The Electric Power Industry -
Deregulation and Market Structure*

by

Robert Thomson

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ABSTRACT

The US electricity industry currently consists of vertically integrated regional utilities welding monopolistic power over their own geographic markets under the supervision of state and federally appointed regulators. Construction of the national grid of interconnected high voltage transmission lines that allow the bulk transport of electricity across the nation, overcapacity and the move away from centralized generation has eliminated many of the justifications for monopoly control and regulation of generation and transmission. As with the airline industry, natural gas and telecommunications, an open and competitive market is now possible.

This thesis investigates and discusses the alternative market structures that are currently being proposed for a deregulated and competitive electricity industry, namely the centralized "Poolco" and the decentralized or bilateral "NetCoor" models and determine the attributes of each most likely to promote market efficiency.

Further, by hypothesizing that both models will be allowed to evolve so as to enhance flexibility and economic efficiency in the market, then the final equilibrium market structures bear remarkable similarities in their underlying characteristics.

The public policy decision then becomes not which market structure to choose for a deregulated and competitive electricity market but rather which path to choose in transition to the equilibrium market structure.

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Introduction

Electricity regulators and utilities are facing increasing pressure from consumers and legislators to open up the previously monopolistic electrical energy markets and allow competitive trading independent of geographic barriers. Such pressures resulted in the enactment of the Energy Policy Act (EPAct) of 1992 and the California Public Utilities Commission’s “Blue Book” proposals\(^1\) of 1994 that would dramatically increased the freedom of electricity producers and consumers in that state to trade across franchise boundaries.

The current industry structure consists primarily of vertically integrated regional utilities wielding monopolistic power over their own geographic markets under the supervision of state and federally appointed regulators. The monopolistic structure of the industry has its origins in the historically capital intensive nature of electricity generation plant and the technical limitations on transmission of electricity.

Construction of the national grid of interconnected high voltage transmission lines that allow the bulk transport of electricity across the nation, over-capacity and the move away from centralized generation has eliminated many of the justifications for monopoly control and regulation of generation and transmission. As with the airline industry, natural gas and telecommunications, an open and competitive market is now possible.

The question currently being hotly debated in California and across the US is how best to design a market structure for electric power transactions that

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encourages efficiency, allows freedom of choice and ensures the reliability of the power grid is maintained.
History

Electricity had very limited applications until Thomas Edison's development of the first commercially practical incandescent lamp in 1879 together with his design for a complete electrical distribution system for lighting and power, culminating in the installation (1881–82) of the world's first central electric-light power plant in New York City. Being safer and cleaner than its nearest rival energy source at that time, gas, the popularity of electricity in the home and in industry flourished.

The capital intensity of generation and the socially undesirable cost of having multiple competing distribution systems supplying the same region lead to early recognition of electricity generation and distribution as a natural monopoly and a public utility. This required the establishing of franchise regions and price regulation together with the necessary institutions to oversee the monopoly industries.

At the turn of the century there were some 3,600 electricity utility systems in the US, by 1917, more than 6,500. It wasn't until the late 1920's that the generation and transmission technology developed to a sufficient state to encourage scale economies and many of the smaller electricity utilities started to consolidate. By 1930, there were some 2,000 systems in existence, a figure that has risen to just over 3,200 today.

The size and efficiency of generating units has grown exponentially up till the last two decades. The earliest generating units were 7.5 kW in size and lucky to get thermal efficiencies of 10%. By 1903, the largest unit was 5,000kW, in 1930, 200MW in 1955, 300MW and from 1970 until today, the

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largest available unit size has plateaued at 1,300MW, however the most
efficient coal fired units range in size from 350MW to 650MW, achieving
thermal efficiencies of around 40%\textsuperscript{4}.

Scale economies, the necessity of locating generating units near a substantial
sources of water for cooling and coal for fuel, has led to increased
centralization of generating plant remote from cities and major load centers.
This has required the construction of a transmission grid to deliver the
generated electricity to the loads. The trend for centralization is, however,
reversing as maximum efficiency is available from smaller units and natural
gas, via pipeline, is supplanting coal as the preferred fuel for new plant.

\textbf{Industry Structure}

\textbf{Ownership and Concentration}

Of the 3,241 electric utilities in the US today, only 8% or 267 are privately or
investor owned. These privately or investor owned utilities are vertically
integrated and account for 76% of all electricity sales to ultimate consumers
and 38% of wholesale power sales to other utilities (public or private) for final
distribution. The largest 50 privately or investor owned utilities account for
60% of sales to the ultimate consumer\textsuperscript{5}

Of the remaining 2,974 utilities, 2,011 are state or locally owned, 953 are
cooperative and 10 are federally owned\textsuperscript{6}. Most of the publicly owned utilities
simply distribute power; they are non-profit local agencies established to
serve their communities and near by customers at the lowest possible cost.

\textsuperscript{4} Messing, Friesema and Morell. 1979.
\textsuperscript{6} Co., 1992.
\textsuperscript{5} \textit{Ibid.}
The three federally owned electricity utilities, Tennessee Valley Authority (TVA), Bonneville Power Administration and Western Area Power Administration account for about 8% of all generation, and the remaining 7 federally owned utilities account for 0.07% of all generation. Almost all is wholesale sales to public and non-profit utilities for distribution to the ultimate customers. The 2,011 state and locally owned utilities account for approximately 14% of generation.\(^7\)

**Regulation**

From the very early days, regulation of the electricity industry was seen as necessary so as to prevent profit making utilities from taking advantage of their monopoly position and ensure the security of supply to all users. Regulation started at the local government level but as electricity companies consolidated and expanded beyond city and county limits, the states started to take responsibility for regulation. By 1932, 70% of the nation's generating capacity was controlled by only eight large holding companies. The Federal Government introduced the Public Utility Holding Company Act of 1935 to break up and simplify the industries structure.

The State regulatory authorities (Public Utilities Commissions or PUCs) still wield most of the regulatory control in the US, with the Federal Energy Regulatory Commission acting as a national umbrella organization, having influence over the State bodies rather than legislated authority and, more importantly, having direct jurisdiction over electricity transactions and rates conducted across state lines.

\(^7\) *Ibid.*
Regulatory Authorities have allowed utilities to set rates on a "cost-plus" basis so as to recoup the capital and running costs of their systems plus a "reasonable" rate of return (generally less than 12% on equity). Regulators have also been involved in planning, both capacity and siting of generation and transmission.

Independent or Non-Utility Generators (NUG's) are allowed to operate within franchise areas but are required to enter into long-term contracts with the existing utility at prices approved by the regulators and based on "avoided costs" of the incumbent franchise utility.

**Transmission and Pooling**

Since the early 1930's, with the enactment of the Federal Power Act, Part II, it has been Federal policy to encourage interconnection and coordination amongst utilities so as to share resources and economies of scale. Up till then, electricity utilities had remained electrically isolated, generating to meet their own franchise region load requirements. From the 1930's onward, the national grid developed into the three interconnected blocks that constitute the US power industry today. These are the Western Interconnect, the Eastern Interconnect and the Texas Interconnect. These three regions are further divided into 133 "controlled areas" within which individual generators pool their resources to meet combined load and reliability considerations of the area and allow some degree of import or export of energy to the area. The utilities within these areas coordinate their

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4 In establishing the price that electricity would be purchased from NUG's, the state commission decided what was "avoided cost", i.e. the system expansion delayed or negated by generation from the NUG. Utilities could not refuse generation from the NUG's once approved by the regulators.


10 It is interesting to note that Texas has kept it's system electrically isolated from that of neighboring state so as to avoid the regulatory influence from the FERC.

operations with varying degrees of formality, ranging from loose bilateral agreements on the exchange of energy with no form of enforcement or penalties, to tightly controlled pools requiring centralized control of facilities as a single operating system, structured operating procedures and enforcement through penalties. Transactions of power from one utility to another are termed bulk or wholesale transactions. About half of the electricity sold at the retail level to the ultimate consumer is transacted in the wholesale market first.

The trend towards centralization, pooling and interconnection have resulted in the well developed national transmission grid now in place across the US and connecting Canada and Mexico. This transmission grid allows bulk power to be efficiently transacted across state and national borders on a routine basis to take advantage of cheaper sources and load diversity.

Regulation on utilities requires that wholesale transactions are accounted for using a "split savings" formula\textsuperscript{12}, which calculates the savings obtained through the transaction, i.e. the welfare surplus, and divides the surplus evenly between the two parties. This results in a multitude of prices for the same commodity, violating the "Law of Single Price"\textsuperscript{13} for open and efficient markets.

Supply and Demand
The demand for electricity has grown with the economy. For the past 15 years, electricity sales have increased at a compound annual rate of 2.7%.

