the event one or more of these files is missing, errors will result when the program is run.

Computer Administration/Security Note

In some cases, the computer user does not have the ability to install a program on their local computer. In this event, the computer administrator must install and enable the necessary program operating permissions before the ESIM03 program can be used. The ESIM03 program was designed to facilitate easy installation and require limited user rights. The following points should be considered during the installation process.

- ESIM03 does not read or write to the system registry
- Permission to read the included data files must be enabled
- In order to write results files, permission must be enabled
- In order to print graphics or text, permission must be enabled.

ESIM03 QUICK START

Many users are not especially interested in the details of program operations and are disinclined to read manuals like this one. To accommodate these users, the ESIM03 program has been designed to use default settings to facilitate its quick and easy use. To run the ESIM03 program, simply double click on the icon to start the program. Click on the “Run” button to make your first simulation.

HOW TO USE THE ESIM03 PROGRAM

Using Windows Explorer, locate and view the folder containing the ESIM03 program. Identify the ESIM03 icon and double click on it. The program should start and the opening window shown in Figure 11 should be displayed.

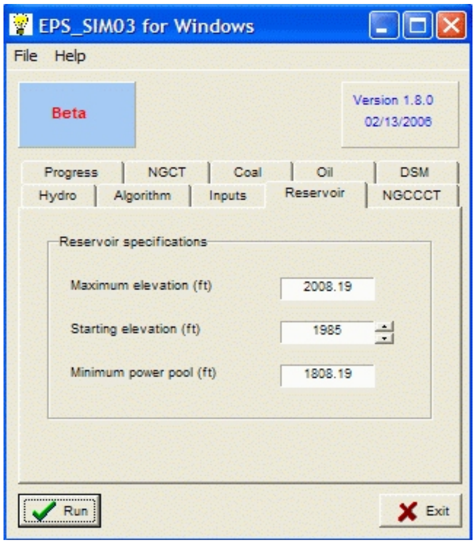

Figure 11. ESIM03 opening screen.

ESIM03's user interface has 10 tabbed pages. These are listed below.

- Hydro
- Algorithm
- Inputs
- Reservoir
- NGCCCT
- Progress
- NGCT
- Coal
- Oil
- DMS

Hydro

The Hydro tabbed page allows users to set the value of parameters influencing operation of the hydropower plant. The controls on this page allow the user to specify the amount of water released during a weekly simulation, to constrain the minimum release, to constrain the maximum release from the hydropower plant and to constrain the hydropower plant's ramp rate or ability to change release over a 1-hour period. Specification of different values for these parameters allows the user to investigate their effect on the operation of the hydropower plant, the other plants in the interconnected electricity system and the subsequent cost of meeting load during the week.

The combination of weekly release, the starting reservoir elevation (Reservoir tab) and the inflow (Inputs tab) have profound effects on the results of the simulation. The effect of each of these factors can be investigated independently or in combination by the user.

Table 5 illustrates the physical and engineering specifications of the hydropower plant. A more complete description of hydropower plant can be found in Appendices 8 and 17. The user is free to constrain operations during a simulation. The constraints specified by the user are one component of the underlying mathematical program used to represent the interconnected power system. If the constraints make the underlying mathematical problem impossible to solve, the program will issue an error message.

Table 5. Hydroplant Engineering Specifications

	Generation Capability (MW)	Turbine Release (cfs)
Maximum	240	12,000
Minimum	0	0

In general, hydropower plants and their storage reservoirs are operated to produce as much electricity as possible without allowing water to bypass the turbines or spill. Should the user specified values of the parameters stray from these goals, the program will issue an information message and may intervene.

Algorithm

The ESIM03 program employs an innovative two-stage solution method to find the optimal solution to the constrained minimization problem. This constrained optimization problem is described in Appendix 13. The integrated solution method employed in this program is described in considerable detail in Appendix 19. The algorithm tabbed page allows the user to control values of the parameters, including the maximum number of iterations and the convergence tolerances, used by this algorithm. For the vast majority of users, there will be no reason to make adjustments to these parameters.

Inputs

The Input tabbed page allows the user to specify the weekly load pattern (summer, fall, winter or spring) and the hourly reservoir inflow pattern (a number of choices). The peak load, amount of energy and time series of electricity demand vary in each load pattern as described in Appendix 3. The amount and sequence of hourly inflows varies with each choice of hourly reservoir inflow pattern. User selectable inflow patterns are described in more detail in Appendix 20.

The specified weekly release (Hydro tab), the starting elevation (Reservoir tab) and the inflow pattern have profound effects on the results of the simulation. The effect of each of these can be investigated independently or in combination by the user. Should the user-specified values of these parameters stray from typical operational goals for a hydropower plant, the program will issue an information message and may intervene.

Reservoir

The Reservoir tabbed page provides limited user control over the storage reservoir. The controls on this page allows the user to specify the starting reservoir elevation (and therefore the starting reservoir volume) for the simulation. The specified weekly release (Hydro tab), the starting elevation and the inflow pattern (Inputs tab) are the most important factors affecting the results of the simulation. The effect of each of these can be investigated independently or in combination by the user.

Table 6 illustrates the physical and engineering specifications of the reservoir which is simulated by the model. Further details about the reservoir, critical elevations and the relationship between reservoir volume and elevation can be found in Appendix 21.

Table 6. Physical Reservoir Specifications

	Elevation (ft)	Contents (acre-feet)
Maximum	2008.19	640,000
Minimum Power Pool	1808.19	240,796
Minimum Storage	1708.19	0

NGCCCT

The natural gas combined cycle combustion turbine (NGCCCT) tabbed page allows the user limited control over operation of the 2 unit 600 MW natural gas NGCCCT plant during a simulation. Table 7 illustrates the physical and engineering specifications of the NGCCCT plant which is characterized by the model. Appendix 6 further describes the NGCCCT plant and how it is characterized in the model.

In the Beta version of ESIM03, the user can alter the price of natural gas used by the plant. The price of natural gas is specified in dollars per thousand cubic feet ($/ccf). The heat content of the gas used by the plant is fixed and is described in Appendix 9. There are two natural gas plants in the interconnected system. The ESIM03 program ensures the price of natural gas used by both plants is the same. Consequently, altering the price of natural gas for either of these two plants will automatically change the price of natural gas used by both plants.

Table 7. NGCCCT Plant Specifications

	Units		Total Plant Capability
Feature	Number	Capacity	
Generator	2	300 MW	600 MW

Progress

The Progress tabbed page is displayed by the ESIM03 program during a simulation. A variety of messages are recorded in the progress dialog displayed there. These messages provide a record of program milestones during a simulation and are primarily useful for debugging purposes should some unforeseen event occur. Of some interest to the casual user, the elapsed program run-time is recorded for each simulation.

NGCCT

The natural gas combustion turbine (NGCCT) tabbed page allows the user limited control over operation of the 8 unit 400 MW natural gas NGCCT plant during a simulation. Table 8 illustrates the physical and engineering specifications of the NGCCT plant which is characterized by the model. Appendix 5 further describes this plant and illustrates how it is represented in the model.

Table 8. NGCCT Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	8	50 MW	400 MW

In the Beta version of ESIM03, the user can alter the price of natural gas used by the plant. The price of natural gas is specified in dollars per thousand cubic feet ($/ccf). The heat content of the gas used by the plant is fixed and is described in Appendix 9. There are two natural gas plants in the interconnected system. The ESIM03 program ensures the price of natural gas used by both plants is the same. Altering the price of natural gas for either of these two plants will automatically change the price of natural gas used by both plants.

Coal

The coal tabbed page allows the user limited control over operation of the 2 unit 1000 MW coal plant during a simulation. Table 9 illustrates the physical and engineering specifications of the coal plant which is characterized by the model.

Table 9. Coal Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	2	500 MW	1000 MW

A further description of the coal plant characterized by the model and an illustration of how coal plants work can be found in Appendix 4.

In the Beta version of ESIM03, the user can alter the price of coal used by the plant. The price of coal is specified in dollars per ton ($/ton). The heat content of the coal used by the plant is fixed and is described in Appendix 9.

Oil

The Oil tabbed page allows the user limited control over operation of the 2 unit 200 MW oil fired steam powerplant during a simulation. Table 10 illustrates the physical and engineering specifications of the oil plant which is characterized by the model.

Table 10. Oil Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	2	100 MW	200 MW

A further description of the oil plant characterized by the model and can be found in Appendix 7.

In the Beta version of ESIM03, the user can alter the price of the number 6 fuel oil used by the plant. The price of oil is specified in dollars per barrel ($/bbl). The heat content of the fuel oil used by the plant is fixed and is described in Appendix 9.

DSM

The demand side management (DSM) tabbed page allows user selection and control of several different DSM programs. DSM programs are designed to save energy thereby avoiding the need to generate as much electricity and saving money. In the Beta version of ESIM03, the available DSM programs are (general) conservation, interruptible supply and on-peak pricing. In addition to selecting one of these DSM programs, the user can also specify the extent of program penetration. Further details about these DSM programs and how they are represented in the model can be found in Appendix 15.

RUNNING THE PROGRAM AND INTERPRETING RESULTS

When the desired input data and parameters values have been selected, click on the "Run" button to start the ESIM03 program. An hour glass cursor will be displayed while the simulation is ongoing. A variety of information, warning or error dialogs can be displayed depending on the user specified inputs. Additional information on these dialogs can be found in subsequent pages. When the program has identified an optimum solution, the cursor will return to its normal appearance and the output window shown in Figure 12 will be displayed.

The ESIM03 output window has ten tabbed pages. These are listed below.

- Thermal Details
- Hydro Details
- Emission Details
- Hydro Graph
- Summary
- Run Specs.
- Tech. Graph
- Reservoir Graph
- Thermal Graph
- Emission Graph

Hydro Graph

The Hydro Graph tabbed page shown in Figure 12 contains four hourly plots. This page contains an illustration of hourly generation at the hydropower plant, an illustration of hourly turbine release, an illustration of hourly tailwater elevation and an illustration of hourly head. The numerical data underlying these graphics can be viewed on the Hydro Details tabbed page.

For a default simulation, a summer load file is used. Electricity demand in the summer is characterized by a single peak during the day as described in Appendix 3. As shown in Figure 12, to supply or meet this load at least cost, the hydropower plant is dispatched primarily to produce power during the onpeak portions of the day. For the default hourly inflow and starting reservoir elevation, it is optimal to either release the required water or store it and no spills result. As a consequence, all of the releases made in this simulation are made through the turbines and the turbine release graph shown on this tabbed page and the total release graph shown on the Reservoir tabbed page are identical.

The tailwater elevation plot illustrates the hourly elevation of the tailwater below the powerplant. This plot is useful for analyzing the effects of hourly power operations on the downstream aquatic and riparian habitat. The net head or difference between the reservoir elevation and tailwater elevation is shown in the graph located at the lower right-hand side of this tabbed page. This graph illustrates the combined effects of inflow and release on the head. For a simulation using the default parameters and inputs, this graph is close to an inverse image of the turbine release graph located above it.

Figure 12. The ESIM03 output screen with the Hydro page open. The results obtained for the default load, inflow and parameter values are shown.

A low resolution version of the four graphs on this page can be printed at a local or network printer by clicking on the "Graphics" button located at the bottom of this page.

Thermal Details

The Thermal Details tabbed page illustrates detailed numerical data for all of the thermal powerplants on an hourly basis. It illustrates the load, system lambda, and hourly generation levels for each thermal plant for all hours in the simulation. The majority of this information is also displayed graphically on the Thermal Graph tabbed page. The hourly system lambda (λ) recorded on the Thermal Details tabbed page is often useful to analysts and policy makers. System lambda is a measure of the marginal cost of supplying load in any given hour. As shown, system lambda varies on an hourly basis and is highest during periods of peak electricity demand. The mathematical derivation of system lambda is described further in Appendix 13.

To facilitate post-processing, the numeric data shown on this page can be printed, saved to a (text) disk file or transferred to a spreadsheet format for subsequent manipulation and analysis. The numerical data can be saved to a text file by clicking on the "Save" file button and selecting the appropriate file type (*.txt) in the windows file save dialog. These data can be copied to the clipboard and pasted to a word processing or text editing program. Appendix 22 contains step-by-step directions for transferring the numeric data produced by the ESIM03 program to a spreadsheet.

Hydro Details

The Hydro Details tabbed page provides hourly numerical data for the hydropower plant, inflow, release and reservoir. For each hour in the simulation, this data is recorded on this page for the load, gamma, hydro generation, inflow, reservoir elevation and volume, total release, spill, tailwater elevation and head. The majority of this information is also displayed graphically on the Hydro Graph and Reservoir Graph tabbed pages. Depending on the analysis being undertaken, these details may be of considerable interest. For example, if the goal is to analyze the effects of operational changes on the downstream aquatic environment, the hour by hour simulated releases may be the most important output from the simulation.

The hourly gamma data recorded on this page is frequently useful to analysts and policy makers. Gamma is the marginal value of an additional acre-foot of water for a particular hour. The derivation of gamma is described in Appendix 13 and factors influencing the value of gamma are described more fully in Appendix 14. The relationship between reservoir elevation and reservoir volume is discussed in Appendix 21. Details of the release, tailwater, and head relationship characterized by the model are found in Appendix 17.

To facilitate post-processing, the numeric data shown on this page can be printed, saved to a (text) disk file or transferred to a spreadsheet format for subsequent manipulation and analysis. The numerical data can be saved to a text file by clicking on the "Save" file button and selecting the appropriate file type (*.txt) in the windows file save dialog. These data can be copied to the clipboard and pasted to a word processing or text editing program. Appendix 22 contains a step-by-step directions for transferring the numeric data produced by the ESIM03 program to a spreadsheet.

Emission Details

The Emission Details tabbed page provides hourly numerical output for selected emissions by each powerplant in the interconnected electricity system. For each hour in the simulation, data is reported on this page for the estimated emissions of carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrogen oxides (NO_x) and mercury (Hg). The total output of these emissions is displayed graphically for each powerplant on the Emission Graph tabbed page and is reported on the Summary tabbed page.

To facilitate post-processing, the numeric data shown on this page can be saved to a (text) disk file or transferred to a spreadsheet format for subsequent manipulation and analysis. The numerical data can be saved to a text file by clicking on the "Save" file button and selecting the appropriate file type (*.txt) in the windows file save dialog. These data can be copied to the clipboard and pasted to a word processing or text editing program. Appendix 22 contains step-by-step directions for transferring the numeric data produced by the ESIM03 program to a spreadsheet.

Emission Graph

The Emission Graph tabbed page contains four hourly plots. Each pie chart on this page illustrates the relative emissions of a particular emission for each of the thermal powerplants in the interconnected system. For example, the chart in the upper left-hand corner of this page displays the emissions of carbon dioxide (CO_2) by the coal, NGCT, NGCCT and oil plant in the model. This allows the user to quickly compare the emissions from each powerplant. For each simulation, the total and relative share of emissions can differ depending on the options and parameters selected by the user.

The numerical data underlying these graphics may be found on the Emission Details tabbed page and the Summary page A low resolution version of the four graphs on this page can be printed at a local or network printer by clicking on the "Graphics" button located at the bottom of this page.

Summary

The Summary tabbed page shown in Figure 13 contains summarized results of the simulation. The Operations Summary block illustrates total generation by each plant during the week and the percentage of the total derived from each plant. Also listed are the minimum and maximum generation level reached by each plant during the week.

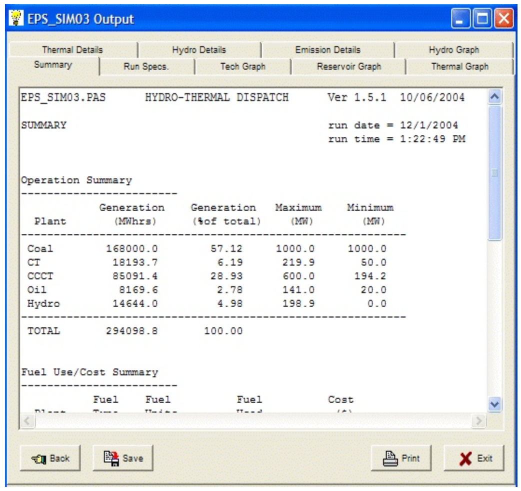

Figure 13. The ESIM03 Summary tabbed page. The results obtained using the default parameters are shown.

The Fuel Use/Cost Summary block lists the amount of fuel used by each powerplant in the system and the cost. The total (minimum) cost of operating the interconnected system to meet load is shown.

The Beta version of ESIM03 calculated and track selected air emissions by thermal hydropower plants. The Emissions Summary block displays the total output of these emissions by powerplant type. The Emissions by MWh block reports these emissions on a per megawatt-hour basis.

To facilitate post-processing, the numeric data shown on this page can be printed, saved to a (text) disk file or transferred to a spreadsheet format for subsequent manipulation and analysis. The numerical data can be saved to a text file by clicking on the “Save” file button and selecting the appropriate file type (*.txt) in the windows file save dialog. These data can be copied to the clipboard and pasted to a word processing or text editing program. Appendix 22 contains step-by-step directions for transferring the numeric data produced by the ESIM03 program to a spreadsheet.

Run Specs

The Run Specifications tabbed page illustrates the values of the input parameters, the value of environmental and powerplant constraints, analysis options, fuel prices, the emission content of this fuel, heat contents, algorithm performance and the minimum dispatch cost.

The first block of information found on this page lists the run date and run time of the simulation as well as the maximum number of lambda iterations permitted and the convergence tolerance in use by the lambda search algorithm which optimally dispatches the thermal powerplants in the system. The technical details are described further in Appendix 34.

The second block of information records whether or not a DSM program was in use during the analysis and, if so, the selected level of program penetration.

Next is a block of information indicating whether the initial solution was feasible and recording the minimum swap volume used by the solution algorithm during the simulation. The default minswpvol is 5.00 af but this can be altered by the user. Convergence of the solution algorithm is indicated by "converge = TRUE." If the algorithm failed to converge for some reason, the remaining results should be viewed with considerable suspicion since they may be spurious. The number of swap iterations varies with the release volume and the user specified minimum swap volume.

The next block of information on this tabbed page shows the starting reservoir elevations and volumes (e.g. elev[0] = 1985.0) and the ending reservoir elevations and volumes (e.g. elev[168] = 1992.8).

The anticipated weekly release volume specified by the user, the amount of the total released through the turbines and the amount spilled, if any, are then displayed. The sum of the turbine release and spill should equal the total release although sometimes there are very small numerical differences between them. Avoidance of spills is a high priority and under most conditions there are no spills during a simulation.

The minimum dispatch cost for the interconnected electricity system characterized by the model is then listed. For the default parameters, the minimum cost of meeting load is $7,096,754.93

The next 4 blocks describe the engineering specifications of the powerplants in the interconnected system, the fuels used, their emission contents, their heat contents and the constraints on these powerplants, if any.

To facilitate post-processing, the numeric data shown on this page can be printed, saved to a (text) disk file or transferred to a spreadsheet format for subsequent manipulation and analysis. The numerical data can be saved to a text file by clicking on the "Save" file button and selecting the appropriate file type (*.txt) in the windows file save dialog. These data can be copied to the clipboard and pasted to a word processing or text editing program. Appendix 22 contains step-by-step directions for transferring the numeric data produced by the ESIM03 program to a spreadsheet.

Tech Graph

The Tech Graph tabbed page, illustrated in Figure 14, contains four hourly plots. This page contains an illustration of hourly load, an illustration of hourly system lambda, an illustration of hourly gamma release and an illustration of marginal thermal cost by load. The data for the marginal thermal cost by load are not displayed elsewhere in the ESIM03 program. This particular graph provides a visual view of the supply function (or marginal cost) for operating the thermal system over a range of output levels. This marginal cost "surface" varies dramatically as fuel costs are changed. Discontinuities in the graph occur when the maximum generation limit on one plant is reached and another, typically more expensive, powerplant begins to generate.

The remaining numerical data underlying these graphics may be found on the Hydro Details tabbed page and the Thermal Details page A low resolution version of the four graphs on this page can be printed at a local or network printer by clicking on the "Graphics" button located at the bottom of this page.

Figure 14. Tech Graph tabbed page. Results shown are for $40.00/bbl oil price and default parameter values.

Reservoir Graph

The Reservoir Graph tabbed page is illustrated in Figure 15 and contains four hourly plots. This page contains an illustration of hourly reservoir elevation, an illustration of hourly inflow, an illustration of hourly total release and an illustration of hourly spill. The numerical data underlying these graphics may be found on the Hydro Details tabbed page.

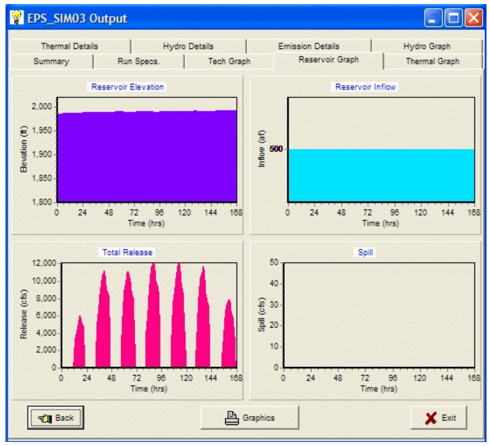

Figure 15. The Reservoir Graph tabbed page. The default results are shown.

This page displays the hourly spill, if any, the hourly inflow, the hourly reservoir elevation and hourly turbine releases. For the default run, the inflow pattern is constant across all hours of the week, inflows exceed releases and the elevation of the reservoir is increasing. The hourly pattern of hydropower release (and generation) is typical of summer months and has only a single peak each day. For the particular weekly release volume shown, the hydropower plant is operating far below its maximum release (12,000 cfs) and generation (240 MW) capability.

A low resolution version of the four graphs on this page can be printed at a local or network printer by clicking on the "Graphics" button located at the bottom of this page.

Thermal Graph

The Thermal Graph tabbed page contains four hourly plots. This page contains a hourly graphs of generation by each of the four thermal powerplants characterized by the model. The numerical data underlying these graphics may be found on the Thermal Details tabbed page.

For the default parameter values, the behavior of all of the thermal plants is illustrated in Figure 16. As shown, the coal plant operates continuously at its maximum output level. The NGCCCT unit provide both baseload and peaking generation. The NGCT and oil plants provide peaking power and are at their minimum output levels during the off-peak hours.

