Cost of Providing Ancillary Services from Power Plants

Volume 1: A Primer

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REPORT SUMMARY

As the electric power industry undergoes deregulation, managers of power plants will need to decide whether it makes business sense to provide ancillary services such as Reactive Supply and Voltage Control and Operating Reserves-Spinning. This report outlines two methodologies for calculating the variable cost of providing ancillary services from power plants.

Background
In an increasingly deregulated industry, new markets will emerge for power plants that can supply reactive power, operating reserves, and system stability. These services are called ancillary services by the Federal Energy Regulatory Commission (FERC). Since 1994, EPRI has been working with utilities to develop tools for calculating the cost of providing such services.

Objectives

To consult with power utility personnel on their requirements for methods to calculate the costs of ancillary services.

Approach
The project team analyzed the recent tariff fillings of 20 utilities from around the United States. The team held two workshops with utility personnel to discuss the industry's requirements and needs for methods that calculate the cost of providing generation based ancillary services.

Results
The report provides background information about ancillary services including the 1996 FERC definition of ancillary services and the current NERC definitions of Interconnected Operations Services (IOSs). The report outlines methodologies for calculating the variable costs of providing Reactive Supply and Voltage Control and Operating Reserves-Spinning, including all the overheads used to illustrate these methodologies at the two workshops. The report also discusses EPRI's future plans for developing additional tools to help owners of power plants compete in a deregulated

power supply industry, including methodologies for calculating fixed as well as variable costs.

Workshop participants identified the principle users of the cost methodologies as plant managers, operating supervisor and shift supervisors, control room operators, production management, and staff. These personnel would need at least daily information about the cost of providing ancillary services. Rate designers, power marketers, business planners, and regulators would need to know these costs on a seasonal or yearly basis. The methods should help management assess risk versus reward issues, understand cost causation factors, and evaluate "what if" scenarios as well as provide needed inputs in tariff filings.

Three additional volumes of this report are forthcoming. Volume 2 will provide a detailed description of a methodology for calculating the variable costs of providing Regulation and Frequency Response. Volume 3 will give additional detail on the methodology for calculating the variable costs of providing Reactive Supply and Voltage Control. Volume 4 will give additional detail on the methodology for calculating the variable costs of providing Operating Reserve-Spinning.

EPRI Perspective

EPRI's plan for its ancillary services projects involves testing methodologies developed for calculating the variable and fixed cost of providing ancillary services using data from several different units. Then, based on the results of these case studies, EPRI expects to identify a range of costs for ancillary services produced by all kinds of power plants. Utilities interested in using the methodologies are urged to contact Jan Stein at EPRI at (415) 855-2390 to participate in the on-going research.

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Interest Categories

Fossil assets management

Power system operations and control

Bulk power markets and transmission

Key Words

Ancillary services

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ABSTRACT

This report presents the results of two workshops held to define the industry's requirements for methodologies that can calculate the cost of providing ancillary services. It contains definitions of ancillary services and describes which services are provided by power plants. Two methodologies are presented that can be used to calculate the variable costs of providing ancillary services from power plants.

PREFACE

Deregulation of the electric utility industry is another in a long series of efforts to deregulate industries and create competition. During the Carter administration oil, airline, and the trucking industries were extensively deregulated. Then came deregulation of the cable, gas, and long - distance telephone industries and the misregulation of the savings and loan industry and the banks. Cable TV has since been re-regulated, after the cable companies raised their rates 40% in real terms, and then recently deregulated again along with most of the telecommunications industry.

Reasons for deregulation of the electric power industry are many. Economies of scale no longer produce lower per-unit cost, conventional wisdom wants to let the policy makers work under the presumption that markets should operate freely unless there is a compelling reason to regulate rather than visa versa, the cost to produce electricity is much lower then the current price, and "customers have choices in most other industries why not electricity?"

Separate lines of business will emerge in the electric power supply system depending on whether or not they can sustain competitive markets. Doing so requires unbundling services and prices. In an unbundled market unregulated generators will sell their output through a power exchange or on a contract. Regulated transmission companies will carry electricity as before to the regulated local distribution monopoly. Distribution monopolies and customers will pay separately for the power itself, for its transportation, and for other services that will include ancillary, and other, services required to ensure reliable operation of the power system.

In the competitive, unbundled, market customers will be eager to test their new freedom of choice. They will demand the lowest price possible that is consistent with their need for reliability, not the utility. Generation will be a tough business. Operating efficiency will count most as will the capability to provide other services, like ancillary services.

Most ancillary services will be competitively supplied. Managers of power plants will need to decide whether to enter or remain in a particular line-of-business, i.e., supplying power and ancillary services. They will make these decisions based on cost structure, expertise, and willingness to incur risks. They must decide what their assets are worth based on what customers are willing to pay for the power and ancillary services they can provide.

Cost of Providing Ancillary Services from Power Plants: A Primer points out why it is important to understand how costs are incurred inside the plant when a plant provides an ancillary service. It discusses how a plant's operating strategy influences the value of the plant. It also contains definitions of the ancillary services, as of October 1996, and which ones are important to the managers of power plants. Detailed methodologies are presented for calculating the cost of providing two ancillary services; reactive supply and voltage control, and operating reserves-spinning. These methods focus on the variable cost of providing these services: there is a direct, causal, relationship between how a plant is operated and the variable cost of providing ancillary services.

Variable costs of providing ancillary services from a power plant are difficult to calculate. They include the fuel, maintenance and repairs costs associated with a plant's operating strategy. The methods described in this report are based on engineering simulation models use to understand how a plant's performance changes under various conditions, i.e., "what if scenarios".

It is the goal of the EPRI projects on ancillary services to evolve these detailed models into a set of simpler and widely accepted methods for calculating all the costs associated with providing ancillary services. These methods are part of an overall effort by the EPRI to develop the tools power plant managers need to assess the value of power plants in a deregulated electric power industry.

ACKNOWLEDGMENTS

Workshop participants were the key success factor. Without their help and knowledge the efforts focused on developing the methodologies would be less effective. They told us what they wanted and needed, giving new direction to the current projects. We are grateful they took the time and effort to participate in the workshops. We also appreciate the efforts of Jim Evans of the EEI and Brent Ingebrightson of Sierra Paciffic Power who hosted the workshops.

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INTRODUCTION

MEASUREMENT IS KEY. IF YOU CANNOT MEASURE IT, YOU CANNOT CONTROL IT. IF YOU CANNOT CONTROL IT, YOU CANNOT MANAGE IT. IF YOU CANNOT MANAGE IT, YOU CANNOT IMPROVE IT -- IT IS AS SIMPLE AS THAT.

Pending deregulation of the electric power industry holds plenty of opportunities and some risks for owners of power plants. New markets for services, beyond power and energy sales, will exist for those plants that can supply reactive power, operating reserves, black start services, or that can become part of a solution to a power system stability or control problem. Some of these services are called ancillary services by the Federal Energy Regulatory Commission (FERC) and they predominately originate from power plants. Due to deregulation these services are now becoming another possible source of revenues for owners of power plants. Actually making a profit under these new market conditions, however, involves understanding one's costs and some risk taking; there will be others seeking to supply these same services.

Heat rate models and other power production computer simulation models are well understood methods for studying production costs under a variety of plant operating conditions. Power plant managers and engineers regularly use these tools for calculating the cost of supplying real power. The same, however, cannot be said for calculating the cost of supplying ancillary services.

Like the tools used to calculate the cost of producing power, new tools are needed for calculating the cost of providing ancillary services, i.e., voltage control and reactive power support, operating reserves, etc. For each ancillary service these new tools must account for two cost components, fixed and variable, to give a complete understanding of how various plant operating conditions affect the cost of providing ancillary services.

1.1 Background

Since 1994, EPRI's Fossil Plant Business Unit has been working with utilities to develop the tools for calculating the cost of providing ancillary services. In 1994 over 50 utilities were contacted in an effort to build a foundation of knowledge about methods needed for calculating the cost of providing ancillary services from power plants. One of these utilities, Consolidated Edison of New York Inc., teamed with EPRI to co-fund a project and develop two methodologies and then test them in case studies using data from two

(2) steam turbine units. Started in 1995, this project has developed methodologies for calculating the cost of Operating Reserves- Spinning, and Reactive Supply and Voltage Control. Case studies, using these methods, will be completed in 1997.

1.2 Workshop Procedures

This report documents the results of two (2) workshops held to discuss the industry's requirements and needs for methods that calculate the cost of providing ancillary services. It also presents specific methods for calculating the cost of providing Operating Reserves-Spinning, and Reactive Supply and Voltage Control based on the developments from the Con Ed/EPRI project. These workshops were hosted by the Edison Electric Institute (EEI) and the Sierra Pacific Power Company. EEI used its headquarters in Washington D.C. to accommodate over 35 attendees during the first workshop March 28th and 29th. Sierra Pacific used its corporate headquarters in Reno to accommodate 40 workshop participants April 30th and May 1st, 1996..

Participation in these workshops was designed to be quite different from a typical conference or meeting. Instead of listening to a series of presenters, workshop participants met in small groups to prepare their recommendations and then present their ideas to the entire workshop. In small groups, participants worked on specific assignments and prepared their responses to questions regarding their needs in a deregulated industry. During these sessions they learned form one another and then the entire workshop heard what they believed the industry needs in terms of tools for calculating the cost of providing ancillary services.

1.3 Workshop Results

These workshops served as a forum for defining the industry's requirements for methodologies to calculate the cost of providing ancillary services from power plants. Workshop participants identified the principal users of the methodologies as plant managers, operating supervisor and shift supervisors, control room operators, production management and staff. These users of the methodologies would need at least daily information about the cost of providing ancillary services. Rate designers, power marketers, business planners, and of course regulators, would need to know these costs on a seasonal or yearly basis.

Workshop participants determined that the methodologies are needed by management to understand all of the cost of providing ancillary services to set bid prices in the market. Indeed information produced by the methodologies could be used when deciding whether or not to participate in the ancillary services market. These methods should help management assess risk versus reward issues, understand cost causation factors, and evaluate "what if " scenarios. And, of course, these methods are needed now to satisfy regulators in tariff filings.

Participants also wanted methodologies that would capture both fixed and variable costs. Indeed the methodologies should include the capability to do sensitivity analysis and have the capability to analyze lost opportunity costs. The methods should help in finding the most economical operating conditions and reference points. And finally, the methodologies must calculate the variable cost components associated with providing an ancillary service, e.g., fuel, maintenance, and equipment wear and tear. Some participants hoped these methodologies would lead to an accepted range of costs for providing ancillary services.

1.4 Organization of the Report

Section 2.0, Ancillary Services, provides background information about ancillary services. It presents the Federal Energy Regulatory Commission (FERC) definition of ancillary services and the additional services defined by the North American Reliability Council (NERC) called the Interconnected Operations Services (IOS).

Section 3.0, Methodology for Calculating the Variable Cost of Providing Reactive Supply and Voltage Control from a Generating Unit describes the methodology for calculating the cost of providing voltage control and reactive power to the power system. This is the description given to the workshop attendees with updates based on the project co-funded by Consolidated Edison and EPRI.

Section 4.0, Methodology for Calculating the Variable Cost of Providing Operating Reserves--Spinning contains a description of the methodology for calculating the cost of providing the service operating reserves-spinning. It is based on the workshop presentations and recent developments from the project co-funded by Consolidated Edison and EPRI.

Section 5.0, Tools to Make Decisions, describes EPRI's future plans to help owners of power plants by developing the tools they need to compete in the deregulated electric power supply industry.

2

ANCILLARY SERVICES

In this section we define ancillary services just as was done during the workshops. The only real difference between the time when this report was written and when the workshops were held is --the North American Reliability Council (NERC) has defined the Interconnected Operations Services (IOS). These are the services required to reliably operate an interconnected power system. Ancillary services, defined by the FERC, are a subset of the IOS.

2.1 The Federal Energy Regulatory Commission's Definitions

April of 1996 the FERC issued orders 888 and 889, which--among other things--defined ancillary services. These orders require any public utility that owns, controls, or operates interstate transmission facilities shall offer comparable, non-discriminatory wholesale transmission and ancillary services. Comparability refers to how services are offered by the transmission provider. These services must be comparable to the transmission services the transmission provider offers to its own power customers.

The FERC rulings are focused on transmission services offered by the transmission provider (TP) to the transmission customer (TC). A TC is defined as an entity that purchases transmission services from a TP. A TC may be a generator, power marketer, municipal or any other entity that enters into a contract for transmission services under a published tariff. A TP is the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission services under a tariff.

According to the FERC, six (6) specific ancillary service must be provided or offered by the transmission provider (TP). Two (2) of these services must be provided by the TP; Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control. Any TC must purchase these two ancillary services from the TP.

The TP must offer four(4) other ancillary services; Regulation and Frequency Response, Energy Imbalance, Operating Reserves--Spinning, and Operating Reserves--Supplemental. A TC must acquire these services from some provider, it does not have to be the TP.(see Appendix A Definition of Terms).

2.1.1 The FERC Definition of Ancillary Services Meaningful to Power Plants

Power plants are a principal resource for providing some of the ancillary services defined by the FERC. They include; Reactive Supply and Voltage Control, Regulation and Frequency Response, Operating Reserves both Spinning and Supplemental. These service are now part of the electric power supply market and someone, TC or TP, needs to purchase these services directly or indirectly from power plants. In the case of the TC, prices paid by the TC for transmission and ancillary services are contained in the TP's published transmission tariff. Whereas, the prices paid by the TP or TC to purchase ancillary services from power plants may be based on either the cost to provide the service -- if the plant is part of an integrated utility-- or a market price if there is a market of competing power plants supplying the same service.

Reactive Supply and Voltage Control service is provided by generating units with operating automatic voltage regulators. These units provide a dynamic (time varying) source for reactive power; where dynamic refers to the ability of a generating unit to produce more reactive power when the transmission voltage is decreasing. This is in contrast with other reactive supply equipment, e.g., shunt capacitors, which can aggravate a voltage collapse condition by drawing more current as the voltage decreases. Reactive supply, by this definition, refers to reactive power from generating units that is an amount in excess of the reactive power supplied by equipment within the transmission system and is required to respond to changing power system conditions and contingencies.

Regulation and Frequency Response is the power system function that continuously maintains the balance between power demand and power generated. It does this by adjusting the power output of a few generators, controlled by the automatic generation control (AGC) system, to follow moment-to-moment power demand changes.

Operating Reserves -- Spinning are provided by generating units that are on-line, serving load, and operating at less than their maximum output capability. Spinning reserves are needed to replace power resources loss due to a contingency, e.g., loss of generation, transmission lines or corridor, etc.

Operating Reserves -- Supplemental are needed to serve power system load after a contingency. This can be made available by generating units that are on-line but unloaded, quick starting units, or interruptible load. Supplemental operating reserves must be provided within a short period of time.

2.2 The North American Reliability Council (NERC) Definition of Interconnected Operations Services

There is a distinct difference between the services identified as ancillary by the FERC and the services required to operate a reliable interconnected power system. The FERC definitions of ancillary services are focused on transmission services involving a transmission provider (TP) and a transmission customer (TC). Furthermore, the FERC is principally concerned with "comparability of service", i.e., non-discriminatory open access transmission service. Services needed to reliably operate interconnected power systems, however, are more numerous than the services defined by the FERC and are the domain of the North American Reliability Council (NERC).

Services needed to operate a reliable interconnected power system are more extensive than the ancillary services defined by the FERC. For example, the FERC is silent on the need for generating units with a black start capability. It is not an ancillary service, yet operators of power systems have a plan for restoring the power after a major power outage using power plants that can start without an external source of power--black start.

The NERC is developing the "Rules of the Road" for operating an interconnected power system in an open access transmission industry. Called the Interconnected Operations Services (IOS) [1], these services are required for power system reliability. And similar to the market for ancillary services, there will also be a market for the IOS. That is, whether it is the TP who also operates of the control area or a control area operator, someone needs to purchase the IOS because they are responsible for the reliability of the interconnected power system.

Under the leadership of the NERC, who organized the IOS Working Group, a structure of the Interconnected Operations Services has been developed and is shown in Figure 2-1. This figure shows all of the FERC's ancillary services and their relation to the IOS defined by the NERC. Additional services defined by the IOS Working Group include:

- Backup
- Transmission Losses
- Stability and Control

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[1] An IOS Working Group is rewriting NERC's Rules of the Road -- guidelines for operating an interconnected power system --with broad support of the industry. This group will submit its technical definitions of the IOS to the FERC while continuing to build industry support for a set of standard definitions of the IOS.

- Black Start
- Load Following
- Dynamic Scheduling
- Power Factor Correction

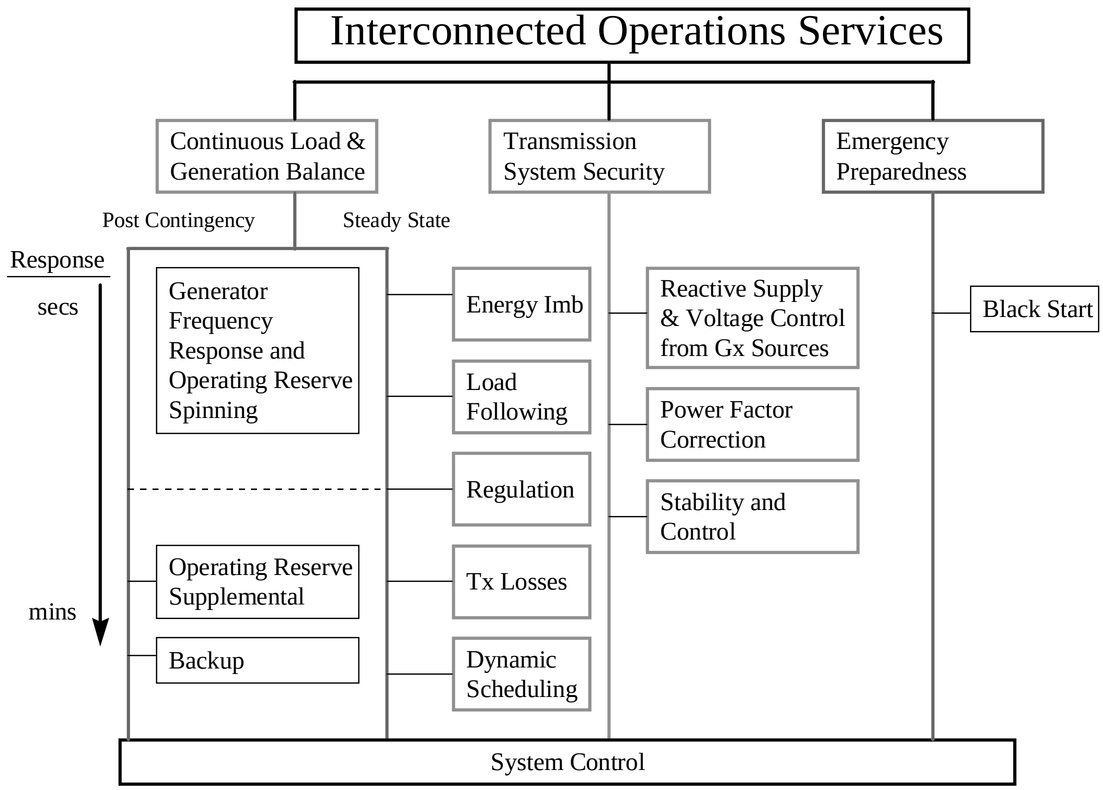


Figure 2-1 IOS Structure

Backup service is defined as generating capacity and energy needed to replace the loss of generation, transmission lines etc. Either the power supplier or its customer can obtain Backup service from the TP or a third party, arrange to provide the service themselves, or accept interruption (curtailment) by the control area operator if the customer's power supplier has an outage.

Real Power Transmission Losses are required to replace power and energy losses associated with transmission service. If transmission power losses are not scheduled by the TP or control area operator, there will be an imbalance between power generated and power demanded due to the loss of real power in the transmission system caused by resistance of the transmission lines. To solve this problem a TC must either provide or otherwise arrange for the supply of real power losses as part of the process of securing transmission services from the TP. The options a TC has are to either arrange for delivery of extra power to replace the losses or to purchase replacement power from the market, i.e., other power suppliers and possibly the TP.

Stability and Control services are provided by power plants with specialized equipment installed for power system stability or control reasons. Examples of Stability and Control equipment include: Power System Stabilizers, Fast Response Excitation systems, Fast Turbine Valve Control, Fast Fault Clearing and Breaker-and-a Half schemes. When these services are to be purchased from a power plant, generating units are equipped with such special equipment.

Load Following service, as defined by the IOS Working Group, refers to a service offered by the TP to the TC. It is not " load following " normally thought of by individuals in the power plant business, which has more to do with " wear and tear". Rather it is a service a TC can purchase from the TP to minimize Energy Imbalance charges. For example, if the TC has a constant or flat power demand, there are no charges for Energy Imbalance. If, however, the TC's power demand exceeds a regulating band, Energy Imbalance charges accumulate every time the TC's power demand is above or below the regulating band. The Load Following service comes into play if the TC wants to avoid these Energy Imbalance charges. In this case the TC purchases the Load Following service from the TP, thus minimizing its Energy Imbalance charges.

Dynamic Scheduling is a service one control area operator can offer another control area operator and does not directly involve services power plants provide to the TP, TC, or others. And Power Factor Correction refers to equipment installed by the TP within the transmission system to maintain voltage, e.g., Switched Capacitors, Static VAr Compensators and Reactor Banks, Load Tap Changing Transformers and series Capacitors.

2.2.1 The NERC Definition of the IOS Meaningful to Power Plants

Stability and Control services are needed to ensure the transmission system operator, TP or control area operator, can comply with the NERC guidelines for reliability. These operating guidelines are required to maintain the security of the interconnected power system. The need for specialized equipment occurs when a power system stability or control problem is identified by the NERC regional coordinating council or a control area operator. If the solution requires modifying one or more generating units by installing specialized equipment , the cost of installing and maintaining the equipment will likely involve a negotiated settlement between the plant owners and the affected control area operators. In some cases the entire interconnected power system may be affected by the stability or control problem and other arrangements may be necessary, i.e., special stability or control equipment may be required for every power plant connected to the power system.

Black Start is a service paid for by all TCs. If a TC has the capability to contribute to the control area operator's restoration plan, prepared by the TP or control area operator, then it can "self provide" the service, i.e., avoid paying for Black Start service.

Power plants seeking to supply Black Start services must agree to operate according to the NERC guidelines. These requirements involve having the capability to provide sustained power output, sufficient fuel resources, right location in the transmission system, communication systems, etc..

2.3 Different Perspectives of the FERC, NERC and Power Plant Owners

From the perspective of the FERC, ancillary services are required for "comparability" and open access of transmission systems. Where comparability refers to comparable service offered by the transmission provider i.e., the TP must offer transmission and ancillary services to other transmission customers that are comparable to the services offered to its own customers.

The FERC is achieving its goal of comparable, non-discriminatory, open transmission access by requiring utilities to publicly post their prices for transmission services. That is, utilities under the FERC's jurisdiction must file a tariff with FERC based on enumerated costs, i.e., costs directly involved in providing the service. Called "cost causation" by rate design types, utilities are required to define--enumerate-- all the costs incurred in providing transmission services. For example, installing shunt capacitors within the transmission system to maintain the scheduled voltage within specified limits is "causally linked" with the act of providing transmission service and can be justifiably recovered by a tariff. A hunting lodge retreat for the utility's stressed-out employees, however, is not causally linked with providing transmission service and therefore cannot be justified for recovery by a tariff.

The FERC reviews tariff filings on a case-by-case basis. Each utility submits a tariff and defines how it determined the costs for each service. These tariffs must be based on cost but the FERC can allow market-based pricing if it determines there is a viable market to supply the services.

From the perspective of the NERC, the IOS are required for reliability. Reliability refers to the ability of an interconnected power system to " take a hit " and continue to keep the lights on. These hits are called contingencies and include events such as the loss of generation, transmission lines or corridor, etc. Handling these contingencies involves operating the power system according to a set of guidelines that have been developed by the utilities over the last 30 years.

The NERC organized the IOS Working Group to define all of the services needed to manage the interconnected power system with open access to transmission systems.

These efforts will, among other things, provide the FERC with a technical, engineering, definition of all of the services required to reliability operate an interconnected power system, i.e., the IOS establish a foundation for the " Rules of the Road " required for open transmission access. The IOS go beyond the ancillary services defined by the FERC. For example, the FERC does not include Black Start as an ancillary service. Yet operators of interconnected power systems have developed plans for restoring the power after a major power outage that rely on some generating units that can start without being supplied with outside power, Black Start.

From the perspective of the owners of power plants these IOS and ancillary services represent an opportunity for new revenues. In the case of ancillary services, the transmission customer (TC) must acquire some ancillary services from the transmission provider (TP) or from a qualified third party, or in some cases the TC can provide the service itself i.e., self supply. In the case of the IOS, the TP or control area operator must secure a source of the IOS for ensuring the reliability of the power system. For example, TCs can purchase Backup Services from or through the TP, from a third party supplier or accept curtailment if the TC decides not to purchase the Backup service and it does not have the capability to provide its own Backup capability.

The prices paid to the owners of power plants who are providing the IOS, or ancillary services, will be an interesting mix of cost-based and market-based prices. Cost-based prices for ancillary services, made public in a TP's tariff, are what the TP charges the TC. They are not necessarily the same prices a power plant will be paid to provide ancillary services. Prices paid for the IOS will likely be based on negotiated or market-based prices created by supply and demand market dynamics. For example, the TP must pay a few power plant owners for backing down their units to provide Spinning Reserves. It is possible that plant owners' costs for providing this service that will require one price while the TP is only offering a lower price. This suggests that the key issues for power plant owners is to know their costs, both fixed and variable, and to have the ability to analyze how various plant operating strategies influence the cost of providing the IOS and ancillary services.

2.4 Fixed and Variable Costs

Both fixed and variable costs are involved in providing the IOS (ancillary) services. Fixed costs are defined as the costs required to purchase and install the equipment used to provide a service. These costs are called fixed costs because they do not vary with output. That is, fixed costs are all the costs incurred even if the unit produced zero output. Variable costs, on the other hand, change with power plant output. They include fuel, maintenance, repairs, etc. needed to provide the service.

Table 2-1 defines the fixed and variable costs associated with providing each of the IOS (ancillary) services provided by power plants. These are the cost categories that need to be included in any calculations performed to determine the cost of providing the IOS or ancillary services.

Initially, EPRI focused its efforts on developing methodologies for calculating the variable cost of providing ancillary services. At that time variable costs were thought to be more difficult to determine because they required detailed engineering models for capturing how changing the generating unit's operation over time influenced costs of operating the plant. This variable component of cost seemed more deserving of a research project, which EPRI and Consolidated Edison co-funded in 1995. Ultimately, EPRI's research efforts are expected to lead to a set of simpler calculations for replacing the complex engineering models. These simpler methods will emerge as a result more case studies using the detailed methodologies using data from different units, e.g., hydro, combined-cycle, etc.

To test our notion that variable costs are more difficult to calculate than fixed costs, we analyzed the recent tariff filings of 20 utilities. Our purpose was to understand why there is some variability in transmission services prices utilities have quoted to the FERC.

We focused on analyzing two (2) ancillary services, Reactive Supply and Voltage Control, and Operating Reserves-Spinning to test our notion that variable costs are more difficult to calculate than fixed costs. We analyzed the recent tariff filings of 20 utilities. Our purpose was to understand why there is some variability in the prices utilities have quoted to the FERC.

We analyzed Reactive Supply and Voltage Control service because it is a predominately fixed costs service when compared to Spinning Reserves, which is a variable cost service (see Table 2-1 - Fixed and Variable Cost). We wanted to determine whether or not utilities generally priced these services within a reasonable and explainable range. And if there where wide variations, would they occur more often when calculating fixed or variable-based cost services.

Our analysis of data from 20 utility filings on Reactive Supply--a predominately fixed cost based service-- showed that on average utilities are pricing this service at $0.17/kW-month. The price range, i.e., (maximum minus minimum) is 0.58, with a maximum at $0.62/kW-month and a minimum at $0.04/kW-month. This suggests that when it comes to determining their fixed costs, utilities are using methods that produce prices falling within a reasonably narrow range.

Table 2-1
Fixed and Variable Costs

	Fixed Costs	Variable Costs
REACTIVE SUPPLY and VOLTAGE CONTROL	Portions of generator and its exciter. Accessory electrical equipment that supports the operation of the generator-exciter. Remaining total production plant investment required to support reactive power production.	Losses in the Rotor, Stator, Transformer. Maintenance and Repair costs.
REGULATION and FREQUENCY RESPONSE	Automatic Generation Control equipment and Communications Link to Control Area Operator	Efficiency Losses in Turbine and Control Valves when Ramping Up/Down—Operated in Constant Pressure Mode or Efficiency Losses in Steam Generator and Turbine when Ramping Up/Down—Operated In Turbine-Follow Mode. Maintenance and Repair Costs.
OPERATING RESERVES—SPINNING		Efficiency Losses in the Turbine and Control Valves. Maintenance and Repair of Steam Control Valves and Wear & Tear in Turbine/Boiler.
OPERATING RESERVES—SUPPLEMENTAL	Equipment Required to Provide Quick Start Capability, e.g., combustion turbines, hydro	When Service is Provided—Fuel, a Portion of Labor and Overhead Expenses. Maintenance and Repair costs.
BLACK START	Equipment Required to Provide Sustained Power, e.g., diesel generator, large turbine bypass system, etc. Additional Costs to ensure sufficient fuel supply.	When service is provided, fuel, overhead expenses, labor, etc.
STABILITY and CONTROLS—Power System Stabilizer, High-response Excitation System. Fast Turbine Valve Control, Fast Fault Clearing.	Equipment Required to Provide the Specialized service—may be paid for by the Operator of the Control Area.	Maintenance and Testing of the Specialized Equipment should be paid for by the purchaser of the service, i.e., Operator of the Control Area.

The same analysis of the prices quoted for Spinning Reserves shows a different result. Based on data from 20 utilities the average price is $1.87/kW-month with a range of 12.92. This means that in one part of the country the price for Spinning Reserves can be over 200 times the price in another part. Such a wide variation in the price for Spinning Reserves cannot be explained based on fuel prices alone. The average price for economy energy in the wholesale market is $23.83/MW with a range of 34.50. Buying economy energy only varies by a factor of 3.

A conclusion drawn from this analysis of the prices for Spinning Reserves is - utilities are using a variety of methods to calculate the variable cost of ancillary services and are finding every different results. One reason may be that utilities are using allocation techniques similar to those used to calculate fixed-cost based services., e.g., Reactive Supply. Others are using ratios and other indirect methods for calculating variable-cost based services.

2.5 Methodology for Calculating the Fixed Cost of Providing Voltage Control and Reactive Supply from Generating Units

The following describes a methodology developed by the American Electric Power Company (AEP) for calculating the fixed cost of providing Reactive Supply and Voltage Control from generating units. This methodology illustrates how AEP enumerated all of the fixed costs for its tariff filings before the FERC. Our purpose in presenting this methodology is illustrate a fixed cost method; the variable costs methodologies are contained in sections 3.0 and 4.0.

As shown in Figure 2-2, this fixed cost methodology is based on data from the FERC Uniform System of Accounts. This approach separates the cost for power plant facilities into three cost components; the generator and exciter, accessory equipment that support the operation of the generator and exciter, and the remaining total power plant investment required to provide real power for supporting real power losses in the generator and exciter used to produce reactive power.

Figure 2.2 - AEP Methodology for Determining Reactive Power Supply Price
(As Filed--Final Version)

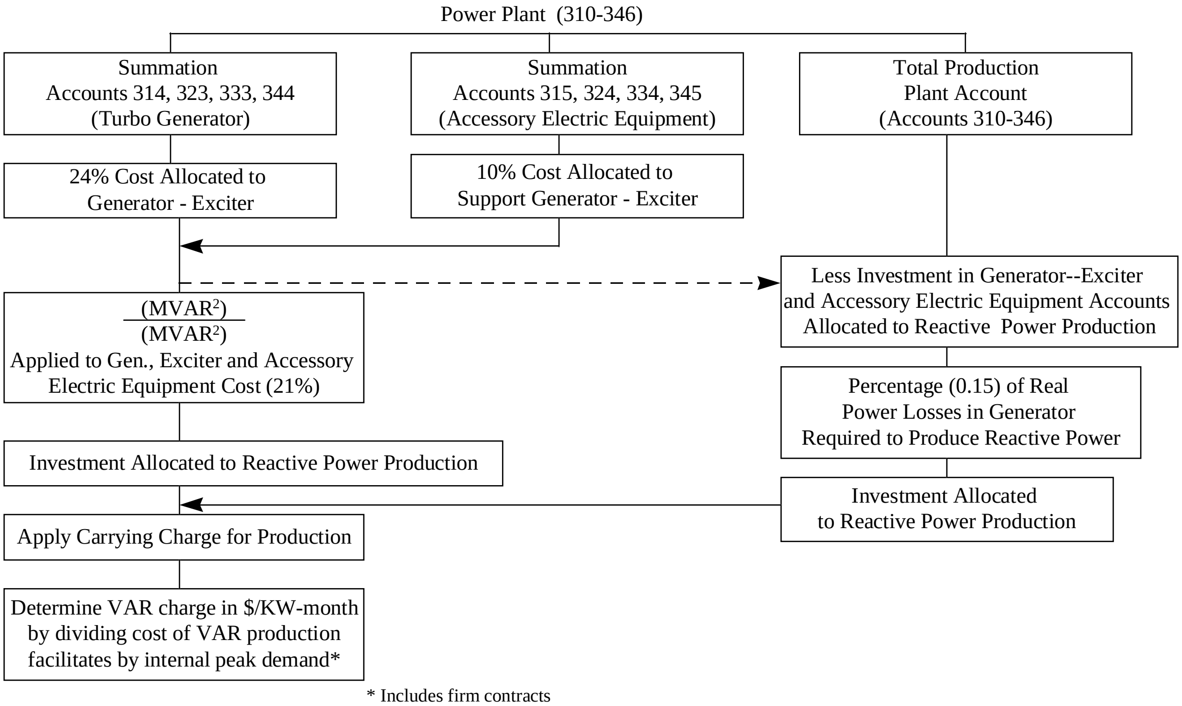


Figure 2-2 Fixed Cost Methodology

At the top of Figure 2-2, the FERC account numbers are identified for the three components. Each component summation aggregates the cost contained in the identified account numbers. Next the percentages of the summed costs are calculated to determine the amount that can be allocated to the fixed cost of producing reactive power. Then the total investment is corrected to account for carrying charges. The final result is divided by the peak power demand to find the $/kW-month price for supplying reactive power. This resulting price is what AEP charges its transmission customers.

3

METHODOLOGY FOR CALCULATING THE VARIABLE COST OF PROVIDING REACTIVE POWER SUPPLY AND VOLTAGE CONTROL FROM A GENERATING UNIT

During the workshops we approached the problem of understanding the IOS and ancillary services by first defining a problem and then finding its solution. That is, each problem was described from the perspective of the power system operator, i.e., TP, control center. Then a solution to the problem was traced to a service offered by power plant. For example, an operator of a transmission system must maintain voltage on the transmission system within a specified range. A possible solution is offered by a generating units, with automatic voltage regulators, in the right locations. In this example, the transmission system operator has the problem and the solution is offered by any power plant that has generating units with automatic voltage regulators, which is also in the right location where voltage control is necessary. Of course, how power plants provide solutions to the problems of operating an interconnected power system are more complex than this simple example illustrates.

3.1 Reactive Supply and Voltage Control from Generating Units

From the perspective of the power system, controlling transmission system voltage means having enough reactive power available to prevent low voltage conditions. It is the responsibility of the operators of the power system to schedule the production of reactive power to ensure low voltage conditions do not occur.

There are a variety of actions a power system operator can take to control voltage. These actions involve using power system equipment to help prevent or mitigate voltage problems. This equipment includes;

- Automatic Voltage Regulators on generating units
- Switched Capacitors
- Static VAr Compensators and Reactor Banks

- Load Tap Changing Transformer
- Series Capacitors

For example, to mitigate the condition of voltage collapse, a problem primarily associated heavy demand caused by a disturbance or an unusual increase in power demand, power system operators have adopted a philosophy of increasing transmission system voltage (inserting capacitors, dispatching generators, etc.) in anticipation of the morning load pick up. Then as the load increases the voltage is brought back down to normal. This is sometimes referred to as " getting under the voltage".