\textsuperscript{12} See Appendix 1 - An Example of Split Savings Pricing.
\textsuperscript{13} Economic theory states that in an efficient and contestable market, all goods transacted at a given time will be sold at the same price, a price equal to the marginal cost of production and marginal utility of consumption. Violation of this law allows arbitrage by traders in the market. See R. Schmalensee and R.D. Willig "Handbook of Industrial Organization. Vol. 1", North-Holland. 1989.
down from the +6% growth of the late 60's and early 70's\(^{14}\). Electricity sales contributes approximately 3% of the U.S. GNP\(^ {15}\). Insufficient capacity to meet demand can result in severe consequences as is evident from the east coast system collapses of 1965 and 1977 that saw large segments of the east coast blacked out for more than 24 hours. Fear of reoccurrence of system collapse due to shortages in supply together with over enthusiastic forecast growth from the 70’s, the long lead time from initialization of new plant to coming on line (3-5 years) and market insulated cost-recovery regulation in place has resulted in over-capacity of generating facilities of approximately 20% of peak demand\(^ {16}\).

**Industry Dynamics**

**Forces for Deregulation and Open Competition**

Electricity is in many respects a pure commodity\(^ {17}\), with no differentiation and no way of identifying the source of electrical power by the end user. Voltage, phase angle and waveform harmonics are qualities of electric power that can be easily “transformed” on the system or at the load using voltage transformers, reactors or capacitive compensators, the underlying energy component of electric power is unchanged. With consumers seeing price variations of two or three times across utilities, even between adjacent utilities\(^ {18}\), and over capacity raising prices rather than resulting in lower prices due to increased competition\(^ {19}\), there has been pressure from

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\(^{16}\) Electric Power Trends 1992

\(^{17}\) Further discussion in this document will be devoted to the homogeneous verses heterogeneous nature of electric power and how much of a “pure commodity” electricity really is.

\(^{18}\) An extreme example of pricing disparity is the comparison between Idaho Power, with retail tariffs averaging around 4c/kWh and Long Island Power with tariffs of 16c/kWh.

\(^{19}\) As regulation sets tariffs to allow cost recovery based on variable and capital costs, over-capacity and hence higher capital costs, will increase tariffs.
consumers to open up the industry to competitive forces. Competition is expected to reduce prices in the same way that deregulation of the airlines, natural gas and telephone industries resulted in reduced prices, as well as establishing the correct price signals and incentives for investment.

With open competition, the price of electricity can be thought of as consisting of three components, the generation price component (production cost), the transmission and distribution price component, adjusting for losses (the transportation cost) and the system administration charge. The generation price component as in any competitive market will be the marginal cost of the most expensive generating unit supplying to the system, the marginal generator, and will set the single price paid by all customers. Establishment of a spot price based on the marginal cost of generation (including marginal cost of fuel, maintenance, losses etc.) is the foundation of an efficient competitive marketplace in electrical energy. The transmission cost is more difficult to calculate as it must capture the losses and the congestion on the transmission system incurred in transporting the energy, as well as ensuring recovery of the substantial capital costs associated with transmission facilities. The system administration charge will be subject to some degree of regulatory control and will be imposed as a form of tax on the system users (suppliers and/or consumers).

With the transition to a competitive market, participants will be able to buy and sell electricity through bilateral contracts or at a time varying spot price, independent of existing regulatory boundaries. New entrants will be able to take advantage of regions served by high cost producers, and those producers

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who are not competitive and can no longer use their monopoly power to recover costs will be forced to exit.

**Bilateral and Centralized Markets and Exchanges**

Before entering into a detailed discussion of competitive electricity market models, it is necessary to define what is meant by a bilateral and a centralized market, the differences and institutions that exist for both.

A bilateral market is an informal or over-the-counter market, in which buyers and sellers meet, in the extreme case, a random pair-wise manner\(^{22}\) or more moderately via intermediaries\(^{23}\) and reach exchange and establish contracts to meet their own unique needs, independent of all other buyers and sellers in the market. Contracts written in a bilateral market will generally have to comply with common law or some set of industry ethics but otherwise can be tailored to match any range of requirements of the parties involved. Bilateral markets are most often observed for transaction of heterogeneous or non-commodity goods such as real estate, used cars and labor.

Bilateral markets are, in general, imperfect, that is to say there exist asymmetries in information and heterogeneous aspects of the goods exchanged. There are costs associated with transactions in a bilateral market, including information gathering costs, communicating costs, negotiating costs and contract administration costs. These costs are most often observed in the form of brokerage fees. A bilateral market for a heterogeneous good cannot act on an instantaneous basis as the information gathering, negotiation and contracting process requires finite time to


Centralized markets, on the other hand, are characterized by commodity goods, a single price for all purchases and sales and institutionalized trading rules and regulations. The best examples of centralized markets are stock exchanges (New York Stock Exchange, London Stock Exchange, etc.) and commodities markets (Chicago Board of Trade). Transactions in these markets are characterized by very low transaction costs and near-perfect market information.

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Although the terms of a transaction in a centralized market are fixed by the governing body (the Securities and Exchange Commission for stock exchange transactions), financial instruments such as futures contracts, options and fixed-price long term supply contracts can be constructed bilaterally to meet the needs of individuals in the market and based on the centralized market's spot price. The form of these contracts becomes a function of, amongst other factors, the spot price level and the anticipated volatility of that price over the term of the contract. Such contracts do not require ownership of resources for production or consumption, only access to the centralized commodity market and sufficient funds to ensure contract closure under all circumstances.

Centralized markets tend to experience greater price volatility and higher trading volumes than bilateral markets in the same commodities, due to the ease with which prices can be changed and the low cost of transactions.\footnote{The Black-Scholes formula for pricing options uses the strike price, duration, current stock price, historical volatility of the stock and the risk-free interest rate to calculate the value of the option contract. Forward and futures contracts use the current spot price, the risk free interest rate and carrying costs (if any) to calculate the value of the contract. See J.C. Cox and M. Rubinstein, "Options Markets", Prentice Hall, 1985.}

\footnote{Biais. 1993}
Functions of an Integrated Utility

Having described in general terms market structures and the characteristics of goods transacted, it is now necessary to consider the functions of a traditional vertically integrated utility and the products of the utility that would become available for sale in a competitive market.

The three functions of a vertically integrated utility are:

**Generation.** The construction, operation and maintenance of generation plant to supply electrical energy to the system. This includes coordination of generators to gain the most economic allocation of load across units (economic dispatch) and maintaining of sufficient reserves to meet peak demand and allow for contingencies due to outages.
Transmission. The transmission lines under the control of utilities ensure bulk transfer of electrical energy from generating plant to the load centers. This includes interconnection of generating units, through the transmission grid, to afford the diversity and economy functions associated with generation dispatch.

Distribution. This is the final segment of the utility's responsibility and links the bulk transmission system to the final customer through the distribution system. Electrical energy is delivered to the customer at the desired voltage and with acceptable noise and reliability characteristics.

The interconnected transmission grid allows exchange and substitution of generation and transmission in a competitive market. The pervasive natural monopoly nature of distribution makes operation of the distribution function as a franchised monopoly subject to regulation the most efficient type of organization.

Requirements of an Electric Power Market
Irrespective of the form a competitive or regulated electricity market takes, a number of public policy requirements have to be met. These include:

Efficiency. An efficient market will ensure the best allocation of resources and the establishment of prices that reflect marginal costs. The efficient market will also establish price signals and incentives for optimal future investment in system modifications and expansion.

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27 Power system noise can consist of voltage harmonics, spikes and switching surges that may adversely affect the consumer's electrical equipment.

28 Competition at the distribution level can occur if "open access" to distribution facilities can be ensured, however there are many difficulties associated with this including valuation of sunk distribution assets and operating costs. See P.L. Joskow and R. Schmalensee. "Markets for Power. An Analysis of Electric Utility Deregulation. The MIT Press. 1983.
Reliability. The consumer has the right to expect continuity and reliability of supply. This is because the final consumer has only one source of supply, the incoming utility service and is dependent on that service. The consumer cannot store electricity or instantaneously switch to another supplier\textsuperscript{29}. The consumer invests in capital plant and durable goods that can operate only on electrical power. These sunk investments and dependence on a single source of supply place considerable hold-up power in the hands of the utility.

Unreliability can arise from a number of sources, including shedding of load due to a shortage of generating resources, outages of transmission or distribution lines or failure of other systems components. Such outages can result in loss of supply in a localized region for a few seconds to a matter of hours, or at the worst, days. Should demand exceed supply, then the system may become unsynchronized, resulting in wide-ranging blackouts and system collapse\textsuperscript{30}. The system operator must ensure that sufficient spinning reserve is maintained across the network to provide voltage and frequency support in the event of an unplanned outage.

Freedom of Entry and Exit. A competitive market must be open to all entrants, both generators and consumers. To ensure competition, there must be freedom of entry and exit. As electricity supply must be considered a necessity rather than a luxury for most consumers, there still exists the obligation to serve, or, more generally, the obligation to connect. That is, a utility cannot abandon some users. Regulation was used as a means of ensuring this obligation was met, but also meant that some generators were

\textsuperscript{29} The exception here being, of course, customers who are extremely sensitive to continuity of supply, such as hospitals and computer facilities, who choose to install their own source of emergency power which they can turn to in the event of the utility supply being disrupted.