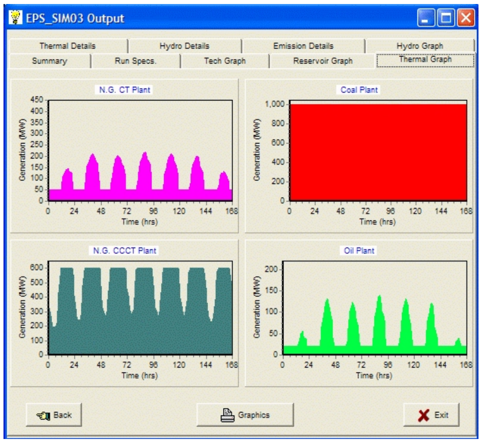

Figure 16. The Thermal Graph tabbed page. Default results are shown.

A low resolution version of the four graphs on this page can be printed on a local or network printer by clicking on the "Graphics" button located at the bottom of this page.

INFORMATION, WARNING AND ERROR MESSAGES

The ESIM03 program is a relatively complex software product which utilizes a variety of parameter values, analysis options and input files. The number of combinations and permutations of these inputs is incredibly large. The number of potential errors that can occur is also very large. The ESIM03 program performs a large number of input validations and logic checks on the inputs.

ESIM03 program can issue three different classes of message dialogs. In order of the seriousness of their effect on a simulation, these are information, warning and error messages respectively. These dialogs cover a wide variety of possible issues. Every effort has been made to make these informative, clear and useful to the user.

Information Messages

Informational messages or dialogs are the least important class of message issued by the program. As the name implies, these messages convey some information about a program event to the user. When information messages appear, no action on the part of the user is required.

The most commonly encountered information dialog is issued by the "Release_helper(.)" procedure. This procedure assists the user by checking the starting and ending reservoir elevation, the user specified inflow pattern and the user specified weekly release volume for logical consistency and consistency with ordinary reservoir operating procedures. The "Release_helper(.)" procedure detects input combinations which would result in either unintended consequences (such as a spill) or would make the mathematical programming problem, which represents the interconnected system, impossible to solve. The procedure either automatically corrects the problem(s) it detected, or issues an information, warning or error message to the user. In Figure 17 for example, the "Release_helper(.) procedure has detected an impending spill and increased the weekly release volume to avoid it.

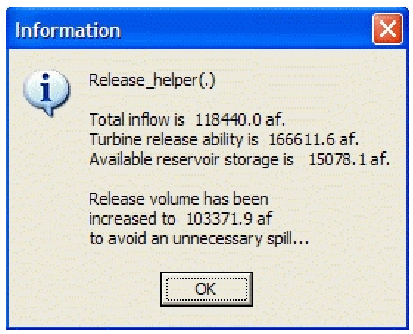

Figure 17. Information dialog issued by the Release_helper(.) routine.

Warning Messages

Warning messages or dialogs are of an intermediate level of importance to the user. These messages typically alert the user to an event which the user should take careful note of and consider whether any action is required. Warning messages are issued by the ESIM03 program if, for example, there is a potential logic error in the user's specification of the input parameters and files but this error does not prevent the program from undertaking a simulation. For example, as shown in Figure 18 a user can specify total weekly releases greater than the turbine release capability. In this case, the Release_helper(.) routine issues a warning message to alert users that a spill will result and proceeds with the simulation. If the user did not intend for a spill to occur, they can take remedial action and re-run the simulation.

Figure 18. Warning dialog issued by the Release_helper(.) routine.

Error Messages

Error messages or dialogs are of the highest level of importance to the user. The appearance of an error message indicates a critical program event requiring user intervention. For example, if the program detects inconsistent, illogical or infeasible combinations of the input parameters or constraints, which it cannot resolve, it will issue an error message. Figure 19 illustrates a case in which the user has selected minimum and maximum release constraints which conflict with each other.

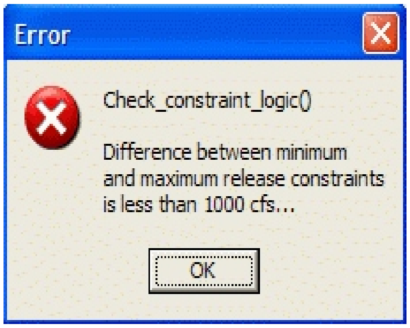

Figure 19. Error dialog issued by the program. The user must take action before the program can continue.

In such a situation, user intervention is required before the program can continue with a simulation. Other error messages may result from unforeseen program conditions which occur, but which are trapped and handled by appropriate error-handling procedures in the code. In general, appearance of an error message requires user intervention and suggests that any results which are produced should be regarded with extreme caution.

KNOWN SOFTWARE ISSUES

At the time this document was written, no operational flaws in the Beta version of the ESIM03 program have been identified. Due to the optimization algorithm employed, violations of ramprate constraints for the thermal plants can occur.

RUNTIME ERRORS AND SUPPORT

Internal errors which occur when the program is running and which are not handled by the program itself, are known as runtime errors. Typically, runtime errors result in immediate program failure and termination. Although every effort has been made to identify and fix all programming errors, there is no way to guarantee this, or any other program, is bug-free.

In the event you encounter a *repeatable* runtime error, please (1) record any and all error messages, and, (2) save, print and transmit a copy of the run specifications page and other information pertinent to the error to:

David A. Harpman
Natural Resource Economist
U.S. Bureau of Reclamation
P.O. Box 25007 (D-8270)
Denver, CO 80225
(303) 445-2733 [voice]
dharpman@do.usbr.gov [email]

FUTURE ENHANCEMENTS

There are limits to the resources available to complete any project and this one is no exception! Although several additional model features were envisioned, these features were not incorporated in the Beta version of the ESIM03 model due to resource limitations. Assuming sufficient resources are made available to do so, future versions of the ESIM03 program are expected to contain the following enhancements:

1. Ability to characterize fixed and other variable costs.
2. Other suggested improvements.

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Appendix 1 – Electricity Background

Introduction

The purpose of this brief appendix is to provide an introduction to electric power. This appendix is designed only to address this topic in a cursory and conceptual manner and purposely omits many of the more technical, mathematical and esoteric details. The content of this appendix are taken largely from Kirby, Hirst and Vancoevering (1995), Perez (1996a, 1996b) and Milano (2004). Without implicating them in any errors which follow—the contributions of these sources to this appendix are hereby acknowledged.

Electricity Basics

People use electricity every day, at home, at work, at play and in all facets of their lives. Even so, most of us have little understanding of electricity, what it really is and the meanings of terms like volts, amps, watts and power factors which are used by engineers and scientists to describe how it works. As is often the case, analogies with other concepts can be helpful. Table A1-1 provides a comparison of useful analogies between water and electricity.

Table A1-1. Analogies Between Water and Electricity.

Concept	Water Measure	Electricity Measure
pressure	pounds per square inch (psi)	volts (V)
flow rate	cubic feet per second (cfs)	amperes (I)

Voltage is a measurement of electrical force or potential. This potential is measured in volts and is often represented in electrical calculations as "V". To paint a simple picture, a voltage source represents a certain amount of electrical pressure in the same way there is water pressure in a faucet. There is pressure in the faucet whether or not it is turned on. A standard "D" cell flashlight battery for example has an electrical potential of 1.5 Volts. The electrical outlets in most homes, which provide electricity to a variety of small appliances, have a potential of approximately 120 Volts. An electric stove, clothes dryer, or central air conditioner usually requires 240 Volts to operate.

The current of an electrical signal refers to the rate at which electrons flow through a conductor within a unit of time. In many ways, this is similar to the amount of water which flows through a garden hose within a specified time. If there is no flow, then no water is delivered. The amount of water delivered per period of time increases with increasing flow. Current is measured in Amperes or Amps and is represented in electrical calculations by the symbol "I." Different types of electrical devices require differing amounts of current to operate. A radio, for example, requires relatively little current while an electric oven or large electric motor requires a much greater current. In the same way that a large fire hose allows a greater flow of water than a garden hose, a conductor or wire must have a larger diameter to allow a high current.

Power is the ability to do work. Electrical power is measured in Watts (W) and in simple terms is equal to the voltage multiplied by the current. One Watt equals one Volt multiplied by one Amp. Power measured in Watts (W) is the product of the voltage (V) and the current (I) as shown in equation (1).

$$P = V \times I \tag{1}$$

Where: P = power (Watts)
V = voltage (Volts)
I = current (amperes or Amps)

This simple power equation has many applications. As an example, consider a flashlight with a 5-Watt bulb that runs on two "D" cell batteries. Since I=P/V, the current flow (I) in the circuit is equal to the power (5 Watts) divided by the total Voltage (2 × 1.5 = 3). In this case, I= 5/3= 1.66 Amps. Or, consider another example: assume a 120 volt, 60 Watt lightbulb draws 0.50 amperes. In other words, 120 volts × 0.50 Amps = 60 watts of power which is used (or absorbed) by the lightbulb to produce light.

An electrical signal can take one of two forms: direct current (DC) or alternating current (AC). Batteries are a common DC electrical source which provide a constant, positive electrical potential. For example, passenger cars typically utilize a 12-volt battery which supplies 12 volts DC. AC electricity is commonly used in homes, offices and industry. AC electricity is conceptually and technically more complex than DC electricity. The basics of AC electric power are discussed in Appendix 2.

Appendix 2 – Alternating Current Electricity Primer

Introduction

The purpose of this brief appendix is to provide an introduction into the complex topic of alternating current (AC) electric power. This appendix is designed to address this topic in a cursory and conceptual manner and purposely omits many of the more technical, mathematical and esoteric details. The contents of this appendix are taken largely from Kirby, Hirst and Vancoevering (1995), Perez (1996a, 1996b) and Milano (2004). Without implicating them in any errors which follow—the contributions of these sources to this appendix are hereby acknowledged.

Basics of AC Power

Alternating current has become the standard form of electricity supplied to homes, offices and industries, primarily because AC electric signals can easily be transformed from one voltage to another. This facilitates efficient and cost effective distribution. As AC electricity is transmitted through the distribution system, its voltage level is usually changed several times between the generator and the end user. This change in voltage levels is accomplished through the use of transformers and is necessary to minimize transmission losses and make the long-distance transportation of electricity less costly. In general, the higher the voltage of an electrical source, the lower the current required to transmit power over a transmission line and less loss will occur.

In the United States, Canada and much of Mexico, electricity is supplied at 60 Hertz (Hz) or cycles per second. This means that voltage and current oscillate 60 times each second in a characteristic sine wave pattern. In order to facilitate this, generators rotate at a constant speed and are synchronized within control areas. U.S. utilities deliver a sine wave voltage that varies between peaks of ±169.7 volts. This cyclically varying voltage is often converted to a standard measure using what is known as the root mean squared (RMS) method. The RMS equivalent of ±169.7 volts is 120 volts. These standards vary geographically. In Europe, for example, the voltage standard is almost twice that of the U.S. and power is supplied at a frequency of 50 Hz.

The power equation illustrated previously in Appendix 1 can be applied directly to DC electricity. In the case of AC electricity, an additional parameter known as the power factor (pf) must be included. The equation describing AC electrical power is shown in (2).

$$P = V \times I \times pf \qquad \textbf{(2)}$$

Where:
P = power (Watts)
V = voltage (Volts RMS)
I = current (amperes or Amps RMS)
pf = power factor

The concept of phase is essential to understanding AC current electricity and this additional parameter (pf). Phase means time, or more specifically, a time interval between when one repetitive thing happens and another repetitive thing happens. In the case of AC electrical waveforms, the focus is on the time when the maxima or minima of the sinusoidal voltage occurs with respect to the maxima or minimum of the current waveform. An event which happens after another related event is said to lag. An event which precedes a second and related event is said to lead. The unit of measure employed for phase is degrees. Degrees are used because each rotation of a generator encompasses 360 degrees.

Although it is desirable, in the case of AC electricity, the voltage and current waveforms do not necessarily alternate together (in phase). The two can potentially be out of phase with one wave lagging or leading the other. The power factor (pf), which varies from 0.0 to 1.0, represents how "in phase" or "out of phase" these waves are relative to each other. AC power delivery is maximized when the voltage and current are in phase. If the voltage and current are perfectly in phase, (peaks and troughs of the waves are perfectly aligned) then the power factor would be equal to 1.0. Conversely, if the current and voltage are 90˚ out of phase, then the power factor would be equal to 0.0 and no real (work producing) AC power would be delivered.

Real Power

Real power is produced when the voltage and current waveforms are in phase (e.g. the peaks and troughs of the waves coincide). In a resistive load, such as that of an electric heater or an incandescent lightbulb, the voltage and current wave forms are always exactly in phase. Figure 20 illustrates an example of a resistive load. As shown in this figure, voltage (V) and current (I) oscillate around zero such that half the time V and I are positive and the other half of the time V and I are negative. Note the voltage and current waveforms reach maxima, minima and zero at exactly the same instant. This illustrates the definition of "in phase."

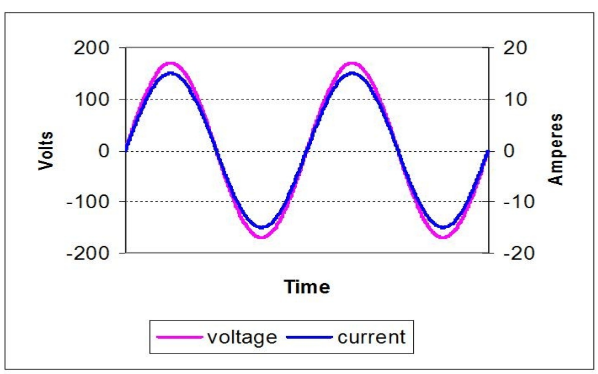

Figure 20. The relationship between AC current and voltage for a resistive load.

For a resistive load, the power factor (pf) is 1.0. Applying equation 2 with a pf=1.0, yields the electric power in watts. For a resistive load, the resulting AC power signal is always positive and sinusoidal as shown in Figure 21.

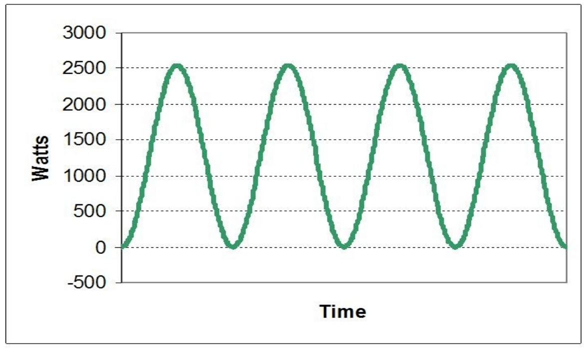

Figure 21. AC power (watts) for a resistive load is characterized by a sine wave pattern which is strictly positive.

Reactive Power

Reactive power is produced when the voltage and current wave forms are out of phase (either lagging or leading). Certain components in a power system have the ability to store energy for very short periods of time– essentially for ¼ cycle. In the next ¼ cycle, the devices release this stored energy. This storage and release occurs in the other one-half of the cycle. No energy is consumed: it is simply transferred back and forth each ¼ cycle.

When energized, coils of wire (inductors) absorb and release energy each ¼ cycle. The energy is stored and released in the creation and collapse of a magnetic field around the wire by electrons flowing in the wire.

When energized, parallel metal plates or parallel wires (capacitors) can also store and release energy each ¼ cycle. In this case, the energy is stored in the electric field between the plates or wires as a result of more electrons accumulating on one plate relative to the other plate. The energy is required to create the electric field and is released when the field collapses.

This inductive or capacitive energy transfer is referred to as reactive (or imaginary[8]) electric power. Inductors are said to absorb reactive power and capacitors are said to generate reactive power. This is merely a convenient method for describing the phase relationship between

[8] Because the mathematics of reactive power utilizes so-called complex or imaginary numbers, scientists and engineers sometimes refer to it as "imaginary" power.

voltage and current since both of these devices merely store energy for a portion of the cycle. A Power system generator can be made to either generate or absorb reactive power. Operationally, this is accomplished by adjusting the generator's excitation system.

Real and Reactive Power

Most people are not aware of the existence of reactive power. The general public is familiar with real power because they use it every day and pay for it every month. Real power over time (watt-hours) is the electrical energy component bought and sold in the market. Reactive power is necessary for the functioning of the electricity system but is not commonly bought or sold in the market (at least under the current market institutions). Because reactive power is necessary for the operation of the system but is not typically sold to the public, it is classified as an ancillary service. The cost of providing reactive power is embedded in the cost charged to most end-use consumers of electricity.

Voltage and Current in Inductive Loads

Not all electric loads are purely resistive like the heater and lightbulb examples described previously. Some electrical devices such as motors, contain wire coils. When energized, the coils of wire (inductors) absorb and release energy each ¼ cycle. Reactive power from the power system must be supplied to inductive motors to magnetize these coils of wire. These motors also do real work, such as pumping water, and they have a real power component. The real and reactive components of load result in a power factor of less than 1.0 and the voltage and current become out of phase. For loads with an inductive component, the current lags behind the voltage.

Figure 22 illustrates the lagging caused by an inductive load with a power factor of 0.707. As shown in this figure, a real load in conjunction with an inductive load causes the current to lag behind the voltage.

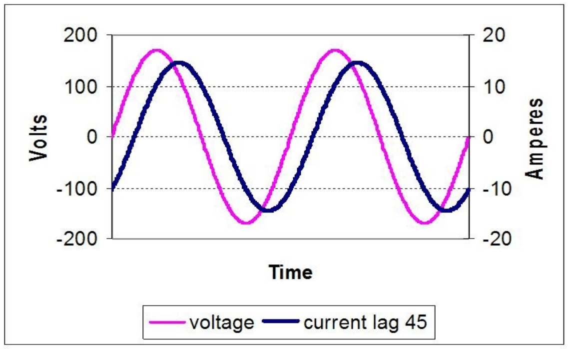

Figure 22. The relationship between AC voltage and current for an inductive load (pf=0.707).

From equation (2), recall that AC electric power (Watts) is a function of voltage (V), current (I) and the power factor (pf). For the inductive load example shown in Figure 22 the corresponding power waveform is illustrated in Figure 23. As shown in figure 23, for the majority of the time, the power is positive (the generator is supplying power to the load). However, at some times, the power waveform is negative (the generator is receiving or taking power from the load).

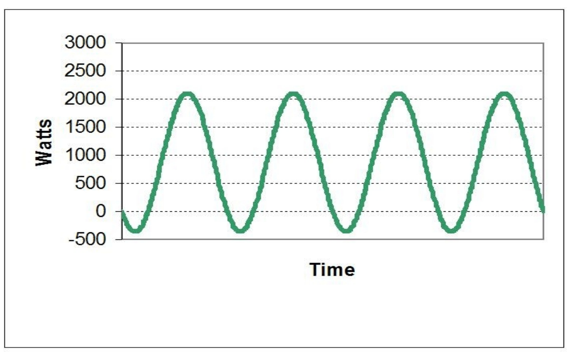

Figure 23. An AC power waveform for an inductive load (pf=0.707) is characterized by a sine wave pattern which is mostly positive but sometimes negative.

Voltage and Current in Capacitive Loads

When energized, parallel metal plates or parallel wires (capacitors) can store and release energy each ¼ cycle. Unloaded extension cords and lightly loaded high-voltage transmission lines are commonly encountered examples of capacitors. Very long extension cords that are energized at the plug and are not connected to a working electrical device (not loaded) are essentially a capacitive device tied to the power system. In this example, the extension cord will generate some (not much) reactive power and provide it to the power system. A lightly loaded high-voltage transmission line has the same effect, but on a larger scale. For a capacitive device, the voltage waveform lags behind the current.

Some electrical devices “switching” power supplies which convert 120 volt AC into other (usually) DC voltages. Switching power supplies are used in most compact fluorescent lights, computer power supplies, and some battery chargers. These loads behave like capacitors and are known as capacitive loads. While not as common as inductive loads, the average household uses many of these capacitive loads. To reiterate, for a capacitive device, the voltage waveform lags behind the current.

The Real World of AC

In the real world, there is no such thing as a strictly resistive, inductive or capacitive load. Nearly all power system components have resistance, capacitance and/or inductance associated with them. In fact inductance is the dominant characteristic of most power system components including generators, overhead lines, transformers and motors. Underground cables and, to a lesser extent, overhead lines have significant capacitance as well.

Calculation of the Power Factor

The energy associated with transferring electrons back and forth between the AC generator and an inductor or capacitor does not deliver nor consume useful energy. The concept of a power factor was developed to express how much of the total current supports the transfer of useful energy to the load (real power) and how much supports the inductive or capacitive needs. Because reactive power results in a current that is out of phase with voltage by 90 degrees (either lagging because of inductance or leading because of capacitance) and real power results from current that is in phase with voltage, the two add geometrically to form apparent power. This is illustrated in Figure 24. Real power is measured in Watts (W), reactive power is measured in volt-amperes reactive (VAR) and apparent power is measured in volt-amperes (VA).

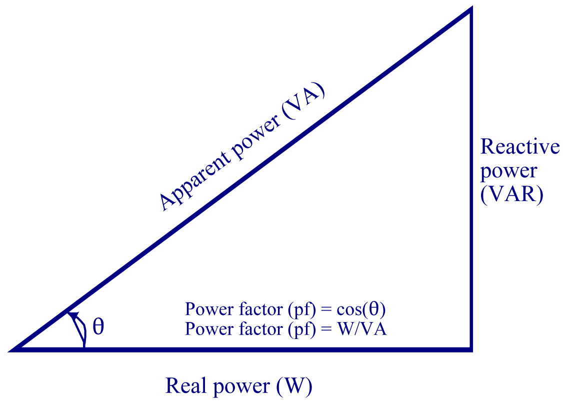

Figure 24. Relationship between real, apparent, and reactive (or imaginary) power and the power factor (pf).

In summary, if the load is resistive, the voltage V and current I will be exactly in phase, the power factor (pf) will be equal to 1.0 and only real power will be produced. Conversely, if the voltage V and current I are out of phase by exactly 90˚, the power factor (pf) will be equal to 0.0 and no real power will be produced. For situations in between these two extreme cases, the power factor indicates the amount of real power which is produced from the generation of apparent power.

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Appendix 3 – System Load

Electricity demand or load is quite dynamic and varies hourly, daily, weekly and across the season. In many respects, the hourly demand for electricity is the primary driver of system operation cost.

Household electricity use in the United States varies on a regional basis. Household electricity consumption is highest in the South due largely to the widespread use of air conditioning. Electricity use is lowest in the Northeast where ambient summer temperatures are more moderate. In 2001, a typical household in the West consumed approximately 8,287 kWh (8.287 MWh) of electricity annually (Energy Information Administration 2001). Peak electricity use for a single family residence varies due to a number of factors but is generally in the range of 10 kW (0.010 MW) or less.

