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Electricity market reform failures: UK, Norway, Alberta and California

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Abstract

An analysis of electricity market reforms already taken place in the UK, Norway, Alberta (Canada) and California (USA) leads to our overall conclusion that the introduction of a competitive generation market, of itself, has failed to deliver *reliable service at low and stable prices*. The market reform failures are attributed to market power abuse by few dominant sellers (especially at times of transmission congestion), poor market design that invites strategic bidding by suppliers, the lack of customer response to price spikes, capacity shortage caused by demand growth not matched by new capacity, and thin trading of forward and futures contracts that are critical for price discovery and risk management. The paper then explains why an electricity market reform can easily fail to deliver the promised gains of better service at lower and more stable prices. The policy implication is that an electric market reform can be extremely risky, and may lead to a disastrous outcome. Thus, it is imprudent to implement such a reform in countries with limited sites for new generation and no indigenous fuels (e.g., Israel and Hong Kong). These countries should therefore consider introducing performance-based regulation that can immediately benefit electricity consumers in terms of lower prices, more stable prices, improved reliability, more choices, while encouraging the electric sector to pursue efficient operation and investment.

Keywords: Electricity market reform; Reform failures; Performance-based-regulation

1. Introduction

The perceived failure of traditional cost-of-service regulation (COSR) for the electricity industry is its lack of strong incentives for cost cutting and optimization of asset management (Biewald et al., 1997; Schmidt, 2000). This is because the regulated utility's costs, subject to prudence review, are fully recovered from ratepayers (Liston, 1993).[1] Costly investments (e.g., nuclear plants) and expensive long-term contracts for fuel and power purchase contracts are often based on erroneous forecasts of electricity demand and fuel costs (Newbery, 1999). Whereas the failure of COSR has catalyzed the political push to introduce regulatory reform in the industry, technological advances in combined cycle gas turbines (CCGT) have made small-scale generation a cost-effective alternative, thereby making competitive generation markets feasible (Newbery, 1999; Joskow, 1997). These developments, among other factors, have been the driving force behind the efforts of many countries to examine the various alternatives for restructuring their electricity sectors.

What has prompted the electricity market reforms that are taking place around the world? The story is similar in many countries and is succinctly captured in the White Paper from the Ontario Ministry of Energy Science and Technology (1997):

> Competition among suppliers will create the conditions for lower electricity prices, thereby supporting investment and job creation across the province. It will ensure that investments in electricity generation and transmission are made prudently and that assets are managed carefully and responsibly. It will mean more choices for customers and will lead to new

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[1] Laffont and Tirole (1993, pp. 18–19), however, note that COSR can have incentives for cost cutting because a regulated utility typically retains its cost savings between rate cases.

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technologies and approaches that are safe, reliable and better for the environment. .... Neighbouring provinces and states are restructuring their electricity sectors and are expecting lower prices. Ontario needs to keep pace to preserve its industrial competitiveness. Favourable electricity prices are critical to attracting investment, and to creating and preserving jobs. .... The business record of Ontario Hydro has been unsatisfactory, as shown most recently in a highly critical assessment of Ontario Hydro's nuclear division prepared by a team of US experts. Ontario Hydro's problems have continued over a number of years, and are in large part due to the fact that the corporation is a monopoly, and has not been subject to the discipline of the marketplace.

To be sure, there are other drivers for reform (e.g., political ideology based on the faith of market forces and distaste for strong labor unions,[2] and the desire to attract foreign investment (Energy Information Administration, 1997)). Nonetheless, the above passage exemplifies the commonly cited drivers for change: consumers and the government want lower prices, more choices, and advancement of technology to preserve their industrial competitiveness and boost their economy. A notable exception to the desire for lower prices is the Norwegian government, which has implemented market reform in the name of environmental policy, even though the reform raises electricity prices and discourages capacity expansion (Newbery, 1999; Royal Ministry, 1999).

A review of electricity market reforms that have taken place in the world indicates two major policy options (Gilbert and Khan, 1996; Joskow, 1997; Newbery, 1999; Surrey, 1996). The first option is to introduce competition in the generation and retail service markets. This option is generally accompanied by (a) unbundling of the once-integrated utility into market-based functions (generation and retail services) and regulated functions (transmission and distribution—T&D); and (b) mandating common access to T&D (Green, 1998; Green and McDaniel, 1998; Johnsen et al., 1999; Joskow, 1997; Lynch and Kahn, 2000; Newbery, 1999; Surrey, 1996). The second option is a regulatory reform, which can occur within the existing market structure, or can be applied to the regulated T&D services of a restructured electricity industry. Regulatory reform replaces COSR with performance-based regulation (PBR) to induce a regulated firm to effect such gains as cost efficiency, customer choices and service improvement (Biewald et al., 1997; Liston, 1993; Laffont and Tirole, 1993; Schmidt, 2000).

This paper analyzes the electricity market reforms already taken place in the UK, Norway, Alberta and California to explain why these reforms have failed to deliver reliable service at lower and stable prices. These markets are chosen because of (a) the worldwide attention received by the UK and California markets; (b) Norway being viewed as a case of reform success; and (c) Alberta's cautious approach to reform. Even though our review does not cover electricity market reforms in Australia, New Zealand, and South America (e.g., Chile and Argentina), our chosen markets reasonably span the diversity in resource mix and the variations in design.[3] A full exploration of all market reforms adds little to our understanding of why a market reform can easily fail.

