## Chapter 5

# Technological Requirements and Performance Under Increased Competition

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## Chapter 5
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## INTRODUCTION

**Proposals for increasing power industry competition raise challenging questions of technical feasibility and cost.** What technological requirements does competition raise? What would meeting those requirements cost, and how would reliability be affected? What is required to make a competitive proposal workable?

**The answers depend on the type of competition envisioned. The five** scenarios of chapter 3 present widely varying visions of power industry change, each with its own specific technical questions. While each scenario is unique, they share two fundamental competitive changes:

- expanded generation market-more companies allowed to enter and compete in supplying electricity; and
- expanded transmission access—a widened avenue of exchange between competing generators and purchasers with the involvement of the local utility restricted to transmission services.

Both types of change involve unbundling, or separating, of generation from transmission to different degrees.

**Power industry competition may take a variety of forms depending on how and to what extent increased supply competition and expanded transmission access are implemented.** For example, supply market competition may unbundle all generation from transmission (scenarios 4 and 5). Alternately, competition may be limited to some (scenarios 1 and 2) or all (scenario 3) new generation only, leaving existing generation under the ownership and control of integrated utilities. Competition in new generation may be limited to certain suppliers, such as facilities qualifying under the Public Utility Regulatory Policies Act (PURPA), or may include other independent power producers as well as new utility generation.

Similarly, alternatives for expanding transmission access range from encouraging further voluntary wheeling (all scenarios) to mandating wheeling among utilities (scenarios 2, 3, and 4) or for large retail customers (scenario 2) to entirely unbundling transmission from both generation and distribution so that all power is wheeled power (scenario 5).

Chapter 5 examines the technical feasibility and costs of the changes that will be required by increasing competition. It also summarizes the general technical and economic impacts of competitive change in the electric power industry. Next are analyses of the challenges of increasing the number of separate bulk power suppliers and those posed by expanded transmission access. This is followed by a review of the cost and performance of the current utility structure, examining where economic performance of industry changes may lie. The last section summarizes the technical issues raised by each of the five scenarios discussed in chapter 3.

In this chapter, the impacts of competition are viewed from a system coordination perspective. As described in chapter 4, all the individual generation and transmission components of a power system must be coordinated. No matter what form competition takes, no matter what the extent of expanded markets, some system will be required to coordinate planning and operation of the individual pieces. Even if the ownership of generation, transmission, and distribution is entirely separated (scenario 5), there still has to be a highly sophisticated system to coordinate planning and operation.

Throughout this chapter, it is assumed that the competitive changes should not result in degradation of the reliability of a power system. This assumption is necessary to keep separate the consequences of competition from other unrelated decisions. For example, service reliability could be reduced deliberately to lower the cost of service or to better match consumer preferences under any scenario. However, by accepting reduced reliability in one scenario but not in another, comparisons of the effects of competitive measures on planning and operating procedures and on physical system requirements would not be meaningful.

## OVERVIEW OF TECHNOLOGICAL IMPACTS

**The technical feasibility of increased competition depends largely on developing new approaches to coordinated planning and operation of the bulk power system. Defining workable institutional arrangements between the participants in the power system is a fundamental requirement. Implementing these new institutional relationships may also require adding some new physical facilities and improving analytical capabilities.**

As discussed in chapter 4, a power system is a vast, complex machine composed of many interacting generators, transmission lines, and distribution systems. A reliable, economic supply of electricity requires carefully coordinated operation and planning of the individual generating units and transmission lines that comprise the bulk power system. Coordinating the bulk power system involves three main functions:

- following changing loads to balance the supply of power with ever-changing demand,[1]
- maintaining reliable operations, and
- coordinating power transactions between interconnected systems.

Typically, these functions are performed in a way that minimizes cost. Many operating and planning procedures are involved in performing these functions (see table 5-l). The procedures range from the immediate (e.g., regulating frequency) to the long term (e.g., planning and constructing needed new supplies) and reflect electricity's complex physical laws.

In today's power systems, the responsibilities for coordinating planning and operation belong to a single utility or group of cooperating utilities.[2] Current utility approaches to planning and operation assume relatively centralized control and decision-making, with a system-wide objective of providing reliable and economic service. The control areas formed by one or more utilities are responsible for regulating frequency and voltage, and coordinating power interchange. They have control over generation and transmission components needed to meet that responsibility. Unit commitment and maintenance scheduling are the responsibilities of the utility owning the equipment, or the utility's power pool. Planning new supply resources and transmission facilities is typically a utility responsibility, often performed with considerable regulatory oversight and review by the North American Electric Reliability Council (NERC) region and local pool to assure reliability.

**Unbundling generation and transmission creates a more complex planning and operating environment by defining new rights and responsibilities for suppliers, purchasers, and transporters** of power. The changes modify basic operating and planning assumptions by raising the number of separate players, each seeking their own economic benefit.[3] Unbundling creates a gap between the entity responsible for coordinating the overall power system and the ownership and final control over the system components.[4] As the number of players grows and unbundling increases, control and decision-making authority is increasingly dispersed. Operations will increasingly depend on individual agreements between generators and purchasers (and in some cases, transported), and will not necessarily

[1] This balancing involves both active and reactive power.

[2] Note that coordinated operating and planning neither implies nor requires ownership by a single entity or small group. For example, in the New England Power Pool (NEPOOL), around 100 separate utilities coordinate their planning and operation, sharing in the resulting benefits. In addition to the multilateral pooling agreement, there are several hundred bilateral arrangements between NEPOOL members that specify how overall benefits are allocated.

[3] Note that it's not necessary t. greatly increase the number of separate players to greatly modify basic operating and planning assumptions. For example, a vertically integrated utility could be separated into one generating company and one transmission/distribution company (possible in scenario 4). In this case, the number of players increases by only one. However, the resulting interactions between the two companies would be all new and substantially different from what had existed before with a single integrated company.

[4] Recall that in the scenarios as discussed in chapter 3, as a practical matter responsibility for ensuring adequate supplies remains with those closest to the customers, i.e., the companies performing distribution or the customers themselves under retail wheeling. This is true no matter if all supply is competitive and owned separately from the transmission and distribution functions or if a competitive market supplies only portion of new capacity needs for vertically integrated utilities, Similarly, responsibility for coordinating all system components must rest largely with the companies performing transmission, since it is the transmission network which provides the link between components.

**Table 5-1--Operation and Planning Functions**

| Function | Purpose | Procedures involved |
|---|---|---|
| ***Following load*** | | |
| Frequency regulation | Following moment-to-moment load fluctuation | Governor control<br>Automatic generation control (AGC) and economic dispatch |
| Cycling | Following daily, weekly, and seasonal cycles (within equipment voltage, power limits) | AGC/economic dispatch<br>Unit commitment<br>Voltage control |
| ***Maintaining reliability*** | | |
| Maintaining security | Preparing for unplanned equipment failure | Unit commitment (for spinning and ready reserves) security dispatch<br>Voltage control |
| Maintaining adequacy | Acquiring adequate supply resources | Unit commitment<br>Maintenance scheduling<br>Planning Capm"ty expansion |
| *Coonlimting* ***transactions*** | Purchasing, selling, and wheeling power in interconnected systems | **AGC/economic eispatch**<br>Unit commitment |

SOURCE: Adapted from F. Mobasheri, Southern California Edison, letter to OTA, May 13, 1986.

focus on overall power system needs. This may affect both reliability and economy.

For example, selecting which supplies to commit and dispatch is currently performed centrally by integrated utilities at energy control centers. The objective is to minimize operating costs (i.e., economic dispatch and scheduling) constrained by reliability requirements and equipment limits. With competitive generation or retail wheeling, the selection is further constrained by the arrangements between supplier, transporter, and purchaser. As a result, in some instances an unschedulable supply may operate even when lower operating cost resources are available.

**With increased unbundling, new institutional arrangements must accommodate both the changing abilities and economic incentives of power system participants and the technical characteristics of electricity. The** new operating and planning procedures must specify priorities for the use of constrained facilities, information flows between parties, and incentive and enforcement schemes. As in today's power systems, the arrangements may include formal contracts between the parties as well as less formal agreements on standards and procedures. Operating agreements and standards may be developed through multilateral organizations (such as NERC and the Institute of Electrical and Electronics Engineers) or bilaterally. In addition to the agreements between suppliers, transporters, and purchasers of power, other arrangements must specify the role of regulatory agencies and other interested institutions.

As unbundling increases, bilateral and multilateral contracts will be increasingly important instruments to communicate needs and define obligations of suppliers, transporters, and purchasers of power. By specifying prices and performance, including penalties for failure to perform, contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties. However, contracts may have some shortcomings when compared to arrangements within a single organization, as in a vertically integrated utility, For example, given the tremendous uncertainty in the power industry, anticipating all the terms and contingencies which a contract should cover requires extensive effort. Even with carefully crafted and flexible contracts, unexpected events outside the scope of the contract may occur.

**Implementing new arrangements may require some changes in physical facilities. New** monitoring and communication equipment may be needed to track and control the new unbundled transactions occurring. Additional transmission capacity may be required as the pattern of loads and supplies changes. Additional reserves of generation and transmission capacity may be needed in the face of increased uncertainty about how well the new institutional arrangements will perform. Alternately, if competition produces improved performance of generating units, reduced reserve requirements may result.

**New or improved analytical methods may be needed both in developing and implementing new procedures.** Many attributes of power systems central to planning and operation are not easily quantified. For example, the availability of additional transmission capacity at any moment is challenging to calculate and somewhat subjective. The value of such generation characteristics as fuel diversity and level of dispatchability is similarly hard to quantify. And as noted by Edison Electric Institute, "In virtually every form of coordination sale, there are subjective determinations and uncertainties which are generally not susceptible to simple quantification for purposes of regulatory adjudication. Many of these uncertainties relate to the potential impacts on system reliability of a particular transaction. "[5] As the functions currently performed by integrated utilities are unbundled and provided by different parties, accurate measures of the performance of each party and calculation of the cost or value of their contribution to the power system will become increasingly important. Evaluating performance is essential for developing prices and priorities, a prerequisite for a functioning market.

**There has been little analysis of the reliability or economic impacts of competitive proposals. The** past decade brought some competitive experience to the industry.[6] PURPA advanced new opportunities for qualifying facilities (QFs) to generate power using untraditional technologies using cogeneration, renewable, and waste products. Some utilities and State regulatory agencies have gained considerable experience in integrating these QFs. A few proposals for non-QF independent power producers using more traditional generating technologies have also been advanced. One is slated for operation in 1989 (see box 5-A on the Ocean State Power Project.) A few experiments based on more flexible pricing have given some utilities expanded transmission access. Analyses of the cost and performance are still to come.[7] These competitive changes continue to play a prominent role in the evolution of the industry. However, many current competitive proposals reach well beyond the experiences gained in the past decade, The lack of experience in widespread wheeling and in competitive generation of unrestricted size, type, kxation, and penetration results in substantial uncertainty over how well the system would work under the scenarios.

How suppliers, purchasers, and transporters of power will respond to any competitive proposal is speculative. It is this individual behavior and how it is coordinated, however, that determines the real feasibility, reliability, and economic impact of increased competition in the electric utility industry. The costs and benefits of increased competition depend not only on the cost of developing and implementing the new procedures but on how those procedures affect the efficiency of the current utility structure and encourage improved performance.

