Case studies: comparator industry design and regulation

prepared for the Department of Energy of Nova Scotia by London Economics International LLC

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The case studies report covers seven jurisdictions and two utilities with varying regulatory framework and experience in restructuring: Alberta, California, FortisBC (utility), Georgia Power Company (utility), New Brunswick, New England, New South Wales, Ontario, and the UK. Jurisdictions were selected to gain a holistic perspective – as such, experience reviewed varies from well-known successes in restructuring (e.g. the United Kingdom) to previous failures (e.g. California) - and includes jurisdictions that have similarities with Nova Scotia in terms of size and initial structure (e.g. New Brunswick). The case studies provide various contextual aspects including an overview of the electricity market (or utility), the current institutional and legal framework, history of restructuring along with recent developments, transitional challenges encountered and remedies adopted. Case studies further exemplify discussion in the Literature Review and illustrate the importance of policy makers' decisions with respect to implementation of specific goals (both in the short and long terms), which includes establishing appropriate policy environment, designing the market based on unmet needs and best practices, involving stakeholders, and allowing for gradual transition.

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1 Overview of the case studies

This report presents detailed case studies covering seven jurisdictions and two utilities. The case studies highlight important features of the different energy markets and key issues and lessons arising from an exhaustive literature review. Case studies cover numerous contextual aspects including, but not limited to, an overview of the electricity market or utility, followed by the jurisdiction's current institutional and legal framework, and history of restructuring and recent developments. These three sections answer the ***'what is'*** question pertaining to electricity industry design and regulation in each of the jurisdictions. Subsequent sections within each case study discuss the ***'why'*** and ***'how'*** aspects: we first delve into the rationale for specific design elements along with a discussion of pros and cons of selected design elements in each jurisdiction, which is followed by exploring transitional challenges faced, and remedies adopted in each of the jurisdictions. Finally, each case study presents key takeaways/implications for Nova Scotia.

1.1 Case selection

The selection of the markets and utilities covered in this report is based on a variety of factors as shown in Figure 1. We chose markets that have had a successful experience in restructuring (e.g. the United Kingdom or "UK") as well as markets that have failed in restructuring (e.g. California). We also included markets that have similarities with Nova Scotia in terms of size and initial structure (e.g. New Brunswick). Several markets studied have extensive experience in performance-based ratemaking (e.g. FortisBC, New South Wales ("NSW"), and the UK). Lastly, we have also reviewed markets of interest to the Department of Energy (e.g. New England, Ontario and Alberta).

Figure 1. Rationale for selection of the case studies

Market or utility	Rationale for choosing this market
Alberta	Functionally unbundled market with recent initiatives by regulator to move to PBR
California	Interesting example of stalling of restructuring, and overlapping regulatory authority; lessons to be learnt from California crisis
FortisBC (utility)	Only vertically integrated Canadian regulated utility with phases of PBR across generation, transmission and distribution
Georgia Power Company (utility)	US example of vertically integrated utility with COS across generation, transmission and distribution albeit with ESM (softer form of PBR) within distribution
New Brunswick	Interconnected and similar to Nova Scotia; New Brunswick System Operator reliability coordinator for Nova Scotia
New England	Significant interest in New England regulatory design particularly due to renewable energy export potential from Nova Scotia
New South Wales	One of the first provinces to restructure in Australia and has extensive experience in PBR regime
Ontario	Largest Canadian province; political considerations have resulted in market design changes that partially reversed the restructuring process
UK	Fully unbundled with extensive restructuring history; lessons to be learned from policies resulting in successful restructuring

The jurisdictions covered in this report vary in several aspects as shown in Figure 2.[1] First, the markets have diverse experiences in restructuring (for instance, the UK's successful restructuring experience in its electricity markets versus California's previous stalling of restructuring), which are reviewed in detail in this report.

Figure 2. Comparison of electricity statistics across jurisdictions

Jurisdiction	Installed capacity (MW), 2013	Peak demand (MW), 2013	Load growth (%) (CAGR, 2009-2013)	Generation (GWh), 2013
Alberta	15,173	11,139	2.1%	77,000
California	78,133	75,503	-0.10%	228,024
New Brunswick	4,839	3,200	0.6%*	13,000
New England	29,923	27,379	2.2%	129,360
New South Wales	17,000	13,946	0.6% (2006-2013)	68,834
Nova Scotia	2,730	2,033	-3.35% (2011-2013)	10,525
Ontario	39,961	24,636	-0.6%	154,000
UK	89,200 (2012)	56,800 (2012)	1.8% (2012)	364,000 (2012)

Second, the case studies reviewed are in different stages of restructuring. Markets such as Alberta, UK, and California were among the first to implement electricity sector restructuring and have gone through the unbundling process. This report covers jurisdictions where restructuring has taken different paths—for example, in California where it has gradually recovered from its challenges, and in New Brunswick where there was an eventual return to a vertical integration from an initial period of restructuring.

Third, the jurisdictions studied have varying industry structures and regulatory frameworks. The case studies covered utilities and a jurisdiction that are still under a vertically integrated structure (such as Georgia Power Company, FortisBC, and New Brunswick) and markets with wholesale and retail competition such as Alberta, Ontario, and the UK.

[1] Nova Scotia statistics have been added to figures in this section for comparative purposes only. This deliverable does not explicitly discuss the Nova Scotia market. A separate deliverable presents a detailed review of electricity market in Nova Scotia.

