A Review of Restructuring in the Electricity Business

by

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Abstract: Since the 1980's, efforts to restructure the electricity industry have received much attention around the world. To date, approximately twenty states have undergone restructuring to introduce formal markets as a vehicle for electricity transactions. Numerous other states are actively pursuing similar paths. Although the general principles which have guided restructuring are generally accepted, a variety of resulting utility and energy market structures have been implemented. In fact, opposing market philosophies have emerged. This paper reviews the present state of restructuring around the world, and describes key elements such as industry structures, market philosophies, dispatching strategies for spot markets and pricing.

1. Introduction: Motivation and History

The economic pendulum has swung decidedly to the side of free enterprise in most industrialized countries over the last twenty years. This movement was spearheaded in the early 1980's in large part by leaders in England and the United States. It followed a generation during which social democratic governments intervened more actively in economic spheres. This change in philosophies has manifested itself in the restructuring[1] of many large economic sectors, the latest of which is the electricity business. Essentially restructuring replaces a market structure that limits profits but cannot stem inefficiencies by another which rewards efficiency with profit.

Historically, disparities had always been observed in the prices of electricity. Initially linked to local energy resources, these disparities had been maintained by institutional structures such as state monopolies or strictly regulated private utilities serving well-defined and mutually exclusive territories. The advent of extra high voltage transmission in the 1960's allowed for the transfer of bulk power, and even though the monopolistic viewpoint prevailed at that time, system operators gradually gained valuable experience in the manipulation and commerce of energy on a large scale. This set the stage for the liberalization of the industry. The 1970's saw tremendous reforms in several major industries worldwide, including telecommunications, transportation and gas [Winston 1993, Chwalowski 1997, Jess 1997]. It was predictable that similar pressures would be exerted on the electricity industry. The general movement in favor of electricity industry restructuring was initiated in the United States during the 1970's [Schweppe 1978]. Two basic reforms were advocated: the introduction of competition and the imposition of prices reflecting real costs according to use. The idea of variable tariffs in a monopoly environment had already been suggested during the 1950's [Vickery 1955] and since extended [Boiteux 1960, Vickery 1971]. The notion of competition in the form of open access to markets and networks by competing producers, marketers and distributors came as a result of stagnation in many utilities which had been limited by regulations with regard to profits and expansion. Early proponents of restructuring in the United States were consumers and marketers in the high-priced markets who sought relief from cheaper neighboring energy markets. The 1980's served as a period of reflection in the United States and Europe for deregulators who saw certain advantages in breaking up the monopoly structure of the industry. They developed a general "philosophy" which would appeal to all energy market participants. The main advantages of the proposed restructuring were expected to be a reduction in energy prices through the opening of competitive energy markets, long-term gains in efficiency, and the influx of private capital. New, more efficient producers and possibly new transporters / distributors would see their efforts rewarded with profits dictated by the marketplace. Note that restructuring does not necessarily imply privatization, and in many countries crown corporations are still very much involved in the electricity sector. In retrospect, other advantages offered by industry reforms were equally important. In several countries the national debt stifled growth; there, the public sector could no longer meet the investment needs of the electricity industry. Hence governments had two added incentives

[1] In this paper the term restructuring is preferred to its often-used synonym, deregulation. The authors feel that the former closer reflects the new reality in which different regulations have been put in place.

for removing themselves from the energy business, namely, to free up public funds and to collect much needed cash from the sale of industry assets [Wolak & Patrick 1997]. Although not openly admitted, additional incentives attracted some countries towards restructuring. These were the desire to free utilities from political meddling, to push through corporate reorganization and downsizing, and to enforce efficient business practices [Rudnick 1996, U.S. Department of Energy 1997].

In several countries, legislators and industry leaders prepared their reforms in concert at both the regulatory and corporate levels. The first major efforts solicited mostly legal and administrative advice. Technocrats, using techniques from both power systems and economics, eventually developed enough tools to operate their power systems in the restructured environment. In this light, some major developments are the application of marginal cost theory to power system operations [Schweppe et. al 1988], its application to the operation of a pool in a restructured environment [Hogan 1992], the coexistence of a spot market and bilateral contract mechanisms [Wu & Varaiya 1995], and market devices for transmission pricing [Chao & Peck 1996, Harvey et al 1997, Green 1997].