Voltage deviations occur in the power system when the voltage on the transmission system differs from the schedule. To solve this problem automatic controllers are set by the control area operators to a scheduled voltage. These controllers work automatically to maintain the scheduled voltage.

In the United States power plants are the primary resources used to control transmission system voltage. For example, voltage on the transmission system is set , i.e., scheduled, by adjustment of the automatic voltage regulators on generating units. A plant operator, often under the direction of the power system operator, will increase the set point to raise the system voltage (and increase reactive power output) or decrease the set point to lower system voltage (and decrease reactive power output), as power system operating conditions change.

The automatic voltage regulator (AVR) is the primary control of the generating unit's excitation system. It continuously measures the generator's terminal voltage and compares the measured value with the set point. If the terminal voltage is less than the setting, the AVR increases the dc excitation voltage applied to the generator rotor (field) windings, which increases the excitation current. As the excitation current is increased the strength of the magnetic field linking the rotor and the stator windings also increases. Consequently, the generator's terminal voltage increases and VArs produced by the generator flow into the power system. Conversely, if the AVR senses a terminal voltage higher than the set point, it decreases the excitation voltage, resulting in a decrease in terminal voltage and flow of VArs into the power system.

Increasing or decreasing the excitation current changes the losses associated with providing reactive power and controlling transmission system voltage. Losses occur in the copper of the rotor windings and stator, in the core stator iron, and there are stray-load losses. Of the total losses that occur in a generator operating at full load, about 30% are due to resistive copper losses in the field windings, 20% in the copper of the stator, about 10% in the core (stator iron) and 20% are stray-load losses where the split between stray and stator losses depends on the design of the generator. Additional losses occur in the transformer; at full load about 85% are from copper losses and 15% due to iron losses. And there are additional maintenance and repairs costs associated with operating the unit to provide reactive supply for controlling transmission system voltage that would not occur if the unit was operated at unity power factor.

The FERC recognizes the fact that reactive power supply from generating units for controlling transmission system voltage is a highly localized service; reactive power cannot be moved long distances on the transmission system like real power. As a result it is somewhat unlikely, unless it can be proven otherwise, that the FERC will let power plants charge i.e., price, this service. Allowing power plants to price this service is too much of an opportunity for dominant "market power", especially if the power plant is the only possible option available for supplying reactive power. The FERC will allow market-based pricing if the power plants can prove they do not have dominant market power, i.e., there is a competitive source of reactive power from other suppliers.

The FERC's solution to this problem of market or cost-based pricing is to require power plants that are part of an integrated utility to offer reactive services at cost. Simply stated this means that only those costs that are actually incurred in providing the service can be recovered. The FERC will only let those components that are directly or causally linked to the act of providing the service to be part of the estimate of cost (fixed and variable). Independent power plants, i.e., not part of a regulated utility, can price reactive power supply if they can prove there is a competitive market to supply the service.

3.2 Calculating the Cost of Providing Reactive Supply and Voltage Control

Cost of providing reactive supply and voltage control service and the price paid for the service are obviously not the same. Cost is what it requires to produce a good or service, including both the fixed and variable costs. Whereas price is the amount of cash a consumer pays to the producer to purchase a unit of a good or service. And the difference between price and cost is what you get to keep..

The following is a detailed step-by-step procedure for calculating the variable cost of providing reactive power and voltage control from a generating unit. This methodology is complete but it has not been tested using data from an operating unit. Results of testing the method, using data from two Consolidated Edison units, will be completed in 1997.

Step 1 Obtain Generating Unit Data

A. Get the manufacturer's data

1. Nameplate rating

2. Saturation and reactive capability curves

3. Electrical parameters and design data

B. Get steady-state reactances

Step 2 Obtain Time Series Data

A. Get recorded data from operating data; for each recorded time interval record P, VAr, V

B. Use power flow program to define I at each time interval by using power system data correlated with the study time period if I is not part of the recorded data

Step 3 Calculate Losses

A. Calculate a base case by assuming that the unit operates at unity power factor for the same time period being used for the study

B. Estimate field temperatures for each operating condition during the study period

C. Estimate resistances using unit design and temperatures

D. Use steady-state reactances and the open-circuit saturation curve to calculate field current

E. Calculate the I2R losses

F. Calculate iron core losses using stator voltages at each time interval of the study

G. Calculate the stray losses using data from the manufacturer's data

H. Calculate the difference between base case and derived values using the recorded data and integrate over time to obtain costs of losses from extra fuel used.

The calculated difference is the additional variable costs incurred to provide voltage control and reactive supply for the study time frame.

Step 4 Calculate Transformer Losses

A. Obtain nameplate data from manufacturer

B. Calculate copper losses using I data for each time interval

C. Calculate iron losses using V data for each time interval

Step 5 Calculate Costs due to Additional Maintenance and Repairs

A. Obtain historical data on unit, or similar units. to define maintenance and repair activities

B. Correlate historical record with P, V, I operating record

C. Separate historical data into their underlying damage mechanism i.e., vibration thermal, other categories

D. Correct historical records of maintenance and repair activities to present day values

E. Obtain average cost sensitivities of repair, maintenance or replacement work as a function of the operating range based on the historical record.

F. Sum costs for each category to find variable costs for a given operating range

G. Compare base case - unity power factor-and actual operating data to find additional variable costs associated with operating at P, Q in recorded data

4

METHODOLOGY FOR CALCULATING THE VARIABLE COST OF PROVIDING OPERATING RESERVES--SPINNING

Again, like the session on Reactive Supply and Voltage Control, we discussed Operating Reserves--Spinning by first defining the power system problem solved by Operating Reserves and then tracing solutions to generating units.

4.1 Operating Reserves--Spinning

From the perspective of the control area operator, Operating Reserves --Spinning, henceforth called spinning reserves is defined as some number of generating units, distributed around and synchronized to the power system, which are partially unloaded and capable of responding immediately. A portion of spinning reserves is provided by generating units with operating turbine-governor controllers. These units provide an immediate response to help arrest a sudden decline in frequency following a disturbance. Spinning reserves are also needed to restore the tie-lines to their scheduled power exchange with neighboring control areas. Spinning reserves are also used to restore power system frequency to the scheduled frequency following a contingency.

The role of a generating unit in providing spinning reserves is based on the following understanding of the mechanical and electrical interactions of the turbine-generator system. A generating unit converts mechanical power to electrical power. The mechanical power from the turbine rotates a rotor assembly in the generator producing electrical power to the power system. A turbine-governor, or speed-load controller, adjusts the proper amount of steam flowing into the turbine so that the mechanical power from the turbine exactly matches the electrical power output of the generator. Sensing any speed deviations in the rotor, the governor constantly adjusts steam flow to maintain a set speed, e.g., 3600 rpm where 3600 rpm/60 sec = 60 Hz.

If there is a sudden increase in the electrical demand, caused by a loss of a generating resource or major increase in customer demand, the electrical output of the generating units in the power system increases to supply in the new demand. This is accomplished by increasing the mechanical power applied to the generators' rotor assembly. The actual sequence of events occur as follows; first there is a sudden increase in electrical power demand that is greater than the mechanical power produced by the turbine. In the next moment kinetic energy is removed from the spinning rotor masses to supply the increased electrical demand resulting in a decrease in rotor speed. As the speed of the generators' rotors slow down the power system frequency declines. That is, the slowing of the generating unit's rotors results in a drop in power system frequency. The frequency continues to drop until the mechanical power from the turbine can be increased to match the new electrical load demand.

Increasing or decreasing turbine mechanical power is accomplished automatically by the turbine governor. This governor changes steam flow into the turbine. Such action takes place within a few seconds after the sudden change in electrical power demand, without any human involvement. It is the action of all the generating units with turbine-governor controllers that stabilizes frequency after a sudden change in power demand. For this reason, turbine-governor or speed-load control is sometimes called primary frequency control because it is primarily responsible for arresting frequency following a major loss of generation, i.e., a contingency.

In some large interconnected power systems the frequency response characteristic of the power system load, i.e., the tendency of power system load to decrease as the frequency declines, may replace the need for generating units that can supply the turbine-governors' immediate response to sudden frequency declines.

Well if the turbine governors are the primary frequency controllers, what does the Automatic Generation Control (AGC) system do? AGC adjusts the load reference settings of turbine-governor controllers on generating units to restore system frequency to the scheduled frequency--60 Hz. It does this automatically, and quite slowly compared with turbine governor speed-load control, taking up to 10 minutes to bring generation power output to the required production. AGC is really a fine tuning method for adjusting power generation. (see section 2.1 Regulation and Frequency Response). It is a supplemental control system that takes affect after the turbine governors have responded to the sudden demand for power and is most effective during steady-state conditions. For this reason it is sometimes referred to as secondary frequency control. In addition to maintaining power system frequency at the scheduled frequency, AGC also controls power exchange over the tie-lines with neighboring control areas by adjusting the power output of a few units operating under AGC.

Operating Reserves -- Spinning is defined as generation capacity synchronized to the power system, which is in excess of the generation required to serve power demand, and that can respond immediately to serve load. In addition, this generation must supply its spinning reserve service completely within 10 minutes. This definition means that a portion of the generating units providing spinning reserves must operate with their turbine valves partially open, ready to provide the immediate response capability. The 10-minute response requirement means the unit must increase its output and provide the spinning reserve offered by the plant, fully, within 10 minutes. For example, a 100 MW unit might provide an immediate 10-15 MW/minute response followed by a slower 1-2 MW/minute response. The amount of spinning reserves a unit can provide depends on its loading and its response rate.

4.2 Calculating the Cost of Providing Operating Reserves - Spinning

The following methodology contains a step-by-step procedure for calculating the cost of providing spinning reserves. It is a functionally complete method. Testing the methodology using data from a generating unit has not been completed. As a result, the method has not been validated. Testing at Consolidated Edison will be completed in 1997.

Step 1 Obtain Unit Data

A. Determine MW rating at the terminals and of the auxiliary power system. Calculate the net rating of the unit.

B. Define the cycle diagram with the applicable parameters P, T, flows, etc.

C. Find design heat balance for turbine and steam generator and any relevant test data.

Step 2 Determine Generating Unit Load Range and Throttle Reserve Needed

A. Define MW range over which the service must be evaluated

B. Determine magnitude of throttle reserve required

C. Verify that these data are compatible with the unit

Step 3 Define Unit Load schedule and Time Period for Cost Evaluation

A. Define the time period(s) for cost evaluation

B. Define the time interval, e.g., 1 hour 1/2 hour, etc., and then the size of load for each period

C. Define total hours of operation within a load range, e.g., 150 hours between 70 and 80% of rated load

D. Repeat above for each time period

Step 4 Define the Operating Mode for Spinning Reserves

A. Define the main steam pressure schedule and temperatures for each load

B. Determine control mode for pressure and temperature

C. Determine control mode for steam generator feedwater pumps

D. Determine control strategy for turbine control valves

E. Determine control mode for all auxiliaries

F. Define the Operating Mode for Comparison, i.e., Without Spinning Reserves

G. Specify steam pressure and temperatures schedule versus load

H. Determine control mode for steam pressure and temperatures

I. Determine control mode for steam generator feedwater pumps

J. Determine control strategy for turbine control valves

K. Determine control strategy for steam generator

L. Determine control mode for all auxiliaries

Step 5 Model Steam/Feedwater/Steam Generator Using a Computer Program

A. Evaluate program capability to model significant effects influencing costs

B. Input data into program from heat balance and P&I diagram

C. Run program to verify model results

D. Calibrate the program to mimic existing data, if available

Step 6 Determine Steam Generator Efficiency

A. Determine steady-state steam generator efficiency versus load

B. Evaluate steam generator efficiency correction for small load variations

C. Determine average fuel cost to be sued for evaluation period

Step 7 Determine Plant Steam/Feedwater and Heat Rates versus Load for the Two Operating Modes

A. Run thermodynamic model at each of the load points for spinning reserves

B. Subtract applicable auxiliary load to find the unit's net heat rate at each load

C. Run thermodynamic model at each load point for non-spinning reserves

D. Subtract applicable auxiliary load to find the unit's net heat rate

Step 8 Calculate Heat Rate Penalty

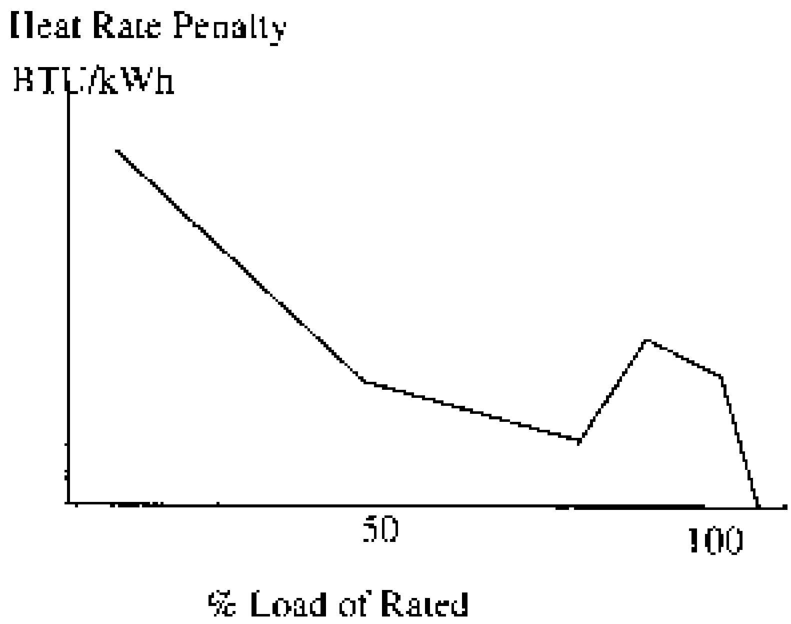
A. Calculate the difference between the net heat rate for the two modes at each operating point

Step 9 Calculate Environmental Cost

A. Determine if the unit may have to burn a fuel that pollutes more at low load than at high load. That is, high sulfur containing oil instead of low sulfur coal.

B. Determine if pollution credits are consumed. Some credits earned by the utility may be used or credits may have to be purchased.

Step 10 Extra Maintenance Cost for Wear and Tear caused by throttling is a debated issue. This step in the methodology will be developed during the case studies. Guidelines on cost and techniques to bound wear and tear will be presented in the project reports based on the experience of the utilities who fund case studies.



The above figure is an illustration showing the possible difference between the two operating modes as a function of unit loading. The actual shape of the curve will depend on the characteristics of the unit. In general, at low load the cost of providing spinning reserves will probably be highest, tapering off at about 70% loading. It will likely increase at higher loading and then drop off to zero at full output when there is no difference between the two operating modes' heat rate.

4.2.1 Treatment of Loss Opportunity Cost

This methodology has been developed specifically for steam cycle units. It is capable of calculating the variable cost of providing spinning reserves based on the perspective of cost causation. That is, the method traces all losses due to inefficiencies caused by operating the generating unit in a mode that allows the unit to respond immediately to turbine governor control.

When deciding whether or not to offer spinning reserve, three general options are possible;

- Unit has a competitive heat rate and the bid price to supply power will likely result in operating the unit at near rated load
- Unit is less than competitive and the bid price to supply power will likely result in only partially loading and the unit can provide spinning reserve
- Unit is started from standstill to specifically provide spinning reserve

In the first case--the possibly of operating at full loading--the decision whether or not to provide spinning reserves requires calculating the revenues produced by selling power at full load and comparing it to the revenues produced by operating at partial loading plus the price paid for providing spinning reserves and then understanding how to include the loss opportunity cost in the decision about the unit's operating mode.

The difference between revenues produced by operating at full load and partial load is called " the loss opportunity cost " of operating at partial loading. That is, if you operate at full output and receive $25/ MW for a12 hour period, you will receive 25(12)(800)= $240,000 if full load is 800 MW. At partial loading you would receive 25(12)(500)=$150.000, assuming partial loading of 500 MW. Your loss opportunity cost is $ 240.000- $150,000= $ 90,000.

The cost of operating at 800 MW and 500 MW differ due to the higher heat rate at partial loading, or heat rate penalty. This additional heat rate penalty for operating at partial load plus the cost of providing throttling reserve for spinning reserve (see methodology above) is the combined variable cost of providing spinning reserve. This means that the price paid for spinning reserve must be greater than (1) the loss opportunity cost of not operating at full output, as shown above, or (2) the combined cost of operating at partial output plus the cost of throttling reserves and including the unit's fixed costs, e.g., debt, fix maintenance, contracts, etc.

The following relationships summarize the important cost and price components;

1 [Revenues @ full load] - [Revenues @ partial load] =

loss opportunity cost of operating @ partial load

2. [Revenues @ partial load] plus [Revenues for providing spinning reserves] must be >> [costs of operating at partial load (fixed + variable)] plus the [cost of throttling reserves]

3. [Revenues @ partial load] + [Revenues for spinning reserves]

must be >> [Revenues @ full load]

Thus,

4. [Revenues for spinning reserves] must be >>

[Revenues @ full load] -[Revenues @ partial load]

5, [Revenues for spinning reserves] >> [[loss opportunity cost]

The above relationships are only true for a unit that has the option of operating at full load.

In the second case--the unit will likely operate at less than full output-- there is no loss opportunity cost. The plant is too expensive and is only scheduled to operate after other cheaper units are fully loaded. Now the decision whether or not to provide spinning reserves involves only calculating the cost to provide the service and comparing it to the price being paid for spinning reserves. That is, this decision is the classic situation of knowing your costs to make sure you sell at a price that exceeds your cost.

In the last case--starting the unit from standstill to provide spinning reserves- involves calculating the start-up cost, partial load costs and the cost of throttling reserves. To this the fixed costs are added to get the total cost of starting a unit to provide spinning reserves. This cost is then compared to the revenues expected for providing spinning reserves. Again, this is the classic case of knowing your costs to ensure you make money when you provide the service.

5

TOOLS TO MAKE DECISIONS

In a competitive market, where prices are based on market supply and demand dynamics, the value of a power plant may be viewed simply as the value of excess of revenues produced by the plant over the costs to own and operate the plant. That is, future REVENUES - TOTAL COSTS = VALUE, where total costs includes both fixed and variable costs. According to this definition of value, the historical costs to buy or build the plant (fixed costs) are not the principle determinate of value. It only matters what can be done with the power plant in the future (expected revenues).

Management decisions about how to operate a plant and the value of the plant are intimately related. As already mentioned, in a competitive power supply market--where prices are set based on supply and demand--a plant's value will be determined based on future revenues over future costs. It is management's responsibility to make decisions about operating strategies that maximize plant value. These decisions involve identifying a wide range of possible operating strategies and then selecting the best strategies that maximize a plant's value.

If management's decision is to sell the power plant, the sale yields the net sale price (sale price less any cost of sales) minus any remaining debt repayment. If the proceeds from the sale are greater than the future revenues of operating the plant minus the variable costs, then operating the plant makes no contribution to the fixed costs and selling the plant is the right decision i.e.,

$$\text{Gain} = \text{Sale Price} - \text{Cost of Sale and any remaining Fixed Costs}$$

$$\text{Gain} \geq \sum_{\text{Projected}} \text{Future Revenues} - \sum_{\text{Projected}} \text{Future Variable Costs}$$

Setting aside for the moment the option of selling the plant, the decision to keep operating the plant should be based on whether future revenues from operating the plant will be greater than the future costs incurred in operating the plant. Stated another way, it pays to operate a plant if revenues are sufficient to cover variable costs and make some contribution to fixed costs because the alternative of not operating the plant makes no contribution to fixed costs.

A situation may arise when it makes sense to keep operating the plant but make no additional investments. That is, projections of future market prices might suggest that operating revenues will cover variable costs, and make some contribution to fixed costs, but that these prices are not high enough to fully recover fixed costs. In such a case the prudent strategy is to operate the plant to cover as much of the original capital investment.

A decision to make an investment in a plant is also unrelated to the plant's fixed costs. Any investment must have a reasonable expectation of earning a return, that is, the investment must produce cash flows to cover variable costs and recover fixed costs. The cash flow expectation must be enough to fully recover the investment or the investment will not make sense because the result will be to increase fixed costs due to the new investment.

Identifying the best plant operating strategies that increase the value of the plant involves analyzing how the plant performs under a variety of conditions. Such analyses require studies using tools, i.e., simulation models and other techniques that capture plant performance and the affects on fixed and variable costs of operating the plant. EPRI's ancillary services projects are focused on developing these tools for the owners of power plants.

EPRI's plan for the ancillary services projects involves testing methodologies developed for calculating the variable and fixed costs of providing ancillary services using data from several different generators. Then, based on the results of these case studies, EPRI expects to evolve the methodologies into a simple set of tools appropriate for all kinds of plants e.g., hydro, combined cycle, etc. Utilities who are interested in using the methodologies should contact EPRI and submit their plant data. EPRI will return a proposed project plan and cost estimate to complete the study. As more utility projects are completed, a simple set of tools can be developed to analyze how different operating modes affect the cost of operating a plant.

A

DEFINITIONS OF TERMS

Back-up- back-up power is used to replace the temporary use of Operating Reserves-Spinning following a contingency, e.g., generation outage, loss of transmission equipment, etc. Capacity, energy or interruptible load used to replace portion of the load that exceeds generation following a contingency.

Energy Imbalance-compensates for the differences between scheduled and delivered energy, typically calculated over one hour time intervals. Provides an incentive to stay within a specified band by penalizing power demand that exceeds the band.

Reactive Supply and Voltage Control from Generating Sources- reactive power from generating resources is needed to support the transmission operations and to continuously adjust the transmission system voltage in response to system needs. Reactive supply from generators supplements reactive supply resources within the transmission system, e.g., switched capacitors, static VAr compensators, etc. in an amount sufficient to maintain transmission voltages within prescribed limits i.e., scheduled voltage following a contingency.

Regulation and Frequency Response- maintains the scheduled frequency at 60 Hz via automatic generation control (AGC control of selected power plants), to follow moment-by-moment load changes.

Operating Reserves --Spinning- provided by power plants that are on-line and only partially loaded, i.e., operating at less than their maximum capability. These reserves are needed to supply demand following a contingency, i.e., a loss of a major generator, transmission line or corridor, etc.

Operating Reserves--Supplemental- resources available within a short time to serve load following a contingency, e.g., quick starting units, interruptible load.

Real Power Transmission Losses- replaces energy losses on the transmission system associated with providing transmission service.

Reactive Power- one of the biggest problems confronting those who are trying to understand what reactive power is, has to do with the desire to have an entirely separate definition that explains reactive power without reference to real power. Real power, of course, is defined to be the ability to do work. But the ability of any power consuming entity to use real power also depends on being supplied reactive power.

Thus reactive power is simply one of the two components of the total power required to make electrical equipment work." You cannot make an omelet without breaking eggs".

B

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C

WORKSHOP OVERHEADS

Ancillary Services Workshop

Washington, DC

March 28-29, 1996

Ancillary Services Workshop

Sponsored by:

Edison Electric Institute Generation Committee
Sierra Pacific Power Company
Electric Power Research Institute Fossil Plant Business Unit

Agenda

Thursday, March 28, 1996

8:30am - 9:15am	Welcome, Introduction, History, Orientation, Objectives and Workshop Agenda
9:15am - 10:15am	Ancillary Services • History • Stakeholders • FERC ruling • Importance of Cost Calculation • Valve
BREAK	
10:30am - 11:00am	Voltage Regulation • Terminology • Overview of a Method to Calculate the Cost of Providing Voltage Regulation
11:00am - 12:00pm	Small Groups Analyze Method • Users • Users Needs and Requirements • What Other Utilities Have Done • Application to Various Power Plants and Systems

LUNCH	
1:00pm - 1:30pm	Small Groups Complete Analysis of Method
1:30pm - 2:30pm	Small Groups Present Their Findings • Modifications to Method • Alternate Methods • Requirements
BREAK	
2:45pm - 3:45pm	Presentation of Project Plan to Determine the Cost of Providing Voltage Regulation • Cost of Voltage Regulation • How to Meet Needs and Requirements • Discussion of Alternative Methods
3:45pm - 4:30pm	Wrap up and Plan for Next Day • Needs and Requirements for the Other Ancillary Services

<u>Friday, March 29, 1996</u>

8:30am - 9:15am	Orientation, Objectives and Workshop Agenda
9:15am - 10:15am	Load Following • Terminology • Overview of a Method to Calculate the Cost of Providing Load Following
BREAK	
10:30am - 12:00am	Small Groups Analyze Method • Users • Users Needs and Requirements • What Other Utilities Have Done • Application to Various Power Plants and Systems
LUNCH	
1:00pm - 1:30pm	Small Groups Complete Analysis of Method
1:30pm - 2:30pm	Small Groups Present Their Findings • Modifications to the Method • Alternative Methods • Requirements
BREAK	
2:45pm - 3:45pm	Presentation of Project Plan for Determining the Cost of Providing Load Following Services
3:45pm - 4:30pm	Open Discussion on Ancillary Services and Methods for Calculating the Cost of Providing These Services

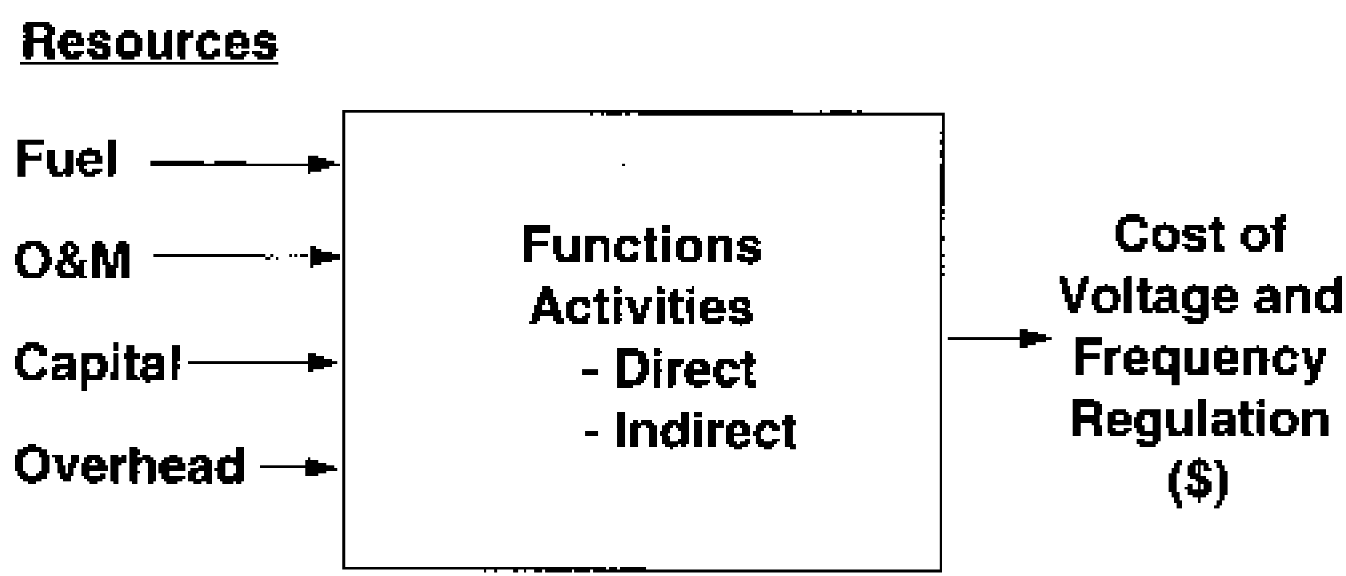
Workshop Objectives

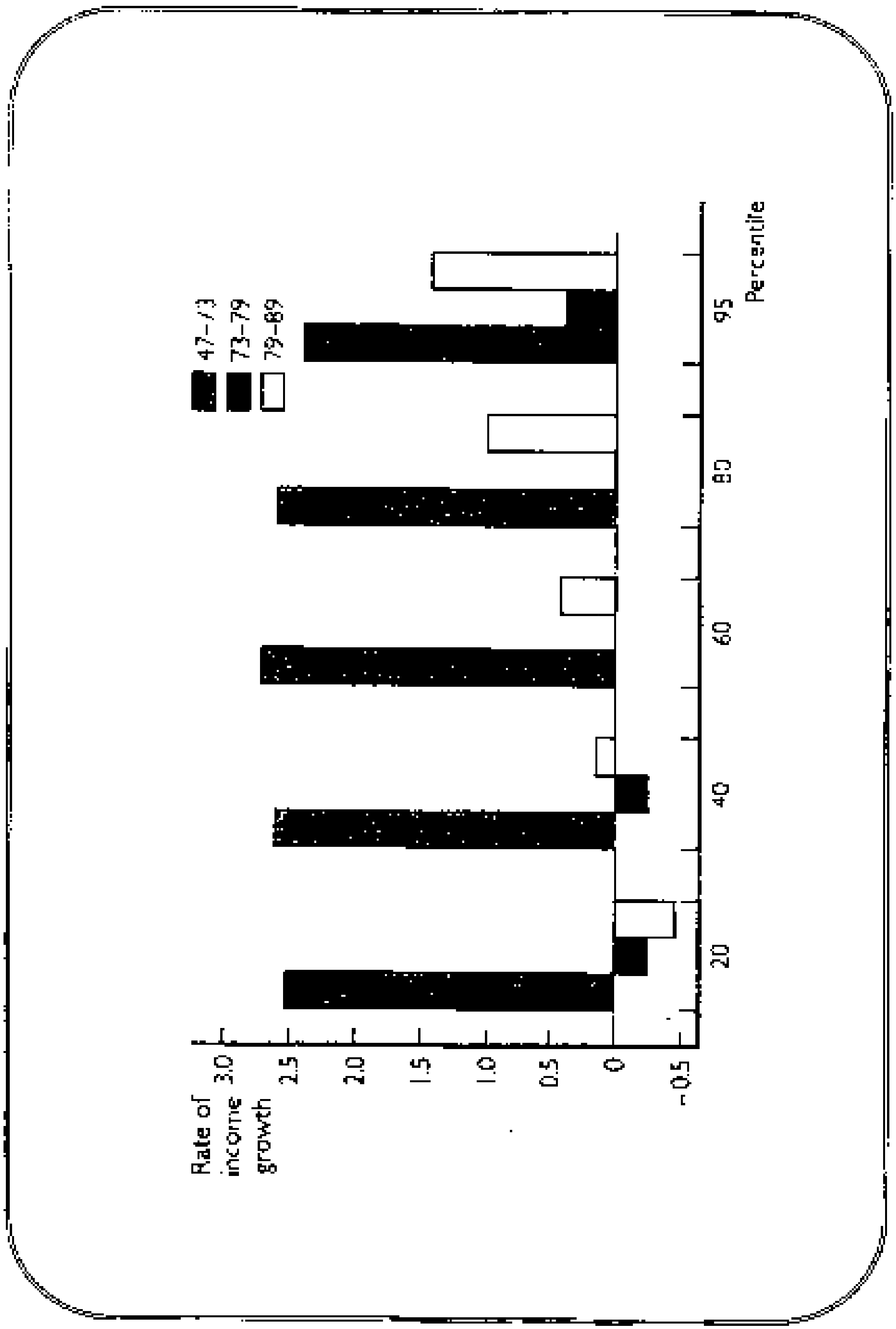
Clarify requirements for methodologies that calculate the variable cost of providing frequency control and voltage regulation

Methodology

- Defined: Step-by-Step Procedure, Identified Data Requirements, Models and Analysis Techniques, Assumptions and Limitations
- Manual: Report on How to Proceed; Guidelines
- Automated: Spreadsheet, Application Software

Methodology
Input/Output

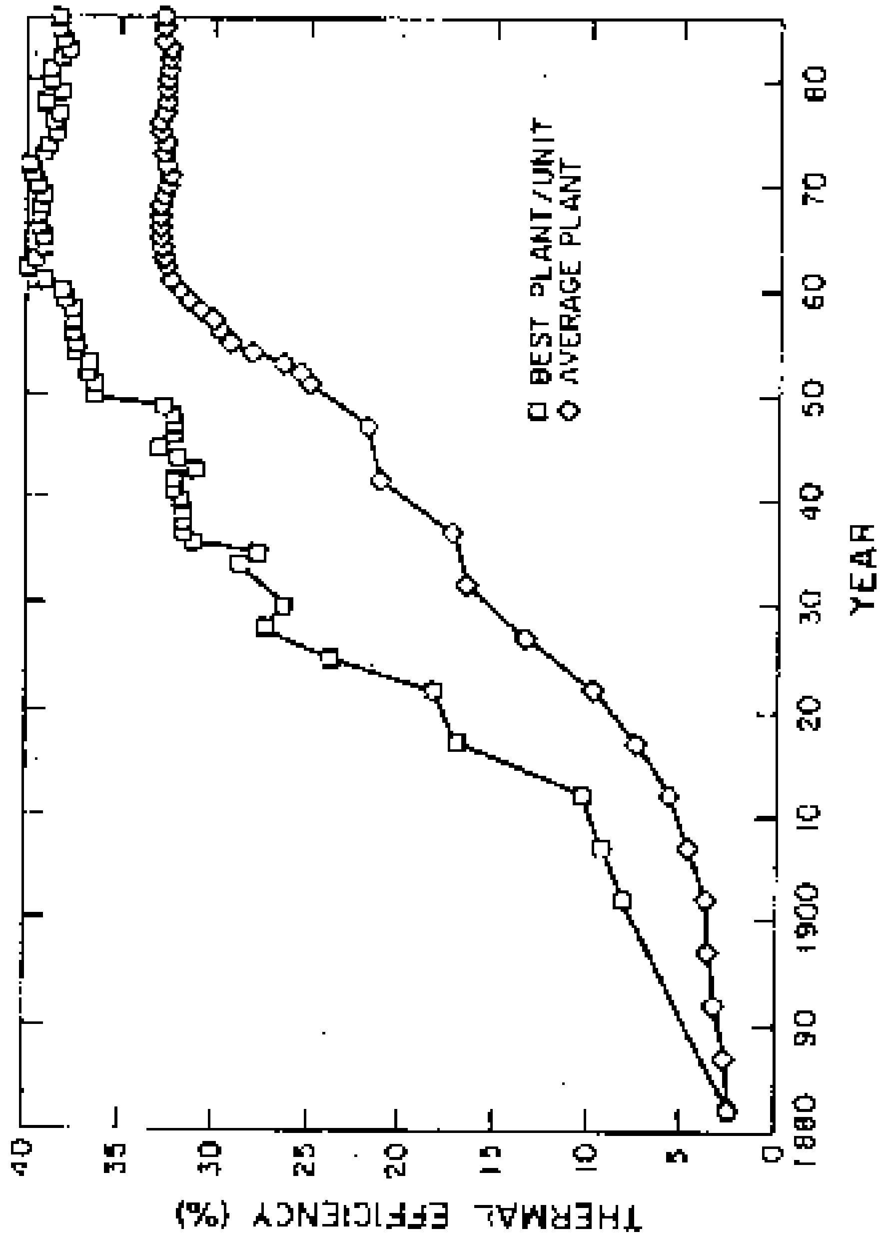


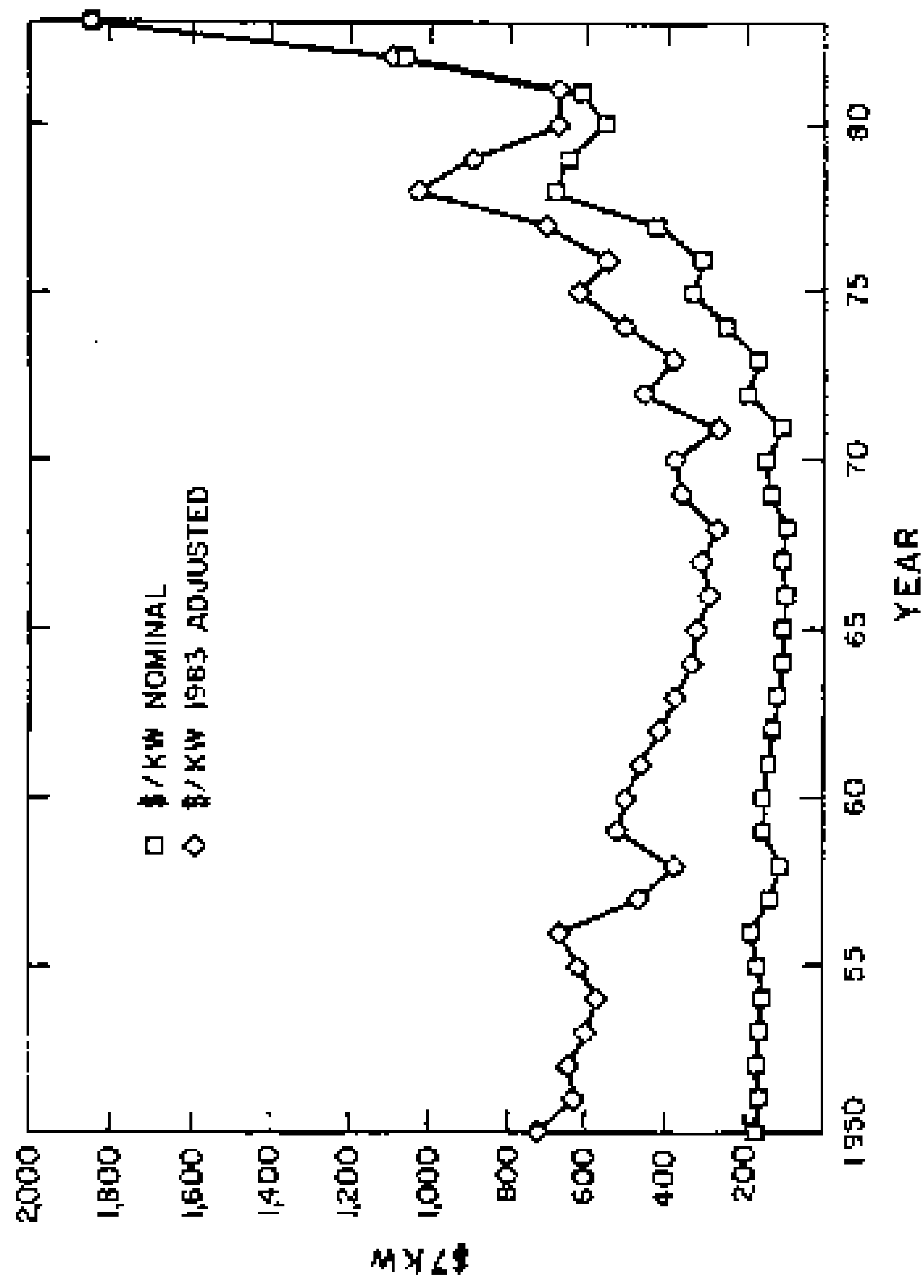

Rate of income growth
3.0
2.5
2.0
1.5
1.0
0.5
0
-0.5
47–73
73–79
79–89
20
40
60
80
95
Percentile