In the ESIM03 model, each simulation spans one week using an hourly time-step. Four predefined typical weekly load patterns are available; one for each of the seasons—spring, summer, fall and winter. These patterns have differing peak and total loads and the chronological sequence is representative of their respective season. Each of these load sets begins at 0100 on a Sunday and ends at 1200 midnight on a Saturday. The four load patterns supplied with the model allow the user to experiment with and understand some of the management implications of electricity demand and its interrelationship with other operational parameters such as inflow, release and reservoir level combinations.

Table A3-1 summarizes the salient characteristics of these available predefined load patterns. The peak load represented in these data is 2,159.8 MW and occurs in the summer. For comparison purposes, on July 13, 2004 Xcel Energy, the company which serves Denver, Colorado and the surrounding area, reported their load reached a peak of 6,421 MW at 5 pm (Chakrabarty 2004). Figure 25 provides a visual representation and allows a comparison between these four typical hourly load patterns.

Table A3-1. Hourly Load File Specifications

Load Pattern	Peak Load (MW)	Minimum Load (MW)	Energy (MWh)
Spring	1755.3	1116.8	249,861.6
Summer	2159.8	1264.4	294,098.7
Fall	1900.5	1187.3	259,234.8
Winter	2098.5	1259.4	280,983.5

In the Western part of the United States, load is typically highest in the summer (summer peaking) and is relatively high in the winter. The spring and fall are known as “shoulder months” and the load during these seasons is typically less than it is in the summer or winter. As shown in Figure 25, the load pattern during a typical week during the summer is characterized by single peaks each day with the load on the weekdays being higher than load on Saturday and Sunday. This load pattern is largely shaped by air conditioning and cooling needs. The load pattern during the winter is characterized by a “double peak” each day. This pattern results primarily from diurnal heating needs in residences. When people wake up, they turn on the heat, make coffee and eat breakfast. Then they turn down the heat and go to work. When they return from work, they turn up the heat and start cooking dinner. When they are ready for bed, they again turn down the heat. This activity pattern results in the characteristic winter load pattern shown. Load during the spring and fall is transitional and can exhibit either single peaks, double peaks or a mixture of both.

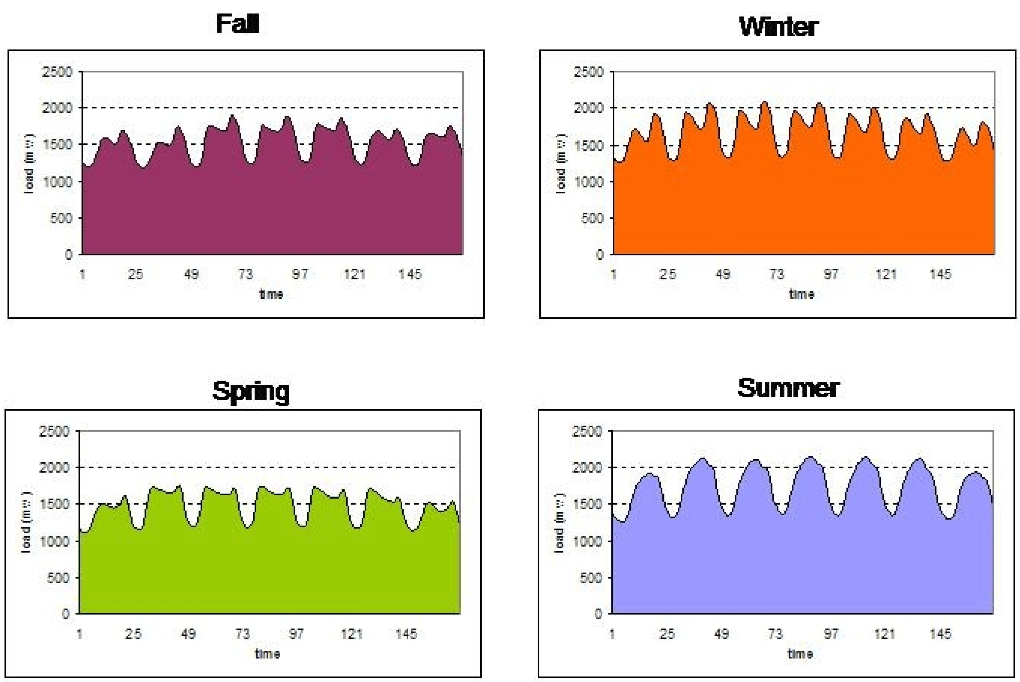

Figure 25. The four predefined load patterns in ESIM03 represent typical chronological hourly load patterns for one week (Sunday, Monday,... Saturday) during each of the four seasons: fall, winter, spring and summer.

Appendix 4 – Coal Plant

Coal fired power plants are large and readily noticeable features of the electric power system. In a coal plant, electricity is generated by burning coal to heat water and produce steam. The steam, in turn, is used to drive a turbine and produce electricity. The coal used to produce electricity is consumed in the process. Air emissions and other wastes result from this process. Figure 26 illustrates the 2,400 MW Navajo coal fired power plant which is located near Page, Arizona.

Figure 26. Navajo coal fired powerplant is located near Page, Arizona. U.S. Bureau of Reclamation file photo.

Typically, coal fired power plants are located near a source of cooling water and in close proximity to a bulk coal source and a railroad line. Long lines of railroad coal cars heading towards powerplants are a familiar sight in many parts of the country.

Large coal fired generation units are relatively efficient from the standpoint of the amount of fuel used per unit of power output. Recent designs are considerably more efficient and the reported efficiencies of some of the advanced designs now being marketed are notable. The initial installation or capital cost of a coal plant is typically greater than a natural gas plant but generally less than a hydropower plant. However, their operational or variable costs are generally lower than, for example, gas fired plants. This is primarily due to the low cost of coal relative to natural gas and other fossil fuels. The variable costs of operating a coal unit are relatively high at low output levels and lower at high output ranges where their energy conversion efficiencies are more favorable. Coal plants can require hours or days to start up and they are incapable of rapid changes in output levels. Because they are relatively slow output responsiveness and their relatively low variable costs, they are typically employed at near constant output levels and furnish power during all hours of the day particularly during the off-peak hours.

In a coal plant, the coal fuel is used to heat water in a boiler mechanism in order to produce steam. The high pressure steam produced is used to drive the blades of a steam turbine. The force of the steam against the blades of the turbine rotate a large shaft. The rotating shaft turns the rotor or moving portion of the generator. The coils of wire on the rotor sweep past the generator's stationary coils (the stator) producing electricity.

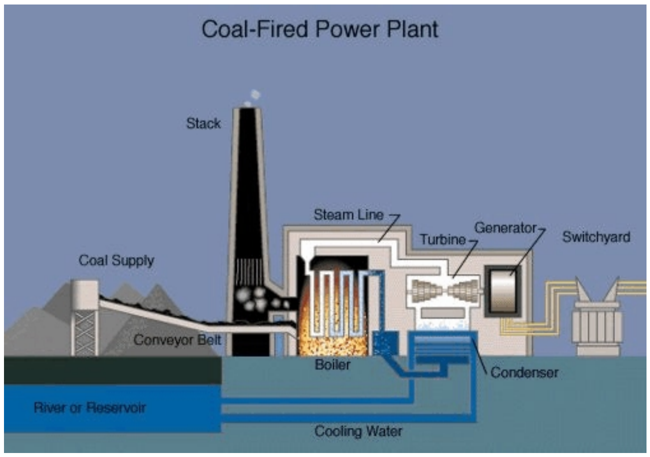

Figure 27. Schematic of a coal fired power plant. Courtesy of the Tennessee Valley Authority.

In larger coal fired power plants, there are often multiple generators. Each of these is referred to as a "unit." Plant designs with multiple units enable more efficient use of the available fuel particularly at less than full output and allow the plant to continue to operate when one or more of the units are being serviced.

The coal fired plant in the ESIM03 program has 2 units. Each unit consists of a generator with a maximum generation capability of 500 MW. The aggregate generation capability of the plant is 1000 MW. This is summarized in Table A4-1.

Table A4-1. Coal Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	2	500 MW	1000 MW

In the ESIM03 model, the coal plant is operated as if it were a single unit. No attempt is made here to address the so-called "optimal unit dispatch problem" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity.

Table A4-2 contains the heat rate and total fuel consumption at 4 levels of output from the coal plant in the ESIM03 model.

Table A4-2. Coal Powerplant Characteristics by Selected Output Level

Percent Output	Plant Output (MW)	Heat rate (Btu/kWh)	Heat rate (MBtu/MWh)	Total Fuel Required (MBtu/MWh)
40	400	9625	9.63	3850.0
60	600	9048	9.05	5428.8
80	800	8803	8.80	7042.4
100	1000	8750	8.75	8750.0

Using multiple regression analysis, a 2nd degree polynomial equation predicting the amount of fuel used (MBtu/MWh) by the coal plant as a function of output level (MW) was estimated from the data shown in Table A4-2. The estimated equation was of the form shown in equation 3.

$$fueluse = a \times p^2 + b \times p + c \qquad \textbf{(3)}$$

Where: fueluse = total quantity of fuel required (MBtu/MWh)
p = (real) electric power output (MW)
a,b,c = coefficients

Th relationship shown in equation 3 is often called an input/output relationship. The estimated coefficients for this relationship are shown in Table A4-3. Using the estimated input/output equation and the coefficients shown in the table allows us to construct a continuous function describing fuel use at the coal plant as a function of output for the entire range of expected plant output levels.

Table A4-3. Coefficients in the Coal Plant Input/Output Equation

Coefficient	Value
a	0.00805
b	7.029800
c	912.2400

The coal plant used in the ESIM03 model has a number of operating constraints. These are illustrated in Table A4-4. The coal plant has a maximum generation capability of 1000 MW and a minimum generation of 250 MW. This minimum output level is typical for large coal fired plants which often cannot be efficiently operated at low output levels. Coal fired plants are not capable of rapidly responding to changes in load. This characterized in the model by specifying a ramprate of 25 MW/hr for this plant.

Table A4-4. Coal Plant Operational Constraints

	Value
Maximum output level (MW)	1000
Minimum output level (MW)	250
Ramprate (MW/hr)	25

Appendix 5 – Natural Gas Combustion Turbine Plant

Natural gas (single cycle) combustion turbine (NGCT) power plants are sometimes small and unobtrusive, sometimes large and prominent features of the electric power system. In a natural gas CT plant, electricity is generated by igniting natural gas in a turbine. Typically, the turbine shaft drives the generator directly and produces electricity. The natural gas used to produce electricity is consumed in the process. Air emissions including carbon dioxide (CO_2), carbon monoxide (CO), sulfur oxides (SO_x) and nitrous oxides (NO_x) result from this combustion process. Figure 28 illustrates a 166 MW natural gas fired CT powerplant located near Rathdrum, Idaho.

Figure 28. This 2 unit 166 MW natural gas CT powerplant is located near Rathdrum, Idaho. Photo courtesy of Avista Corporation.

Although noise is a consideration, natural gas CT plants can be sited in a variety of locations provided they are in proximity to a bulk natural gas line. As a result, they can be sited in large buildings and industrial areas as well as in more remote locations. Because their siting requirements are typically less onerous than, say, those of a large coal plant, natural gas CT plants may be located closer to load centers.

Gas ("combustion") turbine power plants are based on aircraft jet engine technologies. They are available as aeroderivative machines—aircraft engines adapted to stationary applications or heavy duty frame machines— specifically designed for stationary uses. A (single cycle) natural gas CT unit consists of a gas compressor, fuel combustors and a gas expansion turbine. Air is compressed in the gas compressor. Fuel is then injected into the combustor and ignited. The hot, compressed air expands through the gas turbine driving the turbine blades. The rotational motion of the turning turbine blades drives the shaft connected to the generator. An excellent discussion of these topics, including an illustration of how NGCT units work, can be found on the How Stuff Works website: http://travel.howstuffworks.com/turbine.htm .

Early NGCT generation units were not particularly efficient from the standpoint of the amount of fuel used per unit of power output. Recent designs are considerably more efficient and the reported efficiencies of some of the advanced turbine designs now being marketed are path breaking. The initial installation or capital cost of a NGCT unit is typically lower than most other types of electric generating plants. However, their operational or variable costs are generally higher than, for example, coal fired plants. This is primarily due to the high cost of natural gas relative to other fossil fuels. The variable costs of operating a NGCT unit are relatively high at low output levels and lower at high output ranges, where their energy conversion efficiencies are more favorable. NGCT units are especially useful in the interconnected electricity system because they can be started quickly and are capable of very rapid changes in output levels. Because of this responsiveness and their relatively high variable costs, they are typically employed for furnishing power during the on-peak hours and for load following.

In larger NGCT plants, there are often multiple independent generators. Each of these is referred to as a "unit." Plant designs with multiple units enable more efficient use of the available fuel, particularly at less than full output, and allow the plant to continue to operate when one or more of the units are being serviced.

The natural gas fired NGCT plant in the ESIM03 program has 8 identical units. Each unit consists of a generator with a maximum generation capability of 50 MW. The aggregate generation capability of the plant is 400 MW. This is summarized in Table A5-1.

Table A5-1. Natural Gas CT Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	8	50 MW	400 MW

In the ESIM03 model, the natural gas CT plant is operated as if it were a single unit. No attempt is made here to address the so-called "optimal unit dispatch problem" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity.

Table A5-2 contains the heat rate and total fuel consumption at 4 levels of output from the natural gas CT plant in the ESIM03 model.

Table A5-2. Natural Gas CT Plant Characteristics by Selected Output Level

Percent Output	Plant Output (MW)	Heat rate (Btu/kWh)	Heat rate (MBtu/MWh)	Total Fuel Required (MBtu/MWh)
25	100	14,450	14.45	1445.0
50	200	10,700	10.70	2140.0
75	300	9,600	9.60	2440.0
100	400	9,150	9.15	3660.0

Using multiple regression analysis, a 2nd degree polynomial equation predicting the amount of fuel used (MBtu/MWh) by the natural gas CT plant as a function of output level (MW) was estimated from the data shown in Table A5-2. The estimated equation was of the form shown in equation 4.

$$fueluse = ap^2 + bp + c \quad \textbf{(4)}$$

Where: fueluse = total quantity of fuel required (MBtu/MWh)
p = (real) electric power output (MW)
a,b,c = coefficients

The relationship shown in equation 4 is often called an input/output relationship. The estimated coefficients for this relationship are shown in Table A5-3.

Table A5-3. Coefficients in the Natural Gas CT Plant Input/Output Equation

Coefficient	Value
a	0.002125
b	6.322500
c	791.2500

Using the estimated input/output equation and the coefficients shown in the table allows us to construct a continuous function describing fuel use at the natural gas CT plant as a function of output for the entire range of expected plant output levels.

The natural gas CT plant used in the ESIM03 model has a number of operating constraints. These are illustrated in Table A5-4. The NGCT plant has a maximum generation capability of 400 MW and a minimum generation of 0 MW. This minimum output level is typical for natural gas CT plants, which can be quickly started and made operational. Natural gas CT plants are capable of rapidly responding to changes in load. This is characterized in the model by specifying an unlimited hourly ramprate for this plant.

Table A5-4. Natural Gas CT Plant Operational Constraints

	Value
Maximum output level (MW)	800
Minimum output level (MW)	0
Ramprate (MW/hr)	unlimited

Appendix 6 – Natural Gas Combined Cycle Combustion Turbine Plant

Natural gas combined cycle combustion turbine (NGCCCT) power plants are sometimes small and unobtrusive but other times large and prominent features of the electric power system. In a natural gas CCCT plant, electricity is generated in two or more stages or processes resulting in high energy conversion efficiencies. The natural gas used to produce electricity is consumed in the process. Air emissions including carbon dioxide CO_2, carbon monoxide CO, sulfur oxides SO_x and nitrous oxides NO_x result from this combustion process. Figure 29 illustrates Coyote II, a 280 MW natural gas fired CCCT powerplant which is located near Boardman, Oregon.

Figure 29. The Coyote Springs 2 natural gas CCCT powerplant is located near Boardman, Oregon. Photo courtesy of Avista Corporation.

Natural gas CCCT plants can be sited in a variety of locations provided they are in proximity to a bulk natural gas line. Larger plants are typically sited in industrial areas and urban locations. Because their siting requirements are somewhat less onerous than, say, those of a large coal plant, natural gas CCCT plants may be located closer to load centers.

NGCCCT units rely on a multistage process for the efficient production of electricity. In general, the first stage of production process is a gas turbine and the second stage is made up of one or more steam turbines. This is illustrated in Figure 30. In the first stage, natural gas is used to fire a single cycle combustion turbine and generate electricity. Further details about single cycle combustion turbines are provided in Appendix 5. The second stage is a unique feature of NGCCCT plants. In the second stage of the process, the hot exhaust gases from the combustion turbine are then "recovered", used to heat water and produce steam. The steam, in turn, is used to drive a steam turbine which turns another generator also producing electricity. This multi-stage design is much more efficient than any other currently existing fossil fuel technology.

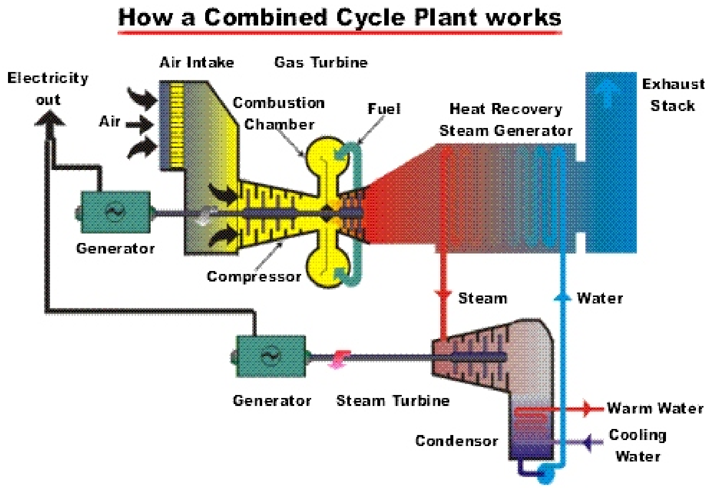

Figure 30. Schematic of a natural gas CCCT plant. Diagram courtesy of Nooter/Eriksen, St. Louis.

NGCCCT generation units are relatively efficient from the standpoint of the amount of fuel used per unit of power output. Recent designs are considerably more efficient and the reported efficiencies of some of the advanced turbine designs now being marketed is path breaking. The initial installation or capital cost of a NGCCCT unit is typically less than most other types of electric generating plants. However, their operational or variable costs are generally higher than, for example, coal fired plants. This is primarily due to the high cost of natural gas relative to other fossil fuels. The variable costs of operating a NGCCCT unit are relatively high at low output levels and lower at high output ranges where their energy conversion efficiencies are more favorable. Although many NGCCCT units can be run in single cycle mode alone, they are far more economical when run in combined cycle mode. NGCCCT units are especially useful in the interconnected electricity system because they can be started quickly and are capable of very rapid changes in output levels. To take advantage of both their responsiveness and operational economies, NGCCCT units are typically operated as "intermediate" type plants—providing both baseload power and some peaking power.

In larger NGCCCT plants, there are often multiple independent generators. Each of these is referred to as a "unit." Plant designs with multiple units enable more efficient use of the available fuel particularly at less than full output and allow the plant to continue to operate when one or more of the units are being serviced.

The natural gas fired CCCT plant in the ESIM03 program has 2 identical units. Each unit consists of a generator with a maximum generation capability of 300 MW. The aggregate generation capability of the plant is 600 MW. This is summarized in Table A6-1.

Table A6-1. Natural Gas CCCT Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	2	300 MW	600 MW

In the ESIM03 model, the natural gas CCCT plant is operated as if it were a single unit. No attempt is made here to address the so-called "optimal unit dispatch problem" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity.

Table A6-2 contains the heat rate and total fuel consumption at 4 levels of output from the natural gas CCCT plant in the ESIM03 model.

Table A6-2. Natural Gas CCCT Plant Characteristics by Selected Output Level

Percent Output	Plant Output (MW)	Heat rate (Btu/kWh)	Heat rate (MBtu/MWh)	Total Fuel Required (MBtu/MWh)
25	150	11,860	11.86	1779.00
50	300	8,860	8.86	2658.00
75	450	7,885	7.89	3548.25
100	600	7,514	7.51	4508.40

Using multiple regression analysis, a 2nd degree polynomial equation predicting the amount of fuel used (MBtu/MWh) by the natural gas CCCT plant as a function of output level (MW) was estimated from the data shown in Table A6-2. The estimated equation was of the form shown in equation 5.

$$fueluse = ap^2 + bp + c \tag{5}$$

Where: fueluse = total quantity of fuel required (MBtu/MWh)
p = (real) electric power output (MW)
a,b,c = coefficients

The relationship shown in equation 5 is often called an input/output relationship. The estimated coefficients for this relationship are shown in Table A6-3.

Table A6-3. Coefficients in the Natural Gas CCCT Plant Input/Output Equation

Coefficient	Value
a	0.000902
b	5.376050
c	955.2375

Using the estimated input/output equation and the coefficients shown in the table allows us to construct a continuous function describing fuel use at the natural gas CCCT plant as a function of output for the entire range of expected plant output levels.

The natural gas CCCT plant used in the ESIM03 model has a number of operating constraints. These are illustrated in Table A6-4. The NGCCCT plant has a maximum generation capability of 600 MW and a minimum generation of 0 MW. This minimum output level is typical for natural gas CCCT plants which can be quickly started and made operational. Natural Gas CCCT plants are capable of rapidly responding to changes in load. This is characterized in the model by specifying an unlimited hourly ramprate for this plant.

Table A6-4. Natural Gas CCCT Plant Operational Constraints

	Value
Maximum output level (MW)	600
Minimum output level (MW)	0
Ramprate (MW/hr)	unlimited

Appendix 7 – Oil Fired Plant

Oil fired steam powerplants are relatively large and prominent features of the interconnected electric power system. In an oil fired power plant, low quality oil, usually fuel oil number 6, is burned to produce steam and make electricity. The oil used to produce electricity is consumed in the process. Air emissions including carbon dioxide (CO_2), carbon monoxide (CO), sulfur oxides (SO_x), nitrous oxides (NO_x) and particulates result from this combustion process. Figure 31 illustrates the 113 MW Punta Prieta oil fired steam powerplant located near La Paz, Mexico.

Figure 31. The 113 MW Punta Prieta oil fired powerplant is located on the Baja Peninsula. Note the large oil storage tanks. Image from Photospin.com

Fuel oil is bulky, expensive and difficult to transport. Consequently, oil fired power plants are usually located in close proximity to seaports or petroleum refineries. Oil fired powerplants are not especially efficient producers of electricity, often have relatively high emissions of regulated sulphur compounds and have fairly restrictive siting requirements. As a result, many of the existing oil fired powerplants are relatively old and reflect less than state-of-the-art designs.