Since 1982, several countries have enacted legislation to open their electricity industries to competition. Three countries are generally recognized as pioneers: Chile (1982) [Rudnick 1996], England and Wales (1990) [Green 1998] and Norway (1990) [Moen & Hamrin 1996]. Unbeknown to most industry observers in the English-speaking world, Chile undertook a bold plan of industry restructuring, passing legislation in 1982 and gradually implementing the plan through the decade [Bernstein 1988]. The work produced in Chile inspired several similar initiatives in Latin America. Argentina, which experienced economic hardships similar to those in Chile, restructured in 1992 [U.S. Department of Energy 1997]. Several South American countries followed suit from 1993 to 1995 [Rudnick 1998], as did many Central American countries in 1997 [http://www.ing.puc.cl /power/ southamerica .htm]. In 1998, Brazil [Secretary of Energy, Brazil] and Mexico [Secretaria de Energia, Mexico 1999] introduced plans to restructure, but they cannot be said to be favoring the Chilean/Argentinian model. The structure developed in England and Wales spread to Scotland and Northern Ireland from 1990 to 1992 [Yajima 1997], and certainly influenced other Commonwealth states such as Australia [Outhred 1998], New Zealand [Read & Ring 1995] and the Canadian provinces of Alberta [London Economics 1998] and Ontario [Ontario Market Design Committee 1999]. The Norwegian reform spread to the other Scandinavian countries since 1995 [London Economics 1997]. In the United States, the pioneering legislation called PURPA first liberalized the trade of electricity in 1978 [Gilbert and Khan 1996]; the EPAct of 1992 finally allowed open access to energy markets [Stalon 1995], but state-by-state restructuring is only now beginning to materialize. Presently six regions fall under the supervision of so-called Independent System Operators, and several other similar organizations are being contemplated [Edison Electric Institute 1999]. Fully operational market structures allowing spot market and bilateral transactions appeared in both California [Philipson & Willis 1998] and in the PJM consortium [Hogan 1998] in 1998. The California experience took form after extensive discussion and resulted in a compromise between the pool and "pure" market structures. The resulting open model is close in spirit to that of Norway, if not in its actual implementation. After years of deliberation, the European Union submitted a directive to its members at the end of 1996, requiring them to present plans by the start of 1999 for the opening of their electricity markets by the early 2000's [Boiteux 1996, Percebois 1997].

Common points can be found in all these reforms, but there remain some profound differences in approach. Each region carries over its own history, general viewpoint, operating principles and dynamics into their new structures.

Other reforms, which cannot be strictly classified as deregulation, have been underway in Eastern Europe (privatization), Southeast Asia (liberalization similar to PURPA) and Southern Africa (international trade) [Izaguirre 1998].

2. Structural Changes within the Electricity Industry

Three major elements pervade every implementation of electricity industry restructuring:

- the opening of energy markets,
- the unbundling of electricity services, and
- open access to the electrical networks.

The combined expectation of higher profits and lower prices resulting from the opening of competitive wholesale energy markets is the central theme of restructuring. An essential requirement is that incumbent producers and newcomers alike be guaranteed access to the market, subject to meeting minimal financial and technical standards. The opening of retail markets, in which consumers buy from competing providers, constitutes a second important step in liberalizing the commerce of energy.

The creation of a new, autonomous institution, the power exchange (denoted PX), has facilitated the sale of energy between producers, consumers and marketers over time horizons which span hours (spot market), days, weeks or months (physical and derivatives bilateral markets). These market mechanisms offer different advantages.

Unbundling refers to the attribution of distinct electricity industry functions to distinct corporate entities (service providers). This stemmed from the primary need to separate the incumbent transmission provider, now serving many producers, from the incumbent producer. The "wires" functions remain regulated and must deal with requests from competing entities on a non-discriminatory basis. Other functions offered by autonomous entities provide distribution, retail sales, metering and billing in a competitive marketplace. Another service of primary importance, the coordination of network operations, is provided by an institution called the Independent System Operator (ISO).

The third element of restructuring, open access to electrical networks for all producers is a necessary condition for energy markets to work. In most implementations, incumbent transmission companies maintain monopoly control and are regulated, but receive some payments related to market-driven opportunity costs.

These basic restructuring principles have generally been put in place by legislation. Beyond that, the implementations vary significantly. Basically two utility structures have emerged. In one variant, separate companies have been formed for each function; in the other, non-generation functions are provided by fairly autonomous subsidiaries of a single parent transmission company [Rahimi & Vojdani 1999]. Either structure is deemed acceptable if participants perceive the operation as being unbiased.

Restructuring has brought about a redefinition of the obligations, roles and practices of the traditional industry participants - the regulator, the generators divisions, and the wires divisions of the utilities. In a monopoly environment, the regulator typically has been an interventionist, acting on behalf of the public. Its main role had been to approve tariffs, a job that has now become mostly superfluous. In the restructured environment, regulators have participated in setting up market structures. Its tasks are: creating rules for participation, defining the responsibilities, potential risks and rewards to market participants including benefits to consumers, imposing limitations on the regulated portions of the industry, and imposing temporary measures during a transition period. Starting during the transition period, a common role of the regulator is to monitor industry profits to assure that captive consumers are not penalized by overly generous tariffs. In the restructured marketplace, the regulators' roles have varied according to the various implementations. For the most part, they are intended to be relatively light-handed, serving to ensure the fair operation of the market in general.