Fourth, the markets also differ in size and geographic scope. For instance, New Brunswick has a size—in terms of installed capacity and generation—similar to Nova Scotia. On the other hand, all other markets reviewed are larger in size and wider in terms of geographic scope.

Lastly, FortisBC is included as one of the case studies. Similar to Nova Scotia Power in some respects, it is a vertically integrated utility, albeit with extensive experience in performance-based ratemaking ("PBR").

1.2 Overview of the jurisdictions covered in the case studies

All the jurisdictions studied have a clear delineation of the responsibilities and duties for each institution. Generally, the government, through the ministry of energy, sets the energy policies, ensures reliability, and promotes innovation in the energy system. An independent regulator, either called a Commission or a Board, is in charge of issuing the licenses for transmission and distribution companies. It is also responsible in setting the rates for the regulated businesses. The electricity system is managed by an independent system operator or a transmission company that is appointed as the system operator. Figure 3 shows the different entities in the energy markets for the jurisdictions reviewed.

Figure 3. Regulatory entities in the energy market

Jurisdiction	Policy setting	Regulatory and rate setting	Market institutions
Alberta	• Alberta Department of Energy • Alberta Ministry of Energy	• Alberta Utilities Commission • Alberta Energy System Operator	• AESO • Balancing Pool • Watt-EX
California	• California Public Utility Commission • California Energy Commission California Air Resources Board	• California Public Utility Commission • Federal Energy Regulatory Commission	• California Independent System Operator
New Brunswick	• Government of New Brunswick	• Electric Utility Board	• NB Power
New England	• Federal Energy Regulatory Commission • State regulators	• Federal Energy Regulatory Commission • State regulators	• ISO-NE
New South Wales	• Australia Energy Regulator • Australia Energy Market Commission • Australian Competition & Consumer Commission	• Australia Energy Regulator • Australian Competition & Consumer Commission • Independent Pricing and Regulatory Tribunal of NSW	• National Electricity Market
Nova Scotia	• Nova Scotia Legislative Assembly • Nova Scotia Department of Energy	• Nova Scotia Utility and Review Board	• Nova Scotia Power Inc. • Nova Scotia Power System Operator
Ontario	• Ministry of Energy	• Ontario Energy Board	• Independent Energy System Operator • Ontario Power Authority
UK	• Department of Energy and Climate Change • Office of Gas and Electricity Markets	• Gas and Electricity Markets Authority • Office of Gas and Electricity Markets	• National Grid

Most markets studied have a generation sector that has multiple investor-owned players. However, there are some markets (like NSW and Ontario) where government still owns some generation units. For instance, in New South Wales, investors have some control of the generation stations (through the gentrader contracts) although the government owns 90% of these assets. On the other hand, majority of the installed capacity in Alberta is owned by private companies with approximately 5% dispatched by the Province's Balancing Pool. Only three jurisdictions studied either implement or plan to implement capacity markets. These are California, New England, and the UK. The UK plans to implement its first capacity market auction end of this year. Ontario is also considering the possibility of having a capacity market. Other deregulated jurisdictions have energy-only markets. Figure 4 illustrates a cross comparison of generation ownership and market model adopted in the jurisdictions reviewed.

Figure 4. Comparison of generation ownership and/or control and market model

Jurisdiction	Ownership of generation units (investor vs. government)	Control of generation units	Market model (Energy only /Energy and capacity)
Alberta	Primarily investor-owned	Balancing Pool controls 5% of installed capacity (or 700 MW) via power purchase arrangements	Energy-only
California	Primarily investor-owned	Primarily investor-owned	Energy and capacity markets
New Brunswick	More than 80% government-owned	More than 80% by the government	No market
New England	Primarily investor owned	Primarily investor owned	Energy and capacity markets
New South Wales	90% government-owned	Investors have some control of units through gentrader contracts	Energy-only
Nova Scotia	95% owned by Nova Scotia Power Inc. (privately owned)	Primarily investor owned	Energy-only
Ontario	49% Ontario Power Generation ("OPG"); remainder is owned by independent power producers and munis	49% by OPG	Energy-only
UK	Investor-owned	Investor-owned	Energy and capacity markets

Among the markets studied, only three jurisdictions (and one utility) use the **PBR mechanism** to set rates for the **transmission sector**. ENMAX - the first transmission and distribution utility in Alberta that went into PBR - moved to PBR to provide increased rate predictability to customers and revenue predictability to its company while maintaining safe and reliable service at just and reasonable rates. The UK and NSW, on the other hand, enforced the PBR mechanism to protect consumers in the transmission (and distribution) sector where there is lack of competition. In addition, in NSW, a PBR approach is used to promote efficient investment in and efficient operation and use of services for the long-term interests of consumers.[2]

[2] Australia National Electricity Law.

More jurisdictions use the PBR mechanism to set rates for the **distribution sector**. Alberta, NSW, Ontario, the UK, and some states in New England have implemented some form of PBR. The UK and NSW use the building blocks approach while the North American markets use the I-X approach. Utilities in California also used PBR in the early 2000s but have reverted back to cost of service in the past few years. Figure 5 provides a table of a comparative matrix on the transmission and distribution rate regulation as well as the entity in-charge of the system operations.