This study has identified no insurmountable problems of technical feasibility with any of the scenarios, although there are some substantial institutional challenges of developing new planning and operating arrangements. The ease or difficulty of implementing the institutional changes to meet technical requirements is necessarily speculative. For the scenarios with incremental competition in generation and controlled transmission access (scenarios 2 and 3), some view the institutional changes as relatively easy to develop; others believe there will be considerable difficulty. However, growing experience indicates that some forms of scenarios 2 and 3 are feasible. Major system-wide changes raise considerable uncertainties and risks to reliability and economy. Separating all generation from transmission (in scenarios 4 and 5) raises the greatest risks. Both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new procedures for such extensive changes.

[5] Edison Electric Institute: FERC Docket RM85-17-000 (Phase I) Comments of Edison Electric Institute, Aug. 9, 1985, p. 10.

[6] See ch. 6 for more discussion of State and utility experiences.

[7] These include the Western Systems power Pool, in operation from ]987 through 1989; and its precursor, the 2-year Southwestern Experiment which ended in 1985 (see boxes on the Western Systems Experiment, and the Southwest Experiment later in this chapter).

**Box 5-A—A Partly Independent Power Producer: The Ocean State Power Project**

In August 1988, the Federal Energy Regulatory Commission (FERC) accepted a power sales agreement for the Ocean State Power Project (OSPP) in Rhode Island. OSPP will use a single 235 MW natural gas-fired combined cycle unit, with a possible second unit at a later date. It is the most advanced example of a large independent power producer (IPP) that is not a qualifying facility under the Public Utility Regulatory Policies Act. While only partly independent of utility ownership, OSPP is one model of a non-QF independent power producer.

**Ownership**

OSPP is a partnership of private developers and electric utilities. Fifty percent interest in the plant is divided among several affiliates of the electric utilities purchasing some of the power output.[2] They are:

- 25 percent Eastern Utilities Associates, parent of Montaup Electric Co.;
- 20 percent Narragansett Energy Resources, affiliate of New England Power Corp.; and
- 5 percent NECO Power, Inc., subsidiary of Newport Electric Corp.

A subsidiary of TransCanada Pipelines has a 40 percent interest. (Another TransCanada subsidiary is OSPP's natural gas supplier. ) The remaining 10 percent interest is held by affiliates of J. Makowski.

According to FERC, with respect to the above utilities, OSPP would not qualify as an IPP.[3] However, a substantial portion of OSPP's power will be sold to Boston Edison, which has no financial interest. With respect to Boston Edison, then, OSPP would qualify as an IPP.

**Operation**

Although not owned primarily by electric utilities, OSPP will operate as a traditional utility generating unit. In New England, the New England Power Pool performs economic dispatch based on generating unit operating costs and system operating requirements. Because of the high operating efficiency of OSPP's combined cycle unit the project developers expect that the plant will generally operate as a base-load unit.[4] Plant operation is expected to begin in 1990.

[1] *Ocean State Power*, Order Accepting Amendments to Power Sales Agreements, FERC Docket No. ER88-478-000, f@. 19.1988. Also, Ocean *State Power, 38* FERC 61,140 (1987).

[2] *Electric Utility Week*, May 23, 1988.

[3] *Ocean* side *Power*, Order Accepting Amendments to Power Sales Agreements, FERC Docket No. ER88-478-000, Aug. 19, 1988, footnote 28.

[4] J. Makowski and C. Riva, "Gas Fired Electricity: The Ocean State Power Project," *Energy Technology XIII: Energy in Transition*, Government Institutes, Inc., March 1986, pp. 189-198.

# INCREASING SUPPLY COMPETITION

This section examines the effects of extending current coordination systems to an increasingly competitive supply market. The challenges of increased wheeling are left to the following section.

In today's power systems most generation is owned and operated by vertically integrated utilities which also own and operate the transmission and distribution systems. However, **there is already a moderate and increasing amount of competitive supply in use employing a variety of generation technologies and forms of ownership.** Competitive suppliers of electricity include:

- PURPA QFs, either cogenerators or small power producers using a variety of untradi-*tional* supply technologies and fuels;
- non-QF independent power producers (IPPs);
- utilities with surplus capacity; and
- foreign electricity suppliers, most notably Canada.

Developers of demand management programs *may* also play a role in increasing competition.

**The physical performance capabilities of competitive suppliers may present both challenges**

**and opportunities to coordination.** For example, some cogeneration units may be inherently less responsive to controls than a typical utility generator. However, those same cogeneration units may also bring the planning and operating benefits of reduced construction lead time, lower capital and operating costs, higher availability, and smaller unit size. The physical characteristics which determine the value of a generator are diverse, including such factors as size, location, construction lead time and cost, ramp rates, dispatchability, voltage and VAR output, fuel type, operating efficiency, and reliability, as described in chapter 4.

Modem planning and operation systems have a demonstrated ability to integrate a wide variety of supply technologies, exploiting the advantages of each. Whether that ability can be extended to coordinate an increasingly competitive supply market depends on two factors. First, does the generation technology used by competitive suppliers raise unique technological challenges? For example, is the equipment used in a cogeneration or independent power facility inherently less responsive to controls than typical utility generation? Second, do the arrangements between the competitive suppliers and purchasers provide the appropriate information and control to coordinate generator operation and planning?

Challenges caused by most generation equipment should be relatively minor or nonexistent. In fact many competitive suppliers-particularly IPPs, utilities with surplus low cost capacity, and foreign imports-may use traditional generating technologies (see box 5-A). The performance capabilities of even those competitive suppliers using cogeneration and less traditional technologies and fuels often produce power with characteristics within the wide range commonly found in today's utility generation equipment.[8]

Some generating units, notably those using wind or solar power and in some cases, cogeneration, have variable power output, unlike traditional utility resources. For example, power may vary regularly with the sun's daily cycle or may change suddenly as clouds block the sun, winds gust, or industrial facilities change steam requirements. These technologies, often grouped together as dispersed sources of generation (DSGs) have been widely used as QFs under PURPA. The technical literature has discussed many aspects of the growth of DSG plants on utility system planning and operation.[9] Many technical problems of the relatively small-sized DSGs are due to the combined effects of the operating characteristics of these plants and the fact that they are often connected to the utility network at distribution voltage levels.

Conservation and load management may also play a role in more competitive supply markets. Many U.S. utilities actively promote conservation and load management as alternatives to traditional supplies. While the cost and operating characteristics of conservation and load management options vary widely, many have some operating characteristics similar to supply resources.[10] For example, interruptible rate programs, which allow utility dispatchers to turn off customer loads at peak periods with little notice, have characteristics similar to peaking generator units. Some conservation programs have characteristics similar to base-load resources. As with DSGs, when properly planned and integrated into a power system, conservation and load management should cause no operating problems.

Although the performance capabilities of technologies used by most competitive supplies raise relatively few difficulties, new arrangements for coordinating planning and operation are required. Unbundling generation from transmission requires modifying current operating and planning proce-

[8]Recall from ch. 4 that today's power systems employ a wide variety of generating technologies with diverse abilities to contribute to voltage and frequency regulation, to provide spinning reserves, and to schedule output and maintenance. Construction lead times and costs, and operating costs also vary widely. A vital role of coordinated planning and operation is to find ways to integrate the wide variety of available resources and harness their beneficial characteristics.

[9]See, for example, Power Technologies, Inc., *Application of Induction Generators in Power Systems* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EL-2043, U.S. Congress, Office of Technology Assessment, New *Electric Power Technologies: Problems and Prospects for the 1990s*, OTA-E-246 (Washington, DC: U.S. Government Printing Office, July 1985). Systems Control, Inc., *integrating Dispersed Storage and Generation Into Power System Control* (Palo Alto, CA: Electric Power Research Institute, 1987), EPRI EL-4957.

[10]See, for example, OTA, op. cit., footnote 9.

dures, including developing new pricing arrangements and analytical capabilities. Most experience to date has come from implementation of PURPA, in developing the pricing arrangements for QFs.

Coordinating generation to follow changing loads and provide sufficient reserves at minimum cost already presents significant and challenging problems. An increasingly competitive supply market raises further challenges by reducing power system operators' direct control over coordinated operation and planning of generation and transmission. The following sections examine how the basic functions of following changing loads, maintaining reliability, and coordinating transactions would be effected.

## Load Following

### Frequency Regulation

Regulation-adjusting the power output of generators to follow moment-to-moment load fluctuations-is a fundamental function in reliable power system operation. Regulation is implemented using generator governors and automatic generation control (AGC)/economic dispatch to control the output of spinning reserves made available under unit commitment schedules.

***How Much Control Is Needed?—There is*** no need for all generators to contribute to regulation.[11] The amount of regulating generation required depends on system conditions including anticipated load changes and the ramp rates and availability of other generators. Spinning reserves required for regulation are typically a few percent of load. Determining the amount of regulating capacity required is one function of unit commitment scheduling. Typically, regulating duty is shared by as many units as possible, each operating at slightly below its capacity. This allows the most rapid response, and minimizes the stress on any individual unit. So long as sufficient generation is controlled by governors and AGC, following changing loads presents few problems.

***How Can Control Be Obtained in a Competitive Market?—There are*** both direct and indirect costs of contributing to frequency regulation. Participation in regulating duty slightly reduces a unit's fuel efficiency and tends to increase maintenance requirements and reduce lifetime, creating direct costs. Also, a generator participating in regulating duty operates at below its rated capacity some of the time, creating an indirect cost if payment is based on total energy output. Competitive suppliers are unlikely to bear the costs of contributing to regulation unless specific arrangements are made. Rather, they are likely to operate at a fixed power output not under AGC control.

As a result, regulation has to be explicitly included in operating arrangements under any scenario resulting in high levels of competitive supply penetration (scenario 1 and 2 at the utility's discretion; scenario 3 eventually; scenarios 4 and 5 immediately). Because most utility-owned generators typically contribute to regulation, calculating the precise value has not been an area of major concern or debate. More precise cost analyses may be required if a rationale for choosing either the amount of compensation or the preference in supply bidding is to reflect the cost of contributing regulation.

The direct costs of regulation-fuel efficiency losses and maintenance cost increases-are relatively small. For this reason, obtaining agreements giving an adequate amount for frequency regulation should not cause significant problems at any level of competitive supply penetration. Metering, communication, and accounting equipment may be required to allow the monitoring of generator performance according to agreement. Such equipment is typically not required now because of the unified utility ownership of generators.

Penetrations of nondispatchable technologies such as wind and photovoltaic generators are unlikely to be high enough to cause system-wide problems. To the extent that problems do arise, system planning may require the use of storage devices or in the extreme, limit total penetration.

[11] In fact, nuclear generating units also do not typically contribute to regulation but operate at their full capacity all the time, Other supplies such ss wind turbines, photovoltaics, and some cogeneration technologies are physically unable to provide regulation. 'heir power output depends on local conditions, not on the need to regulate frequency. Wind and solar generators, by having rapidly fluctuating output, may actually create a need for more regulating capacity.

Some QFs and IPPs contribute to frequency regulation now.[12] This gives some evidence of the willingness of independent suppliers to provide regulation when required to or compensated. In some cases, competitive supplies such as IPPs may operate essentially as traditional utility-owned generating units, as in the case of the Ocean States Power Project.