Although recent examples are few, the initial installation or capital cost of an oil fired powerplant is somewhat lower than that of a coal fired plant of comparable size. However, their operational or variable costs are generally higher than other thermal powerplants. This is primarily due to the high cost of oil relative to other fossil fuels. As with other powerplants, the variable costs of operating an oil fired plant are relatively high at low output levels and lower at high output ranges where their energy conversion efficiencies are more favorable. Oil fired units play a role in the interconnected electricity system because they can be started relatively quickly and are capable of making moderate changes in output levels. Because of their operational costs and typical age, many oil fired powerplants are used in reserve mode for long periods of time.

In larger oil fired plants, there are often multiple independent generators. Each of these is referred to as a "unit." Plant designs with multiple units enable more efficient use of the available fuel, particularly at less than full output, and allow the plant to continue to operate when one or more of the units are being serviced.

The oil fired power plant in the ESIM03 program has 2 identical units. Each unit consists of a generator with a maximum generation capability of 100 MW. The aggregate generation capability of the plant is 200 MW. This is summarized in Table A7-1.

Table A7-1. Oil Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Generator	2	100 MW	200 MW

In the ESIM03 model, the oil fired powerplant is operated as if it were a single unit. No attempt is made here to address the so-called "optimal unit dispatch problem" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity.

Table A7-2 contains the heat rate and total fuel consumption at 5 levels of output from the oil fired plant in the ESIM03 model.

Table A7-2. Oil Plant Characteristics by Selected Output Level

Percent Output	Plant Output (MW)	Heat Rate (Btu/kWh)	Heat Rate (MBtu/MWh)	Total Fuel Required (MBtu/MWh)
25	50	12,608	12.07	603.40
40	80	10,949	10.95	875.92
60	120	10,286	10.29	1234.32
80	160	9,979	9.98	1596.64
100	200	9,900	9.90	1980.00

Using multiple regression analysis, a 2nd degree polynomial equation predicting the amount of fuel used (MBtu/MWh) by the plant as a function of output level (MW) was estimated from the data shown in Table A7-2. The estimated equation was of the form shown in equation 6.

$$fueluse = ap^2 + bp + c \tag{6}$$

Where: fueluse = total quantity of fuel required (MBtu/MWh)
p = (real) electric power output (MW)
a,b,c = coefficients

The relationship shown in equation 6 is often called an input/output relationship. The estimated coefficients for this relationship are shown in Table A7-3.

Table A7-3. Coefficients in the Oil Plant Input/Output Equation

Coefficient	Value
a	0.002351
b	8.557432
c	172.25201

Using the estimated input/output equation and the coefficients shown in the table allows us to construct a continuous function describing fuel use at the oil plant as a function of output for the entire range of expected plant output levels.

The oil plant used in the ESIM03 model has a number of operating constraints. These are illustrated in Table A7-4. The oil plant has a maximum generation capability of 200 MW and a minimum generation of 25 MW. This minimum output level is specified for a plant which is primarily being used to provide reserve generation capability. The plant is operating at a low level so that its addition output capability is available if needed. Oil plants are capable of relatively rapid changes in output. This is characterized in the model by specifying an unlimited hourly ramprate for this plant.

Table A7-4. Oil Plant Operational Constraints

	Value
Maximum output level (MW)	200
Minimum output level (MW)	25
Ramprate (MW/hr)	unlimited

Appendix 8 – Hydropower Plant

At a hydropower plant, electricity is generated by the force of falling water. Unlike a thermal powerplant, this electricity is generated without the production of air pollution. The water used to produce electricity is not consumed and is available for other purposes downstream.

Some powerplants are located on rivers, streams and canals. In many cases, a dam is required to store water so it is reliably available when needed to generate electricity and for other purposes. The reservoir created by a dam acts much like a battery, storing water (energy) for later use. Figure 32 illustrates Glen Canyon Dam a 1,320 MW powerplant (Seitz 2004) constructed on the Colorado River by the U.S. Bureau of Reclamation.

Figure 32. Glen Canyon Dam is located on the Colorado River near Page, Arizona. U.S. Bureau of Reclamation file photo.

Locations suitable for the construction of hydropower plants are extremely rare. Siting considerations include the amount of water available, ownership of water rights, suitable geology, current land use, human habitation, potential ecological impacts and perhaps most importantly—favorable topography. Although there are some sites suitable for hydropower development remaining in the continental U.S., the vast majority of feasible sites are already in use.

A schematic for a typical hydropower plant located on a storage reservoir is shown in Figure 33. The height the water falls is known as the "head." This height is measured from the elevation of the reservoir's surface to the elevation of the tailwater. Relative to the pre-dam condition, a storage reservoir increases the head available for power production and stores water for use as needed by the powerplant.

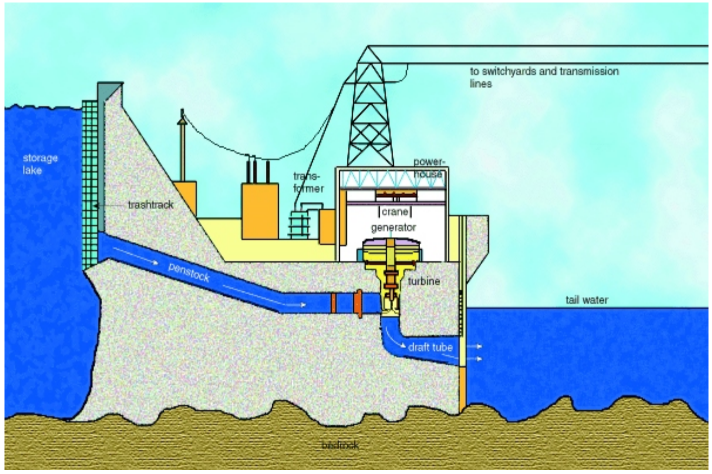

Figure 33. Schematic of a typical hydropower plant. Argonne National Laboratory diagram.

When the control gates are opened, water from the reservoir passes through the trash racks and into a pipe known as a penstock. Water flowing through the penstock can be controlled and selectively directed to one or more turbines to produce electricity.

Hydropower generating units have four main components: a turbine, a rotor, a shaft connecting the turbine to the rotor and a stator. These components are illustrated in Figure 34. Water falls through the penstock into the turbine. The wicket gates shown in this figure allow the amount of water directed into the turbine to be varied. The force of the falling water against the blades of the turbine rotates a large shaft. The rotating shaft turns the rotor or moving portion of the generator. The outside edge of the rotor is made up of very strong electromagnets. These electromagnets are formed by wrapping copper wires around a steel core (sometimes referred to as a pole). These magnets are located so as to provide north and south poles around the rim of the rotor.

The stator is the donut-shaped structure surrounding the rotor. The key component of a stator is the stator windings or conductors. In a larger generator, stator windings are made up of individual coils each of which is comprised of multiple strands of copper wire, an excellent conductor of electricity. The stator windings are located around and very close to the rotor. The movement of the electromagnets in the rotor causes electricity to flow in the conductors.

The turbine shaft is directly connected to the rotor. As the turbine is turned by the force of the falling water, the rotor turns. The electromagnets on the rim of the rotor sweep past the generator's stationary coils (the stator) and induce or create electricity. By changing the strength of the electromagnets in the rotor and varying the amount of water flowing in the penstock, the voltage and power output of the generator can be regulated.

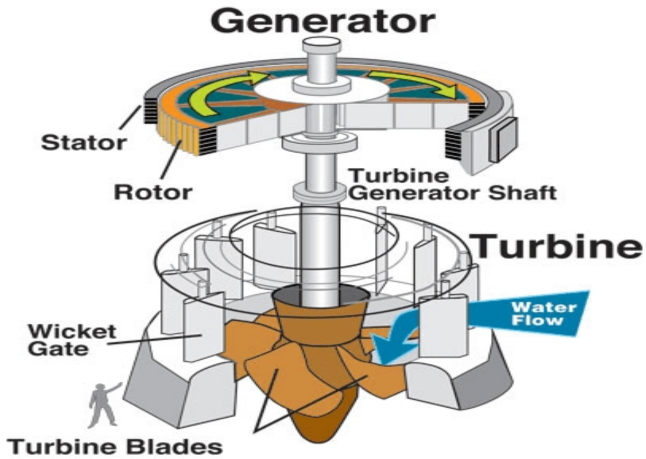

Figure 34. Schematic of a turbine and generator. Diagram courtesy of U.S. Army Corps of Engineers.

The initial cost of installation or capital cost of a hydropower plant is typically higher than a thermal plant. In general, this is because (a) the costs of constructing a storage reservoir are quite high, and, (b) no two hydropower plants are the same. Because each hydropower plant is unique, many of their components must be individually designed and manufactured. Hydropower plants do not consume fossil fuels. Consequently, their variable costs of operation are generally quite low in comparison to thermal plants. Hydropower plants are especially useful in the interconnected electricity system because they can be started quickly and are capable of very rapid changes in output levels. When sufficient water storage is available and there are no other operational constraints, hydropower plants are typically operated as "peaking" type plants—providing power during the on-peak hours of the day.

In larger hydropower plants, there are multiple turbines and generators. Each of these is referred to as a "unit." Typically, but not always, each unit is fed by a separate penstock. Plant designs with multiple units enable more efficient use of the water at less than full release and allow the plant to continue to operate when one or more of the units are being serviced.

The hydropower plant in the ESIM03 program has 4 units. Each unit consists of a turbine and generator pair. Each of the turbines has a maximum release capability of 3,000 cfs. Each of the generators has a maximum generation capability of (approximately) 60 MW. The aggregate release and generation capability of the plant is 12,000 cfs and 239.96 MW respectively. This is summarized in Table A8-1.

Table A8-1. Hydroelectric Plant Specifications

Feature	Units		Total Plant Capability
	Number	Capacity	
Turbine	4	3,000 cfs	12,000 cfs
Generator	4	60 MW	239.96 MW

Optimal operation of the 4 generation units is known as the "unit dispatch problem." In the ESIM03 model, the hydroplant is operated as if it were a single unit. No attempt is made here to address the so-called "optimal unit dispatch problem" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity.

The hydropower plant characterized in the ESIM03 model generates electricity in response to the user specified total release, the user specified inflow and the starting reservoir elevation specified by the user. Appendix 17 contains a more specific (mathematical) description of the hydropower plant and a more rigorous representation of the relationship between head, release and the production of (real) electric power. Appendix 21 provides a description of the storage reservoir and details the manner in which this reservoir is mathematically represented in the model.

The ESIM03 model allows the user to vary several parameters influencing the operation of the hydropower plant. These include the total release, the starting reservoir elevation, the inflow, the minimum release, the maximum release and the hourly ramprate. The hydropower plant represented in the ESIM03 model has a number of operating constraints. When the reservoir is full, the hydropower plant can release a maximum (default) of 12,000 cfs through the turbines which generates 239.96 MW of real power. The (default) minimum release from the hydropower plant is 0.0 cfs which generates 0.0 MW of real power. Typically, hydropower plants with substantial storage reservoirs are capable of rapidly changing output levels. This is characterized in the model by specifying an unlimited (default) hourly ramprate for this plant. The user can specify the value of these parameters singly and in combination, in order to simulate their effect on the operation of both the hydropower plant and the interconnected electricity system.

Appendix 9 – Fuels and Heat Content

Thermal powerplants use a variety of fossil fuels including coal, natural gas, oil and a variety of biofuels. There are 4 thermal powerplants in the ESIM03 model which use three different types of fossil fuels. This appendix briefly describes those fuels and their energy content. Table A9-1 summarizes much of this information.

In the context of electric power production in the United States, the energy content of a fossil fuel is described by its "heat content." The heat content of a fuel is measured in millions of British thermal units (Mbtu). A British thermal unit is the amount of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit. The heat content of fossil fuels varies both by fuel type and fuel quality. As might be expected, fuels with higher per unit heat content are generally more valuable for power production.

Various types of coal are mined in the United States including anthracite, lignite and bituminous coals. In the Western United States, coal fired powerplants are fueled predominantly by bituminous coal. Bituminous coal is dense and black (often with well-defined bands of bright and dull material) with a moisture content of usually less than 20 % (Energy Information Agency 2005). It is produced at mines located in various western locals from Arizona to Montana. The quantity of coal is measured in tons. In the ESIM03 model, the assumed heat content of the coal used by the coal fired steam powerplant is 21.00 MBtu/ton.

Table A9-1. Fuels, Units and Heat Content

Fuel	Units	Units Abbreviation	Heat Content MBtu/unit
Coal	short tons[9]	tons	21.00
Natural gas	1000 cubic feet	ccf	1.027
Fuel Oil #6[10]	barrels[11]	bbls	6.287[12]

[9] A short ton is equal to 2000 U.S. pounds.

[10] Oil fired steam plants typically are fueled by residual fuel oil #6 while oil fired combustion turbine powerplants are typically fueled by the lighter more volatile fuel oil #2.

[11] A barrel is equal to 42 U.S. gallons.

[12] Energy Information Administration (2005).

Crude oil is a mixture of hydrocarbons that existed in liquid phase in underground reservoirs and that remains liquid at atmospheric pressure (Energy Information Agency 2005). Residual oil is a heavy oil and a (by)product of refining oil to produce various distillate petroleum products such as gasoline and jet fuel. It is relatively thick and viscous, more difficult to ignite and often has a relatively high sulphur content. Residual oil #6 is typically used in powerplants, certain industrial processes and for fueling some kinds of marine vessels. Residual oil is usually measured in barrels (bbls). The heat content of residual fuel oil #6 used by the oil-fired steam powerplant in the ESIM03 model is assumed to be 6.287 MBtu/bbl.

Natural gas is a relatively common mixture of hydrocarbon and nonhydrocarbon gasses found in porous geological formations associated with oil bearing strata throughout the world (Energy Information Agency 2005). Its chief constituent is methane (gas). It is relatively volatile, can be corrosive, prone to explosive combustion and difficult to capture, store and transport. In the not so distant past (circa 1970), the infrastructure to transport natural gas was virtually nonexistent and it was considered an unusable and unwanted byproduct of oil production. As a result, it was common to see natural gas being "flared off" or burned at oil wells and refineries across the United States. This practice continues today in oil producing areas in Mexico, Asia and the Middle East. In the United States, the installation of appropriate infrastructure has facilitated the use of natural gas resources in powerplants and industrial processes nationwide. Natural gas is sold commercially in one thousand cubic foot (ccf) units. The heat content of the natural gas used by the natural gas fired powerplants in the ESIM03 model is assumed to be 1.027 MBtu/ccf.

Appendix 10 – Powerplant Costs

Estimating the costs of constructing and operating different types of powerplants can be a resource intensive and trying effort. These costs vary considerably by plant type and location. In addition, costs are classified in a variety of fashions and for different purposes. The electric power industry has a number of additional cost categories which are in common use.

The Department of Energy (DOE), Energy Information Agency (EIA) employs a standardized system of cost categories which they use in their widely read report entitled the *Annual Energy Outlook*. To compare construction costs, both the EIA and the electric power industry rely on a measure known as the "total overnight cost." The EIA classifies other costs as "fixed O&M costs" and "variable O&M costs" where the term, "O&M," is used to denote a rather broad category known as operation and maintenance.

The total overnight cost of constructing a powerplant is the instantaneous cost of constructing a powerplant at a particular location. It is typically measured in dollars per kilowatt of installed capacity. Major components of the total overnight cost include the permitting and compliance, design, engineering, actual construction and interest during construction of the powerplant.

Fixed O&M costs are those costs which must be incurred on a periodic basis whether or not the powerplant is operated. Fixed O&M costs are typically measured in dollars per kilowatt of installed capacity. Fixed O&M costs includes such things as labor costs. These costs must be incurred whether the plant is running or not.

Variable O&M costs are those costs which must be incurred in proportion to the operation of the powerplant. These costs are typically measured in dollars per megawatt-hour of electricity produced. Cooling system costs, for example, vary with the output of the powerplant and fall into the category of variable O&M costs.

Fuel costs are not included in the variable O&M cost category. The cost of fuel used by a powerplant in order to generate electricity is a function of the price of the raw fuel, its heat content and the heat rate of any particular powerplant. Fuel costs are often measured as the average cost of fuel per megawatt-hour of electricity produced.

Due to recent advances in technology, there are differences between the costs of constructing and operating existing powerplants and those of new or planned powerplants. The estimated costs of new powerplants are employed by the EIA and a variety of other entities in utility planning and forecasting studies.

The cost data for existing plants are collected by the EIA through a variety of mandatory and voluntary industry reports and surveys. These include but are not limited to: Federal Energy

Regulatory Commission (FERC) form 1 and EIA form 412 (Martin 2005). Cost data are collected from Federal Power Administrations, investor owned utilities (IOU's), non-utility generators (NUGS), public utilities and other entities.

Table A10-1 illustrates representative costs for selected types of powerplants commonly encountered in the interconnected electricity system. As shown in the table, there are significant tradeoffs between performance, capital and variable costs.

Table A10-1. Representative New Plant Costs (2003$)

Plant Type	Total Overnight Cost ($/kW)	Fixed O&M ($/MW)	Variable O&M ($/MWh)	Avg. Fuel Cost ($/MWh)
Coal	1,213	24.36	4.09	10.59[13]
NGCT	374	9.31	2.80	49.04[13]
NGCCCT	558	10.35	1.77	40.25[13]
Oil	na	8.80[14]	3.64[14]	65.93[13]
Hydropower	1,415	12.35	4.80	none
Wind	1,134	26.81	none	none
Nuclear	1,957	60.06	0.44	4.53[15]
Solar (thermal)	2,960	50.23	none	none
Geothermal	3,108	104.98	none	none

Source: Unless otherwise specified, all data are from EIA (2005) Table 38 p. 67. Coal refers to "scrubbed" coal plants; oil refers to "oil fired steam" plants; NGCT, NGCCCT and Nuclear refer to "advanced" plant types, and hydropower refers to "conventional" hydropower plants.

[13] Calculated using the fuel heat content assumptions and heat rate curves in the ESIM03 model. See filename=calc_avg_fuelcost.xls for fuel costs per unit and other details.

[14] Martin (2005).

[15] Calculated from EIA (2005a) Table 38 and EIA (2005b) Figure 72 data (2004 price used).

For the interconnected electric power system characterized in the ESIM03 model, the powerplants are already constructed and online. Consequently, the economic decision being explored is how to optimally dispatch these existing plants to satisfy load while minimizing the costs of doing so. Economic theory tells us that only the variable costs are pertinent to this short-run decision. Although the fixed costs of constructing and maintaining the powerplants do not enter into the optimal dispatch decision, utilities do recover these costs from their customers and they are included in the rates consumers pay.

The Beta version of the ESIM03 model uses the fuel costs (only) to identify an optimal hourly pattern of generation. It does not track or report the fixed costs of powerplant construction or the fixed and variable operation and maintenance costs. It is envisioned that future versions of this software will include this capability.

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Appendix 11 – Emissions

All of the thermal powerplants characterized by the ESIM03 model burn fossil fuels to produce electricity. Combustion of these fuels produces electric power but also results in undesirable emissions of gasses and other compounds into the atmosphere. This appendix describes the relationship between these thermal plants, their operation and selected emissions.

In the United States, thermal powerplants produce a significant proportion of the total carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x) and mercury (Hg) emissions. In 2002, thermal powerplants were the source of 39% of the CO_2, 69% of the SO_2, 29% of the NO_x, and 40% of the Hg emitted nationwide (Miller and Van Atten 2005).

Carbon Dioxide (CO_2). All fossil fuels contain carbon, which when burned, combines with oxygen to produce carbon dioxide (CO_2). Large amounts of CO_2 have been injected into the atmosphere as a result of human activities and CO_2 has accumulated to above historical levels. This buildup of CO_2 is believed to limit the re-radiation of heat from the earth's surface back out into space, causing an increase in global average temperatures. This is known as "greenhouse effect." CO_2 is the largest contributor to the volume of greenhouse gasses. For this reason, CO_2 emissions are closely associated with global warming.

Reduction of CO_2 emissions presents a particularly challenging policy dilemma because the scope of potential remedies is far reaching and pervasive. Reducing CO_2 emissions with current technologies will require much more than simply installing some sort of treatment system at fossil-fueled powerplants. Reducing CO_2 and the accumulation of other greenhouse gasses will require a suite of potentially painful economic and regulatory measures. These may include increasing reliance on non-CO_2 emitting generation technologies (solar, wind etc), increasing the efficiency of new and existing powerplants, reductions in the demand for electric power such as demand side management (DSM) and the initiation of large-scale carbon sequestration activities.

CO_2 emissions from a fossil fuel plant are related to the amount of carbon contained in the fuel (closely associated with the "heat content") and the efficiency of the power plant in converting the fuel to electricity (the "heat rate"). In general, the CO_2 emissions rate for a coal plant is approximately double that of a natural gas fired plant. This is because the carbon content of coal is much higher than the carbon content of natural gas. The emissions rate for any specific plant depends, of course, on the specific carbon content of the fuel used and the efficiency of the plant in converting that fuel into useful energy. Table A11-1 illustrates representative CO_2 emission input rates for coal, gas, and oil fired power plants. These emission input rates represent the amount of CO_2 contained in each unit of fuel expressed in terms of its heat content (MMBtu). The input emissions rates in Table A11-1, the heat content of the fuel (Appendix 9) and the heat rate curves for each power plant in the ESIM03 model (see Appendices 4 through 7) are used to compute the output of CO_2 illustrated in Table 4 and in the modeled output.

Sulfur Dioxide. Sulfur dioxide (SO_2) emissions from power plants combine with other compounds in the air to form sulfur particles. These particles are a major constituent of the suspended particulate matter we breath. Fine particles have been linked to a number of serious health conditions in children, older adults and members of the general population. In addition, suspended particulate matter scatters the sunlight contributing to the degradation of view sheds and natural vistas across the country. SO_2 is a major contributor to downwind sulfuric acid deposition, also known as "acid rain." Acid rain has been shown to be harmful to terrestrial, riparian and aquatic ecosystems alike.