Figure 5. Comparison of grid operations and rate regulation in the transmission and distribution sector

Jurisdiction	Grid operations - independent system operator (ISO) or Transco	Transmission rate regulation (COS or PBR)	Distribution rate regulation (COS or PBR)
Alberta	ISO (Alberta Energy System Operator)	PBR (ENMAX)	PBR
California	ISO (California ISO)	COS	COS
New Brunswick	Vertically integrated (NB Power)	COS	COS
New England	ISO (New England ISO)	COS	COS and PBR
New South Wales	ISO (Australian Energy Market Operator)	PBR	PBR
Nova Scotia	Nova Scotia Power System Operator (NSPSO) functionally unbundled from Nova Scotia Power (NSPI)	COS	COS
Ontario	ISO (Independent Energy System Operator or "IESO")	COS	PBR
UK	Transco (National Grid)	PBR	PBR

All unbundled markets reviewed also provided retail access, i.e., they give consumers the option to choose their electricity suppliers. Some markets provide retail access to only a section of the consumers. For instance, in California, retail access is just limited to large customers.

In addition, markets differ in terms of the retail pricing options that are provided to consumers. In Alberta, New England, NSW, and Ontario, the government provides a default service (also known as rate regulation option in some jurisdictions) for consumers that do not want to choose their own supplier. Under a default service, the distribution utility is required to offer service at regulated prices to the deregulated customers, which is generally provided to protect consumers from price volatility in the spot market. The UK implemented default service as a transitional mechanism for a defined period of time and full retail contestability in NSW is expected to end in July 2014.

Figure 6. Comparison of retail access

Jurisdiction	Retail access	Retail access to all consumers?	Retail access to some consumers?	Currently has a default service standard?
Alberta	Yes	√		√
California	Yes		√ (large consumers only)	
New Brunswick	No			
New England	Yes	√		
New South Wales	Yes	√		√
Nova Scotia	Renewable power only*			
Ontario	Yes	√		√
UK	Yes	√		

* The Electricity Reform Act in Nova Scotia (passed in 2013) allows licensed generators to sell renewable power generated within the province directly to all retail customers.

1.3 Restructuring experience

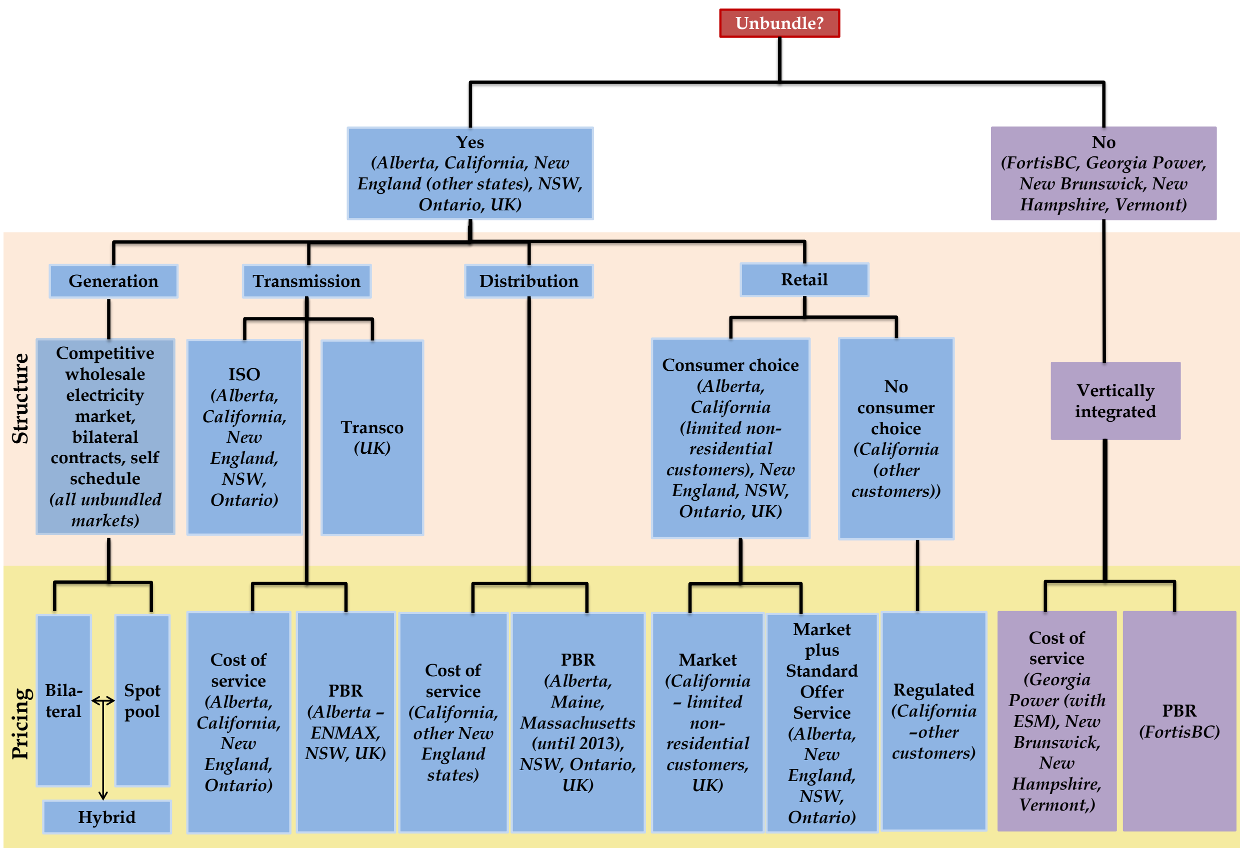
Unbundled/deregulated and vertically integrated systems both have their advantages and disadvantages. For example, unbundled systems allow greater market competition, which may ultimately result in customer benefits such as lower pricing. Meanwhile, integrated systems may assure government of a more stable supply because of better coordination and, to some extent, lesser market intervention (or "risks").