\textsuperscript{30} The northeast utility failure of 1965 which left much of the northeastern states of the US, including New York City without power for 24 hours or more was the result of a system collapse brought about by demand exceeding supply over a very short time frame and slow response by utilities in attempting to adjust. A similar failure occurred again in New York in 1977.
excluded from the system. Some degree of regulatory intervention is required at the distribution level to ensure all customers are connected.

**Economic Characteristics of Electric Power**

Electric power demonstrates a number of interrelated characteristics that influence the manner in which a market will operate. The ideal market model must deal with all of these characteristics with difference to the unique nature of electric power.

In an efficient market, all commodity goods will trade at the same price (Law of Single Price). Debreu defines a commodity as:

"... a commodity is a good or a service completely specified physically, temporally and spatially."

To specify the physical, temporal and spatial elements of electrical and hence understand how the market will best determine efficient pricing, it is necessary to define the characteristics that constitute electrical energy.

**The Physical Characteristics of Electric Power**

In many regards, electric power delivered at a particular place and at a point in time can be considered a homogeneous commodity. Each unit of electrical energy (kWh) delivered at the same location at any instant is indistinguishable from any other, and there is no means of determining the source of electricity once it enters into the interconnected power grid. There cannot be asymmetries of information or differences in price associated with the commodity nature of electricity.

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The Temporal Characteristics of Electric Power
As demand for electrical energy varies with time, the cost characteristics of the generating source will vary with load and/or different sources of generation must be used to supply the demand. As market efficiency requires marginal cost pricing, then the price of electrical energy will vary with time. The temporal variation of electrical energy price is determined by the level of demand and the cost characteristics of the sources of energy.

The Spatial Characteristics of Electric Power
There are characteristics of electricity that are unique. The location and time at which electricity is supplied and used is unique. Electricity at a given location and given time will have a different value than for any other point on the power system. This difference may arise from the cost of transmission of electricity from the source to the load or from the cost of different means of generation at different locations or, in the case of a multi-generator interconnected grid, a combination of these effects.

Electric Power as a Public Good
There are non-energy characteristics of electricity, in particular, reliability, that add an additional dimension to electric power. Reliability is the continuity of supply to meet a load without interruption, and has dimensions that relate to the historic and cumulative supply of energy to a load (i.e. cumulative kWh of lost load per total cumulative kWh supplied). As the benefits of reliability are shared by all users connected to the grid, that is, for the most part, reliability is non-exclusionary\(^{32}\). Also “consumption” of reliability does not affect other users, reliability is non-rival\(^{33}\). Reliability of electricity supply demonstrates the characteristics of a public good.

\(^{32}\) It is possible to establish “interruptable” tariffs, that is to shed insensitive consumers first in the event of a system contingency. In effect, this would unbundle and price reliability on the system.

The aim of establishing a competitive market framework is to establish fair and efficient pricing of these distinct but interdependent characteristics of electric power. To achieve this it is necessary to unbundle, price and transact the characteristics of electricity separately. The energy component will have a price determined by the cost of generation and will be predominantly a commodity. The location inherent characteristics of electricity will be linked to transmission resources and will be unique in nature. Reliability will be a complex function of factors including system congestion, instantaneous supply and demand and random fault elements and where it is impossible to unbundle this component of electricity supply, the cost of system security will be passed on to all users in the form of a tax.

A Bilateral Power Market

In a bilateral power market, buyers and sellers will commit to supply contracts independently and to meet their own particular needs. Contracts will be arranged either directly or through intermediaries, brokers or marketers. Inherent in these transactions is an unbundling and rebundling of generation and transmission. That is, as buyers are no longer tied to sellers through the utility franchise, transmission and generation become separate commodities in the market. The bilateral supply contract must, however, rebundle generation and transmission to meet the needs of the customer. In this manner, the bilateral market takes care of the unique temporal and locational-specific characteristics of electric power by letting the market decide the value.

The bilateral market does not, however, automatically deal with the public good aspects of electricity. The bilateral market requires some mechanism to ensure reliability. Also some mechanism for making up shortfalls or surpluses, either planned or unplanned must be incorporated in the market.
function. An Independent System Operator (ISO) must be established to ensure stability and reliability as well as accounting for contract differences. An independent and price-insensitive ISO, would be required in the bilateral market. The ISO would operate on the margin of the market, would not be responsible for market transactions or efficient allocation of resources and would only be responsible for maintaining reliability and stability across the system. Such a model can be seen in operation for most of the loosely coordinated control regions across the US and is the form wholesale wheeling has taken in the past. Utilities have engaged in bilateral contracts of this nature since the establishment of transmission inter-ties allowed exchange of bulk power across franchise regions. Stability and reliability was handled within the utilities franchise area by the responsible operators. It is only with further fragmentation of existing utilities with contracts being written on a retail scale that the need for an ISO becomes necessary.

A Centralized Power Market
As with a commodity or stock exchange, a centralized electric power market would require the establishment of a trading institution to act as the clearing house for market transactions and establish the spot price for all purchases and sales. Such a model exists in the form of a Pool.

The Pool model of utility operation relies on tight coordination of resources over a control region. There exist currently in the US a number of tightly coordinated power pools including most notably the New England Power Pool (NEPool), the New York Power Pool (NYPP), and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). These pools were established to share the benefits of the combined diverse resources and loads of the member utilities, resulting in savings from economic dispatch and shared reserve
capacity\textsuperscript{34}. Power pooling is, in effect, a form of horizontal integration of generating and transmission resources by the member utilities.

The horizontal integration across the pool is never absolutely complete. For most pools, the responsibility for meeting own-load requirements as a priority resides with the utility. Only for load and capacity in excess of own-load requirements is pooling and dispatch conducted. An exception to this requirement is NEPool, the most tightly operated power pool in the US. for which participating utilities must hand over full responsibility for committing generating units and meeting load to the central dispatcher.

\textbf{Pricing of Electricity.}

The three unbundled components of electricity can be priced using different methods depending on the applicability to the model adopted. Pricing methods are not mutually exclusive and may be combined to match the needs of participants.

\textbf{The Pricing of Energy}

Since electric energy at a specific point of time and location is a defined commodity we expect the market to clear (supply to equal demand), then price will equal marginal cost of production and marginal cost of consumption, assuming efficiency of the market. The difference in the centralized market and bilateral market is the duration of the equilibrium price. In the centralized market, the spot price will vary continuously or at short time intervals (15 minutes to an hour) as does the equilibrium. Whereas in the bilateral market, market clearing will occur over a much longer time frame, as bilateral contracts will "average" instantaneous costs.

\textsuperscript{34} FERC. "Power Pooling in the United States", 1981.
over their duration\(^{35}\). The duration of bilateral contracts could be as short as that for the central market or could be for an entire year or more. Assuming that there are transaction and agency costs incurred in bilateral contracts, then it can be expected that longer duration will be more efficient. Further, it is safe to assume the lower the transaction costs, the shorter the duration, the extreme being zero transaction costs and continuous recontracting. If such zero cost continuous contracts are multilateral rather than just bilateral, then we have a centralized market.

### The Pricing of Transmission

The heterogeneous nature of transmission and the interdependency of generation and transmission increases the complexity of pricing of transmission in a competitive market. Transmission and generation are interdependent in so far as transmission capacity is required to deliver generated energy to the load and that for an interconnected grid there are numerous substitutable combinations of generation and transmission available to supply a load.

One solution to transmission pricing is to establish tradable transmission capacity rights that could be exchanged in the bilateral markets either bundled or unbundled with generating capacity. The monopolistic nature of some sections of the transmission system, i.e. those that are the only path to a group of consumers or are the only alternative paths to a constrained line, offer the possibility for opportunistic behavior by some holders of transmission rights. Such behavior is not in the best interests of the public and would result in market failings.

\(^{35}\) The theories of transaction economics imply that the greater the cost of a transaction, that is, the agency and contracting costs, then the less frequent recontracting will occur and the longer the duration of the contract. Refinancing a home mortgage is a good example. See P. Milgrom and J. Roberts, “Economics, Organization and Management”, Englewood Cliffs, NJ. Prentice Hall. 1992.
The allocation of control of all transmission resources to a centralized operator, the ISO, would prevent opportunistic behavior but still leaves us with the question of fair pricing. One option is to allow single priced access to the grid, or postage stamp transmission charges, to provide a "level playing field" for all generators competing in the market. Rates would be set to allow cost recovery of investments by owners of the transmission grid. The postage stamp charges would not vary with user or time of day.

The problem with postage stamp charges or any other form of fixed transmission tax is that it does not allow for or attempt to price congestion. In this case, when congestion does occur on the system, some mechanism must be incorporated in the operation of the market to compensate those affected. This encourages gaming by generators against the compensation system and does not establish incentives to build transmission capacity to negate the congestion.

A variation on the single transmission price is to establish zones on the system with boundaries defined by congestion on the interconnecting transmission lines, and having additional postage stamp charges for transmission between zones. This will send price signals that deter trading of energy across the congested boundaries of the zone and encourage investment in transmission capacity to relieve the congestion and hence allow access to cheaper power by consumers and higher paying markets by generators.