Coal and oil contain significant amounts of sulfur while natural gas contains only relatively small amounts. As a result, coal and oil fired powerplants are the largest generators of SO_2 emissions and natural gas fired plants emit only limited amounts of SO_2. The emissions rate for any specific plant depends, of course, on the specific sulfur content of the fuel used, the efficiency of the plant in converting that fuel into useful energy and the nature of the pollution control systems installed on the plant. Table A11-1 illustrates representative SO_2 emission input rates for coal, gas, and oil fired power plants. These emission input rates represent the amount of SO_2 contained in each unit of fuel expressed in terms of its heat content (MMBtu). The input emissions rates in Table A11-1, the heat content of the fuel (Appendix 9) and the heat rate curves for each power plant in the ESIM03 model (see Appendices 4-7) form the basis for the output of SO_2 illustrated in Table 4 and in the modeled output.

Nitrogen Oxides. The emission of NO_x into the atmosphere has long been associated with smog and ozone formation. Smog and ozone have been linked to human respiratory health problems and damage to crops and forests. Like SO_2, NO_x contributes to the fine particulate matter suspended in the air and it contributes to acid rain. The precipitation of nitrogenous compounds from the atmosphere onto terrestrial and particularly aquatic habitats has been shown to contribute to eutrophication. Eutrophication occurs when unnaturally high levels of nutrients cause algal blooms. These blooms reduce the habitat available for other species and can suffer sudden crashes or die-offs. Decomposition of large quantities of algal biomass can reduce the biologically available oxygen to near zero causing the death of other organisms.

NO_x emissions are formed during high temperature combustion of fuels. Under these conditions, nitric oxide (NO) is formed which rapidly oxidizes further to NO_2. Collectively, these two compounds are referred to as NO_x. NO_x is, or can be, a byproduct of the combustion of any fossil fuel. The emissions rate for any specific plant depends, of course, on the specific fuel used, the temperature of the combustion process, the efficiency of the plant in converting that fuel into useful energy and the nature of the pollution control systems installed on the plant. Table A11-1 illustrates representative NO_x emission input rates for coal, gas, and oil fired power plants. These emission input rates represent the amount of NO_x contained in each unit of fuel expressed in terms of its heat content (MMBtu). The input emissions rates in Table A11-1, the heat content of the fuel (Appendix 9) and the heat rate curves for each power plant in the ESIM03 model (see Appendices 4-7) form the basis for the output of NO_x illustrated in Table 4 and in the modeled output.

Table A11-1. Representative Emission Input Rates by Generator Type

Plant Type	Carbon Dioxide CO_2 (lbs/MBtu)	Sulphur Oxides SO_x (lbs/MBtu)	Nitrous Oxides NO_x (lbs/MBtu)	Mercury Hg (lbs/MBtu)
Coal	205.20	0.07	0.30	2.0e-06
NGCT	120.00	0.03	0.30	na
NGCCCT	120.00	0.03	0.30	na
Oil Fired Steam	173.76	0.53	0.23	na
Hydropower	0.00	0.00	0.00	0.00
Nuclear	0.00	0.00	0.00	0.00
Source: constructed by the author.				

Mercury. Powerplants, natural and industrial processes are all significant emitters of mercury (Hg) into the air. Several distinct forms of mercury are produced by powerplants. Among these are elemental mercury and oxidized mercury. Elemental mercury can be transported vast distances in the atmosphere. One class of oxidized mercury is readily water soluble, less volatile than elemental mercury and adheres to surfaces it contacts. Once deposited, biological processes can transform mercury compounds into a highly toxic compound known as methylmercury.

In the aquatic ecosystem, methylmercury is known to concentrate in the tissue of fish, particularly predatory fish at the top of the food chain. Some birds and other animals that prey on fish bio-accumulate the mercury in their tissues. Certain species, such as tuna, can accumulate very high concentrations of mercury in their bodies. Human exposure to methylmercury is linked primarily to the consumption of fish but other factors may also play a role.

Methylmercury is known to adversely effect humans through several different organ systems. The severity of the effect is largely dependent on the magnitude, timing and extent of the exposure. Children in developmental stages can be acutely affected. Some studies suggest that mercury can also effect the adult immune and reproductive systems.

At the present time, the emission of mercury by power plants is largely unregulated at the Federal level. Several states, are now regulating mercury emissions and national regulatory measures are being drafted. It seems likely that comprehensive and uniform Federal mercury emission standards will be enacted in the relatively near future.

Mercury is present in varying amounts in coal and in trace amounts in other fossil fuels. Because it is present in relatively higher concentrations in coal and large amounts of coal are burned by coal plants, coal fired power plants are, by far, the primary emitters of mercury among powerplants. The emissions rate for any specific plant depends, of course, on the specific fuel used and its Hg content, the efficiency of the plant in converting that fuel into useful energy and the nature of the pollution control systems installed on the plant, if any. Table A11-1 illustrates representative Hg emission input rates for coal fired power plants. As shown, data for gas and oil fired plants are not currently available. These emission input rates represent the amount of Hg contained in each unit of fuel expressed in terms of its heat content (MMBtu). The input emissions rates in Table A11-1, the heat content of the fuel (Appendix 9) and the heat rate curves for each power plant in the ESIM03 model (see Appendices 4-7) are used to compute the output of Hg illustrated in Table 4 and in the modeled output.

Appendix 12 – Elasticity of Demand for Electricity

This appendix defines the term (own price) "elasticity of demand," describes its use in the electricity context and explains some of its policy implications. Substantial portions of this appendix were written by Earl Ekstrand, a friend and colleague at the U.S. Bureau of Reclamation. His generous contributions are gratefully acknowledged.

Economic theory states that supply and demand equilibrate to determine the price and quantity of a good sold. A supply function relates the quantity of a good that would be offered for sale at a given price. The costs of production generally increase as output increases and supply functions typically are upward sloping. A demand function relates the quantity of a good a consumer is willing to purchase to its price. Generally, the quantity of a good consumed increases as the price decreases and demand functions are downward sloping.

The term "elasticity of demand" is an economist's way of describing how responsive consumers are to changes in price. For some goods, like salt, even a big increase in price will not cause consumers to cut back very much on consumption. For other goods, like chocolate ice cream cones, even a modest price increase will cause consumers to cut back on consumption.

Demand is the multi-dimensional relationship between the quantity of a good consumed and the factors that determine how much is consumed. The determinants of demand are divided into two groups; a movement parameter (own price) and shift parameters (all demand determinants except own price). We often describe the relationship between these determinants using the notation shown in equation 7.

$$Q_D = f(P, P_s, P_c, I, \ldots) \tag{7}$$

Where:

Q_D = the quantity demanded.
P = the (own) price of the good
P_S= the price of substitutes
P_C= the price of complements.
I= consumer income.
....= all other factors not explicitly mentioned.

Holding the values of all of the shift parameters constant we can trace out a two dimensional relationship between the quantity demanded, Q_D , and the (own) price, P.

The ellipses '...' emphasize that demand is affected by a number of other factors which may not be explicitly represented in the mathematical representation. These include such things as tastes and preferences.

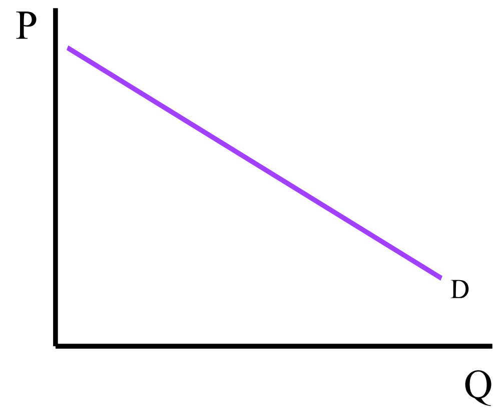

Figure 35. The Demand Curve

The demand curve, shown in Figure 35 is negatively sloped. It is the graphic expression of the law of demand—consumers buy less at higher prices. Or stated in another way, holding all shift parameters constant, price and the quantity demanded are inversely related.

We now have a precise definition of the demand curve: the relationship between the quantities of a good that consumers are willing to buy and all possible prices, in a specified time period, *ceteris paribus*. The phrase in a specified time period emphasizes that demand is time dependent. Any specific quantity demanded occurs in a specified time. The Latin phrase, *ceteris paribus*, means "all other things held constant." This refers to the shift parameters.

In addition to own price, P, the price of substitute goods, P_s are also determinants of demand. Substitute goods are goods that can be used in place of each other. For example, a good substitute for a McDonald's Big Mac could be a Burger King Whopper. Another example could be synthetic motor oil for petroleum based motor oil. There are many examples...

In general, the price of substitutes, P_s, affects the demand for the good. For example if the price of a Big Mac were $1.50 and the price of a Whopper fell to $0.25, then the demand for a Big Mac would most likely fall. The thing to remember is that the demand for a good and the price of substitute goods are positively correlated. *Ceteris paribus*, if the price of a substitute good increases, the demand for the good for which it substitutes will increase. If the price of a substitute good falls, then the demand for the good for which it substitutes will fall.

Other goods are complementary to demand. The price of complements in equation 7 is denoted by P_c. In other words, they are used with the good or service under consideration. For example, hamburger buns and hamburger meat are complementary goods. If the price of hamburger buns were to suddenly skyrocket, then the demand for hamburger meat may well fall. *Ceteris paribus*, if the price of a complementary good increases, the demand for the good for which it is a complement will fall. If the price of a complementary good falls, then the demand for the good for which it is a complement will rise.

Consumer income, I, also has a profound effect on the demand for goods and services. If a consumer has more income to spend, *ceteris paribus*, their demand for goods and services will be greater. In the limit, any individual's ability to consume goods and services is constrained by their income.

The (own) price elasticity of demand is the percentage change in quantity demanded divided by the percentage change in (own) price. It is usually meaningless to talk about the elasticity of an entire demand schedule (because, except for special cases, it differs at each point). Economists typically measure the elasticity at a particular point. To compute a point elasticity, the formula given by equation 8 is employed.

$$\varepsilon = \frac{\partial Q_D}{\partial P} \times \frac{P}{Q_D} \tag{8}$$

Notice that if you apply the formula above exactly, the elasticity value is always negative. This is because demand curves are negatively sloped. An increase in price will always cause a decrease in the quantity demanded. Often, economists will ignore this negative sign which can really be confusing. Technically what they are doing by ignoring the sign is referring to the absolute value of the elasticity, i.e. $|\epsilon|>0$.

By convention, there is a way of classifying elasticity values. When the numerical (absolute) value of the elasticity is less than 1.0, demand is said to be "inelastic." When the numerical value of elasticity is greater than 1, demand is said to be "elastic." If a good is elastic, it means that people are relatively responsive to price changes. Inelastic demand means that people are relatively unresponsive to price changes.

What does an own price elasticity of demand mean? If the elasticity of the good in question were 0.5 (inelastic), it means that a 1 % increase in the price would result in a 0.5 % decrease in the demand for a good. In other words, a price increase causes a less than proportionate decrease in demand. If, on the other hand, the elasticity of the good in question were 2.5 (elastic), it means that a 1 % increase in the price would result in a 2.5 % decrease in the demand for a good. In other words, a price increase would cause a greater than proportionate decrease in demand.

Although the slope of a linear demand curve is constant, the elasticity is not. The reason for this is that P and Q change as you move along the demand curve. Second, demand is most price elastic at the top of the demand curve. It becomes less elastic as price is lowered. This is shown in Figure 36.

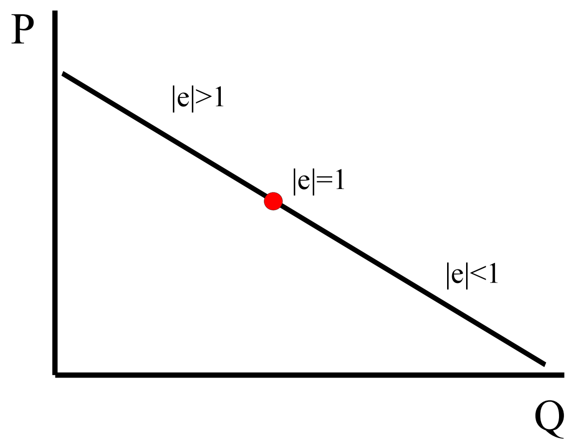

Figure 36. Linear demand and elasticity relationship

The focus of this appendix is on own price elasticity. However, there are a number of other elasticity measures. In addition to own price elasticities, elasticity measures can be calculated for complements and substitutes (cross price elasticities) and for income (income elasticities).

Cross-price elasticity of demand refers to the relationship of the quantity demanded of one good reacting to the %age change of the price of another good. If the two goods are substitutes, then the elasticity will be positive. Goods that are complements have a negative elasticity measure. An example of substitutes could include coffee and tea, meaning that an increase in the price of one leads to greater demand for the other. Complements have the opposite effect, a decrease in the price of barbeque grills may lead to greater demand for charcoal briquets.

The income elasticity of demand measures the % change in quantity demanded for a one percentage change in income. For normal goods, the income elasticity is a positive value. If the elasticity is greater than one, then economists refer to this good as a luxury good because purchases of this good increases more rapidly than income. Automobiles are likely to fit this category. On the other hand, goods with an income elasticity of less than one include food.

Elasticities of demand vary with the time period allowed for adjustment. For example, in the short-run, the price elasticity of demand for gasoline is fairly inelastic. One might infer from this that it would take a large increase in the price of gasoline to induce a decrease in demand. And so it would— in the short-run! The reason for this is that, if the price of gasoline went up to $10.00 per gallon tomorrow, you would still have to get to work, the grocery store etc. and there are few substitute ways of doing so except to drive your car. In the long-run however, you would perhaps buy a more fuel efficient car or perhaps an electric car. In the long-run, more money would be invested in public transportation, bus and light-rail service would become more frequent and efficient and you would drive your car much less. The relationship between long-run and short-run demand and their associated elasticities is captured in Figure 37.

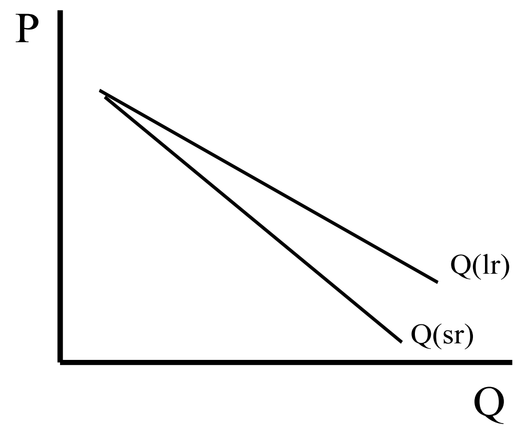

Figure 37. Long-run and Short-run demand and elasticities

There has been considerable research devoted to estimating elasticities of demand for electricity. Several approaches have been employed in different regions and over various time intervals. A short run elasticity measurement may be made over a time period of hours to months while a long run measurement reflects elasticity over many years. A summary of this research is shown in Table A12-1. Complete references for these studies may be found in the literature cited section of this document.

Most studies of U.S. households found the own price elasticity of demand for electricity was inelastic ($|\epsilon|<1.0$). Their findings were generally consistent with economic theory— estimated demand elasticities were more elastic in the long run and less elastic in the short run. As detailed in Table A12-1, estimated own price elasticities of demand for U.S. residential customers were remarkably similar with short run values ranging from -0.09 to -0.57, and long run values ranging from -0.38 to -1.42.

In summary, while there are some long-term price elasticities of demand having an absolute value greater than 1.0, most studies show the demand for electricity to be very inelastic. Industrial users were found to be relatively responsive to price. Their elasticities of demand were highly inelastic with short-run elasticities ranging between -0.13 and -0.22. As might be predicted, long-run elasticities were more elastic with an average value of about -0.697.

Table A12-1. Summary of Selected Elasticity Studies.

Reference	Location	Time frame	Own Price Elasticity
Zarnikau (1990)	U.S.A.	Short-run	-0.09
Elkhafif (1992)	Canada	Short-run	-0.147
Elkhafif (1992)	Canada	Long-run	-0.697
Hsing (1994)	U.S.A.	Short-run	-0.239
Hsing (1994)	U.S.A.	Long-run	-0.543
Houthakker & Taylor (1970)	na	Long-run	-1.89
Houthakker et al (1974)	U.S.A.	Long run	-0.45 to -1.20
Houthakker (1980)	U.S.A.	Long-run	-1.42
Terza (1986)	U.S.A.	Long-run	-1.20
Munley et al (1990)	U.S.A.	Short-run	-0.37 to -0.57
Morse and Small (1989)	U.S.A.	Short-run	-0.23
Morse and Small (1989)	U.S.A.	Long-run	-0.38
Dubin (1985)	na	Short-run	-0.14
Hewlett (1977)	U.S.A.	na	-0.09 to -0.16
Parti and Parti (1980)	U.S.A.	Short-run	-0.15
Archibald et al (1982)	na	na	-0.12 to -0.60
Branch 1993	U.S.A.	Short-run	-0.20
Filippini (1995a)	Switzerland	na	-1.25 to -1.50
Filippini (1995b)	Switzerland	na	-2.3 to -2.57
Nesbakken (1999)	Norway	na	-0.24 to -0.57

Appendix 13 – Optimal Hydro-Thermal Dispatch

The mathematical problem describing the optimal operation or dispatch of the thermal and hydropower plants in a system is called, "optimal hydro-thermal dispatch." This appendix presents the major components of this problem. The goal of the exposition which follows is to illustrate the underlying mathematical framework and provide the mathematical basis for gamma (γ), the marginal value of water and lambda (λ), the marginal system cost. Admittedly, not all of the constraints specified in the ESIM03 model are illustrated in this appendix and some readers may consider this appendix incomplete. Since the exposition of γ and λ would be made more complex if the problem was completely specified, we have deliberately avoided describing the mathematical problem in its entirety.

In the general exposition of this problem, there are I={1, 2, 3, ..., np} powerplants in the interconnected power system. Of these, np-1 are thermal powerplants and 1 hydropower plant. Each of the np-1 thermal powerplants has a quadratic fuel requirement (input/output) equation of the form shown in 9.

$$H_i(p_t) = ap_t^2 + bp_t + c \tag{9}$$

where: H_i is the fuel requirement (MBtu/hr) for plant I.
p_t is the power generation level (mw) at time t
a, b, c are (fixed) coefficients

We also have a single hydropower plant for which the total volume of water which can be released is strictly limited. We assume the total release volume (af) for the hydropower plant is H_{tot} which is exogenously determined (given). The hydropower plant has a water requirement of the form shown in 10. The explicit form of (10) is described in Appendix 17.

$$H_{np}(p_t) = H[q(p_t)] \tag{10}$$

where: H_{np} is the water volume released (af) during time period t
q is the release (cfs) over the time period t.
p_t is the power generation level (mw) at time t

The cost of generation at any one of the np-1 thermal powerplants is characterized by equation 11.

$$F_i(p_t) = R_i \times H_i(p_t) \tag{11}$$

Where the fuel cost, $R_{i,}$ is measured in \$/MBtu. For the Hydropower plant, the "fuel" cost of generation is characterized by equation 12.

$$F_{np}(p_t) = R_{np} \times H_{np}[q(p_t)] \quad \textbf{(12)}$$

For the hydropower plant, the water cost, R_{np}, is measured in \$/af. Except in cases where there is a "falling water charge"or other charge for the water itself, R_{np} is usually 0.0.

The initial state or volume content of the storage reservoir (V_0) is known or given. We assume the inflows in each period (r_t) are fixed and for purposes of simplification, there is no evaporation. The volume of water in the reservoir at any given time period (t) is then described by equation (13). Equation 13 is also known as the "mass balance" equation. It specifies the volume state of the reservoir (a.k.a.: water balance) from one period to the next.

$$V_{t-1} + r_t - H(p_{np,t}) = V_t \quad \textbf{(13)}$$

Since the inflow is fixed and the initial (V_0) reservoir state is given, if the ending state (V_T) of the reservoir is given, this is equivalent to specifying the initial reservoir state and the total amount of water to be released during all T periods.

The goal of the power system operator is to dispatch the np-1 thermal powerplants and the 1 hydropower plants so as to minimize the cost, satisfy the electricity demand in each hour and use all of the water scheduled for release by the hydropower plant. This problem can be written mathematically as:

$$Min \quad \sum_{t=1}^{T} \sum_{i=1}^{np-1} F_{t,i}(p_{t,i}) + \sum_{t=1}^{T} F_{t,np}(p_t) \quad \textbf{(14)}$$

Subject to:

$$\sum_{i=1}^{np-1} p_{t,i} + p_{np,t} = Load_t \qquad \forall_t \in \{1..T\} \quad \textbf{(15)}$$

$$V_{t-1} + r_t - H(p_{np,t}) = V_t \quad \forall_t \in \{1...T\} \quad \textbf{(16)}$$

The Lagrangian expression for this constrained minimization problem is then:

$$L = \sum_{t=1}^{T}\sum_{i=1}^{np-1} F_{t,i}(p) + \sum_{t=1}^{T} F_{np,t}(p) + \sum_{t=1}^{T} \lambda_t \left(Load_t - \sum_{i=1}^{np-1} p_{t,i} - \sum_{t=1}^{T} p_{np,t} \right) + \sum_{t=1}^{T} \gamma_t (-V_{t-1} - r_t + H_{np,t} + V_t) \tag{17}$$

We can solve this problem by finding the $p_{i,t}$'s, $p_{np,t}$'s, λ_t's and γ_t's which minimize the lagrangian function. For a given t=k, the first order conditions (FOC's) for this problem are:

$$\frac{\partial L}{\partial p_{i,k}} = \frac{\partial F_{i,k}}{\partial p_{i,k}} - \lambda_k = 0 \tag{18}$$

$$\frac{\partial L}{\partial p_{np,k}} = -\lambda_k + \gamma_k \frac{\partial H}{\partial p_{np,k}} = 0 \tag{19}$$

$$\frac{\partial L}{\partial \lambda_k} = Load_k - \sum_{i=1}^{np-1} p_{i,k} - p_{np,k} = 0 \tag{20}$$

$$\frac{\partial L}{\partial \gamma_k} = -V_{k-1} - r_k + H(p_{np,k}) + V_k = 0 \tag{21}$$

It should be noted that $\frac{\partial F_{np,k}}{\partial p_{np,k}} = 0$ because the total amount of water used is a constant (H_{tot}).

For this reason, this term does not appear in equation 17.