The utility has seen many of its traditional responsibilities devolved towards other organizations or removed altogether. The obligation for generators to serve has been removed in many regions. The obligation of the utility to plan, i.e. to prepare expansion to meet future needs, has been given to separate entities or has disappeared with the expectation that market forces will serve as a substitute. The responsibility of operating the system has fallen on the PX and the ISO, often built from the ashes of the old utility structure. In addition, several scenarios of utility segmentation have appeared. The independent generating companies can vary in size from a single plant (Victoria, Australia [Department of Energy 1997]) to large chunks of the generation market (England). The process can involve a legislated breakup as in England, a quick "voluntary" breakup as in California or Victoria, or a slow divestment over time accompanied by partial regulation, as recently arranged in Ontario. Alberta opted to keep its three major producers intact, but in a novel approach they are required to auction off their generation to numerous marketers in long-term contracts [Adamson & Goulding 1999]. In countries with hydroelectric resources, hydrological basins can be shared by independent producers (South American countries, Norway) but are scheduled by a central entity. Ownership of generating resources has usually been restricted to limit market power, although in one case (New South Wales), until recently, competing plants were all government-owned. Separation of functions usually prohibits cross-ownership of different types of facilities; the only notable difference so far has been in Chile. A few exceptions to the unbundled corporate model are now appearing. In its recent legislative proposals, France expressed its desire to maintain EDF intact as a public service utility, with all the obligations that entails. EDF would submit to regulation but would compete with other producers in its energy market. In Canada, the market design committee in British Columbia [British Columbia Utilities Commission 1998] has come out in favor of this approach, and the feeling is that two other large provincial utilities, in Québec and Manitoba, will eventually follow that route. In many but not all implementations involving public utilities, restructuring also involved privatization of generation; reasons have varied but tended to echo local economic concerns. All in all, higher overall efficiency cannot be attributed to either private or public ownership [Atkinson & Halvorsen 1986].

At first glance, the wires business is the least affected by restructuring. Actually in most implementations, restructuring has reduced the scope of activities usually performed by transmission / distribution providers to the basic construction and maintenance of the network. However, recent proposals in the United States aim at creating business-oriented transmission companies, or Transcos [Lenard 1998], to introduce the same competitiveness in the wires business as in the generation business.

3. Responsibilities of the New Institutions

As noted already, autonomous entities have taken over the tasks of generation scheduling and network coordination. The separation of these entities into corporate structures to fit the required functions varies from one implementation to another. These structures balance questions of efficiency and transparency of operation in the presence of competing interests. [Rahimi & Vojdani 1999] summarizes implementations in several countries in a clear, succinct form using block diagrams. Their four block types are the ISO, PX, Scheduling coordinator (described below) and Transco. For example, in California, the four blocks are separate; in England the ISO, PX and Transco form a single pool, all grouped within a common corporation, the National Grid Company.

The Independent System Operator is normally the first to appear in a restructured environment. Its tasks are wide ranging and complex. In preparing activities for the next day, the ISO displays important network information for market participants in the form of network availability (ATCs and TTCs [NERC 1996]) and load forecasts. It also verifies and reserves requests for transfer capability provided that they satisfy network security. In addition the ISO controls network operation in real time, adjusting for disturbances and ordering the required ancillary services needed for network operation. Such services include loss compensation, capacity reserves, frequency regulation, congestion management and voltage support. Finally, the ISO handles the administration and billing of network services.

The PX collects economic bids submitted for the energy transactions on a short-term spot market, and then dispatches generation to best satisfy load. Implemented dispatching functions vary in complexity. In its simplest form, the PX dispatch ignores network constraints. Then, if network congestion is foreseen, adjustment schemes oblige producers to deviate from the initially announced dispatch. Producers are then accordingly compensated. More complex dispatches include network constraints, integrating information from both the simpler PX function and the ISO.

In California, a third type of entity, called the scheduling coordinator, collects requests for transmission services from participants who have entered into bilateral contracts. Basically each scheduling coordinator serves a territory previously occupied by one of the state's three large incumbent utilities. It was felt that independent scheduling coordinators could better serve their regions by actually facilitating trades and optimizing local arrangements, while freeing the ISO and PX to concentrate on bulk power transactions [Moore & Anderson 1997]. Considering the enormity of the California market, their presence greatly eases the burden of the ISO.

Autonomous corporate entities vary but the above discussed functions can now be considered generic.

4. Prevailing Operating Philosophies for Electricity Markets

Identifiable philosophies have emerged in terms of institutional structures and the level of control that they are allowed to exert on commercial activities. Presently there is no clear winner. Basically two poles have formed around the pool model and a market-driven model with little or no centralized intervention. Intermediate positions are held by mixed power exchange / bilateral contract models in which one or the other dominates. Major points of contention between these poles center around (1) economic inefficiencies, and (2) the inadequacy of centralized control practices. This section expands on these points.