Regulation as Culprit in Productivity Slowdown

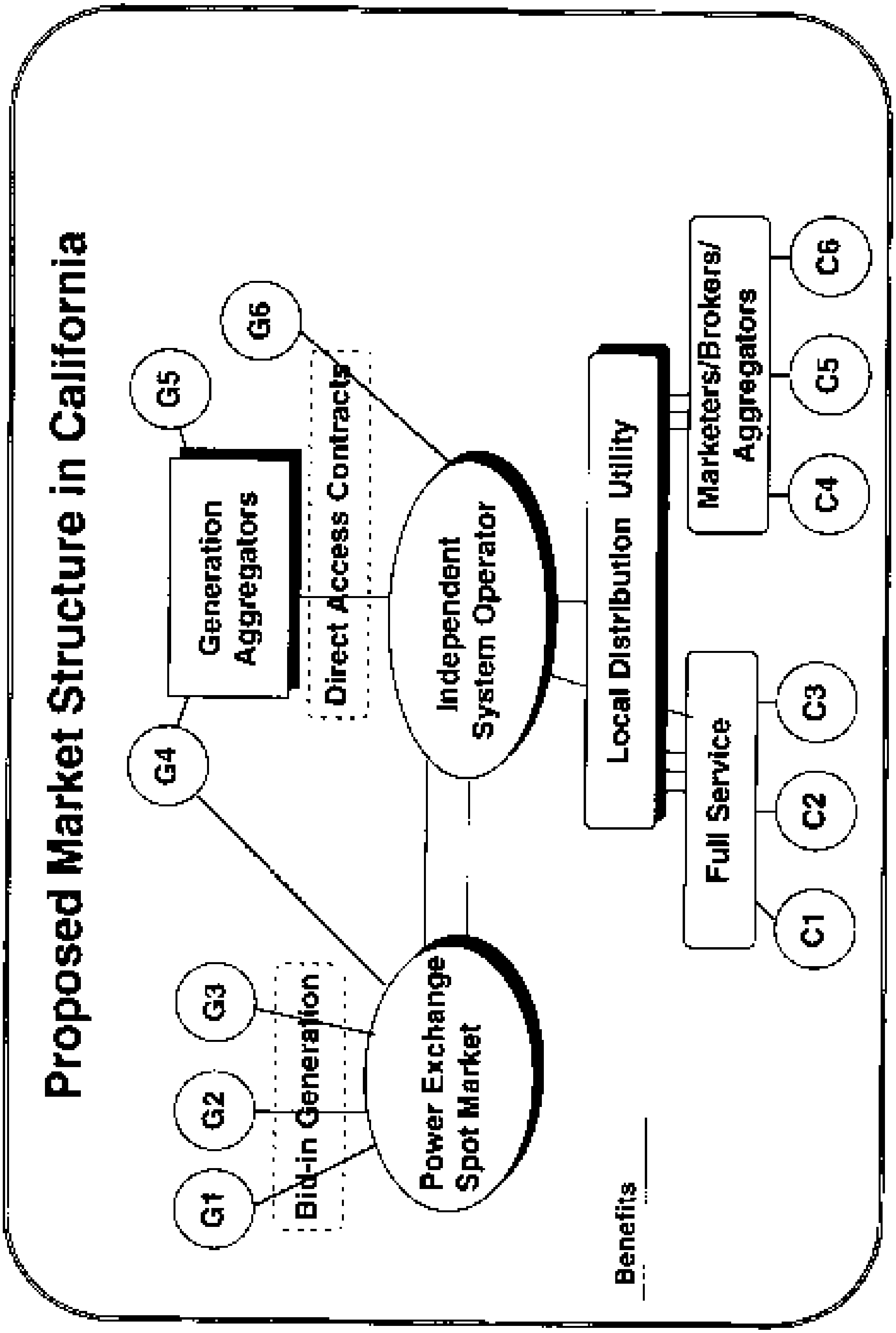
- Regulatory costs imposed on U.S. business cost the economy more than 100 billion annually
- 1970's sharp rise in regulatory burden on business

Trucking	Savings & Loan
Airlines	Cable
Oil	Natural Gas
Banks	Telecommunications


THERMAL EFFICIENCY (%)
0
5
10
15
20
25
30
35
40
YEAR
1880
90
1900
10
20
30
40
50
60
70
80
BEST PLANT/UNIT
AVERAGE PLANT



$/KW NOMINAL
$/KW 1963 ADJUSTED
$/KW
2000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
1950
55
60
65
70
75
80
YEAR


Proposed Market Structure in California
G1
G2
G3
Bid-in Generation
Power Exchange Spot Market
G4
Generation Aggregators
G5
G6
Direct Access Contracts
Independent System Operator
Local Distribution Utility
Full Service
C1
C2
C3
Marketers/Brokers/ Aggregators
C4
C5
C6
Benefits

Proposed California Independent System Operator ISO

- Transmission access for wholesale and retail power sales
- Scheduling and dispatching power from all sources
- Balances load and generation on a real-time basis
- Manages transmission congestion
- Maintains reliability, security and stability
- Recovers costs of ancillary services

Power Exchange

Take and match supply bids with demand bids

Spot price

Ancillary

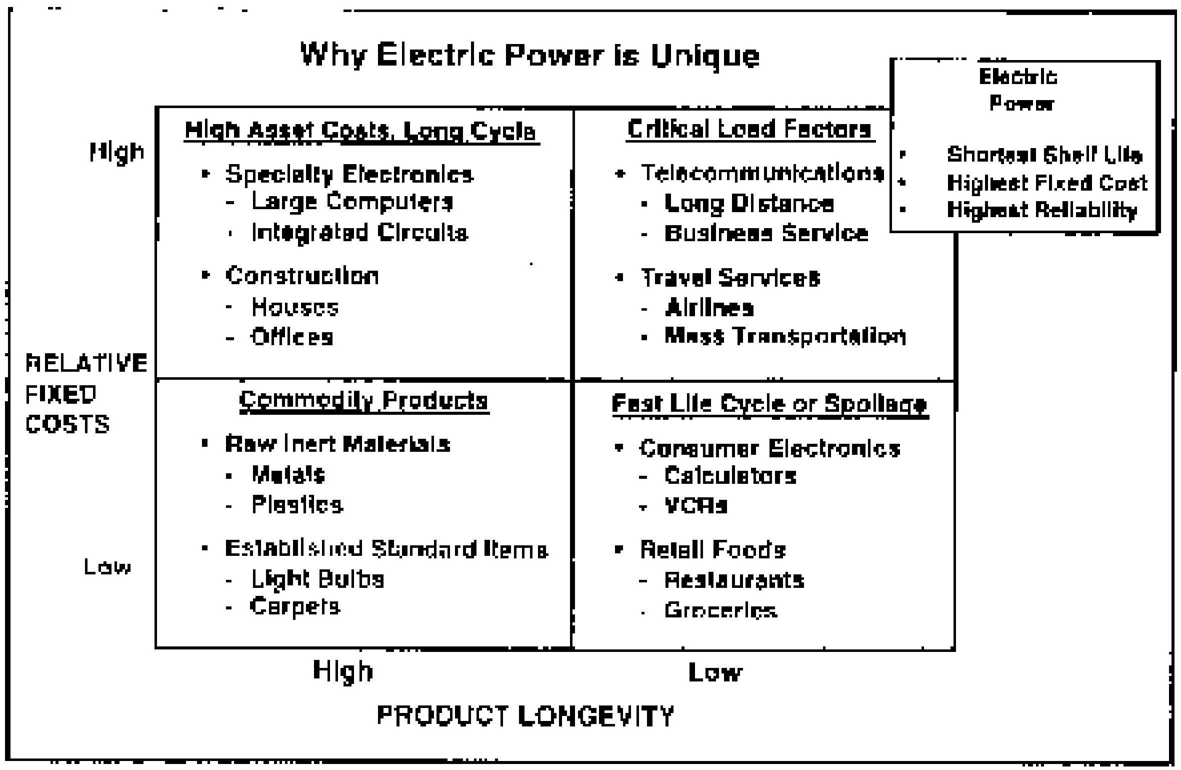
auxiliary or supplementary goods and/or services that are related to, required by, or integral to another good.

Ancillary

subordinate; in support of

Ancillary Services

services subordinate to, in support of


Why Electric Power is Unique
High
RELATIVE FIXED COSTS
Low
High Asset Costs, Long Cycle
• Specialty Electronics
- Large Computers
- Integrated Circuits
• Construction
- Houses
- Offices
Critical Load Factors
• Telecommunications
- Long Distance
- Business Service
• Travel Services
- Airlines
- Mass Transportation
Electric Power
• Shortest Shelf Life
• Highest Fixed Cost
• Highest Reliability
Commodity Products
• Raw Inert Materials
- Metals
- Plastics
• Established Standard Items
- Light Bulbs
- Carpets
Fast Life Cycle or Spoilage
• Consumer Electronics
- Calculators
- VCRs
• Retail Foods
- Restaurants
- Groceries
High
Low
PRODUCT LONGEVITY

Cost

What is required to produce a good or service

Price

Amount of cash paid by a consumer to a producer to purchase a unit of a good or service

Fixed Costs

What it costs to purchase and install the equipment, power plant, etc.

All those costs that are incurred even if the unit produces zero output.

Variable Costs

All those costs that change with output

- fuel costs, maintenance, repairs

Fixed Costs

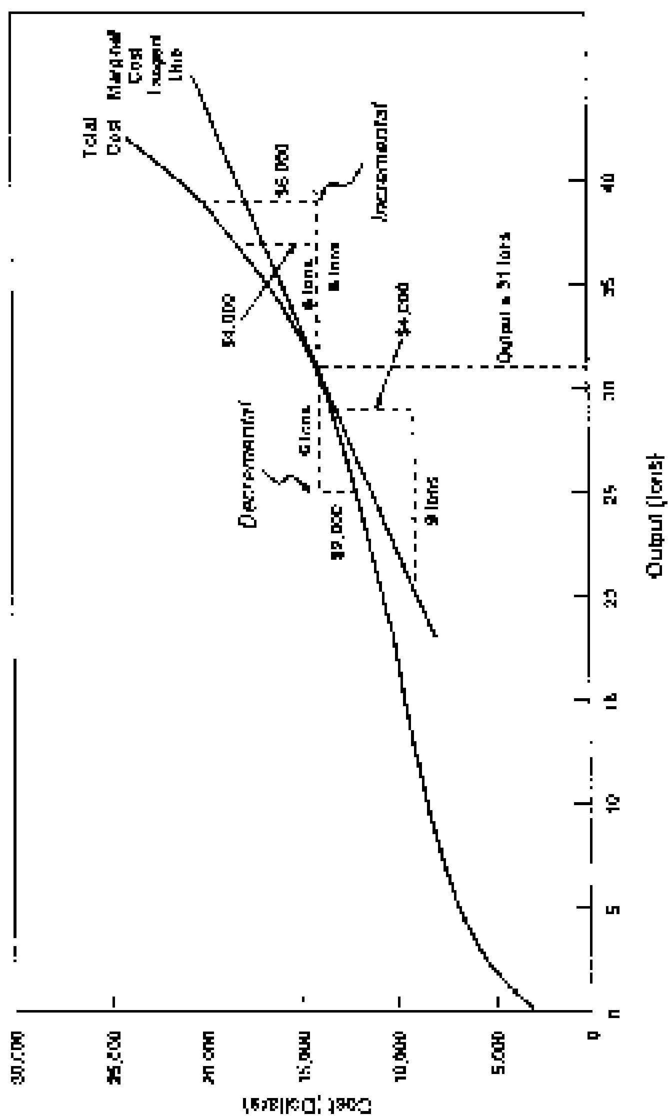
are beyond the control of a plant manager

Variable Costs

are affected by operating strategies of the plant

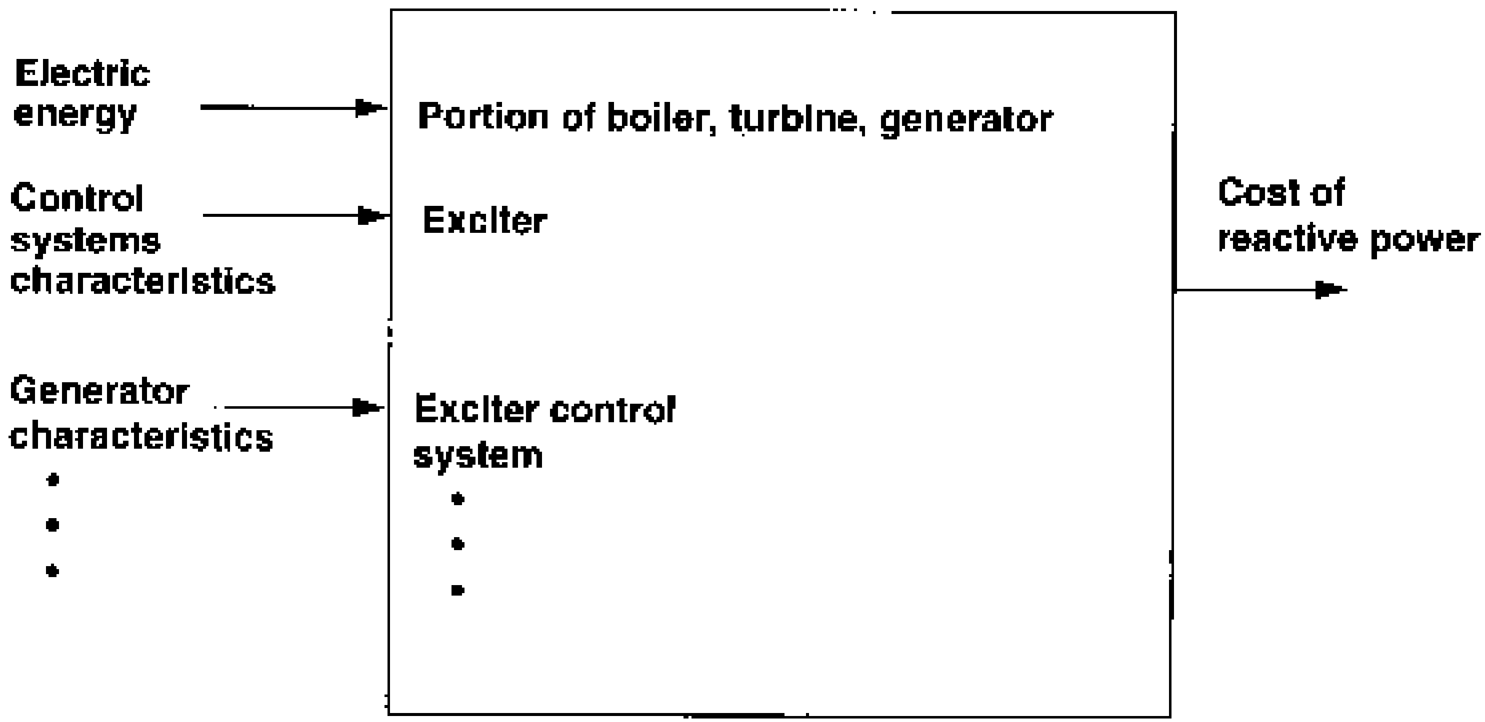
Incremental Cost

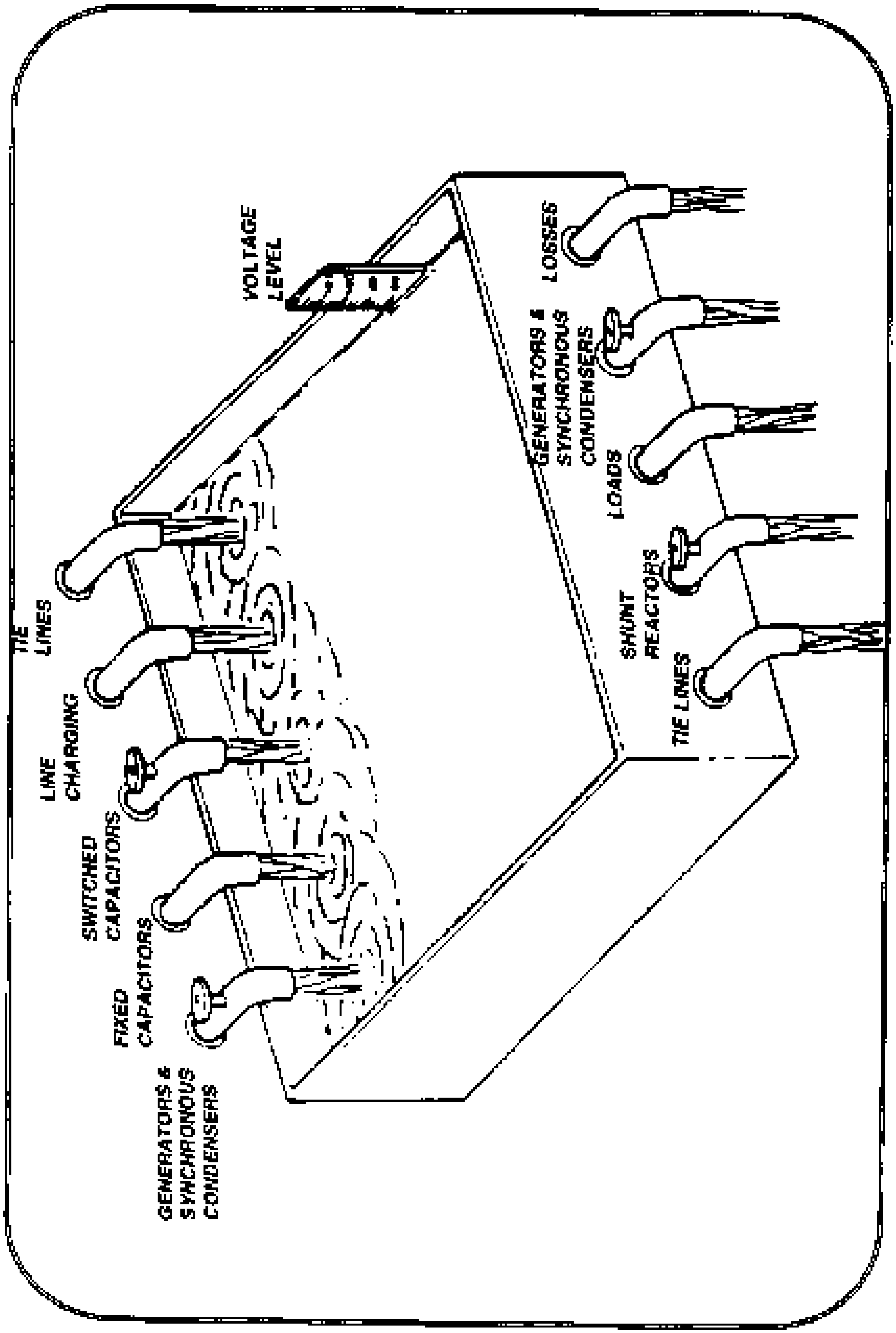
additional cost required to produce a given increment of additional output

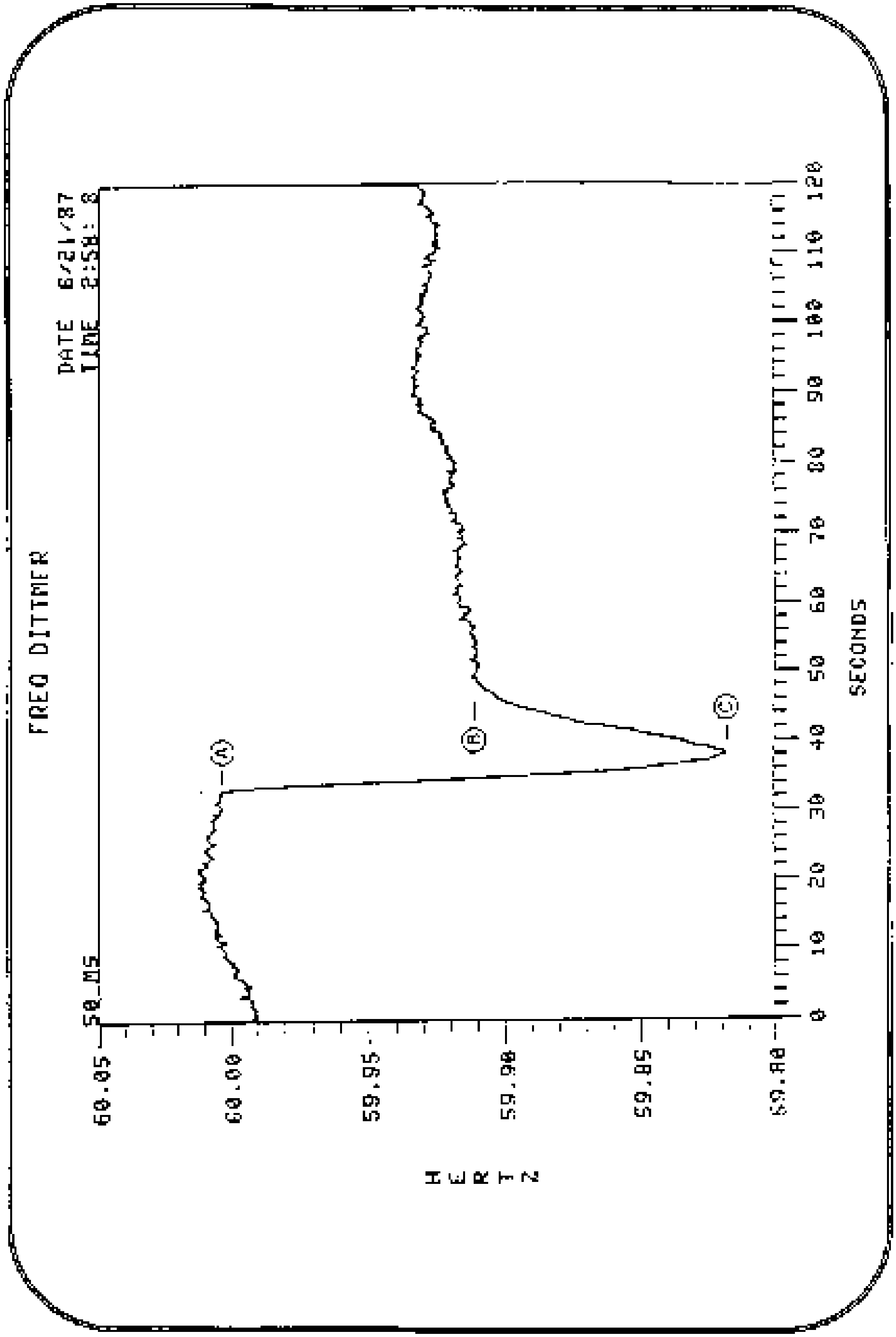

Total Cost
Marginal Cost Tangent Line
Incremental
Decremental
$6,000
$4,000
$4,000
$2,000
6 tons
6 tons
9 tons
Output = 31 tons
Output (tons)
Cost (Dollars)
0
5,000
10,000
15,000
20,000
25,000
30,000
0
5
10
15
20
25
30
35
40

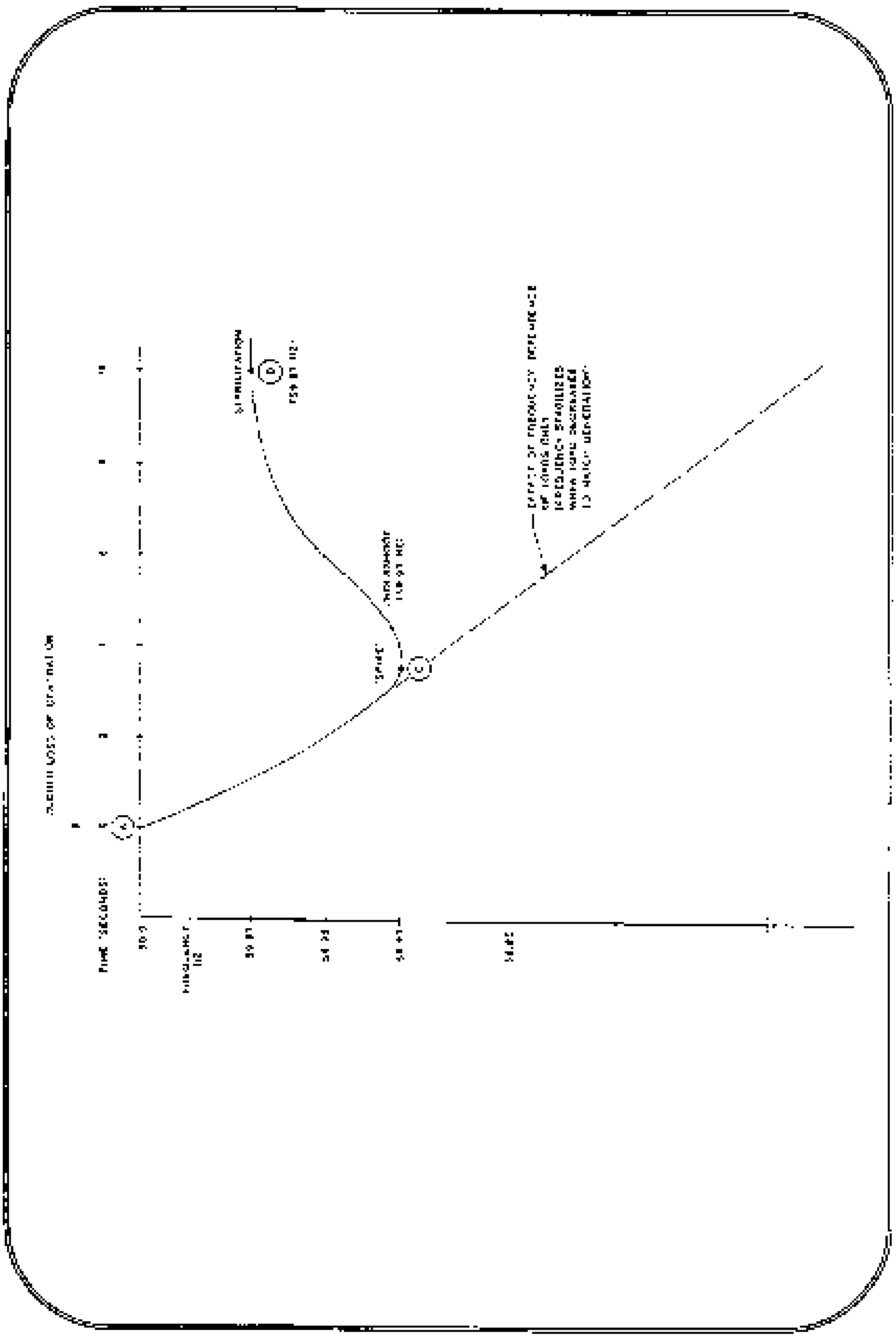
Cost Causation

Service-voltage regulation




VOLTAGE
LEVEL
TIE
LINES
LINE
CHARGING
SWITCHED
CAPACITORS
FIXED
CAPACITORS
GENERATORS &
SYNCHRONOUS
CONDENSERS
LOSSES
GENERATORS &
SYNCHRONOUS
CONDENSERS
LOADS
SHUNT
REACTORS
TIE LINES

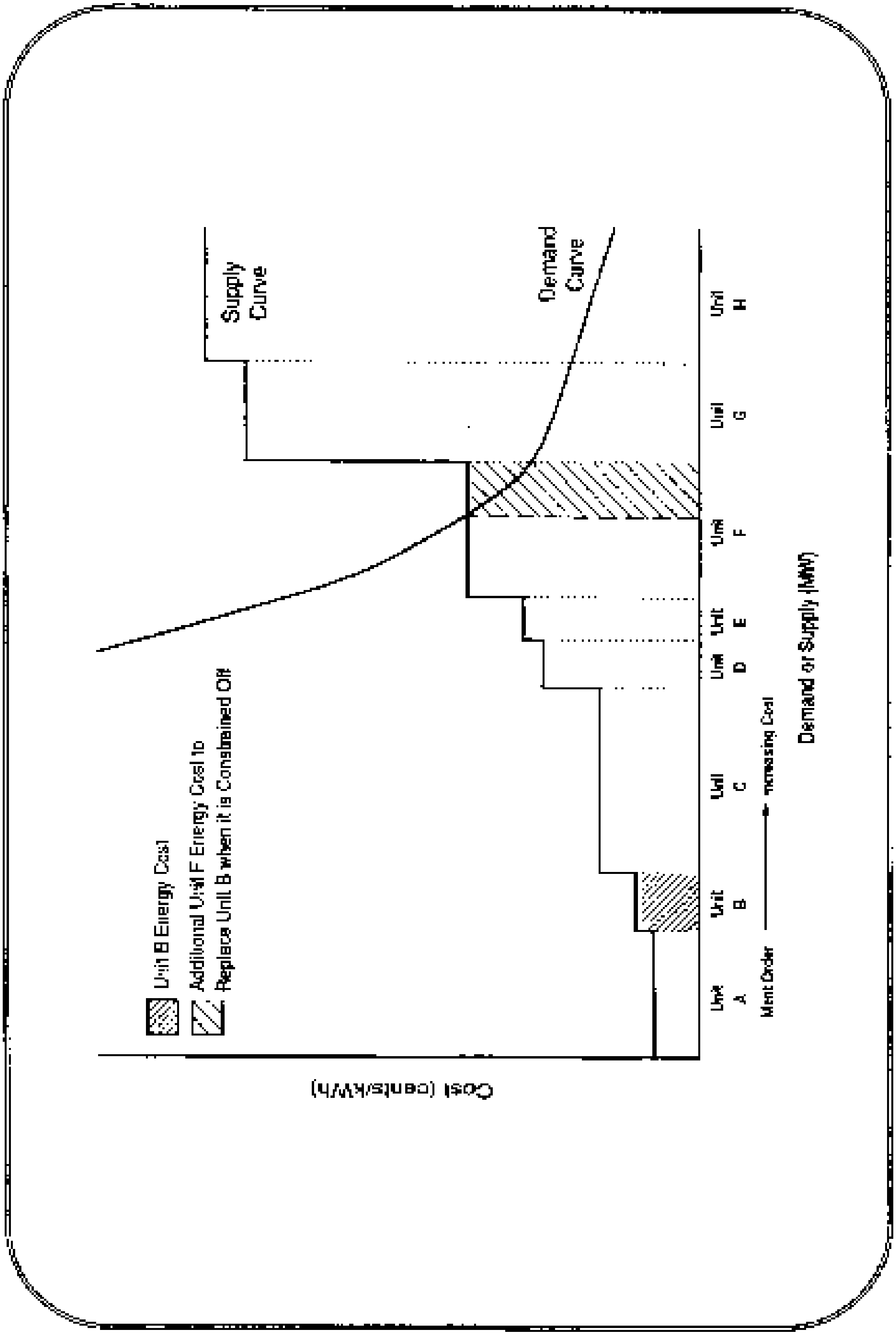

FREQ DITTMER
DATE 6/21/87
TIME 2:58: 8
50 MS
HERTZ
60.05
60.00
59.95
59.90
59.85
59.80
SECONDS
0
10
20
30
40
50
60
70
80
90
100
110
120
A
B
C

