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Energy Regulation in Québec

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SUMMARY

This report characterizes

This report characterizes the regulation of energy markets in general and focuses on the electricity and natural gas markets of Québec. Markets are regulated if they are deemed to represent natural monopoly situations or if unregulated firms would not take into account externalities that they might generate. Energy market regulation has been justified with the claim that regulation represents the “second-best” alternative. That is, given a situation in which there is market failure, the outcome derived under regulation may be better than the outcome that would arise if the market were unregulated. Government intervention may be required in order to protect the interests of consumers. Energy markets have been considered natural monopoly situations in large part because of the enormous fixed costs associated with production and distribution. Furthermore, electricity and natural gas are generally considered essential goods, or more accurately, goods with significant positive externalities from reliable supply. A reliable supply is necessary for the proper functioning of any modern economy and a private market might not provide equally for all people in a service area.

In recent years, however, certain segments of some energy markets have been liberalized, since these segments might not actually be natural monopoly situations and/or because the market may provide means to ensure that firms internalize externalities. We describe the experiences of a number of jurisdictions that have experimented with energy market liberalization and show that restructuring is feasible and may provide an improvement over the status quo if market power can be limited.

We consider the potential for restructuring in Québec’s energy markets which are currently mainly regulated by the Régie de l’énergie du Québec. Québec’s electricity market does not represent a typical case for the restructuring of the production side since the vast majority of its generating capacity comes from hydro projects. Over 90% of Québec’s installed electrical capacity is hydro generated, making Québec the second most hydro-dominated market in the world after Norway. Furthermore, this capacity is highly concentrated on three river systems. The usual model of forced divestiture by hydrologic system is therefore likely to

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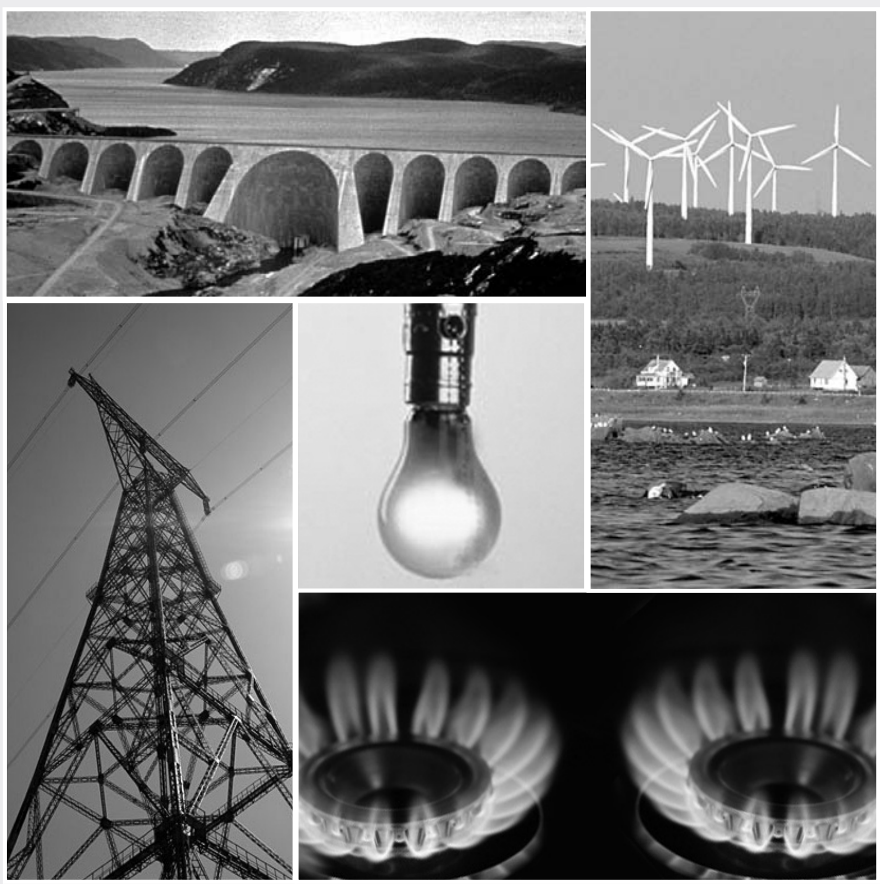
introduce market power in a restructured market, and may lead to greater inefficiencies than those present under regulation. In order for any market restructuring to succeed, (at least) one of two approaches must be undertaken. A system of tradable water rights could be established in parallel with a competitive power pool in order to allow divestiture of individual plants within a river system and/or Québec's markets could be opened to foreign production.

The retail segment of Québec's energy markets could potentially benefit from liberalization. The only obvious difference between Québec's energy markets and those in other jurisdictions is Québec's price-equalization policy. Lower prices could prevail if competition were introduced to the markets for electricity and natural gas, but not for all consumers. Québec's insistence on uniform prices throughout the province means that some consumers are currently paying below market price for energy. Prices for these consumers could rise if the market is restructured.



Introduction

Energy market liberalization has taken place or is currently underway in regions throughout the world. Meanwhile, Québec's energy markets remain mainly regulated by the Régie de l'énergie du Québec. In particular, the Régie oversees Québec's electricity and natural gas sectors. In this report, we will discuss the economic rationale that led to regulation of electricity and natural gas markets in the first place and explain the current trend towards restructuring. We will examine Québec's electricity and natural gas markets and the role of the Régie in their functioning, and we will consider the potential for the restructuring of energy markets in Québec.

While Québec's electricity and natural gas markets are both regulated by the Régie, they are very different. Québec is a huge producer of electricity, generating nearly one-third of all Canadian capacity. Over 90% of Québec's installed electrical capacity is hydro generated, making Québec the second most hydro-dominated market in the world after Norway. Much of this capacity is produced far from the principal consumers of power at large-scale generating complexes and travels long distances to the retail market. On the other hand, Québec produces no natural gas at all, importing instead from Western Canada via the TransCanada Pipeline. Once in Québec, gas is sold to consumers or exported to the U.S.

International experiences demonstrate that restructuring energy markets is possible but often difficult to implement. It is now recognized that the generation and retail segments of energy markets are not necessarily natural monopoly situations, and so restructuring is feasible and is likely to provide an improvement over the status quo where market failure due to externalities and excessive market power can be eliminated. However, at least in the case of Québec's electricity market, any attempt at restructuring must take into account the fact that a large fraction of the installed capacity is generated at very large hydro complexes on individual river systems, making the construction of new hydro-electric facilities, or forced divestiture, more complicated.

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PART ONE

Energy Market Regulation

The goal of regulation is to reproduce as closely as possible the advantages of a competitive market or, alternatively, to minimize the impacts of market failure.

1.1 The Economics of Regulation

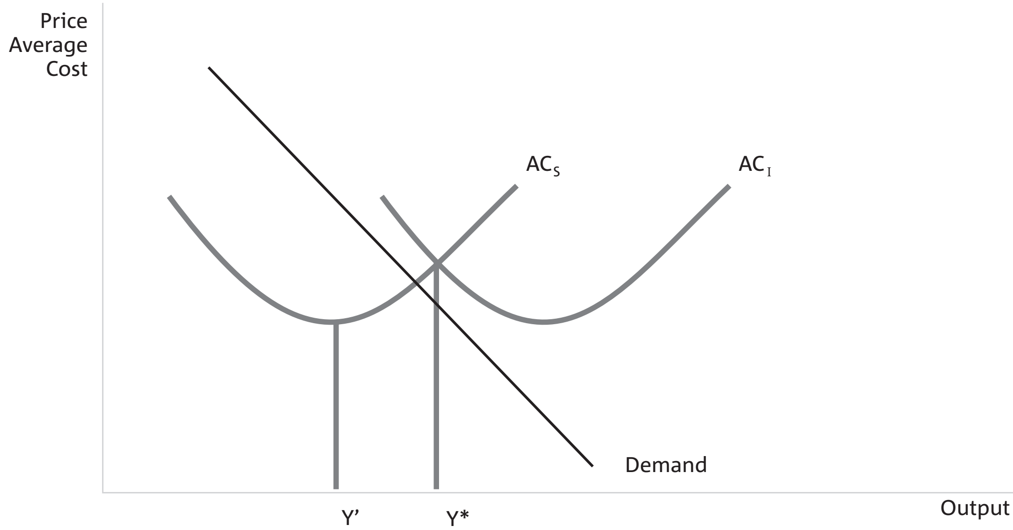
The goal of regulation is to reproduce as closely as possible the advantages of a competitive market or, alternatively, to minimize the impacts of market failure. If a market is truly competitive, the last unit of electricity or natural gas supplied to the market would not reduce social welfare, nor could social welfare be increased by producing additional energy. This directly implies that marginal social cost pricing must occur in a truly competitive market. Firms in a competitive market would have incentive to reduce costs as much as possible, since this would allow them to earn greater profits given the market price. A regulated energy market cannot accomplish these goals simultaneously. Generally speaking, a regulator may choose to regulate firms based on a cost-of-service condition or a price-cap. Under cost-of-service regulation, a firm is permitted to charge a price that allows it to recoup its costs, but not to experience an economic profit. Under this regulatory approach, it is possible to ensure marginal cost pricing; however, the firm faces no incentive to reduce its aggregate cost of production, since no further profits will be experienced. Alternatively, the regulator can impose a price-cap, whereby firms are constrained by a maximum price they can charge for power sold on the market. In this case, incentives exist for firms to reduce costs, since they can increase profits; however, this does not come with a coincidental decrease in price. There are margins on which this technique can be improved, principally through creative price-cap schemes and more frequent adjustments. In the natural gas industry, the advent of negotiated, multi-year settlements between pipeline operators and distributors signalled an era of lighter regulatory control. Stoft (2002) argues that historically, regulation has erred on the side of driving prices down toward marginal costs, to the likely detriment of incentives for cost reduction.

The fact that a regulated energy market cannot simultaneously involve marginal social cost pricing and incentives for cost reduction leads us to question why energy markets are so often heavily regulated. The justification most often proposed is that regulation represents the "second best" alternative. That is, given a situation in which there is market failure, the outcome derived under regulation may be better than the outcome that would arise if the market were unregulated. In particular, industries that are characterized by externalities or by natural monopoly may require government intervention in order to protect the interests of consumers — particularly if the good or service is deemed essential. Externalities are generated when the behaviour of one economic agent affects the well-being of another. If the externality generated is positive, since the producing agents fail to take into account the external benefits provided by their behaviour, too little of the good is produced from a social perspective. If the externality generated is negative, too much is produced.