4.1 Pool Structures

In this paper, a pool is defined as a compulsory power exchange/ISO to which all transactions must be submitted for analysis and approval. Only imminent transactions are handled, typically over the horizon of one day. Participants transact with the pool rather than with each other. Requests are treated based on bid prices and the availability of network resources and energy reserves. Transactions, characterized by pool prices and dispatched quantities, are determined by the pool based on a mathematical optimization, typically minimizing the total bid cost. This often mimics the central dispatch process used in the monopolistic environment. Models can also be adjusted to optimize social welfare, a component of which is the demand benefit function. An important component of the final selling price to the consumer is the centrally-computed marginal cost arising from the optimization. The components of the final selling price fall into two categories: those which are explicitly modeled in the marginal price and those which are not. The most complex optimizations incorporate many marginal-cost-producing components [Baughman et al 1997], including those resulting from water resource scheduling (New Zealand [Scott & Read 1995] and several South American countries), unit commitment (England [Jia 1998] and PJM [PJM 1998]), capacity constraints expressed explicitly or as loss-of-load probability, and active power dispatching with/without security constraints (New Zealand, PJM / England, Australian states). Network losses can be handled with varying degrees of complexity, which can be based on a "center of gravity" marginal cost scheme (Chile), aggregated by zone, based on pro rata methods, or included in the marginal prices. The explicit modeling of losses or network congestion results in different marginal prices in each location of the network; these are coined the locational marginal prices (LMC)[2]. Charges for transmission between buses are then based on LMC differences.

The cost components not explicitly modeled in marginal pricing are recovered using "averaged" charges, called uplift charges in England, or by price adjustments.

Preference for a particular pool pricing model is justified by subjective factors. Such factors are the comprehension or past experience with a model, the simplicity of the solution, the importance of central control in scheduling resources, the importance of representing certain price components, avoidance of highly volatile price components, avoidance of the imposition of costs which could penalize some consumers, and the inclusion of social costs to be born by all.

Pool-type markets were the first to appear, in Chile and then in England and Wales. The Australian states of Victoria and New South Wales also operate pools [U.S. Department of Energy 1997]. Most South American countries, New Zealand and PJM have mixed systems (pool/bilateral) where the pool activities dominate.

Historically, several of the above systems have applied a tight technical control on power systems operation. It seems that technical rather than economic control is still the main issue in choosing pool structures. Actually pool economics have been circumvented by the creation of financial hedges called contracts for differences (CFD). In these agreements, buyers and sellers set a price for energy transferred through the pool. That part of the price not collected by the pool is paid by one participant to the other. This effectively takes the form of a financial bilateral transaction. One criticism of CFDs is that since their prices go undisclosed, pool prices tend to be skewed. It has been estimated that as much as 80% of power sold through the pool in England and Wales is also backed by CFDs [Helm & Powell 1992].

4.2. Advantages and Disadvantages of Pool Operation

Defined by a closed set of rules, the pool system can readily be analyzed, but its complexity leaves room for interpretation. Proponents of the pool model advance several advantages: it provides a rigorous structure to maximize overall economic efficiency; it serves as an easily-accessed central clearing house to buy and sell electricity; it sets market prices according to well established commodity market rules; it removes opportunities for arbitrage; it dispatches and sets prices for ancillary services. A readily admitted disadvantage of the pool is that it is prone to volatile prices, probably due to its inflexibility and the immediacy of the needs it seeks to satisfy. Detractors of the pool model have mounted much criticism [for example, Oren et al 1995]. They point out that present market models do not minimize the cost to the consumer. This is due to the inherent economic rents rolled into the pricing mechanisms. They also contend that practices forged in a non-competitive single-utility environment no longer hold true, and that participants in a competitive environment are unduly restricted by central planning tools. The unintended consequences of the use of two standard functions, unit commitment and economic dispatch, are singled out here.

Unit commitment provides the on-off status of generating units. In a multi-producer environment, it effectively distributes entry permits into the market. In many cases, the result of the unit commitment is highly insensitive, i.e. costs for a wide class of commitments differ by little

[2] In the power system context, LMC is a recent term coined by economists. In the power industry, this term has been in use for several decades and was traditionally called the bus incremental cost [Ponrajah 1984].

from the final solution [Oren, Svoboda & Johnson 1997]. Moreover, the optimal itself is practically unattainable, and has to be approximated by a suboptimal solution [Zhuang 1988]. Hence any instance of unit commitment in a large class of near-optimal commitments would likely discriminate against certain producers. This argument convinced California to adopt self-commitment by producers.

Hourly or half-hourly auctions run by the pool are basically bid-based economic dispatches. Bid-based economic dispatch can result in gaming opportunities, in which producers adjust bid data in the hope of generating opportunity costs or securing other advantages [Wolfram 1997, Gross 1999].

Another criticism raised relates to the use of the OPF which is data sensitive and non-robust, and therefore cannot be counted on to guide participants fairly [Papalexopoulos 1999].

Misgivings about pool operation go deeper than the above criticisms however. Detractors fear that as a monopoly power broker, the pool can overcharge obscure uplift charges and administrative costs, and has little incentive to increase its own efficiency through the adoption of more cost-efficient market models. Already in American circles, newborn ISO structures are being criticized as being inefficient and anti-competitive. Superstructures called Regional Transmission Organizations (RTOs) are now being proposed to eliminate many of these concerns [Edison Electric Institute 1999].