### Cyclical Loads

Following daily, weekly, and seasonal cycles in load is also a fundamental function in power system operation. Unit commitment schedules are developed reflecting forecasted load changes over daily, weekly, and seasonal cycles. Generators in the unit commitment schedules increase or decrease their output either under AGC/economic dispatch following actual loads as required, or according to a schedule, following predicted loads. Performing economic dispatch and scheduling unit commitment for following load cycles is central to minimizing the operating costs of power systems.

***How Much Coordination and Control Is Needed?***— As with regulation, not all competitive supplies need to provide complete control of dispatch and scheduling to minimize operating cost. For example, current power systems use minimal dispatch and commitment scheduling of some plants since a large portion of demand, called the base-load, is constant. Nuclear units and to a lesser extent large fossil-fired steam turbines, with long and relatively expensive warm-up and cool-down requirements operate continuously to meet base-load requirements (although the fossil units may contribute to regulation as well). Few are designed to be operated in a cycling mode.[13] Furthermore, most modem large coal-fired generating units are not designed to operate below output levels of between 25 to 40 percent of maximum capacities.

The amount of base or off-peak load limits the use of generation which cannot be cycled. With a large amount of such generation operating during off-peak periods, low operating cost units may be turned off while less efficient cycling units are run. The result is true whether that generation is physically incapable of cycling or is only unschedulable due to operating agreements. Utilities typically choose a mix of generating units intended to operate as base load, intermediate, and peaking units reflecting daily and seasonal loads (see ch. 4).

The ability of generators to follow loads may also be limited by transmission availability, voltage constraints, and stability. Those constraints are highly dependent on the location and time-varying patterns of load and available transmission and generation. As a result of constraints on the ability of generators to cycle, additional voltage control devices may be required.

The possibility of reduced operating economics grows as the fraction of power which is not under coordinated and flexible scheduling and dispatch increases. The amount of schedulable generation required for following daily and weekly cycles depends on system conditions, including anticipated load changes and the ramp rates and availability of other generators and available transmission. Daily cycles vary from system to system but may have off-peak loads (typically between midnight and 6 a.m.) as low as 30 to 50 percent of daily peak loads. Weekly and seasonal variations are even larger. Following such wide cycles requires a large amount of schedulable generation.

How ***Can Coordinated Control Be Obtained in a Competitive*** *Market?—As* with regulation, Specific arrangements must be made for competitive suppliers to follow load cycles, since that requires operating at below capacity. Provisions for following cyclic loads have to be explicitly included in at least some operating arrangements under any scenario resulting in moderately high levels of competitive supply penetration (scenarios 1 and 2, depending on the utility's choice; scenario 3 eventually; scenarios 4 and 5 immediately).

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[12] In an OTA survey of 23 utilities, 6 of the 16 with nonutility generators on their system had at least some that contributed to regulation.

[13] A significant issue in life extension projects for old generators is that units designed for base load duty are expensive to retrofit for cycling duty.

[14] Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, Mar. 30, 1988, pp. 7-23.

To date, most nonutility suppliers schedule and dispatch their own operations.[15] For small amounts of competitive generation (possibly scenarios 1 and 2; and in early years, scenario 3), this approach should present few problems, particularly if purchase prices reflect less than optimal operating economics. Purchase prices for nonutility power may reflect time-of-day or seasonal variations in expected costs, encouraging supplier operation in peak hours and seasons over off-peak times. However, this approach will become increasingly less economic as the fraction of uncontrollable supply increases. The magnitude of increase in system operating costs depends on system-specific load and resource characteristics and the fraction of supply not under coordinated dispatch and scheduling. As a result, actual value of dispatchable v. nondispatchable generation is not entirely straightforward to calculate and may be the subject of disagreement in pricing or bid evaluation.

With large amounts of competitive or unbundled generation (scenarios 4 and 5 immediately; scenario 3 eventually; scenarios 1 and 2 possibly) explicit arrangements for coordinated dispatch and scheduling will be required. Such arrangements are becoming more common today. Increasingly, competitive suppliers and purchasing systems are developing operating agreements giving the system increased control over unit commitment scheduling and, in some cases, dispatch. In a few cases, independent suppliers are scheduled and dispatched by the utility, behaving much like a utility generator. In others, the amount of dispatchability is quite limited, say to a specific number of hours per year and only under specific conditions. For example, some QFs in California agree to reduce output for a specified number of hours per year when loads are low and inexpensive hydroelectric power would otherwise be wasted.

In these cases, the purchasing system can schedule unit commitment and dispatch the nonutility unit based on price and other contract terms. However, several factors determine the operating cost and efficiency of any plant, including whether it's operating at full or part load, the amount of reactive power output, and whether it's ramping. All of these factors may change over time for any plant. These details are important in determining the actual operating cost of a plant but may be difficult to include accurately in any dispatching agreement.

Spot pricing (or real-time pricing) is another approach which has been considered for coordinating the output of generators to follow loads. Under spot pricing, the price paid to competitive generators is recalculated regularly (e.g., hourly or daily) to reflect actual power system requirements and the availability of alternate supplies.[16] Based on these "real-time" prices, competitive suppliers schedule and dispatch their own generation reflecting system conditions.

The use of spot pricing requires new technologies, including algorithms for calculating prices and telecommunication equipment to transmit the prices. This approach holds some promise as an alternative to central dispatch for coordinating competitive supply markets. However, a lack of experience with spot pricing leaves significant uncertainties about its practical application. For example, such basic questions as the responsiveness of suppliers to hourly, daily, or weekly spot price changes are yet to be answered.

### Coordinating Transactions

Coordination—scheduling and controlling the flows of power between utilities—is fundamental to interconnected power system operations. Scheduling transactions requires analyzing both the economic merit and physical ability to perform the transactions, as is the case in unit commitment and dispatch of a utility's own supplies. Inadvertent interchange, the unscheduled transfers of power between systems, is kept within NERC operating standards for Area Control Error by having sufficient generation available under AGC in each

[15] According t. an Edison Electric Institute survey of nonutility generation, less than 1 percent of interconnected capacity placed in operation since PURPA is fully dispatchable by the purchasing utility. Another 36 percent had limited dispatchability. In contrast, over 6 percent of pre-PURPA nonutility capacity was fully dispatchable, with another 14 partly dispatchable. 1986 *Capacity and Generation of Non-Utility Sources of Energy,* Edison Electric Institute, 1988. Still, evidence of the willingness of most nonutility suppliers to provide dispatchability is limited. While most nonutility suppliers are not dispatchable, it is unclear whether that reflects a lack of emphasis placed on obtaining dispatchability in the past rather than an inability or unwillingness of the nonutility sources to be dispatchable.

[16] See, for example, F.C. Schweppe et al., *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic, 1988).

system to perform load following net of transfers. Thus the control of unit commitment scheduling and AGC for coordination is essentially an extension of that required for load following. Insufficient generation under AGC and unit commitment scheduling may result in poor regulation or increased inadvertent interchange.

## Maintaining Reliability

### Security

Maintaining security-preparing for continued operation after equipment failure or other disturbances and restoring service after outages-is essential to reliable power system operation. Security is maintained through unit commitment schedules that provide spinning and ready reserves and the coordination of scheduled outages of generation and transmission. Also, security constrained dispatch techniques may override economic dispatch to avoid transmission constraints and provide transmission reserves. Together with the coordinated engineering of relays and circuit breakers used to isolate failed or overloaded components, they ensure that no single failure will result in cascading outages.

***How Much Control Is Needed?—NERC*** operating guides require each region or subregion to have spinning and ready reserves[17] equal to the loss of generation resulting from the most severe failure of a single generation unit or transmission line.[18] Typically, the required reserves area few percent of total demand. These reserves are in addition to the spinning reserves scheduled for load following and must respond rapidly when needed. As long as competitive supplies are no larger than the largest existing generators and have similar reliability, higher levels of spinning reserves for security should not be required.

Beyond the need to schedule some units for spinning reserves, all generating units must be responsive to security constrained dispatch during emergencies and for restoration following a system failure. At a minimum, that response may be as simple as isolating the generator from the power system using automatic relays. Control of generation for security is relatively infrequent compared to the control required for load following. The occasions on which security constraints require overriding the least costly generation schedule are highly dependent on the location and time-varying patterns of load and available transmission and generation. When security constraints require redispatching generation, there are usually a number of choices of generators which could make the change. As a result, the frequency and amount of control actions required on any particular generator to avoid potential cascading outages are hard to predict, as is the total cost increase over optimal economic dispatch.

***How Can Coordination Be Obtained in a Competitive*** Market?—From the perspective of a generating unit, coordinated control of scheduling and dispatch of spinning reserves for maintaining security and for frequency regulation are much the same. For this reason, the problems and approaches to obtaining spinning reserves are similar to those discussed above under load following.

Control of generation under security constrained dispatch is somewhat different for maintaining security than for following load, however. The main difference is that the control required for security is more immediate than for load following—if the proper control isn't exercised rapidly, bulk system failure may result. Also, the dispatch control required for security is less predictable and less frequent, and all generation must be under some control for occasional emergencies and system restoration following outages. Operating arrangements must specify the emergency conditions under which a normally undispatchable generator may be dispatched. Because of the difficulty of predicting and defining emergencies, developing and implementing appropriate arrangements will require careful attention.

Finally, planning secure operations requires resolving security-related system engineering problems involving both generators and transmission components. For example, stability problems may be due to the interaction of the system controls, the electro-mechanical behavior of generating units, and the properties of the transmission system. Possible solutions may require modifying generator voltage

[17] Ready reserves include generating units and interruptible loads available within 10 minutes.

[18] North American Electric Reliability Council, *NERC Operating Manual* (Princeton, NJ: December 1987), p. 11.1.

controls, adding controllable reactive power supplies on the transmission system, rejection of excess generation and load reduction by voltage control or intentional interruption of customers. System engineering problems depend on complex interactions between interconnected systems and their components and are hard to anticipate. In any power system, cooperation between all participants is required, and contract terms or other arrangements establishing the framework for solving the problems need to be established.

## Adequacy

Maintaining adequacy-providing enough supplies to meet consumer demand while remaining within the operating limits of system equipment—is also essential to reliable power system operation. In addition to unit commitment and economic dispatch discussed above, maintaining adequacy involves the vital function of adding new capacity. Coordinating maintenance scheduling is also important in maintaining adequacy. Maintenance schedules are designed to time equipment upgrades and repairs so that adequate supplies are always available while minimizing overall system operating costs, In the extreme, uncoordinated maintenance scheduling could result in insufficient available generation if for some reason enormous amounts of maintenance were planned simultaneously. The issues are similar to unit commitment scheduling for load following.

***How Much Coordination of Planning IsNeeded?***— Long-term planning seeks to provide adequate resources to meet demand at lowest cost, reflecting the long construction lead times of generation and transmission. There has to be enough total capacity available after accounting for maintenance and unplanned outages to meet both real and reactive power requirements. Some capacity has to be capable of following changing loads to balance supply with demand. Transmission capability must reflect the location of both the supplies and demand. Furthermore, uncertainty abounds because demand is uncertain, as are fuel costs and the availability and performance of supplies.