It is useful to further examine equations (23) and (24). Recall that (23) may be interpreted as the fuel cost times the marginal fuel use must be equal to lambda. Casual comparison of equations (23) and equation (24) as shown below reveals they are very similar. In fact, equation 24 can be interpreted similarly. Specifically, equation 24 may be interpreted as saying the shadow price of water (its "fuel" cost or value) times the marginal ("fuel") water use must be equal to lambda.

$$R_i \frac{\partial H_{i,k}}{\partial p_{i,k}} = \lambda_k \tag{23}$$

$$\gamma_k \frac{\partial H_{np,k}}{\partial p_{np,k}} = \lambda_k \tag{24}$$

The marginal value of water (γ) at any point in time is a quantity of interest to economists, engineers and policy analysts. As illustrated in equation 25, the marginal value of water is dependent both on the marginal cost of operating the thermal component of the power system and on the marginal contribution of an acre-foot of water to hydropower production. As described more fully in Appendix 14, the marginal value of water is highly variable and can be positive, negative or zero.

$$\gamma_k = \frac{\partial p}{\partial H_k} \lambda_k \tag{25}$$

Solution of the optimal hydro-thermal dispatch problem described here presents a daunting mathematical undertaking. In general, it is not possible to solve this problem analytically and highly specialized computer software must be used to obtain a numerical solution. The solution of this difficult problem was perhaps the chief technical issue involved in this effort. Appendix 19 provides a detailed description of the methodology used to solve the optimal hydro-thermal dispatch problem in the ESIM03 program.

Appendix 14 – The Marginal Value of Water (γ)

The Greek symbol gamma (γ) is used throughout this document to represent the marginal value or shadow price of an acre foot of water released from the reservoir. For example, if the value of gamma in hour 112 was 23.20, this may be interpreted as the (approximate) value of an additional acre foot of water released measured in $ per acre foot.

The numerical magnitude of gamma is shaped by a number of factors. For any given hour, gamma is determined by the electricity demand, the amount of water available for release, the marginal cost of operating other powerplants at that time and the operational constraint set. More formally, gamma is a function of the marginal effect on generation of a change in release times the marginal value of doing so. This is shown in equation 26.

$$\gamma = \frac{\partial P}{\partial H} \times \lambda \qquad \textbf{(26)}$$

Where: H = total water release (af)
P = (real) power generation (MW)

In equation 26, lambda (λ) is the marginal value of a change in generation and the partial derivative of generation with respect to water volume released gives us the marginal contribution of a change in release.

The value of gamma is of considerable interest to economists, engineers and policy makers since it can be compared to the marginal value of water in other uses. It can vary considerably across time, load and release conditions. Perhaps most surprising, the value of gamma can be positive, zero or even negative as shown in Figure 38.

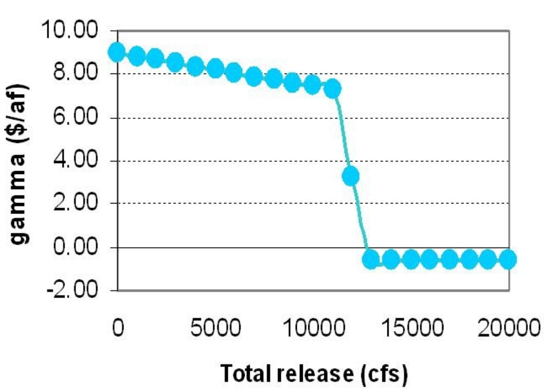

Figure 38. Gamma as a function of total release holding load constant at 1650 MW.

This aspect of gamma's behavior can be readily observed in the ESIM03 model and can be somewhat confusing. To understand why gamma can vary so much and even change signs, first recall that when load is highest, the marginal cost of generation (λ) is the greatest. We would expect the value of gamma to be highest during onpeak hours when the load is highest. Next, recall the hydropower plant has an upper limit on its generation and turbine release capability. These are 239.9551 MW and 12,000 cfs respectively. Holding load constant, as more water is released, more electricity is generated[16]. Since the relationship between release and generation is quadratic in nature, the incremental amount of generation obtained for each acre foot of water falls as more and more water is released. In other words, $\partial p/\partial H$ falls. In addition, generation from the hydropower plant offsets or displaces generation from the thermal units, thereby driving down the value of lambda. For these reasons, we would expect the value of gamma to fall as we released more and more water. At the maximum hydropower generation and release level, the value of gamma is typically very low and is often zero. This is because releases made beyond the release capability of the turbines are made from outlet works. Releases from the outlet works do not generate any more electricity but they do cause the tailwater elevation to increase. This increase in the tailwater elevation causes the net head to fall thereby reducing generation. This reduction in generation requires an associated increase in thermal generation in order to meet load. As a result of both of these factors, Gamma is typically negative for releases above the maximum release ability of the generators and turbines.

In summary, for a given load, we would expect the value of γ to be higher when less water is released and lower when more water is released. If water is released in excess of the maximum turbine release ability, we would expect the value of γ to be negative.

[16] But only up to the point where the maximum generation capability is reached.

Appendix 15 – Demand Side Management (DSM)

Introduction

Demand Side Management (or DSM, as it is often called) is a term used to describe a variety of programs whose focus is either on the direct conservation of energy or the provision of incentives to do so. DSM spans a range of treatments, from residential and industrial insulation and the use of compact fluorescent light bulbs to the deliberate manipulation of energy prices in order to promote energy conservation. In many cases, the aim of these programs is not only to reduce total or peak energy use in the near-term but also to avoid or defer the construction of new and expensive powerplant, transmission and distribution capacity.

For purposes of this document, we will examine three of the many possible DSM programs. These are conservation, interruptible supply and on-peak pricing. The effect of these and other DSM programs is, as the name implies, on the demand for electricity.

Problems with DSM

From the electric utilities viewpoint, the large-scale provision of DSM programs is incompatible with their incentive structure. Electric utilities earn their revenue from the sale of electricity. DSM programs can be costly. To the extent DSM programs are successful in reducing demand, utilities lose revenue. The combination of the cost of such programs and the resultant potential losses in revenues can result in significant impacts on their cash flow. As a consequence, it is not necessarily in a utility’s best interest to promulgate DSM programs on a large scale.

From the consumer’s viewpoint, some DSM programs are relatively expensive and electricity prices are relatively low. As a result, the adoption or penetration rates of some types of DSM programs have been lower than some analysts have forecast. For example, the replacement of windows in a residence with thermally efficient windows is a large capital expense. When electricity prices are relatively low, the energy savings realized by consumer implementation of this program may not outweigh the costs incurred by participating in the program.

Conservation

There is a wide variety of potential opportunities for energy conservation program in industrial, commercial, agricultural and residential settings. These include programs such as residential energy audits, insulation of existing hot water tanks, incentives for the use of low wattage and compact fluorescent light bulbs, incentives for the installation of high efficiency air conditioning and heating units, rebates for the installation of thermally efficient windows and stoves, and so forth. A quick internet search will reveal a lengthy list. Since residential loads make up a high percentage of the total load served by many utilities, the prospects for electricity conservation are quite good. Energy savings from 1 to 25% have been realized for some packages of conservation programs.

Generic characterization of conservation programs in the ESIM03 program is relatively straightforward. The underlying premise is that a generic conservation program reduces electricity use by residential and commercial users during all hours of the day. To represent a conservation program in the ESIM03 software package, the user specifies the percentage load reduction. This percentage reduction is applied uniformly by the program to the hourly load data to produce an adjusted hourly load data set. Figure 39 illustrates the effect of a conservation program on hourly load during a typical summer day. As shown in Figure 39, hourly load with the conservation program is lower in all cases than it is without the program.

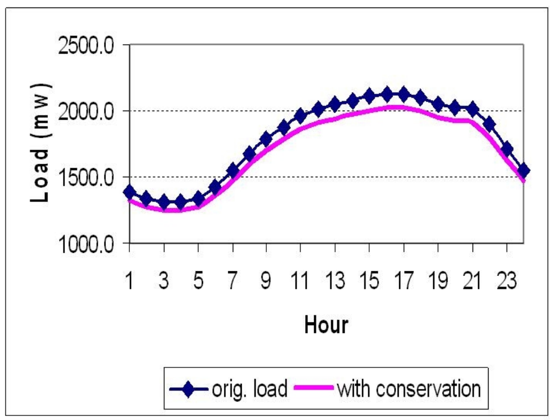

Figure 39. Hourly load shape on a typical summer day with and without conservation program.

The ESIM03 program then dispatches the interconnected hydro-thermal system to satisfy the adjusted hourly load at least cost. Because the adjusted load is uniformly lower, the cost of meeting load with a conservation program is lower than it would be without such a DSM program.

Interruptible Supply

One class of DSM program operates by ensuring peak demand will not exceed a specified upper limit. Although such programs can take many forms, they are typically called "interruptible supply" programs. Although these programs are more commonly employed in industrial and commercial settings, they are now becoming more popular in certain residential applications. Typically, a utility and the user enter into an interruptible supply agreement in which the consumer agrees to an involuntary service curtailment if load exceeds some specified peak, in return for a lower than normal electricity rate (to compensate for the probability of a service curtailment and the cost of a service interruption, should one occur).

The effect of an interruptible supply program is characterized by the ESIM03 program in a simple and straightforward manner. In the ESIM03 software package, the user specifies a percentage of peak load reduction. This percentage reduction is applied to the maximum load in the hourly load file to determine the maximum allowed load under the program. For example, if the maximum load in the original hourly load file is 1000 MW and the user specifies a peak load reduction of 8%, the maximum allowed load under the interruptible supply program is then 1000*(1-0.8)=920 MW. The hourly loads in the adjusted load data set are then limited to this maximum (920 MW). Figure 40 illustrates the effect of an interruptible supply program on hourly load for a typical summer day. As shown in Figure 40, (peak) load with the interruptible supply program is limited to the specified amount relative to without the program.

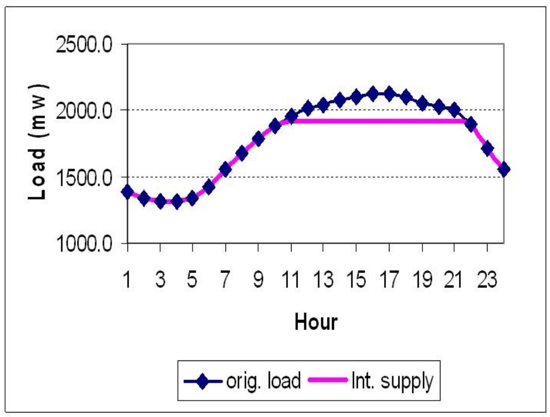

Figure 40. Hourly load shape on a typical summer day with and without interruptible supply program.

The interconnected hydro-thermal system is then dispatched to meet the adjusted hourly load at least cost. Because the maximum load is limited to a lower level, the cost of meeting load with an interruptible supply program is lower than it would be without such a program.

On-Peak Pricing

Differential or on-peak pricing programs are based on fundamental principles of microeconomics. Specifically, the demand function for electricity is downward sloping and consumers will purchase less electricity when the price is higher. The idea behind on-peak pricing programs is to differentially increase the price during on-peak periods of the day and use economic incentives to reduce electricity during this period, thereby promoting conservation.

The effect of an on-peak pricing program is represented in the ESIM03 program by using the estimated elasticity of demand for electricity with respect to price and the user specified peak load pricing differential. The elasticity of demand is assumed to be 0.50 (in absolute value terms). This means that for each 1% increase (decrease) in the price of electricity, demand will decrease (increase) by 0.50 %. To simulate the use of an on-peak pricing program using the ESIM03 software package, the user specifies the percent (on-peak) price increase. This percentage price increase, multiplied by the estimated price elasticity, yields a percentage effect on load. The percentage effect on load is applied only to hourly loads during the on-peak period 0800-2300 hours Monday through Saturday. It is assumed some load shifting to off-peak hours (all other hours) will also result. To represent this effect, it is assumed that off-peak electricity use will increase by 5 %. The hourly loads in the on-peak period are decreased and those in the off-peak period are increased as described to create an adjusted load set. Figure 41 compares the hourly load during a typical summer day with and without an on-peak pricing program. As shown in Figure 41, hourly load during the on-peak period is reduced and load during the off-peak hours is increased somewhat.

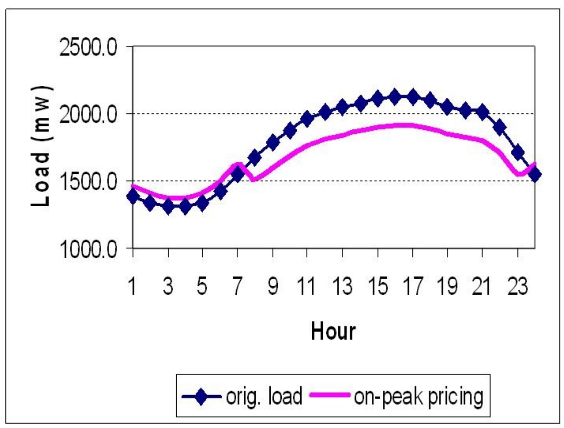

Figure 41. Load shape during a typical summer day with and without an on-peak pricing program. In this example, the assumed on-peak price differential is 20 percent.

The interconnected hydro-thermal system is then dispatched to meet the adjusted hourly load at least cost. Because load during the on-peak hours is lower and the costs of production is higher on-peak, the cost of meeting load with an on-peak pricing program is lower than it would be without such a program.

Appendix 16 – Hydrology Concepts and Terms

The purpose of this appendix is to familiarize the reader with some basic hydrology concepts, the terms used to describe them and the “mass balance” calculation. The following five hydrologic terms are used throughout this document, are tracked explicitly by the ESIM03 model and are components of the mass balance calculation. These terms are illustrated in Figure 42.

- inflow
- reservoir content (volume)
- bypass or spill
- turbine release
- total release

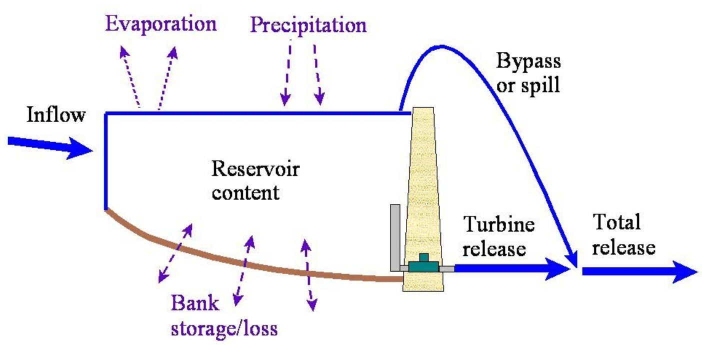

Figure 42. The hydrologic components tracked in the ESIM03 model are shown in black text.

Reservoir inflow is typically, although not always, derived from water flowing down streams and rivers which empty into the reservoir. In the absence of human intervention, the water flowing down these streams reflects upstream precipitation and subsequent run-off from the basins they drain. The magnitude and sequence of inflows can effect the operation of a hydropower facility. This is particularly true in low or high reservoir conditions or when the volume of inflow is relatively large relative to the amount of storage space available in the reservoir.

The total release from a hydropower reservoir is made up two components—turbine releases and bypasses or spills, if any. Turbine releases are releases made though the turbine blades and generate electricity. Spills are releases made from auxiliary outlet works such as spillways. These releases bypass the turbines. From the power production standpoint, spills are undesirable since they do not result in the generation of electricity. Spills are considered wasteful and reservoir managers will go to great lengths to avoid conditions which might necessitate a spill. For example, if a large inflow is forecast, reservoir operators may increase current releases (through the turbines) to increase the amount of free reservoir storage space available. When the large inflow arrives, there will then be space in the reservoir to store it. This strategy is often used to avoid or reduce what would otherwise be an expected spill.

In the ESIM03 model, evaporation, precipitation and bank storage/losses are assumed to be negligible and are ignored. In general, these factors can affect reservoir contents to varying degrees depending on the location of the reservoir and how it is operated. In locales where temperatures are high, the moisture content of the air is low and winds are frequent, evaporation can result in significant losses in reservoir contents. In other locations, precipitation in the form of rain or snow on the reservoir's surface can contribute significantly to reservoir contents. Depending on the nature of the geology and soil types where the reservoir is located, water can seep out of the reservoir into bank storage and/or enter the reservoir and add to its contents. This is often termed bank storage/gain and can be locally important in some cases. For simplicity, these possible effects are not considered in this document or the ESIM03 model.

The amount of water in the reservoir is variously referred to as the reservoir contents or storage volume. The contents of the reservoir at the end of any given hour is calculated from the contents of the reservoir at the end of the previous hour, the inflow during the hour and the total release during the hour. This computation is referred to by hydrologists as "mass balance." The initial state or volume content of the storage reservoir (V_0) is known or given. We assume the inflows in each period (r_t) are fixed and for purposes of simplification, there is no evaporation, precipitation or bank storage/gain. The volume of water in the reservoir at any given time period (t) is then described by equation (27). Equation 27 is also known as the "mass balance" equation. It specifies the volume state of the reservoir (a.k.a.: the water balance) from one period to the next.

$$V_{t-1} + r_t - H(p_{rp,t}) = V_t \tag{27}$$

The ESIM03 model calculates equation 27 for each hour of the simulation process. It maintains mass balance during all hours of the simulation.

Appendix 17 – Generation, Head and Release

In a hydropower plant, electricity is produced by the force of falling water. The distance the water falls is called the "head." The amount of water released is often measured in cubic feet per second (cfs). The relationship between the head, the amount of water released and the generation can be specified mathematically. In this analysis, the equation used to characterize real power generation is shown in (28)

$$p_t = \frac{q_t \times \omega \times eff \times head_t}{fptokw \times 1000} \tag{28}$$

Where:

- p_t = (real) electric power generated (mw) at time (t)
- ω = 62.40, specific weight of water at 50 degrees Fahrenheit (lbs/ft^3)[17].
- eff = 0.850, efficiency factor[18] (dimensionless)
- q_t = release (cfs) at time (t)
- $head_t$ = net head (ft) at time (t)
- fptokw = 737.5, foot-pounds to kilowatt conversion factor (kW/(ft-lbs/sec)

Net head at any point in time (t) is the difference between the reservoir elevation and the tailwater elevation. While the reservoir elevation at time (t) is fixed, the elevation of the tailwater varies with the release rate (q_t). For our purposes, we characterize net head as shown in (29).

$$head_t = [\, Lelev_t - (w0 + w1 \times q_t)] \tag{29}$$

Where:

- $Lelev_t$ = reservoir elevation (ft above mean sea level) at time (t).
- w0 = 1708.186, height of the tailwater (ft above mean sea level) when q=0.0
- w1 = 0.00183, rate of change in tailwater elevation as release changes (ft/cfs)

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[17] Many textbooks use gamma (γ) to represent the specific weight of water. To avoid confusion with the γ employed in the optimization algorithm, in this document we will use omega (ω).

[18] In this application the efficiency (eff) is represented as a constant. More generally, efficiency may vary as a function of release and head.

The fully specified relationship for generation at time (t) as a function of release and head is then (30).

$$p_t = \frac{q_t \times \varpi \times eff \times [Lelev_t - (w0 + w1 \times q_t)]}{fptokw \times 1000} \qquad \textbf{(30)}$$

Collecting terms, the generation equation can be further simplified as shown in (31). Note equation (31) is nonlinear and more specifically is quadratic in q_t.

$$p_t = \frac{\varpi \times eff \times [(Lelev_t - w0)q_t - w1q_t^2]}{fptokw \times 1000} \qquad \textbf{(31)}$$

Due to engineering limitations on the turbines and generators, power generation is typically limited. For purposes of this analysis, generation is limited to a maximum of 239.9551 MW at a reservoir elevation of 2008.186 ft. The corresponding maximum turbine release capability is 12,000 cfs. When this maximum generation constraint is considered, the relationship between total release (turbine release plus other releases) and generation is shown in Figure 43. As shown in this figure, generation increases until the point where the maximum generation and release capability is reached. Increases in total release beyond this point must be made through the outlet works (e.g. spillways) and do not generate any additional electricity. On the contrary, releases in excess of 12,000 cfs increase the elevation of the tailwater. As the tailwater elevation rises, the net head decreases causing generation to fall.

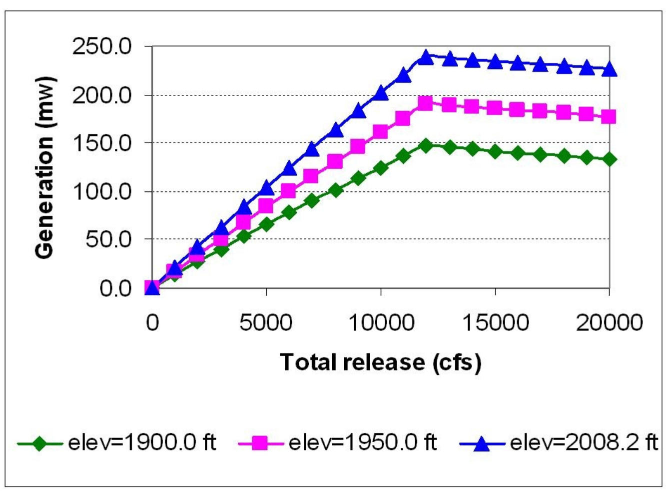

Figure 43. Generation as a function of total release.

Appendix 18 – Assumptions and Simplifications

A number of assumptions and simplifications have been made in order to accommodate a non-technical audience and to facilitate operation of the ESIM03 model. In the electric power system, as in life, there are many complexities. It is not necessary to understand all of these complexities to gain an intuitive and broadly useful understanding of the power system. The assumptions and simplifications made here allow for a more straightforward and comprehensible treatment of this relatively complex subject matter. Some of the more important assumptions and simplifications made are described in the narrative which follows.

Powerplants. The period of analysis described in this document is the very short-run. There is no consideration in this document or the ESIM03 model of changes in the capital stock (changes in the number or size of generators). For purposes of this educational document and the ESIM03 program, we assume that the powerplants characterized in the interconnected electricity system have already been constructed prior to the analysis and are operational over the period of analysis.

Transmission. The focus of this document and the ESIM03 program is on the operation of the generation system. Although the transmission system is at least as important to the functioning of the interconnected electricity system, it is not treated in this analysis or characterized in the model. It is presumed the transmission system exists and does not constrain the operation of the generation resources in the system.

Outages. Outages may result from unplanned mechanical failures, pending mechanical failures or planned maintenance to prevent such failures from occurring. There is no consideration in this document or the ESIM03 model of outages. It is assumed that all of the powerplants in the model are fully operational and available for use over the period of analysis.

Physics of Electricity. This document and the ESIM03 model are designed for use by a non-technical audience. With the exception of the cursory explanation provided in Appendices 1 and 2, we make no attempt to address the actual physics or physical behavior of electricity. More specifically, we provide an abstract treatment of real electric power only.

The "Unit Dispatch" Problem. Powerplants typically have several generating units. For example, the NGCCT plant in the ESIM03 model has eight 50 MW units. Typically, these units are operated as efficiently as possible. For example, if there are eight 50 MW units and the load is 120 MW, three units could be operated at 40 MW of output. Alternatively, there may be some other combination unit operations and unit output levels which could achieve 120 MW of output at the least cost. The subject of how to most efficiently operate multiple generation units at the same plant to meet load is called the "unit dispatch" problem.