4.3. The "Pure" Market Model

The seed of the "pure" market model fell in the American Southwest some five years ago, but it has not yet taken firm root. It originated in 1994 as a reaction against the pool model proposed in California's policy paper on restructuring [Blumstein & Bushnell 1994] . Lead by academics from Berkeley and senior engineers at Pacific Gas & Electric, and encouraged by a growing fleet of power marketers and large customers, this group has looked to develop market mechanisms which would require a minimal amount of intervention from the centralizing institutions. Ideally, the dynamics of supply and demand between knowledgeable participants in a decentralized market would allow each participant to reach its own best deal by reducing or even eliminating economic rents. Recourse to bilateral contracts was therefore strongly encouraged. Market designers in California experimented with new spot market mechanisms based on auction theory [Sheblé 1996, Sheblé 1998]. Participants would respond to marginal costs announced by a central dispatcher rather than provide bid curves; an equilibrium would occur after several iterations when the announced price reached the right level. Ironically, this is quite similar to the well-known central dispatching technique called lambda-dispatching [Kirchmayer 1958]. Congestion would be relieved in a similar manner, in that congestion costs announced by for-profit Transcos would be adjusted until tenants of unprofitable transactions would voluntarily withdraw from the market. The minimal role foreseen for a PX would be to send price signals to the market, while for the ISO it would be to signal unacceptable modes of network operation resulting from the commercial requests. The term Independent System Administrator (ISA) [Imparato 1999] was coined for this new minimal operator. The pure market theory is still embryonic, and so California renounced its implementation. The mixed system adopted in California in 1998 provides formal pool structures but also retains some of the openness of the pure market system. A readily admitted shortcoming of the pure market model is its present inability to properly handle transmission-related costs. Detractors point out that as it stands, its mechanisms are untried, and they do not guarantee economic efficiency nor even stable market operation. The California experience begot a bevy of consultants who are now trying to advance the cause elsewhere, but more work needs to be done to further this approach. The ill-fated Desert Star ISO initiative (American Southwest) embraced the minimalist philosophy, as will its successor.

4.4. Mixed Pool / Bilateral Market

Without fanfare, Norway opened a mixed power exchange / bilateral market in 1991. From its creation, it has been the world's most liberal electricity market. It immediately removed the obligation to serve on producers, and gave all consumers immediate access to energy markets. Bilateral contracts were encouraged, and over a period of five years power exchange structures were broadened. By 1996, a diversified energy market was in place, consisting of the short term spot and regulating markets, the longer term futures and options financial markets, and bilateral contract markets. Prices on all of these are divulged and readily available, allowing to set reference prices and lending stability in general. It is estimated that 90% of electricity contracts in the country are transacted through bilateral contracts. This market structure expanded to other Scandinavian countries in 1996, and is controlled by a superstructure known as Nordpool.

California's mixed market went into operation in 1998. Its power exchange runs both day-ahead and hour-ahead markets, but bilateral transactions are strongly encouraged. Presently certain restrictions force incumbent utilities to deal through the power exchange. At the end of a four-year transition period, all participants will be free to transact through any of the available instruments.

Being just one player among many, the PX in a mixed system has less impact than when integrated in a pool. In a mixed system, the PX basically trades in short term and regulation power. Prices reflect the market value of that final slice of the power market, and can tend to be volatile because small load forecast errors appear amplified on the smaller market. For example, off-peak energy prices as low as $2.41/MWh in California, in June 1998 [http://www.calpx.com], reflect little need for the excess generation offered at that time.

The mixed market is not defined by as closed a set of rules as the pool. A resulting difficulty for its designers has been the equitable distribution of ancillary service and transmission charges between spot market and contract participants. As in pool operation, two schools of thought have appeared. One assumes that services are bought entirely on the regulation market following marginal pricing mechanisms. In the two markets described here, that approach was rejected. Instead, simpler pricing schemes were implemented limiting congestion price differences to a reduced number of zones. Prices in each zone are modified based on adjustment bids submitted by participants. Costs for average losses in each zone are recovered through uplift charges. Cost-based alternatives have appeared in the literature [Galiana & Phelan 1999, Gross & Tao 1999] allocating precise losses to bilateral contracts.

Of the market mechanisms discussed above, bilateral contracts appear to be the preferred vehicle. At the very least they offer stable pricing. On the other hand, large consumers are no doubt optimizing their portfolios through a mix of energy holdings in the various markets. Regrettably, the interaction of spot and contracts markets has received little attention so far in the literature. A lesson offered by the experience of mixed markets is that the multiplicity of financial instruments does not hamper the technical operation of the network.