An increasing reliance on competitive supplies alters traditional long-term planning in several ways. First, decisionmaking for new generation investment is increasingly separated from the power system planners. This reduces the system planners' direct role in developing supplies with desired characteristics such as the mix of base load and peaking units, fuel mix, load following ability, and siting near available or planned transmission. However, even in a competitive system, planners should still be able to direct the type of development desired.

Also, in the current power industry, utilities conduct cooperative planning studies to determine transfer capacities and requirements and perform coordinated regional studies. Data about system forecasts and resource plans are exchanged freely. An increasingly competitive supply environment may reduce the incentives and avenues for cooperative planning, with resulting increase in uncertainty and inability to plan optimally. The degree of reduced cooperation and the resulting reliability and economic impact are speculative and yet to be determined. Even if data is shared freely, the complexity of permutations of several competitors may make the planning problem of system optimization larger.

Second, a competitive supply market may increase uncertainty about the long-term availability and performance of supplies. For example, will a generating unit under construction-be completed, or will a completed unit continue operation if the owner has severe financial problems?[19] How will the requirements of an industrial process affect the availability of an associated cogeneration unit? Will competitive suppliers without fixed prices contracts greatly increase price when supply shortfalls occur and reduce prices when there is surplus capacity? While these issues are not unknown in present utility planning, dissimilar objectives of competitive sup-

[19]Some part of any increased uncertainty over supplies may actually demonstrate a more responsive process in which proposers of uneconomic resources rapidly withdraw their projects when market conditions are unfavorable. However, it is conceivable that some competitive suppliers may have performance problems unrelated to a power system's need for their power. For example, a plant closing could halt operation of an industrial cogeneration facility regardless of the electric system's power requirements. Even in this case, the plant closing may not necessarily result in a loss of the power resource. If proper arrangements were made, the generator could conceivably continue operation, although not using the waste heat for industrial processes. Also, a plant shut-down would also eliminate the plant electric load so the net effect on the power system would not be the simple loss of the generation unit.

pliers and the power system purchasing the electricity may increase volatility in the supply market.

Third, competitive markets hold some promise for shortening construction lead times. While lead time varies greatly by generation technology, there is a possibility that competitive generation markets will produce more efficient construction practices and thus shorter lead times for any technology.[20] As a result, the responsiveness of new supply to uncertain and changing power system needs may improve. To the extent that lead-time reductions occur, the importance of forecast uncertainty will diminish, to the benefit of system planning.

***Coordinating Planning--Long-term*** contracts will be essential in coordinating planning. The process of developing contracts will be instrumental in communicating needs and defining the obligations of suppliers and the power system. By specifying prices and performance, including penalties for failure to perform, long-term contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties.

Individual competitive suppliers could also choose to develop generation without long-term agreements, speculating on future needs of the power system. This could occur either if no long-term contracts were offered, or if the supplier believed the future market would offer more favorable terms. However, there is no evidence that suppliers are willing to make such speculative investments. Similarly, a power system may find short-term agreements with speculative suppliers advantageous if a large enough oversupply develops or if it anticipates more favorable terms in the future.

Once a purchaser (a utility in scenarios 1, 3, and 4; a utility or a larger retail consumer in scenarios 2 and 5) has determined its supply requirements through its own planning process, it needs to select among alternate suppliers (assuming sufficient suppliers materialize). Supply requirements may be specified in terms as wide-ranging as the type of fuel used, location of units relative to existing and planned transmission, and type of operation (e.g., cycling or base load). In the past few years, utilities and regulatory agencies in several States have developed a wide variety of bidding procedures for procuring generation from competing suppliers.[21] The bidding procedures developed in different States incorporate a variety of mechanisms to accommodate the needs of coordinated planning and operations (see boxes 5-B, 5-C, and 5-D) which describe bidding in Virginia, California, and Maine.

In the face of uncertainty regarding how well new competitive procurement systems will work, one possible planning response is to increase generation and transmission reserves. The amount of additional generation reserves needed to maintain reliability, if any, depends on subjective assessments of not only the construction and operating performance of competitive suppliers relative to utility generation but also on the ability of new operating arrangements to adequately accommodate system requirements. Additional transmission reserves would support the higher level of generation reserves and also prepare for more varied siting decisions by competitive suppliers.

## INCREASING TRANSMISSION ACCESS

Wheeling is the transmission of electricity from a seller to a purchaser using the transmission facilities of a third (or "wheeling") party. A key feature distinguishing wheeling from other electricity transmission is power ownership. Usually a utility owns the electric power flowing on its transmission system. The utility either generates the electricity or purchases it from others and then transports it for sale to customers. In wheeling, however, the wheeling utility neither purchases nor generates the electricity being transported; rather, it accepts power at one point and delivers it to another.

Wheeling allows both buyers and sellers of electricity access to expanded markets.[22] A variety of both purchasers and sellers may desire transmis-

[20] Further, the choice of technologies maybe shifted in favor of those with shorter lead times, although such a choice may occur without increased supply competition.

[21] M.J. Matousek and W.J. LeBlanc, "Bidding for Electric Resources: An Industry Review of Competitive Bid Design and Evaluation," prepared for Electric Power Research Institute, November 1988; M.H. Rothkopf et al., ***Designing PURPA Power Purchase Auctions: Theory and Practice,*** University of California, LBL 23906

[22] Wheeling normally involves the bulk power systems, but some small nonutility generators may be directly connected to the distribution system.

## *Box 5-B—Bidding in Virginia*[1]

### Status

In March 1988, Virginia Electric and Power Company (VA Power) solicited bids from qualifying facilities, independent power producers, and other utilities for 1,750 MW to provide power to come on-line starting between 1989 and 1994. VA Power chose about 2,000 MW for further negotiation from the nearly 14,000 MW of received bids. The accompanying figure breaks down the offers by fuel and generation type.[2] Find contracts are now being negotiated.

### Approaches To Meeting Operating and Planning Needs

VA Power's system uses several approaches to ensure that its planning and operating needs are met. These include: minimum performance requirements and liquidated damages; a bid scoring system including various nonprice factors; and additional incentives for dispatchability.

**Performance Requirements and Liquidated** Damages-Liquidated damages are to be paid if a project does not come on-line and stay on-line as agreed. Performance requirements set limits on the number of days of forced outage and standards by which a bidder's compliance with dispatch orders are measured; capacity payments are to be cut if these performance requirements are not met. Some of the specific terms included are as follows:

- Each successful bidder must pay $30/kW in "earnest money. " If a facility does not reach commercial operation within 2 months of the scheduled date, the bidder loses 10 percent of the earnest money in each of the next 10 months if the project does not come on-line.
- If a facility's dependable capacity proves to be less than expected during testing (before commercial operation), the bidder will pay a penalty of $30/kW of reduction.
- If, during the life of the power plant, dependable capacity is less than 90 percent of what was expected, the bidder will pay a penalty of $21 .60/kW of reduction; this penalty is increased each year to keep pace with inflation.
- A penalty of 4 percent of the capacity payment each year is imposed for each day of forced outage beyond an established limit. The limit is the greater of 25 days or 10 percent of the days operated under dispatch. (This is an indirect encouragement to offer full dispatchability.)
- A penalty of 10 percent of the capacity payment each month is imposed for each time the facility does not operate within 5 percent of the dispatched level of operation; an alternative to this penalty is to declare the incident equivalent to a forced outage day.

**Scoring System**—The bid evaluation system accommodates VA Power's planning and operating needs by including a variety of nonprice factors. Explicit numerical values were not assigned to specific nonprice factors, although the general factors to be taken into account were listed and given a weight. The factors noted for bid evaluation and their relative weights were:

- 70 percent weight to price.
- 10 percent weight to project viability. This includes factors such as level of development and the experience and financial status of the bidder.
- 10 percent weight to fuel type. VA Power used this category to express its preference for fuels with stable prices (e.g., coal) and for projects that used instate fuels.
- 10 percent weight to other factors including location of the project in terms of its proximity to load centers and transmission lines, and extent of dispatchability.

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1 The material in this box is drawn primarily from C.R. Roach, "competitive Procurement of Generating Capacity: Summary of procedures in Selected States," contractor report prepared for the Office of Technology *Assessment,* December 1988.

2 *Electric Utility* Week, June 2.0, 1988, p.19.

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**Dispatchability Incentives and** Requirements-Dispatchability received only slight encouragement from the bid evaluation: it is just one of six factors which, as a group, have 10 percent of the weight in evaluation. However, other incentives were given to bidders encouraging them to operate under full economic dispatch.[3] These incentives include the following:

- Dispatchable bidders were allowed to index their fuel prices to actual energy prices, Nondispatchable bidders were eligible only for a fixed (and thus riskier) price for a price tied to VA Power's lower cost units.
- As noted above, by offering dispatchability, a bidder limits the extent of performance penalties for forced outages. For example, a fully dispatchable plant would be allowed 36 days (10 percent of the year) of forced outages before a penalty is imposed, rather than the standard of 25 days.

[3]In the *pro forma* contract, dispatchability is defined with [he following requirements: 6-hour notice for start-up and shutdown, and 5-minute notice for changes in the level of operation. All facilities over 100 MW were required to be equipped for automatic generation control.

sion access. Without transmission access, an IPP or QF can only sell its power to the local utility that owns the transmission system. Similarly, a utility with competitive supplies cannot sell to the retail customers of neighboring utilities or to distant utilities unless access is provided through the intervening transmission system.

When power is wheeled to a utility for resale to its customers, the transaction is called "wholesale wheeling." Vertically integrated utilities may use both short- and long-term wheeling arrangements to displace their own existing or planned generation. Utilities with little or no generation of their own (in this report, called "requirements utilities''[23]) may use wheeled power to displace generation from the local generation and transmission utility. "Retail wheeling" is the delivery of power from a generator other than the local utility to an ultimate consumer such as a large commercial or industrial user.

To a large extent, the challenges in creating new methods of coordination revolve around developing workable definitions of obligations and rights of all parties and the institutions to carry them out. For example, when a retail or requirements utility chooses a distant supplier, does the local utility have an obligation to serve if those customers return? How much advance notice will purchasers and suppliers need to give the transporter? If the nonutility supplier fails to deliver power, does the wheeling utility have to provide back-up power? These definitions of rights and obligations, while critical for determining technical feasibility and economic impact, also raise fundamental questions of equity and appropriate levels of cooperation.

A wide variety of wheeling arrangements are possible, depending on the types of power suppliers, purchasers, and transporters and specific agreements among them (see boxes 5-E, 5-F, 5-G). Wheeling agreements must specify the amount of advance notice and other conditions under which the transporter can halt a transaction. The duration of wheeling arrangements may vary from hours to years. The amount of advance notice buyers and sellers must give the transporter before increasing or decreasing the amount of power to be wheeled may also vary.

The technical challenges and the likely cost and reliability impacts of increased wheeling depend on the buyers, sellers, and transporters and on the type of service being provided by each and their mutual obligations. The ability to accommodate increased wheeling also depends on the volume of transactions envisioned.

Increased wheeling poses new challenges for operation and planning. In today's power system operations, coordinated unit commitment and dispatch procedures perform several functions. They ensure that both real and reactive power needs are met and they provide sufficient ready or spinning reserves to following changing loads and prepare for

zsRwuiremcn~ utilities with some of their own generation are called partial requirements utilities. Those with no generation of their own are called full requirements utilities.