In the ESIM03 model, each type of powerplant is operated as if it were a single unit. No attempt is made here to address the "unit dispatch" described in Wood and Wollenberg (1996) and elsewhere. Although this may reduce the technical rigor of the material presented in this document to some extent, it also greatly reduces the computational complexity without reducing its educational merit.

Variable Costs. In the Beta version of the ESIM03 model, the variable costs of operation are restricted to the fuel costs only. In general, the variable costs of operating a powerplant are more encompassing and would also include variable operations and maintenance (O&M) costs and perhaps other costs as well. Future versions of the ESIM03 model will include these omitted variable costs.

Fixed Costs. In the Beta version of the ESIM03 model, only the variable costs of powerplant operation are calculated and displayed. While in general, the capital costs of a powerplant are "sunk" and are not pertinent to the dispatch decision, these costs are often allocated over the hours of operation. To the extent warranted, future versions of the ESIM03 model will include some measure of these fixed costs.

Appendix 19 – Solution Method

Identification of the optimal generation pattern in a combined hydro-thermal system is a complex and daunting mathematical task. As illustrated in Appendix 13, this problem can be categorized as a large-scale nonlinear constrained mathematical programming problem. In the case examined, there are 5 powerplants (oil, natural gas CT, natural gas CCCT, coal and hydropower) which operate over a 168 hour time-horizon at a 1-hour time step conditional on a variety of physical, engineering and environmental constraints. The equations which characterize each plant's generation as a function of fuel use are nonlinear. The constraint equation are numerous but are either linear or take the form of simple upper and lower bounds. The resulting mathematical problem is quite large and its solution is not only extremely difficult but is computationally intensive.

Only a handful of commercially available software programs are capable of reliably solving this class of mathematical problem. As might be expected, these software packages are expensive, have a number of licensing restrictions and can not be freely distributed.

The ESIM03 program uses a recently developed methodology to identify the optimal hourly pattern of generation for each of the powerplants represented in the model. This approach utilizes two different solution algorithms: the lambda search algorithm and a variant of the Substitution-based Non-linear Approximation Procedure (SNAP) algorithm. The resultant solution approach is robust, relatively fast, fully integrated with the ESIM03 code and facilitates distribution of the ESIM03 program for educational and instructional purposes.

Figure 44 provides a high-level overview of the solution methodology within the ESIM03 educational program. As shown in this figure, the first step in the operation of the program is to obtain a variety of inputs. When the user has selected the desired parameter values and clicked on the run button, these parameter values are read from the graphical user interface and the appropriate data files are read from disk. Second, the program checks for input logic and constraint errors. Such problems can arise because there are possible combinations of input values and constraints which are illogical or conflict with each other. This can yield an infeasible problem or a problem which cannot be solved mathematically. For example, if the user selects a low reservoir elevation and a high release while the inflow into the reservoir is quite low, it is possible the user specified release cannot be physically achieved. The ESIM03 program checks the input and constraint values in order to identify input combinations like this which are infeasible. If an infeasibility is detected, a message is displayed and program control is returned to the interface.

If the specified problem is determined to be feasible, the solution algorithm proceeds and the four thermal powerplants in the model are optimally dispatched using the lambda search algorithm. The thermal plants are dispatched against a range of hourly loads to obtain a surface of hourly total and marginal avoided costs. Using these cost surfaces, the SNAP algorithm dispatches the hydropower plant to minimize to the total cost of meeting load during the week.

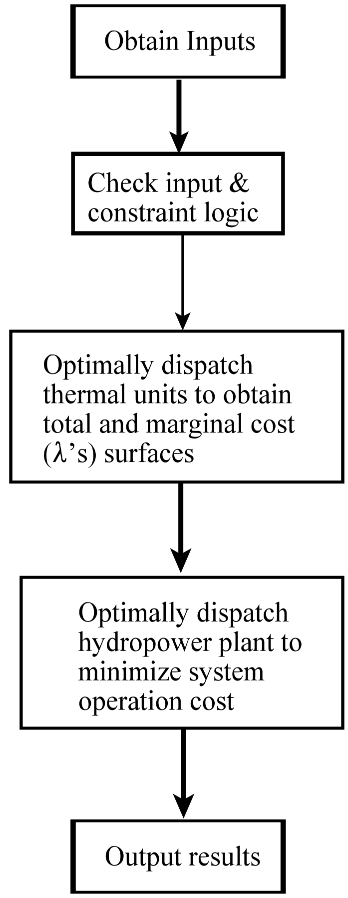

Figure 44. Overview of the Solution Method used in the ESIM03 Program

Lambda Search

The lambda search algorithm is employed to optimally dispatch the 4 thermal powerplants against load. The lambda search algorithm and its application to the dispatch of thermal units is rather well established and is described in Wood and Wollenberg (1996). The use of this algorithm in the ESIM03 program and much of the discussion which follows draws heavily from this source.

The lambda search algorithm is used to dispatch the thermal plants against an artificially constructed load vector which encompasses the range of loads found in the user specified load pattern (e.g. "Summer"). The plants are dispatched against load from the lowest load in the (e.g. "Summer) load pattern to the highest load in the (e.g. "Summer") indicated pattern. Within these extremes, the artificial load vector is constructed in 1-megawatt increments. For each value in the artificial load vector, the lambda search algorithm determines the optimal (cost minimizing) pattern of generation required from each of the four thermal power plant which will exactly satisfy load subject to the specified constraints on operations at the plants. This is repeated for each value in the artificially constructed load vector. The results of this process are mathematical "surfaces" which relate the optimal pattern of hourly (thermal plant) operation, the (minimized) total and marginal costs of meeting load (with the thermal system alone) to electricity demand. These surfaces are then stored for subsequent use.

As described more explicitly in Appendix 13, dispatch of the four thermal powerplants is a minimization problem with an equality constraint. In this case, the cost functions are relatively uncomplicated and their derivatives can be readily solved for q_i if λ is known. Under these conditions, this problem can be solved using an iterative lambda search routine which we will henceforth simply call "lambda search." Figure 45 illustrates the application of the lambda search algorithm employed.

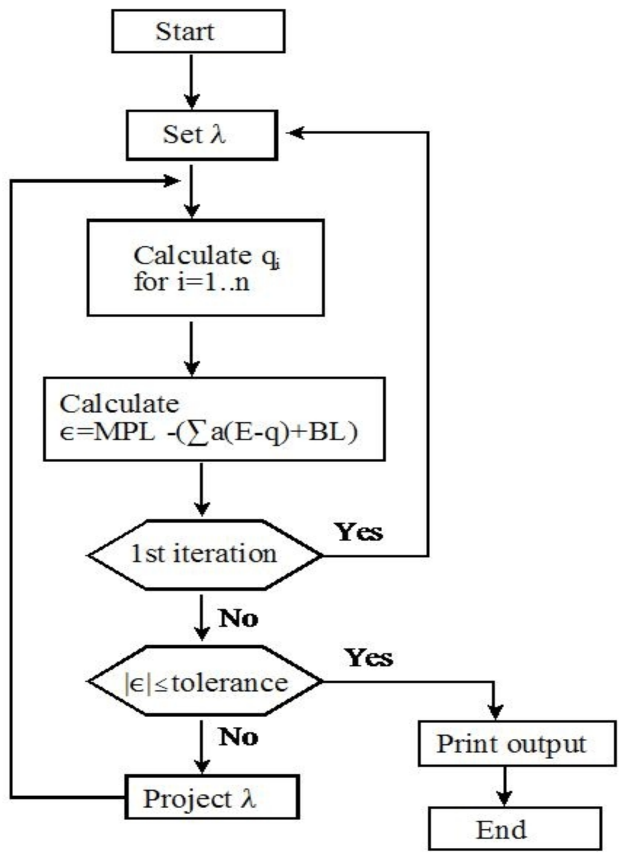

Figure 45. Constrained Minimization Using Lambda Search

The lambda search algorithm begins with a starting λ. Given this starting λ value, the expressions for the (n) first derivatives can be used to compute a set of output levels for each thermal powerplant (q_i). In order to meet the load constraint, the q_i. should sum exactly to the load in that hour (L). In practice, there is usually some error which will define as $\epsilon = L - \sum q_i$. We would be satisfied if the absolute value of this error ($|\epsilon|$) was less than some arbitrarily small value which we will call the convergence tolerance (ctol). In the default case, a tolerance level of ctol=0.01 is employed. It is unlikely that $|\epsilon|$<ctol on the first iteration unless we make an extremely lucky guess for the value of λ!! Since the probability of this happening is virtually zero, the algorithm requires a minimum of at least 2 iterations. On the second iteration a heuristic or simple rule is used to "set" the value of λ. This heuristic works as follows, if $\epsilon>0$ set $\lambda_2= \lambda_1*0.90$, if $\epsilon<0$ set $\lambda_2=\lambda_1*1.10$.

At the end of the second iteration, if $|\epsilon|$<ctol, the algorithm terminates and the result is written to an output window. In the event $|\epsilon|$>ctol, a new value for λ is projected.

If more than 2 iterations are required, a more sophisticated approach to projecting λ is employed. Because each thermal powerplant has different performance characteristics and an upper bound on its generation capability, discontinuities in λ exist. Due to these discontinuities, interval bisection (Press et al 1989) is used to identify a new value of lambda for iterations 3 and higher. This new or "projected" value of λ is used in the subsequent iteration.

These iterations or loops continue until the difference between the sum of the q_i's and L is driven to within the user specified convergence tolerance level (ctol). When $|\epsilon|$<ctol, the lambda search algorithm concludes and the results are written to an output vector.

The lambda search procedure converges very rapidly for the particular type of optimization problem examined here. The actual computation procedure is slightly more complex than that indicated in Figure 45 since the q_i's are constrained to remain nonnegative during the iterations. This is accomplished by restricting the value of all of the $q_i \geq 0$ immediately following their calculation.

The iterative process used in this algorithm can fail due to oscillations, roundoff error, truncation, or incorrect specification of the problem. In this application, the number of iterations is limited to some pre-set maximum to prevent the process from continuing forever should such a failure occur.

The lambda search procedure is used to identify the marginal and total avoided cost associated with each value in the artificial load vector. An example marginal avoided cost surface is illustrated in Figure 46.

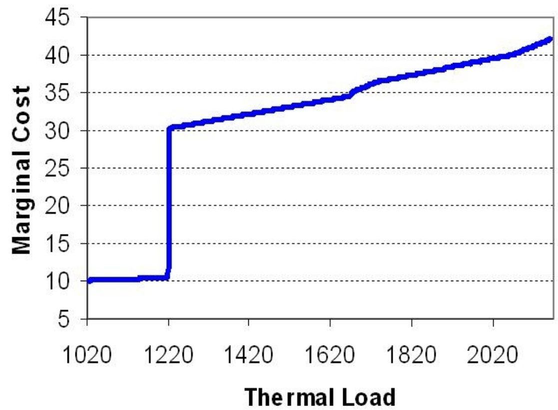

Figure 46. Example marginal avoided cost surface generated by the lambda search algorithm.

SNAP Algorithm

The Substitution-based Non-linear Approximation Procedure (SNAP) is employed to dispatch the hydropower plant so as to minimize the costs of operating the interconnected power system and meet environmental and physical constraints. In the ESIM03 program as well as the real-world, electrical demand must equal supply. In the model, load must be met either by the thermal component of the interconnected system or by the hydropower plant. In the absence of any generation from the hydropower plant, the cost surfaces generated by the lambda search algorithm allow us to determine the optimal pattern of thermal generation, the (minimum) total cost and the marginal cost for any given hourly load. The objective of the SNAP algorithm is to release the available water and generate electricity at the hydropower plant so as to minimize the total cost of operating the system while meeting hourly electricity demand and simultaneously honoring the physical, engineering and environmental constraints specified by the user. Using the total cost surfaces and the indicated load, the SNAP algorithm identifies the hourly pattern of hydropower generation which will minimize the total cost of meeting electricity demand over the user specified analysis week.

SNAP is an ingenious heuristic technique developed by Veselka, Schoepfle and Mahalik (2003). Heuristic techniques enable the fast solution of mathematical problems that might otherwise be too difficult or take too long to solve via generalized and more formal optimization methods. The heuristic solution of an optimization problem generally involves the iterative application of a set of carefully designed procedures or rules to quickly obtain a good solution. In general, it is not possible to determine whether a heuristic has obtained an optimal solution. A heuristic is useful, however, if it is found after thorough and careful testing to be consistently fast and produce reasonably good answers for a wide range of potential situations (both highly probable and unlikely). This is especially true where the original problem of interest is found to be inordinately difficult, expensive, or otherwise impossible to solve via generalized solution procedures.

The SNAP heuristic begins with an initial set of "feasible" hourly releases. The sum of this set of hourly releases equals the given weekly release level. This initial flow pattern is feasible only in a very limited sense since it is not necessarily feasible with respect to any of the other constraints. One valid initial release pattern and the one used in this program is a constant release pattern—all hourly releases equal the total weekly release divided by the number of hours (168) in a week.

The SNAP algorithm minimizes the value of a fitness function. The fitness function is an artificially constructed function which contains information on both the objective function value (the minimum dispatch cost) and the penalty function value. The objective function is simply the sum of the hourly minimum costs of operating the interconnected system. Penalties are incurred if any of the physical, engineering or environmental constraints are violated. The penalty function is the sum of these penalties across all of the hours in the week. For purposes of this analysis, the fitness function is simply the sum of the objective function and penalty function values. Since in this case the object is to minimize costs while simultaneously meeting all of the constraints, a decrease in the fitness function is an improvement.

At its core, the SNAP model relies upon a repeated "pair-wise substitution" procedure. Starting with the initial "feasible" release pattern, the SNAP heuristic attempts to improve the fitness function value by reallocating reservoir water releases between a selected pair of hours. If a water swap between the pair decreases the value of the fitness function, then the water reallocation is implemented. If the potential swap were either to increase the value of the fitness function, or have no effect, it is rejected and no changes are made to the release in either hour. Water reallocations among all possible combinations of hourly swap pairs at the reservoir and are repeatedly evaluated and implemented until a lower fitness function value cannot be found. A flow chart of the SNAP heuristic solution process is shown in Figure 47.

Water reallocations between hourly swap pairs maintain a conservation of water mass. The amount of water that is moved *from* one hour must exactly equal the amount that is moved *to* the other hour. The time series of water storage volumes in the reservoir is adjusted to account for water releases that are shifted from one hour to the other. For example, if a water release is reduced at the 3 AM hour and reallocated to 6 PM, reservoir storage is increased from 3 AM through 5 PM. The reservoir storage volume is decreased by the same amount at 6 PM. Note that since reservoir storage volumes are reported at the end of the hour, the storage volume for 6 PM is unaffected by the reallocation. Changes in water storage volumes affect the reservoir water elevation and therefore head and generation. The economic impact of these changes is evaluated via fitness function calculations.

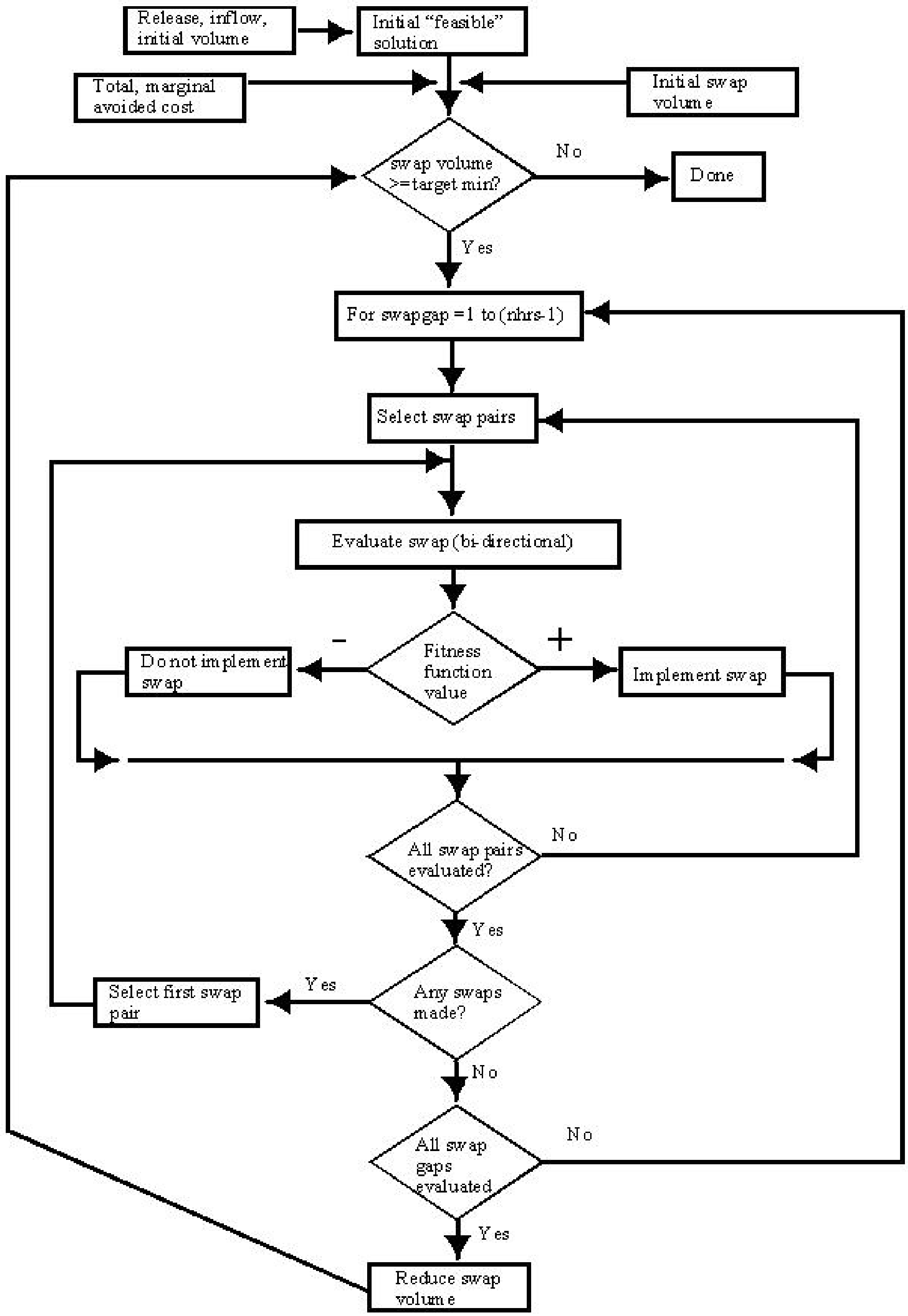

Figure 47. Flowchart of the SNAP heuristic used for optimal hydropower dispatch.

Violations of constraints are heavy penalized in the fitness function. In this sense constraints are "soft" in that violations are permitted—just at a very high cost. When a large penalty is placed on constraint violations, release reallocations that either create an infeasible result or increase a pre-existing violation are typically rejected. On the other hand, water release reallocations between hourly swap pairs are typically accepted if they reduce a constraint violation.

As implemented in the ESIM03 program, the SNAP algorithm proceeds as follows:

1. The desired weekly release from the reservoir, the hourly pattern of inflows and the initial reservoir elevation (volume) are selected by the user and the corresponding data are read from the user interface and the appropriate data files.

2. The indicated release is used to construct an initial "feasible" hourly release pattern. For purposes of this program, a constant hourly release pattern is employed. This initial release pattern is feasible only in the limited sense the indicated hourly releases exactly satisfy the indicated weekly release. It is entirely possible that the initial "feasible" release pattern will result in violations of other constraints such as the maximum reservoir elevation. These violations will cause penalization of the initial feasible solution. The value of the fitness function for any particular solution is the sum of the objective function and penalty function values.

3. The hourly total avoided costs which have been estimated for the thermal system are read and these are used to calculate the value of the objective function for the initial "feasible" release pattern. Similarly, the value of the penalty function is calculated for this initial feasible solution. The fitness of this initial solution is then calculated by adding the objective function and penalty function values. This fitness function value is used as the basis for evaluating the effects of all subsequent changes in the release pattern.

4. The quantity of water that is reallocated via pair-wise substitution between two hours is called the swap volume. In the ESIM03 program, the initial swap volume is 0.30 × hourly release volume. Initially, the amount of water swapped is relatively large (e.g., 112.5 af). The swap volume is reduced as the heuristic continues until the user indicated minimum swap volume has been reached (e.g., 5.0 AF/hr). By first examining large swap volumes, SNAP is able to leap over local optimums. Once a good region has been identified, the search area is refined to increase the overall objective function.

5. A swap gap or time distance between hours for which pair-wise trade-offs are evaluated is determined. For example, if the swap gap is 2 hours, pair-wise trade-offs of water between hours 1 and 3, hours 2 and 4, 3 and 5...are evaluated.

6. For any given swap gap, there are a number of potential swap pairs. A particular swap pair is selected for evaluation.

7. For a given swap volume, gap and swap pair, the effect on the fitness (objective function value plus the penalty function value) of a potential pair-wise trade-off of water volumes is evaluated. Pair-wise trade-offs are evaluated bi-directionally. For instance, the value of the fitness function which would result from subtracting the swap volume from hour 1 and adding it to hour 3 is evaluated and as well as the effect on the fitness function if the swap volume were added to hour 1 and subtracting it from hour 3. Care is taken to ensure mass balance is maintained across all effected hours and the resulting hourly release volumes are constrained to be non-negative.

8. If a potential swap causes a decrease in the fitness function, the swap is made and the pair-wise evaluations are continued. If a potential swap increases the value of the fitness function, or has no effect, no swap is made and the pair-wise evaluations continue.

9. At a particular swap gap, if a swap is made, pair-wise trade-off evaluations continue. These pair-wise evaluations continue until no further improvements (decreases) in the fitness can be made at that swap gap.

10. When the opportunities for improving the value of the fitness function at a particular swap gap are exhausted, a larger swap gap is examined.

11. When all of the swap gaps have been examined and no further improvements in the fitness can be identified, the swap volume is decreased and the process begins anew.

12. Ultimately, the swap volumes used for pair-wise substitutions are reduced below the user indicated minimum. At that point the SNAP algorithm terminates. Highly constrained problems with small minimum swap volumes result in longer solution times than unconstrained problems with large minimum swap volumes.