While negative externalities are important to consider as a motivation for regulation, the existence of positive externalities and public-good production should also be considered. If a good or service is deemed essential but the cost of provision is such that the private market might not supply it to all people in a service area at affordable or equal prices, governments may intervene. Consumption by a group for whom the marginal cost of provision is quite low can subsidize consumption by a group for whom the cost is quite high.

The other market failure that leads to government intervention is the existence of a natural monopoly situation. A market is said to be a natural monopoly situation if it is cheaper for one firm to serve the entire market than it would be for more than one firm. Usually, natural monopoly is associated with economies of scale — average costs that are always decreasing in quantity. Faced with such a cost curve, a single large producer is able to drive competitors out of the market, at which point it can charge the monopoly price. If entry is unrestricted, consumers could face fluctuating prices since competitors will be attracted to the market by the single firm's positive economic profits. Upon entry, the incumbent would again lower price to drive the entrants from the market. Regulation is necessary to control entry and limit the exercising of market power by the single producer.

Figure 1
Range of subadditivity



However, it is important to note that even if the average cost schedule is not declining over all ranges of output, but is instead u-shaped, it may still be more efficient for a single firm to provide for the entire the market. That is, it may still be a natural monopoly situation. Consider the following market structures: (i) a single firm serves the entire market and has a u-shaped average cost curve AC_S, and (ii) n firms (with identical cost structures to that of the single firm) serve the market with industry-average cost curve (AC_I). We are interested in determining the output levels for which a single firm yields the least-cost production alternative. Figure 1 helps us make such a determination. Even to the right of the minimum of AC_S , where diseconomies of scale exist, it is still the case that it is cheaper for one firm to serve the entire market. The single firm is the least-cost producer up to the output level Y*, where AC_S and AC_I intersect. In general, we can say that an industry is considered to be a natural monopoly if costs in the industry are subadditive over the entire relevant range of output levels (Baumol, Panzer, and Willig, 1982). Again, regulation is necessary since price fluctuations could occur if the market-demand curve intersects the single firm's average cost curve (AC_S) to the right of its minimum, but to the left of its intersection with AC_I. It is still cheaper for a single firm to serve the entire market, but socially inefficient entry may occur. Potential entrants may be attracted to the market, even if the single firm is only earning normal profits, since they can produce a smaller output at lower cost.

1.2 Energy Market Regulation

Energy market regulation in different jurisdictions has been put into place for one or more of the reasons described above. Electricity and natural gas are generally considered essential goods. As a result, governments have intervened in energy markets to ensure low and stable prices that are roughly equal for all of their constituents. Consumption by residents of large, urban areas for whom the marginal cost of provision is quite low subsidizes the distribution of electricity or natural gas to those living in more remote areas. The private market would not provide equally for all people in a service area, and so, since the supply of energy is considered an essential service, it has historically been felt that private provision would come at a high social cost.

Governments have intervened in energy markets to ensure low and stable prices that are roughly equal for all of their constituents.

Electricity and natural gas markets may be characterized by the presence of externalities, especially when producers do not pay for environmental damage as a result of pipeline construction, displacement of people for reservoir creation, and other severe social costs. Also, if multiple hydro-electricity generating plants owned by different firms were located on a single river system, the decisions made by the upstream plant would impose externalities on the downstream plant. When enforceable property rights do not exist for all of the inputs to energy production, the government may choose to impose regulations such that social costs be implicitly taken into account by producers.

Energy markets have generally been viewed as natural monopoly situations, in large part because of the enormous fixed costs associated with energy production and distribution. A generalizable characteristic of energy production (generation, extraction) is increasing returns to scale over at least some range of output. This implies that a doubling of output does not require a doubling of all inputs, but often substantially less. In the case of electricity, this is seen as declining costs of generation per MWh (megawatt-hour), while in the gas industry this takes the form of decreased per-cubic-metre extraction and delivery costs.

Stoft (2002) argues that for most types of electricity generation (namely, nuclear and coal-fired), the level of technology determines the limits up to which economies of scale are generally available. In contrast, for hydro-electric projects, the optimal scale is determined, for the most part, by the specific project.

In the transmission of power, economies of scale are generally known to exist within a service area, but not between service areas (Stoft, 2003). It is intuitive that there could be gains from high-tension lines between a generating plant and a municipality, as compared to low voltage transmission, but there would be few gains in efficiency to serving multiple service areas. The logic of state-owned utilities has been the ability to exploit returns to scale in transmission and generation simultaneously. In essence, transmission lines have gains across service areas if they allow two municipalities to be served by a single, large plant rather than two smaller ones.

Energy markets have generally been viewed as natural monopoly situations, in large part because of the enormous fixed costs associated with energy production and distribution.

Hydro retail sales represent a separate market segment which includes only the billing and metering of electricity. Nonetheless, since electricity is deemed an essential service, governments have generally felt it necessary to couple this segment with the distribution of power (the lines running from house to house). As discussed above, it is clear that the distribution segment of the market is able to realize significant economies of scale; as a result of this coupling, retail sales have been traditionally handled by monopoly providers.

In natural gas markets, the fixed costs of extraction represent a large part of any firm's commitment to the industry. Once a particular firm has discovered (and secured rights to a particular deposit of natural gas), investment takes place in drilling equipment (which may include offshore platforms), pipelines, and compressors (for distribution). Gas is extracted and transmitted to large-scale consumers (industrial users and utilities) using external sources of energy, and many of these techniques exhibit increasing returns to scale. In general, gas extraction exhibits increasing returns to scale within a field, but not across fields, since the fixed costs are field-specific. The same is true for pipelines, where we can see significant unit-cost savings by looping, increasing pressure, or expanding pipeline size; however, there are limited scale economies across pipelines. The unit cost of delivered gas from a particular source is thus generally considered to be a decreasing function of the size of the gas resource and the exploitation investment (Banks, 2003).

Electricity and natural gas vary greatly in the technology employed for the storage and distribution of their respective forms of energy. The use of storage facilities is a very important link in the chain between production and retail sales of natural gas, while in the electricity market, all electricity in the system clears every fraction of a second. Gas storage and distribution certainly exhibits increasing returns to scale in a service area (from economies of density and usage patterns), but these are virtually non-existent across service areas (Banks, 2003).

PART TWO

Energy Market Restructuring

In principle, as discussed above, regulation is put into place to invoke a second-best outcome; the best outcome that can be achieved when there is market failure. Energy markets are regulated because the assumed existence of scale economies renders energy production by monopolists (or oligopolists) cheaper than the competitive alternative, and/or because firms in unregulated environments will not take into account the externalities they generate. It is important as part of the regulatory process to re-evaluate constantly the continued existence of (or potential for) this market failure. If it is reasonable to expect that the market could function efficiently, then there may be substantial allocative losses to regulation. Moreover, it is not always clear that governments intervene strictly to address market imperfections. Economists point out that empirical evidence suggests that regulation is in fact not associated with market failure (Viscusi et al., 2000). Therefore, the theoretical justification presented above--regulation to address externalities, natural monopoly situations or public good provision--may not be compelling. An alternative theory is that economic regulation arises because of the influence of interest groups, not as a result of potential benefits to society as a whole. According to this hypothesis, the firms in an industry lobby the government to intervene since regulation actually favours producers. This hypothesis further predicts that eventually, the regulatory agency of the government will end up under the influence of the firms in the industry (Viscusi, et al., 2000). Whether or not regulation was initially welfare improving, the evolution of the market may have led to a situation where the potential allocations without regulation dominate those under regulation, such that the outcome no longer represents the second-best.

Liberalization of energy markets has taken place in a number of jurisdictions throughout North America and around the world, and many more are considering doing the same. For a government contemplating the restructuring of its energy markets, the critical question is: When regulatory controls are removed, what will transpire? The motivation for restructuring is the view that some parts

Whether or not regulation was initially welfare improving, the evolution of the market may have led to a situation where the potential allocations without regulation dominate those under regulation

of electricity and natural gas markets do not represent natural monopoly situations, and so if these segments are restructured and competition is permitted, greater efficiencies will arise. In particular, it is generally felt that it is primarily the transmission and distribution portions of energy supply that present natural monopoly situations. In most electricity and natural gas markets, the retail and production sectors have been found to reap substantial potential benefits from competition and the real-time marginal cost pricing that is supposed to ensue. The goal of restructuring efforts has been to produce benefits for consumers in the form of the lowest prices possible while guaranteeing a reliable supply and maintaining or creating incentives to innovate.

Although each jurisdiction that has engaged in the restructuring of its energy markets has adopted a somewhat different approach, some common threads which constitute a basic model of energy sector restructuring can be seen (Joskow, 2003). The vertically integrated energy-providing monopolist is dismantled and ownership of production, transmission, systems operations, distribution and retail segments is vertically separated. The potentially competitive segments, namely production, marketing and retail supply, are separated from the segments that remain regulated (transmission, distribution, systems operation). Since imposing competition in transmission and distribution would imply building new supply grids or pipelines, the transmission and distribution portion of energy supply is usually thought to represent a natural monopoly situation (Wolak, 2003). Usually a single, independent transmission company is integrated with the system operations and is overseen by an independent systems operator whose responsibility it is to ensure sufficient energy is available to satisfy demand. Entry of producers is encouraged and sometimes accelerated with forced divestiture. Retail segments are functionally separated from distribution segments of the original utility.

What are the benefits of restructuring energy production markets to allow for competition? The principal rationale holds that this will lead to greater efficiency, more appropriate allocation of risk and potentially cleaner production. According to Joskow (1997), restructured electricity markets can expect to realize efficiency gains in the medium-run through the improvement of generating facilities, such that inefficient plants can be shut down and labour productivity can be improved. In the long-run, new investment in generating facilities can be expected where demand will support it, since competitive rates of return will now be available on capital investment. The competitive market should provide incentive to control costs and to innovate. As a result, in some markets, dirty coal-fired plants may be replaced with natural gas and aero-derivative, combined-cycle generating technology (Joskow, 1997).

In order for wholesale market competition to occur, a clearing house must exist in which energy supply and demand are allowed to determine the price. A spot energy market is usually created such that supply of and demand for energy may be balanced through the setting of the spot price. End-use consumers can purchase their energy directly on these spot markets or from competing retailers. The latter either purchase energy on the wholesale market or generate it themselves. Many regions have also incorporated forward or futures markets or long-term contracts into their restructuring programs, in an attempt to smooth out market fluctuations and provide better signals of anticipated supply and demand.