We find that the market reform failures are due to market power abuse by a few dominant sellers (especially at times of transmission congestion), poor design that invites strategic bidding by suppliers, the lack of customer response to price spikes, capacity shortage caused by demand growth not matched by new capacity, low volume of power pool sales at prices set by the market (e.g., the UK's contracts for differences (CfDs) and Alberta's legislated hedge governed the bulk of power sales in the initial years of reform), and thin trading of forward and futures contracts that are critical for price discovery and risk management.[4] We then identify the many avenues to failure. The ensuing policy implication is that a rapid and radical reform of an electric sector can be extremely risky, and may lead to a disastrous outcome. Thus, it is imprudent to implement such a reform in countries with limited sites for new generation and no indigenous fuels (e.g., Israel and Hong Kong). These countries should therefore consider the second option of gradually introducing PBR that can immediately benefit electricity consumers in terms of lower prices, more stable prices, improved reliability, more choices, while encouraging the electric sector to pursue efficient operation and investment (Tishler et al., 2002).

2. Electricity market reform

2.1. The typical structure adopted for reform

The initial restructuring activities of the UK, while not the first, were probably the most visible and radical,

[2] The restructuring of the state-owned Central Electricity Generating Board (CEGB) in England and Wales was strongly supported by the Prime Minister (Green, 1998; Newbery, 1999).

[3] The UK market's fuel mix is dominated by nuclear, coal and natural gas. California's main fuels are natural gas, hydro, nuclear and renewable (e.g., wind, biomass and geothermal). Norway's generation is almost 100% hydro. Alberta's fuel mix is predominantly coal along with some gas and hydro. The next section will detail the four market designs.

[4] Woo et al. (2001a, b) explain how to hedge spot price risks with electricity futures contracts.

and have to a large extent set the pattern for subsequent restructuring (Newbery, 1999; Wolfram, 1999a). The basic elements of reform are (Energy Information Administration, 1997; Joskow, 1997; Newbery, 1999; Wolfram, 1999b):

(a) The unbundling of the four distinct functions of the electricity industry: generation, transmission, local distribution, and retail services.
(b) Deregulation of those functions where competitive markets can be introduced, typically wholesale generation and retail services.
(c) T&D services that remain regulated and are made available to all users under mandatory open access.
(d) The creation of physical and financial markets for electricity trading.
(e) The creation of an independent system operator (ISO) to operate the transmission system (i.e., generation dispatch and reliability maintenance). The ISO may be a function of the transmission provider (e.g., the UK), or a separate entity (e.g., California).

Fig. 1 is a simplified illustration of the typical elements of the restructured electricity markets, based on the reasonable assumption that all generators and electricity consumers will use the T&D services and rely on the ISO. In a competitive wholesale market without direct retail access, distribution companies procure power from a pool or through bilateral trades for resale to final electricity consumers. Under direct retail access, a competitive retail market develops and consumers have the choice of buying electricity from competing distribution companies, retailers, or directly from the wholesale markets. California is an example of a market that introduced full retail competition from the start of market restructuring.

In contrast to California, many market reforms have started with the wholesale market, followed by a gradual introduction of a competitive retail market. An example

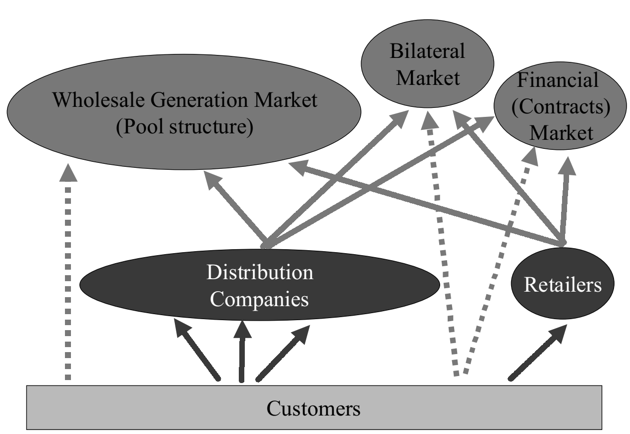

Fig. 1. Generic model of the restructured electricity markets.

of this structure is found in the initial stages of the UK and Alberta reforms. In the UK the distribution companies initially held a monopoly franchise for all consumers under one MW demand in their service territories, with full retail competition introduced in three stages over 8 years. In Alberta, distributors retained a monopoly franchise for all customers until 1999 when a limited retail access program was available to industrial and commercial customers with time-of-use (TOU) meters. The retail market opened up to all customers in Alberta in 2001.

Table 1 compares the British, Norwegian, Alberta and Californian models. While differences abound in transfer of ownership and market operation, the basic elements can be observed: independent operation of the transmission grid; physical and financial markets for electricity generation; common access to regulated T&D services; and retail competition.