## *Box 5-C'-Bidding in California*[1]

### Status

**The** heart of California's bidding procedure is a long-term power purchase contract, referred to as the Final Standard Offer Number 4 (S04).[2] S04 requires a' 'price-only bid" competition through a' 'second price auction. " Price-only competition means that the only variation among the bids is the price offered. Nonprice factors such as dispatchability and siting are not included. A second price auction means that all winning bidders are paid the same price, specifically, the price offered by the first losing bid.

Because there has been no need for additional generating capacity in the State recently, the bidding procedure has not been used yet. The agreed-to S04 is the contract that will be used when generating capacity is needed and a bid solicitation is announced. However, the investor-owned utilities in the State are now mounting an effort to change the basic bidding regulations underlying S04. The investor-owned utilities propose a change to the bidding system to include both price and nonprice factors. A switch to a first price auction has also been proposed.

### Approach

**The** California bidding system has no numerical ranking which places explicit value on operational and planning needs. This does not mean, however, that these nonprice factors are not taken into consideration. California's system reflects nonprice factors through minimum requirements that must be met by all bidders and financial incentives for additional performance features. These requirements and incentives of the S04 contract are discussed below.

#### Project Milestones

**Each** successful bidder must provide a $5/kW project fee to be refunded upon project completion. project milestones are set which track the project development; from securing a site, through initial construction, to beginning operation. If a milestone is missed, the $5/kW project fee is forfeited and the utility may terminate the contract.

#### Liquidated Damages

Suppliers under firm capacity contracts are liable for liquidated damages if they default on the contract, or if they reduce the level of firm capacity. Liquidated damages are meant to compensate the utility for losses it incurs because the supplier does not deliver capacity and energy as contracted. If a supplier defaults on the contract or reduces the firm capacity rating, it must pay an amount equal to the utility's replacement cost for the energy and capacity.

#### Minimum Performance Requirements and Bonuses

For firm capacity contracts, the full payment is made on the facility's full capacity only if specific performance requirements are met. The primary requirement is that the facility achieve at least an 80 percent capacity factor during the on-peak times-of-day of each peak month. If the facility fails to meet this requirement its firm capacity will be derated after a probationary period. Alternately, if the supplier substantially maintains a capacity factor of 85 percent or higher, the utility pays a bonus.

#### Curtailment Requirements and incentives

Curtailment is a form of limited dispatchability. Under S04, suppliers must agree to have their generation curtailed under certain circumstances. Suppliers are required to choose one of two forms of curtailment. Under the first, a supplier maybe curtailed in cases of "Hydro Spill" or "Negative Avoided Costs. " (Hydro Spill conditions occur when low system demand forces the utility to allow water to pass an unloaded turbine in order to reduce generation. Negative Avoided Costs are said to be incurred when the utility's high-cost units are at their lowest level of operation and the acceptance of further nonutility supplies would actually lead the utility to incur higher costs). If either Negative Avoided Cost or Hydro Spill conditions exists, the supplier must reduce generation to 30 percent of capacity or less. No energy payments are made during these curtailment periods.

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[1] The material in this box is drawn primarily from Boston Pacific CO., k., "Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States," contractor report prepared for the Office of Technology Assessment, December 1988.

[2] The discussion herein is based on the SO4 contract negotiated by the utilities, private power producers, and Commission staff as of Jtme 1988.

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The second curtailment option allows the utility to curtail the supplier's generation up to 1,500 hours per year during off-peak and super-off-peak periods, No more than one curtailment can be imposed in a single day and the curtailment period cannot be less than 3 hours. Curtailments can be imposed during periods of Negative Avoided Cost. Economic curtailments can also be imposed; in these cases, energy payments are based (generally) on actual utility incremental costs. Supplier's choosing this second curtailment option receive higher energy prices in other off-peak and super-off-peak periods than those choosing the first option.

**Adders, or Incentives for Other Performance**

Additional payments by the utility can be negotiated to gain features such as greater dispatchability and for reactive power support. An early CPUC Decision ordered the utilities to consider the payment of "adders" if additional performance features are requested from suppliers beyond those in the S04. The specific list of adders is as follows: emergency availability; black start capability; reactive power support; scheduled maintenance; real-time pricing; prescheduled dispatch; and full dispatchability. A later CPUC Decision created the possibility of "subtracters" as well. These payment adjustments would be based on a comparison of the performance features offered by the supplier through its contract to the performance features offered by the utility resource assumed to be avoided; adjustments maybe upward or downward, Final details have yet to be worked out.

equipment outages. Finally, these functions minimize operating costs while remaining within the constraints imposed by the generation and transmission system capabilities.

By reducing the centrally coordinated control of generation, increased wheeling raises the possibility of less economic operation and reduced reliability. Reduced economics and operation problems are the same concerns that may result with improperly integrated competitive supplies discussed in the previous section. However, expanded transmission access adds new complications.

As the number and magnitude of wheeling transactions increase, scheduling use of the transmission will require increasingly accurate and objective analytical methods. In particular, calculating transmission capacity will be critical as was discussed above under long-term planning. The use of a local utility to provide load following capacity may also result in disagreements about the cost of providing spinning reserves, load following, and regulation services. More accurate methods of determining the cost of these services will then be required.

The following sections examine how wheeling may effect the functions of following load, coordinating transactions, and maintaining reliability.

## Load Following

### Frequency Regulation

Providing frequency regulation has a relatively small direct cost, assuming sufficient coordinated control has been obtained, and should not prove to be a very challenging requirement. Assuming the correct amount of regulating capacity has been acquired and brought under coordination of the local control area as discussed above, wheeling should add little complication. However, use of wheeled power will displace generation within the purchaser's control area. This may result in shutting down units during light load times, reducing the regulating capacity available.

**Frequency regulation must be provided by the control area entity, whether that is an integrated utility (scenarios 1, 2, and 3), or the transmission company (in scenarios ,4 and 5).** Even with increased telemetry between individual sellers and buyers to keep each informed about the other's performance, the ability of an individual generator to exactly match load is limited since loads can typically change faster than an individual generator. Also, because fluctuations in individual loads tend to offset each other, the larger the power system being regulated, the smaller the fraction of regulating capacity required.

## Box 5-D—Bidding in Main[1]

### status

Established in 1984, Maine's bidding system is the oldest in the United States. Four Requests for Proposal (RFPs) had been issued by the end of 1987 and 78 contracts had been signed for a total of 500 MW. Operational projects total 275 MW, and another 222 MW were expected on-line by 1991. In its June 1987 solicitation, Central Maine Power's (CMP) solicited 100 MW and received 1,444 MW in actual bids. CMP'S June 1987 solicitation is the basis for this discussion,

### Approach

CMP's system has three main components. These components, prequalification (or screening); bid evaluation; and liquidated damages; are used to select new capacity to meet CMP's operating and planning needs.

### Prequalification or Screening

CMP asked bidders to demonstrate their ability to construct and operate the proposed facility. The screening requires that a bidder present substantial evidence that the project is well along in areas such as engineering design and permitting, fuel contracting, and financing.

### Scoring System

To accommodate CMP's planning and operating needs, the bid evaluation system considers a variety of price and nonprice factors. The value of the nonprice factors was explicitly quantified using six scoring indices. Each index had a base value of one, so all respondents started with a score of six,

- *Price Index:* This index reflected the extent to which the bidder's price was below CMP's forecasted avoided cost. For each percent discount offered by the QF, its score is increased by 0.1 points. For example, a 10 percent discount would add a full point to the score.
- *Capacity index:* An additional point was added to the score for bidders providing reliable firm capacity. To obtain the point, the bidder must meet NEPOOL's test for firm capacity and (for thermal units) commit to high on-peak performance or (for hydro units) agree to a semi-annual capacity audit and to a minimum generation level.
- *Operating Index:* Dispatchability earned an additional 0.3 points. Coordinated maintenance scheduling earned 0.2 points more. Finally, scheduled operation favoring peak periods was rewarded by up to 1.5 points.
- *Security Index and Endurance index: These* indices rewarded bidders that took steps to reduce the risk to CMP of future project nonperformance. Bidders that set up a security fund to cover the utility's cost of replacing the energy and capacity if the facility does not operate as contracted scored up to 0.5 points. Bidders that did not require levelized payments (i.e., payments exceeding the forecasted avoided cost in any year) or provided a security fund received up to 1.5 points.
- *On-line Index:* This index encouraged bidders to come on-line later in the 1990's. An additional score of 0.05 points is given for each year the Initial Delivery Date is set beyond 1990.

### Liquidated Damages

Winning bidders are subject to penalties, or liquidated damages, if they do riot perform as contracted. The payments for liquidated damages are an attempt to make the QF responsible for the cost of replacement energy and capacity if that QF falls short on providing capacity and energy as planned, or if the contract is terminated. A standard long-term contract specifies damages in cases such as capacity shortfalls during peak periods; energy deliveries below the guaranteed minimum; and abandonment of the contract.

[1] The material in this box is drawn primarily from Boston Pacific Co., Inc., "Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States," contractor report prepared for the Office of Technology Assessment, December 1988.

## Cyclical Loads

The need to follow cyclical loads raises four issues for wheeling in addition to those described for competitive supplies. These are:

- feasibility for retail consumers and full requirements utilities,
- impact on the economy of operations,
- control center limits, and
- transmission scheduling.

### *Box 5-E-Southwest Bulk Power Market Experiment*

In December 1983, FERC approved a 2-year experiment in bulk power marketing and transmission access involving six utilities in the Southwest. ' The experiment was intended to determine the economic efficiency gains and competitive impacts of modifying FERC's regulation of coordination transactions-transactions between utilities with their own generating capacity. Transactions involving distribution utilities with little or no generation were not addressed. There were no apparent concerns or problems with the technical feasibility of implementing the experimental power transactions and transmission access.

In the experiment the participants were allowed substantial freedom in setting prices for "economy energy" (for interruptible sales from hour to hour up to 30 days) and "block energy" (for sales extending at least one month). Prices were allowed to range from 0.9 ¢Wh to 9.4 ¢/kWh. The utilities were allowed to retain 25 percent of the resulting savings as profit, with the remaining 75 percent flowed through to customers. (Traditional regulation requires 100 percent of such savings to be passed on to customers). Further, the utilities agreed to provide transmission access (up to technical limits) at a fixed price of O. 15¢Wh, and thus not prevent trades involving other participants.

FERC contracted with the Rand Corp. for technical assistance in evaluating the experimental design proposed by the utilities; assessing the usefulness of the data; and analyzing the experimental results.[2] Rand published first year results in October 1985. The analysis of economic efficiency impacts was inconclusive: "Our findings with respect to efficiency are decidedly mixed, and vary depending on the analytic technique selected. . . . By some measures, efficiency increases under the experiment; by others it is unchanged or falls by a statistically significant amount."3 Rand noted that *the first year* findings were possibly unrepresentative for several reasons.

According to Rand's first year report, the second year was expected to be more representative of the efficiency gains resulting from the experimental regulatory changes. Results of the experiment's second year have not been published to date.