The simple illustration presented in Figure 7 captures the decision paths and options that were taken by the jurisdictions that decided to unbundle or remain vertically integrated.

Every market has its own circumstances. It is wise to begin the decision-making with the question, "Is there a significant need or a series of needs that are still largely unmet by the prevailing system?" This is an important starting point because any shift to a new system should evolve from market needs which the current system is not fulfilling adequately. Needs such as cost efficiency, delivery of services in a more timely and stable manner, or fairer/lower prices should result from the new or proposed system as compared with the market in its current system of operation. To be more specific, one may need to ask: "will unbundling or deregulation cover the unmet needs and solve the current problems in the energy market?"

Different drivers (and unmet needs) serve as impetus towards restructuring and deregulation in the electricity market. These events may include significant increases in supplied electricity price (e.g. Massachusetts), a mismanagement of important functions (e.g. Ontario), lack of competition (e.g. Alberta), urgent political objectives, and low efficiency (e.g. the UK).

Figure 7. Decision options to unbundle or remain vertically integrated



The jurisdictions reviewed have varied in terms of the pace of restructuring. In Alberta, the regulation was implemented slowly by first implementing legislated hedges to gradually increase competition. Full retail competition was introduced five years after the implementation of deregulation. In Ontario, however, unbundling and liberalization was implemented simultaneously.

The markets included in this study highlight some key similarities in their restructuring process. The introduction of competition in the generation (and retail in some markets) is generally accompanied by unbundling of vertically integrated utilities (into market based functions for generation and retail services) and regulated functions (for the transmission and distribution). Ontario, New South Wales, and the UK unbundled the vertically integrated utilities successfully. Alberta also unbundled some of the companies functionally.

All unbundled markets reviewed created an electricity pool where generators can sell their outputs. Participation in the electricity pool is mandatory in some markets such as the UK (until 2001) and Alberta. Under a competitive market, it is also crucial that there is open and non-discriminatory access to transmission and system operations. The system operator needs to be independent of all generators, traders, buyers, and sellers. In Alberta, California, New England, NSW, and Ontario, the system operator is a separate organization (independent) from the transmission owners. Another option - which is currently adopted in the UK - is to consolidate transmission and system operations (i.e. the Transco model, as discussed earlier in the Literature Review report).

Each restructured market also has an independent regulator that oversees the activities in the transmission and distribution sectors. The list of the independent regulators in jurisdictions reviewed was shown earlier in Figure 3.

Furthermore, most jurisdictions have opened their markets to full retail competition. The pace of implementation however differs among markets. The UK implemented retail competition in three phases, beginning (in 1990) with customers with peak demand more than 1,000 kW, followed by customers with peak demand more than 100 kW (in 1994), and ultimately for all consumers (by 1999). On the other hand, Ontario and NSW implemented retail competition for all customers at once. With the market collapse in California, the California Public Utilities Commission suspended retail competition. However, it reintroduced it for non-residential customers in 2008.

1.4 Transitional challenges encountered and remedies employed

The jurisdictions that transitioned from a regulated and vertically integrated system to a restructured and deregulated market have encountered various challenges, as discussed below.

- **Ensuring competition in the generation sector**: in Alberta, the power purchase arrangements ("PPAs") were used to infuse competition in the power market. PPAs are virtual divestitures where plant owners still retain ownership of the plant while the PPA owner has the right to determine the amount of energy to bid into the energy markets. In the UK, the government auctioned off some of its shares in the two government-owned generating companies, and also allowed distribution utilities to build generation units (although with a restriction that their generation units could not account for more than 15 percent of their individual electricity sales).

- **Dealing with volatility in the spot market**: the UK imposed vesting contracts for generators and distributors for a three-year term (1990 to 1993). The vesting contracts assisted by stabilizing prices for the first few years while the generation market settled down. Likewise, NSW utilized vesting contracts to avoid exposing retailers to wholesale price risk. Ontario, on the other hand, did not adopt such a system of contracting as a transitional mechanism.

- **Avoiding conflict of interest and risk of potential cross subsidy**: when competitive and regulated activities are in the same company, there is a concern of possible cross-subsidization between a competitive activity and a regulated activity. The UK government protected the financial viability of regulated businesses through ring-fencing mechanisms, which were part of the licensing conditions for operations.

- **Treatment of strategic assets**: as discussed in the Literature Review report, ownership restriction is one way of dealing with this. In Ontario, the government set regulated payments to Ontario Power Generation ("OPG")'s hydro and nuclear assets to reduce price volatility, ease the burden on taxpayers, and ensure that the Ontario prices are competitive relative to its neighboring markets. The UK government held some golden shares in the generation, transmission, and distribution businesses to ensure that it can veto any move of unfriendly buyouts or takeovers.

- **Treatment of stranded costs**: regulators need to ensure that there are mechanisms in place for the collection of stranded costs. In Alberta, the government provided hedges to ensure that shareholders were able to recover the costs of their investments while ensuring that customers did not have to pay higher prices for electricity generated from existing plants.

- **Ensuring smooth transition to full retail competition**: markets such as Alberta, NSW, and the UK provided a transitional regulated rate plan for customers who decided not to choose an electric retailer. Generally, this transitional rate option is designed for a specific number of years for smaller customers (residential, farm customers, small industrial and business customers) and set by the regulator.