2.2. Experience to date

This section assesses the "success" of market restructuring by examining the experience to date (as of June 2001).[5] We do not define success in political terms, as exemplified by the weakening of the coal miners union in the UK. We consider market restructuring a success only if it affirmatively answers the following questions: "Do the generation markets function properly?" and "Do the markets deliver the promised gains?" Negative answers to these questions lead to the regulatory imposition of price caps (Dres et al., 1998; Wolak et al., 1998, 1999; Wolfram, 1999a; Woo, 2001).

To appreciate this assessment, consider the case of California. The dream and confidence of success was summarized in a press release from the former Governor of California (San Diego, September 26, 1996):

> Every time a resident of this state flicks on the electric switch, they pay 40% more than residents across the United States… The legislation I am signing today will end that by ushering in a new era of competition, making California the first state in the nation to dismantle its electricity monopoly. This landmark legislation is a major step in our efforts to guarantee lower rates, provide customer choice and offer reliable service, so no one literally is left in the dark.

But the California dream turned into a nightmare. Fig. 2 shows that the generation market prices in the summer had been rising and becoming increasingly

[5] We recognize that market reorganization is a continuous and ongoing process. It is evident in most jurisdictions that regulators and other key industry participants are learning from experience and working to fix any market design problems. Even if the fixes are effective, we question the wisdom of initiating an ill-conceived market reform.

Table 1
Comparison of UK, Norway and Californian models

	UK[a]	Norway[b]	Alberta[c]	California[d]
Pre-restructuring				
	State-owned vertically integrated utility.	Many vertically integrated utilities with right and obligation to serve customers in their own service territory.	Vertically integrated investor and municipally owned utilities with the right and obligation to serve customers in their own service territories.	Vertically integrated investor and municipally owned utilities with right and obligation to serve customers in their own service territories.
Post-restructuring				
Structure	Three privately owned sectors: (1) National grid company (NGC); (2) Regional distribution companies; (3) Generators (initially, non-nuclear generation was split between two generation companies).	State-owned transmission unbundled from generation. Functional separation of integrated utilities with competitive generation and services and regulated grid company and distribution.	Functional separation of generation, transmission and distribution. Competitive generation and regulated T&D service.	State-level restructuring efforts.
	Vertical integration allowed but closely monitored to prevent monopoly power.	The power pool (Nord Pool) is an integration of Norway, Sweden, Finland and West Denmark markets, with each grid company providing system operation.	Independent transmission administrator coordinates the regional transmission grid with regulated payments made to the utility owners of the wires.	California required unbundling of generation from distribution and divestiture of generation assets.
			Local delivery and retail services provided by distributors who retain their service territories.	An independent system operator (ISO) administers the regional transmission grid with regulated payments made to the utility owners of the wires.
The markets	Compulsory power pool until March 2001.	Voluntary power pool (Nord Pool), which also offers clearing services for bilateral contracts.	Compulsory power pool.	Voluntary power pool (California Power Exchange or PX), suspended Feb 2001.
	During the first decade of operation the only available financial market was contracts for differences (CfDs). From 2001, the financial markets expanded to include futures and options contracts.	Bilateral physical markets.	Financial hedges allowed. Legislated financial hedges covered existing generation until 2001. These accounted for 85% of generation sold through the power pool.	Real-time balancing and ancillary services market.
	Competitive retail market (introduced in stages by customer size). End-use customers can select between distributors, generators, or purchase directly from the pool.	Financial markets for futures and forward contracts, and options.	Competitive retail market introduced in 2001.	Bilateral physical markets.
		Competitive retail market.	Bilateral trading and forwards markets planned for 2001	Financial markets for PX forward contracts and futures contracts for delivery in neighboring wholesale markets (e.g., California–Oregon-

Table 1 (*continued*)

	UK[a]	Norway[b]	Alberta[c]	California[d]
				Boarder and Palo Verde). Competitive retail market.
Operation	Generators must bid their output to the pool. The pool operates as a day-ahead auction with generators submitting their bids for output and price on a daily basis. Suppliers submit estimates of demand for each half-hour of the following day. The NGC then runs their scheduling program to determine order of dispatch so as to minimize financial operating costs.	Nord Pool operates as a day-ahead spot market for Norway, Sweden and Finland.	The power pool operates as an hourly day ahead spot market for energy.	California PX operates as a day-ahead and day-of auctions.
	Generators are paid the pool purchase price (PPP), which is the sum of the system marginal price and a capacity payment. Purchasers pay the pool-selling price (PSP), which is the PPP plus an uplift charge.	Pool participants submit supply and demand schedules for each hour of the following day. Taking account of existing bilateral contracts, Nord Pool computes hourly prices from the supply and demand curves. Market clearing prices by region are announced in the event of transmission constraints.	Pool participants submit hourly supply and demand bids. The bids form a forecast for which units will be dispatched in an hour. The final pool price is a weighted average of the highest priced unit dispatched during the hour to balance the system supply and demand.	PX participants submit supply and demand bids for each hour of the following day in a sequence of five iterations. After the final iteration the day-ahead schedule is submitted to the ISO. Non-PX participants submit their bids and offers to scheduling coordinators who submit balanced schedules to the ISO.
	CfDs accounted for 80-90% of trades in the first year of operation and later for 50%.	A real-time balancing market sets the price for settling any imbalances in the day-ahead commitments.		The ISO operates a real-time balancing market, and purchases ancillary services to ensure system reliability.
		There is no central dispatch. Generators schedule and dispatch based on their commitments and the price in the balancing market.		