5. Some Thoughts on Marginal Cost Pricing for Spot Markets

A major point of contention between proponents of pool and pure markets has been the imposition of marginal cost pricing. Marginal cost pricing based on the results of economic dispatch has been implemented in all spot markets to date, whether participation is mandatory or optional. In this practice, all the power bought or sold in the spot market goes for a single price. Arguments pro and con have already been expounded in the previous section under the headings of proponents and detractors.

There is no doubt that marginal cost pricing provides useful costs signals. Explicit modeling of economic processes provides marginal costs indicating the value of resources as affected by the constraints limiting their use. Within modeling accuracy, marginal costs provide the cost of use of the last unit sold. However, marginal costs in themselves are not the actual costs. In the energy market, where generation costs/bids increase monotonically with production, the marginal cost pricing mechanism systemically generates revenues for producers; this is the merchandising surplus. These revenues go towards paying fixed costs not covered by uplift charges and towards profits. Individual revenues for producers depend on their own performances with respect to the market's aggregate cost versus load curve. Typically in a competitive market, marginal costs increase little over a wide range of demand. A recent study of the early behavior of the California market [Skantze et.al 1999] corroborates this. In that range, systemic revenues for producers are relatively low. On the contrary, when demand is high and resources become scarce, revenues soar because the marginal costs/bids are determined by expensive peaking units and more generally by market opportunities. Recent price spikes in the young American Midwest market [Rose 1998] are a case in point.

Marginal cost pricing is both a competitive-based and an opportunity-based scheme. In a pool context, it handles requests in a fair, non-discriminatory manner. It allows potential participants free reign to set their bids, but rewards only the lowest bidders with market participation. It ultimately offers all market participants uniform conditions despite the bids; this anticipates the behavior of informed market participants, who would eventually adjust bids, and offers the same advantages to all. In some markets, congestion rents have been added to the process. This goes towards the same general idea of curtailing opportunities of arbitrage for some [Oren 1996], and using the rewards to pay general fixed charges for all. Economists have long championed marginal cost pricing, particularly in commodity markets.

Surprisingly, the power engineering community has not yet published any analysis of the profitability of marginal cost pricing in the emerging energy markets. (Maybe we should be reading financial journals.) Global profit statements of energy companies are readily available and give a general indication from an accountant's point of view, but that does not provide the desired economic breakdown of revenues. Revenues must recover sizable fixed costs, such as investment and maintenance costs, which typically in the electricity industry are much higher than in other commodity markets. Several questions would require econometric analysis in each market. For example:

- How much systemic revenue is built into the pricing scheme? Note that if costs/bids increase linearly with demand, then the constant marginal costs are equal to bid costs, and no systemic revenue is forthcoming. Systemic revenues are only possibly if bid curves "turn upward" with load.

- In particular, how much revenue is gained in low, medium and high load markets? Are profitable high-load periods required to sustain the industry?

- How much revenue has been built into the bids? Theorists contend that in competitive markets there is no room to pad the bids. Is this true for the electricity markets? If systemic revenues are insufficient, then revenues must be incorporated into bids.

In the absence of such analyses, some contend that there seems to be no correlation between true costs, bids and profits. This sort of information is certainly very sensitive and therefore not likely to be shared. It provides important signals for investment, consumer strategies, etc.

Marginal cost pricing produces optimal prices in the context described earlier - anticipation of adjustments to freely submitted bids and non-discriminatory pricing. However, examples in the literature have hinted at other pool pricing schemes that produce lower aggregate costs to consumers. Simple examples in the literature [Jacobs 1997, Debs & Rahimi 1999] show instances of power dispatching which avoid congestion and the accompanying congestion rents. The resulting cost to consumers is lower than that of the optimal economic dispatch. A mathematical formulation for minimal aggregate marginal costs to consumers will be proposed further in a review of dispatching tools.

Some discriminatory cost-based pricing schemes, championed by engineers, have received relatively little attention so far. Proposals in [Bialek 1996, 1997] or [Kirschen et. al 1997; Strbac et. al 1998] trace contributions from generators to individual loads and attribute transmission costs to transactions using a graph theoretic approach. [Galiana & Phelan 1999] attributes transmission losses to bilateral contracts by integrating marginal losses. These techniques are certainly useful for determining costs, and could serve as an analytical basis for pricing bilateral contracts. Indeed, the bilateral contract market is the ultimate example of a discriminatory pricing system. Applied to a spot market, they are examples of "you get what you asked for" pricing. They have the advantage of eliminating merchandising surpluses and congestion rents. Still, economists shun such a scheme, pointing out that without systemic revenues, participants would continually adjust bids, causing more volatility and higher prices. Auction theory would be the proper setting to test how such schemes would fare against marginal cost pricing on average. So far, writings in the power literature have not touched on this.