- **Ensuring recovery of capital investments by transmission and distribution utilities under an incentive ratemaking mechanism**: Ontario recently provided distribution utilities the option to choose the framework in setting their distribution rates based on their needs and requirements during the PBR term. In NSW and the UK, utilities' capital expenditures are included ex ante in the revenue requirements, which means that there is assurance that these investments will be recovered. In Alberta, distribution utilities can apply for capital trackers as long as the criteria set by the Commission are met.

1.5 Lessons learned from the case studies

The UK's experience in restructuring and deregulation can be considered successful relative to other markets. Some experts have stated that UK's experience in restructuring is the "gold standard for electricity sector reform" and followed "the basic architecture of textbook model and have led to significant performance improvements in many dimensions."[3] Some of the ingredients for successful restructuring and market reforms in the UK market include providing clear objectives for electricity reforms upfront, restructuring the utilities prior to privatization, and providing transitional mechanisms, to note a few. The UK was also able to ensure that competitive segments are separated from regulated segments by imposing conditions in the licenses issued to transmission and distribution utilities.

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[3] Joskow. Paul. "Lessons Learned From Electricity Market Liberalization." *The Energy Journal*: Special Issue. The Future of Electricity: Papers in Honor of David Newbery. P. 15.

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On the other hand, although restructuring worked well in the beginning, California's experience with restructuring was less favorable. As will be discussed in Section 3, the market collapsed and the utilities filed for bankruptcy. The failure can be attributed to several factors such as those related to policy and design flaws, timing, market readiness, and inappropriate transitional mechanisms. Nevertheless, every market has its own unique circumstances. However, the California and other markets' experiences underline the difficulty of any restructuring exercise. Decision-makers should, most of all, have a full grasp of the market, agree on specific goals (both for the short and long terms), establish the appropriate policy environment, design the market based on unmet needs and best practices, involve stakeholders, and allow for gradual transition. The following summarizes the lessons learned on restructuring from the case studies reviewed:

- **Developing clear objectives and policies**: the California experience is a good example of the importance of developing a full grasp of what the actual needs are and connecting those with the appropriate policies. California created an over-complicated regulatory structure, which could have been caused by unclear (or disagreements on) policy goals. The disconnect (combined with inability to hedge) led to increased uncertainties, higher risk premiums, and roadblocks for implementation of critical decisions. The prolonged design and passage of the initial restructuring bill led to tightness in the system, discouraging new generation of investments by utilities (eventually triggering the crisis). Delay in permitting and siting for proposed new entrants did not assist, and this is a problem that continues to plague California even today given the complex regulatory approval process.

- **Unbundling vertically integrated monopolies before introducing competition**: it is vital to separate the wires from all other activities, either through legal unbundling of the network entities or through full unbundling.

- **Creating competition in the generation sector**: the Alberta case presents an example where a market, which was previously dominated by a few vertically integrated utilities, moves gradually to controlled deregulation to achieve stronger competition. While the concept is applicable to Nova Scotia, minimum efficient size also needs to be a consideration.

- **Opening at the right time (avoiding high demand periods)**: the experience in Ontario and California show that the market should be opened during periods of least system stress.

- **Opening market gradually**: most if not all markets require an adequate preparatory and early-stage implementation periods. Particularly for the generation sector, the slow introduction of competition contributed to the successful transition in the Albertan and the UK markets.

- **Maintaining a regulated price for ratepayers**: any market reform should consider the welfare of the general public and small consumers. Alberta, New England, NSW, and the UK introduced a regulated rate mechanism to protect consumers. A policy like the regulated rate option may assist in implementing full retail competition in Nova Scotia while ensuring that its residents can enjoy certain predictability in their monthly bills.

- **Creating transitional hedges**: the California crisis highlighted the importance of transitional hedges such as guaranteeing full recovery of power procurement costs as a pass-through to ratepayers and allowing IOUs to enter into long-term contracts. Hedges provide 'cushioning effect' that help markets transition to a restructured environment. In the case of California, restructuring could have been designed with contracts that matched the default supply obligations in price, thereby protecting customers and generators.

There are also lessons to learn from the case studies in terms of designing the appropriate PBR mechanism:

- **Setting appropriate rates to protect both the utilities and the customers**: jurisdictions that have successfully implemented PBR such as NSW and the UK have set rates that enable the utilities to meet their obligations to customers as well as earn sufficient rates of return to support future investments.

- **Providing mechanisms to ensure that capital investments are recouped on a timely manner**: in NSW and the UK where utilities use the building blocks approach, capital investments are included ex ante when determining the revenue requirements. This process provides certainty around recovery of capital costs and reduces financing costs for utilities. Nevertheless, during the PBR review process, active participation of the regulator is required, resulting in administrative burden on the regulator, utility and stakeholders. For markets that use the I-X approach (such as Alberta and Ontario), capital investments are recovered through an explicit mechanism such as capital trackers or the incremental capital module ("ICM"). On the other hand, FortisBC followed a hybrid approach; although under a PBR mechanism from 2007-2011, its capital expenditure was recovered on a cost-of-service basis.

- **Providing mechanisms to manage risks beyond utilities' control**: all the markets reviewed provided mechanisms such as exogenous factors, flow throughs, and reopeners to manage the utilities' risks that are beyond their control.