[a] *Source*: Green and McDaniel (1998), Newbery (1999), and OFGEM (1999a,b, 2000a).
[b] *Source*: Newbery (1999), Statkraft (2000a, b), Statnett (2000), and Royal Ministry (1990, 1999).
[c] *Source*: Alberta Energy and Utilities Board (1995, 1998), and Alberta Resource Development (1999).
[d] *Source*: Joskow (1997), Lynch and Kahn (2000), and Newbery (1999).

volatile, with more and sharper spikes in 2000 than in 1998 and 1999. In late August 2000, the California legislature capped the electricity bills for San Diego consumers, who had seen their electricity bills for the summer double over the previous year. This action seriously challenges the wisdom of the Californian market reform, which is now irreversible because of the divestiture of power plants formerly owned by the previously integrated utilities.

The California power crisis has been worsening since Summer 2000 (Woo, 2001). On January 16, 2001, a severe capacity shortage prompted the California ISO to declare Stage 3 emergency with rolling black-outs. The day-ahead energy price was \$250/MW h, nearly 10 times

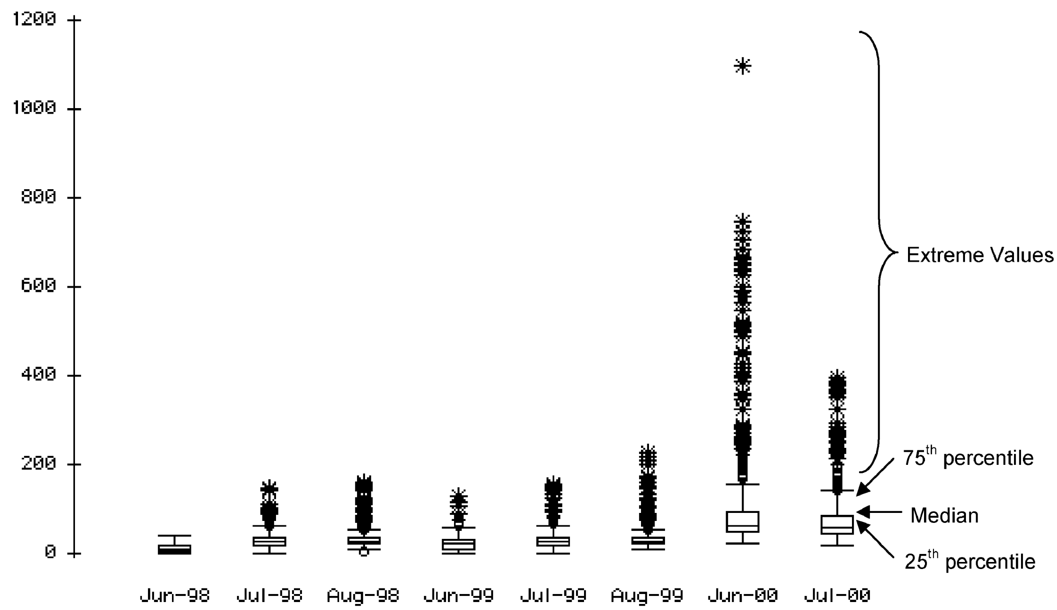

Fig. 2. California PX day ahead prices (US$/MW h).

the average January price a year ago. Southern California Edison (SCE), the large utility with over four million customers, suspended its scheduled payments of $586 million to the California Power Exchange (PX), qualifying facilities that supply power under pre-market-reform contracts, and debt holders. On February 1, 2001 the California PX discontinued operation due to lack of trading.[6] During the $4\frac{1}{2}$-month period of January 17–May 31, 2001, the state government spent $7.6 billion to buy wholesale power at an average price of $270/MW h because the two largest electric distribution companies in the state could not pay their wholesale purchase bills (*Megawatt Daily* June 18, 2001). The California Legislature passed emergency assembly bill AB IX to create a state power authority that will procure long-term supply contracts at fixed prices. The contracted supply will be sold at cost to PG&E, SCE, and SDG&E. However, state intervention in energy procurement was not sufficient to prevent Pacific Gas and Electric (PG&E) filing for protection under Chapter 11 of the federal bankruptcy law on April 6, 2001. Finally, the California ISO declared frequent Stage 3 emergency during January–May 2001. The outage cost estimates in Woo and Pupp (1992) suggest that the rolling blackouts associated with Stage 3 emergency had caused substantial economic loss to electricity consumers in California. Even though California enjoyed reliable service since June 2001, it is the result of the relatively cool weather and the extraordinary conservation effort by Californians that has reduced the system peak demand by over 10%.

2.2.1. Evaluation criteria

The California experience is obviously a disappointing failure, though to a lesser degree, the market restructuring in the UK, Alberta and Norway are not overwhelmingly successful either. To delineate the causes of failure, we use three criteria to evaluate the generation markets in the UK, Norway, Alberta and California.