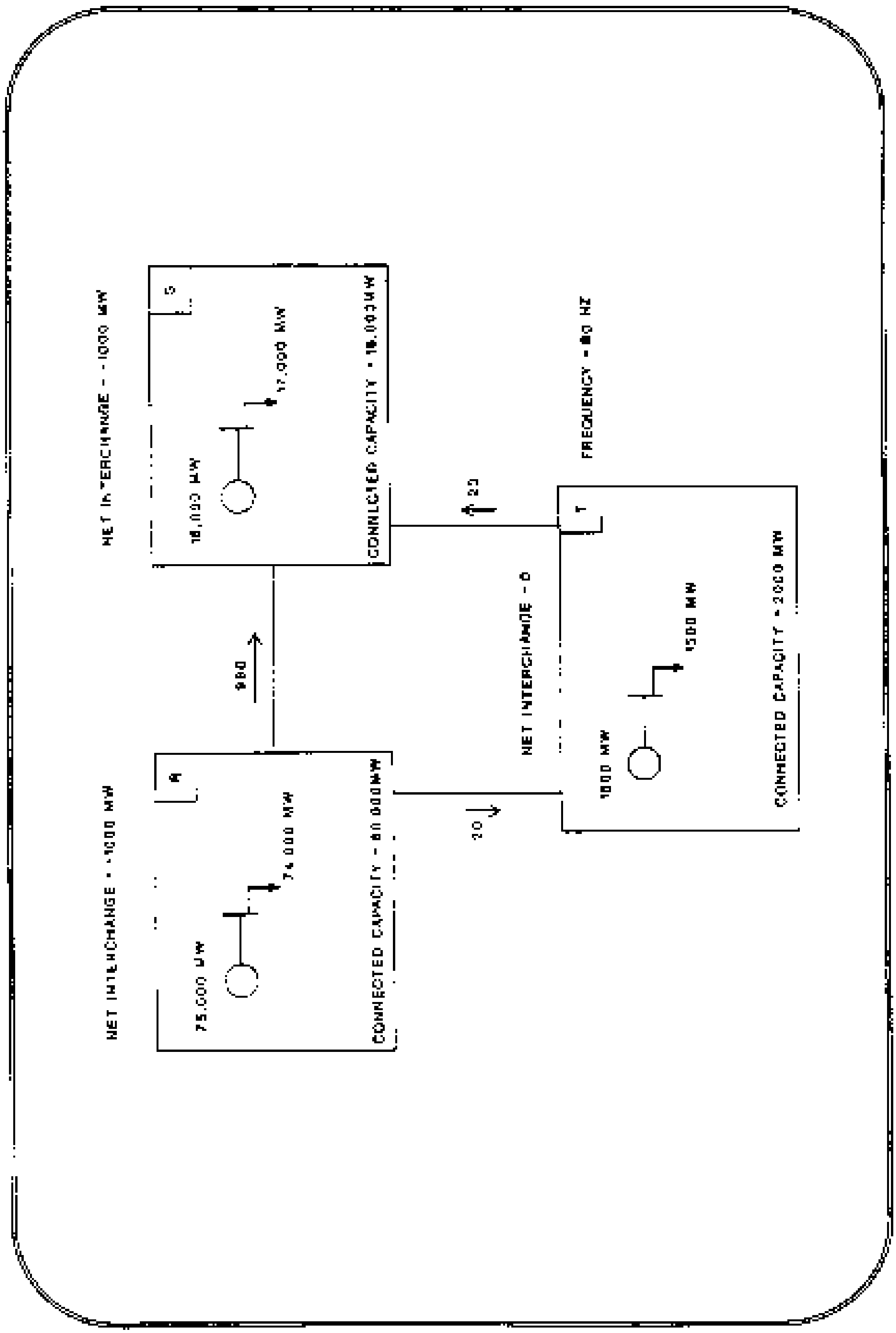


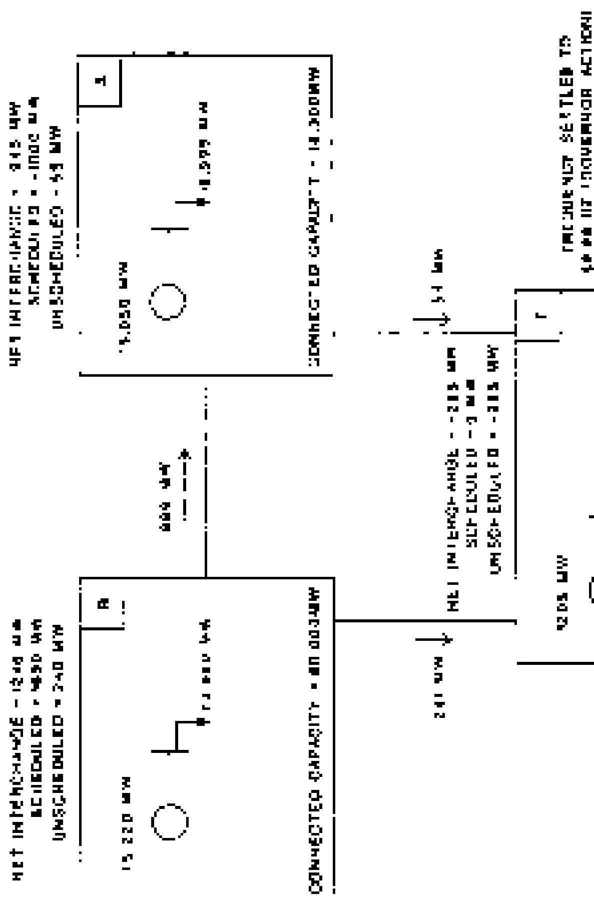
Out-of-Merit

Merit order is ordering the variable costs of generating units from lowest to highest

Congestion -- transmission system cannot carry power flows from the merit order generators to the loads at a particular point in time


Unit B Energy Cost
Additional Unit F Energy Cost to Replace Unit B when it is Constrained Off
Supply Curve
Demand Curve
Cost (cents/kWh)
Unit A
Unit B
Unit C
Unit D
Unit E
Unit F
Unit G
Unit H
Merit Order → Increasing Cost
Demand or Supply (MW)


NET INTERCHANGE = -1000 MW
S
17,000 MW
CONNECTED CAPACITY
NET INTERCHANGE = +1000 MW
A
75,000 MW
74,000 MW
CONNECTED CAPACITY = 80,000 MW
980
20
20
FREQUENCY
NET INTERCHANGE = 0
T
1000 MW
1500 MW
CONNECTED CAPACITY = 2000 MW


NET INTERCHANGE
SCHEDULED
UNSCHEDULED = 240 MW
15,220 MW
CONNECTED CAPACITY
NET INTERCHANGE
SCHEDULED
15,050 MW
CONNECTED CAPACITY
241 MW
NET INTERCHANGE
SCHEDULED
9205 MW
9500 MW
CONNECTED CAPACITY
FREQUENCY SETTLED TO
GOVERNOR ACTION

Area Control Error

$$ACE = T_a - T_s + \beta (F_a - F_s)$$

- Why VArs?
- How Produced?
- How Consumed?
- The Cost of Generation

Power System Needs

- kW for Frequency Control
- kVAr for Voltage Regulation

kVar Producers

- Shunt Capacitors
- Series Capacitors
- Lightly Loaded Transmission Lines
- Synchronous Machines

kVar Consumers

- Shunt Reactors
- Transformers
- Heavily Loaded Transmission Lines
- Induction Motors
- Synchronous Machines

Losses

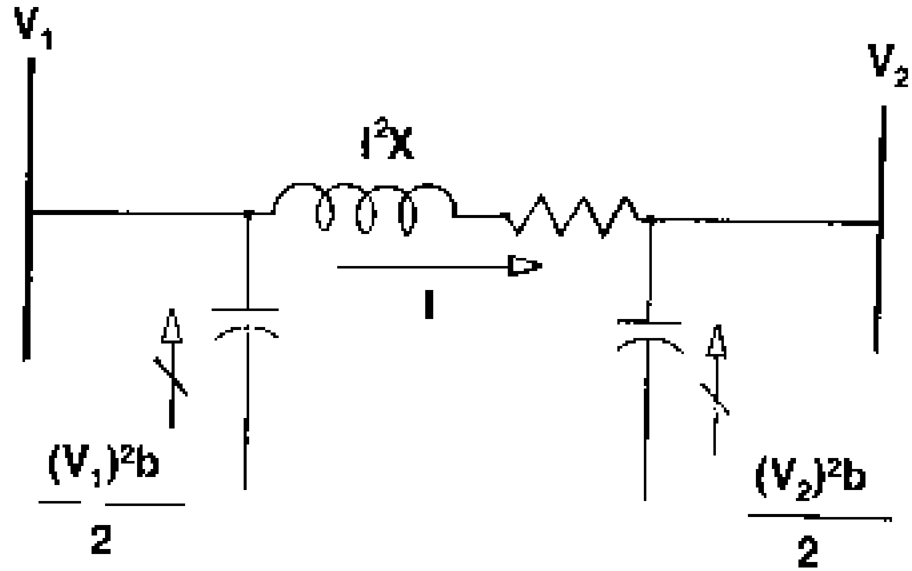
$$kW = I^2R$$

$$kVAr = I^2X$$

Lines: $\frac{X}{R} = 4 \text{ to } 15$

Transformers: $\frac{X}{R} = 20 \text{ to } 50$

High Voltage Lines

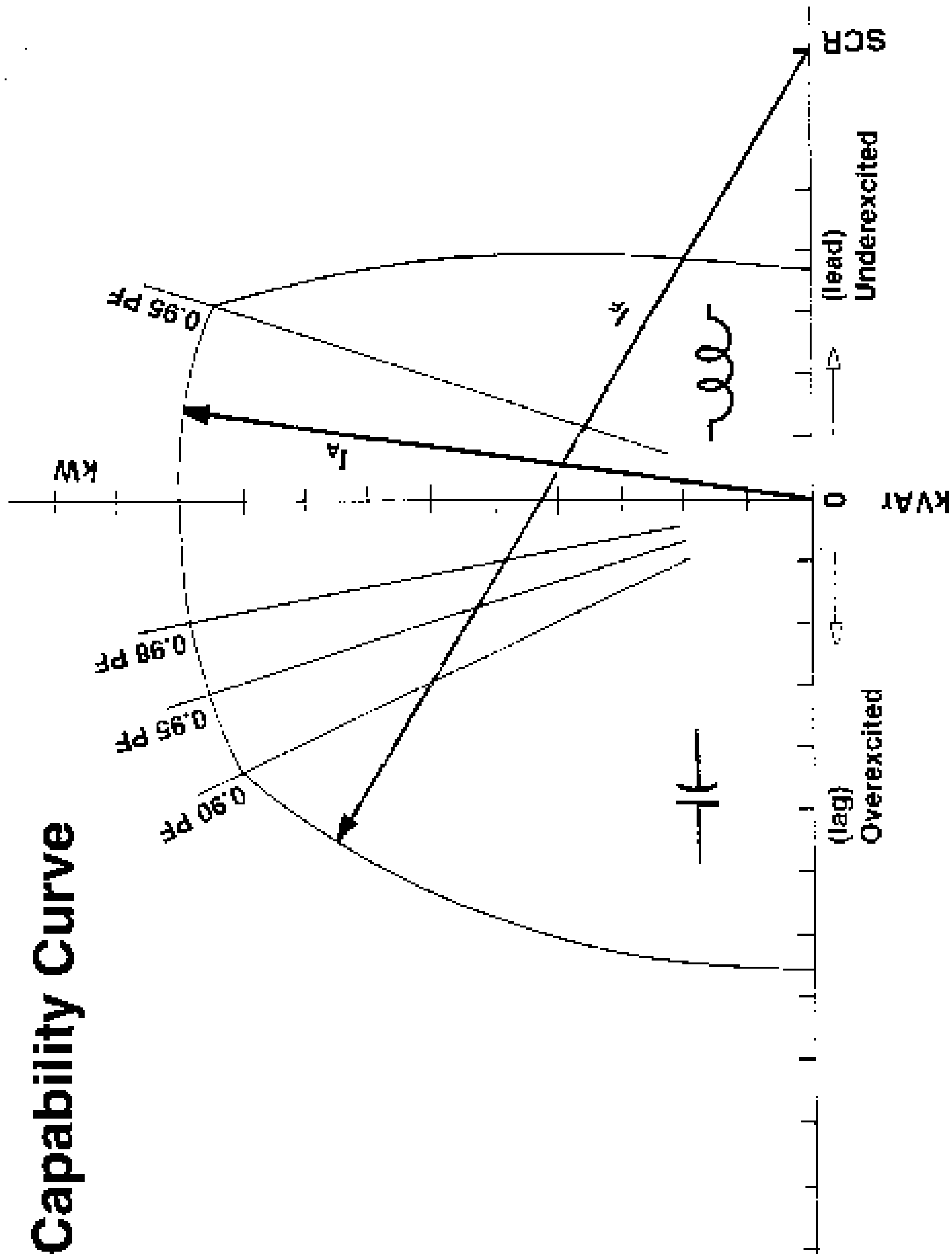


Surge Impedance Loaded when:

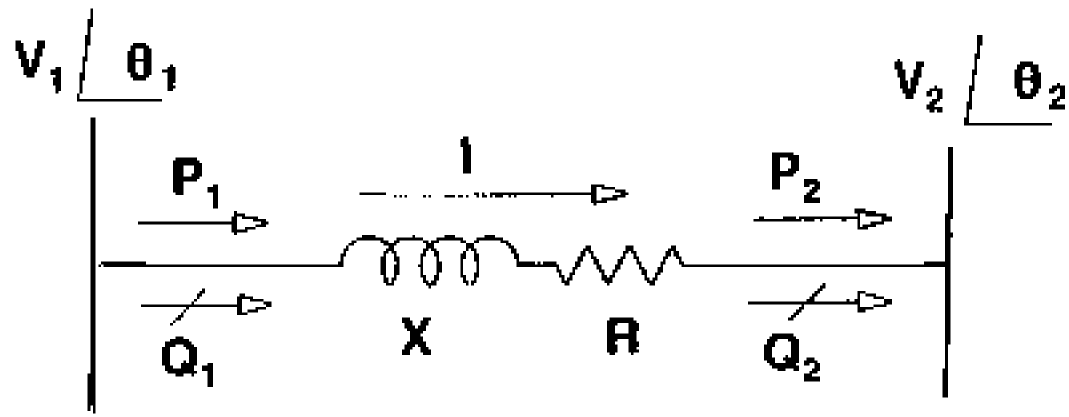
$$I^2 X = \frac{(V_1)^2 b}{2} + \frac{(V_2)^2 b}{2}$$

SIL:

230 kV = 130 MW
345 kV = 300 MW
500 kV = 625 MW


Capability Curve
SCR
Underexcited
(lead)
Overexcited
(lag)
KW
KVAr
0
0.95 PF
0.98 PF
0.95 PF
0.90 PF
I_A
I_F

Network Elements



$$P_1 = \frac{V_1 V_2}{X} \sin(\theta_1 - \theta_2)$$

$$Q_1 = \frac{V_1 V_2}{X} - \frac{V_1 V_2}{X} \cos(\theta_1 - \theta_2)$$

$$\Delta V = V_1 - V_2 \approx V_1 - I_Q X$$

Losses

Stator Losses = $\left(\frac{P}{V}\right)^2 R_S + \left(\frac{Q}{V}\right)^2 R_S$

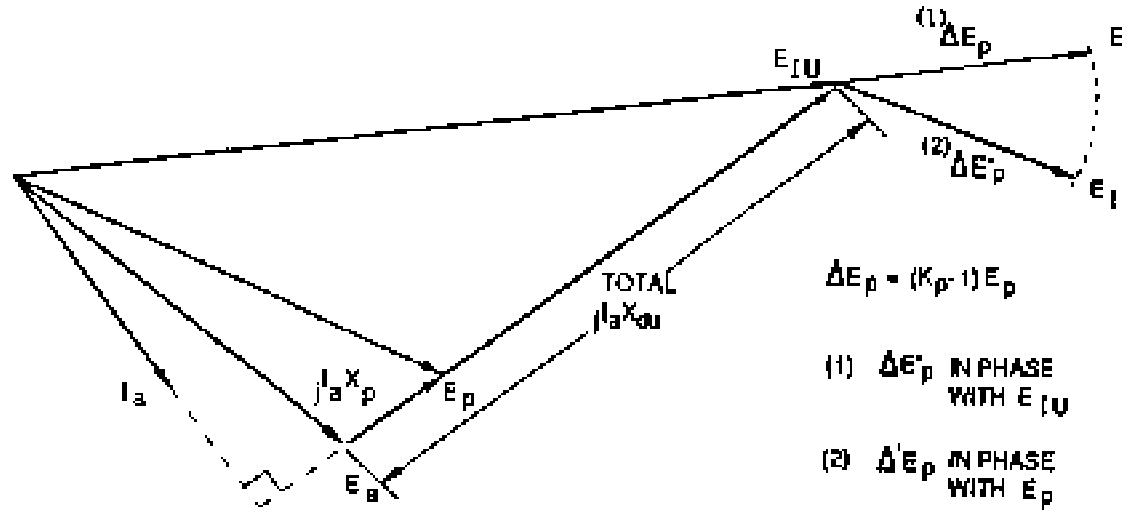
Field Losses = $\left[f(V, P, Q, X_L, X_d, X_q)\right]^2 R_F$

Generator Load-Variable Losses

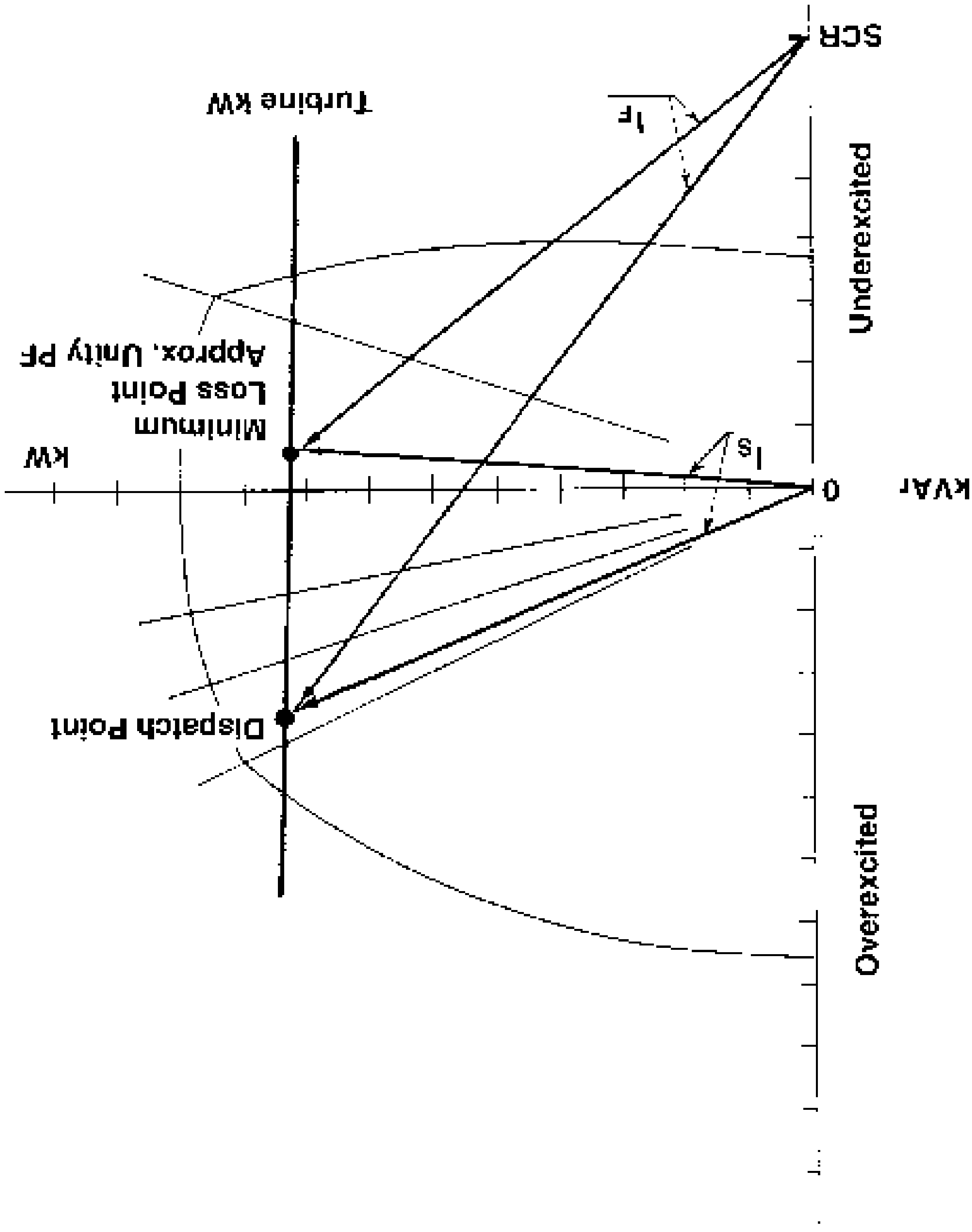
		Guestimate of % of Losses at Full Load
Copper Losses		
Field	$(I_F)^2R_F$	40%
Armature	$(I_A)^2R_A$	15%
Core Losses		
Stator Iron	$(E_i)^2$	20%
Stray-Load Losses		25%
Total Load Variable Losses		100%

$$\frac{\text{Total Load-Variable Losses}}{\text{Unit Output}} = 1\%$$

$$\frac{(I_F)^2R_F + (I_A)^2R_A}{\text{Total Load-Variable Losses}} = 1/2$$



IEEE Standard Method in Phasor Diagram Form


SCR
Turbine kW
I_F
Underexcited
Minimum
Loss Point
Approx. Unity PF
kW
I_S
0
kVAr
Dispatch Point
Overexcited

Readily Available Data

- Stability Study Data Bank
- Generator / Transformer "Name Plate" Data

Possible Data Sources

- Instruction Books
- Manufacturer Inquiry
- Plant Observations / Test Program

OHMIC Losses - Error Sources

$P = I^2R$

For an error in I of ΔI

$$\left.\frac{\Delta P}{P}\right|_{\Delta I} = 2\left(\frac{\Delta I}{I}\right)$$

I.e., a 5% error in current produces a 10% error in losses.

For an error in R of ΔR

$$\left.\frac{\Delta P}{P}\right|_{\Delta R} = \left(\frac{\Delta R}{R}\right)$$

If the error is due to an error in estimating temperature:

$$\Delta R = R\,\alpha\,\Delta T$$

For copper $\alpha = 0.00393\ /\ ^\circ C$

I.e., a 10°C error in temperature produces a 4% error in losses

Major Stumbling Blocks

1.

- Generator Part Load Efficiency
  Never Historically of Interest
- Loss Variations are Small

2.

- AVERAGE winding temperature, at partial load needed for loss evaluation
  vs.
- HOT SPOT needed to establish equipment rating and guarantees

3.

- VARIATION in coolant temperature needed for loss evaluation
  vs.
- MAXIMUM coolant temperature is specified for rating purposes

Challenge

- Evaluation for transient benefits of the synchronous machine
- Increased security for loss of tie lines

Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

The UK Situation - Power

- System operated by National Grid
- Generating companies bid generating units into pool
  - 24hrs ahead for next 24hr period
  - offer prices for each 30min period
- Bids ordered to satisfy demand and fix the price received by all
- Transmission line constraints used to modify actual plant scheduling
- All units get the fixed price; special arrangements for constrained plant

POWERGEN

ANCILLARY GENERATION SERVICES - COSTING VArs

The UK Situation - VArs

- All generators must comply with a Grid Code document
- Grid Code requires all units to offer VArs between limits of:-
  - rated output at 0.85pf lag
  - rated output at 0.95pf lead
- Generator AVR controls to constant terminal voltage
- VArs controlled by on-load tap-changing
- National Grid requests units to generate VArs to support voltage
- Fixed income provided for VAr support based on declared capability

POWERGEN

ANCILLARY GENERATION SERVICES - COSTING VArs

Sources of Variable Costs

- Efficiency losses
- Maintenance
- Repair
- Plant replacement
- Others: spares holding
  managing risks
  regulatory obligations

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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

Project Aim

- Identify factors influencing variable costs of generating VAr
- Provide methods to calculate variable costs for:-
  - efficiency losses
  - maintenance
  - plant damage
- Methods and algorithms to be flexible
- Provide means of establishing cost sensitivities
- Provide means of averaging costs over a generation profile

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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

Costs of Efficiency Losses

- Gen/Tx losses calculated for P and Q operating point at Tx HV terminals
- VAr generation loss = Gen/Tx loss at P+Q - Gen/Tx loss at P only
- Costs related to fuel costs not electricity sales price (= kW extra losses x fuel cost per kW/overall plant fract.effy)
- Cost sensitivities at given P + Q derived from calculation
- Costs numerically integrated over daily/annual generation pattern

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ANCILLARY GENERATION SERVICES - COSTING VArs

Data Sources

- Generator - Nameplate information
  OC/SC Characteristics
  Manufacturer's works test cert (loss breakdown)
  Rotor and Stator cold resistances
  Excitation current/voltage at various loads
- Transformer - Nameplate information
  Winding resistances
  Manufacturer's works test report

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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

Efficiency Losses

- Generator - Rotor field (I^2R)
  Stator winding (I^2R)
  Stator iron
  Stray
  Exciter
  Friction and Windage
- Transformer - Copper/load
  Iron

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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

Information Flexibility - Generator

Nameplate information	-	use estimate of typical efficiency use typical loss breakdown for m/c type
+ Excitation 'V' curves	-	Back-fit excitation loss algorithm
+ OC/SC Curves	-	Refine excitation loss model
+ Winding resistances	-	Estimate I^2R loss at operating temp
+ Efficiency curve	-	Back calculate loss breakdown
+ Manufacturer's test	-	Full knowledge of loss breakdown and typical winding temperatures

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ANCILLARY GENERATION SERVICES - COSTING VArs

VAr Related Maintenance/Repair Costs

- Variable costs based on historical records
  - maintenance/repair
  - P + Q generation levels
- Assign costs dependent on damage mechanism
  - vibration (wear/abrasion/slackness/fatigue)
  - thermal (overheating/expansion)
- Historical costs corrected to present-day values
- Variable cost for VAr extracted by summing costs for each damage mechanism

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ANCILLARY GENERATION SERVICES - COSTING VArs

Maintenance/Repair - Damage Mechanisms

- Mechanical stress (low cycle)
  - thermal cycling/centrifugal (run-up/down)
- Mechanical stress (high cycle)
  - mechanical - electromagnetic vibration/barring
- Wear and Abrasion
  - vibration/thermal expansion/relative movement
- Thermal ageing
- Electric stress

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ANCILLARY GENERATION SERVICES - COSTING VArs

Examples - Maintenance/Repair Costs

Event	Problem	Mechanism
Stator wedge tightening	Stator vibration	Mainly (I_a^2)
Rotor rebalancing	Displaced end-ring	Thermal (I_a^2.R)
Stator coil replacement	Overheating	Thermal (I_a^2.R)

Note: where multiple damage mechanisms possible, costs split in proportion to likelihood

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ANCILLARY GENERATION SERVICES - COSTING VArs

Maintenance/Repair Cost Methodology

1. Obtain historical maintenance/repair costs
2. Correct costs to present-day values
3. Split and assign costs to specific task/problem areas (ie. wedge tightening)
4. Apply appropriate damage mechanisms to each task
5. Integrate damage mechanisms over historical operating regime
6. Obtain cost factors for each damage mechanism
7. Apply damage mechanism costs for any future operation

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ANCILLARY GENERATION SERVICES - COSTING VArs

Conclusions

- Efficiency losses calculated for VArs at Tx terminals
- Maintenance/Repair/Ageing costs analysed in terms of damage mechanisms
- Historical costs related to plant P, Q generation at Tx terminals
- Future Maintenance/Repair costs predicted via damage mechanisms and P, Q generation levels

POWERGEN

EPRI WO4161-01

Methodology To Determine Cost of Providing Frequency Control

presented by
J. Kure-Jensen, P.E.
Encotech, Inc.
Schenectady, NY

at
Ancillary Services Workshop
March 28-29, 1996
Washington DC

Sponsored by
EEI Generation Committee
EPRI Fossil Plant Business Unit
Sierra Pacific Power Co.

Cost of Providing Frequency Control

Objective

- Describe method for determining the cost of frequency control
- Obtain comments from workshop

User Requirements

- Method applicable to steam turbine units at power plant level
- For units capable of both frequency control and "optimum" mode operation

Meeting the Needs

- Help utilities that are wheeling power to determine cost of providing frequency control
- Method to be "sound" and accurate enough to stand up to rate making authority's scrutiny
- Simple enough for use by utility without costly testing or large investment

Cost Analysis

- Based on analysis of heat rate penalty rather than testing
- User can evaluate and modify inputs

Strengths / Key Benefits

- A methodology based on data already available at utility supplemented by a small software program to implement calculations

Next Steps

- Provide feedback during following discussion

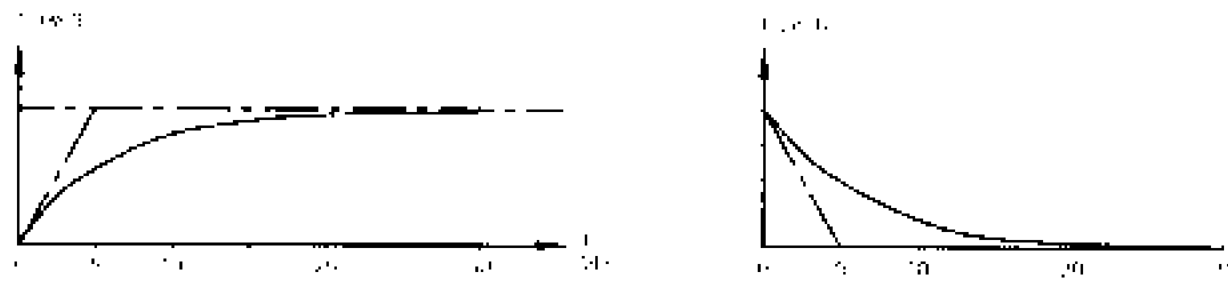
Cost of Providing Frequency Control

Definition of Frequency Control

- Two source of frequency control signals:
  1. AGC Signal
  2. Turbine Speed Control
- AGC Change = Frequency Bias + Economic Load Bias + Intertie Bias
  - Frequency bias is updated every 5-10s and requires fast response
- Turbine speed control - acts instantaneously on turbine valves
  - Normal 5% regulation equivalent to 1% load change for 0.03 Hz frequency deviation
- Method evaluates cost of fast load changes, ie. changes within 5-10s and lasting up to 30s

Cost of Providing Frequency Control

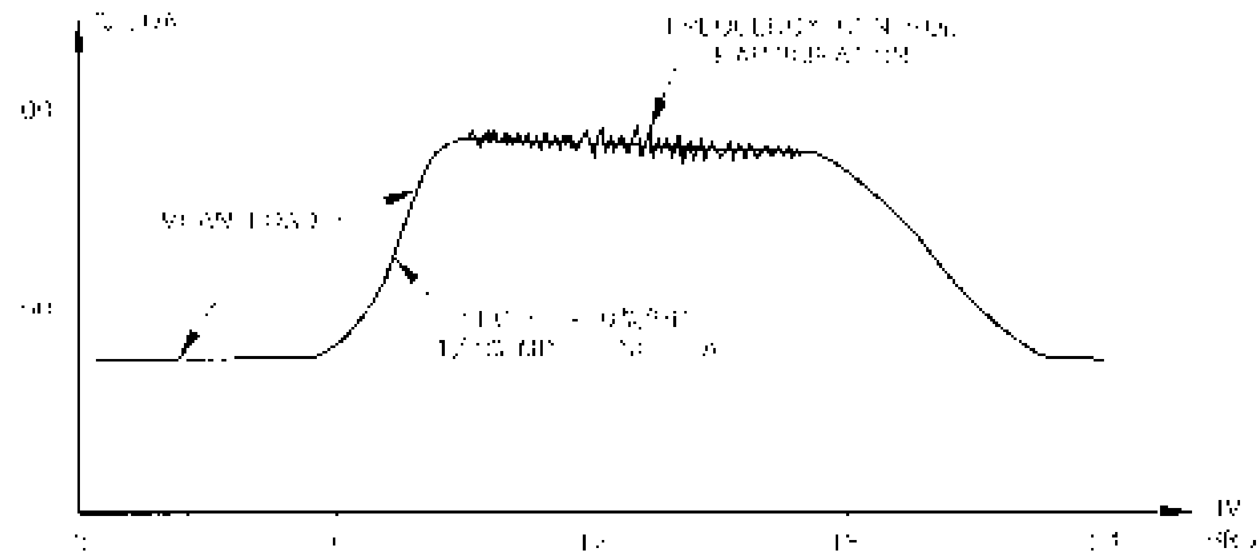
Examples of Fast Load Changes



- Any turbine can decrease load fast by closing valves
- Fast increase requires valve(s) that are not wide open, or "throttle reserve"
- Turbine speed control signals will be implemented fast if valves are not wide open
- AGC signals will only be implemented fast if sent directly to turbine controls with unit in "Boiler Follows Turbine" mode.

Cost of Providing Frequency Control

Example of Daily Load Variation



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Cost of Providing Frequency Control

Operating Modes for Cost Analysis

- **Throttle Reserve Mode:** Requires continuous throttling equivalent to required reserve, for example 5% of rated.
  - Throttle reserve leads to heat rate penalty ► additional cost for frequency control
- **Optimum Mode:** Has no fast load pickup capability, no throttling and hence potential for better heat rate
  - Optimum mode must be defined by utility for comparison with throttle reserve mode to determine cost of frequency control

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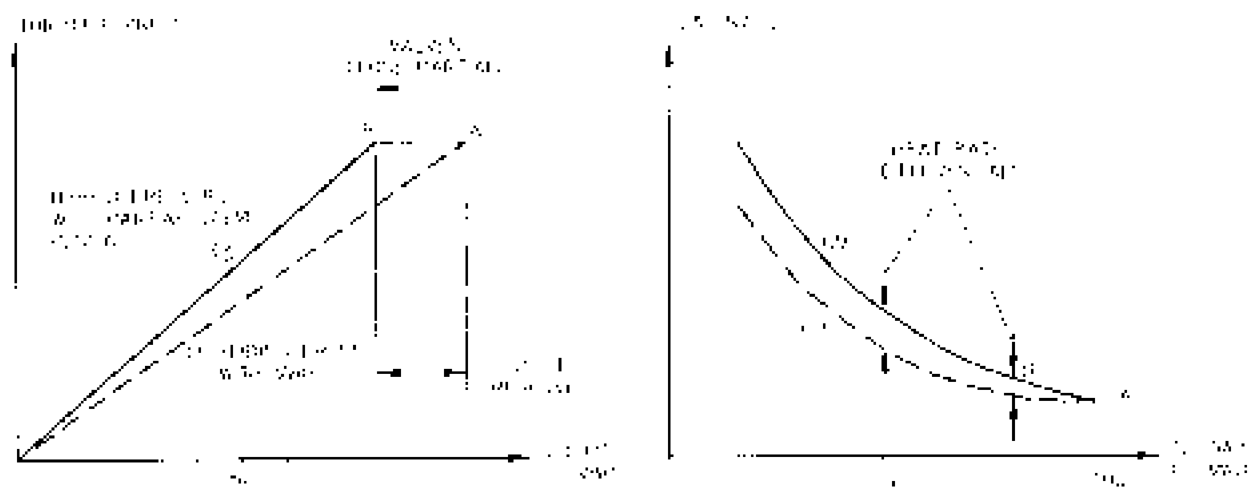
Cost of Providing Frequency Control

Examples of Operating Modes:



Mode ① has no Throttle Reserve

Mode ② has Throttle Reserve and has a poorer heat rate

Cost of Providing Frequency Control

Two Cost Components from Valve Throttling

- **Additional hardware repair** due to **severe duty possible:**
  - Control valve wear due to throttle duty
  - CV Actuator wear due to frequent motion
  - Thermal fatigue of control stage

These cost elements are not conducive to analysis. Survey of historical repair cost is recommended.

- **Additional Fuel Cost:**
  - Due to differences in heat rate as shown on previous overhead

Cost of Providing Frequency Control

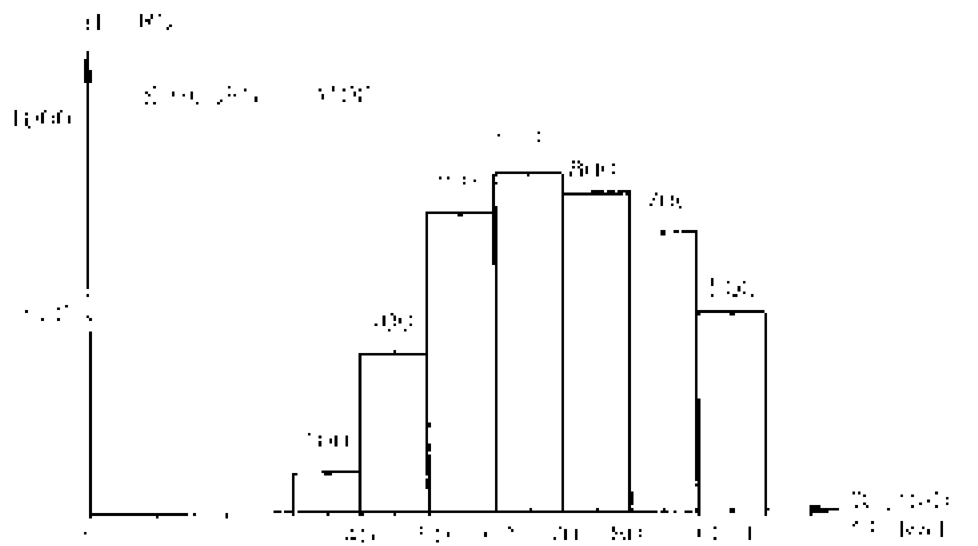
Major Steps of Cost Analysis

1. Define unit to be analyzed; obtain data
2. Determine load range for frequency control and throttle reserve needed
3. Determine time period to be analyzed and load schedule for this period

   Period can be short or long - e.g. one day (24hrs), one week, one season, one year

Cost of Providing Frequency Control

Example of Load Schedule for Frequency Control



- Each bar indicates total hours of operation within a load range. e.g. 800 hrs between 70 and 80% of rated load
- Finer subdivision of load ranges can be used for greater accuracy. e.g. every 5% load range

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Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

4. Define operating mode to be used for load schedule
   - Main steam pressure schedule, steam temperatures
   - Control strategy for turbine valves and entire cycle. e.g. FA/PA, BFP pressure & drive, boiler mode

   This mode will be well established if unit has participated in F.C.