[1] *Southwest Experiment*, FERC Opinion No. 203, Docket No. ER84-155-000, Dec. 30, 1983. The six utilities were Arizona Public Service; the City Of Farmington; El Paso Electric; Public Service Company of New Mexico; Salt River Reject; and Southwestern Public Service (which began participation in the final 3 months of the first year.

[2] The Rand Corp. provided an advisory report t. FERC before the experiment was approved. The Rand Crop., *Issues in the Design of a Market Experiment for Bulk Electrical Power,* December 1983.

[3] J. Acton and S. Be=, Regulation, *Efficiency, and Competition in the Exchange of Electricity: First Year Results From the FERC Bulk* Power *Market* Experiment/, The Rand Corp., October 1985, p. vii.

***Retail Consumers and Full-Requirements Utilities***-Following the load cycles of retail customers and full-requirements utilities with wheeled power may prove difficult. For vertically integrated utilities (scenarios 1, 2, and 3), purchasing wheeled power presents no significant problem since they have the capability to follow their own loads. Similarly, control-area size transmission and distribution utilities (scenario 4) or distribution-only utilities (scenario 5) that buy power from individual generation companies with large amounts of supplies should have no problems beyond those described above under competitive supplies for generators within the control area.

However, for small full-requirements utilities and retail customers, following actual load cycles will require either: 1) the purchaser to accurately forecast loads far enough in advance to arrange a schedule with the supplier; or 2) the supplier to monitor the purchaser's loads and adjust output accordingly. Failure to meet one of these requirements will result in an over- or under-supply of wheeled power. This would have to be accounted for with the local control-area utility and may result in increased spinning reserves for frequency regulation. Accounting for transmission losses further impedes the ability to match supply with individual loads. The dependence of losses on ever changing system conditions and the possibility that some transactions may actually decrease losses add to the difficulty.

***Impact on the Economy of Operations***-With increased levels of wheeling in which individual

***Box 5-F—Western Systems Power Pool: A Current Experiment in Transmission Access and Bulk Power Pricing***

In March 1987, the Federal Energy Regulatory Commission (FERC) accepted another 2-year bulk power marketing experiment, called the Western Systems Power Pool (WSPP).[1] The WSPP experiment began on February 1, 1987. Like the Southwest Experimen~ the WSPP experiment is intended to determine whether more flexible pricing and greater information sharing will promote more efficient use of generation and transmission facilities and reduce costs to consumers. As with the Southwest experiment, there have been no apparent concerns or problems with the technical feasibility of implementing any of the experimental power transactions, including transmission access.

There are several differences between the WSPP experiment and the Southwest Experiment. One principal difference is transmission access. The WSPP provides only for voluntary transmission service and gives substantial pricing freedom to the transmitting utilities. Transmission access prices are allowed to range from 0.1 ¢/kWh to 3.3 ¢/kWh. In contrast, the Southwest Experiment provided mandatory transmission access (subject to availability) at a fixed price of 1.5 ¢/kWh. Thus, according to FERC, the WSPP experiment will examine ‘‘whether mandatory transmission access is a prerequisite to a competitive market. ”[2]

WSPP also allows a much wider range of prices for generation than did the Southwest Experiment. In the WSPP experiment’s first year, prices were allowed to range up to 24.5 ¢/kWh, compared to the earlier experiment’s cap of 9.4 ¢/kWh.

Size is another difference between WSPP and the Southwest Experiment. WSPP is very large, including over 20 utilities in 10 Western States. The utilities in this region produce about ***12*** percent (82,000 MW) of the total electric generating capacity of the United States. That is substantially larger than the Southwest Experiment, which was open to six utilities in three States, with under 13,000 MW capacity. To implement the experiment over this large group of utilities, the WSPP experiment uses a computer “bulletin board” into which buy and sell offers are placed each day.

The experiment is scheduled to conclude on May 1, 1989, but the participants have requested a 2-year extension. As a condition of FERC approval, the participants are required to produce interim and final reports examining economic efficiency impacts and potential monopoly power. The interim report does not draw conclusions on these issues due to a lack of data.[3] However, the report notes that some transmission owners are holding less transmission in reserve for their own uses, resulting in increased availability to others.

[1] Order Accepting Experimental Rates for Filing, FERC Docket No. ER87-97-001, Mar. 12, 1987.

[2] Ibid., p. 3.

[3] T.W. Keelin et al., *Western Systems Power Pool Assessment Interim Report* (Menlo Park, CA: Strategic Decisions Group, January 1989).

purchasers and sellers specify generation patterns, the control area’s options; for economically scheduling and dispatching generation will be less flexible and less responsive than they are currently. A likely result is increased operating costs.

In particular, overall system economic impacts of scheduling constraints will be exacerbated if a large number of relatively small wheeling arrangements specify the dispatch and unit commitment of independent suppliers. For this reason, wheeling for retail customers (scenarios 2 and 5) and for smaller utilities, particularly those without generation (scenarios 2 through 5), are most likely to affect economic dispatch and scheduling. Wheeling of power to integrated utilities (scenarios 1,2, and 3) or to large transmission and/or distribution companies (scenarios 4 and 5) should not have the same negative impact.

***Control Center Constraints-A*** third complication for following cycling loads introduced by wheeling is a limit to the number of generators and wheeling transactions that can be handled from any control center. If the number of transactions increases significantly (most likely in scenarios 2 and 5; possible in scenarios 3 and 4), control center equipment, personnel, and procedures will have to

### *Box 5-G-Innovative Transmission Access: Turlock Irrigation District*

In June 1988, FERC approved a novel agreement under which Turlock Irrigation District gained transmission access to a number of competing power suppliers.[12] In exchange, Pacific Gas and Electric (PG&E) gained a Pricing system allowing it to retain more of the savings from coordination transactions than were previously allowed. PG&E also gained release from responsibility to provide power and transmission beyond which it committed itself contractually.[3]

Turlock is a partial requirements utility, with capacity of approximately 157 MW and peak loads of approximately 266 MW in 1988. According to FERC, ''Turlock has always been a captive customer of PG&E due to its reliance on the PG&E transmission system. "[4] Under the new agreements, Turlock will have "reserved transmission service" providing 176 MW of import access to three other northern California utilities and to Southern California Edison at cost-based prices. Together with its own capacity and approximately 5.3 MW of firm capacity from PG&E, this gives Turlock sufficient resources to meet its own load. In addition, the agreement allows PG&E and Turlock to negotiate "coordination services. " The coordination services would allow Turlock to pursue short-term purchases with PG&E and other utilities when low-cost opportunities exist. In addition, the agreement covers such provisions as charges for unauthorized power flows, voltage regulation, scheduling, and regulation services.

FERC'S order of approval noted uncertainty and some concern about "whether PG&E may exercise any leverage over Turlock because of its control over Turlock's transmission access to other suppliers. " The agreement is not an experiment, however, and no formal mechanism has been instituted to determine whether such leverage is exercised.

Finally, it's worth noting that neither FERC, nor PG&E, nor other interveners expressed concern with the technical feasibility of reliably implementing the agreement.

[1] *Pacific Gas* &Electric, FERC Docket No. ER88-219-000, Mar. 31, 1988.

[2] *Pacific Gas and Electric*, FERC Docket No. ER88-219-001, June 1, 1988.

[3] FERC approved a similar transmission access and pricing agreement between Modesto Irrigation District and PG&E in July 1988. *Pacific Gas and Electric*, FERC Docket No. ER88-302-001, July 5, 1988.

[4] *Pacific Gas* and Electric, op. cit., Mar. 31, 1988, p. 10.

be upgraded. The cost and reliability of control center upgrades to accommodate increasing numbers of transactions will be location specific. Increases in the volume of wheeling transactions, especially those whose levels change frequently, have already led to changes. For example, Houston Lighting and Power has added an energy scheduler to the dispatch staff, with over half his time dedicated to handling the effects of cogeneration and wheeling cogenerated power.[24]

***Transmission Scheduling*-*Finally, increased*** wheeling creates an expanded challenge for transmission scheduling. In current power systems, following loads while controlling voltage and power flows on the transmission system to remain within physical limits is performed in part through generation control. With few exceptions, scheduling the use of transmission is not a significant problem today. If a utility has a transmission bottleneck, as many do, it selects an alternative (although less economic) generation dispatch which avoids the constraint. The options for different dispatch patterns are limited mainly by the operating capabilities of the generators. The ability to choose a variety of generation patterns is critical for reacting to the complex and uncertain changes in power flow requirements and transfer capabilities that power systems face.

As wheeling increases, scheduling transmission use independently of generation becomes increasingly necessary, distinct from the current combined generation and transmission scheduling problem. Generation scheduling constraints caused by wheel-

[24] Institute of Electrical and Electronic Engineers, Committee Report, "problems in Coping With the proliferation of Interchange Schedules," *IEEE Transactions on Power Systems, vol.* PWRS-2, *No.* 4. November 1987, pp. 883-889.

ing arrangements will reduce ability to control transmission flows. In particular, if purchasers need wheeled power to follow changing and uncertain loads, the uncertain and changing pattern of generation usage could create unanticipated transmission loadings which would otherwise be avoided by redispatching generation.

The more predictable the level of wheeling transactions, the less challenging transmission scheduling will be. For example, with long-term fixed patterns of power transfers, perhaps specified through contracts, the transmission scheduling problem reverts to a transmission planning problem in which new facilities can be developed as required (assuming capacity can be built as required and transmission owners can earn sufficient returns on investment).

Transmission scheduling involves setting priorities for who gets to use the transmission system and at what price. As wheeling transactions become more common, setting these priorities and prices will become increasingly contentious. These are issues of both economic efficiency and equity, and beyond the scope of this analysis.[25] There is no single technically correct solution to the priority and pricing problems, although a variety of approaches do exist. (See boxes on *Southwest Bulk Power Market Experiment; Western Systems Power Pool; and Turlock Irrigation District). These* demonstrate that untraditional uses of transmission are technically feasible and that arrangements can be developed that participants view as acceptable.

The idea of using marginal cost-based prices to allocate transmission capacity has received considerable attention. This method would have the effect of allocating transmission use to those willing to pay most for it. The marginal cost analyses are necessarily technical because of the complex physics and engineering of power systems.[26] Among the efforts, the United States Department of Energy and the New York State Energy Research and Development Authority have cosponsored development of public domain computer software for examining the marginal cost of wheeling.[27] The software, called WRATES, incorporates such factors as transmission losses, fuel costs, and the operational costs of generation and line capacity limits.

## Coordinating Transactions

As noted above, increasing the number of transactions requires additional metering, telemetry, and telephone communication for the AGC. This is true for wheeling between control areas as well as within them. If the volume of transactions becomes large, power control centers of the transporting utility will need upgrading, and more dispatchers may be required.

Also, AGC systems used to coordinate transactions are based on the current structure of utilities in which control areas are clearly defined. Metering of tie lines into each area is an integral part of these systems and is easily accomplished. However, implementing large numbers of wheeling transactions may require revisiting the concept of control areas and AGC. In particular, the present concepts of control areas and AGC may be strained to the extent that wheeled power is used to continuously balance load and supply for a large number of retail customers or small full-requirements utilities. As loads and generators become independent from integrated utilities under retail wheeling or wheeling to requirements utilities, they can in concept become separate control areas purchasing and selling power using interchanges with the transmission system.