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Appendix 20 – Reservoir Inflow

Reservoir inflows are typically quite variable and differ by season, location in the basin and geographic basin. When upstream reservoirs are present, inflows into downstream reservoirs may be controlled to a greater or lessor extent by upstream management actions.

In the ESIM03 model, seven predefined inflow patterns are available. These inflow patterns have differing total inflows and differing chronological sequences. These seven inflow patterns allow the user to experiment with and understand some of the operational implications of inflow, release and reservoir level combinations. Table A20-1 summarizes the salient characteristics of the available predefined inflow patterns.

Table A20-1. Summary of Inflow Characteristics

	Minimum Inflow		Maximum Inflow		Total Inflow
Description	**(af/hr)**	**(cfs)**	**(af/hr)**	**(cfs)**	**(af)**
Declining	665.0	8,046.5	1,500.0	18,150.0	181,860.0
Increasing	500.0	6,050.0	1,335.0	16,153.5	154,140.0
High increasing	665.0	8,046.5	1,500.0	18,150.0	181,860.0
Constant high	1,100.0	13,310.0	1,100.0	13,310.0	184,800.0
Constant low	500.0	6,050.0	500.0	6,050.0	84,000.0
High peak	490.0	5,929.0	1,340.0	16,214.0	152,890.0
Mid peak	495.0	5,989.5	915.0	11,071.5	118,440.0

The turbine release capability for the powerplant is 12,000 cfs. As shown in this table, several of the hourly release patterns could result in a spill depending on the reservoir elevation specified by the user. Depending on the inflow pattern, these spills could occur at different times during the week.

Figure 48 provides thumbnail graphical illustrations of each of these predefined inflow patterns. Although these patterns are artificially contrived, they are representative of the type of inflow patterns faced by reservoir owners and powerplant operators.

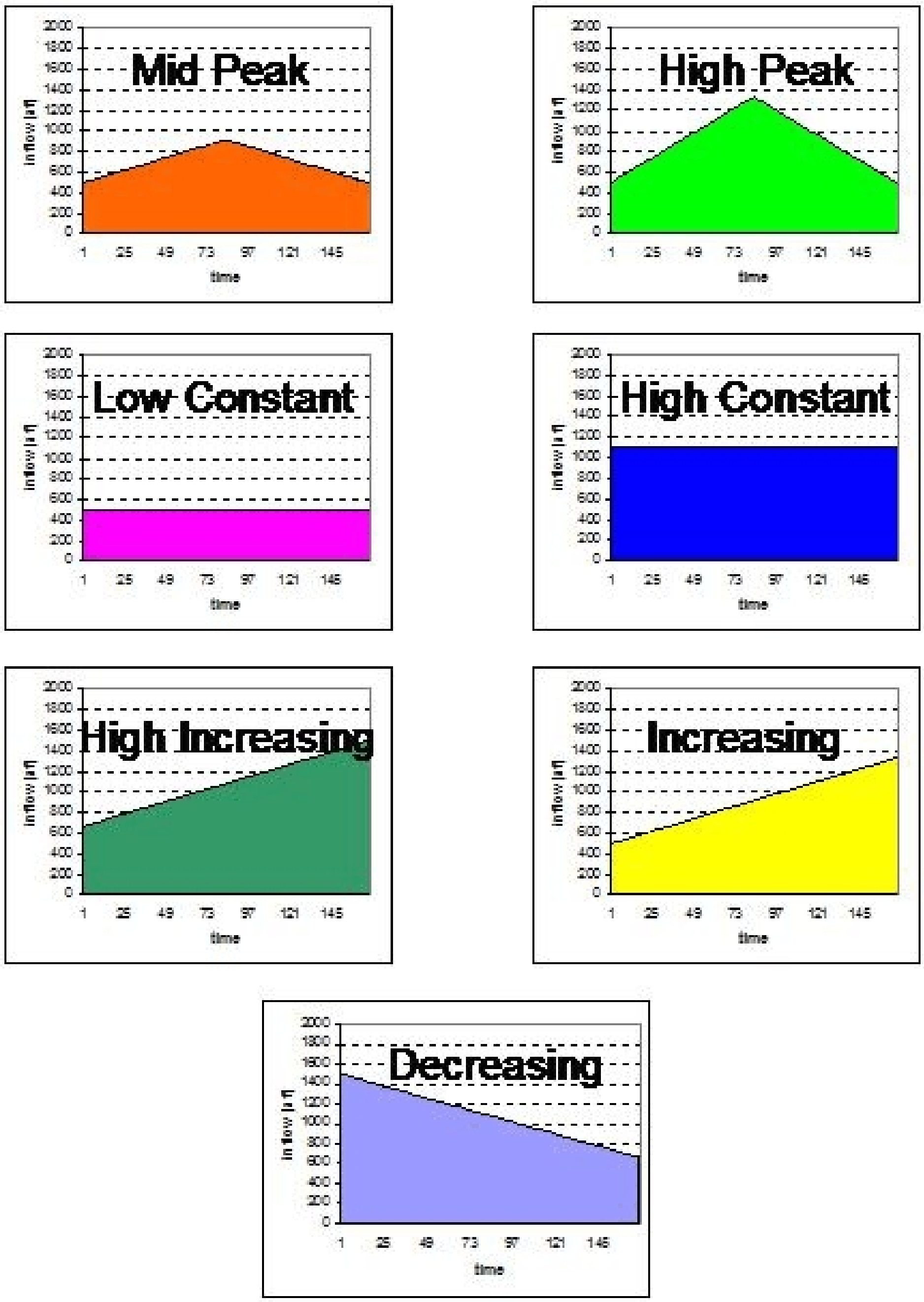

Figure 48. Thumbnail graphics of the seven inflow patterns available in the ESIM03 program.

Appendix 21 – Storage Reservoir Characteristics.

Operation of the hydropower plant is made possible by and affects the state of the storage reservoir. Conversely, the state of the storage reservoir, in particular its elevation and the existence of physical and engineering constraints directly effects the manner in which the hydropower plant can be operated.

The reservoir characterized in the ESIM03 model has a maximum storage capability of 640,000 af when it is full. A reservoir full condition occurs when the water surface elevation reaches 2008.1856 ft above mean sea level. The reservoir can be drafted by 200 ft for power generation purposes. The minimum power pool occurs at an elevation of 1808.1856 ft or a volume of 240,795.83 af. There is a difference between the elevation at the top of the penstock and the minimum power pool elevation. This difference reflects the minimum submergence depth[19] necessary for power production. When there is no release from the dam, the elevation of the tailwater is 1708.2 ft. An illustration of these critical elevations and depths is provided in Figure 49.

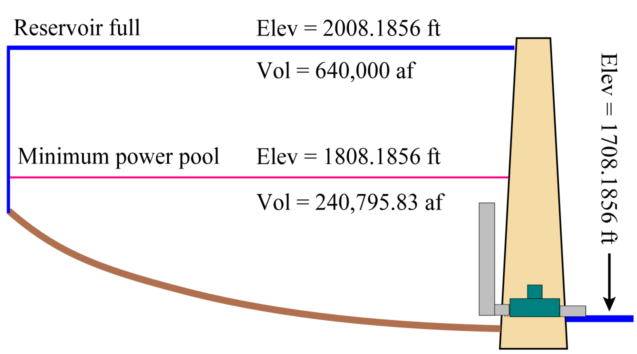

Figure 49. Critical depths and elevations of the reservoir and powerplant.

The relationship between the volume content of the reservoir and the elevation of the reservoir is represented by a cubic polynomial of the form shown in equation 32.

$$elev = a \times vol^3 + b \times vol^2 + c \times vol + d \qquad \textbf{(32)}$$

[19] A minimum submergence depth is necessary to prevent the creation of vortices and the entrainment of air in the turbines. If this were to occur, it would cause cavitation and damage the turbines.

Where: elev = water surface elevation of reservoir (ft above mean sea level)
vol = volume of the reservoir (acre-feet)
a,b,c,d are coefficients.

The coefficients for this relationship are shown in Table A21-1.

Table A21-1. Coefficients in the Reservoir Volume and Elevation Relationship

Coefficient	Value
a	2.400e-15
b	-3.85e-09
c	0.0024
d	1420.00

Figure 50 shows a plot of this relationship (equation 32) over a range of applicable storage volumes.

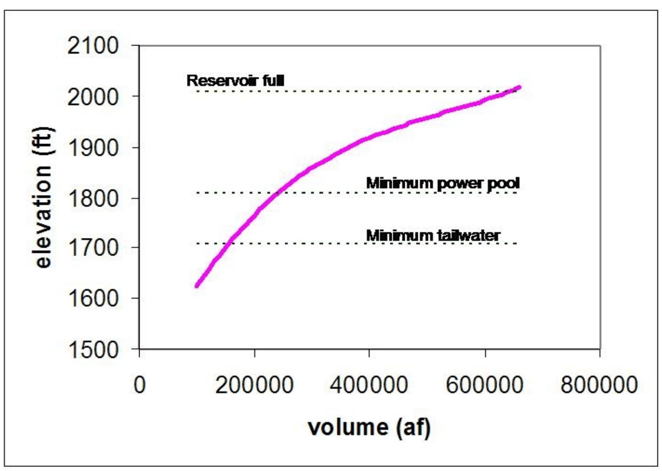

Figure 50. The relationship between reservoir volume (af) and elevation (ft).

The relationship shown characterizes a topography which is fairly typical for storage reservoirs. Initially, the elevation increases rapidly as the volume of the reservoir increases. As the reservoir approaches its full condition, the elevation increases much less rapidly.

There is a one to one relationship between reservoir volume and reservoir surface elevation. Specifying the reservoir volume is equivalent to specifying the elevation and *vice versa.* Since some calculations require the elevation and some calculations require the reservoir volume, the ability to convert rapidly back and forth between the two measurements is essential. Given a specified reservoir volume, the reservoir elevation is easily computed by using equation 32. However, computing the reservoir volume from a known reservoir elevation requires the solution of a cubic equation which is somewhat more difficult. In the ESIM03 program, the (cubic) relationship for volume as a function of elevation is solved using the methodology described in Press et al (1989 page 163).

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Appendix 22 – Copying Data to Microsoft Excel Via the Clipboard

This appendix describes how to copy numeric data from the program's output window to the Microsoft Excel spreadsheet using the MS-Windows clipboard. The approach described here may or may not be adapted to work with other brands of spreadsheets.

To copy data from the program's output window to Microsoft Excel, use the following steps:

1. Using your mouse, select or highlight the data in the program's output window you wish to transfer to Excel. By far the best strategy is to (a) select only the data you need, and, (b) ensure that you select a rectangular range of numeric data (I recommend you also select the column headings to avoid later confusion) for the transfer.

2. With the desired data range selected, click on the RIGHT mouse button. A dialog will appear, answer "yes." This will copy the selected data to the Windows clipboard.

3. If you haven't already done so, open the Microsoft Excel program.

4. In Excel, place the cursor in the upper left-hand corner of the range where you want the data to go.

5. Using the mouse, click on the "paste" speed button (which should be highlighted) or go to the edit menu and click on "paste." The data will be pasted to the worksheet in text format. In text format, all the data is contained in a single column and is not recognized as numeric data by Excel. Naturally, this is very inconvenient if you plan to use the data for subsequent numerical analysis or manipulate it in any fashion. Luckily, the clever programmers at Microsoft have foreseen this possibility.

6. *Without moving the cursor from its original position*, use the mouse to go to "Data" in the Excel menu. From the drop down Data menu, select "Text to Columns." A "Wizard" will appear to guide you through the remainder of the procedure. For your first choice, select "Fixed Width." A window will then appear in the Wizard which shows you where the Wizard has parsed the text or inserted column breaks. If the rectangular data table you selected is relatively uncomplicated, the "Wizard" will usually be able to parse the data correctly without any intervention on your part. However, you can't count on it! So, I recommend that you carefully inspect the columns shown in the window. Scroll up and down, scroll left and right all the while watching to ensure that a column line is not inserted partway through a data field. If everything looks OK, then click on "Finish." If not, manually adjust the column breaks to correctly parse up your data. Then, click on "Next" and follow the remaining directions which are provided to you by the "Wizard."

7. Congratulations! You are now ready to use the numeric data in Excel.

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GLOSSARY

Acre-foot (af): Volume of water (43,560 cubic feet) sufficient to cover 1 acre, 1 foot deep.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Ancillary Services: FERC (1995) defines ancillary services as, "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." FERC identifies six ancillary services. These are reactive power and voltage control, loss compensation, scheduling and dispatch, load following, system protection, and energy imbalance.

Anthracite Coal: A hard, dense type of coal that is hard to break, clean to handle, difficult to ignite, and that burns with an intense flame and with the virtual absence of smoke because it contains a high percentage of fixed carbon and a low percentage of volatile matter.

Apparent Power: The aggregate of real and reactive electric power. Usually measured in megavolt amperes.

Automatic Generation Control (AGC): Computerized automated equipment that adjusts a generator to maintain load, voltage and frequency

Avoided Cost: Costs not incurred as a result of operating a lower cost generation resource in lieu of operating a higher cost resource.

Baseloaded. A condition in which the output level of the powerplant is fixed or constant.

Baseload Powerplant: A power plant that is normally operated to generate a base load, and that normally operates at a near constant output level; examples include coal fired and nuclear fueled power plants.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U. S. gallons.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bituminous Coal: A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu (MBTU) per ton on a moist, mineral-matter free basis. The heat content of bituminous coal consumed in the United States averages 24 MBTU per ton.

Blackstart Capability: The ability of a generating unit to go from a shutdown condition to an operating condition without assistance from the electrical grid and to then energize the grid and help other units start after a blackout occurs.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits; may be in the form of rigid bars or stranded conductors or cables.

Busbar: The power conduit of an electric powerplant; the starting point of the electric transmission system.

Bypass Flow: A "spill" or release of water which does not pass through the generation plant or generate electricity. Sometimes used to achieve minimum stream flows or other environmental purposes.

Carbon Dioxide (CO_2): A colorless, odorless, incombustible gas formed during combustion in fossil-fuel electric generating plants.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The full-load continuous rating of a generator, prime mover, or other electric equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached to the equipment.

Capacity Factor: The ratio of the average load on (or power output of) a generating unit or system to the capacity rating of the unit or system over a specified period of time.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A readily combustible black or brownish-black rock whose composition, including moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted hardened, chemically altered and metamorphosed by heat and pressure over geologic time.

Combined-Cycle Powerplant: A power plant that uses two or more thermodynamic cycles to achieve higher overall system efficiency; e.g.: the heat from a gas-fired combustion turbine is used to generate steam to operate a steam turbine or generate additional electricity.

Cubic feet per second (cfs). A measure of a moving water volume. The number of cubic feet of water passing a reference point in 1 second.

Combustion Turbine: A turbine that generates power from the combustion of a fuel.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Decommissioning: The process of removing a powerplant, apparatus, equipment, building or facility from operation.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

Demand Side Management (DSM): The process of managing the consumption of energy, generally to optimize available and planned generation resources.

Dependable Capacity: The load-carrying ability of an electric power plant during a specific time interval and period when related to the characteristics of the load to be/being supplied; determined by the capability, operating power factor, and the portion of the load the station is to supply.

Design Life: Period of time a system or equipment is expected to function at its normal or design capacity without requiring significant refurbishment and/or replacement.

Downramp rate. Rate of decrease in the water release from the dam during a one hour period.

Efficiency: Under the first law of thermodynamics, efficiency is the ratio of work or energy output to work or energy input and cannot exceed 100 percent.

Electric Utility: An enterprise that is engaged in the generation, transmission, or distribution of electric energy primarily for use by the public and that is the major power supplier within a designated service area. Electric utilities include investor-owned, publicly owned, cooperatively owned, and government-owned (municipals, Federal agencies, States projects, and public power districts) systems.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Fahrenheit: A temperature scale on which the boiling point of water is at 212 degrees above zero on the scale and the freezing point is at 32 degrees above zero at standard atmospheric pressure.

Federal Energy Regulatory Commission (FERC): This is an independent regulatory agency within the U.S. Department of Energy that has jurisdiction over interstate electricity sales, wholesale electric rates, natural gas pricing, oil pipeline rates, and gas pipeline certification. It also licenses and inspects private, municipal and state hydroelectric projects and overseas related environmental matters.

Federal Power Marketing Administrations (PMA): These are separate and distinct organizational agencies withing the U.S. Department of Energy that market power at federal multipurpose water projects at the lowest possible rates to consumers consistent with sound business principles. There are five PMA's: Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration and Western Area Power Administration.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Francis Turbine: A type of hydropower turbine that contains a runner that has water passages through it formed by curved vanes or blades. As the water passes through the runner and over the curved surfaces, it cause rotation of the runner. The rotational motion is transmitted by a shaft to the generator.

Frequency: The number of cycles through wich an alternating current passes per second; in the U.S. the standard for electricity generation is 60 cycles per second (60 Hertz).

Frequency Support: The ability of a generation unit to assist the interconnected system in maintaining the frequency at 60.0 Hertz. This assistance can include both turbine govenor response and automatic generation control (AGC).

Fuel Oil: Any liquid petroleum product burned for the generation of heat in a furnace or firebox, or for the generation of power in an engine. Domestic (residential) heating fuels are classed as Nos. 1, 2, and 3; Industrial fuels as Nos. 4, 5, and 6.

Gas Turbine: A type of turbine in which combusted, pressurized gas is directed against a series of blades connected to a shaft, which forces the shaft to turn to produce mechanical energy.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power productions equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Head: A unit of pressure for a fluid, commonly used in water pumping and hydropower to express height a pump must lift water, or the distance water falls. Total head includes friction losses, etc.

Heat content: The amount of heat in a quantity of matter at a specific temperature and pressure.

Heat rate: The ratio of fuel energy input as heat per unit of net work output; a measure of powerplant thermal efficiency, generally expressed as Btu per net kilowatt hour.

Horsepower: A unit for measuring the rate of work (or power) equivalent to 33,000 foot-pounds per minute or 746 watts.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Interruptible Load: Energy loads that can be shut off or disconnected at the supplier's discretion or as determined by a contractual agreement between the supplier and the customer.

Kaplan Turbine: A type of turbine that has blades whose pitch is adjustable. The turbine may have gates to control the angle of the fluid flow into the blades.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Kilovolt-ampere (KVa): One thousand volt-amperes.

Lignite: The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It is brownish-black and has a high inherent moisture content sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu (MBTU) on a moist, mineral-matter free basis. The heat content of lignite consumed in the U.S. averages 13 MBTU per ton.

Load Factor: The ratio of average energy demand (load) to maximum demand (peak load) during a specific period.

Load Following: The demand for electricity changes rapidly across time potentially causing imbalances between the demand for electricity (load) and the supply. Powerplants which can rapidly change their generation levels, such as gas turbine units and hydropower plants, are used to supply electricity to accommodate these rapid changes in load. These plants are employed to react to or "follow" load.

Load Forecast: An estimate of power demand in some future period.

Load Shifting: A load management objective that moves loads from on-peak periods to off-peak periods.

Marginal Cost: The cost of the next infinitesimally small unit of output. In common usage: the cost of the next unit of output.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

Megavolt Ampere (MVa): One million volt-amperes.

Nameplate capacity: The full-load continuous rating of a generator, prime mover, or other electric equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached to the equipment.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Generation: Equal to gross generation less electricity consumption at the powerplant.

Nominal Price: The price paid for goods or services at the time of the transaction; a price that has not been adjusted to account for inflation.

Non-Utility Generator (NUG): A class of power generators or producers that is not a regulated utility and that has generating plants for the purpose of supplying electric power required in the conduct of their industrial and commercial operations.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC Regions are:

ASCC - Alaskan System Coordination Council
ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAIN - Mid-America Interconnected Network
MAAC - Mid -Atlantic Area Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool
WECC - Western Electricity Coordinating Council

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

On-peak Period: The time during the day when the demand for electricity is greatest. In the Western United States, this is typically between 0700-2300 hours Monday through Saturday. All other hours are typically considered "off-peak."

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Pelton Turbine: A type of impulse hydropower turbine where water passes through nozzles and strikes cups arranged on the periphery of a runner, or wheel, which causes the runner to rotate, producing mechanical energy. The runner is fixed on a shaft, and the rotational motion of the turbine is transmitted by the shaft to a generator. Generally used for high head, low flow applications.

Penstock: A component of a hydropower plant; a pipe that delivers water to the turbine.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Ramp rate: The change in release from one hour to the next hour. Usually measured in cubic feet per second (cfs).

Real power: Usually measured in watts or megawatts. Real or active power is used to power electric motors and other common electrical devices. Real power is bought and sold commercially.

Reactive power: Usually measured in volt-amperes reactive (VARs). The amount of energy stored in electric or magnetic fields. Although it is important to the stability and operation of the electric power system, it typically does not have commercial value. The electrical power that oscillates between the magnetic field of an inductor and the electrical field of a capacitor. Reactive power is never converted to non-electrical power. Calculated as the square root of the difference between the square of the kilovolt-amperes and the square of the kilowatts.

Real Price: The unit price of a good or service estimated relative to a specified base year in order to provide a consistent means of comparison.

Release Capability (hydro, maximum): The maximum amount of water which can be released through the powerplant at the normal maximum reservoir elevation.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting also are included in this category.

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Run-of-the-River Hydropower: A type of hydroelectric facility that uses the river flow with very little alteration and little or no impoundment of the water.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Short Ton: A unit of weight equal to 2,000 pounds.

Spill(s): Releases from a hydropower plant which are over and above the release capability of the powerplant. These releases do not produce electricity and are wasteful and undesirable from the power production standpoint.

Spinning Reserves: Electric powerplant or generating capacity which is unloaded, synchronized, online and ready for immediate use in the event of an outage.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Total Power: Usually measured in volt-amperes or kilovolt-amperes (KVa). The output from a generator is total power. Total power consists of two components: real and reactive power.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Transmission and Distribution Losses: The losses that result from inherent resistence in electrical conductors and transformation inefficiencies in distribution transformers in a transmission and distribution system.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Upramp rate. Rate of increase in the water release from the dam during a one hour period.

Volt-Ampere (Va): a unit of electrical power in an alternating current circuit equal to the power dissipated when 1 volt produces a current of 1 ampere. The product of a volt and an ampere.

Volt-Ampere reactive (VAR): unit of measure for reactive power.

Voltage Support: The ability of a generation unit to assist the interconnected system in maintaining the voltage at 110. This assistance can include making adjustments in generator reactive power output and transformer taps and by switching capacitors and inductors on the transmission and distribution system.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

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U.S. Department of the Interior
Mission Statement

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to the Tribes.

Bureau of Reclamation
Mission Statement

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.