In restructured markets, consumers are allowed to purchase energy directly on the wholesale market if they like, or through agents or marketers. Usually, a single agent, the current monopoly retailer, remains in place and acts on behalf of consumers on the wholesale market. In addition, a competitive market implies that the consumer no longer bears the risk of the technology choice, construction cost overruns, and operating mistakes. It is important to distinguish the restructuring of the retail market from the necessary imposition of real-time or time-of-use pricing schemes. These are not intrinsically linked, although they are often associated (Stoft, 2002).

In restructured markets, consumers are allowed to purchase energy directly on the wholesale market if they like, or through agents or marketers.

Real-time pricing is the name given to a system which charges prices which differ by day and by hour of the day. Real-time pricing does not necessarily imply that the retail price is equal to the wholesale price, but it may well be based on the wholesale price. Time-of-use pricing is generally the term given to pricing schemes whereby a specific schedule of prices is predetermined based on the time of day, and usually remains fixed for a given period of time, either a month or a season (Borenstein, 2001).

If either of these time-of-day pricing schemes is implemented, further gains can be achieved as rational consumers will adapt their behaviour in order to maximize their utility. For example, while there is currently no incentive to displace high-load tasks outside of peak hours, the imposition of peak-load pricing may alter this behaviour for cost-saving reasons. The upshot of this is that the ratio between peak and base load decreases, and therefore energy becomes cheaper. There is some dispute over the effectiveness of this sort of pricing scheme in reducing generation costs. Stoft (2002) argues that since load factors for electricity production are currently relatively low in most jurisdictions, the cost savings to real-time billing would not be as large as many predict. The success of fixed-price contracts in restructured electricity markets as well as traditional markets such as heating oil show that consumers are willing to pay a premium for insurance against price risk. This is not reflected in Stoft's analysis, so it remains unclear whether real-time billing will lead to reductions in overall consumer expenditure.

Other suppliers have chosen to implement demand charges, which imply a charge based on the maximum use of power during any fixed time interval (usually a fifteen-minute period) during the billing cycle. Borenstein (2001) argues that the economic incentives established here are a highly imperfect proxy for either of the time-of-day pricing schemes discussed above. There is little incentive for a given household to displace household power usage outside of aggregate peak demand. It is clear that the reason that aggregate peaks exist is because many consumers within a jurisdiction are using large loads simultaneously, so there may be some effect from customers trying to reduce their individual peak demand. In any case, the effect of this scheme on the retail price charged to consumers must be less than that outlined above by Stoft (2002).

Many governments have chosen not to fully liberalize the retail electricity market. In Ontario, California, and Alberta, some form of retail price cap was implemented in the market as part of the restructuring of the production and/or retail sectors. In this case, the price cap creates scarcity, since supply will not equal demand wherever the cap is binding, and thus the market operator must choose between blackouts, or subsidizing the shortfall from government coffers. In California and Ontario, this has been the chosen approach.

Natural gas market properties on the retail side are very similar to those of electricity, where retail implies metering and billing of gas provided to residences by the distributor. The retailer purchases distribution rights to a bulk quantity of gas, which it then sells to its customers. The presence of competition and a regulated distribution authority should drive price to marginal cost in this market as well. It is also clear that there are benefits to the reduction of peaks and valleys in demand for natural gas, although contrary to electricity, where these are felt in diminishing needs for peaking plants, the natural gas savings occur through a reduced need for storage facilities.

The final element of a restructured energy market is some sort of regulatory oversight mechanism. This, at the limit, will take the form of anti-trust oversight, ensuring that no party is able to exercise market power. In some cases, there may be more heavy regulatory oversight of restructured markets (Wolak, 2003). In many jurisdictions, this will imply greater control of environmental externalities. In regulated markets, projects are approved, and prices set by government agencies, and these prices can be assumed to reflect, in some measure, the social cost of generating electricity. At least the project-approval decision should reflect a net social benefit. Under private production, project adoption and pricing decisions are made at the firm level, so it will be up to the regulator to assure, as with any industry, that the private costs of production accurately reflect the social costs.

There are of course some costs involved with energy market restructuring. In particular, there is the potential for market power to arise if there is insufficient competition in the marketplace. As a result of the specific characteristics of the electricity market, wherein there exists inelastic short-run demand in combination with a good that has no shelflife, the gains to the exploitation of market power are very large for firms, and as such must be carefully monitored (Borenstein and Bushnell, 2000). Given the nature of the good as an essential service with immense positive externalities, consumption implies that the social costs to a service interruption may outweigh the private costs, so it is possible that sufficient new investment to ensure supply may not come online in time. Instituting real-time pricing also involves heavy start-up costs in the form of new metres capable of allowing for such a system. Divestiture can also be difficult, since responsibility for the stranded costs of the vertically integrated utility must somehow be assigned. Finally, there are environmental and other externality concerns that must be addressed if a market is to be restructured. If these externalities are not addressed, price will be driven down to marginal private costs, and social losses due to pollution and other external effects may exceed those from the existing regulation.

Wolak (2003) proposes five key conditions (...) meant to ensure that energy producers face as elastic a residual demand curve as possible.

We have described the manner in which energy market restructuring generally has taken place. The success of any attempt at restructuring depends on a number of factors. Wolak (2003) proposes five key conditions necessary for the successful restructuring of energy markets. Essentially, these conditions are meant to ensure that energy producers face as elastic a residual demand curve as possible in order to prevent (or at least reduce) the exercise of unilateral market power:

1) There must be actual competition in the market. No dominant firm can exist since firms will exercise market power if they have it, and so forced divestiture must be undertaken if necessary.

2) There must be a forward market for the energy source in question. Forward markets incite suppliers to bid more aggressively on the spot market, resulting in more elastic demand curves. Energy a supplier purchases on the spot market may represent a cheaper way of satisfying its long-term commitment than energy it could generate itself. Forward contracts can also help to raise current funding for investment in new capacity.

3) Consumers must be involved in the wholesale market and ideally some form of real-time pricing must be adopted in order to shift demand across times of day.

4) The transmission system must have sufficient capacity to allow distant firms to act as competition for local providers. Without an extensive transmission network, the result is essentially just a series of local monopolies.

5) There must exist a credible regulatory mechanism. Monitoring must be ongoing in order to deal with the inevitable flaws in the restructuring process.

A brief analysis of the energy market restructuring experiences of a number of jurisdictions demonstrates the importance of the conditions proposed by Wolak (2003). In what follows, we examine the energy markets in England and Wales, Alberta, Ontario, and California. The first two markets have seen reasonable success from restructuring, and have generally met the conditions set out above. On the other hand, in the province of Ontario and the state of California, where the conditions mentioned above have not been met, existing producers can exercise market power and the results have been disastrous.

2.1 Energy Market Restructuring in England and Wales

In the past two decades both the electricity and natural gas markets have been restructured in England and Wales and the transition has been fairly successful. Prior to the *Electricity Act of 1989*, the Central Electricity Generating Board (CEGB) was the sole generator and distributor of electricity in England and Wales and was operated as a cost-of-service public utility. As a result of restructuring, the electricity market has been broken into four separate segments: generation, transmission, distribution and retail sales (Wolak, 2004). The generation segment was split into three companies: the publicly owned Nuclear Electric was granted control of all nuclear power plants, while all fossil fuel plants were privatized into two competing firms, National Power and PowerGen. Twelve privatized regional electric companies (REC's) were formed to distribute electricity. These distributors must allow competitors to transmit power over their systems at the same price that they charge themselves. Initially, these companies had ownership over the company that operated the transmission network, the National Grid Company (NGC). In addition to operating the grid, the NGC also acted as the power exchange, clearing supply and demand by determining spot prices. Forward trading was also allowed, although only of contracts for differences (mutual hedging contracts between producers and distributors involving a benchmark price for an agreed-upon quantity of electricity at an agreed-upon period of time). In 1995, the REC's were required to divest their ownership of the NGC. Its operation of the transmission network is now overseen by the Office of Gas and Electricity Markets and power is now traded on the London Stock Exchange (Hrab and Trebilcock, 2004a).

The retail market was also liberalized. Immediately, customers with peak demands of at least 1 MW (so-called nonfranchise customers) were permitted to choose their suppliers from among the twelve RECs or to purchase directly from National Power or PowerGen. The 1 MW limit was lowered to 100 kW (kilowatts) in 1994, and as of 1999 all customers were allowed to choose their supplier (Wolak, 2004). As of 2003, the REC's serviced 61% of the available customers, while new entrants serviced the remainder (Hrab and Trebilcock, 2004a). In fact, 38% of domestic electricity users have switched suppliers (Zhou, 2003).

Moreover, the retail market involves some degree of time-of-use pricing, if not real-time pricing. Some residential customers and most commercial and industrial users pay a fixed-price per MWh for consumption during the day and a different fixed-price per MWh for night-time use (Wolak, 2004).

Following restructuring, prices in England and Wales initially increased as National Power and PowerGen were able to exercise market power. Although some new capacity had come online following the Act (combined-cycle gas-turbine technology facilities), the combined market share of National Power and PowerGen still exceeded 50% in 1995 (Wolak, 2004). In an effort to rectify this problem, further divestiture of the two companies was ordered and the New Energy Trading Agreements (NETA) replaced the Electricity Pool in 2001. Under these agreements, the uniform price system that had been in place, which determined the uniform market clearing price based on the system marginal price, was replaced with a bilateral, pay-as-bid system trading between generators, retail intermediaries, traders and customers. Under the new system, prices are determined through individual transactions between traders (Hrab and Trebilcock, 2004a). Also under NETA, forward contracting of actually physical delivery was allowed (Bower, 2002).

Between 1999 and 2003, total generation capacity in England and Wales increased from 73200 MW to 78900 MW (Zhou, 2003). From 1998, when the NETA was first announced until the end of the first year of its implementation (2002), wholesale spot electricity prices fell by 40%.(Hrab and Trebilcock, 2004a). In addition to lower prices, the electricity market in England and Wales has moved towards cleaner production - its dependence on coal-fired generation has been reduced. Between 1993 and 2000, the generation capacity of major power producers in combined-cycle gas turbines increased from about 1400 MW to about 20000 MW (Zhou, 2003).

The restructuring of the natural gas market in England and Wales has followed a similar path. The vertically integrated monopolist British Gas was privatized in 1986 and the Office of Gas was formed to oversee its activities. In 1996 it was broken up into a supply component, transportation and storage component, and a research and development component. On the retail side, beginning in 1992, large industrial and commercial consumers were allowed to choose their suppliers, providing incentive for new providers to enter the market. By 1998, all customers were allowed to choose their supplier (Energy Information Administration, 2004). Indeed, 37% of customers have switched providers (Zhou, 2003).