5. Define operating mode if unit were not in F.C. mode
   - Best possible heat rate for same load schedule

   This mode must be realistic and use the exact same plant as the mode for frequency control

Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

6. Determine heat rate versus load for the two modes

- Accuracy must be about ± 10 BTU/kWh
- Would require very accurate testing - not recommended
- Recommended method is computerized thermodynamic model of the steam cycle. Must model correctly effects of the two modes. e.g.

  Valve throttling, efficiency at partload, variable pressure drops, FWH performance
- Calibrate model from existing accurate data. e.g. Acceptance Test- ASME PTC6 or other
- Encotech's SCDP © will be used for case studies

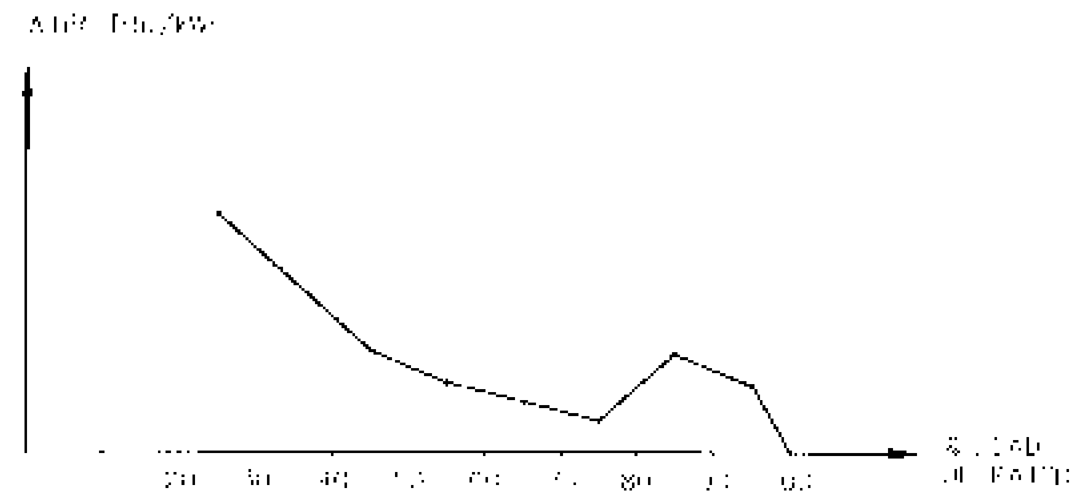
Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

7. Run steam cycle program at each % load point of load schedule for the two modes, and

   Form the difference in heat rate - Δ HR between the two modes in each % load point.

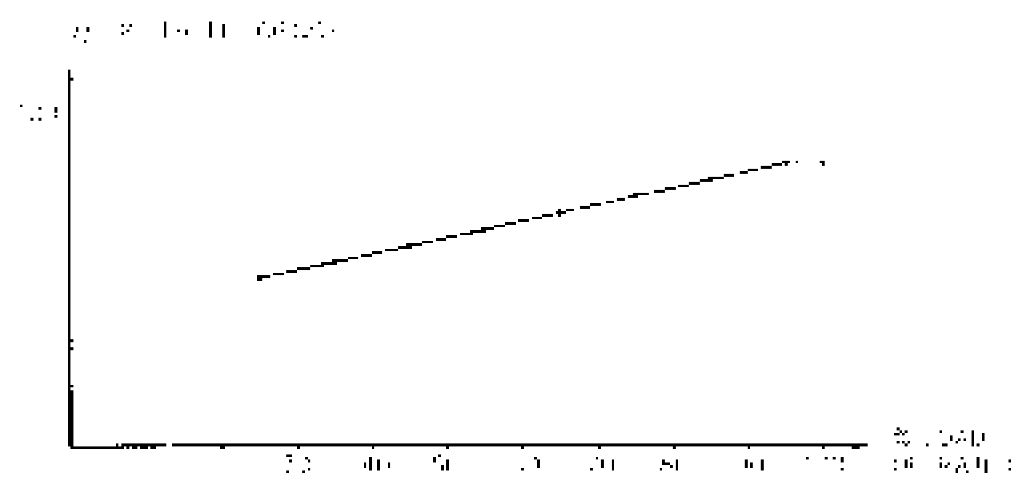
   Example:



Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

8. Determine the boiler efficiency (η) at the % load points used for load schedule



- Determine average fuel cost ($/MBTU) over period of study

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Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

9. Use results of steps 3, 7, and 8 as input to new software to calculate the following quantities as a measure of cost.

Generated el. energy = 10^{-2} * kW rating * Σ %LOAD * HRS (kWh)

Heat input penalty for cycle = 10^{-2} * kW rating * Σ %LOAD * HRS * ΔHR (Btu)

Specific heat input penalty = {Σ %LOAD * ΔHR * HRS}/{Σ %LOAD * HRS} (Btu/kWh)

Heat input penalty for boiler = 10^{-2} * kW rating * Σ1/η * %LOAD * HRS * ΔHR (Btu)

Spec. input penalty for boiler

= {Σ1/η * %LOAD * HRS * ΔHR}/{Σ %LOAD * HRS} (Btu/kWh)

Fuel cost penalty = 10^{-8} * kW rating * Σ1/η * %LOAD * HRS * ΔHR * \$/MBTU (Dollars)

Spec. fuel cost

penalty = 10^{-3} * {Σ1/η * %LOAD * HRS * ΔHR * \$/MBTU}/{Σ%LOAD*HRS} (mills\$/kWh)

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Cost of Providing Frequency Control

Special Case of F.C. - Spinning Reserve @ Partload

This case can be analyzed by methodology by:

- Reducing load schedule to single load with hours = spinning reserve duty
- Making Δ HR = HR @ Spinning Reserve - HR for alternate of generating same load
- Run method with this input to determine, e.g. Additional spec. fuel cost = xx Mils$/kWh

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Cost of Providing Frequency Control

Next Steps for Methodology

- Absorb inputs from this workshop
- Review with EPRI and sponsoring utility
- Program and run test cases
- Evaluate results - modify as required
- Report and make available to EPRI members

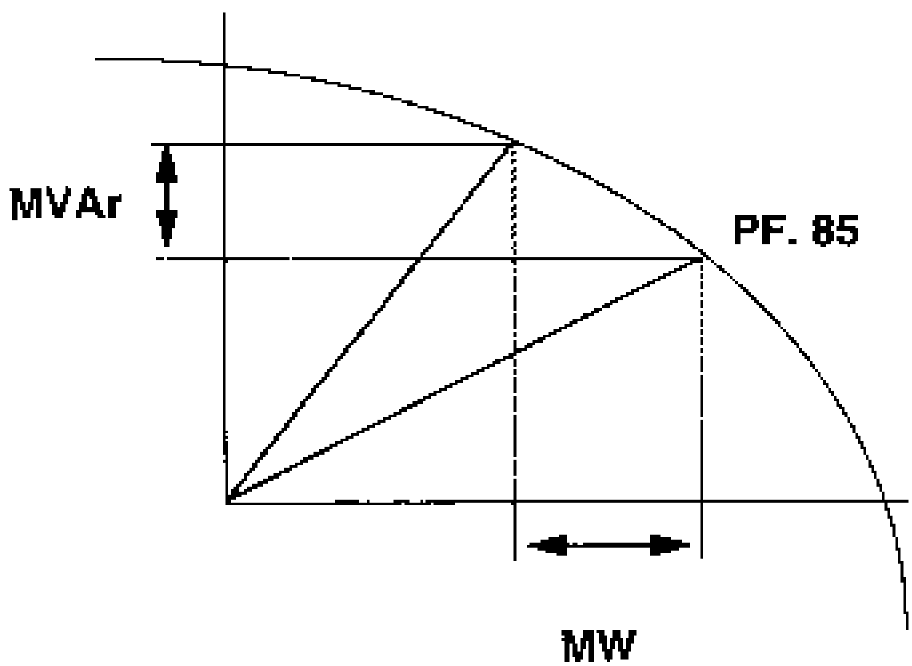
Voltage Regulation Discussion Group 1

Users: System Operations
Plant Manager
Production Super.
Power Marketers
Customers of Trans. Sys.

Calculators:
1. Generation Planners
2. Rate Designers
3. Production Engineers

Objectives:
- Make sure your costs are covered
- Keep the method simple & auditable
- Cost causation
- Satisfy Regulators
- A method to increase revenues
- "What if" planning

Mechanics of the method:



Voltage Regulation Discussion Group 2

Who are the Users?	Frequency of Use
Plant Mgr. (Plant)	(Daily?)
Oper. Supv. (Plant)	(Daily?)
Shift Supv. (Plant)	(Daily?)
Control Room (Plant)	(Daily?)
Production Mgmt. (VP + Staff)	(Daily?)
Elect. Syst. Ops./Maint.	(Seasonal)
System Dispatchers	(Daily)
Power Marketers	(Daily)
System Planning	(Yearly?)
Rates	(Seasonally, Quarterly) Frequency depends on volatility.

Who is method designed for?
General: The person who needs to calculate the cost.
Could be: Control room (Plant)
Prod. Staff
Dispatcher
Marketer
Rates analyst

What is management objective?

- Know real cost of providing service
- Better energy price by excluding ancillaries (<1%)
- Profit
- Better position against IPPs & marketers
- Support tariff filings

Processes:
Capture fixed & variable cost
Allocate on ..... (what?)
What if/sensitivity capability
Balance between VArs & energy
Data: Gen capability curve
Real + react power output
Impedances (design or test)
Aux loads
Limiting factors
Market clearing price

Voltage Regulation Discussion Group 3

Users:
1. Generation services
2. Plant managers
3. Sys Ops
4. Marketing
5. Business planners
6. Regulators FERC/state regulator
7. IPP's

Objectives:
Identifying costs
Opportunities to manage cost
Determinant of price
Decision to participate in market

Process:
1. Define the voltage regulation function & the parameters you are going to monitor.
2 Define the cost components associated with this service
    Fuel
    Maint.
    Equipment
    Opportunity
3. Define operation for most economical condition-reference point
4. Calculate or measure costs for cost components identified

Frequency Regulation Discussion Group 1

Frequency Controls
- Governor response ("automatic")
- AGC (tie-line bias)
- Spinning reserve (Contingency loss)
- Operating reserve (Contingency loss)
- Load following

Governor response
- Installation cost
- Maintenance cost
- Performance loss/effect
- Replacement cost

How often are governors active? Is it too "cheap to meter"?

AGC (tie-line bias)
Plant-related
- Installation cost
- Operating cost --function of unit type
- Production cost
- Maintenance cost
- Volatility of use ("mileage")

System control center related cost
- Telemetry
- AGC software/tuning
- Operators
- Inadvertent/other accounting
- Performance "policing"
- Voice communications

Frequency Regulation Discussion Group 2

Who are the users?	What is the frequency?
Plant staff	Daily (or more often)
Production staff	Daily (or more often)
Marketers	(Daily)
Dispatchers	(Daily)
Generation Planners	(Seasonal)
Rate Analysts	(Seasonal)

Who is it designed for?
Plant and/or production staff

What are mgmt's objectives?

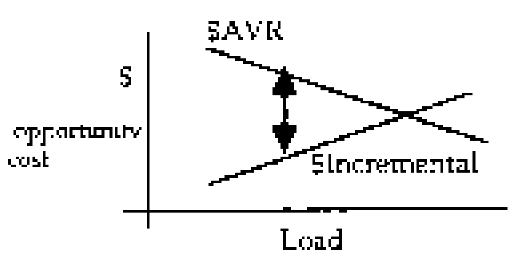
- Profit
- Determine costs to set bid prices
- Determine optimal points for regulation
- Determine risk vs. reward
- Be paid for providing the service at the unit level

Process
Primary frequency response
  Opportunity cost
  Variable costs
  Fixed Costs
  Forward & backward look

Data Needed:
Heat rate curve
Fuel cost
system forecast

AGC
  Efficiency impact
  Wear & tear
  Opportunity costs
  Fixed costs
  Variable costs
  Forward & backward looks

+ maint costs/
history

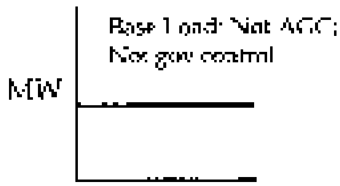


Frequency Regulation Discussion Group 3

(steps 1-4) ▪ Same users as voltage control (but more of a global issue)

Process

- Identify cost
- Optimize & manage costs
- Determinant for price
- Decision to participate in freq. control



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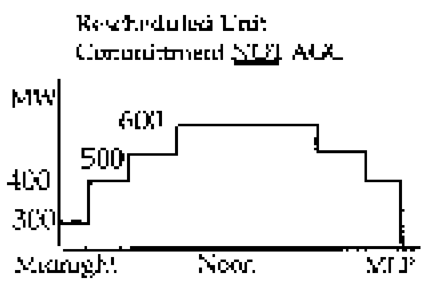
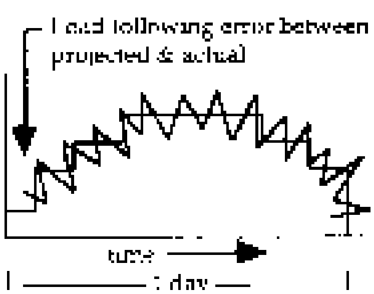




System needs for generation

1. Base load

2a. Hourly load fluctuations

2b. Fluctuations (within seconds)

Fluctuations (within minutes)

2c. Moment-to-moment load fluctuations

3. Loss of generation or load

Frequency Regulation Group 3 (Continued)

1. Base Load
   - Low cost & must run units
   - Not on load control (demand)
   - Load limit control
   - On freq. control (Governing only--Not an ancillary service; same rules to follow)

Basic Service

2a. Moment-to-moment load fluctuations (within hours)
   - Based on eco. dispatch & commitment schedule
   - Requires intervention
   - Manual, phone call (Not an ancillary service, included in the bid for basic service)

2b. Moment-to-moment fluctuations (within minutes)
   - Units on AGC (ancillary service)
   - Units on load control (automatic; units that are on eco. dispatch schedule) (ancillary service)

2c. Moment to moment fluct. (within seconds)
   - Units on active governing control (part of basic service)
   - Units on AGC (incl. in 2b)

3. Loss of load or gen.
   - Units w/available margin
   - Units w/governing control
   - Units w/ AGC
   - Units on load control
   - Spinning reserve (ancillary service)
   - Quick start units (ancillary service)

Additional Ancillary Services

- Spinning reserves
  - Variable
- Quick start
  - CT load 10 min.
  - Fixed
  - Wear & tear
- Black start
  - Fixed cost?
  - Variable cost
- Load rejection
  - Turbine bypass
- PSS
- Later workshop
  - send out material before workshop
- EEI Task Force coordination
- Regional workshop
  - Objective
  - Definition
  - Focus 1-2 day

Ancillary Services Workshop

Reno, NV

April 30 - May 1, 1996

Project History

Fall 1993	Discussions with PG&E
Feb. 1994	Advisory WG Meeting
Summer	Contacted 50+ Utilities
August	Proposal to SCE
October	Presentation to EEI
October	Presentation to BPA
January 1996	Consolidated Edison Project
March	Workshop with 19 Utilities

Ancillary Services -- Order 888

- FERC finds that six ancillary services must be included in an open access transmission tariff.
- The six services must be provided as follows: (1) scheduling, system control and dispatch; (2) reactive supply and voltage control from generation sources service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve -- spinning reserve services; and (6) operating reserve -- supplemental reserve service

Ancillary Services -- Order 888 (Cont'd)

- The requirement that the six services be included in an open access transmission tariff does not preclude the transmission provider from offering voluntarily to provide other interconnected operations to the transmission customer along with the supply of basic transmission service and ancillary services.
- Pricing for ancillary services will be considered on a case-by-case basis, under enumerated pricing principles.

Agenda

Tuesday, April 30, 1996

8:30am - 9:15am	Welcome, Introduction, History, Orientation, Objectives and Workshop Agenda
9:15am - 10:15am	Ancillary Services • History • Stakeholders • FERC ruling • Importance of Cost Calculation • Valve
BREAK	
10:30am - 11:00am	Voltage Regulation • Terminology • Overview of a Method to Calculate the Cost of Providing Voltage Regulation
11:00am - 12:00pm	Small Groups Analyze Method • Users • Users Needs and Requirements • What Other Utilities Have Done • Application to Various Power Plants and Systems

LUNCH	
1:00pm - 1:30pm	Small Groups Complete Analysis of Method
1:30pm - 2:30pm	Small Groups Present Their Findings • Modifications to Method • Alternate Methods • Requirements
BREAK	
2:45pm - 3:45pm	Presentation of Project Plan to Determine the Cost of Providing Voltage Regulation • Cost of Voltage Regulation • How to Meet Needs and Requirements • Discussion of Alternative Methods
3:45pm - 4:30pm	Wrap up and Plan for Next Day • Needs and Requirements for the Other Ancillary Services

<u>Wednesday, May 1, 1996</u>

8:30am - 9:15am	Orientation, Objectives and Workshop Agenda
9:15am - 10:15am	Load Following • Terminology • Overview of a Method to Calculate the Cost of Providing Load Following
BREAK	
10:30am - 12:00am	Small Groups Analyze Method • Users • Users Needs and Requirements • What Other Utilities Have Done • Application to Various Power Plants and Systems
LUNCH	
1:00pm - 1:30pm	Small Groups Complete Analysis of Method
1:30pm - 2:30pm	Small Groups Present Their Findings • Modifications to the Method • Alternative Methods • Requirements
BREAK	
2:45pm - 3:45pm	Presentation of Project Plan for Determining the Cost of Providing Load Following Services
3:45pm - 4:30pm	Open Discussion on Ancillary Services and Methods for Calculating the Cost of Providing These Services

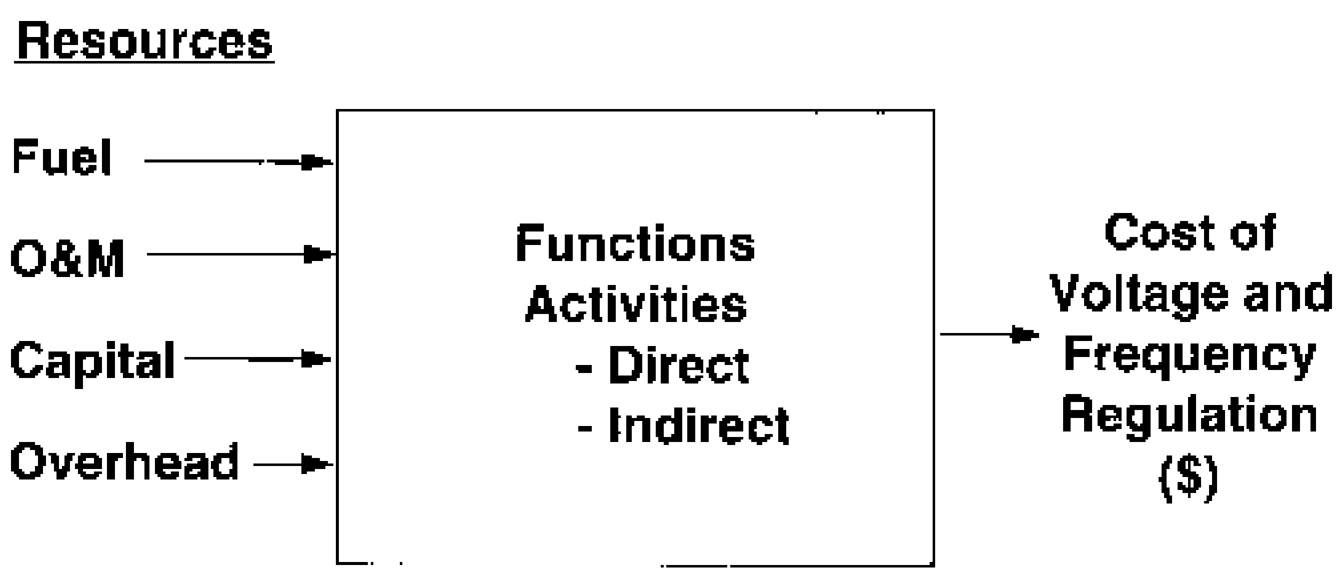
Workshop Objectives

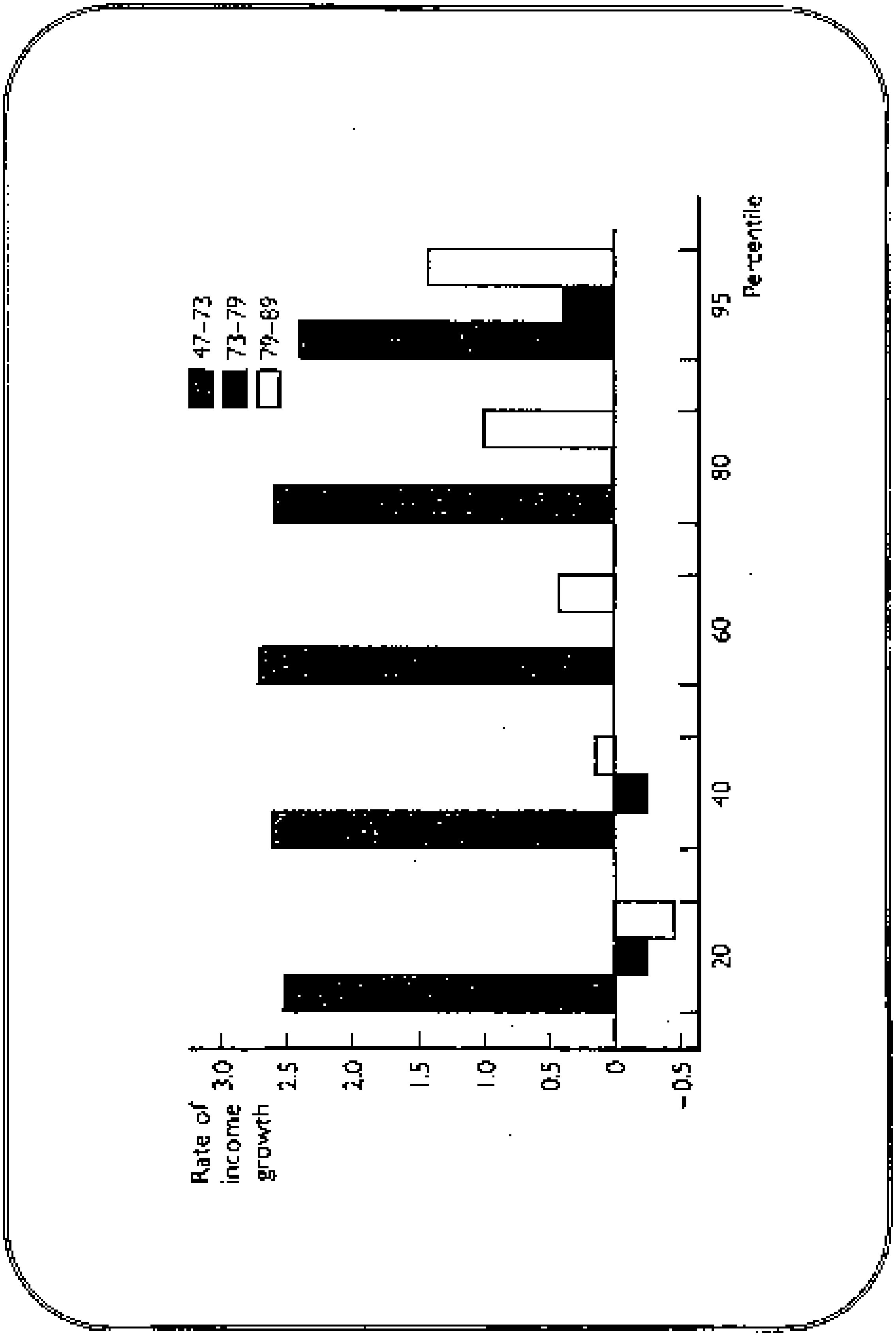
Clarify requirements for methodologies that calculate the variable cost of providing frequency control and voltage regulation

Methodology

- Defined: Step-by-Step Procedure, Identified Data Requirements, Models and Analysis Techniques, Assumptions and Limitations
- Manual: Report on How to Proceed; Guidelines
- Automated: Spreadsheet, Application Software

Methodology
Input/Output

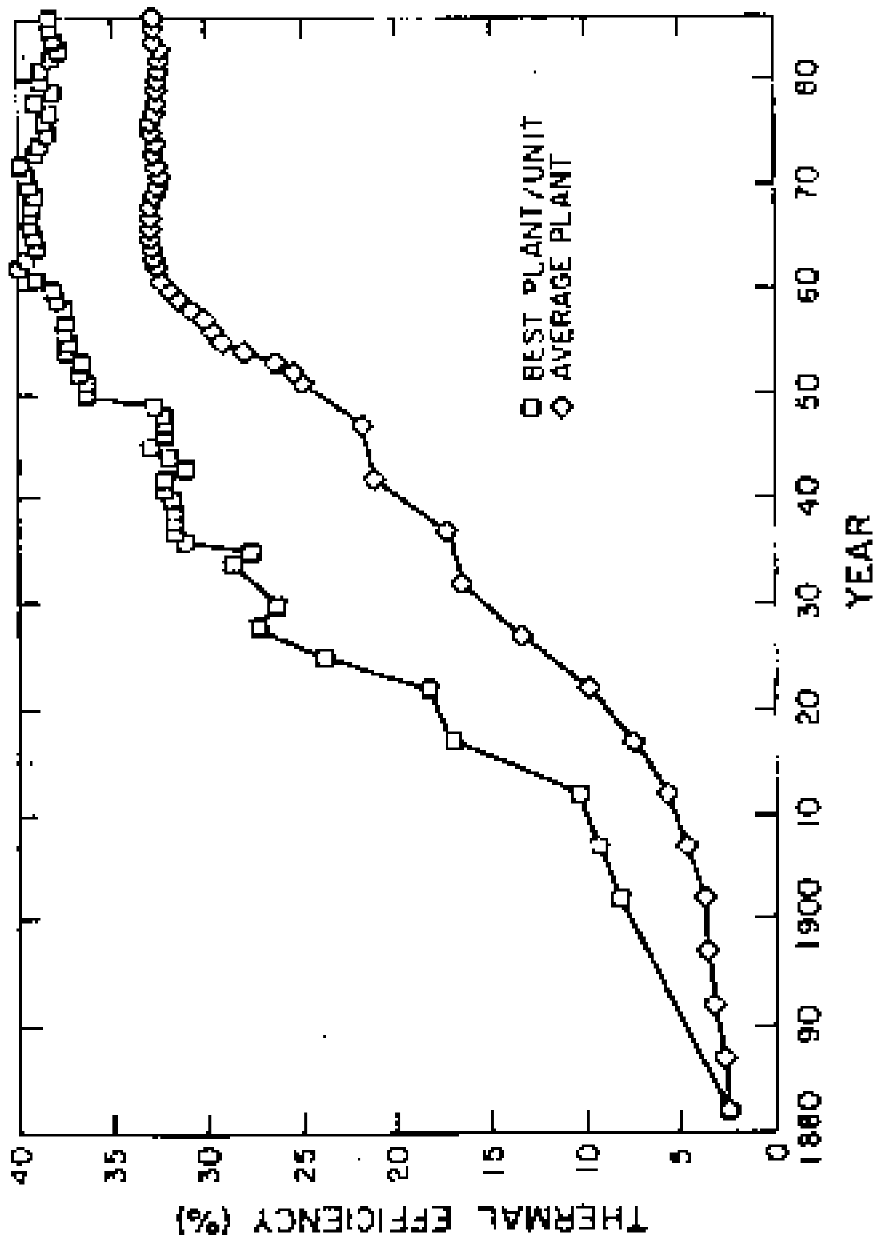


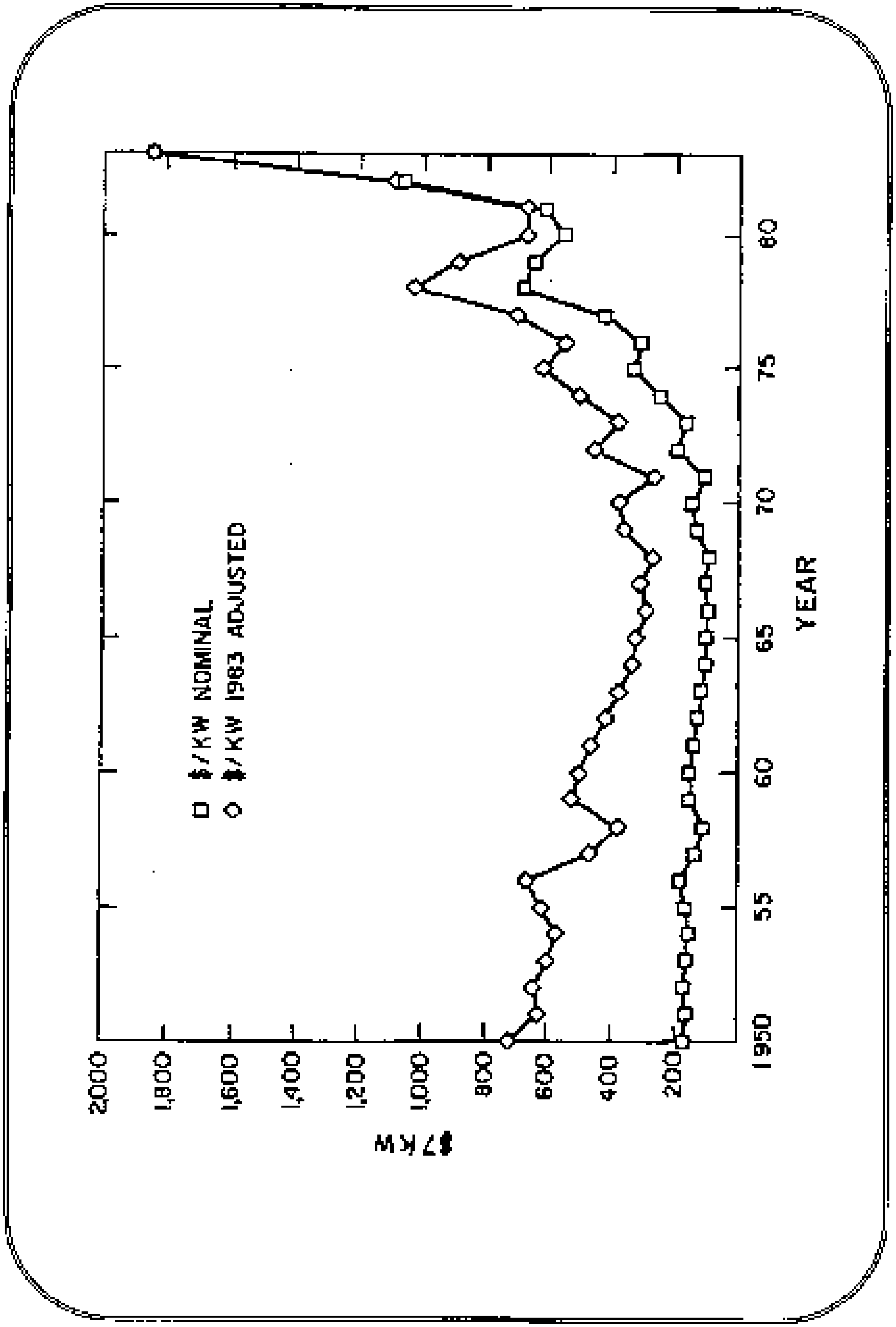

Rate of income growth
3.0
2.5
2.0
1.5
1.0
0.5
0
−0.5
47–73
73–79
79–89
20
40
60
90
95
Percentile

Regulation as Culprit in Productivity Slowdown

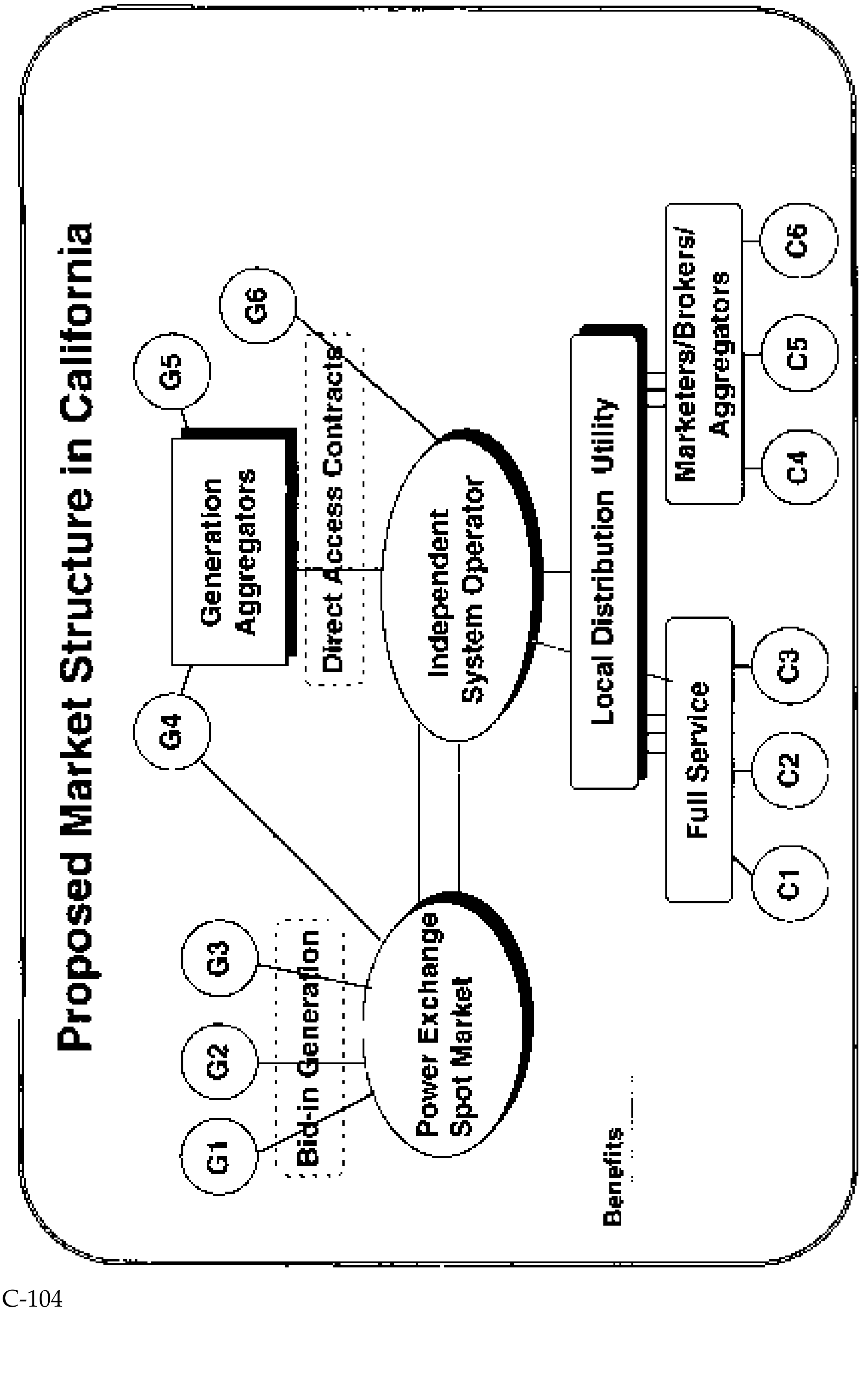
- Regulatory costs imposed on U.S. business cost the economy more than 100 billion annually
- 1970's sharp rise in regulatory burden on business

Trucking	Savings & Loan
Airlines	Cable
Oil	Natural Gas
Banks	Telecommunications


THERMAL EFFICIENCY (%)
YEAR
BEST PLANT/UNIT
AVERAGE PLANT
0
5
10
15
20
25
30
35
40
1880
90
1900
10
20
30
40
50
60
70
80



$/KW NOMINAL
$/KW 1983 ADJUSTED
$/KW
2000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
1950
55
60
65
70
75
80
YEAR


Proposed Market Structure in California
G1
G2
G3
Bid-in Generation
Power Exchange Spot Market
G4
Generation Aggregators
G5
G6
Direct Access Contracts
Independent System Operator
Local Distribution Utility
Full Service
Marketers/Brokers/ Aggregators
C1
C2
C3
C4
C5
C6
Benefits

Proposed California Independent System Operator ISO

- Transmission access for wholesale and retail power sales
- Scheduling and dispatching power from all sources
- Balances load and generation on a real-time basis
- Manages transmission congestion
- Maintains reliability, security and stability
- Recovers costs of ancillary services

Power Exchange

Take and match supply bids with demand bids

Spot price

Ancillary

auxiliary or supplementary goods and/or services that are related to, required by, or integral to another good.