- Is the market competitive? A competitive market requires easy entry, many players and absence of market power. In the absence of market imperfections, competition ensures that market prices converge to marginal costs and effect an efficient allocation of resources (Joskow, 1997; Newbery, 1999). As will be seen below, evidence of market power exists in the generation markets in the UK and California.
- Does the market function properly? A properly functioning market enables buyers and sellers to make informed decisions, allocate risk, and transact at minimal cost. As will be seen below, the markets in California were dysfunctional because of their complexity, must-buy requirements imposed on the three

[6] The figure shows a Boxplot representation of the data series. The outlined central box for each bar value depicts the middle half of the data between the 25th and 75th percentiles. The horizontal line across each given box marks the median. The whiskers extend from the top and bottom of the box to depict the extent of the main body of the data. Extreme data values are plotted individually, with a circle. Very extreme values are plotted with a starburst (Velleman and Hoaglin, 1981)

large load-serving utilities, thin trading, lack of risk management instruments, and denial of the opportunity of price response by consumers (Wolak et al., 1999; Woo, 2001).

- Does restructuring lead to marginal cost pricing? It is an unrealistic expectation that restructuring will achieve perfect competition in a properly functioning market. A more realistic expectation is workable competition in a reasonably well-functioning market environment. This would hopefully produce prices that are close to the marginal costs under least cost dispatch (Joskow, 1997; Newbery, 1999; Wolfram, 1999b).

2.2.2. Results to date

Table 2 analyzes the UK, Norwegian, Alberta and Californian markets using the above evaluation criteria. Evidence of market power exists in all four markets. The markets do not function properly due to the lack of risk hedging instruments, limited price discovery, blunted price signals to consumers, slow market entry due to uncertainties caused by the market reform, and strategic bidding by suppliers to take advantage of a poor market design. Marginal cost pricing is obviously not the norm in either the UK, Alberta or California, and regional prices may exceed marginal costs in Norway during times when the system experiences transmission constraints.

2.3. Common elements of failure

Table 3 presents the apparent key elements of failure for the four markets. First, the generation markets are generally not competitive, especially when transmission congestion prevents unfettered power flow and trading, and consumers do not have reasonable opportunities to respond to the price spikes. Market power abuse and capacity withholding by a few generators cause market price spikes, prompting a regulatory remedy of price caps in the UK and California (Dres et al., 1998; Wolak et al., 1998, 1999; Woo, 2001).

Second, market restructuring at times of insufficient capacity leads to higher prices. Market reform was conceived at times of excess capacity, in the anticipation that market prices would initially be less than the pre-restructure average-cost rates, and would then gradually rise to the long-run average cost of entry, i.e., the all-in cost of a CCGT (see Fig. 3). The reality for California is that generation capacity is constrained due to higher than expected demand growth not matched by new capacity (Woo, 2001).

Third, transitional rate freezes mask the price signals, blunting the need for risk hedging and customer price response. In California, only end-use customers in San Diego briefly saw the effects of high wholesale prices. Elsewhere in California, end-user customers still enjoy a rate freeze. Similarly, residential and commercial customers in Alberta are entitled to remain on a regulated rate for the first 3–5 years of retail competition. However, even when exposed to wholesale prices, many consumers have little opportunity to change their consumption in response to prices. Albeit they are not guaranteed a regulated rate, domestic and small commercial customers typically do not have hourly meters and the bills of the utility's default customers are calculated on their total energy consumption at the average wholesale price (Lynch and Kahn, 2000; Newbery, 1999). Even if price signals are correctly conveyed to final consumers, price spikes and volatility can still occur because hourly demands for electricity by households and business firms are highly price insensitive (Aigner, 1984; Acton and Park, 1987). Inelastic demands magnify the price effects of capacity shortage and market power (Wolak et al., 1999). Only customers in Norway, with its predominantly hydro system, are able to make reasonably informed decisions. This is not a result of market design, but a consequence of their energy, rather than capacity, constrained hydro system that experiences seasonal variation of prices and stable prices over the hours of a day. Whereas small consumers have little opportunity to respond to hourly price fluctuations they can respond to seasonal fluctuations.

Finally, regulatory uncertainty before and during the initial stages of restructuring discouraged new plant development in Norway, Alberta, and California. Slow regulatory approval after restructuring further delayed plants coming on-line in California. Both factors worsen the shortage and raise market prices (Lynch and Kahn, 2000). Even though new capacity development and market entry in the UK have been substantial, high market prices still occur occasionally, a likely result of market power (Green, 1998; OFGEM, 2000a, b; Wolfram, 1999a).

3. Anatomy of failure

Why can market restructuring so easily fail to deliver the promised gains? As shown in Fig. 4, there are many avenues to failure. Mistakes can occur at each of the three stages of a market reform: design, implementation and operation.