## Maintaining Reliability

### Security

With or without wheeling, maintaining system security depends on carefully coordinated control of generating units as described earlier. This control is needed both to schedule generation and transmission reserves and to redispatch generation and transmission following contingencies. Wheeling extends two issues beyond those previously described. These are:

[25] See National Regulatory Research Institute (NRRI), *Some Economic Principles for Pricing Wheeled power* (Columbus, OH: NRRI, August 1987).

[26] See, for example, ibid.; F.C. Schweppe et al., "Wheeling Rates: An Economic-Engineering Foundation, " MIT Laboratory for Electromagnetic and Electronic Systems, Report TR 85-005, September 1985; and F.C. Schweppe et al., *Spot Pricing of Electricity,* op. cit., footnote 16. H.M. Merrill, "Economically Efficient Allocation of New York's Transmission and Distribution System, " Power Technologies, inc., June 1985.

[27] M.C. Caramanis et al., 'WRATES: A Tool for Evaluating the Marginal Cost of Wheeling," IEEE 88 SM 649-6, IEEE/PCS 1988 Summer Meeting, July 24-29, 1988.

setting transaction priorities, and measuring transmission availability.

***Setting Transaction Priorities*-There** is simply no way to maintain reliable operations unless wheeling is subject to availability of transmission capacity. The same is true of any use of transmission. Even if a wheeling transaction is scheduled, contingencies may occur that require curtailing the transaction. Any wheeling agreements, whether mandatory or voluntary, must recognize this reality (as is the case in all of OTA's scenarios). Thus purchasers of wheeled power must have either aback-up supply—either their own or purchased-or be willing to risk not meeting loads. (Note that curtailing a transaction does not equate with curtailing the load if back-up supplies have been arranged.)

As wheeling transactions become more common, determining which transmission uses to curtail or continue when transmission limits are reached, and determining the appropriate price of back-up supplies may become increasingly contentious. As with setting priorities and prices for transmission scheduling, these are issues of both economic efficiency and equity, and beyond the scope of this analysis. However, the technical requirements of operating a power system mandate that these issues be addressed.

***Measuring Transmission Availability*-Increas**ingly accurate measures and definitions of available transmission capacity will be required. Without accurate measures of capacity and costs, conflicts between those who want to wheel and transmission system managers will undoubtedly arise. Regulatory authorities may not have sufficient credible information on which to render decisions.

Recall from chapter 4 how available transmission capacity is measured today. There is no simple equivalent of the telephone company's busy signal on a power network. Transfer capacity is not the rating of a single line or a few lines. It is a function of the strength of the network as a whole. Transfer capacity depends on reliability criteria, which are selected somewhat subjectively. It varies as switching operations occur and as demand, generation, and transmission patterns change. Loop flows and actions taken by operators of other systems affect the available transfer capability. Furthermore, developing estimates of transfer capability requires a lot of engineering time and cooperation among all parties involved.

Transfer limits today are determined by complex system studies based upon reliability criteria established by mutual agreement among power system engineers. This is a satisfactory arrangement as long as the parties involved understand and trust each others' judgments. As the number of competing generating entities and wheeling transactions increases, there may be a greater need for more easily calculable and verifiable assessments of available transmission and transfer capability.

## Adequacy

Long-term planning involves ensuring that adequate transmission and generation resources are available for operation. To the extent that wheeled power will be used for long-term supplies, expanded transmission access raises one crucial long-term planning issue in addition to those resulting from increased bulk supply competition. It is the prospect of increased planning uncertainty.

***Increasing Planning Uncertainty*-As** increased wheeling allows power purchasers to buy from a greater number of suppliers, confusion regarding who will supply power to whom could exacerbate other capacity planning uncertainties. The result may be either under- or over-estimates of capacity needs for both generation and transmission.

Mandatory wheeling to retail customers (possibly in scenarios 2 and 5) raises the most critical source of uncertainty. Because of the long lead-times needed to build generation and transmission facilities, lack of sufficient advance knowledge of the plans of retail customers who may wish to obtain their power from outside sources could result in inadequate transmission facilities and excessive generation. Alternately, if a utility incorrectly assumes that a retail customer will obtain power through wheeling, excess transmission capacity and insufficient generation could result. For these reasons, advance notification of requests for wheeling and subjecting wheeling to transmission availability is required. A system of "transmission access on demand" or unrestricted access can not be implemented. (Note that none of the OTA scenarios include such unrestricted access.)

Wholesale wheeling and voluntary retail wheeling pose relatively few planning problems since there should be little confusion about who has obligations to acquire adequate power supplies. However, in every case, increased competition may reduce incentives for cooperative planning between utilities, generators, and customers, with a resulting increase in uncertainty and the inability to plan optimally.

As with competitive supplies alone, long-term contracts provide one instrument to communicate needs and define obligations of suppliers, buyers, and transmission systems. By specifying prices and performance, including penalties for failure to perform, long-term contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties. The allocation of risks and responsibilities between the power system and competitive suppliers under long-term contracts depends in part on performance and pricing terms.

## CURRENT UTILITY PERFORMANCE

The cost (and the benefit) of implementing increasing competition depends largely on how the economy of current utility planning and operations are affected. This section briefly reviews current performance.

### Individual Utilities

Most utilities appear to operate their plants efficiently, although that is difficult to ascertain. However, there is some indication that the quality of economic dispatch varies between utilities, although conclusions are difficult to draw. Consider a study performed by Philadelphia Electric Company for the Electric Power Research Institute.[28] That study found that different utilities had significantly different practices of monitoring the actual operating efficiency of their generators, resulting in slightly less than optimal economic dispatch.[29] If dispatchers believe that a suboptimal plant is operating at peak efficiency, they may call on it in preference to one that is actually more economic.

Units are maintained regularly to keep generation capacity operating efficiently, although there is a marked difference in the availability of otherwise similar plants owned by different utilities. Part of this difference is apparently due to differing maintenance programs.[30]

Utility planning and addition of new capacity has, in hindsight, often resulted in expensive and unneeded facilities. Still, the ability of independent power producers to outperform utilities in construction, maintenance, and operation of generators is yet to be determined, as is the impact of competition on planning uncertainty and planning practices.

### Interutility Coordination and Power Pooling[31]

Interutility transactions are essential to minimizing operating costs of the U.S. power system. There appears to be a regular and increasing tendency on the part of systems with higher operating cost capacity to seek out more economic sources of power to purchase. The growth of imported power from Canadian sources to displace higher cost, oil fired generating capacity and to meet growing loads is a well known example, as are the increasing bulk transactions described in chapter 6.

However, there are some indications that economic interutility transactions, while high, could be substantially improved.[32] Proposed mergers be-

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28 Philadelphia Electric Co., /reproved *Economic Dispatch of Power Systems* (Palo Alto, CA: Electric Power Research Institute June 1982), EPRI EL-2461, vol. 1.

29 That study also identified opportunities for improved economic dispatch from more frequent monitoring. It is worth noting that the study was undertaken in the late 1970s, before significant competitive pressures were being felt, reflecting the industry's ongoing activities in identifying and developing areas for increased efficiency.

30 See for example, U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty*, OTA-E-216 (Springfield, VA: National Technical Information Service, February 1984).

31 The material in this section is drawn from Power Technologies, Inc., "l'ixhnical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-Utility Generation, " OTA contractor report, March 1988, unless otherwise referenced.

32 See, for example, E.J. Tirello, Jr. and M. Worms, *Electric Utilities: The Case for Consolidation*, Shearson Lehman Hutton Equity Research, March 1988. That study concluded that cost savings of $2,6 billion per year could be obtained through more efficient economic dispatch and maintenance procedures alone. See also, Federal Energy Regulatory Commission, *Power Pooling in the United States*, December 1981.

tween utilities indicate that some utilities believe that coordinated operations and planning could be improved. For example, SCEcorp (parent of Southern California Edison) in supporting its proposed merger with San Diego Gas & Electric noted that "Major cost savings are anticipated through more efficient use of generation and deferral or elimination of capital expenditures. " In addition there would be staffing reductions. Projected savings from operations are $100 million annually and about $350 million in capital spending within the coming decade.[33] Similar projections of savings have accompanied other merger proposals such as that between Utah Power & Light and Pacific Power& Light.

There are a number of regions where centrally dispatched power pools coordinate plans for system development and operate systems economically to reduce both long-run investment costs and short-run operating costs. These have taken the form of power pool agreements among unaffiliated utilities and the coordinated operation and planning of large utility holding companies. These existing operations offer one example of a practical and tested way of improving overall efficiency of the utility systems in other areas. One recent assessment of interutility coordination found that annual savings exceeded $15 billion—about three-quarters resulting from reduced capital investments with the remainder due to fuel cost savings.[34]

These economic gains are substantial. They could perhaps be augmented with an increased level of power brokering, pooling, and central dispatch systems. These approaches involve cooperation as well as competition. The benefits of pooling are balanced by responsibilities of pool members to deal openly and fairly with each other and to exchange data freely concerning future load projections, expansion plans, and operating costs. Centrally dispatched power pools require investment in a pool control center, communications and computer facilities, and the support of an adequate engineering and dispatching staff. These are not inconsequential costs. Ranges of initial costs for a large pool control center have been informally given at levels of $10 million to $50 million. A support staff of 30 to 40 professional level people might require an ongoing cost of $3 million to $5 million per year.

These costs must be compared to possible reductions in system expansion cost savings and annual operating cost savings that may be obtained from a central dispatch system for a large enough pool. Coordinating operations on a pool-wide basis rather than on an individual system basis means that the most efficient units within the region are being used to produce the energy required by customers on a planned minimum costs basis. The consumers' costs are reduced overall by this production efficiency. A system with a peak load of 10,000 MW and fossil-fired generation could have an annual fuel bill in excess of $1 billion per year. An operating cost savings of one-half percent would be $5 million per year; enough to pay for the pool operating staff costs cited above.

A large portion of the savings from interutility coordination are due to the reduction in facilities required to handle the load growth in a region when the interconnected systems plan and implement system expansions on a coordinated basis. Installed reserve requirements for generation are reduced when systems substitute lower cost interconnection capability that allows them to share generation reserves for new generation capacity, This has been done in all of the power pools over the years.

The pool planning organization, whether a holding company staff or a committee organized from unaffiliated pool members, may plan for adequate reliability and lower generation reserves by taking advantage of the diversity in loads, the diversity in both planned and forced outages, and by coordinating capacity additions so new facilities are installed on a pool need basis rather than by each individual system. Transmission plans can be studied and implementations developed that will provide adequate transmission for exchanging power and energy on a regular and emergency basis.

Arrangements can be made to allow the use of the entire transmission system within the pool area for the mutual benefit of all of the pool members. In

[33] *Electric Utility Week,* Aug. 1, 1988, pp. 7-8.

[34] J.A. Casazza, "Free Market Electricity: Potential Impacts On Utility Pooling and Coordination," *Public Utilities Fortnightly,* vol. 121, No. 4, Feb. 18, 1988, pp. 16-23.

most pools, ties are "free flowing," eliminating the requirement for complex wheeling contracts. If transmission ownership is unbalanced, arrangements can be made to share transmission costs on a relatively simple basis. New transmission capacity may be planned jointly to develop optimal systems at the lowest costs.