From 1998, when the NETA was first announced until the end of the first year of its implementation (2002), wholesale spot electricity prices fell by 40%.

2.2 Electricity Market Restructuring in Alberta

Daniel et al. (2001) argue that Alberta makes a very interesting test case for energy-market restructuring because it is large enough to provide the same general challenges and potential advantages of restructuring as in California and Ontario without the complicating factors brought about by the interconnectedness of those markets.

Prior to restructuring, Alberta had three vertically integrated monopolies: Edmonton Power, TransAlta Utilities, and ATCO Electric, that generated, transmitted and distributed electricity in Alberta. These companies operated under franchise monopolies and were regulated on a cost-of-service basis. The wholesale market in Alberta has been integrated and jointly managed since the 1970's, with generation capacity being dispatched centrally over the three service areas. Alberta is essentially isolated from other electricity grids, with only 550 MW of interconnecting transmission lines, so it is impossible to make up substantial excess demand.

The Electric Utilities Act was tabled in 1995 and restructured Alberta's energy markets. Wholesale prices were to be determined by supply and demand in a power pool. Generating plants were to have open access to the transmission system, and there was to be more competition in electricity generation. Changes to the system included the establishment of an independent power pool, through which wholesale prices would be determined on an hourly basis. The wholesale price would apply only to new generating capacity, not to existing capacity held by the three large utilities. Furthermore, consumers whose retail demand was served by the large utilities would also be insulated from the pool price, under what were called legislated hedges.

Higher than forecast economic growth in the province led to a tightening of the electricity market in the late 1990's (Daniel et al., 2001). Since the legislative hedges provided no incentive to invest in new generating capacity, no new capacity came online. Daniel et al. argue that despite the hedges, the tightening market should have sent long-run signals on the potential profitability of future investment. This was, however, likely mitigated by policy uncertainty.

In response to this lack of new investment, Alberta passed an Amendment to the Electric Utilities Act in 1998 which called for the removal of the legislated hedges in 2001. Furthermore, in order to encourage competition, the government decided to force the existing utilities to auction off their ownership rights to the electricity from the remaining life of their regulated units. The new owners of these units were required to bid all of their electricity capacity into the Power Pool. Alberta also established the Watt Exchange in 2001, a futures market which trades one-month, three-month, and one-year-out contracts. It is evident that these additional changes to the regulatory framework make the established system much more consistent with the requirements set out by Wolak (2003).

Since it has taken these steps, competition in Alberta has increased; there are now eight firms bidding electricity into the Alberta Power pool. Moreover, since 1998, approximately 3000 MW of new generating capacity have become operational and proposals for 5200 MW of new generation have been announced in Alberta's electricity market. Wholesale prices have continued to increase, likely because the retail side of the market is still not fully liberalized and because Alberta's transmission network, as discussed above, does not have very much import capacity, since it is connected only to neighbouring British Columbia and Saskatchewan (Hrab and Trebilcock, 2004a). In fact, retail prices will not be completely liberalized until 2006.

Overall, the Alberta experience seems to be one of cautious progression toward the stated objectives (Daniel et al. 2003). In the beginning, measures were taken to recognize and mitigate the potential for the exercise of market power through the legislated hedges. In some sense, these provided a buffer while the wholesale market was established. When it became evident that there was not a significant ability for prices to signal the need for new investment in a tight market, some of these restrictions were relaxed, resulting in less potential for the exercising of market power. The key problem which has not been addressed is that retail prices are isolated from real-time fluctuations in the wholesale price.

Overall, the Alberta experience seems to be one of cautious progression toward the stated objectives. (Daniel et al. 2003)

2.3 Electricity Market Restructuring in Ontario

In Ontario, prior to restructuring, generation and transmission and some distribution of electricity had been provided by Ontario Hydro. Small amounts of distribution were done by municipal distributors. Wholesale rates and the rates charged to large industrial customers and to rural customers were reviewed by the Ontario Energy Board (OEB), which could make recommendations but could not insist on rate changes. In the late 1990's, Ontario began its transition to a competitive market. The idea was to allow consumers to contract with any energy retailer they wanted, to leave the transmission and distribution segments to be regulated by the OEB and to split Ontario Hydro into five separate entities (Littlechild and Yatchew, 2002). These were: i. Hydro One Inc., which is responsible for the transmission and distribution segments; ii. Ontario Power Generation Inc., which owns 75% of Ontario's generating capacity; iii. Independent Electricity Market Operator Inc., whose job it is to dispatch power and operate the electricity market; iv. the Electrical Safety Authority Inc., which is in charge of installation inspection; and v. Ontario Electricity Financial Corporation Inc., whose responsibility it is to manage the existing debt (as of 1999, $38.1 billion) (Hrab and Trebilcock, 2004b). Ontario Power Generation was subject to an average annual revenue cap of 3.8 cents per kWh (kilowatt-hour) and was to reduce its share of the province's generating capacity to 35%. In an effort to do so, Ontario Power Generation leased the Bruce nuclear power plants to the private sector in 2001 and sold four hydro plants in 2002 (Hrab and Trebilcock, 2004b).

A wholesale market was created and consumers could establish physical or financial contracts with wholesale sellers or generators. The retail side of the market was also set to be liberalized, and customers were allowed to purchase fixed-price contracts from retailers or remain with their local utility, which would supply them at the spot price (Hrab and Trebilcock, 2004b).

The competitive market opened on May 1, 2002 and prices quickly began to rise. The average hourly energy price was 3.01 cents per kWh in May, 3.71 cents in June and 6.2 cents in July. The provincial government reacted by enacting the Electricity Pricing, Conservation and Supply Act, 2002, on December 9, 2002. This Act restricted the price of electricity to 4.3 cents per kWh for low-volume consumers. It was increased on April 1, 2004 to 4.7 cents per kWh for the first 750 kWh/month, then 5.5 cents after and there will be a new pricing structure as of May 2005 (Hrab and Trebilcock, 2004b).

The competitive market opened on May 1, 2002 and prices quickly began to rise. The average hourly energy price was 3.01 cents per kWh in May, 3.71 cents in June and 6.2 cents in July.

From the beginning, the situation was one of insufficient supply. Ontario relied heavily on nuclear power and much of this had gone offline just prior to restructuring (Hrab and Trebilcock, 2004b). Furthermore, little new capacity came online prior to restructuring. In fact, just two generating plants were constructed, capable of generating only 620 MW of electricity (Hrab and Trebilcock, 2004b). The price ceiling will only exacerbate the problem. As a result of the price controls there has been no new investment in generating capacity, and the problem is set to become worse as the Ontario provincial government has promised to retire coal-fired plants in the upcoming years.

2.4 Energy Market Restructuring in California

Prior to restructuring, there were three privately owned, vertically integrated utilities that generated, transmitted and distributed electricity within predetermined service areas in California. These companies' prices and service requirements were regulated by the California Public Utilities Commission (CPUC). While these companies operated their own generating facilities, they were also able to buy power from other western states, Mexico, and Canada.

In the late 1980's in the U.S., the Federal Energy Regulatory Commission (FERC) promoted the opening of energy markets to competition. In this context, California embarked on a program which aimed to promote a competitive market for generation. The California legislature passed Bill AB1890 in 1996, the essential elements of which are summarized by Joskow (2001):

- Consumers would be able to choose between their current service provider and a set of new firms in the market.
- Existing utilities were required to provide access to transmission and distribution networks at prices determined by FERC and the CPUC.
- Existing utilities' retail prices were fixed in proportion to the wholesale, day-ahead price of electricity.
- Provisions were made for utilities to recover stranded costs through divestiture.
- Utilities were allowed to issue bonds for recovery of some portion of stranded costs. The return on these bonds was to be guaranteed by the state.
- Residential and small commercial customers received an instantaneous 10% price decrease (a price cap).
- Existing utilities were responsible for installing an independent system operator and a power pool.
- Forced divestiture of fossil-fuel generation facilities for the two largest utilities.

New generating capacity was expected to come online from independent service providers, and independent firms would also be able to purchase divested fossil-fuel capacity from the existing utilities.

Things certainly did not go as planned. Between 1999 and 2000, prices in the wholesale market increased by 500%. In 2001 peak prices were $300/MWh, which represented a ten-fold increase over 1998 and 1999 prices. The two largest utilities became insolvent, as they were forced to purchase power on the wholesale market at prices ten times above previous prices, but retail prices were capped at 10% below 1998 prices. In order to combat this trend, retail prices were raised by 40% in 2001. At about the same time, falling national natural gas prices and specifically regional natural gas prices, combined with the return/installation of previously unavailable capacity and the decrease in power demand caused by the price increase, resulted in a dramatic fall in the wholesale price.

In the aftermath of these events, the independent system operator declared bankruptcy, and the CPUC terminated retail competition. Joskow (2001) lists several lessons learned from the California crisis, and many of these reflect the fact that the efforts to restructure the delivery of electricity in California did not meet the criteria laid out in Wolak (2003). First, the California restructuring experiment insulated consumers from the wholesale market. If consumers are not provided with price signals on the scarcity of power, then the restructured market cannot be expected to achieve the desired allocative efficiency. Second, market power continued to exist in California, specifically on the part of the natural gas suppliers. Joskow (2001) cites the existence of a premium on natural gas sales to Southern California during the crisis. Since the competitive fringe of the wholesale market was, by design, made up only of fossil-fuel plants, the natural gas suppliers were able to exercise market power over this segment of the market, extracting higher prices for gas as the wholesale price for power was free to rise unabated.

California's restructuring experience provides clear evidence of the important role of market power and consumer price signals in ensuring the success of a restructured energy market.

Between 1999 and 2000, prices in the wholesale market increased by 500%.

PART THREE

Québec's Energy Markets

3.1 Energy Regulation in Québec

Until the 1940's, Québec's electricity was provided by a small number of privately owned enterprises. In 1944, concerned about high electricity prices relative to those in Ontario, the Québec government expropriated ownership of the monopoly provider in Montréal and formed a provincial crown corporation — Hydro-Québec (Dupré and Patry, 1998). Rural electricity provision was left in the hands of the Rural Electrification Agency. In 1963, Québec's electricity system was made almost entirely public. As a vertically integrated entity, Hydro-Québec's mandate was to take advantage of Québec's endowment of hydraulic resources to the benefit of the residents of Québec and to ensure that all of Québec had access to electricity at uniform rates. Rates were to be set such that they covered only investment and operational costs. (The National Energy Board, 2001).