Ancillary

subordinate; in support of

Ancillary Services

services subordinate to, in support of

Why Electric Power is Unique

RELATIVE FIXED COSTS	PRODUCT LONGEVITY: High	PRODUCT LONGEVITY: Low
High	**High Asset Costs, Long Cycle** • Specialty Electronics - Large Computers - Integrated Circuits • Construction - Houses - Offices	**Critical Load Factors** • Telecommunications - Long Distance - Business Service • Travel Services - Airlines - Mass Transportation
Low	**Commodity Products** • Raw Inert Materials - Metals - Plastics • Established Standard Items - Light Bulbs - Carpets	**Fast Life Cycle or Spoilage** • Consumer Electronics - Calculators - VCRs • Retail Foods - Restaurants - Groceries

Electric Power

- Shortest Shelf Life
- Highest Fixed Cost
- Highest Reliability

Cost

What is required to produce a good or service

Price

Amount of cash paid by a consumer to a producer to purchase a unit of a good or service

Fixed Costs

What it costs to purchase and install the equipment, power plant, etc.

All those costs that are incurred even if the unit produces zero output.

Variable Costs

All those costs that change with output

- fuel costs, maintenance, repairs

Fixed Costs

are beyond the control of a plant manager

Variable Costs

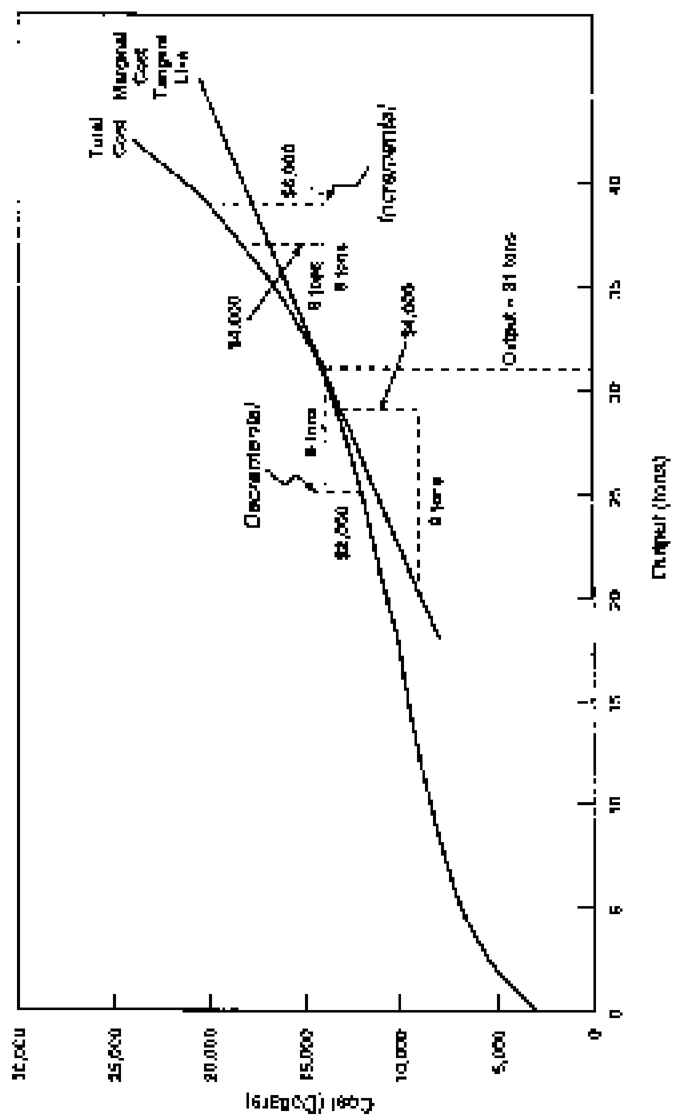
are affected by operating strategies of the plant

Total Costs

Total Costs = Fixed Costs + Variable Costs

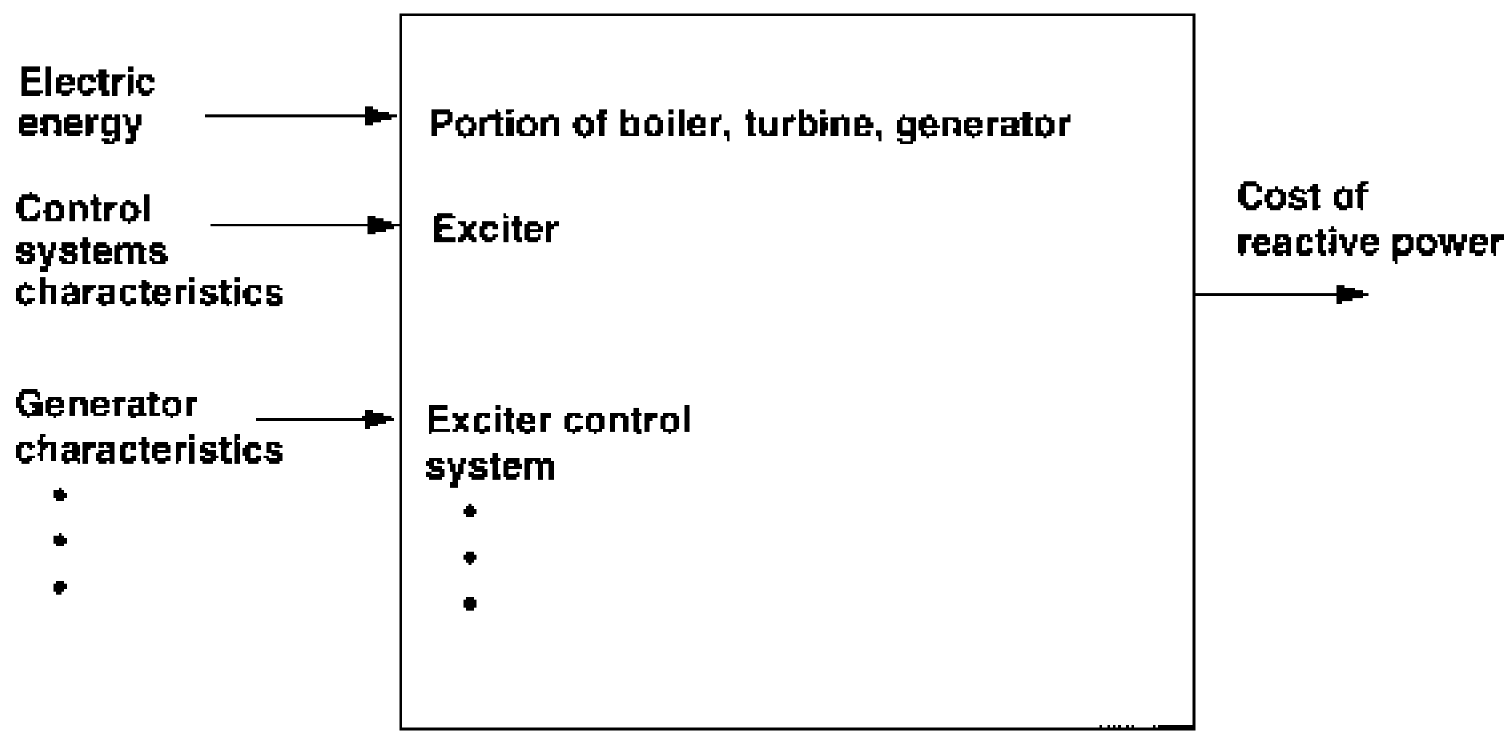
Incremental Cost

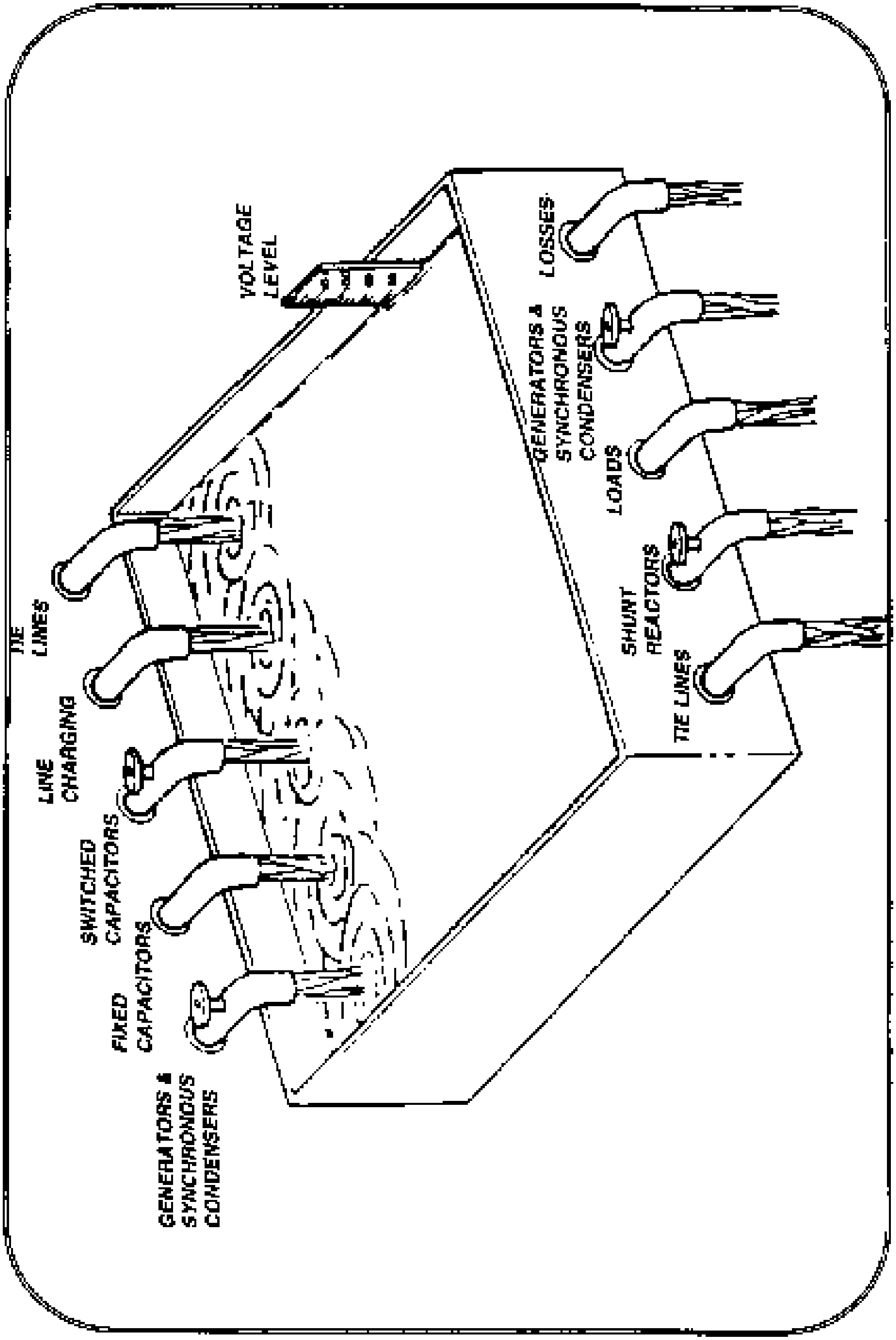
additional cost required to produce a given increment of additional output

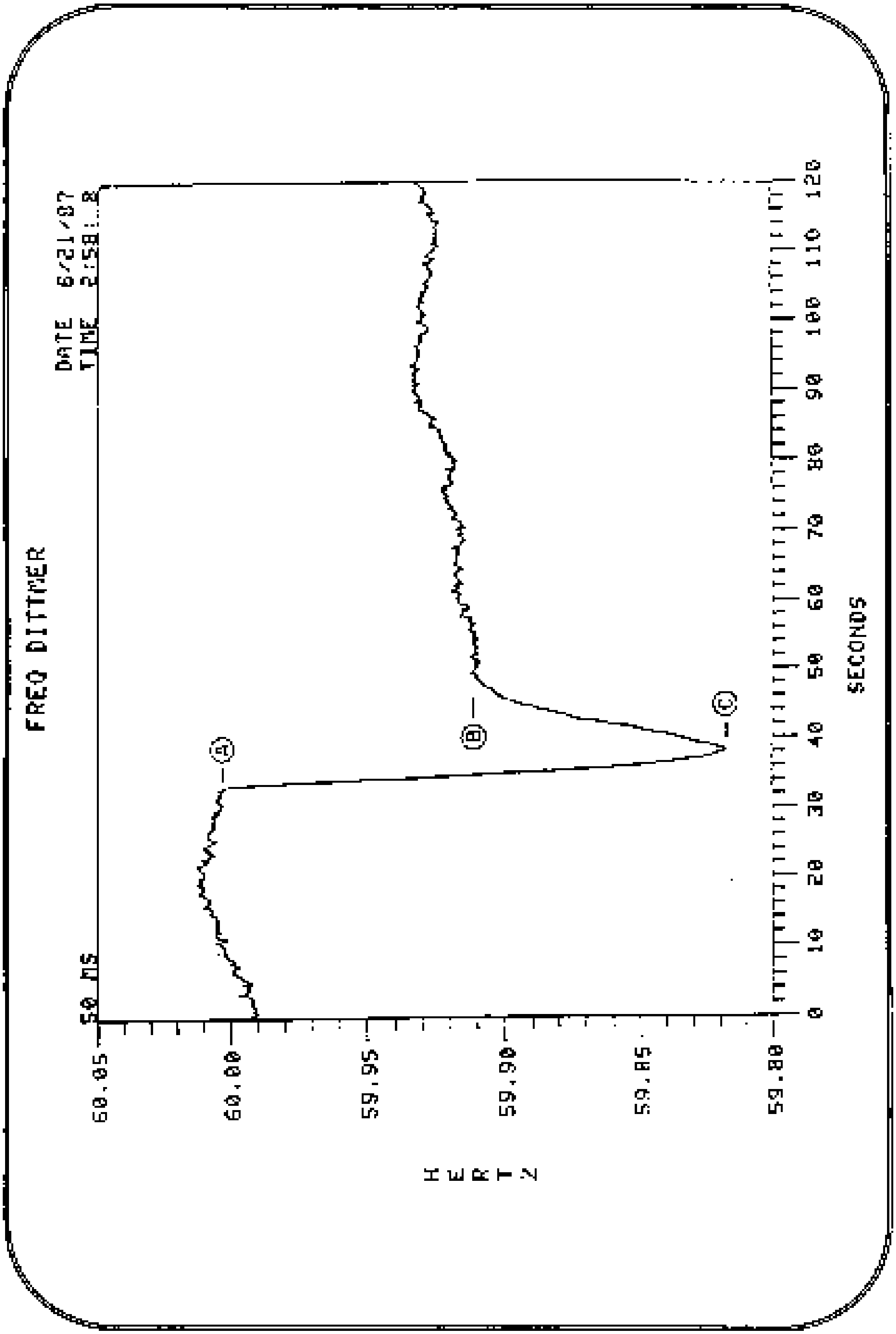


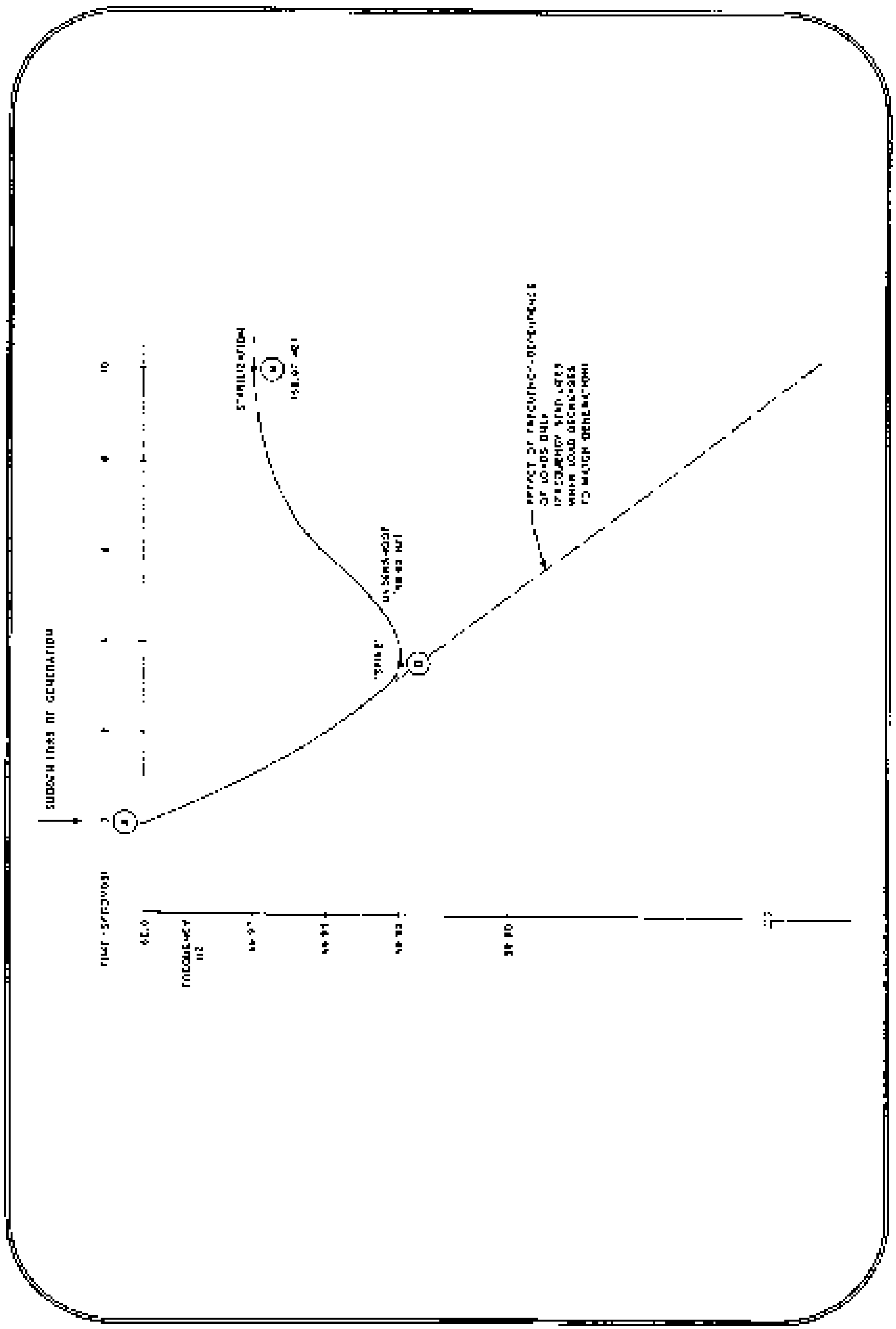
Total Cost
Marginal Cost Tangent Line
Incremental
Decremental
$6,000
$4,000
$4,000
$2,000
8 tons
8 tons
8 tons
8 tons
Output = 31 tons
Output (tons)
Cost (Dollars)
0
5
10
15
20
25
30
35
40
5,000
10,000
15,000
20,000
25,000
30,000

Cost Causation
Service-voltage regulation




GENERATORS & SYNCHRONOUS CONDENSERS
FIXED CAPACITORS
SWITCHED CAPACITORS
LINE CHARGING
TIE LINES
VOLTAGE LEVEL
LOSSES
GENERATORS & SYNCHRONOUS CONDENSERS
LOADS
SHUNT REACTORS
TIE LINES

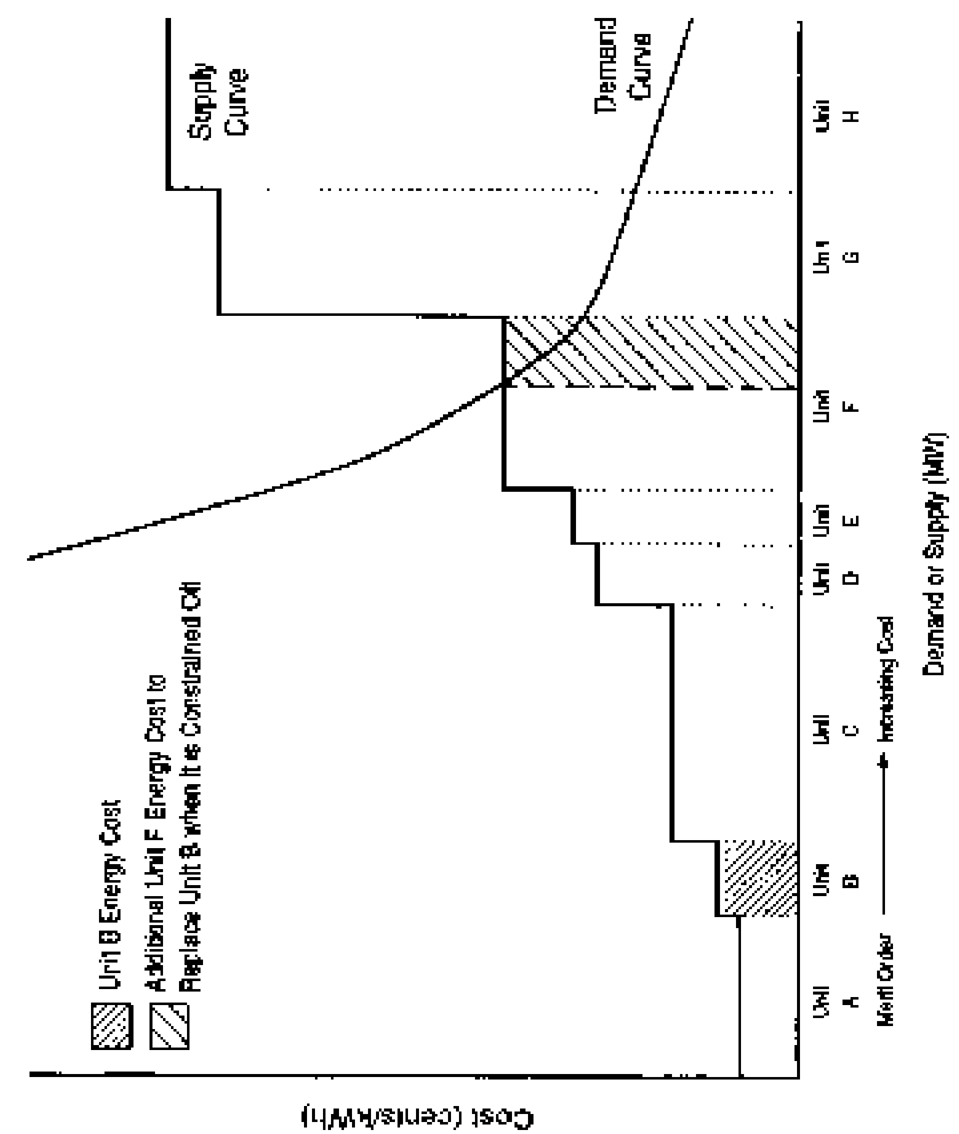

FREQ DITTMER
DATE 6/21/87
50 MS
HERTZ
SECONDS
60.05
60.00
59.95
59.90
59.85
59.80
0
10
20
30
40
50
60
70
80
90
100
110
120
A
B
C

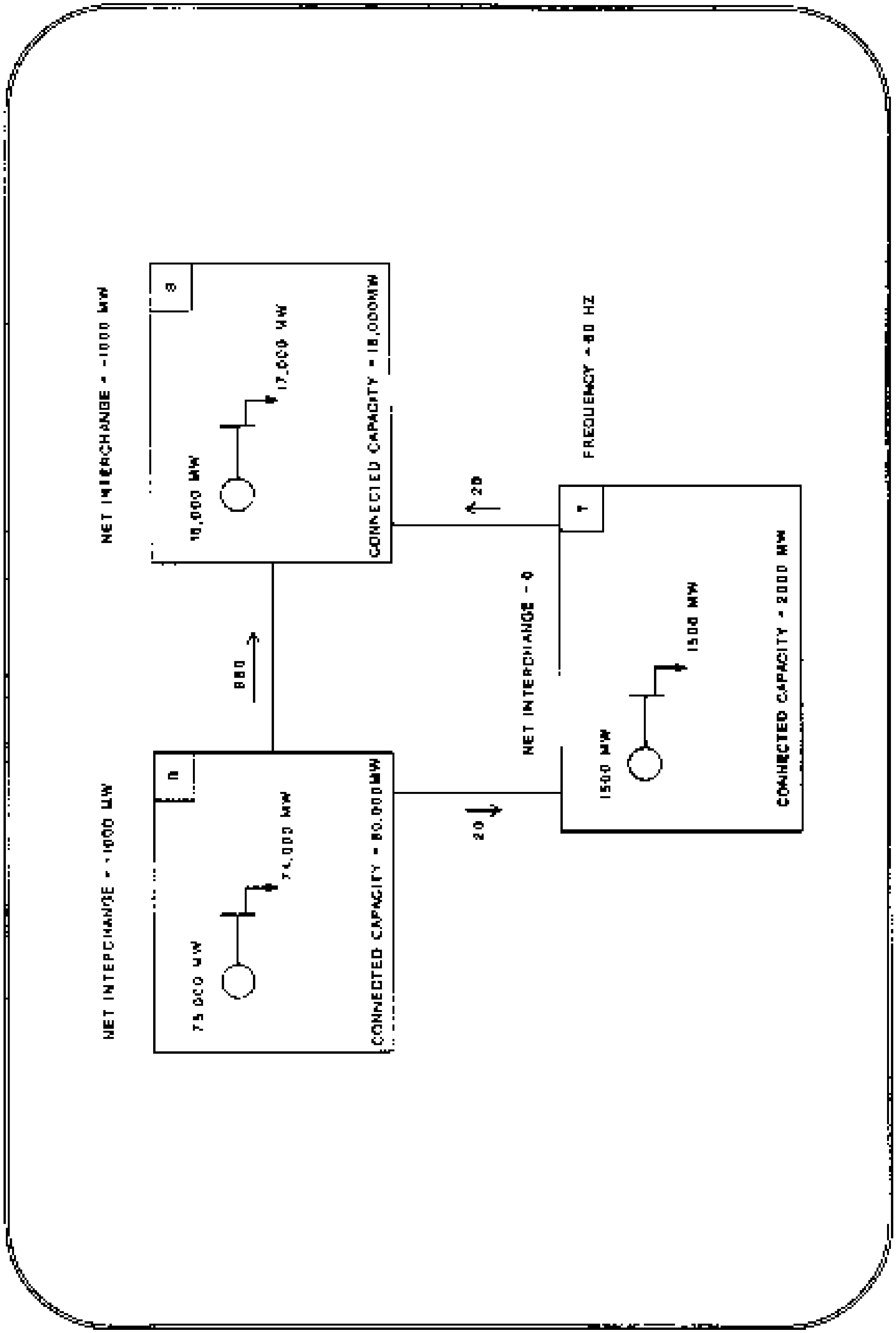

SUDDEN LOSS OF GENERATION
STABILIZATION
TIME - SECONDS
FREQUENCY
Hz

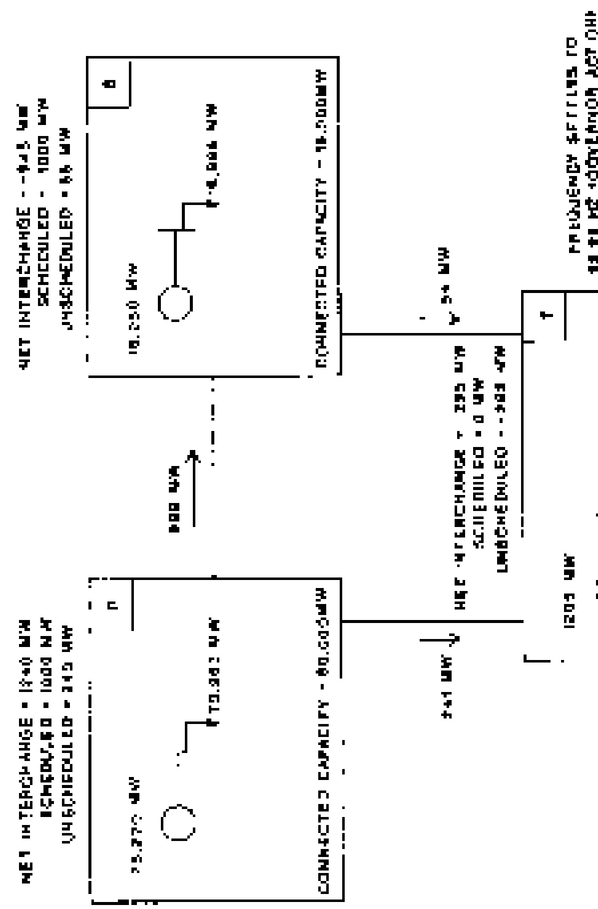
Out-of-Merit

Merit order is ordering the variable costs of generating units from lowest to highest

Congestion -- transmission system cannot carry power flows from the merit order generators to the loads at a particular point in time


Unit B Energy Cost
Additional Unit F Energy Cost to Replace Unit B when it is Constrained Off
Supply Curve
Demand Curve
Cost (cents/kWh)
Unit A
Unit B
Unit C
Unit D
Unit E
Unit F
Unit G
Unit H
Merit Order → Increasing Cost
Demand or Supply (MW)


NET INTERCHANGE = +1000 MW
75,000 MW
74,000 MW
CONNECTED CAPACITY = 80,000 MW
NET INTERCHANGE = -1000 MW
17,000 MW
CONNECTED CAPACITY = 18,000 MW
20
20
NET INTERCHANGE = 0
1500 MW
1500 MW
CONNECTED CAPACITY = 2000 MW


1205 MW
1500 MW
CONNECTED CAPACITY = 1700MW
54 MW
FREQUENCY SETTLES TO

Area Control Error

$$ACE = T_a - T_s + \beta\,(F_a - F_s)$$

- Why VArs?
- How Produced?
- How Consumed?
- The Cost of Generation

Power System Needs

- kW for Frequency Control
- kVAr for Voltage Regulation

kVar Producers

- Shunt Capacitors
- Series Capacitors
- Lightly Loaded Transmission Lines
- Synchronous Machines

kVar Consumers

- Shunt Reactors
- Transformers
- Heavily Loaded Transmission Lines
- Induction Motors
- Synchronous Machines

Losses

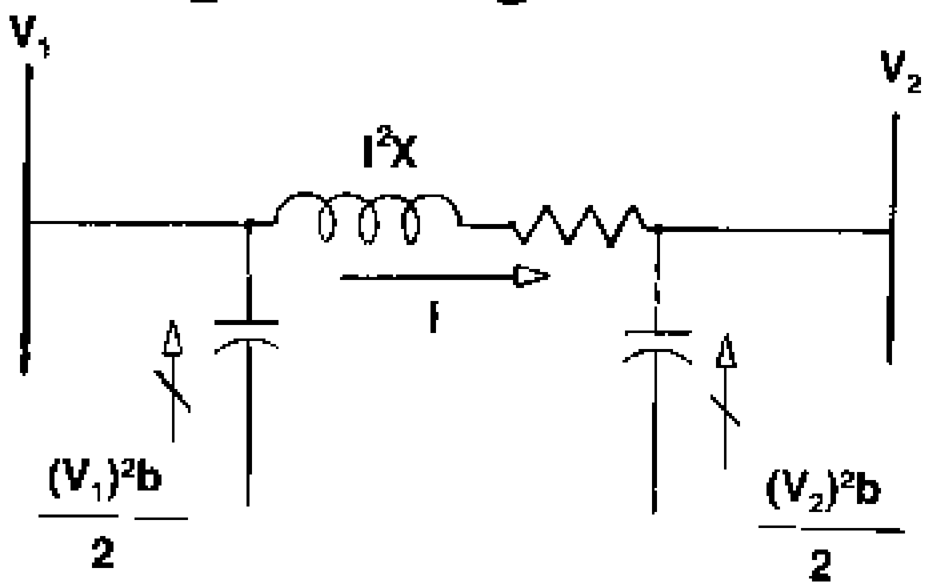
$kW = I^2R$

$kVAr = I^2X$

Lines: $\frac{X}{R} = 4 \text{ to } 15$

Transformers: $\frac{X}{R} = 20 \text{ to } 50$

High Voltage Lines



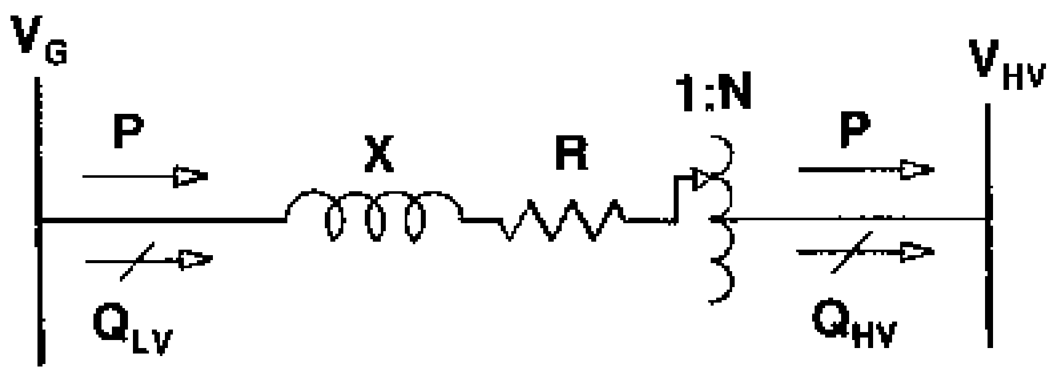
Surge Impedance Loaded when:

$$I^2X = \frac{(V_1)^2b}{2} + \frac{(V_2)^2b}{2}$$

SIL:

230 kV = 130 MW
345 kV = 300 MW
500 kV = 625 MW

Step-Up Transformer

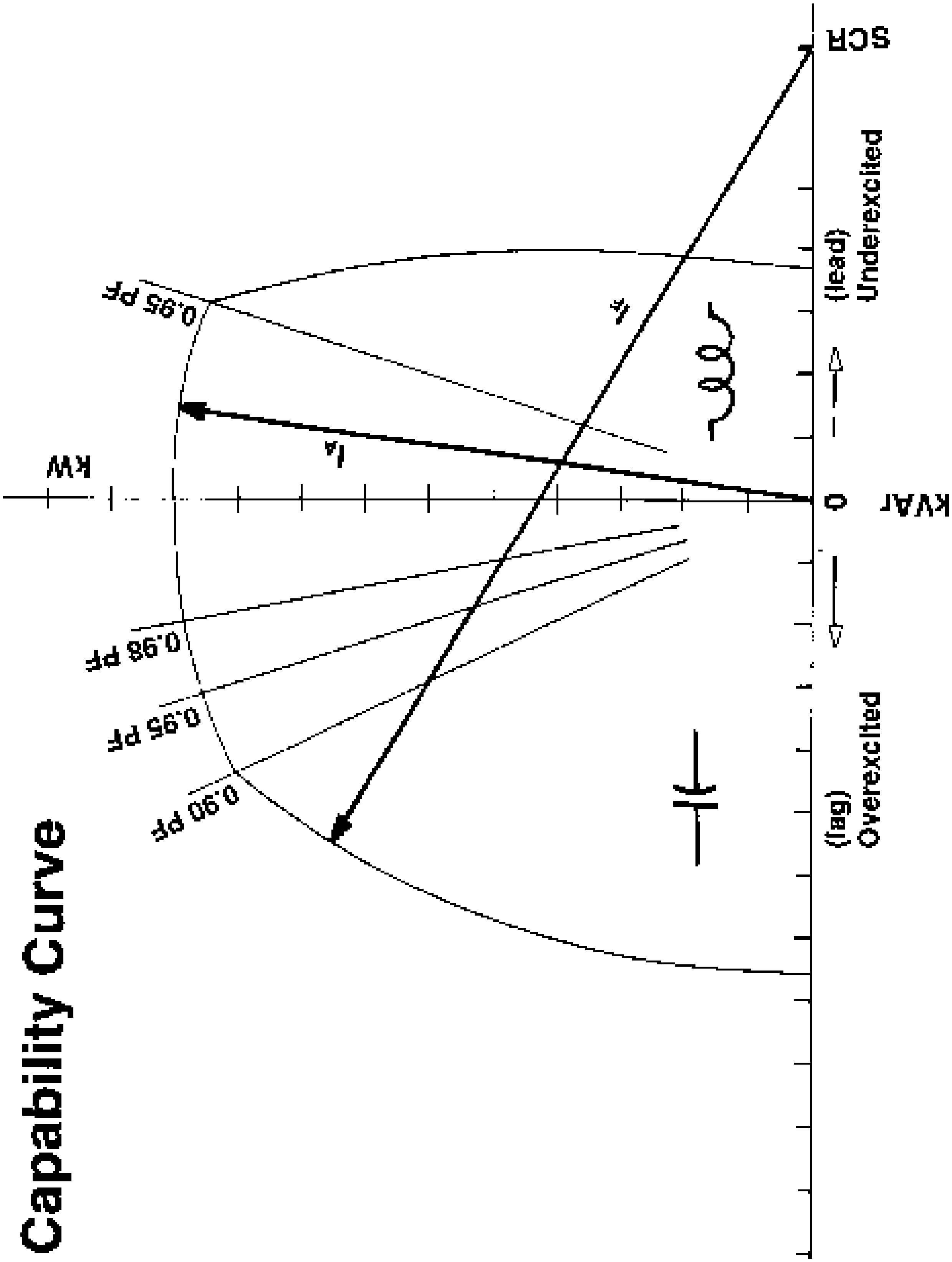


Typical Parameters

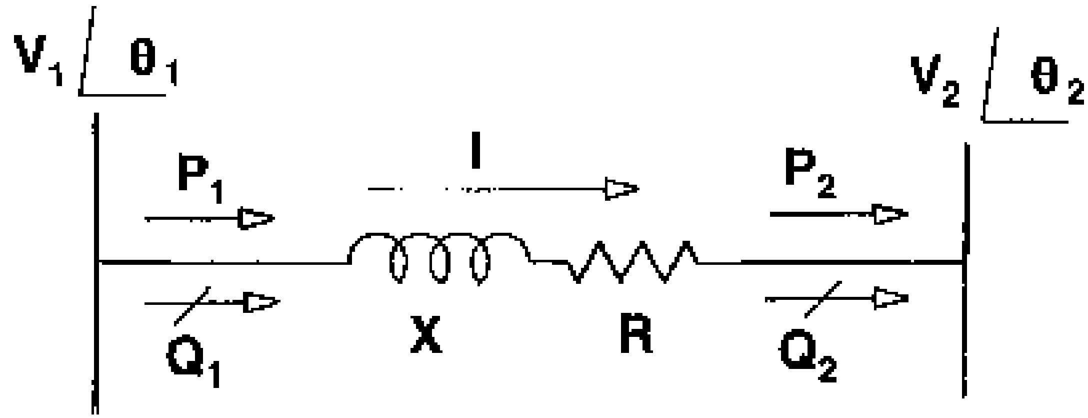
$X = 0.10$

$R = 0.003$

$N = 1.05$


Capability Curve
kW
KVAr
0
SCR
(lead)
Underexcited
(lag)
Overexcited
0.95 PF
0.98 PF
0.95 PF
0.90 PF
I_A
I_F

Network Elements

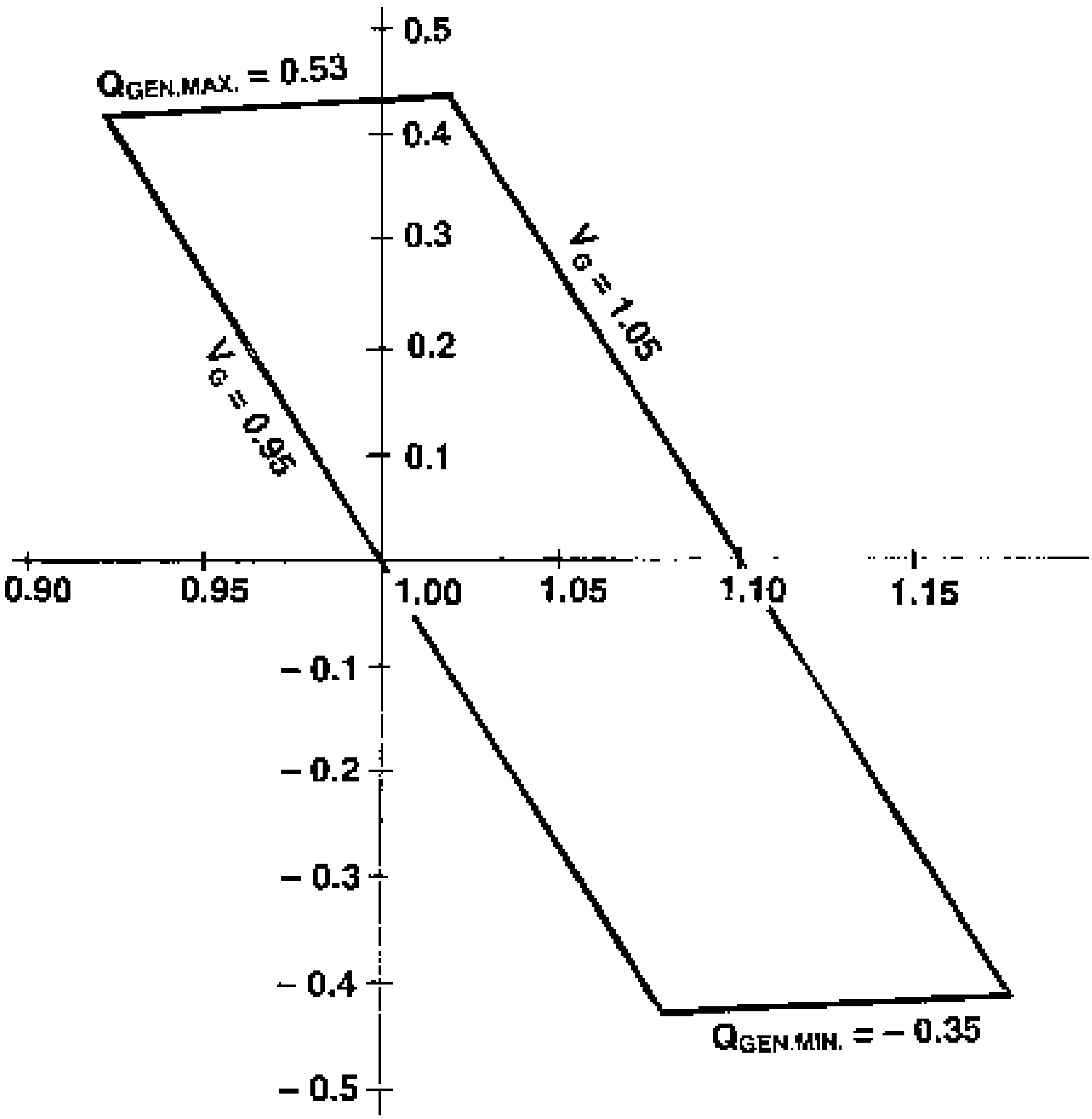


$$P_1 = \frac{V_1 V_2}{X} \sin(\theta_1 - \theta_2)$$

$$\theta_1 = \frac{V_1 V_2}{X} - \frac{V_1 V_2}{X} \cos(\theta_1 - \theta_2)$$

$$\Delta V = V_1 - V_2 \approx V_1 - I_Q X$$

Combined Generator Plus Transformer Characteristics at HV Bus



Losses

Stator Losses = $\left(\frac{P}{V}\right)^2 R_S + \left(\frac{Q}{V}\right)^2 R_S$

Field Losses = $\left[f(V, P, Q, X_L, X_d, X_q)\right]^2 R_F$

Generator Load-Variable Losses

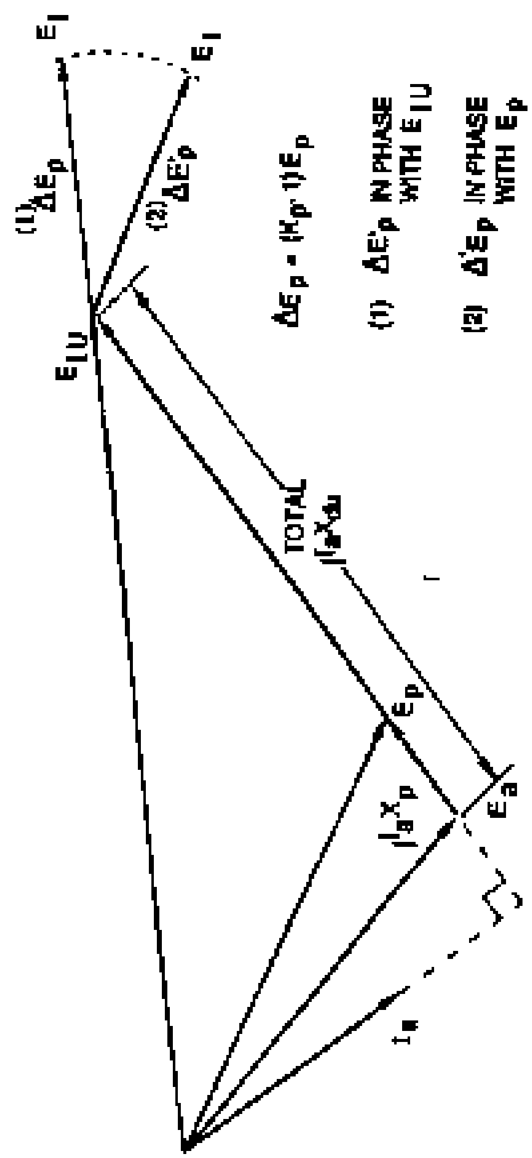
		Guestimate of % of Losses at Full Load
Copper Losses		
Field	$(I_F)^2R_F$	40%
Armature	$(I_A)^2R_A$	15%
Core Losses		
Stator Iron	$(E_I)^2$	20%
Stray-Load Losses		25%
Total Load Variable Losses		100%

$$\frac{\text{Total Load-Variable Losses}}{\text{Unit Output}} = 1\% \qquad \frac{(I_F)^2R_F + (I_A)^2R_A}{\text{Total Load-Variable Losses}} = 1/2$$

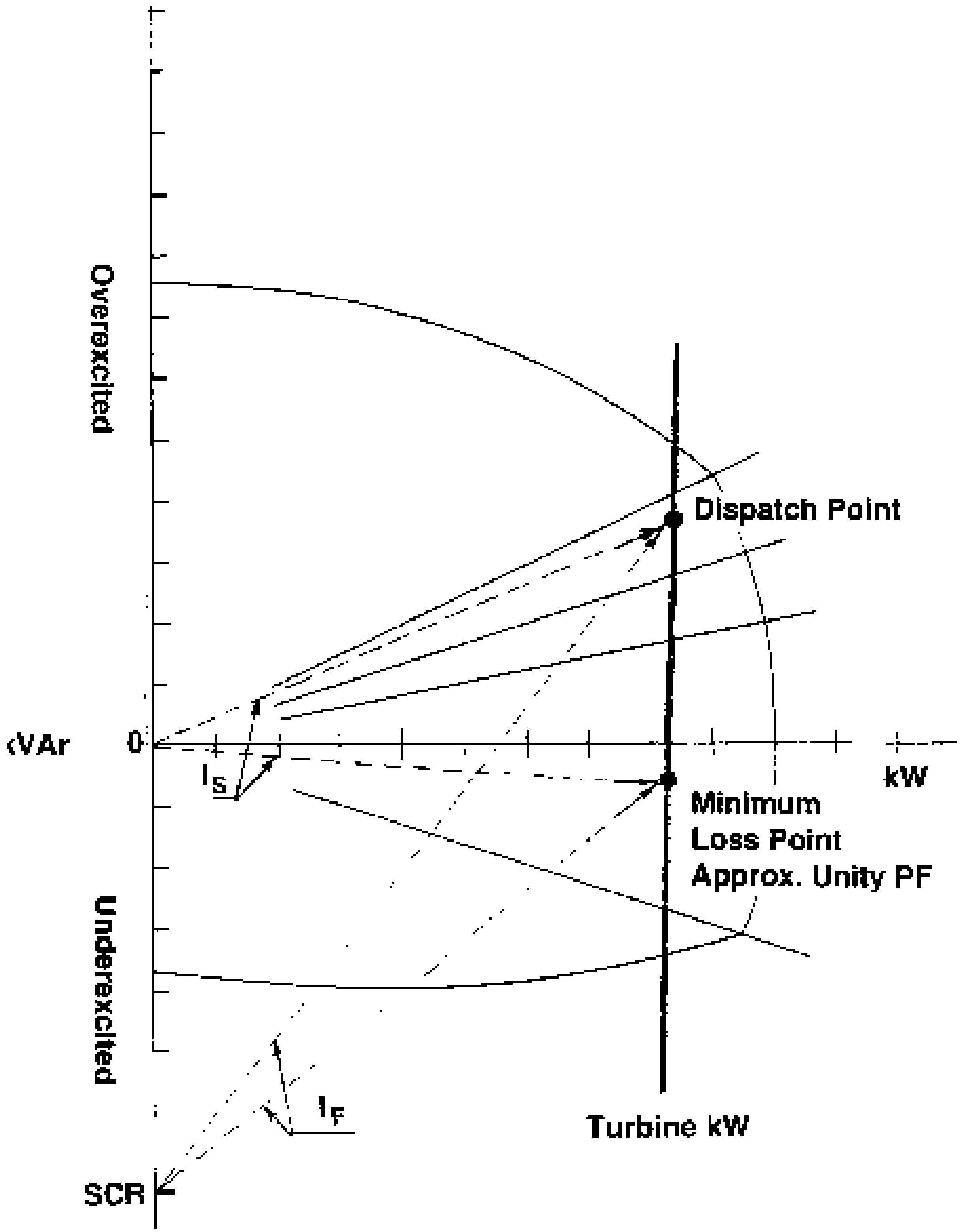
Transformer Variable Losses

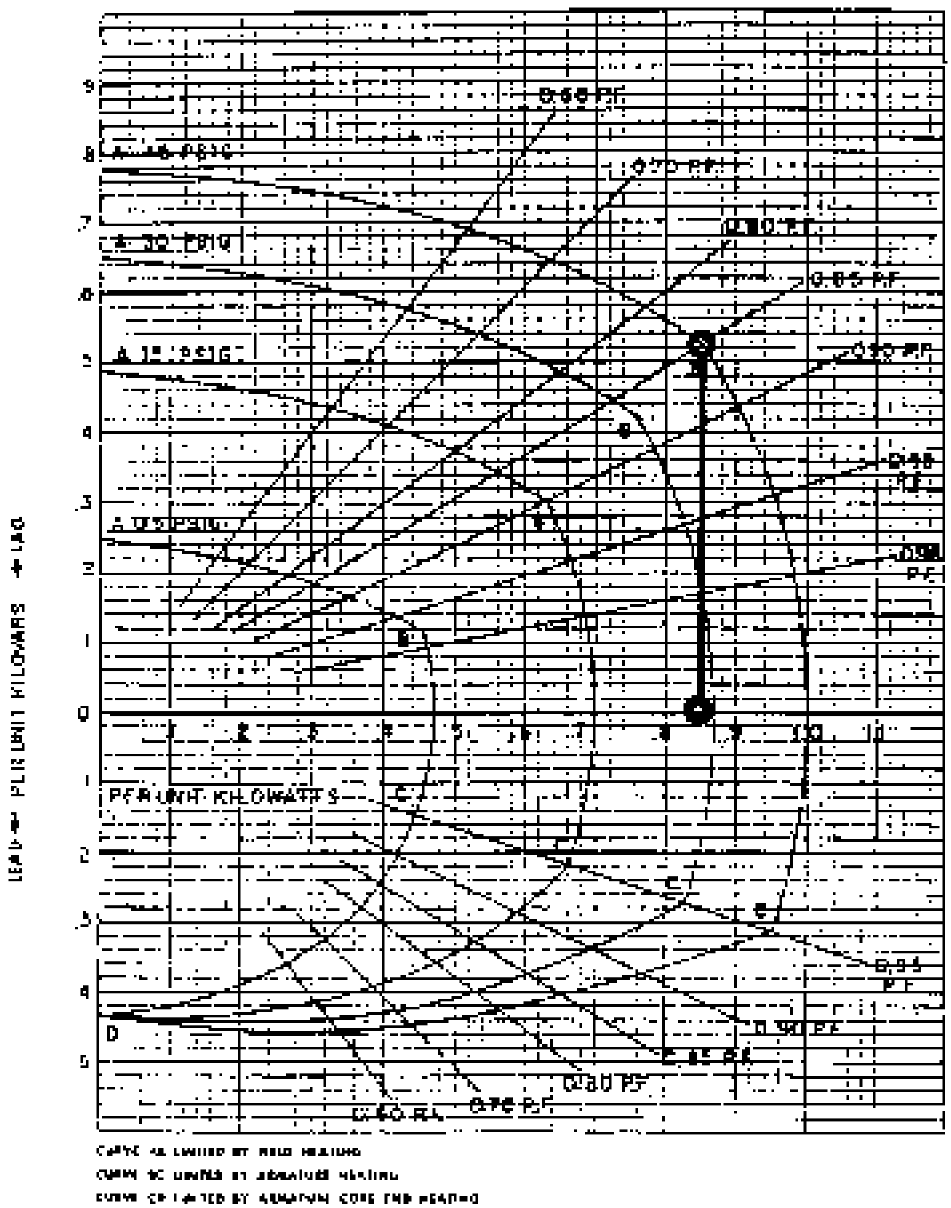
		Guestimate of % of Losses at Full Load
Copper Losses	$(I)^2R$	60%
Iron Losses	$(V)^2$	40%
Total Variable Losses		100%

$$\frac{\text{Total Variable Losses}}{\text{Unit Output}} = 1/3 \text{ to } 1/2\ \%$$

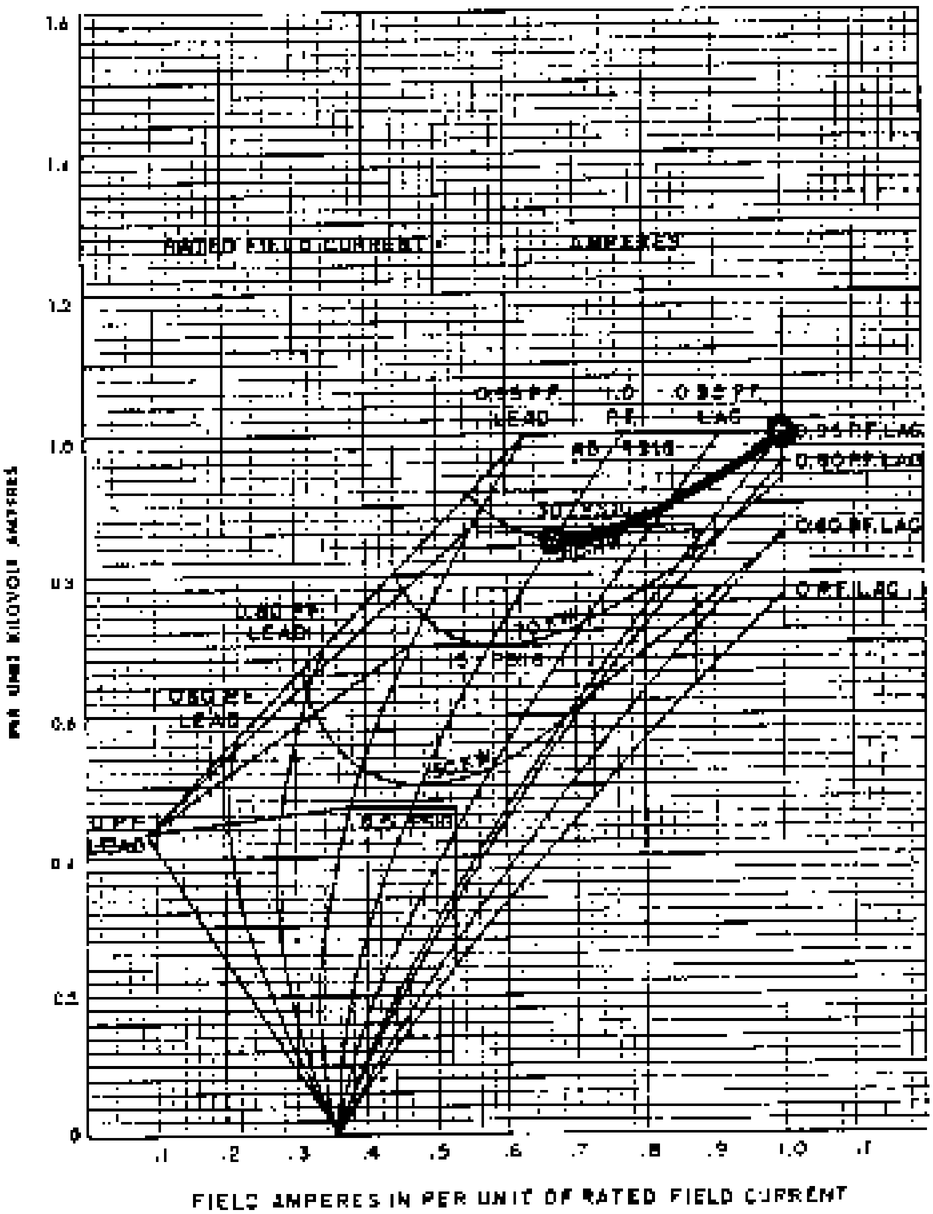


IEEE Standard Method in Phasor Diagram Form

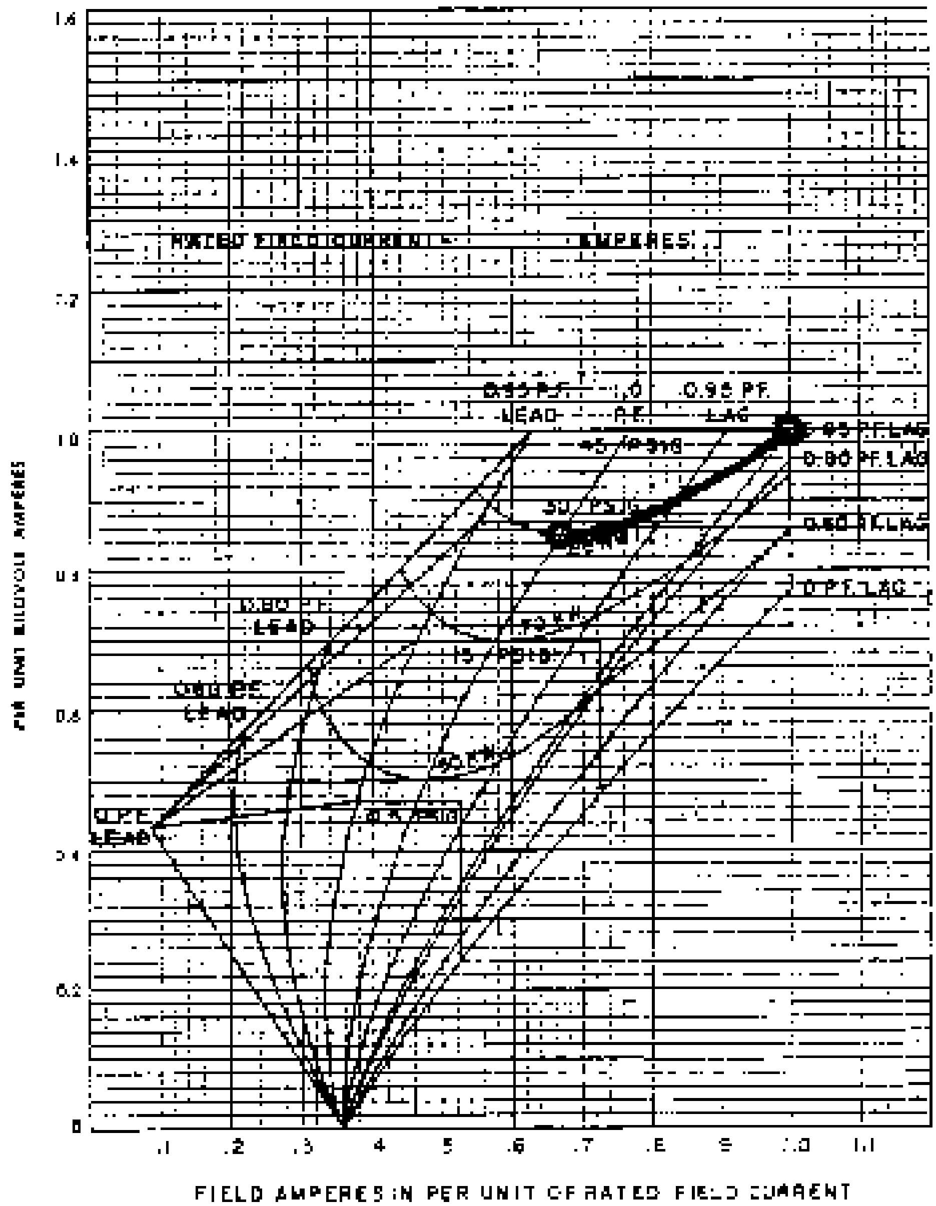

Overexcited
Underexcited
kVAr
0
kW
I_S
I_F
SCR
Dispatch Point
Minimum
Loss Point
Approx. Unity PF
Turbine kW



Typical Reactive Capability curves



Typical "V" curves



Typical "V" curves

Generator Load-Variable Losses

At 0.85 Power Factor (0.85 kW, 0.53 kVAr)
Losses 1%

At 1.0 Power Factor (0.85 kW, 0 kVAr)
Losses 2/3%

Readily Available Data

- Stability Study Data Bank
- Generator / Transformer "Name Plate" Data

Possible Data Sources

- Instruction Books
- Manufacturer Inquiry
- Plant Observations / Test Program

OHMIC Losses - Error Sources

$P = I^2R$

For an error in I of ΔI

$$\left.\frac{\Delta P}{P}\right|_{\Delta I} = 2\left(\frac{\Delta I}{I}\right)$$

i.e., a 5% error in current produces a 10% error in losses.

For an error in R of ΔR

$$\left.\frac{\Delta P}{P}\right|_{\Delta R} = \left(\frac{\Delta R}{R}\right)$$

If the error is due to an error in estimating temperature:

$$\Delta R = R\,\alpha\,\Delta T$$

For copper $\alpha = 0.00393\ /\ ^\circ C$

i.e., a 10°C error in temperature produces a 4% error in losses

Major Stumbling Blocks

1.

- Generator Part Load Efficiency
  Never Historically of Interest
- Loss Variations are Small

2.

- AVERAGE winding temperature, at partial load needed for loss evaluation
  vs.
- HOT SPOT needed to establish equipment rating and guarantees

3.

- VARIATION in coolant temperature needed for loss evaluation
  vs.
- MAXIMUM coolant temperature is specified for rating purposes

Challenge

- Evaluation for transient benefits of the synchronous machine
- Increased security for loss of tie lines

Power Technology

ANCILLARY GENERATION SERVICES

The UK Situation - Power

- System operated by National Grid
- Generating companies bid generating units into pool
  - by 10.00am previous day for each 24hr period
  - provide unit "offer bids" for each half hour period
- Each 'offer bid' contains 39 pieces of information
  - 6 bid-price components (start-up, no-load, incremental costs at 3 load ranges, + max gen.cost)
  - limits/constraints to unit operation (minimum on-time, minimum shut-down time, inflexibility etc.)

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Power Technology

ANCILLARY GENERATION SERVICES

The UK Situation - Power

- Bids ordered to minimise cost of satisfying demand
- Transmission line constraints used to modify actual plant scheduling
- Notification of generating schedule by 3.00pm each day
- All units get the fixed Pool Purchase Price (PPP); special arrangements for constrained plant

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ANCILLARY GENERATION SERVICES

The UK Situation - Power

- SMP (System Marginal Price) based on the cost of the last unit required to operate to satisfy forecast demand
- PPP (Pool Purchase Price) = SMP + LOLP (VLL-SMP)
- PSP (Pool Selling Price) = PPP + uplift
  - uplift is the extra cost of system reserve, transmission constraints, demand inaccuracies, generator availability

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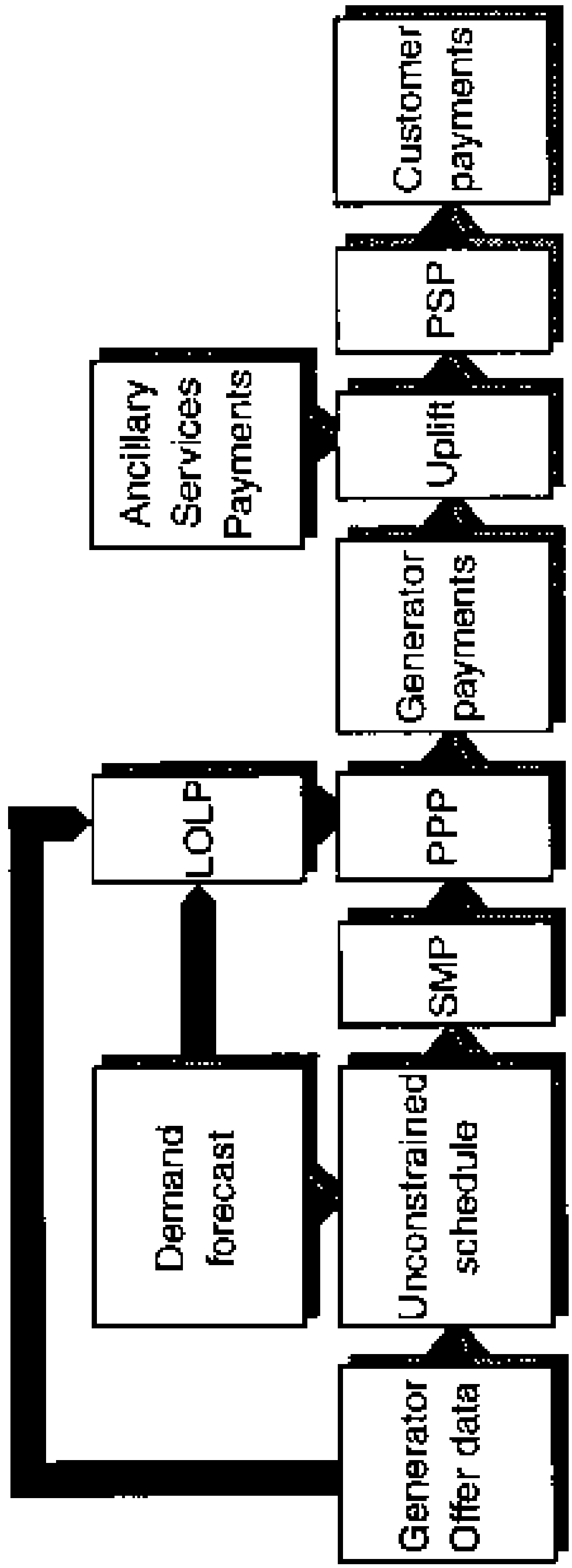
ANCILLARY GENERATION SERVICES

The UK Situation - Power



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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

The UK Situation - VArs

- All generators must comply with a Grid Code document
- Grid Code requires all units to offer VArs between limits of:-
  - rated output at 0.85pf lag
  - rated output at 0.95pf lead
- Generator AVR controls to constant terminal voltage
- VArs controlled by on-load tap-changing
- National Grid requests units to generate VArs to support voltage
- Fixed income provided for VAr support based on declared capability

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ANCILLARY GENERATION SERVICES

The UK Situation - Frequency Response

- Primary response - extra output within 10s and sustained for 20s following freq. drop
- Secondary response - extra output within 30s and sustained for up to 30 minutes
- High frequency response - reduction in output within 10s and sustained for duration of of incident
- Frequency response payments agreed via an annual tender process

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ANCILLARY GENERATION SERVICES - COSTING VArs

Sources of Variable Costs

- Efficiency losses
- Maintenance
- Repair
- Plant replacement
- Others: spares holding
  managing risks
  regulatory obligations

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ANCILLARY GENERATION SERVICES - COSTING VArs

Project Aim

- Identify factors influencing variable costs of generating VAr
- Provide methods to calculate variable costs for:-
  - efficiency losses
  - maintenance
  - plant damage
- Methods and algorithms to be flexible
- Provide means of establishing cost sensitivities
- Provide means of averaging costs over a generation profile

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ANCILLARY GENERATION SERVICES - COSTING VArs

Costs of Efficiency Losses

- Gen/Tx losses calculated for P and Q operating point at Tx HV terminals
- VAr generation loss = Gen/Tx loss at P+Q - Gen/Tx loss at P only
- Costs related to fuel costs not electricity sales price (= kW extra losses x fuel cost per kW/overall plant fract.effy
- Cost sensitivities at given P + Q derived from calculation
- Costs numerically integrated over daily/annual generation pattern

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ANCILLARY GENERATION SERVICES - COSTING VArs

Data Sources

- Generator - Nameplate information
  OC/SC Characteristics
  Manufacturer's works test cert (loss breakdown)
  Rotor and Stator cold resistances
  Excitation current/voltage at various loads

- Transformer - Nameplate information
  Winding resistances
  Manufacturer's works test report

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ANCILLARY GENERATION SERVICES - COSTING VArs

Efficiency Losses

- Generator - Rotor field (I^2R)
  Stator winding (I^2R)
  Stator iron
  Stray
  Exciter
  Friction and Windage
- Transformer - Copper/load
  Iron

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ANCILLARY GENERATION SERVICES - COSTING VArs

Information Flexibility - Generator

Nameplate information	-	use estimate of typical efficiency use typical loss breakdown for m/c type
+ Excitation 'V' curves	-	Back-fit excitation loss algorithm
+ OC/SC Curves	-	Refine excitation loss model
+ Winding resistances	-	Estimate I^2R loss at operating temp
+ Efficiency curve	-	Back calculate loss breakdown
+ Manufacturer's test	-	Full knowledge of loss breakdown and typical winding temperatures

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ANCILLARY GENERATION SERVICES - COSTING VArs

VAr Related Maintenance/Repair Costs

- Variable costs based on historical records
  - maintenance/repair
  - P + Q generation levels
- Assign costs dependent on damage mechanism
  - vibration (wear/abrasion/slackness/fatigue)
  - thermal (overheating/expansion)
- Historical costs corrected to present-day values
- Variable cost for VAr extracted by summing costs for each damage mechanism

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ANCILLARY GENERATION SERVICES - COSTING VArs

Maintenance/Repair - Damage Mechanisms

- Mechanical stress (low cycle)
  - thermal cycling/centrifugal (run-up/down)
- Mechanical stress (high cycle)
  - mechanical - electromagnetic vibration/barring
- Wear and Abrasion
  - vibration/thermal expansion/relative movement
- Thermal ageing
- Electric stress

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Power Technology

ANCILLARY GENERATION SERVICES - COSTING VArs

Examples - Maintenance/Repair Costs

Event	Problem	Mechanism
Stator wedge tightening	Stator vibration	Mainly (I_a^2)
Rotor rebalancing	Displaced end-ring	Thermal (I_a^2.R
Stator coil replacement	Overheating	Thermal (I_a^2.R

Note: where multiple damage mechanisms possible, costs split in proportion to likelihood

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ANCILLARY GENERATION SERVICES - COSTING VArs

Maintenance/Repair Cost Methodology

1. Obtain historical maintenance/repair costs
2. Correct costs to present-day values
3. Split and assign costs to specific task/problem areas (ie. wedge tightening)
4. Apply appropriate damage mechanisms to each task
5. Integrate damage mechanisms over historical operating regime
6. Obtain cost factors for each damage mechanism
7. Apply damage mechanism costs for any future operation

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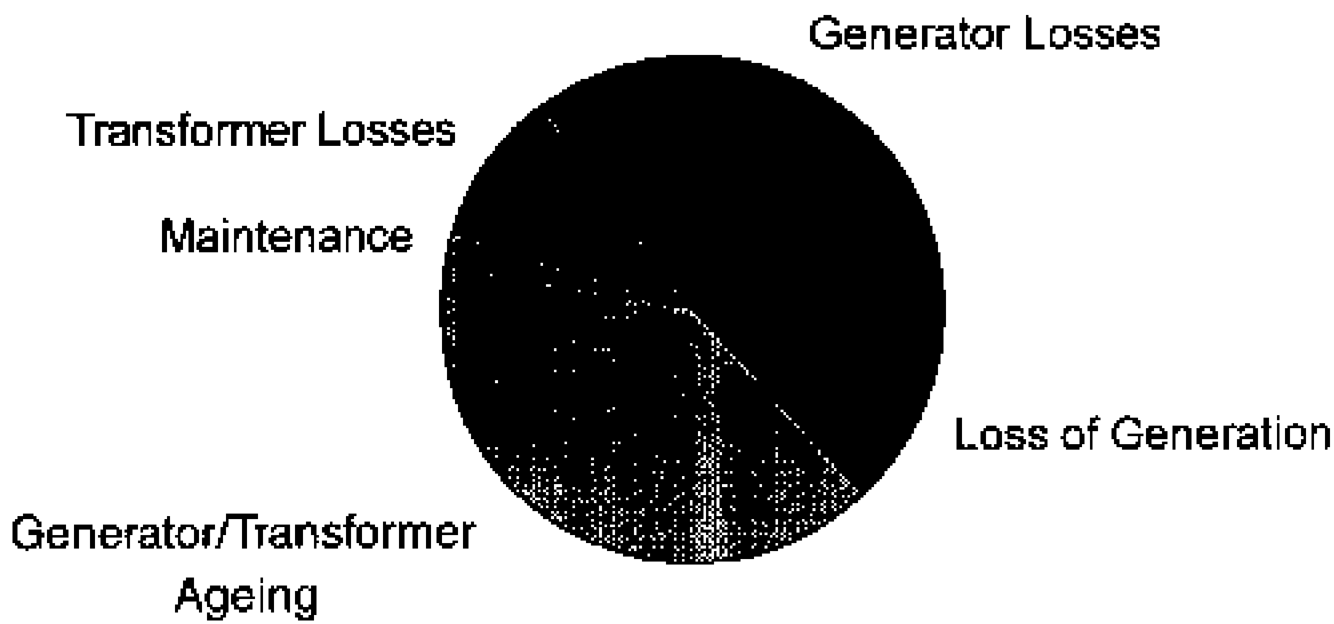
Approximate Relative Costs



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ANCILLARY GENERATION SERVICES - COSTING VArs

Conclusions

- Efficiency losses calculated for VArs at Tx terminals
- Maintenance/Repair/Ageing costs analysed in terms of damage mechanisms
- Historical costs related to plant P, Q generation at Tx terminals
- Future Maintenance/Repair costs predicted via damage mechanisms and P, Q generation levels

POWERGEN

EPRI WO4161-01

Methodology To Determine Cost of Providing Frequency Control

presented by
J. Kure-Jensen, P.E.
Encotech, Inc.
Schenectady, NY

at
Ancillary Services Workshop
April 30 - May 1, 1996
Reno, NV

Sponsored by
EEI Generation Committee
EPRI Fossil Plant Business Unit
Sierra Pacific Power Co.