3.1. Design stage

Table 4 lists the elements of a good market design and evaluates which of them were present in the UK, Norwegian, Alberta and Californian market designs. This table shows that among the four markets, California has the worst design and Norway has the best design. This finding is expected, as reflected by the relative price and reliability performance of the four

Table 2
Evaluation of market restructuring in the UK, Norway, and California

	UK	Norway	Alberta	California
Competition	At the initial restructuring in 1989, two firms jointly controlled over 80% of total capacity. Since 1998 the number of players in the generation market has increased and presently no one player controls more than 25% of total capacity (Green, 1998). This is a result of: (1) entry by independent power producers (IPPs) and increased imports from France and Scotland displacing output from the dominant generators; and (2) required divestiture of a portion of the generating capacity of those same dominant generators. However, evidence abounds that market power exists and generators are manipulating prices through a number of mechanisms, e.g., capacity withholding, bidding strategies, and manipulation of rules. (Green, 1998; OFGEM, 2000a; Wolfram, 1999a).	Norway's generation capacity is almost entirely hydro (99%) and is distributed among a large number of small firms, with the four largest firms generating 44% of total capacity. Nord Pool connects Norway to other Scandinavian markets.	The 1995 Electric Utilities Act treated existing generation differently from new generation. Existing generation was covered by a legislated financial hedge and covered 85% of generation sold through the power pool. Although existing units bid into the pool and received the pool price, the financial hedge ensured that generation owners received payments to cover the fixed costs of their existing generation.	There are around 30 players in the market; however only a few are important once prices exceed US$75/MW h.
		Despite the large number of players, there is evidence that generators exercise market power when transmission constraints result in smaller, more concentrated markets (Johnsen et al., 1999).	Power purchase arrangements replaced the legislated hedge in 2001, which increases the number of players in the market and the volume of generation that has the price set in the market.	Allegations and preliminary evidence of local market power are being made by the oversight and monitoring arms of the PX and ISO. Recent price spikes and rotating blackouts have been cited by the CPUC as corroborative evidence of market power and capacity withholding (Lynch and Kahn, 2000).
			New generation plants coming on line indicates ease of entry.	
Market Operation	Industry costs of production are common knowledge. However, there are no generally recognized price reports for the current financial market in CfDs, and so there is little information available on contract volumes and prices.	The fragmented nature of the industry pre-restructuring obstructed least-cost planning and resulted in high price dispersion throughout the country. The transparent generation market appears to have reduced that price	The legislated hedge set the price for 85% of generation traded through the power pool, this together with a lack of financial markets in forwards and options leads to poor price discovery.	The overlapping PX and ISO ancillary services markets and the use of reliability-must-run contracts encourage capacity withholding by generators.

Table 2 (*continued*)

	UK	Norway	Alberta	California
		dispersion (Newbery, 1999).		
	There is poor correlation between price and demand, and regulator-imposed rate caps have blunted price signals.	There has been minimal development of new generation capacity, due in part to more rigid environmental standards and also to investor uncertainty.	Only industrial customers are fully exposed to market prices. Residential and commercial can remain on a regulated rate for 3–5 years. This blunts the market price signals.	Even though PX energy and ancillary services are substitutes, their prices and sales do not correlate highly. Rigid and highly predictable rules allow suppliers to predict when their own supply is critical, thus facilitating strategic bidding. Low volume of trading in financial markets. Stranded cost recovery and rate freezes blunt price signals and discourage entry.
Marginal cost pricing	Since 1991, real wholesale prices have remained around £25/MW h (on a 12-month rolling average). This is despite a fall in the overall costs of generation of 40–50% (due to falling fuel costs, a decline in the capital costs of new CCGTs, and rising plant efficiency rates and labor productivity (OFGEM, 2000a).	Range of household prices went from 0.127–0.196 Krone/kW h in 1994 to 0.105–0.459 Krone/kW h in 1997.	Average peak power pool prices went from CAN\$55.54/MW h for 1999 to CAN\$137.97 for 2000. Average off-peak prices went from CAN\$23.97 to CAN\$50.82.	The 1998 PX prices were found to be 22% above competitive levels. The high and volatile prices in 1999 led to price caps of US\$750/MW h for PX energy and US\$250/MW h for ancillary services. Frequent price spikes in 2000 resulted in lower price cap of US\$250/MW h for PX energy. Such high prices cannot be totally explained by increases in fuel costs and capacity shortage (Lynch and Kahn, 2000).

Table 3
Common elements of failure

UK	Norway	Alberta	California
Market power arising from few sellers.	Market power arising from transmission congestion.	Market power arising from few sellers and transmission congestion.	Market power evidenced by few sellers setting the market-clearing price during times of transmission congestion.
Poor market design that invites strategic bidding by suppliers.	Capacity shortage caused by demand growth not matched by capacity additions because of uncertainties introduced by market reform.	Capacity shortage caused by demand growth not matched by sufficient capacity additions.	Capacity shortage caused by demand growth not matched by capacity additions because of uncertainties introduced by market reform.
Little demand response to price changes.		Little demand response to price changes.	Poor market design that invites strategic bidding by suppliers.
No published information on forward trading for price discovery.		Thin forward and futures trading that limit price discovery and risk allocation.	Little demand response to price changes.
			Thin forward and futures trading that limit price discovery and risk allocation.

markets. Alberta opted for a very gradual entry to market reform and, distinct from California and the UK, did not require divestiture of generation assets. The initial phase limited competition to the wholesale market and effectively fixed the price of 85% of available generation through legislated financial hedges for all generation built under regulation before 1996. This limited the available capacity subject to market price to just 15%.