Natural gas was provided by a number of private companies, among them Gaz Métro, which by the 1980's had essentially become the monopoly provider in Québec. Since the market was not being serviced by a crown corporation, as was the case with electricity, it was regulated by the Régie du gaz naturel.

In June of 1997, the Régie de l'énergie was created, replacing the Régie du gaz naturel, and is now responsible for regulating major energy markets in Québec. According to the *Act Respecting the Régie de l'énergie, 2001* (Éditeur Officiel du Québec, 2001), the Régie is responsible for fixing the rates and conditions for the transmission of electricity by the carrier and the distribution of electricity by the distributor. It is also responsible for fixing rates reflecting the costs of acquisition, transmission, delivery, and storage of natural gas obtained through domestic suppliers Gaz Métro and Gazifère. The Régie is also charged with making sure that consumers are adequately supplied with both electricity and natural gas.

In June of 1997, the Régie de l'énergie was created, replacing the Régie du gaz naturel, and is now responsible for regulating major energy markets in Québec.

Rates are determined after consideration of numerous factors. The rate base takes into consideration the fair value of the assets used for electric power transmission or natural gas distribution, research and development and marketing expenditures, pre-operating costs, and working capital required for these operations. The Régie also allows for a reasonable return on the rate base and takes into account financial ratios, sales forecasts, service quality, competition between

> The *Act Respecting the Régie de l'énergie 2001* states that to fix rates, the Régie must consider the cost of acquisition, transmission, and distribution of electric power.

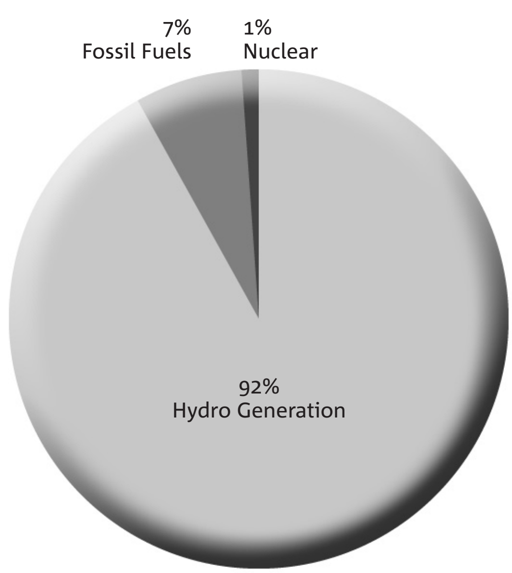
different forms of energy and uniformity of rates throughout Québec (An Act Respecting the Régie de l'énergie, 2001. Éditeur Officiel du Québec, 2001).

The *Act Respecting the Régie de l'énergie 2001* states that to fix rates, the Régie must consider the cost of acquisition, transmission, and distribution of electric power. According to the Act, Hydro-Québec is required to supply 165 TWh of electricity per year to Québec residents at a fixed rate of 2.79 ¢/kWh. Any additional load is subject to market-based prices via a tender solicitation process (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 2003). The Act requires that equal tariffs be charged to any resident of Québec. This directly implies the cross-subsidization of some rural, residential consumers by urban consumers and consumers located close to generation facilities. Similarly, for natural gas, the rates are fixed as a function of the cost of acquisition to the distributor of gas. The distributor is required by law to supply and deliver natural gas to anyone within the territory served by their distribution system. Subject to additional demand by consumers not serviced by the distribution system, the Régie may order the distributor to extend the network.

3.2 The Electricity Market in Québec

As of December 31st, 2001, Québec had 40,500 MW of available capacity. Most of this capacity (77%) is owned by Hydro-Québec. Of the remaining capacity, 10.3% is privately owned, 0.1% is owned by municipalities and 12.4% comes from contracts with Churchill Falls (Labrador) Corporation which are treated as domestic capacity (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 2003). The vast majority of the installed capacity comes from hydro-electric facilities — 91% from domestic hydro-electric facilities of which 10% is from Churchill Falls. Domestic installed capacity breakdown is displayed

Figure 2
Domestic Installed Capacity, 2004



Source: Hydro-Québec, 2004

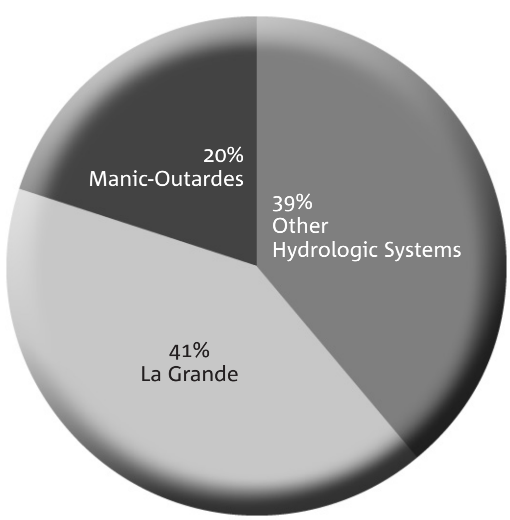
in Figure 2, with percentages rounded to the nearest integer. In 2003, actual electricity production was 96.5% hydro-electric, on a total annual generation of more than 200 billion kWh of electricity.

The hydro capacity in Québec is characterized by large installations. In addition to the long-term generation contract with Churchill Falls in Labrador, domestic hydro installations are highly concentrated. As shown in Figure 3, the La Grand and Manic-Outardes river systems account for 40% and 21% of the total installed hydro capacity, respectively.

Québec possesses a very extensive network of high-tension power lines linking the often remote hydro-electric installations with consumers and export markets. Transmission services are undertaken by TransEnergy, a subsidiary of Hydro-Québec, which administers more than 32000 km of high-tension lines and more than 500 substations. Part of this network of lines allows Hydro-Québec to export power to other jurisdictions in eastern North America. Thirteen interconnections allow for an installed export capacity of 6825 MW, or 55 billion kWh/year. This compares to actual exports of 17.1 billion kWh in 2001. TransEnergy has recently initiated approval proceedings for its first rate increase since 2001, as it seeks authorization for a 1% increase in approved operating cost figures which determine the rates it can charge Hydro-Québec (Hydro-Québec press release, September 30, 2004).

With only a couple of exceptions, the inhabited territory of Québec is serviced by Hydro-Québec's distribution network. Less than 4% of the total population of Québec is serviced by independent, municipal grids. Québec domestic consumption in 2001 stood at 176.6 billion kWh. Of this consumption, approx-

Figure 3
Domestic Installed Hydro Capacity by River System



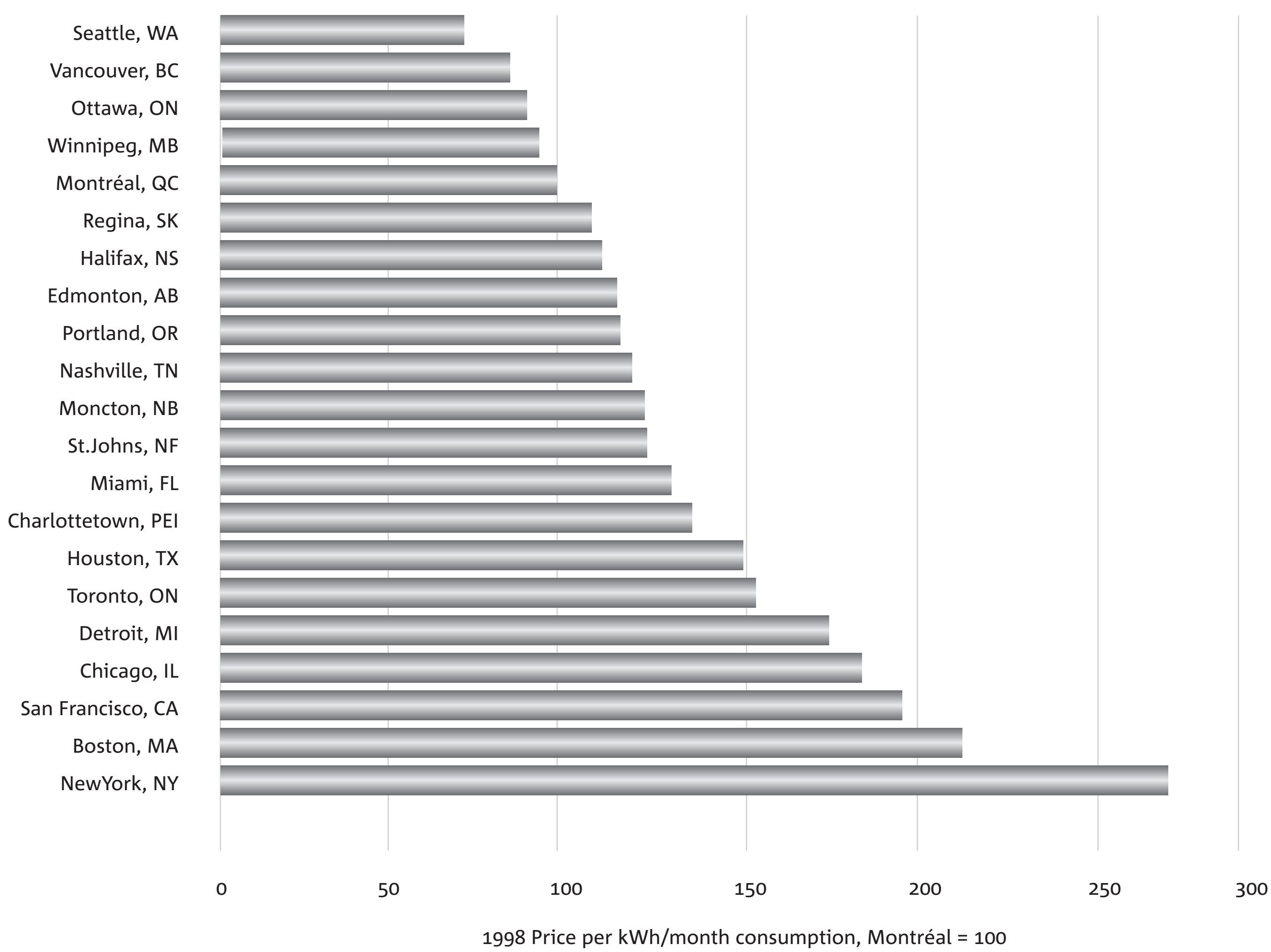
Source: Hydro-Québec, 2004

imately 51% was industrial, 19% commercial and 30% residential, with small uses in transportation. Peak-load demand on the system in 2002 was 34989 MW, or 81% of installed capacity.