6. Some Thoughts on Dispatching for Spot Markets

The terms auction and merit order dispatching are often used in describing the attribution of resources on spot markets. As implemented, auctions have been simple merit order dispatches, with some offering the possibility of updating bids before the moment of decision (for example, in California). Another notion bandied in more complex dispatches is the maximization of social welfare, used as a replacement to fuel cost minimization in traditional dispatch. Actually, mathematical optimization theory shows that all of these methodologies are quite similar in purpose if not in form. In this section we wish to highlight these similarities. Conceptually, the only major difference between central utility dispatching and the dispatch of competing generation in spot markets is the replacement of costs by bids.

Placed in a general mathematical setting, merit order dispatch is an active power dispatch formulated only with piecewise linear cost functions, a lossless power balance equation and constraints on generation. This differs from a similarly linearized, traditional lambda-dispatch only in its treatment of cost-sensitive loads. In condensed form, the merit order expressed as a linear program can be formulated as follows:

$$\begin{aligned}
\max_{\mathbf{P_d},\mathbf{P_g}} \quad & (\mathbf{b_0} + \mathbf{b_1^T P_d}) - (\mathbf{c_0} + \mathbf{c_1^T P_g}) \\
\text{s.t.} \quad & \mathbf{e^T}\left(\mathbf{P_g} - \mathbf{P_d}\right) = \mathbf{0} \\
& \mathbf{P_g^{min}} \le \mathbf{P_g} \le \mathbf{P_g^{max}} \\
& \mathbf{P_d^{min}} \le \mathbf{P_d} \le \mathbf{P_d^{max}}
\end{aligned} \qquad \textbf{(MO)}$$

where

b's and **c**'s are the coefficients of piecewise linear benefit and cost functions defined over the ranges of load $\mathbf{P_d}$ and generation $\mathbf{P_g}$ respectively;

e is the unit vector;

P_g^{min}, P_g^{max} are generation limits, and
P_d^{min}, P_d^{max} are loading limits.

Due to its simplicity, this linear program can be solved via the well-known merit-order algorithm rather than with linear programming techniques.

Cost-sensitive loads can be treated either through the social welfare or the traditional cost minimization approaches. Depending on the approach, load information is represented in either the objective function or in constraints. Here we show two equivalent quadratic programming formulations for real power dispatch, including transmission constraints. With a bit of effort, proof of this equivalence can probably be extended to more general mathematical settings. The equivalent social welfare (SW) and minimal fuel cost (FC) formulations are as follows.

$$\begin{aligned}
\max_{P_d, P_g}\ & \left(b_0 + b_1^T P_d - \tfrac{1}{2} P_d^T B_2 P_d\right) - \\
& \left(c_0 + c_1^T P_g + \tfrac{1}{2} P_g^T C_2 P_g\right) \\
\text{s.t.}\quad & h_0\left(P_g - P_d\right) = k_0 \qquad\qquad \textbf{(SW)} \\
& h_T\left(P_g - P_d\right) \le k_T \\
& P_g^{min} \le\ P_g \le P_g^{max}
\end{aligned}$$

with additional notation

$\mathbf{h_0}$, $\mathbf{h_T}$ are matrices representing the linearized load flow and line flow relations
$\mathbf{k_0}$, $\mathbf{k_T}$ are the right hand sides of the linearized load flow, and line limits respectively

and

$$\begin{aligned}
\min_{P_g}\ & \left(c_0 + c_1^T P_g + \tfrac{1}{2} P_g^T C_2 P_g\right) \\
\text{s.t.}\quad & h_0\left(P_g - P_d\right) = k_0 \\
& h_T\left(P_g - P_d\right) \le k_T \\
& P_g^{min} \le\ P_g \le P_g^{max} \qquad\qquad \textbf{(FC)} \\
\text{but}\quad & \\
& P_d = P_{d0} - M\pi_d \\
& 0 \ \le\ P_d\ \le\ P_{d0}
\end{aligned}$$

where

P_{d0} is the load vector unrestricted by cost
M is a diagonal sensitivity matrix of the loads with respect to price
$\boldsymbol{\pi_d}$ is the price vector

The two problems present identical optimality conditions if the following conditions are met, linking the **b** parameters on one hand to the ($\mathbf{P_{d0}}$, **M**) parameters on the other:

$\boldsymbol{\pi_d}$ is the set of bus incremental costs
$P_{d0} = B_2^{-1} b_1$
$M = B_2^{-1}$

The latter two conditions are automatically met by the definition of the benefit coefficients. Note that in the context of problem (FC) the notion of social welfare need not be invoked.