3.2. Implementation stage

In the UK, the Office of Gas and Electric Markets (OFGEM) has stepped in numerous times at evidence of market power abuses. Regulatory remedies have included price caps, required divestiture to decrease market concentration, and introduction of market abuse conditions into the licenses of certain generators (Green, 1998; OFGEM, 2000a, b; Wolfram, 1999a). While these interventions have stabilized prices and have not discouraged market entry, they were not successful in lowering market prices to marginal costs. In March 2001, the market structure underwent a major change under the new electricity trading arrangements (NETA). Under NETA, the former system, which required generators and suppliers in England and Wales to trade electricity through the electricity pool, was changed to a system based on bilateral trading between generators, suppliers, traders, and customers. NETA also introduced forwards and futures markets, a balancing mechanism to enable the National Grid Company to balance the system, and a settlement process.

In California, bad implementation has exacerbated an inherently bad design. Market power was not well understood and resulted in the divestiture of the plants owned by the formerly integrated utilities (Woo, 2001). While the ISO correctly anticipated the need for reliability-must-run (RMR) contracts, the payment schemes of these contracts induced profitable capacity withholding by the RMR plant owners (Wolak et al., 1998). Regulation of the transmission system and market prices has shifted from the state to the federal level, and now there is no clear regulatory body that is responsible for maintaining reasonable retail prices (Lynch and Kahn, 2000). The PX (folded in February 2001) and ISO are not answerable to the state or California consumers and have no incentives to prevent high wholesale prices or avoid serious errors. A case in point is that in May 2000 the ISO made a calculation error and lost track of 1500 MW of available power. That mistake resulted in the declaration of a Stage 2 emergency and the curtailment of several hundred large customers.

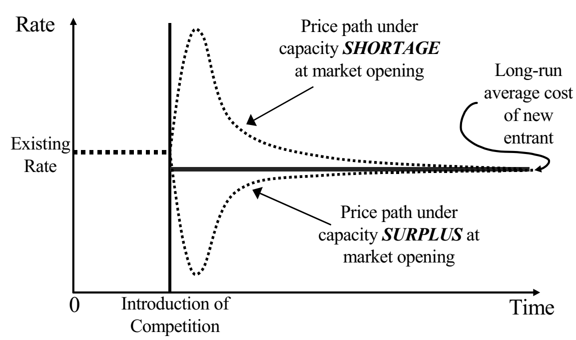

Fig. 3. Importance of excess capacity.

3.3. Operation stage

The UK has benefited from excess capacity at market opening, and rapid entry by new players (Newbery,

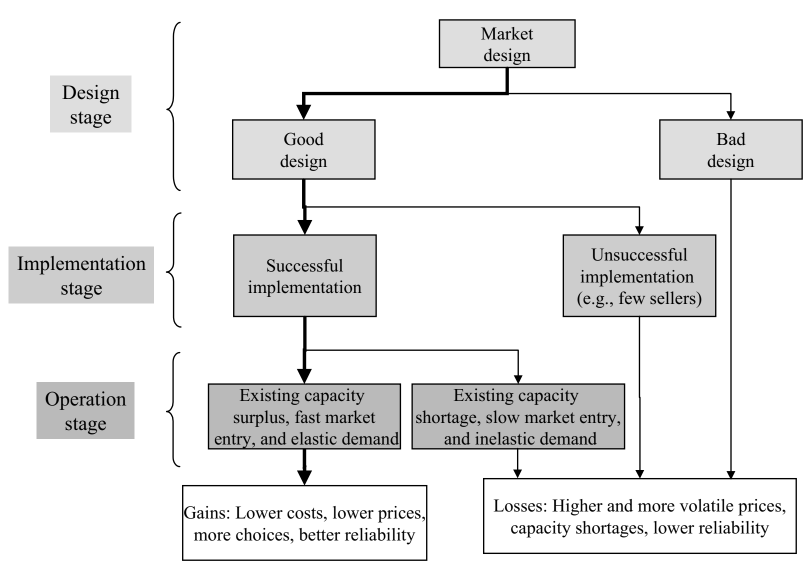

Fig. 4. Many avenues to failure.