36 The competitive U.K. electricity market suffers from such problems. Generators that are "constrained on" or "constrained off" due to transmission system congestion are compensated for additional or lost generation based on the difference between their bid price and the spot price. Generators that are "constrained on" can increase returns by over pricing their bids, and generators "constrained off" can benefit by underbidding their price. See "An Introduction to the Initial Pool Rules", Prepared for the Executive Committee by NGC Settlements Limited, March 1991 for a description of the U.K. electric power market operating procedure.
The problem with zonal pricing of transmission is that it does not account for the fact that congestion varies with load and hence time. To prevent congestion, the inter-zonal transmission price must be set to the price difference between the zones at times of peak load (i.e. when congestion will be greatest). This discourages transmission across an unconstrained zone boundary during low demand periods when such transfers would otherwise be economic and efficient. Also zones must be established with boundaries at all points of congestion on the system, potentially leading to a highly fragmented and unnecessarily expensive transmission costs across multiple zones.

By varying the inter-zonal transmission cost with time to reflect the cost of congestion\(^\text{17}\), and declaring each bus on the system to be a zone, we have nodal pricing of transmission\(^\text{18}\). The nodal price at a bus is the marginal cost of generation plus the opportunity cost of congested transmission to deliver the energy to the bus.

An example of the simplest case of nodal pricing of transmission is for a consumer who can either import power over a transmission line for a cost of remote generation of, say, 4c/kWh or generate locally at 6c/kWh. The transmission line has a capacity of 600MW. For the consumer’s load of up to 600MW, all power will be imported, with payments to the remote generator of 4c/kWh and no payments to the transmission rights holder. As load exceeds 600MW, the local generator will start to supply energy at a cost of 6c/kWh. The nodal price at the load is now 6c/kWh and is paid for all electricity consumed, irrespective of whether it is generated locally or imported. The remote generator is unaffected by the constraint of the

\(^{17}\) The cost of congestion is the difference, in real time, in the marginal cost of generation on each side of the congested line.

transmission line and the new nodal price at the local bus. The remote
generator is still able to supply electricity at the remote bus at 46/kWh, the
nodal price at that bus, and will receive payment at that price for exported
electricity. The price difference between the 60/kWh paid by the consumer
and the 4¢/kWh received by the remote generator i.e. 2¢/kWh is paid to the
owner of the transmission line rights. The 2¢/kWh is the value added to the
electricity by transporting it through the transmission line from the remote
generator to the local load. With open access and competition, anyone who
can transmit that power for less or supply it from a source generating a cost
below 6¢/kWh and deliver it over unconstrained transmission lines is able to
do so and by doing so would lower the cost of all electricity at the load and
the transmission payments.

This simple example can be extended to a complex transmission grid with
any number of transmission lines, generators or loads. The principals of
marginal cost pricing and of a single price for open markets are maintained.
The market is, in effect, composed of two interdependent commodities,
generation and transmission. Alternatively, two markets could be
established, one for generation and another for transmission. The
interdependency and instantaneous nature of supply makes very close
coordination of these markets essential as purchase of generation may be
rendered useless to the consumer unless access to specific transmission can
be guaranteed.

In a single market, a combination of generation and transmission to supply a
specific load competes with other combinations of generation and
transmission or local generation to supply the same load across a complex
grid of interconnected loads, generators and transmission lines. This leads to
different nodal prices for electricity at locations across the grid, varying due
to the degree of congestion, and hence cost of transmission, imposed in delivering electricity to the location of the load.

The Pricing of Reliability
As discussed earlier, reliability is a common good, and cannot be sold in "units of reliability". It seems likely then that under either a bilateral or centralized market, where consumers cannot control their own level of reliability and the actions of one market participant have the potential for adversely affecting many others connected to the system, reliability will be centrally controlled and the cost of reliability will be spread across all users in the form of a tax on energy usage or indirectly through increased energy costs charged by generators.

The cost of reliability is the opportunity cost or lost efficiency imposed by maintaining the necessary spinning reserve on the system to ensure the system does not collapse\(^\text{39}\) due to an unforeseen contingency such as a generator outage or transmission line failure. In a centralized market, the system dispatcher will determine the optimal dispatch across all generators on the system, subject to transmission congestion but in the absence of spinning reserve requirements, to give the unconstrained dispatch\(^\text{10}\). The dispatcher will then determine the actual dispatch including spinning reserve requirements to give the constrained dispatch. The difference in profits between the constrained and unconstrained dispatch for each generating unit will determine the opportunity cost to the unit of supplying spinning reserve to the system. Generating units can then be compensated

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\(^{39}\) A system collapse occurs when short run supply cannot meet short run demand, system frequency starts to drop, tripping off more generators and increasing the imbalance, eventually resulting in total system collapse. The solution to this problem is to ensure there is enough spinning reserve on the system, that is, unused generating capacity synchronized to the system frequency that can make up the short fall in generation very rapidly or, alternatively, have loads on the system that can be shed very quickly.

\(^{10}\) See Appendix 2 on economic dispatch and constrained verses unconstrained dispatch.
for the opportunity cost of supplying spinning reserve by the dispatcher or
ISO, who will, in turn, recover the costs from all connected customers on the
grid.

Spinning reserve can be derived from sources other than generation,
including dispatchable load or system intertie arrangements, a competitive
market could be developed for spinning reserve. The spot price for spinning
reserve is the marginal opportunity cost of spinning reserve determined from
the generators cost curve\(^{41}\) and as with energy, all sources of spinning reserve
could be paid the spot price for all reserve supplied. The total payments
made by the dispatcher for spinning reserve will then be recovered from
consumers in the form of an energy tax.

In a bilateral market, the ISO will determine the amount of spinning reserve
required and location of congestion points on the system. How the ISO
ensures reserve margins are maintained is not clear. One method is to
require each generating unit to be responsible for maintaining the reserve
margin proportional to the unit's output\(^{42}\), and then allowing inter-generator
trading of reserve margins to encourage efficient allocation of spinning
reserve across all units. The cost of spinning reserve to the generator, either
in the form of opportunity cost to it's own lost generating capacity or the cost
of spinning reserve contracts with other generators, will be passed on to the
consumer in the energy contract.

\(^{41}\) See Appendix 3. Spinning Reserve Marginal Cost and Price

\(^{42}\) Since spinning reserve requirements are determined by the largest unit connected to the
system i.e. largest contingency, then different generating units will impose different reserve
requirements and costs on the system. It has been suggested by Brendan Ring and Grant
Reed of Canterbury University in New Zealand that generators be charged the marginal cost
of spinning reserve on the system due to the individual generating unit connected to the
system. See B. Ring, G. Reed and G. Drayton, “Optimal Pricing for Reserve Electricity
Generation Capacity”, Proceedings of the 29th Annual Conference of the Operations
An alternative method of establishing reserve margins by the ISO is for the ISO to purchase call contracts on generating capacity on the system\(^{43}\). To maintain system stability in a case of unplanned outage, the ISO can then call on the contracted capacity to supply the shortfall. In this manner, competitive bidding of call contracts will encourage efficient allocation across generators and dispatchable loads alike.

**Bilateral Trading and Centralized Pools - Market Design and Evolution**

To date, the two market models for electricity, decentralized trading and centralized pooling, have been presented as bipolar opposites, requiring a commitment to one or the other in structuring a competitive market. It is necessary to reconsider the arguments supporting each model in light of the preceding discussion and determine if these arguments truly stand up or if some intermediate market model can be encouraged to evolve that allows the freedom of a bilateral market and matches the efficiency of a centralized pool. Finally, the path to reaching the optimum market model and the costs of the transition can be considered.

**The Case for Centralized Pools**

Supporters of centralized pools argue that by allocating the control of generating unit commitment and dispatch, together with all cost and bid information, then the optimum or least cost economic dispatch will always be achieved in operating the system. Also, a centralized and cost-controlling operator can ensure system reliability for the least cost for all contingencies.

By establishing and announcing a centralized spot price equal to marginal cost and transmission price equal to congestion opportunity cost, and

\(^{43}\) As proposed by Richard D. Tabors, Laboratory for Electromagnetic and Electronic Systems and Technology and Policy Program, MIT.
combining these to give nodal spot prices, the centralized dispatcher facilitates the observability of all price information in the market and thus eliminates asymmetries of information and the associated inefficiencies thus providing all customers with immediate, direct access at arms-length market prices. This form of pricing does not discriminate against smaller participants with limited market power.

In a bilateral market, it is left to each market participant to obtain pricing information across the system, so as to determine efficient pricing. As electricity prices vary significantly spatially as well as temporally, and given the interaction of power flows on the system, gathering the required information so as to assess efficient pricing requires a very high degree of data acquisition and system modeling resources. In effect, each market participant would have to reproduce the pricing function of the centralized dispatcher.

In a pool, from the spot price and using "contracts for differences", financial instruments can be constructed to implement bilateral commercial contracts that meet the individual needs of buyers and sellers without compromising system efficiency.