The three formulations displayed so far couple marginal cost pricing to the economic dispatch solution. Below we offer a new formulation which applies marginal cost pricing to a different dispatching strategy. The object is to define the parameters g_0 and G_1 of the dispatching strategy

$$P_g = f\left(P_d\right) = g_0 + G_1 P_d \qquad (1)$$

which minimizes total costs to consumers, assuming that the new marginal costs

$$\frac{\partial C}{\partial P_d^T} = \frac{\partial C}{\partial P_g^T}\frac{\partial f}{\partial P_d} \qquad (2)$$

define prices. The strategy would be piecewise linear versus load since coefficients would change as active constraints are met. Certain restrictions could be placed on $\mathbf{G_1}$ to reduce the number of degrees of freedom. The minimal cost problem (MC) is as follows.

$$\begin{aligned}
&\min_{g_0,G_1} \quad \pi_d^T P_d \\
&\text{s.t.} \quad h_0\left(P_g - P_d\right) = k_0 \\
&\qquad\quad h_T\left(P_g - P_d\right) \le k_T \qquad\qquad \textbf{(MC)} \\
&\qquad\quad P_g^{min} \le P_g \le P_g^{max} \\
&\text{with} \\
&\qquad\quad P_g = g_0 + G_1 P_d
\end{aligned}$$

Again with quadratic generation costs, and with the dispatching strategy defined by equation (1), marginal costs are expressed as follows:

$$\begin{aligned}
\pi_d^T &= \frac{\partial C}{\partial P_d^T} = \left(C_2 P_g + c_1\right)^T G \\
&= \left(C_2\left(g_0 + G_1 P_d\right) + c_1\right)^T G
\end{aligned}$$

Additional constraints could be added to (MC) to ensure that participants would be no worse off than with an economic dispatch solution; for example:

$$\begin{aligned}
&\pi_d \le \pi_d^* \qquad \text{at load buses} \\
&\pi_g \ge \pi_g^* \qquad \text{at generator buses}
\end{aligned}$$

where the asterisk denotes the optimal solution to the economic dispatch, and subscripts d and g pertain to load and generator buses respectively. These constraints assure a ceiling price of π_d^* to loads and a floor price of π_g^* to generators.

The optimal solution to this problem is probably identical to that of the economic dispatch as long as the latter is uncongested. The former would choose a different route when facing congestion. We have not tested this formulation, and so more work needs to be done. Although we are not advocating the use of any new pricing strategy, our purpose is to show that pricing reflects human preferences, and is not carved in stone.

7. Some Thoughts on Transmission Pricing in a Spot Market

Transmission pricing is a complicated issue in most restructuring models. Regulated transmission companies recover their costs and their predefined profits through diverse schemes. A large part comes from tariffs, of which many types have been proposed. A smaller part comes from the collection of real-time charges in the spot market, such as congestion rents or adjustment bids. The latter have always been deemed a vital pricing component, since they force participants to respond to signals of scarcity [Ilic et. al 1997]. As noted in [Hogan 1992] however, they are purely opportunity costs. Viewed in a setting of classical economic dispatch, the higher costs resulting from congestion are energy costs, incurred when unavailable cheap energy is replaced by higher priced energy. This in no way affects the transmission provider. With marginal cost pricing, part of the charge collected in the marginal bus cost goes towards paying that higher priced energy, but part is the congestion charge returned to the transmission providers. Hogan has championed financial instruments called transmission congestion contracts (TTCs) to transact congestion charges.

Charges for non-energy related ancillary services in a spot market can be subject the same kind of opportunity costs [Baughman & Siddiqi 1991].

8. Pricing Schemes and Some Longer Term Considerations

Well-designed pricing schemes are said to provide strong signals for investment. For now there is no consensus on the right signals to cultivate, except to say that in situations of scarcity, signals should scream [Lecinq 1996]. The literature sends contradictory messages on this issue. Consumer-friendly messages proclaim that competitive spot markets normally cut profits to the bone. This is because providers dare not bid higher than their marginal costs to assure a place in the market. On the other hand, high peak-load prices and congestion rents send signals for investment. It has been observed however that the proportion of global revenues recovered under such conditions is relatively small. What's more, the addition of new generation or transmission resources would silence those signals, removing the incentives which attracted investments in the first place. The signals focus attention on needs but do not ensure profits to investors. It must be concluded that even in the most competitive of markets, providers must extract a reasonable profit in any operating condition. Simply put, only generally profitable businesses attract investment.

Costs associated with maintaining technical standards are not explicitly considered in short term pricing. Standards address the obligations to operate well, to build well and to maintain well. It is felt that these standards must not be abandoned or fall through the cracks of a decentralized industry structure. How to achieve this is not yet well-defined.

9. Conclusions

All forms of restructuring have been declared successful by their authors. This is generally true, although some implementations have been criticized for their rocky starts, specifically concerning excessive profits and insufficient consumer benefits (England [Newbury 1995, Wolfram 1998], Alberta [London Economics 1998]). Success of the restructuring process depends on many factors. The efficiency of the market structure, the topic most considered in this paper, is but one element. Other elements include the improved management brought on by corporate restructuring and the new level of competitiveness of the industry. These should not be confused with exogenous factors such as abundance of energy resources and the dramatic drop in the price of oil over the last decade. In those states where restructuring has reached beyond its infancy, it is generally agreed that competition has reinvigorated the industry and has contributed to reduce prices.

Acknowledgements. F. Galiana aknowledges the support of the the Natural Sciences and Engineering Research Council, Ottawa and the Fonds pour la Formation de Chercheurs et d'Aide à la Recherche, Québec.

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