Table 4
Elements of a good market design

Elements	UK	Norway	Alberta	California
Active trading with many buyers and sellers	× Initial divestiture resulted in two dominant firms.	✓ Many players already existed before restructure.	× Legislated hedge for 85% of generation traded until introduction of power purchase arrangements in 2001.	× Power plant auctions won by a few large players and slow entry by new players
Open and comparable access to transmission	✓ Under locational pricing based on long-run incremental cost.	✓ Under multi-part tariff with locational pricing based on zonal market clearing prices.	✓ Access fees based on locational pricing.	✓ Under multi-part tariff with locational pricing based on zonal market clearing prices.
Price discovery and risk allocation	× Initially the only financial market was in CfDs. Unlike other over the counter markets there are no generally recognized reports on contract volumes and prices.	✓ Bilateral and forward contract trading offers price discovery and risk allocation.	× Rate caps blunted price signals and shielded players from risk. Thin trading in futures and forwards.	× Rate caps blunted price signals and shielded players from risk. Limited opportunity given to utilities to manage risk.
Low transaction cost	× Because of the additional transactions required to generate and deliver electricity for final consumption.	× Because of the additional transactions required to generate and deliver electricity for final consumption.	× Because of the additional transactions required to generate and deliver electricity for final consumption.	× Because of the additional transactions required to generate and deliver electricity for final consumption.
Efficient information flow	✓ Both buyers and sellers have access to market conditions and price information.	✓ Both buyers and sellers have access to information on market conditions and price.	✓ Both buyers and sellers have access to information on market conditions and price.	× Complicated market design obscures price information (e.g., actual price of ancillary services only becomes known long after the transaction taken place).
Informed response to price changes	× The market clearing price determination assumes a vertical demand curve.	✓ The predominantly hydro system is energy rather than capacity constrained, and prices remain stable over the hours of a day, only varying from season to season. This allows market participants to make reasonable informed decisions.	× Small customers have rate caps or have bills calculated on their total energy consumption at the average market rate. They cannot make informed response to price spikes.	× Small customers have rate caps or have bills calculated on their total energy consumption at the average market rate. They cannot make informed response to price spikes.
Least cost congestion management	✓ Retained benefits of a centrally dispatched system.	✓ Benefits from large amount of hydro storage.	× Relies on central dispatch. Because the supply bids are not marginal cost based, the resulting dispatch is inefficient.	× Relies on central dispatch. Because the supply bids are not marginal cost based, the resulting dispatch is inefficient.
Easy market entry	✓	×	✓	×

Table 4 (*continued*)

Elements	UK	Norway	Alberta	California
	Substantial plant development reflects relative ease of entry.	Restricted site availability and environmental restrictions.	Recent plant development reflects relative ease of entry.	Restricted site availability and environmental restrictions.

1999). However, adding to California's electricity woes is the fact that demand for electricity from an expanding economy has outstripped the minimal new supplies (Lynch and Kahn, 2000). Lagging investments are partly a result of investor uncertainty in the direction and rules of the new market environment, a factor which has also been attributed to increased prices in Alberta's power pool (Alberta Market Surveillance Administrator, 2000).

Constraints on the transmission system have exacerbated problems of market power and gaming.[7] Alberta has experienced higher and volatile prices, partly due to high prices in neighboring markets. The other reason is transmission constraint. Alberta is served by interconnections to the west and east. However, the British Columbia (BC)–Alberta interconnection has only 800 MW capacity. A seller in the Alberta market wishing to import US power must arrange for firm transmission from the US to BC and from BC to Alberta. If firm transmission from BC to Alberta has been exhausted, firm power import into Alberta dwindles. The report by Alberta's Market Surveillance Administrator (2000) acknowledges that in times of constrained supply within Alberta, the BC–Alberta transmission limitation causes high and volatile prices. Even in Norway, reduced excess capacity, transmission constraints and connection to other Scandinavian markets with higher-cost thermal and nuclear generation have resulted in higher electricity prices (Johnsen et al., 1999). It should be remembered, however, that in Norway, higher prices and reduced excess capacity was both anticipated and encouraged by the government.

4. Conclusion

Market restructuring along the lines of the models adopted in California, Norway, Alberta, or the UK is almost certain to fail in a country with rapid growth, limited generation sites, and no indigenous fuel (e.g., Israel and Hong Kong). More importantly, electricity market reform is highly risky and irreversible. Once the power plants owned by the formerly integrated utilities are divested, it is very difficult, if not impossible, to turn back. The California experience surely suggests that a reversible regulatory reform is a safe alternative to an irreversible market reform.

An example of a regulatory reform is PBR with a price cap that escalates at the inflation rate less the productivity target (i.e., CPI-X). By design, consumers will immediately see stable prices that will decline in real terms over time. As the PBR can grant a regulated utility flexibility in pricing and product differentiation, consumers will also have more choices. Moreover, the PBR can offer the utility incentives to operate efficiently and invest rationally because the utility can retain the resulting cost savings. This addresses the common concern that COSR induces cost inefficiency and excess capacity. Finally, the price cap formula may contain additive (Z) factors that reward (penalize) the utility for superior (inferior) performance in (a) delivering service reliability and quality, and (b) implementing cost-effective energy efficiency and conservation.[8] Even if PBR will not achieve all of the highly touted benefits from a market reform, PBR's downside risk is minimal. This is one of the primary reasons supporting our PBR recommendation for the Israeli electric sector (Tishler et al., 2002).

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[7] Borenstein et al. (2000) show how generators may congest a transmission path to enhance their local market power and profits. Gaming is taking advantage of the imperfect market rules by some market players who may not necessarily have market power. An example is that some generators intentionally produce more energy than scheduled with the ISO in order to earn more revenue in the real-time market at times of high prices.

[8] These Z-factors can also be used to account for certain cost changes (e.g., fuel cost for natural gas and coal) that are beyond the utility's control (Biewald et al., 1997; Schmidt, 2000).

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