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16 Ibid.
17 Efficient pricing is the price that maximizes the sum of producer and consumer welfare in the market. From the first theorem of welfare economics, if everyone trades in the marketplace and all mutually beneficial trades are completed, the resulting equilibrium allocation will be economically efficient. To determine if all mutually beneficial trades are completed, then all participants must have knowledge of all trades available.
18 Contracts for differences can be used where delivery takes place in the spot market and long term contracts can be honored through a simple settlements process: 1) For spot price below contract price - Customer uses savings to pay difference to the generator. 2) For spot price above contract price - Generator uses profits to pay difference to customer.
The Case for Bilateral Markets

Bilateral markets offer all participants “freedom of choice” in supply and consumption, as well as providing greater operational flexibility for participants and stronger incentive for innovation in new customer products and services. The laissez-faire market allows any consumer to buy from any generator, if the transmission resources can also be contracted in the market.

The bilateral market has no boundaries or participation rules, other than those related to failure to meet contractual obligations. The ISO does have an area of control in the market but contracting of electricity between participants subject to different ISO control is entirely feasible, as long as the ISO's are notified of the corresponding inflows and outflows.

The pool based market model has been criticized as representing a new form of franchise and hence regulation, imposing unwarranted controls on participants, restricting membership, stifling innovation and inhibiting competition. It is argued that the bilateral can provide efficiencies equal to the pool and, since a bilateral model is not limited in it's scope of trading by regulatory boundaries, it is conceivable that the bilateral model may achieve higher efficiencies. The informational problems associated with a bilateral market can be relieved by market intermediaries or brokers who can gather market information for generators and consumers alike and facilitate mutually beneficial trades.

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Optional or Flexible Pools

In an optional pool, bilateral contracts can be structured through the centralized market by generators bidding quantity rather than price. The dispatcher commits and dispatches units bidding price into the pool together with those units that bid quantity. With regard to the bilateral contract (a quantity only bid), the dispatcher does not collect from the consumer or pay the generator for all energy for which generation equals consumption. The dispatcher does, however, collect and pay for differences and for transmission congestion charges. In the dispatch, the generator is treated as a "must run" unit and never sets spot price. In a similar manner, an optional pool can also allow for transactions across the boundary of the pool into or out of an adjacent pool by keeping account of the effect of the flow on the dispatch and allocation of the remaining resources.

A question arises as to what proportion of generation and load in a region needs to be under direct dispatch of the pool so as to ensure system stability and reliability, and what proportion can operate outside of the pool. It is the opinion of the author that the answer to this question will be system dependent and will be determined by the responsiveness of the pool and outside market participants to price. As demand starts to outstrip supply in

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50 In a bidding system for centrally dispatched generating units, both generators and customers can bid price and let the market (via the dispatcher) determine quantity or bid quantity and let the market determine price. Both price and quantity together cannot be bid unless a third party is willing to hedge the difference.

51 See Appendix 2 on economic dispatch.

52 It is possible for bilateral transactions of this type to occur between pools even if there is no electrical connection between the pools. For example, if a generator and a customer in two different pools which have no electrical connection enter into a bilateral contract for 100kW of exchange, the generator's pool dispatcher runs the generator as a "must run" unit and calculates the spot price. Similarly, the customer is supplied by the generating resources connected to the pool in which it is located and the spot price determined. The generator's dispatcher pays the consumer's dispatcher for the energy used, up to the consumer's spot price. The "virtual" transmission charge is the difference in the spot prices and is charged to (or paid to) the contracting parties to compensate the pool dispatchers for the difference. Reliability charges, incurred by the consumer's pool are also charges to the contracting parties.
the pool. price will rise and elastic consumers in the pool will curtail supply (as in any price elastic market). As the pool spot price is transparent to all consumers and generators, it is feasible to construct the optional pool so that as price rises, consumers in the contract market can also curtail consumption and "resell" contracted power into the pool at a profit. The pool dispatcher need only have control over generating resources that can fill the gap between supply shortfall and demand over the time it takes for the contract market to react to observable price changes in the spot market.

As transactions can be made across pool boundaries, it is now necessary to define the pool. Simply put, the pool is defined by the resources that it controls as a single entity. That is, the generating units available for dispatch, the transmission that facilitates connection of generation and loads and finally the loads themselves. As discussed in the preceding paragraphs, generators can control their own dispatch through bilateral contracts within the pool or outside of the pool, and allow the pool to determine allocation of transmission resources.

In a competitive pool, allocation of these resources by the dispatcher is determined by the bidding process, subject to operational constraints. In determining the economic dispatch, the dispatcher combines transmission and generation in the optimum configuration to meet the load and establish spot prices. If generation is bid into the pool for which the dispatcher does not have control of the transmission rights to connect it to load, then the congestion is infinite for the unit and it will not be called on to run. The generator must then bid into a pool for which connecting transmission is also

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53 The FERC report, "Power Pooling in the United States", 1981 gives the definition of a power pool as: "When utilities form a group to examine their joint needs and resources and agree to operate and plan their system for the best combined economy and reliability, they may be considered to be "pooling", their resources and such a group is often referred to as a "power Pool"."
bid. Similarly, unconnected load will produce an infinite spot price at it's load bus for the dispatch. Generators will be induced to bid into the pools for which the spot price appears most favorable but must also take into consideration the control and capacity of the connecting transmission.

Where adjacent and interconnected pools have differing spot prices at their boundaries, it seems obvious that these pools should enter into exchanges to equalize the spot price. If the dispatchers attempt to calculate exchange quantity with spot price then they will run up against the problem of simultaneity. That is, the optimum exchange between the two pools will be determined by the spot price but the spot price will be affected by the exchange. Only if both dispatchers know the other's load and cost curves will they be able to determine the optimum exchange. If this information is shared freely and all exchanges (including spinning reserve) are optimized at all points of interconnection between the pools, then the two pools become effectively one54.

Alternatively, if pool members are allowed to change pool membership freely and have control of the interconnecting transmission rights, thus forming a flexible pool, then consumers will shift to pools offering the lower spot price until price (including transmission congestion charge) increases to a level of indifference for consumers on the boundary. Conversely generators will shift to the pool offering the highest spot price until price (again, including

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54 An alternative form of market structure somewhat similar in nature is described in Michael C. Caramanis and Richard C. Tabors “Discussion of FERC Docket No. RM93-19-000, Transmission Pricing Issues”. Tabors Caramanis and Associates, Cambridge, Massachusetts, November, 1993. The discussed market structure consists of hierarchical transmission regions, controlling exchange and setting price based on marginal cost within their regions. For exchange between or across regions, a higher order institution, responsible for a number of regions is used, calculating the price of transmission as the difference of the marginal costs on the transmission path. For large exchanges, the congestion and hence marginal cost will change within the regions, and the higher level institution must have access to power flows within the lower level regions to calculate accurate prices and optimal transmission paths. The boundaries between control regions start to appear blurred.
transmission congestion charge) drops to the level of indifference for generators on the boundary. Thus, the boundary of the adjacent pools will reach equilibrium, and the boundary will correspond to the location of highest congestion or least generator marginal cost difference. There is no reason to think that this boundary need remain fixed with time. Generators and consumers could be free to switch pools each forecast and dispatch cycle.

The author believes that this form of flexible membership would result in dynamic and flexible pools, offering the efficiencies of central dispatch, the freedom of choice of bilateral markets and allowing the market to determine pool boundaries. Taken further, the pool starts to react to changes in the boundary conditions, expanding in response to lower congestion constraints in transmission on the boundary or increased load bidding into the pool, contracting with lower load demand or increasing congestion constraints. It becomes possible to imagine the pool starting to look like an organism, reacting to stimuli on the boundary with its environment (the remaining power grid and neighboring pools) and the internal forces of supply and demand.

By allowing the pool to be optional and flexible, operating as an organic entity, it is possible to eliminate the objections of rigidity and restricted choice generally attached to pool based proposals.

Bilateral Markets With Customer and Generator Aggregators
In a bilateral market, there is the opportunity for market specialists to emerge and facilitate the trading process. These "market makers" will act as intermediaries between buyers and sellers, contracting generating and transmission resources, offering financial services such as tailored tariff structured and aiding the flow of market information. These market makers may also be permitted to acquire portfolios of generators and loads and
match generation and demand within these portfolios so as to supply contracted demand with least cost generation available to the market maker. By aggregating generators and customers in the market in this manner, in building in flexibility of dispatch of the generating resources, the market maker has created a “pool”.

The function of ensuring that stability and reliability conditions are met within the region must still be considered, either by an ISO or by the market aggregators as their portfolios grow.

Market makers will compete based on the best price they can offer generators and the lowest price they can supply customers. The closer the customer to the generation, the better the advantage to both. Thus market makers will tend to aggregate customers and generators within geographic regions or may trade resources with each other until a pattern of pool-like regionally concentrated generators and customers are dispatched against each other. These aggregated dispatch regions will be flexible and optional in the same manner as the “organic” power pools described in the preceding section.