Since the nationalization of the electricity market, consumer prices in Québec have been very low. As shown in Figures 4 and 5, Montréal prices for typical residential consumption have been lower than in most cities in North America. This trend appears to be continuing as 2003 prices are relatively lower than those in 1998, particularly when compared to certain jurisdictions (Seattle prices, for example were 42 % lower than Montréal in 1998, and 71 % higher in 2003).

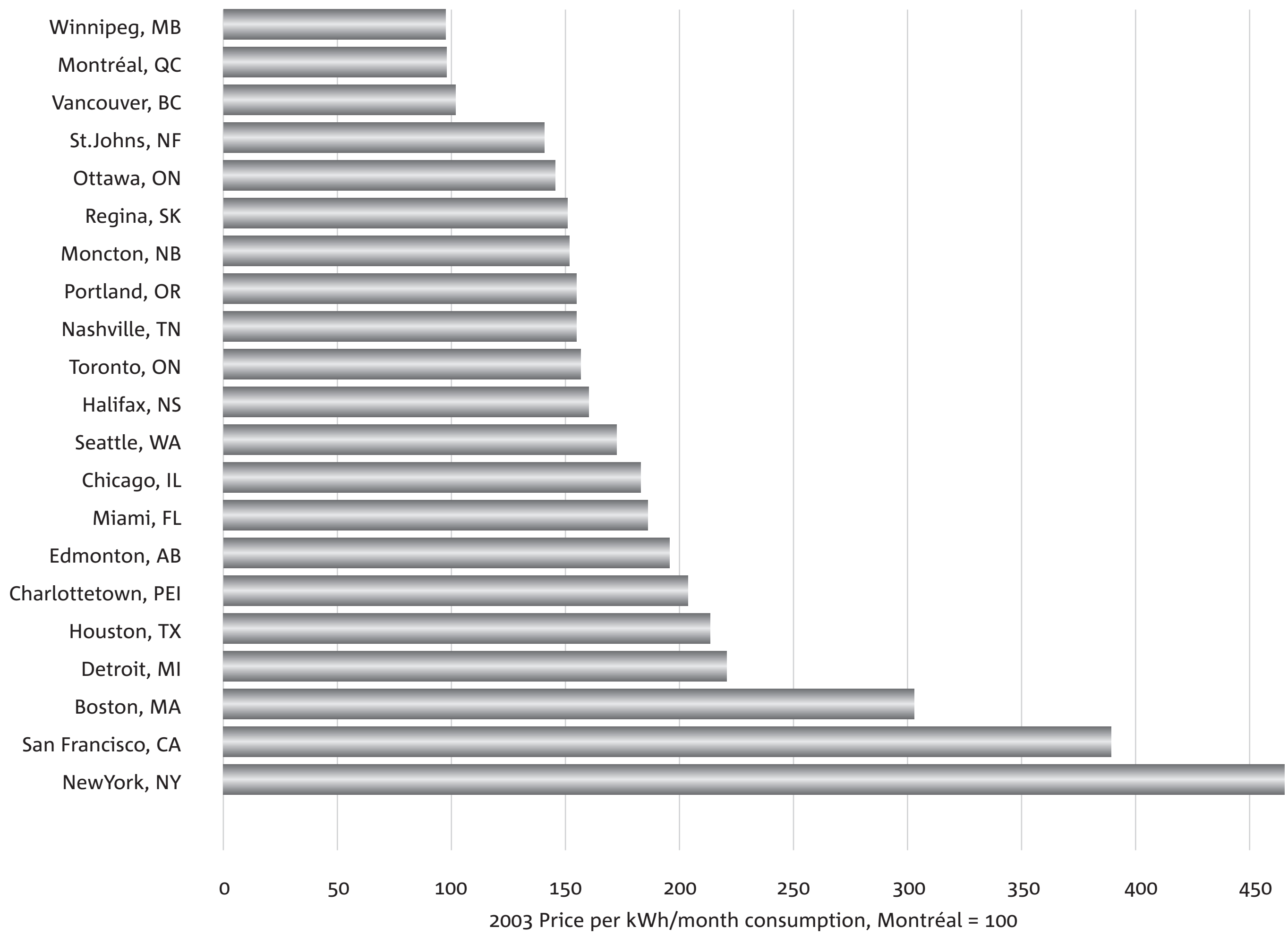
Figure 4

Relative Prices of Electricity, 750 kWh/month consumption



Source: Hydro-Québec, 1998

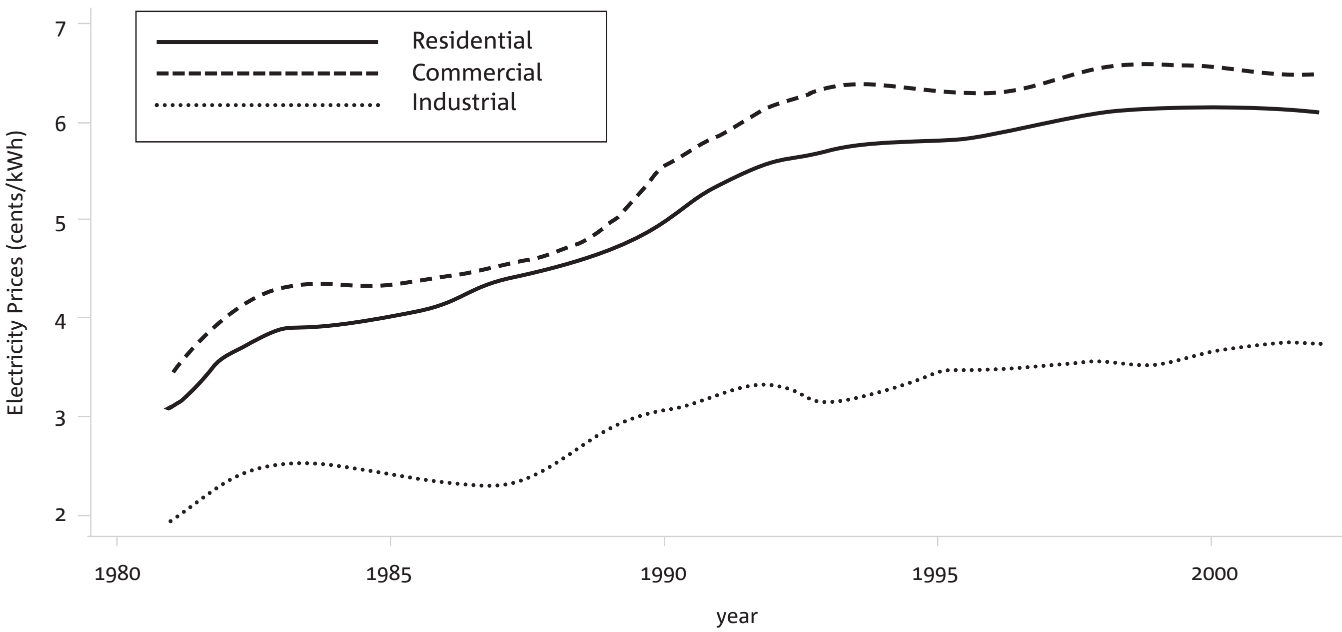
Figure 5
Relative Prices of Electricity, 1000 kWh/month consumption



Sources: Hydro-Québec, 2003; Parcs du Québec, 2003

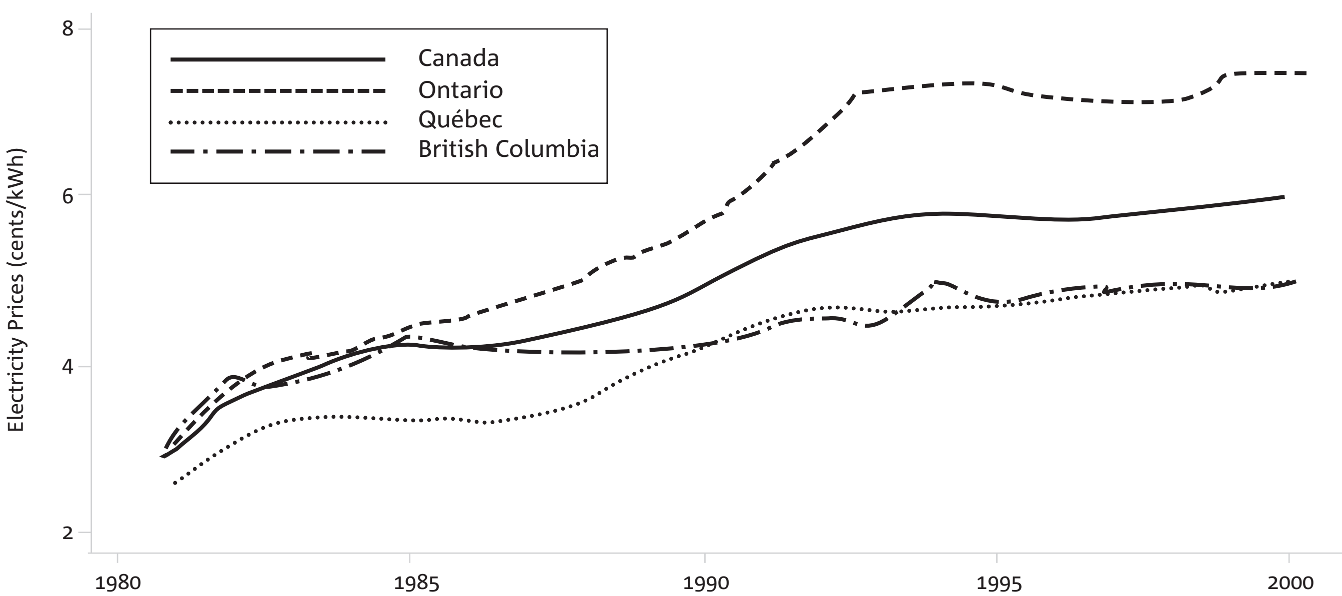
The rates applied to individual consumers in the province vary by their demand characteristics, but not by location. The evolution of Québec domestic electricity prices over time is shown in Figure 6, while the relative evolution of these prices as compared to the rest of Canada is shown in Figure 7. We can see that the prices of electricity are clearly lower in the hydro-dominated markets of Québec and BC, and in fact the difference is growing. The difference between Québec prices and the Canadian average has grown by half a cent since 1981. (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 2003).

Figure 6
Residential and Commercial Price of Electricity in Québec



Source: Ministère des Ressources naturelles, 2003

Figure 7
Relative Prices of Electricity by Province



3.3 The Natural Gas Market in Québec

Québec currently does not produce significant amounts of natural gas. As a result, domestic demand must be entirely serviced by imports, mostly coming from Western Canada. The province imported 8.5 billion cubic metres of natural gas in 2001, of which 2.3 billion cubic metres were re-exported to the U.S. northeast.