- **Putting in place mandatory performance standards**: all PBR regimes reviewed have some mandatory performance standards to ensure that any cost reductions implemented by the utility would not affect reliability and cause any service quality deterioration. Some markets (e.g. the UK) and utilities (e.g. Central Maine Power) have penalties for failure to achieve the targets set by the regulator.

2 Alberta

The Alberta power market has evolved into a competitive, energy-only wholesale electricity market. Alberta managed the restructuring process gradually, beginning in 1996 and transitioning from a system dominated by a few large, vertically integrated utilities from both the public and private sector. Alberta's gradual restructuring using power purchasing arrangements ("PPAs") to ensure competition in the market represents an important success factor. A key lesson learned for other jurisdictions is that steady, committed pursuit of a competitive power market can be successful but also requires multiple buyers and sellers and clear, realistic, up-front goals as well as a degree of flexibility in addressing uncertainty.

2.1 Overview of the Alberta market

Since January 1996 with the *Electric Utilities Act* ("EUA"), the Alberta power market has evolved into a competitive, energy-only wholesale electricity market.[4] It operates on a real-time, zonal basis as administered by the independent system operator known as the Alberta Electric System Operator ("AESO"). There is no day-ahead energy market, no capacity market, and no nodal energy market (locational based marginal prices ("LBMP")).

Following the establishment of the Alberta Power Pool,[5] the generation side of the power market has remained heavily reliant on coal generation to meet the demand created by rising economic growth. By ownership, large generators include TransAlta Corporation, ATCO Power, Capital Power, TransCanada, and ENMAX, with the largest 4 players owning approximately 52% of Alberta generating capacity. Since the 2001 implementation of PPAs,[6] there have been a growing number of independent power producers ("IPP"). These have helped to meet rising power demand, to introduce competition in the generation sector, and to expand renewable energy production in the province.

In the wires industry, there are four major transmission asset owners and distribution asset owners.[7] The largest owner is AltaLink which owns approximately 12,000 kilometers of transmission lines, 28 substations, and over half the provincial electrical system serving 85% of the Alberta population.[8] The assets were purchased from TransAlta in 2002 which previously

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[4] As of 2014, Alberta market remains one of the two North American electricity markets that continue to employ a pure energy-only market. The other is operated by the Electric Reliability Council of Texas ("ERCOT") which is currently in the process of debating the option of introducing a capacity market design.

[5] The Alberta Power Pool evolved into the current independent system operator ("ISO"), the Alberta Electric System Operator ("AESO"). See Section 2.2.

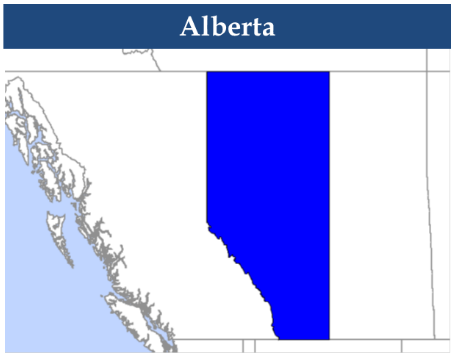
[6] The Gentrader model used in New South Wales, Australia is similar to Alberta's sale of PPAs.

[7] The major transmission owners are: ATCO Electric Ltd., AltaLink Management Ltd., EPCOR Energy Services and ENMAX Power Corp and the distributors are: FortisAlberta Inc., ATCO Electric Ltd., EPCOR Distribution Inc. and ENMAX Power Corp.

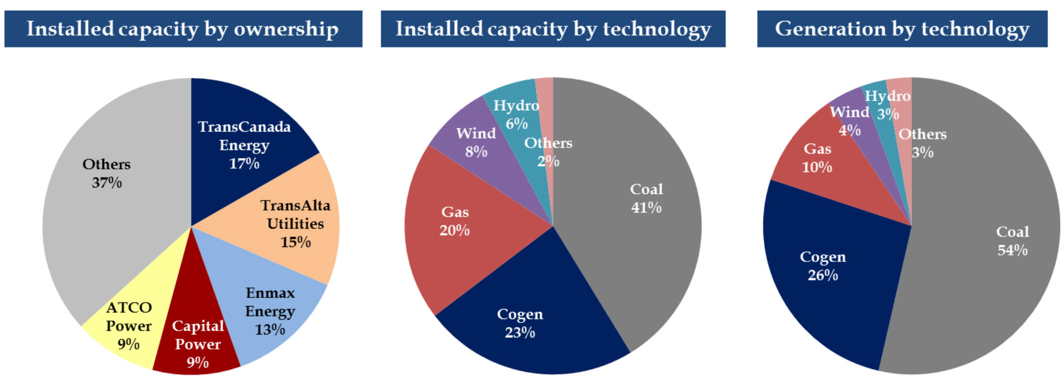
[8] AltaLink. *Company Overview*. Accessed: April 28, 2014. <http://www.altalink.ca/about/company-overview.cfm>

had been a vertically integrated utility.[9] Unlike in New Brunswick and Quebec, there are no Crown Electrical Corporations in Alberta as all entities are corporatized as shown in Figure 8.[10] Historically, the wires business has been regulated under a cost of service ("COS") model. This, however, has begun to change, first with ENMAX in 2009 moving to a performance based ratemaking ("PBR") structure (called a formula-based ratemaking "FBR" regime) and the Alberta Utility Commission's ("AUC") "Rate Regulation Initiative" of 2011 which has led to the adoption of PBR regulation in electric and gas distribution utilities.[11]

Figure 8. Snapshot of the Alberta market



Key facts	
Population (2013)	4, 082,571
GDP growth est. (2013)	3.5%
Installed capacity (2014)	15,173 MW
Peak demand (2013)	11,139 MW
Production (2013)	77 TWh
Compound annual load growth rate (2009-2013)	2.1%
Number of distributors	4
Number of transmitters	4



Source: AESO 2013 Annual Market Statistics and commercial database

There are several important Alberta electricity market drivers:

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[9] AltaLink. *The History of AltaLink's Transmission System*. Accessed: April 28, 2014. <http://www.altalink.ca/about/history.cfm>

[10] Alberta has several municipally owned entities, the largest being ENMAX and EPCOR.