**Transition and Public Policy**

From this somewhat abstract thought experiment, it is evident that the same market structure has evolved via two different paths. By letting a pool liberalize and allowing optional participation and flexible boundaries or encouraging aggregation of generators and suppliers in a bilateral market, the end point of the evolutionary process appear the same. The decision for public policy now becomes not the market structure but the best path of transition. In deciding the path by which the market should evolve, there are a number of issues that must be taken into consideration.
The issues include:

- Ensuring reliability of supply through the transition
- Minimizing volatility and uncertainty of prices
- Provide mechanisms for fair stranded assets and sunk cost recovery
- Avoiding market failure or market distortion by groups with holdup power
- Ensuring fairness to all stakeholders including consumers, utilities, and shareholders
- Allowing full access and participation
- Encouraging evolution and preventing stagnation in reform

This list is not exhaustive and virtually all interested parties will identify different choices and priorities based on their own particular perspectives. The transition will disenfranchise some existing stakeholders and establish new stakeholders, a process that will disrupt and redistribute. It is fair to say that discussion of the choice between bilateral and pool based electricity markets should center on the transition as a process rather than on the end state.

**Power Pools as Transitional Structures**

The use of power pools as a transitional structure offers the most stability and predictability in the transition. In fact, the current tightly coordinated pools, such as NEPool, NYPP and PJM, require little modification to their organization to implement the operation of competitive market pool. Dispatch and reliability functions will be unchanged and stability will be maintained. The main difference will be the switch from split-savings pricing of interchanges to marginal cost pricing for all energy transacted.

For those utilities that are not members of tight pools, then new institutions must be created to accommodate them. These new institutions may be
viewed by some as restricting the operational flexibility of the utility and restricting access to the pool. Such restrictions may unfairly benefit participants with significant market power within the pool. To alleviate such concerns, built into the regulatory framework must exist mechanisms that allow loosening and evolution of the pool structure into the flexible and optional pools described earlier.

Transition via pool based markets appears to offer the smoothest transition to a competitive market but there is always the risk of stagnation. As benefits are recognized, through lower prices, and some uncompetitive utilities start to suffer from financial distress, there exists the opportunity to halt liberalization or even reverse reforms already evoked.

**Bilateral Markets as Transitional Structures**

Taking a single step to complete deregulation and a bilateral market represents a sharp and dramatic change to the operation of resources for all utilities. There is no precedent in the world for such a move, with other countries who have moved to competition, namely Chile, the UK, New Zealand and Argentina, adopting various forms of pool based structures. A deregulated bilateral market is more likely to lead to uncertainty of prices and offer windfall gains to market makers until the market stabilizes. The price wars, bankruptcies and mergers in the airline industry during the 80’s has been linked to deregulation of that industry.

Unrestricted bilateral markets, once established, would be very difficult to reverse. The institutions that were the basis of regulation, that is, the vertically integrated utilities, would be so radically changed by consolidation and vertical de-integration that appears to be an inevitable result of deregulation. Also, new stakeholders in the form of new entrants in the industry would be disenfranchised by any reversal of regulatory policy.
Freedom of the market, aggregation of generators and suppliers and the irreversible maintaining of evolutionary momentum is apparently more certain in a bilateral market, the cost being initial uncertainty and a more dramatic transition.

**Conclusions**

The underlying and interdependent functions of electric power generation, transmission and distribution can be described in terms of the physical, temporal and spatial characteristics of a commodity, and as a public good. Each of these characteristics must be considered in establishing the new institutions of competitive markets for electric power.

The debate surrounding regulatory reform of the electricity industry has focused on the choice between bilateral markets and pool based market institutions. Each of these market forms has different methods for dealing with the product characteristics of electricity and are generally viewed as polar differences in the way markets would operate. If, however, we allow flexibility of membership and the option of direct trading in the pool and permit market aggregators to operate in the bilateral market, then both the flexible pool and aggregating bilateral market evolve to the same functional form.

Since we can now say with some confidence that the final market structure will be the same if evolution is allowed to proceed within the markets, the debate now becomes one of which market model to choose as a path of transition so as to ensure the fairest redistribution of opportunity to the existing and entering stakeholders.
Using pool-based competitive markets as the transition vehicle for deregulation offers the smoothest change but may result in stagnation or even reversal of the deregulatory process. A move to bilateral markets would be a more permanent step, offering the greatest freedom to all participants but would involve greater uncertainty associated with the unknown territory of regulatory reform such a move represents.
Appendix 1 - An Example of Split Savings Pricing
An Example of Split Savings Pricing*

The following simplified example describes, in general, how split savings pricing works. The actual treatment of more complex issues such as hydro, pumped storage and fast reacting gas turbines varies from pool to pool and is ignored for the purposes of this example.

In this pool, there is a total of six participants in the pool, of which three are net exporters (A, B & C) and three are net importers (D, E & F). Pool overheads are charged to participants at 19% of total pool savings. Transmission losses are ignored.

Net Exporters:

<table>
<thead>
<tr>
<th>Seller</th>
<th>Net Export</th>
<th>Production Cost</th>
<th>POOL DISPATCH</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0</td>
<td>$1,000</td>
<td>60</td>
</tr>
<tr>
<td>B</td>
<td>0</td>
<td>$1,500</td>
<td>30</td>
</tr>
<tr>
<td>C</td>
<td>0</td>
<td>$2,000</td>
<td>70</td>
</tr>
<tr>
<td>TOTAL</td>
<td>0</td>
<td>$4,500</td>
<td>160</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Seller</th>
<th>MWh</th>
<th>Cost</th>
<th>c/kWh</th>
<th>BILLING</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>60</td>
<td>$240</td>
<td>4.000</td>
<td>$118</td>
</tr>
<tr>
<td>B</td>
<td>30</td>
<td>$150</td>
<td>5.000</td>
<td>$47</td>
</tr>
<tr>
<td>C</td>
<td>70</td>
<td>$210</td>
<td>3.000</td>
<td>$167</td>
</tr>
<tr>
<td>TOTAL</td>
<td>160</td>
<td>$600</td>
<td>3.750</td>
<td>$332</td>
</tr>
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</table>

Net Importers:

<table>
<thead>
<tr>
<th>Net Import</th>
<th>PURCHASE</th>
<th>BILLING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buyer</td>
<td>Net</td>
<td>Production</td>
</tr>
<tr>
<td></td>
<td>Import</td>
<td>Cost</td>
</tr>
<tr>
<td>D</td>
<td>0</td>
<td>$1,000</td>
</tr>
<tr>
<td>E</td>
<td>0</td>
<td>$3,000</td>
</tr>
<tr>
<td>F</td>
<td>0</td>
<td>$2,500</td>
</tr>
<tr>
<td>TOTAL</td>
<td>0</td>
<td>$6,500</td>
</tr>
</tbody>
</table>

The total Buyer's values ($6,500 - $5,000 = $1,500) exceeds the total sellers costs ($5,100 - $4,500 = $600) by $900 ($1,500 - $600). This is the total pool savings resulting from the dispatch. The pool collects 19% of these savings in the form of a tax to pay for overheads and compensate transmission network owners for pool use of their facilities. The remaining 81% of savings are shared amongst the Buyers and Sellers.

Sellers' share of savings = (1-t)x1/2(v* - c) x (MWh sold)

Where: t = Pool overhead tax (19%)

v* = Average Buyers’ value (8.875 c/kWh)

\(c = \text{Individual Sellers’ Cost}\)
Sellers' Net Receipts = Sellers' Cost + Sellers' Share of Savings

e.g.
Seller A Share = (1-0.19)x1/2(8.875-4.0)x(60) = $118
Seller A Receives = $240 + $118 = $358

Buyers' share of savings = (1-t)x1/2(v - c*) x (MWh purchased)

Where:
v = Individual Buyers' value
c* = Average Sellers' Cost (3.75 c/kWh)

Buyers' Net Payment = Buyers' Value - Buyers' Share of Savings

e.g.
Seller E Share = (1-0.19)x1/2(9.0-3.75)x(100) = $213
Seller E Pays = $900 - $213 = $687

Energy supplied to members for scheduled or unscheduled outages is billed at cost plus a margin to cover pool operating expense. The cost is defined as the additional cost incurred by the pool as a whole to supply the energy shortfall caused by the outage.

The example given is from the NYPP, but similar pricing methods are used by both NEPool and PJM.

This multi-level pricing structure means that, at any instant, there are different prices charged or paid for energy transferred through the pool dependent on each member's costs and the use of the energy by the member. This violates the "law of single price" for open markets that states that only one price can exist in an efficient open market otherwise there will be opportunities for arbitrage. If a pool were to operate as a market with split cost pricing then a "cheap" importer could purchase electricity from the pool.
at a lower price than an "expensive" importer. The "cheap" importer could then re-sell the purchased electricity to the "expensive" importer outside of the pool and at a profit. In this manner the multitude of prices creates opportunities for arbitrage on transactions conducted outside of the pool's jurisdiction.

The NYPP has experienced such arbitrage with members trading outside of the pool's control and accountability, either with each other or with external parties so as to take advantage of costs savings greater than would be applicable for transactions through the pool. Members can currently trade in such a manner while still taking advantage of pool membership. As the NYPP is not empowered to discipline members, this trend seems set to continue.
Appendix 2 - Economic Dispatch
Economic Dispatch: An Overview

The objective of economic dispatch is to schedule output across interconnected generating units within a power pool so as to minimize the total cost of generation while meeting the needs of all loads fed from the pool, obeying system constraints and ensuring system security. The solution to this problem must be considered with reference to the time horizon for which the dispatch is determined.