The individual systems must relinquish something for these benefits. They must support the pool operation, both with sufficient funding and with adequate engineering support. The operating arrangements mean that the most efficient production units in the pool will be operated to supply customer demands throughout the power pool. The owners of these units must receive fair compensation and energy purchasers must be charged a fair price. The arrangements to accomplish this require negotiation and time to develop and implement.

Individual system members of a pool must agree to complete exchange of data and forecasts, which has been encouraged by the generally noncompetitive environment that utilities have been operating in to date. The members must be willing to coordinate plans and system developments. They must agree on generation plans and transmission system construction. They must be willing to surrender some of their responsibilities in operations and scheduling to the pool center. Finally they agree to coordinate plans to:

- avoid system emergencies,
- coordinate corrective actions during emergencies, and
- restore service after an emergency occurs.

It is logical to ask why there are not more power pools of affiliated and unaffiliated utilities. The answer is not clear. The potential savings in operating costs do require a fairly large pool size to support the annual costs of the pool operation. The individual utility may not escape the need for its own operations control center by belonging to a power pool of unaffiliated companies. (A holding company may be different with all of the generation operated by a centralized staff of the parent or one of its service company subsidiaries.) A substantial portion of the available operating savings maybe achievable by other means such as economic interchange, power brokers, or long-term interchange agreements.

## TECHNOLOGICAL ISSUES OF OTA's SCENARIOS

This section examines technological issues raised by increased competition as defined in OTA's scenarios. As discussed before, feasibility depends largely on developing new institutional relationships between suppliers, consumers, and transporters which accommodate the need for coordinated operations and planning of the power system. Implementing these new institutional relationships will likely require adding some new physical facilities and improving analytical capabilities.

In examining the ability to accommodate competitive supplies and transmission access, the question is not whether it can be done, but how much is feasible under what conditions without impairing reliability and economics. There is no point at which increased competition becomes clearly infeasible. Rather, increasing competition expands the institutional modifications required and raises the uncertainty of success.

Any proposed change from the existing system naturally raises uncertainty about how well the new system will work. We know that the power system of today does work, although some believe it to be somewhat inefficient or inequitable.[35] We also know that the system is currently evolving and accommodating increased competition: Nonutility generation and competition among suppliers is increasing substantially in many regions of the country; transmission access is also increasing, although to a lesser degree. The suppliers, transporters, and purchasers of power are defining institutional relationships and responsibilities which they feel meet their individual and joint needs. However, we will not know the actual impact of these changes on the reliability and economy of the power system for years to come.

The costs of implementing any scenario include developing new operating and planning procedures, adding new equipment and personnel to implement the procedures, and possibly less efficient economic

[35] See chs. 1 through 3 of this report for a description of the concerns expressed over current industry performance.

dispatch, scheduling, and planning resulting from reduced coordination.

## Scenario 1: Reaf'firming the Regulatory Compact

The first scenario envisions little change in industry structure. With no substantial, rapid increase in competition, existing operating and planning procedures will require only gradual evolution. This raises no major challenges or uncertainties.

Existing State regulatory programs would be modified to include ongoing approvals of major construction projects. Except for meeting the requirements of project proapproval or rolling prudence review, utility planning and operations would evolve along the lines they are following presently. It's possible that proapproval could result in increased development of power plants with long lead times and high capital costs. However, in an OTA survey of **23** utilities, only a few indicated they would consider revising their supply plans if given prior approval. Several utilities expressed concern over the risk of regulatory disallowances. However, many indicated they either accept that risk and build the generation most suited to their area's needs or believe that proapproval and rolling prudence would not be effective in reducing risk.

### Supply Competition

Nonutility generation would continue to be developed under PURPA. Modifying the rules for pricing under PURPA would increase the likelihood that operating and planning requirements, or nonprice factors, would be reflected in avoided costs. These nonprice factors are receiving considerable attention today. Scenario 1 would encourage continued analysis of the requirements, costs, and benefits of different levels of coordinated utility control of dispatch and scheduling—both for load following and for maintaining security. The impacts of nonutility generation on planning would similarly receive continued analysis. For example, the requirements, costs, and benefits of such factors as fuel type and diversity, location relative to transmission facilities, and construction lead time and risk would receive continued attention. Utilities obtaining power from IPPs-also allowed under this scenario-would have to address these same issues of cost and value.

### Transmission Access

Increased voluntary transmission access would be encouraged, too, although in an unspecified way. It is not known how effective these efforts will be to actually increase access. Efforts to encourage utilities to provide additional voluntary transmission access would likely involve continued analysis of the costs of transmission service. For example, for wheeling between vertically integrated utilities, analyses would examine reliability-the adequacy of and costs of transmission capacity; the costs of spinning reserves; the system engineering of relays and other protection devices—and the ability of control centers to coordinate an increasing number of transactions. For wheeling to small full requirements utilities, the costs and requirements of following changing loads-including frequency regulation and following daily, weekly, and seasonal cycles-require examination as well. Retail wheeling, although unlikely, would require similar analyses.

## Scenario 2: Expanding Transmission Access and Supply Competition

### Supply Competition

Under scenario 2, nonutility generation, including IPPs, would be further encouraged. The resulting change in costs and performance among competing supplies is speculative. As in scenario 1, to the extent that nonutility generation develops, nonprice factors will require increasingly careful analysis. Again, this will require site-specific analyses of the requirements, costs, and benefits of different levels of central control of generation (e.g., scheduling and dispatch for use in load following and maintaining reliability). The technical-economic questions that arise in system planning and operation will have to be made explicit and acceptably understood to all parties involved: utilities, regulators, nonutility generators, consumers, and other possible interveners. This may be challenging, since expertise in detailed areas of power system engineering and economic analyses are required.

### Transmission Access

The second scenario also leaves the vertically integrated utilities in place. However, access to the transmission system is expanded by allowing utilities and large retail customers to seek mandatory wheeling. It is not possible to determine how much wheeling would result from implementation of a "broad public interest standard" for wheeling. The demand for transmission access will depend on the type of service mandated (e.g., load following or base load), the pricing of transmission service, availability of transmission capacity, and the availability of lower cost bulk power supplies from nonutility generators and remote utilities.

To the extent that transmission access is mandated, the efforts in analyzing costs and availability of transmission services and developing procedures for dispatch and scheduling for voluntary wheeling, as discussed under scenario 1, would be critical. The new wheeling orders would have to address issues of developing priorities for transmission scheduling and for curtailing transmission uses as contingencies occur. Provision of backup supplies and spinning reserves for reliability and adequate generation to follow changing loads must also be addressed for wheeling to retail consumers and requirements utilities.

Given the decreased authority of utilities to claim transmission limits and set priorities for use of constrained facilities (e.g., a rebuttable assumption that the capacity to wheel exists places the burden of proof on the utility), regulators must make provisions to ensure that significant degradation of reliability and economy does not occur under mandatory wheeling. Determining which wheeling orders can be issued without exceeding a system's capabilities will require expertise and data in detailed areas of utility engineering and analysis, including economic dispatch modeling, load flow analyses, and contingency and stability analyses. This expertise will also be required to give informed judgments on the prices charged under wheeling orders. Wheeling may require revising both generation and transmission system planning as new patterns of loads and suppliers develop. Provisions addressing the advance notification given by retail and requirements utilities before switching suppliers will need to be developed. Additional generation and transmission reserves may be required to account for any increased uncertainty or loss of coordinated control in operating and planning.

## Scenario 3: Competition for New Bulk Power Supplies

### Supply Competition

Scenario 3 creates a competitive market for all new electricity supplies. Utility affiliates would be able to ''bid" to supply power in their own service areas, with appropriate safeguards. Utilities would remain the suppliers of last resort under traditional rate-base regulation. This would further encourage nonutility generation including IPPs. The resulting change in costs and performance among competing supplies is, again, uncertain. If competitive procedures prove more attractive than rate base supplies, scenario 3 will eventually result in a generation sector separate from transmission and distribution.

Utilities obtaining their new capacity through a competitive process will face the same challenges described under scenario 2. The technical requirements of analyzing the requirements, costs, and benefits of different levels of coordinated control of generation operation and planning, and developing procedures to obtain that control, remain. Many of these will need to be specified in advance of solicitations so that they can be reflected in pricing and evaluation. Again, included in the possible changes is a need to increase reserves of both generation and transmission as a response to greater uncertainty. The uncertainty involves not only how well generators will perform individually, but also how well new institutional relationships for coordinating individuals will work.

Regulators and utilities will have a new and challenging job in assessing the hard-to-quantify value of supply characteristics such as dispatchability, fuel diversity, location, and likelihood of project completion. As with mandatory wheeling, meeting this requirement will call for expertise in detailed areas of utility engineering and analysis, including economic dispatch modeling, load flow analyses, and contingency analyses, as well as system restoration, communications, and power control.

### Transmission Access

Scenario **3** raises the same requirements and challenges of mandatory wheeling discussed under scenario 2. However, the extent of transmission access and who it is available to differs. Again, the extent to which transmission access orders would be requested is speculative. The provision for public interest transmission orders in scenario 2 would continue to be available to utilities. In addition, utilities seeking new power supplies or competing to supply others must offer transmission access to other suppliers. However, there would be no regulatory orders for retail wheeling, simplifying some of the wheeling issues discussed under scenario 2.

### Scenario 4: Generation Segregated From Transmission and Distribution Services

Under scenario 4, the power industry would be restructured to create a competitive unregulated generating sector separate from transmission and distribution. That is, all supplies would be obtained by transmission and distribution companies from a competitive generation sector. Scenario 4 raises immediate problems of establishing coordinated operations. Coordinated control of generation for frequency regulation and following cyclic load changes, for maintaining reliability as system conditions change, and for controlling transactions between parties must be implemented. The transmission and distribution companies would retain the traditional utility responsibility of planning and acquiring supplies, although now from an unregulated competitive generating sector. The allocation of rights and responsibilities between generators and the transmission company must be carefully instituted.

The need to rapidly develop and implement radically new operating and planning procedures for competitive generation and mandatory wholesale customer transmission access makes scenario 4 considerably more risky and uncertain than the previous three. Both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new operating and planning procedures.

The vital technical difference between scenarios 3 and 4 is the abruptness and certainty of change in separating the generation sector. As existing utility-owned generating units are decommissioned, scenario 3 may eventually result in a transmission and distribution sector separated from generation similar to scenario 4. However, that outcome assumes that utilities will not successfully compete in building and operating generating units in their own service areas, which may not be the case. Thus, the evolution will occur slowly, if at all, giving a long time to develop the procedures required for coordinating operations and planning. Also, the long transition period gives many opportunities for experimentation and the chance to reverse the course of change if necessary.

### Scenario 5: Common Carrier Transmission Service

**The** last scenario completes the separation of utilities into generation companies, transmission companies, and distribution companies. The transmission companies become common carriers with the responsibility to provide for adequate transmission capability. The main technical distinctions from scenario 4 are the separation of transmission from distribution; and the requirement to provide wheeling service to all retail customers, reintroducing the operating and planning issues discussed in scenario 2. As in scenario 4, a great technical challenge is presented by the abruptness and certainty of change. The need to rapidly develop and implement radically new operating and planning procedures immediately, including retail wheeling and the complete separation of transmission from distribution, makes scenario 5 even more risky and uncertain than scenario 4. Again, both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new operating and planning procedures.