The transportation of natural gas in Québec is handled by TransCanada Pipelines.

Retail-level gas sales are handled in the majority by Gaz Métro, the default supplier for most of the territory of Québec, which sold 5.9 billion cubic metres, or 97% of domestic consumption, in 2001 (Gazifère is the default supplier of natural gas in Gatineau). As of October 2004, costs of network natural gas were \$6.28 per GJ for Gaz Métro. Delivered natural gas prices over time in Québec are shown in Figure 8, and Québec prices compared to prices in other Canadian provinces are shown in Figure 9. Differences in delivered gas prices reflect increasing transportation costs the further markets lie from production sites. Clearly, natural gas prices have been rising in all jurisdictions. The average annual growth rate in Québec retail prices from 1981 to 2001 was 4.8%, while the same statistic for Canada was 5.1%. The difference between Canada and Québec growth rates over this time period is not statistically significant. It is therefore clear that, while gas prices have consistently risen at rates higher than inflation, there is little divergence between the market in Québec and the market in the rest of Canada on average. Certainly, Alberta has the lowest retail price in Canada, which is not surprising since it produces the vast majority of the country's natural gas and thus does not have to incur high transportation costs. Québec prices are 4.8 cents higher than the Canadian average over the sample period, with no perceptible trend in the difference, reflecting higher transportation costs (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 2003).

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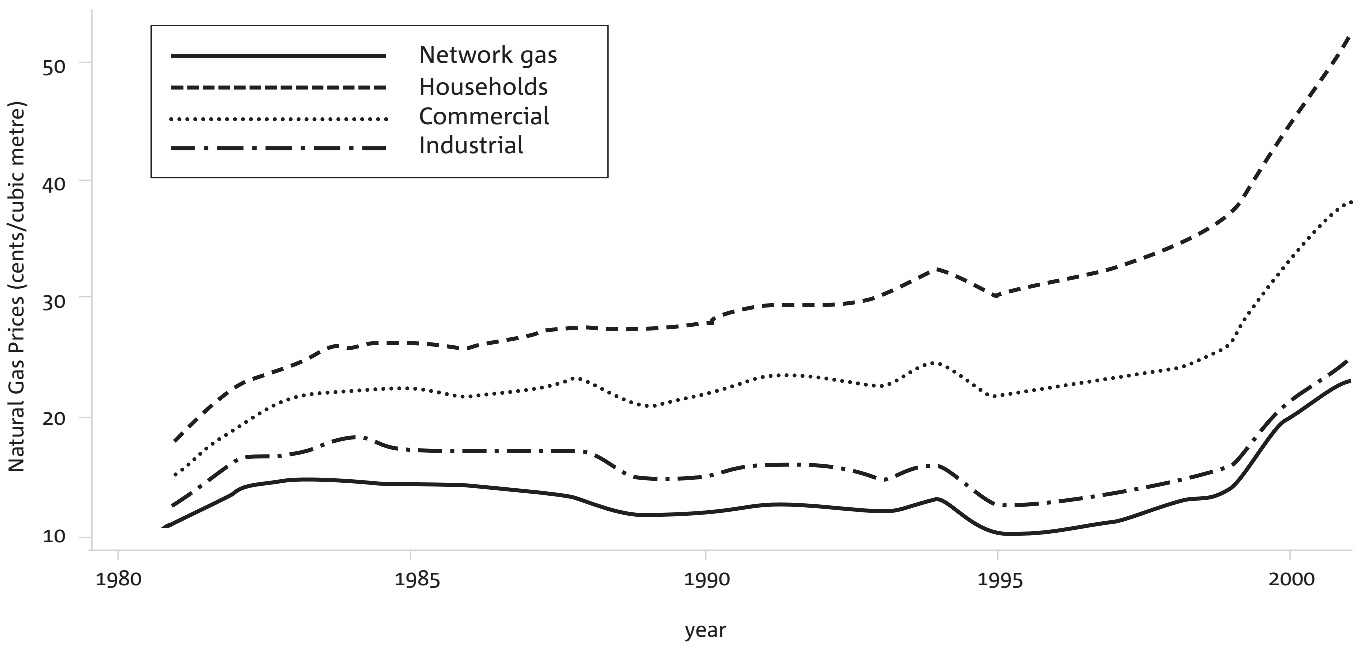
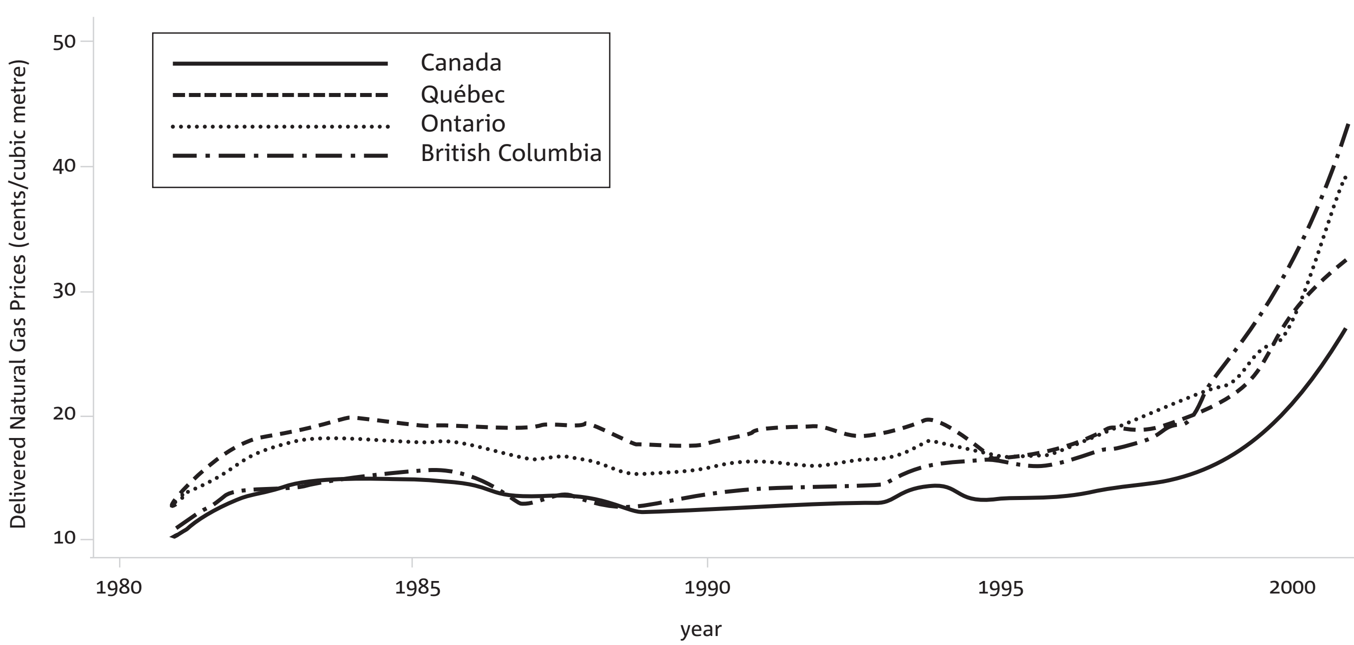
Figure 8
Network and Delivered Prices of Natural Gas in Québec



Source: Ministère des Ressources naturelles, 2003

Figure 9
Relative Prices of Delivered Natural Gas



Source: Ministère des Ressources naturelles, 2003

PART FOUR

Energy Market Restructuring in Québec

4.1 Current Restructuring Initiatives in Québec

Québec has recently taken some steps toward the liberalization of its energy markets. The main reason for this move is that in order to be able to export its electricity to the restructured markets in the United States, Québec must conform to certain requirements. When the U.S. FERC restructured the wholesale electricity market in 1996, it required individual states to allow the import of electricity generated outside their borders. However, in order to have access to U.S. transmission systems, foreign jurisdictions had to provide reciprocal conditions (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 1996). This is why, in 1997, Hydro-Québec unbundled its transmission and dispatching operations from its generating and sales segments. TransÉnergie is now responsible for the operation of the transmission grid.

The wholesale electricity market in Québec is evolving towards a monopoly market with a competitive fringe as a result of recent regulatory changes. Hydro-Québec's market share is guaranteed by Law 116, passed on June 16, 2000, which established the Heritage Pool of electricity. Under this law, Hydro-Québec is required to supply 165 TWh of electricity per year to Québec consumers at a fixed rate of 2.79 ¢/kWh. Any additional load is subject to market-based prices via a tender solicitation process. Tenders are not necessarily open, as they may be constrained to a particular type of generation, or to a particular location. The Québec government has stated that it would like these tenders to allow the private sector to have access to hydraulic resources, but only to sites with less than 50 MW of power. Larger sites will remain the exclusive territory of Hydro-Québec (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 1996). The most recent call for tenders was to provide 1000 MW of wind energy to Québec consumers.

In the natural gas market, fixed-price, institutional contracts are also currently available for consumers of 7500 m^3 or more annually, administered by eleven independent service providers. For residential customers, rates charged by the default suppliers remain fixed by the Régie de l'Énergie.

Québec's electricity market is hydro dominated, and a big proportion of the generating capacity is provided by large complexes on individual river systems.

In addition to wanting access to restructured U.S. markets, the government might consider restructuring in order to achieve the efficiency gains discussed above, if indeed the production or retail side of Québec's energy markets do not represent natural monopoly situations. However, further restructuring of Québec's energy markets would not be easy, due to a number of conditions. Most important is the fact that Québec's electricity market is hydro dominated and a big proportion of the generating capacity is provided by large complexes on individual river systems. We discuss this issue below. Beyond this, the fact that Québec insists on uniform rates for rural and urban energy consumers makes restructuring more difficult. Moreover, the Ministry of Natural Resources insists that any restructuring of the electricity market must be done without compromising the health of Hydro-Québec (Ministère des Ressources naturelles, de la Faune et des Parcs du Québec, 1996). Also, Hydro-Québec currently has $32.5 billion in long-term debt, and an asset value of $58 billion. If divestiture were to take place, this debt would have to be assigned to assets at the time of sale. The net proceeds of these sales, the stranded debt or surplus, would have to be transferred to Québec consumers, either in the form of taxes/subsidies or through charges/rebates on electricity consumption.