Automatic generation control makes the real time adjustments of generation to the grid to meet the technical requirements of real and reactive power flow, voltage support and system security for minor short term fluctuations in load. The economic factors of dispatch become meaningful for extended time horizons beyond that associated with automatic generation control.
<table>
<thead>
<tr>
<th>TIME HORIZON</th>
<th>CONTROL PROCESS</th>
<th>FUNCTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>SECONDS</td>
<td>Automatic Generation Control (AGC)</td>
<td>Minimize area control error subject to machine and system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>dynamics constraints</td>
</tr>
<tr>
<td>MINUTES</td>
<td>Optimal Power Flow (OPF), Static Economic Dispatch</td>
<td>Minimize instantaneous cost of operation or other indices, e.g.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pollution</td>
</tr>
<tr>
<td>HOURS, DAYS</td>
<td>Unit Commitment, Hydro-Thermal Coordination</td>
<td>Minimize expected cost of operation or other indices</td>
</tr>
<tr>
<td>DAYS, WEEKS</td>
<td>Hydro-Thermal Coordination</td>
<td>Minimize expected cost of operation</td>
</tr>
<tr>
<td>MONTHS</td>
<td>Maintenance and Interchange Scheduling</td>
<td>Minimize operational cost subject to reliability constraints</td>
</tr>
<tr>
<td>YEARS</td>
<td>Maintenance Scheduling and Generation Planning</td>
<td>Minimize expected investment and operational costs with</td>
</tr>
<tr>
<td></td>
<td></td>
<td>reliability constraints</td>
</tr>
</tbody>
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Table A2-1 - Time Frame and System Control Criteria
Static Optimization

For fossil fuel thermal power generation not subject to system constraints, the instantaneous least cost solution is achieved when all generating units feeding into the pool operate at the same incremental cost of generation. The Cost Rate for a generating unit is obtained from the fuel input required to run the unit at a specific level of output multiplied by the fuel cost. The incremental cost is the first derivative of the Cost Rate with respect to output for a generating unit and has units of $/MWh or c/kWh.

Figure A2-1 - Least Cost Solution for Static Optimization

For the simple case of two generators given in Figure A2-1, the least cost or optimal solution is given for the generators A and B, each having different heat rates and fuel costs, but operating at the same incremental cost to supply a total load of Qa+Qb.

This example can be extended to a complex network of generating units and loads. As system load increases, the dispatcher will call on the cheapest generating units (i.e., those with the lowest incremental cost) to increase their output and will progressively allocate increasing cost generation to the grid as load increases, adjusting the load across all generating units on line...
to maintain an equal incremental cost (also called system lambda).

Transmission losses on the system can be accounted for in terms of a penalty factor multiplier, scaling the cost of generation for each unit and dependent on the unit's output and location on the grid. Static optimization of the pool is obtained from the optimal power flow (OPF) for the minute-by-minute allocation of real power generating capacity for units on line as well as solving for other related variables associated with the transmission system such as reactive power flows and bus voltages. The cost of production is an instantaneous function of system demand.

Generating units, particularly coal and oil fired thermal units, must be fired up from cold before they can start generating, a process that can take up to 24 hours and will consume fuel without generating electricity. Similarly, when disconnected from the grid, units must be cooled down in a controlled manner. These start-up and shut-down procedures incur costs and reduce the flexibility of the generating units, factors that must be considered in committing the units to run. Once on line, generating units cannot react instantaneously to changes in power but have limited rates at which power output can be ramped up to meet system demand.

The static optimal power flow solution to the dispatch problem in it's simplest form assumes there is no restriction on when or how quickly a generating unit can be bought on line and ignores the cost of start-up and shut-down (cycling cost) and the ramp-up rate for the generating unit. It also ignores the limits on the energy capacity of hydro generation and the reserve margin necessary to maintain the security of the system in the event of an unforeseen plant failure.

The load on a system is not constant may vary by a factor of 2 or more during a normal 24 hour period. Static optimization of the system alone can not
provide the best solution for a system that has generating units being started up or shut down as load varies. The optimization of the system must be performed over a finite period of time, and the tools used to optimize dispatch must be extended to include load forecasting and dynamic optimization.

The two types of dynamics that must be incorporated into the optimal solution are those associated with thermal plant cycling characteristics and the efficient use of hydro generation.

**The Unit Commitment Problem**
The unit commitment problem involves deciding which generating units will be operating, which will be shut down and which will be on unsynchronized or hot standby. The unsynchronized standby units are those generating units that are maintained in a state of readiness so that they can be bought on line at short notice. Unsynchronized standby units generally consist of hydro, pumped storage or gas turbine units with very short run-up times in the order of 5 - 10 minutes. In the case of thermal steam plants used as unsynchronized standby, boilers must be maintained at the required operating temperature. These unsynchronized standby units are maintained in this condition between demand peaks and provide reserve margin necessary to meet system peak load and spinning reserve requirements. If there are no costs associated with start-up, shut-down or maintaining reserve, then under varying load conditions the optimum solution can be obtained by finding the static optimal load flow for the system at each point of time. Every solution to the optimal load flow will be independent of every proceeding and future solution.

In reality, however, there are costs associated with the start-up and shut-down of generators and these costs must be accounted for in finding the optimum solution. These costs mean that as load increases, the optimum
solution will depend on which units are already committed, and hence the associated start-up costs have already been absorbed, and which units will be committed in the future and must have their startup costs absorbed over their scheduled running period. Similarly, for generating capacity in excess of current needs, the cost of shut-down or spinning reserve for the excess units together with the anticipated future load profile will determine if these units will be maintained as excess spinning reserve or shut-down, incurring the shut-down and start-up costs associated with cycling the units.

For example, consider the case where we have an oil fired thermal unit as our most expensive (marginal) unit on line. This unit was bought on line to meet the morning peak load and will be required again for the evening peak. However between these peaks, the generator's capacity will be in excess of demand for about three hours, during which time all load and reserve requirements can be met by cheaper base load generating units. To shut down the unit and then restart it in three hours to meet the evening peak will incur cycling costs of $5,000. If, however, the unit is maintained on line at minimum output, the cost is $1000/hr. A static optimization solution would ignore the cycling costs and determine that the unit be shut down and restarted even though maintaining the unit on line between peaks would save the operator $2000.

It is clear that the optimum or least cost solution under conditions such as these can no longer be calculated ignoring the past and expected future states of the system. The optimum solution can only be found if the changing system state over a finite time period is considered. For thermal plant his time period is generally a day, for which load tends to be cyclic. If maintenance considerations are taken into account, this period may be extended to weeks or even months. When there is hydro generating capacity
on the system, the commitment horizon may be extended further to take into account seasonal rainfall variations.

The Hydro-Thermal Commitment Problem
The second aspect of system optimization not accounted for in the static optimal load flow solution is that of scheduling the most efficient use of hydro generation. Under static conditions, the static optimum solution would have hydro generation scheduled first on line as hydro has a very low incremental cost (since the 'fuel' is virtually free). However, as the total energy hydro generation can supply to the grid is limited by the permitted variation of water head in the supply dam, the hydro unit can only run for a limited period at full capacity. As start-up and shut-down costs are low for hydro generation, it is often used for peak leveling of load, i.e. at the load peaks. This allocates hydro capacity when the system lambda is highest rather than at the lowest incremental cost periods as would be the solution for the static optimization.

Dynamic Optimization
The unit commitment and hydro-thermal problems require a solution that takes into account the dynamic nature of generating units and goes beyond solving for the static state of the system. This leads to the need for dynamic optimization of the system over a finite period. This is achieved by using dynamic programming, a recursive extension of non-linear programming.

The dynamic programming approach models the system as a series of possible states at discrete time intervals over the chosen optimization period and calculates the optimum or least cost trajectory of the system in moving through the allowable states, taking into account the costs of transition from one state to the next at each discrete point of time along the possible trajectories. The allowable states at each point on the trajectory must meet
the system requirements for that time interval in terms of meeting the forecast load, spinning reserve and other operational constraints. Even so, the dynamic programming algorithm must select from an almost infinite number of possible states and trajectories. The vast majority of possible states are superfluous and can be eliminated by rationalization techniques and heuristic strategies to reduce the number of trajectories to a manageable level.

Economic dispatch methods have been further refined with the use of linear programming combined with decomposition techniques, artificial intelligence, expert systems and artificial neural networks to improve on the computational speed and accuracy of dynamic programming.*

The application of dynamic programming techniques to the economic dispatch problem requires that a forecast of the load profile for the system be available and that dispatch be planned ahead. The dispatcher must also have a method of adjusting the system in real time for forecasting errors and for unforeseen contingencies such as equipment failure.

Generators supplying into the pool will start up, run and shut down generating units according to the predetermined schedule. To meet load variations from the forecast and unplanned outages, the dispatcher will implement real time variations in both timing of transitions and level of supply.