Cost of Providing Frequency Control

Objective

- Describe method for determining the cost of frequency control
- Obtain comments from workshop

User Requirements

- Method applicable to steam turbine units at power plant level
- For units capable of both frequency control and "optimum" mode operation

Meeting the Needs

- Help utilities that are wheeling power to determine cost of providing frequency control
- Method to be "sound" and accurate enough to stand up to rate making authority's scrutiny
- Simple enough for use by utility without costly testing or large investment

Cost Analysis

- Based on analysis of heat rate penalty rather than testing
- User can evaluate and modify inputs

Strengths / Key Benefits

- A methodology based on data already available at utility supplemented by a small software program to implement calculations

Next Steps

- Provide feedback during following discussion

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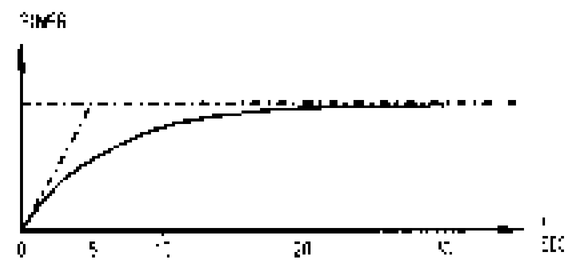
Cost of Providing Frequency Control

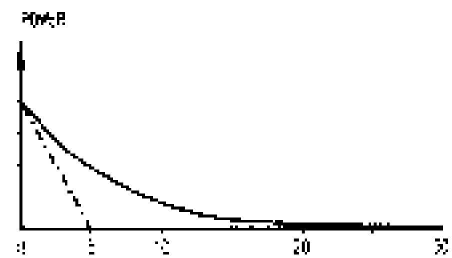
Definition of Frequency Control

- Two sources of frequency control signals:
  1. AGC Signal
  2. Turbine Speed Control
- AGC Change = Frequency Bias + Economic Load Bias − Intertie Bias
  - Frequency bias is updated every 5-10s and requires fast response
- Turbine speed control - acts instantaneously on turbine valves
  - Normal 5% regulation equivalent to 1% load change for 0.03 Hz frequency deviation
- Method evaluates cost of fast load changes, ie. changes within 5-10s and lasting up to 30s

Cost of Providing Frequency Control

Examples of Fast Load Changes

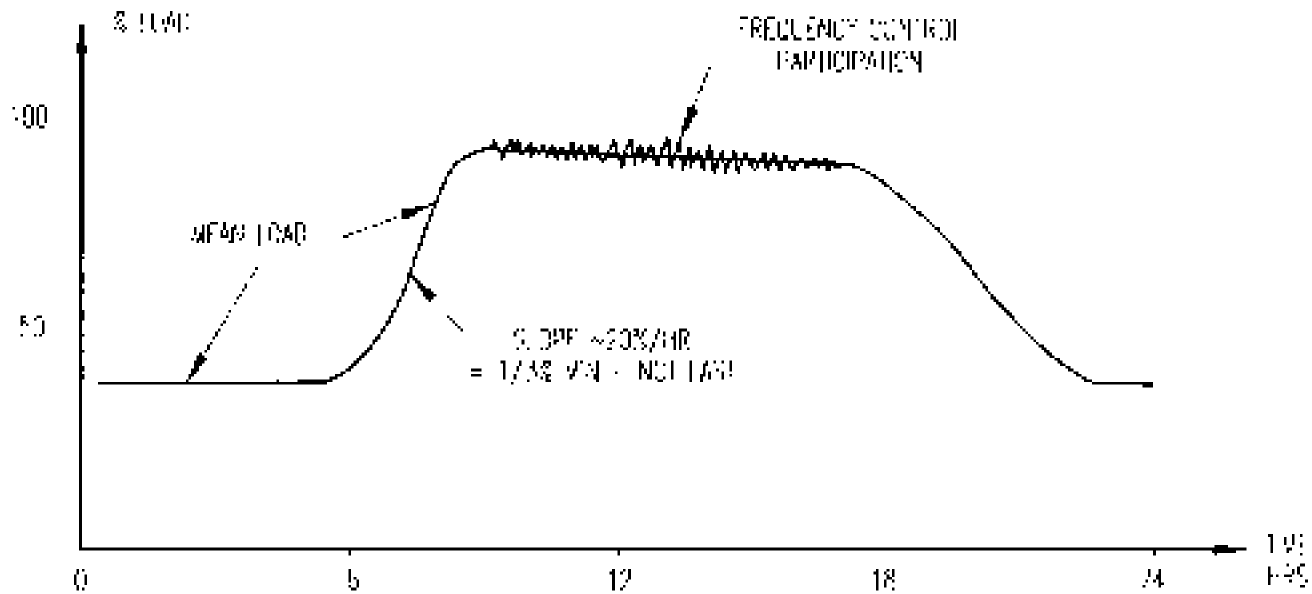




- Any turbine can decrease load fast by closing valves
- Fast increase requires valve(s) that are not wide open, or "throttle reserve"
- Turbine speed control signals will be implemented fast if valves are not wide open
- AGC signals will only be implemented fast if sent directly to turbine controls with unit in "Boiler Follows Turbine" mode.

Cost of Providing Frequency Control

Example of Daily Load Variation



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Cost of Providing Frequency Control

Operating Modes for Cost Analysis

- **Throttle Reserve Mode**: Requires continuous throttling equivalent to required reserve, for example 5% of rated.
  - Throttle reserve leads to heat rate penalty → additional cost for frequency control
  - Frequent load changes reduce boiler efficiency → heat rate penalty & additional cost for frequency control
- **Optimum Mode**: Has no fast load pickup capability and no throttling or frequent boiler load changes. Hence, the potential for better heat rate.
  - Optimum mode must be defined by utility for comparison with throttle reserve mode to determine cost of frequency control
  - Boiler is in quasi steady state operation → best possible operation

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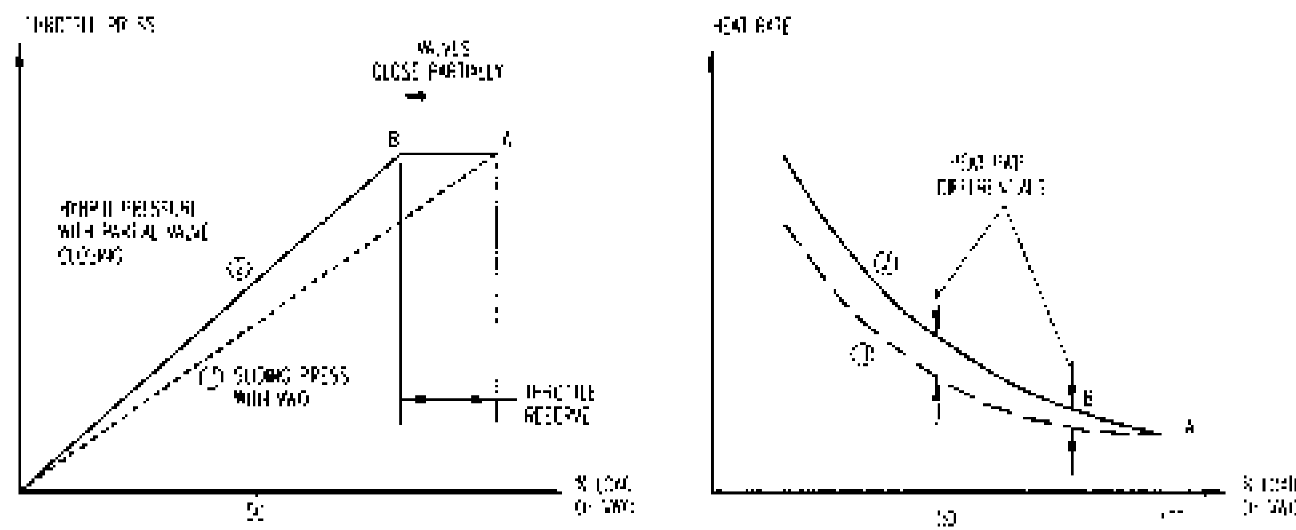
Cost of Providing Frequency Control

Examples of Operating Modes:



Mode (1) *has no Throttle Reserve*

Mode (2) *has Throttle Reserve and has a poorer heat rate*

Cost of Providing Frequency Control

Three Cost Components from Valve Throttling and Load Changes

- **Additional hardware repair due to severe duty possible:**
  - Control valve wear due to throttle duty
  - CV Actuator wear due to frequent motion
  - Thermal fatigue of control stage

These cost elements are not conducive to analysis. Survey of historical repair cost is recommended.

- **Additional Fuel Cost:**
  - Due to differences in heat rate as shown on previous overhead
- **Reduced Boiler Efficiency**
  - Due to continuous or very frequent boiler control adjustments

Cost of Providing Frequency Control

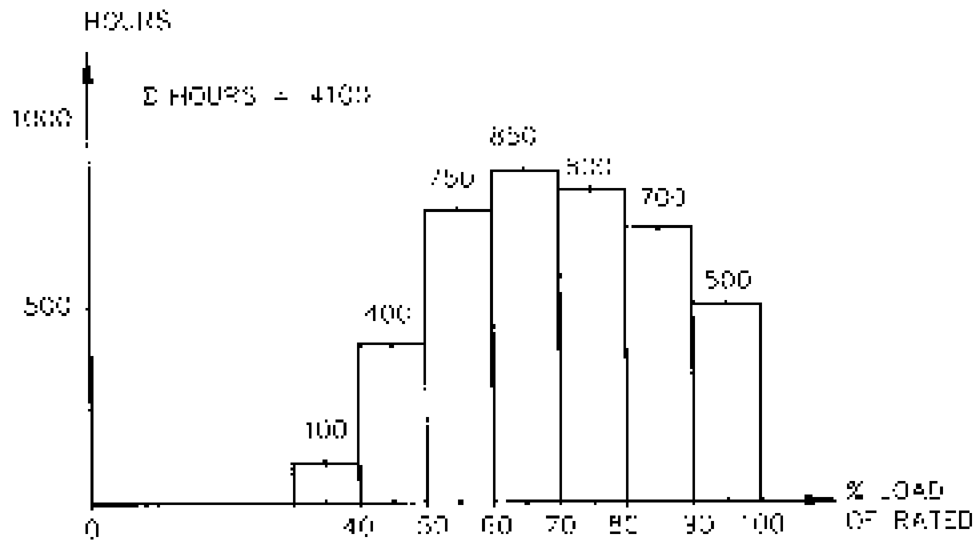
Major Steps of Cost Analysis

1. Define unit to be analyzed; obtain data
2. Determine load range for frequency control and throttle reserve needed
3. Determine time period to be analyzed and load schedule for this period

   Period can be short or long - e.g. one day (24hrs), one week, one season, one year

Cost of Providing Frequency Control

Example of Load Schedule for Frequency Control



- Each bar indicates total hours of operation within a load range. e.g. 800 hrs between 70 and 80% of rated load
- Finer subdivision of load ranges can be used for greater accuracy. e.g. every 5% load range

Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

4. Define operating mode to be used for load schedule

- Main steam pressure schedule, steam temperatures
- Control strategy for turbine valves and entire cycle. e.g. FA/PA, BFP pressure & drive, boiler mode

This mode will be well established if unit has participated in F.C.

5. Define operating mode if unit were not in F.C. mode

- Best possible heat rate for same load schedule

This mode must be realistic and use the exact same plant as the mode for frequency control

Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

6. Determine heat rate versus load for the two modes

- Accuracy must be about ± 10 BTU/kWh
- Would require very accurate testing - not recommended
- Recommended method is computerized thermodynamic model of the steam cycle. Must model correctly effects of the two modes. e.g.

  Valve throttling, efficiency at partload, variable pressure drops, FWH performance
- Calibrate model from existing accurate data. e.g. Acceptance Test-ASME PTC6 or other
- Encotech's SCDP © will be used for case studies

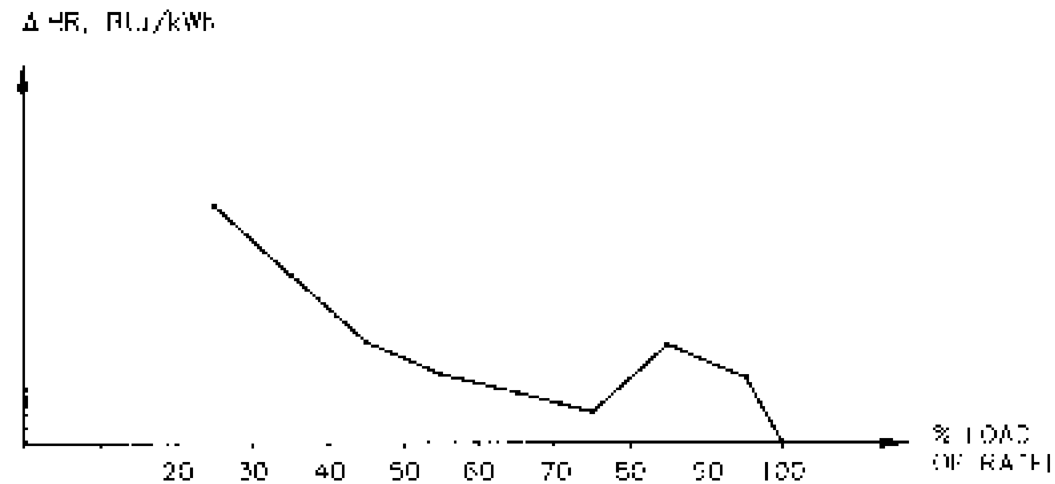
Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

7. Run steam cycle program at each % load point of load schedule for the two modes, and

   Form the difference in heat rate - Δ HR between the two modes in each % load point.

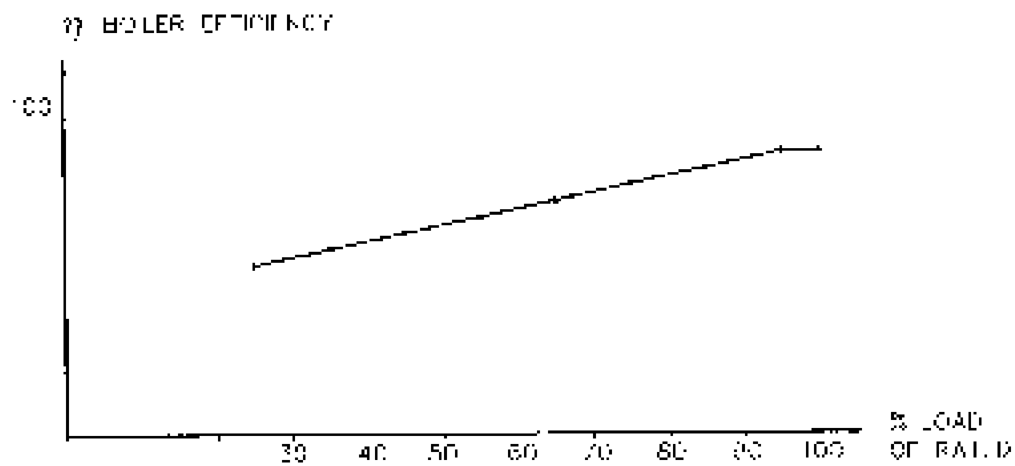
Example:



Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

8. Determine the steady state boiler efficiency (η_{ss}) at the % load points used for load schedule



Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

9. Determine the reduction in boiler efficiency to small, frequent load changes; expressed as a reduction factor, BERF, such that

$$\text{Actual } \eta = \eta_{ss} \times \text{BERF}$$

No analytical derivation of BERF has been found yet. Empirical data must be used. Range of 0.99 - 0.96 has been quoted.

Use best estimate of actual η for cost calculations

- Determine average fuel cost ($/MBtu) over period of study.

Cost of Providing Frequency Control

Continuation of Major Steps of Cost Analysis

10. Use results of steps 3, 7, 8, and 9 as input to new software to calculate the following quantities as a measure of cost.

Generated el. energy = 10^{-2} * kW rating * Σ %LOAD * HRS (kWh)

Heat input penalty for cycle = 10^{-2} * kW rating * Σ %LOAD * HRS * ΔHR (Btu)

Specific heat input penalty = {Σ %LOAD * ΔHR * HRS}/{Σ %LOAD * HRS} (Btu/kWh)

Heat input penalty for boiler = 10^{-2} * kW rating * Σ1/η * %LOAD * HRS * ΔHR (Btu)

Spec. input penalty for boiler

= {Σ1/η * %LOAD * HRS * ΔHR}/{Σ %LOAD * HRS} (Btu/kWh)

Fuel cost penalty = 10^{-8} * kW rating * Σ1/η * %LOAD * HRS * ΔHR * $/MBTU (Dollars)

Spec. fuel cost

penalty = 10^{-3} * {Σ1/η * %LOAD * HRS * ΔHR * $/MBTU}/{Σ%LOAD*HRS} (miles$/kWh)

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Cost of Providing Frequency Control

Special Case of F.C. - Spinning Reserve @ Partload

This case can be analyzed by methodology by:

- Reducing load schedule to single load with hours = spinning reserve duty
- Making Δ HR = HR @ Spinning Reserve - HR for alternate of generating same load
- Run method with this input to determine, e.g. Additional spec. fuel cost = xx Mils$/kWh

Cost of Providing Frequency Control

Next Steps for Methodology

- Absorb inputs from this workshop
- Review with EPRI and sponsoring utility
- Program and run test cases
- Evaluate results - modify as required
- Report and make available to EPRI members

Voltage Regulation
Discussion Group 1

<u>Users (customers/clients)</u>
Gen Sta (plant)
A. Business analyst
  Determining costs Cost
  Bid strategy Price
B. Operations
  Implementers of your business plan

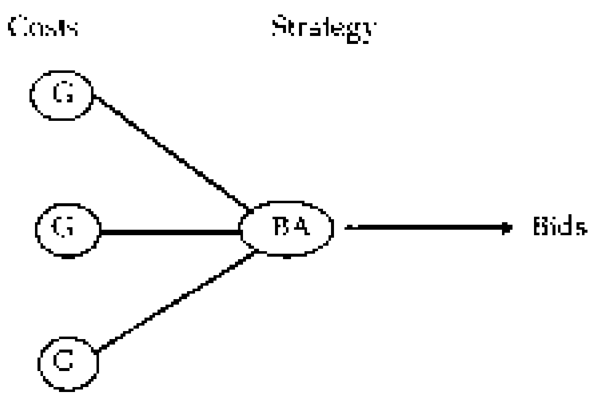
Dispatch Center
A. ESOC
B. GEN
C. Trans.

<u>General Office</u>
Hydro
Fossil Prod
Nukes Prod
Rates
Regulatory
Marketing
Accounting

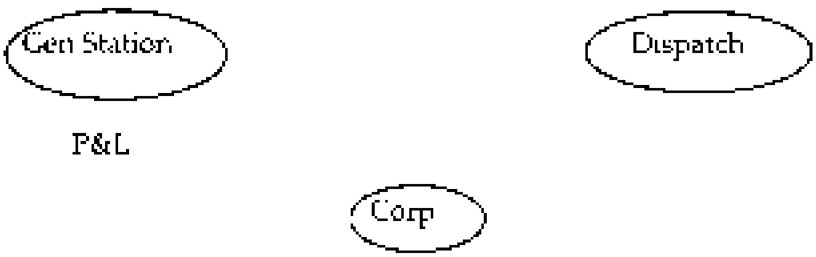
Planning

Regulators - State/Fed

Customers-Wholesale/Retail



Voltage Regulation
Discussion Group 1



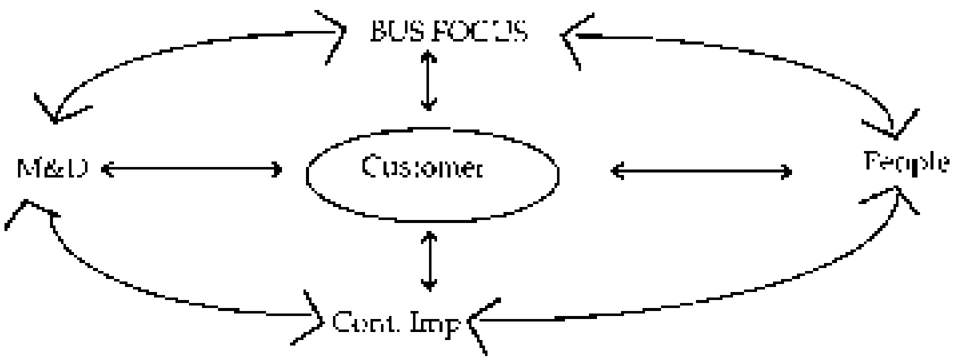
1. Make a profit — Reduce customer cost
   Incr shareholder profit

2. Methodology
   Std Accepted by regulators
   cause/causation

Process Documentation

<u>Suppliers</u>	<u>Inputs</u>	<u>Outputs</u>	<u>Customer</u>
	Data inputs/feeds		Market
Gen Sta	Energy	Value	
	VArs		
Plant personnel	Tech info Costs Opr restrictions "components" Uniform system of accounts Proxy Value -- Data not available		

Voltage Regulation
Discussion Group 1 (Cont'd)



Expectations:

1. Simple (KISS)
    a. consistent
    b. "deadly parallel" (dissimilar)

2. Flexible
    a. calc. $ costs at varying pts
    b. unit specific & system ....

3. "Visual" results

Do Not Want!!
- Energy strategy
- A.N.N.
- Forecasting

Voltage Regulatory
Discussion Group 2

Methodology Users
(Δ = Daily user; + = designed for)

+ Rates group (justify @ FERC)
Δ+ Powerplant operators
Δ+ Transmission supplier
+ Management
+ Regulating bodies
Δ+ System operator (Poolco)
Δ+ Marketing groups
+ End-use customer?

<u>Management Objectives</u>

- Identify costs
- Recover costs
- Causation
- Make money
- Reliability
- Communicate
- Regulatory ease
- New project justification
- Properly allocate costs among participants
- Lower capacity/energy costs

<u>Quantify?</u>
properly allocate costs among participants

<u>Processes for Method</u>
Inputs/Impacts
- Unit capability
- Start up costs
- No load-costs
- Opportunity cost
Losses (unit)

Voltage Regulation
Discussion Group 3

What & Why?
Who are the Users?

Daily Basis	Long-term Focus
Plants	Corp. rate people
-Bidders	
-Business Sect.	
-Operational	
-Fuel	
- Own use	Genco -Central staff
	ISO-Central staff
Regulators	Regulators
-State	-State
-FERC	-FERC
Legal	Legal

Capture all cost to capture variable cost -

Operational data-Gen capability and "V" curve, loss curves

Operational data svs -Design

Daily oper. change for MVAR need

Accounting-FERC account data (314 acct)

Manufactures est. for cost of components

Gen

Turbine

Controls

Worst case scenario -- Peak load with no generation in area

Must recognize role of generator in "Brave new world":

Gen-Always running-base 24 hrs HPE

Intermediate running 12 hrs

Peak running-0-3 hrs

Not normally running

MVArs-cost will vary dramatically

Methodology-must be continually monitoring & reacting to changing world, including political realities (esp FERC reg ancillary pricing to a deregulated Genco)

Voltage Regulation
DiscussionGroup 4

Users of this methodology
(Dept./Div. in parenthesis)

Plant Mgr (supv., engr., mgmt): To allow managing costs & setting prices

Plant Customer (ISO, Retail & wholesale, etc.): To verify how good the deal is. Smarter buyers.

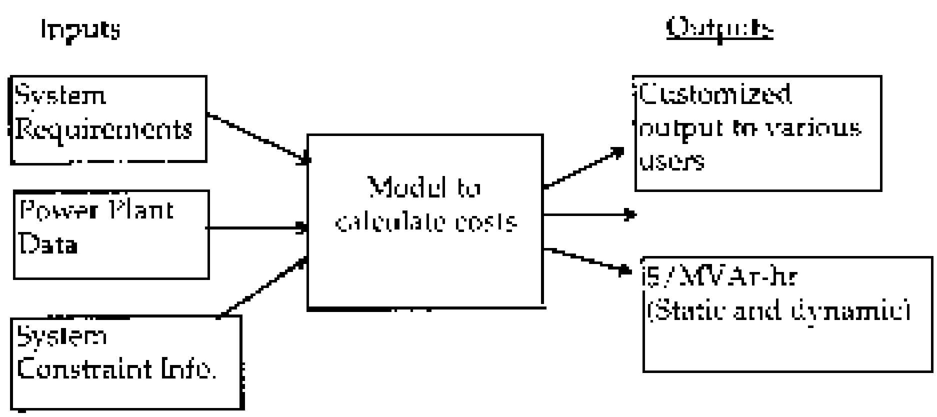
Regulatory (Rates, etc.): To develop accounting systems to track costs; dev. rates; justify with regulators.

Operators (Plant): To control costs in real time.

Gen. Marketers (Not "power marketers"): For pricing services

Management's Objectives
1. Recovery of cost of supply
2. Understand costs (fixed & variable; including system constraints)
3. Manage the costs of supply
4. Develop competitive strategies
5. Manage the supply

Methodology Process



Frequency Regulation
Discussion Group 1

Definitions

- Regulation - moment to moment matching gen. against ties
- Load following: Longer term commitment of resources to meet load (includes regulation)
- Frequency Control: Governor action to respond to system changes instantaneously without operator intervention
- Cycling: unit response to provide regulation and load following
- AGC: cruise control—> system that provides regulation & load following

Reg. moment match ties schedules
Load following include regulator dispatch (manual)

$ACE = T_A - T_S + \beta (F_A - F_X)$
AGC => ACE to zero

Freq. reserve - Reg. 10 sec load

Planner Definition
Regulation, load following, frequency control --> capability versus needs

Rate Definition = Money ($)

Marketing = Money ($)

Plant (all)
Unit efficiency, (not system) maintenance

System Operations
Compliance (A_1-A_2)

Common Ground
Cost to supply services
Adequate recovery
Terms-->see NOPR ruling

Frequency Regulation
Discussion Group 1 (Cont'd)

<u>Processes</u> (Frequency)
<u>Inputs</u>

- Which units provide
- Type, size?
- Governor characteristic
- Fuel

Could categorize

<u>Processes</u> (load following)
<u>Inputs</u>

- Unit characteristics
- Load type & location (ramp rates, etc.)

<u>Processes</u> (regulation)
See above plus

- Unit control systems
- Non-economic dispatch
- AGC
- Maintenance costs

Users-<u>Method</u>
Address are furnace

- Units providing service
- location
- ramp

Frequency Regulation
Discussion Group 2

Regulation & Frequency Response Service (Not load following)

Definition
--Extra generation capacity, called Regulating Margin to follow moment to moment changes in load/generation within a control area, for purposes of maintaining system frequency at 60Hz.

Frequency Control/AGC/Cycling
Covered in above definition

Cost of Providing Service
O&M (non-fuel)

- Governor
- Control Systems (AGC, etc.)
- Telemetering
- Wear & Tear (turbines, generators, auxil. thermal, mechanical, elect.)
- Personnel? (training, "head count")

O&M (fuel)
Efficiency

- Unit eff.
- Auxiliaries
- Stabilization
- Head loss (Hydro)

Capital

- Gov./Contr. Syst./Telem.
- EMS

Stakeholders
Plant managers
Plant Operators
Schedulers & Dispatchers
Engineering
Marketers
Rate Analysts
System Planners
"Customers"

Frequency Regulation
Discussion Group 3

Load Following

Frequency control
Cycling
AGC

Dispatchers
System planners
Rates
Markets
Plant manager
BA
Production engineers

Load Following

Disp.'s - actual vs scheduled
Sys. Pln - (not a concern) planning
Rate -- (not a concern today) today/tomorrow
Marketers -- (can they sell/buy it)
Plant managers -- Cost development
    BA -- Cost development
    Production Engineers -- Cost development

Load Following = Ability to match supply and actual demand over a period greater than 10 minutes

Frequency Control
Disp's -- I.O. clear to go
Sys pln -- N/A (trans studies)
Rate -- how to cost it!
mktrs -- (not int'd)
Plant managers -- cost of maintaining the governor
    BA
    Production

Frequency Control - The ability to instantaneously respond to freq deviations. i.e., govn'r response NO human intervention.

Frequency Regulation
Discussion Group 3 (Cont'd)

<u>Cycling</u>
Disp's -- unit on/off
sys planner -- model
rate -- (not a concern)
mktrs -- add'l piece of data
plant -- do not want to!
managers — high O&M / $ LOL / cost model

Cycling =
A. on/off operation
B. move unit from min/max/min... .. ....

<u>AGC</u>
Disp -- provides "auto" operation of a unit for purposes of: L.F., control area obligation, spinning reserve

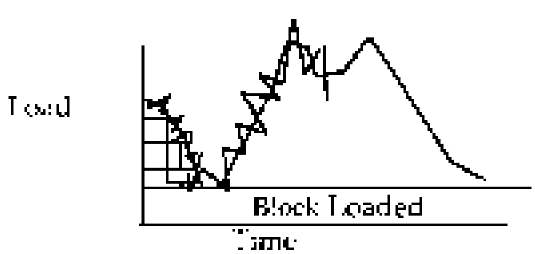
sys plnr--n/a
rates--provide/pay
mkts -- n/a
plant mngr --very interested!
BA Value vs. <u>Cost</u>
PE

AGC The ability of a unit to "automatically" respond to a control signal!

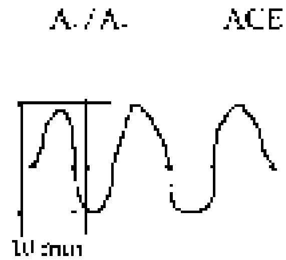
<u>Tie Line Thermal BU</u>

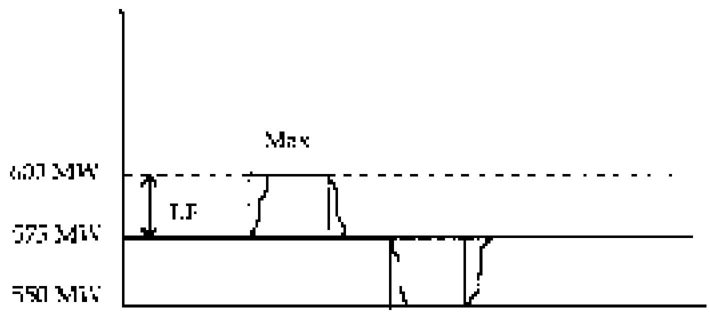
oper. reserve--
shared reserves--
spin--?--> 10 minutes
given: synchronized S. can produce its offer

supplement -----> 10 Q.S., L.D.



Frequency Regulation
Discussion Group 3 (Cont'd)





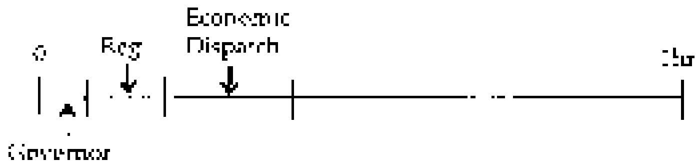
Methodology--See it'

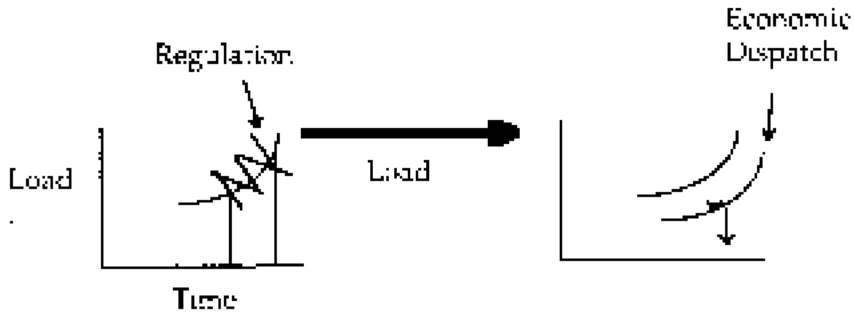
A. Consistent with FERC ruling
B. Simple, institutionalized
C. "Roll up" into sys. cost
D. Dynamic/Static? (time dimension)

Frequency Regulation
Discussion Group 4

$ACE=T_A-I_S + B(F_A-F_S)$

Time Scale





Unit viewpoint

Determine price for unit to be on AGC
- Cost
  - Not at most economic point
  - Causing unit damage

Unit of AGC-Unit response
Premium for rapid responding units
Fuel cost versus actual wear & tear on the units for regulating?

Opportunity costs that are lost
Daily cycling of units & min to min cycling

Frequency Regulation
Discussion Group 4 (Cont'd)

Stakeholder: Plant Managers
Producers Side: What are costs
Load following: AGC or manual
- Balance Gen w/load over time
- Obligations & requirements to follow directions via contract?

Governor Response
- Fix gov. (maint)
- Maintain "room" not optimal point
  - Heat rate
  - Lost MW
  - Added Maint
  - Capacity value
- If $ incentive may see better GR.
- Benefit of providing this service??
- Depends on Area Eastern Inter.
- Have not identified a "Benefit"

Cost to Regulate Automatic (AGC) (2-10 sec; 0-5 min)
- Lost opportunity
- Heat rate losses (more than for GR? Could be 100-200 BTU per hour) [Large Cost!]
- Added war/tear (control valves: 1%)
- Increased maint. (boiler tubes: turbine)
- Environmental penalties are possible
- Used as other ancillary services (reserves) [Benefit]
- Higher metering maintenance costs

Cost to Regulate Manual (10-15min)
- Less lost opportunity cost
- Steam (sync) or peaker / hydro units

Staffing more/same/skills
- Contract services
- Operating cost: Nobody to operate equipment