[11] For example, ATCO Electric entered into a PBR regime in 2013. For information on the "Rate Regulation Initiative" see: AUC. *Bulletin 2010-20 – Regulated Rate Initiative – PBR Principles*. July 15, 2010; and AUC. *Rate Regulation Initiative. Request for Deadline Extension – Electronic Notification*. March 29, 2011.

- **Growth and size of market**: With an installed capacity of 15,173 MW, the Alberta power market is among the smallest, but fastest growing, wholesale markets in North America.

- **Market design**: Alberta does not have either LBMPs or a capacity market. Without LBMPs, planners must use other tools to incentivize generators into historically constrained regions. Without a capacity market, potential investors must rely on peak prices alone to ensure the financial viability of new generation projects.

- **Proportion of industrial load**: Approximately 63% of total Albertan electricity load comes from the industrial and oil sands sectors.[12] As a consequence, Alberta may have a higher system load factor than Nova Scotia, which has a smaller industrial load share.

- **Scale of pending retirements:** As a consequence of the Government of Canada's August 2012 approval of *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations,* a large proportion of Alberta older coal-fired generation capacity will need to be replaced. Since approximately 51% of Nova Scotia Power Inc.'s ("NSPI") generation is coal fired, Nova Scotia may face similar challenges.[13]

- **Scope of regional trade:** Albertan electrical interconnections with neighboring regions are relatively limited.[14] Similarly, Nova Scotia has historically only maintained interconnections with New Brunswick.[15]

- **Carbon pricing:** There is an explicit cost for carbon dioxide emissions in Alberta. Following the 2007 *Specified Gas Emitters Regulation*, any facility emitting over 100,000 tons of carbon dioxide per year in Alberta must reduce their emissions intensity to 12% below 2003-2005 levels. A greenhouse gas emissions levy of $15/ton of carbon dioxide is imposed for any emission over the reduction target.[16]

Alberta operates a competitive energy-only market in which the largest five generation owners control approximately 63% of capacity and there are four major transmission distribution owners. In contrast, the Nova Scotia electricity market is dominated by the vertically integrated, investor-owned NSPI which produces approximately 95% of the electricity consumed in the

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[12] AESO. *2012 Long-Term Outlook Update.* February 25, 2013.

[13] Environment Canada. *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations.* (SOR/2012-167).

[14] Average export and import capacities are as follows: 146 MW and 253 MW with Saskatchewan, 1,000 MW and 1,200 MW with British Columbia; and 300 MW with the US state of Montana. For more information, see: AESO. *2013 Annual Market Statistics*. February 13, 2014. p. 18.

[15] This is proposed to change with the possible Nova Scotia Power Maritime Link Project which would connect Nova Scotia with Newfoundland and Labrador.

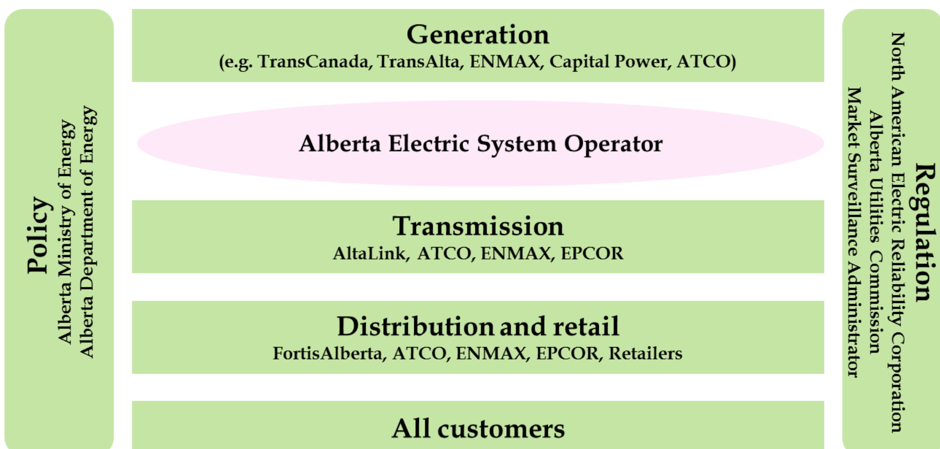
[16] Energy Alberta. *Facts and Statistics.* Accessed: March 7, 2014.

province.[17] By contrast, moreover, the total installed system capacity and peak in Nova Scotia were approximately 18% and 17% of that of Alberta in 2012. Total electrical demand in Nova Scotia was approximately 13% of that of Alberta in 2012.[18] There are almost 1 million residents in Nova Scotia and just over 4 million residents in Alberta.