It is technically feasible, although computationally complex, to continuously update the dynamic program start point and forecast with changes in the

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actual load and then re-solve the dispatch over, say, a 24 hour horizon. The generation schedule can then be modified to match each updated solution for the dynamic optimization. This is equivalent to the issuing of generation schedules every minute or every hour for the immediately following 24 hours instead of daily so as to optimize for variations in the load from the forecast as they occur.

In summary, we can divide the various physical properties of generating units into cost factors used by the pool dispatcher in determining the least cost trajectory, and properties that place constraints on the scheduling of the generation unit.

**Cost Factors**
- Incremental cost
- Start-up cost
- Shut-down cost
- No-load cost
- Transmission loss costs

**Constraint Factors**
- Minimum load requirement
- Maximum capacity
- Minimum time on line
- Minimum time off line
- Ramp-up rate
- Energy capacity (e.g. hydro generation)
- Transmission congestion
- Reserve requirements
- Environmental restrictions (SO₂, NOₓ permits)
It is a reasonable conceptual extension of the system dispatch model discussed so far to consider the constraint factors on generating units in terms of the opportunity cost, that is, the additional cost imposed on the operation of the system due to those constraints. A limited ramp-up rate of a generating unit that is constraining the system means that a more expensive generating unit elsewhere on the system must be bought on line, implying an opportunity cost equal to the difference in incremental costs for the units that could be realized through modification of the cheaper unit to give a faster ramp-up rate. Calculation of such opportunity costs will allow owners and investors to quantify different generator characteristics in making planning decisions.

Dispatch With Transmission Congestion Effects

The inclusion of transmission congestion effects in economic dispatch does not represent a conceptual problem as both static and dynamic optimal dispatch computer models incorporate transmission losses and constraints in their formulation. Congestion charges are the allocation of price to the opportunity costs imposed by transmission constraints on the system and give varying nodal prices across the network. Congestion charges are costs of transmission similar to losses but are payments to the transmission rights owner as opposed to absolute system losses.

The inclusion of nodal pricing means that system lambda or generator marginal cost will vary from bus to bus and will not be equal for all generators as has been assumed for discussion so far. In traditional dispatch optimization, the dispatcher aims to keep the system lambda constant across the system but allocates those generators that are required to deviate from the system lambda due to congestion of the transmission system as being 'constrained on' or 'constrained off'. An alternative approach has been to segment the system into regions bounded by constrained transmission lines.
and dispatching within these regions to achieve equal generator lambda across the segmented region. Nodal pricing is an extension of this approach, with each bus on the system having its own system lambda that reflects congestion and line losses.

Inclusion of nodal pricing will not change the optimal dispatch currently determined by regulated pools but will consolidate the line loss and transmission congestion effects currently used in dispatch optimization calculations since, like the net marginal cost calculated for centrally dispatched generating units, the congestion charges are calculated ex-post.

Example:
New Gen and Old Gen have costs of generation of 4¢/kWh and 6¢/kWh respectively for all electricity generated. New Gen is connected to Big City via a transmission line of 600MW maximum capacity. Old Gen is located adjacent to Big City and can supply load up to its maximum capacity.

1. Load at Big City equals 500MW - no system constraints

The dispatcher will allocate all of the load to the cheapest unconstrained generating unit, New Gen. The nodal prices and payments are:

New Gen generates 500MW and sells to the spot market at 4¢/kWh. The spot price at the New Gen generator bus is 4¢/kWh. Big City purchases 500MW from the pool at 4¢/kWh. The spot price at the Big City load bus is 4¢/kWh. There are no transmission congestion payments

2. Load at Big City equals 700MW - Line 1 constrains the system
The dispatcher can only allocate 600MW of Big City's load to New Gen as the transmission line is now congested. The remainder of Big City's load must be supplied from the next cheapest unconstrained unit, Old Gen. The prices and transactions now become:

New Gen generates 600MW and sells to the spot market at 4¢/kWh. The spot price at the New Gen generator bus is 4¢/kWh.
Old Gen generates 100MW and sells to the spot market at 6¢/kWh. The spot price at the Big City load bus is 46¢/kWh.
Big City purchases 700MW from the spot market at 6¢/kWh. The owners of the transmission rights for Line 1 receive 2¢/kWh in congestion charges for the 600MW transmitted between New Gen and Big City.

![Figure A2-2 - Nodal Spot Pricing for a Simple System](image)

The point of this very simple example is to emphasize the order of events in the dispatch and pricing of electricity to Big City.
1. The optimum economic dispatch is established based on marginal cost and system constraints.
2. The nodal spot price is calculated based on the economic dispatch.
3. The congestion charges are calculated based on the nodal prices.

Network congestion pricing adds a layer of complexity to the market transactions but not to the scheduling of economic dispatch. For large interconnected systems, the congestion cost for a single line is a function of generating marginal costs and congestion costs across the network and not just transmission through the line as is the case for line losses.
Appendix 3 - Spinning Reserve Marginal Cost and Price
Spinning Reserve Marginal Cost and Price

A power pool must remain secure for a wide range of possible contingencies, including the unforeseen loss of generating and transmission capacity. This can only be achieved by maintaining reserve generating capacity either on unsynchronized standby or synchronized to the system, capable of meeting capacity shortfall due to a system contingency.

The requirements of spinning reserve varies depending on the system characteristics. A small system with relatively few interconnected generators will be more vulnerable to a plant outage than a larger system. For a small system, a generating unit outage results in rapid drop in the system frequency from 60Hz (or 50 Hz in the U.K. and N.Z.) due to the imbalance of load and generation that must be made up by spinning inertial energy from the remaining connected generating units. This results in a slowing of the remaining units as spinning inertial energy is converted to electrical energy. The fewer the number of synchronized generators on the grid, the lower the system's total inertia and the faster the frequency will drop before the load can be reduced through reduction of bus voltages or made up by the remaining connected generators.

The New Zealand system, for example, is entirely isolated and has generating capacity of 7,360 MW. The system will experience a frequency drop to the minimum allowable of 48 Hz (from 50 Hz) in a matter of seconds after a major generating unit outage. Spinning reserve synchronized to the grid must be maintained to ramp up and meet the shortfall in 5 -10 seconds. The NEPool, with 25.500 MW of capacity together with interconnections with adjacent pools of similar size and Hydro-Quebec, has a far higher system inertia and a generating unit outage creates a much less dramatic frequency disturbances. NEPool can schedule spinning reserve with much longer
response times of 10 minutes or more, and reserve is allocated to meet system peak capacity rather than for frequency support as in smaller systems such as New Zealand.

The requirement for spinning reserve will force generators to be scheduled out of merit order and to operate at other than their most economic level of generation. The total cost of spinning reserve is the difference between the cost for the optimized economic dispatch without reserve requirement and that with. The marginal cost of spinning reserve is the change in cost of the optimized economic dispatch for one additional or one less unit of spinning reserve*.

The availability of reserve for a generator is of the form given in Figure A3-1.

![Figure A3-1 - Reserve Availability Curve](image)

Spinning reserve can be considered in the same manner as energy, as a commodity with a price and tradable within a competitive market. In such a competitive market, generators would be compensated for spinning reserve made available at the system marginal cost for spinning reserve. Generators are not the only sources of spinning reserve. Customers could bid their load or components of their load as available to be disconnected on demand by the pool dispatcher during a system contingency. Customers would be paid for all periods at which such dispatchable load were available, whether disconnected or not. During times of excess capacity on line, spinning reserve will have very little or no cost.

Spinning reserve can be considered a type of system wide common good, that is, spinning reserve avoids system collapse and the incurring unacceptable costs on users due to an unplanned outage. All connected users should be taxed in the form of a margin on the electricity energy price to cover the cost of providing spinning reserve in the same manner that pool operating and administrative costs are recovered*. Those users that do not require or are not willing to pay for the level of security normally provided by the pool can bid their load as dispatchable as described above.

The marginal cost of spinning reserve will be determined during dispatch and will generally be set by the generator that is maintaining spinning reserve on line and has the lowest marginal cost for energy generation, hence has the highest opportunity cost associated with maintaining spinning reserve (see Figure A3-2).

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* The degree of spinning reserve required is determined in part by the size and reliability of generating units on line. It has been suggested by others that part or all of the costs for spinning reserve imposed on the system be charged to the responsible parties, that is, the largest and most unreliable generating units.
Figure A3-2 - Determination of Spinning Reserve Marginal Cost

As for energy, all suppliers of spinning reserve could be paid the system spinning reserve spot price (c/kWh) as determined by the marginal cost of reserve, irrespective of their individual costs. The cost of spinning reserve to generators is inherent in the energy bid cost structure and is the opportunity cost associated with the cost of generation below market price for generation foregone so as to maintain required spinning reserve. Customers bidding dispatchable load capacity into the system will be allocated in merit order against each other and generating units providing spinning reserve. Only the customers bidding below the spinning reserve spot price will be scheduled and will receive payment of the spot price for the scheduled period. As with the energy spot price, the spinning reserve spot price is established after the optimal schedule has been set and all energy and security requirements are met.
By creating a separate but related competitive market for spinning reserve capacity, efficiency of the system as a whole is improved through the market. Dispatchable load bidding by customers allows the customer to determine their own value of reliability of supply.