Raphals (1997) notes other effects of restructuring that must be considered. In particular, he comments on the impact on prices of permitting American access to electricity generated in Québec. It is intuitive that the northeastern states want access to the power market in Québec as a result of generally lower production (and thus wholesale) costs. If Québec's spot market for power is opened up to US consumers, higher US retail (and equally wholesale) prices can only serve to increase domestic prices. This is contrary to what is normally expected from the opening up of markets — that restructuring will yield significant medium-term price decreases. It is reasonable to expect that prices will rise for many domestic and commercial users in Québec in a more deregulated market.

4.2 Restructuring in Hydro-Dominated Electricity Markets

The case for restructuring has been made successfully in markets where load is handled principally by relatively small, fossil fuel-fired generators. It is argued that in this situation the market can be served at lower cost by small, independent producers bidding to supply power to a pool, as a result of a lack of interdependency of input supply and the fact that no firm can exercise market power. In hydro-dominated markets this may not be the case. Restructuring may not result in greater efficiencies, as firms may still have too much market power and/or externalities may be generated. Market power may arise as a result of the ability of hydro plants to defer production to later time periods. Externalities may be generated since, in a hydro-dominated market, the key input, water, is not priced according to its true value within a river system. Moreover, this effect is magnified in the presence of cascaded power plants on the same river system.

Restructuring may not result in greater efficiencies, as firms may still have too much market power and/or externalities may be generated.

Raphals (2001) discusses the possibility for hydro producers to exercise market power. Provided a reservoir exists, hydro producers possess an ability to defer sales which is not present with other generating technologies. Thermal generators cannot defer sales, although they can act to reduce sales in the present time. Raphals argues that the ease with which hydro plants can adjust output, and the inability to distinguish the exercise of market power from water resource management, implies an ability to manipulate the market in more sophisticated ways. It has been alleged that Hydro-Québec has used the nature of its production resources for market manipulation in the northeastern U.S. Specifically, it was challenged by the FERC for profiting from arbitrage opportunities in the forward energy market produced as a result of its ability to influence market prices (Raphals, 2001).

Market-power abuse is most easily solved by reducing the market share of individual producers. One possible means of achieving this is to open the market to producers and consumers from other jurisdictions. This is the approach taken by Norway, the only country in the world in which a larger fraction of electricity is hydro generated than in Québec, as 99% of its capacity is hydro-electric. Since 1990, Norway has been restructuring its energy markets. The Energy Act of 1990 called for the breakup, but not privatization, of Statkraft, the state-owned, vertically integrated utility. There are approximately 70 firms producing electricity in Norway, but Statkraft has retained 30% of the generating capacity, while Hydro Energy has 10%. The remaining firms are primarily owned and operated by municipalities (Aam and Wangensteen, 2004). These producers have access to Nord Pool, which unites the electricity markets of Norway, Sweden, Denmark, Finland and Iceland. Producers and consumers can form bilateral contracts, and may also trade forward contracts on a futures market (Wolak, 2004).

It appears that this approach allows potential market-power effects to be mitigated (Aam and Wangensteen, 2004). This is important in the context of the Québec energy market, since the access to a larger overall market reduces the effective market power of a single producer. If no priority is given to Québec producers on the spot market, the entry of producers from Ontario, New York, and elsewhere could drastically reduce the market share of any Québec production facility. In this case, the interconnection capacity would become an important determining factor for efficiency.

In addition to market-power-abuse problems, hydro-dominated generation externalities may be generated since in a hydro-dominated market, water is not priced according to its true value. Regardless of where plants are located on separate or common river systems, reservoir volume and downstream flows generally do not have a market value. Thus, the private, variable costs of electricity production for any firm will not reflect the true cost of generation. Dunsky and Raphals (1998) state that a power pool is meant to serve as a clearinghouse through which market prices come to reflect (largely predictable) variable costs, but that, in this environment, hydro-electric generators would be led to effectively give away their power since the variable costs are generally almost nil. In fact, this captures the essence of market failure. Hydro producers will sell their power at their marginal private cost, which in this case is near zero, without regard for the social costs, which leads to the inefficiencies. For example, they are likely to only take account of the private option value of water held in reservoirs, not the social value. Abstracting for the moment from the costs of transmission, consider the opportunity costs involved in the production of electricity. First, a cubic metre of water held in a reservoir above the dam has a value, despite the fact that it is renewable, which is tied to the expected future price of water and electricity. There are costs related to the watershed as a whole even if there is just a single dam. A cubic metre of water used in generation today has a value to other downstream users such as agriculture and consumers. Furthermore, reservoir volume has a value in its ability to mitigate hydrological fluctuations. Since the upstream firm does not have to pay for lost flow downstream, and is not directly compensated for its role in water management, this represents an externality problem and water will not be efficiently allocated on the river system.

To capture the potential impacts of these external effects, consider the example of market restructuring in Brazil, another hydro-dominated market. The government felt that it would be feasible to rely on private investment to provide new generation capacity. Mensah-Bonsu and Oren (2002) state that reservoir capacity was not priced in the new market system, so hydro producers were artificially able to meet demand at low marginal cost. Because of this, the system's reservoirs were depleted at a rate much greater than would have been optimal if the stored water had been accorded its true value. As a result of the fact that hydro power was supplied below its social costs, investment in new generating facilities has not kept pace with load. New plants would not be able to recoup investments in fixed costs when existing hydro plants can offer power to the grid at essentially zero cost.

Now, consider how these problems are magnified in the case where multiple plants are arranged on a single watershed. It is clear that hydro plants at the head of the river system can influence the availability of water to plants and other uses further downstream. For electricity markets, this can generate market power. Consider an extreme example in which a single river system contains a reservoir with a small-capacity dam at its head and a large plant further downstream. While it may represent only a small proportion of the generating capacity, and cannot directly influence price through its choice of supply, the production decision of the small plant implicitly affects downstream production, and thus the market price.

The fact that water is not generally a priced input or output leads to the externality problem discussed above. Since a firm which owned all of the plants on a river system would take into account all of the external effects on production imposed by one plant on another, it is generally accepted that hydro plant divestiture should occur by river system, and not by individual dam (Dunsky and Raphals, 1998). This presents a particular challenge for Québec, since this would require divesting a very large complex such as La Grande as a single entity. This complex accounts for 40% of installed capacity in Québec, and so divestiture would result in the type of market-power effects described above.

The fact that water is not generally a priced input or output leads to the externality problem discussed above.

As discussed earlier, the presence of externalities may be justification for regulation, but maintaining a single producer over an entire watershed is only one option for correcting this market failure. Downstream users should be willing to pay for water flow. If all the generation facilities are arranged such that a single firm owns all the dams on a river, these costs and benefits are all internalized; however, if these facilities are individually divested, price mechanisms can be used to generate the same outcome.

Suppose one wanted to tax efficiently the disruption of flow on a river. The marginal external cost of storing a cubic metre in the reservoir of an upstream dam would thus be the willingness to pay of all downstream consumers of water for this flow. More pertinently, this could be solved recursively, such that the tax on each dam represents only what the next downstream user would be willing to pay for water in a particular period. Approaching from the river delta toward the head, this implies that all downstream value will be taken into account by the furthest upstream firm. If the tax were set efficiently, the downstream consumers of water would be indifferent between receiving compensation in the amount of the tax, or receiving an additional cubic metre of water during that period. Given the imposition of this efficient tax, the external impact of the upstream dam on downstream producers will be internalized. The productive capacity of the dam farthest downstream will therefore implicitly figure in the production decisions of all upstream facilities, even without them being owned by the same company.

The same outcome created by taxes could be accomplished by the distribution and exchange of flow rights, provided the latter could occur with low transaction costs. Each facility would have flow rights in their possession and an upstream dam would have to purchase these rights from the downstream firms in order to decrease production and store water in their reservoir. As long as a system with reasonably low transaction costs exists for the purchase and sale of flow rights, and no market power exists in this market, this can produce the same result as the efficient tax, as discussed in the seminal paper by Coase (1960). Doucet and Ambec (2001, 2003) analyze the issue of restructuring within and among cascaded hydro projects. Their work is based on the theoretical tenets examined in Ambec and Sprumont (2002). Specifically, they show the analog to the Coase result: for two hydro plants located on the same river, an environment with zero coordination costs and a market for water-flow rights will produce the same outcome, and thus the same level of welfare, as a single firm would choose.

The above arguments suggest that having a large hydro-electric producer on the grid may lead to greater market-power abuse. Québec's hydropower installations render this question one of particular importance for restructuring. As mentioned above, over 95% of installed capacity is hydro-generated and the vast majority of provincial installed capacity depends on three river systems. Moreover, the large complexes operating on each of these river systems are each made up of a number of facilities. The La Grande complex, for instance, is composed of thirteen facilities of varying size lying on the same watershed. Given the above discussion, it seems that the imposition of a mechanism for the pricing of river flow and reservoir storage, or the opening of the Québec wholesale market to a much larger set of producers, are necessary conditions for the restructuring of electricity in Québec.

...having a large hydro-electric producer on the grid may lead to greater market-power abuse.

PART FIVE

Discussion and Conclusion

Québec's electricity market does not represent a typical case for the restructuring of the production side since the vast majority of its generating capacity comes from hydro projects. Furthermore, this capacity is highly concentrated on three river systems. The usual model of forced divestiture by hydrologic system is therefore likely to introduce market power in a restructured market, and likely to lead to greater inefficiencies than those present under regulation. If any market restructuring is to succeed, a system of tradeable water rights would have to be established in parallel with a competitive power pool in order to allow divestiture of individual plants within a river system.

The retail segment of Québec's natural gas and electricity markets could potentially benefit from liberalization. The only obvious difference between Québec's energy markets and those in other jurisdictions is Québec's price-equalization policy. Lower prices could prevail if competition were introduced in the market, but not for all consumers. Québec's insistence on uniform prices throughout the province means that some consumers (namely, rural consumers) are currently paying below market price for energy. Prices for these consumers could rise if the market is restructured.

This report characterizes the regulation of energy markets in general and focuses on the electricity and natural gas markets of Québec. Markets are regulated if they are deemed to represent natural monopoly situations or if unregulated firms would not take into account externalities that they might generate. However, in recent years certain segments of some energy markets have been liberalized since these segments may not be natural monopoly situations and/or the market may provide means to ensure that firms internalize externalities.

We have presented standard conditions that must be satisfied in order for deregulation to be successful. In order to reinforce the importance of the elimination of market power and adhesion to these necessary conditions, four case studies were presented. These demonstrate quite clearly that, under certain conditions, deregulation can lead to welfare improvements. However, the downside risk is great if these standard conditions are not met.

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