2.2 Alberta institutional and legal framework

Institutional entities with jurisdiction in the Alberta power market include the Alberta Ministry of Energy ("AMOE"), the Alberta Utilities Commission ("AUC"), the AESO, the North American Electric Reliability Corporation ("NERC") and Alberta's regional NERC affiliate, WECC. Figure 9 provides an overview of the electricity market structure in Alberta.

Figure 9. Overview of the electricity market structure in Alberta



2.2.1 Regulation and policy setting

The Alberta Department of Energy ("ADOE") is the main branch of the AMOE[19] and serves as the Ministry's policymaking arm. Its stated objective is to "optimize the sustained contribution from Alberta's energy and mineral resources in the interests of Albertans." The ADOE has three primary divisions – Gas & Electricity, Mineral Development, and Oil Development.

The ADOE's role in the power sector is to develop a framework for the electricity sector and to ensure its continued effectiveness. This effectively means ensuring that consumers enjoy the

[17] Martillac Limited and Thompson & Associates. *Atlantic Energy Gateway Report on Regional Electricity System Operations*. March 30, 2012 p. 11.

[18] Nova Scotia Power. *10 Year System Outlook: 2013-2022 Report*. July 2, 2013 and AESO *2013 Annual Market Statistics.* February 13, 2014.

[19] The Ministry of Energy consists of the ADOE, the Alberta Energy Regulator ("AER"), the AUC (Section 2.2.4), the Alberta Petroleum Marketing Commission ("APMC") and the Post-Closure Stewardship Fund.

benefits of a secure, reliable, and competitively priced power. The ADOE sets policy for both the wholesale and the retail markets.

2.2.2 Administration of the electricity system

Primary entities responsible for the administration of the Alberta power market include the Alberta Electric System Operator ("AESO"), the Balancing Pool ("BP"), and the Watt-Exchange Limited ("Watt-Ex"). The **AESO** is an independent not-for-profit corporation mandated to operate the provincial transmission system. The AESO administers the hourly wholesale market, oversees the development of new transmission new facilities, develops and administers transmission tariffs, and acquires the ancillary services needed to ensure system reliability.

The Balancing Pool ("BP"), independent of the AESO organization since 2003, is unique to the Alberta electricity structure. The BP serves two essential functions in the Alberta marketplace. First, it serves as the institutional backstop to power purchasing arrangements ("PPA") between incumbent generators and PPA buyers. This facilitates arrangements intended to reduce electricity market power in Alberta. These contract-like instruments serve as a form of fixed for variable swap whereby plant owners receive a predictable revenue stream tied to plant availability, while buyers take on the risks and benefits of trading in the wholesale market.

Second, the BP manages customer benefits from the transition to wholesale electricity market competition in Alberta. These benefits arose from the increase in value of selected generation assets relative to their book value as a result of the establishment of a competitive wholesale market for electricity. This value was crystallized though the sale of the PPAs. Proceeds of the sale were retained by the BP to distribute to customers over time, and to cover any residual obligations of the BP (such as site reclamation costs) under the PPAs.

Because some of the PPAs failed to sell at auction, the BP has also assumed the role of default buyer. Presently, the BP serves as the counterparty for the Genesee PPA. In addition, to further ameliorate potential market power issues, the BP was designated as the financial counterparty for a number of hydro stations which collectively provide a large proportion of Alberta's ancillary services. In total, the BP has approximately $2.5 billion in assets on its balance sheet or approximately $610 per Alberta resident.[20] For more information on PPAs see Section 2.3.3.

The legislative foundation for the BP can be found in Part 4 of the EUA. The EUA provides limited guidance for BP operations. In Section 83 of the EUA regarding BP investments, the BP is held to a "prudent investment standard", defined as the standard "a reasonably prudent person would apply to investments made on behalf of another person with whom there exists a fiduciary relationship to make such investments *without undue risk or impairment and with a reasonable expectation of fair return or appreciation*." [emphasis added] Section 85 of the EUA elaborates further on BP duties, including that it "manage generation assets in a commercial manner"; that it sell generation assets when a "competitive sale" results in "fair market value";

[20] Balancing Pool. *2013 Annual Report*. April 4, 2014. p. 8.

and that it "manage risks prudently." Section 86 mandates the BP to be "responsible and efficient."

The third institution responsible for Alberta power market administration is Watt-Ex which independently operates an exchange for energy derivative products in Alberta. Watt-Ex offers trading in forward contracts based on the Alberta energy market, both for physical and financial delivery. Watt-Ex also operates markets for energy swaps and ancillary services in Alberta.

2.2.3 Monitoring arrangements

Monitoring arrangements in Alberta are differentiated into competition and reliability monitoring. Competition in the Alberta power market is typically monitored at the provincial level through the Market Surveillance Administrator ("MSA"), while reliability is the jurisdiction of both NERC, at the international level, and the AESO, at the provincial level.

2.2.3.1 Competition

At the provincial level, the MSA is tasked with assuring that transactions through the Pool are efficient and equitable, and that the objective of free and fair competition is being met. Additionally, the MSA has oversight responsibilities regarding affiliate relationships, imports, and exports. The MSA has a broad set of investigative powers, including the right to enter premises and to compel divulgence of information. The MSA does not impose sanctions or penalties directly - it acts by making recommendations for remedies to other parties, most notably the AEUB. In the most extreme cases, the MSA can request that the AUC empanel a tribunal which has the authority to impose administrative fines of up to Cdn. $100,000 per day. Beyond its forensic investigative role, the MSA has a mandate to monitor the market more generally, and to make recommendations to participants with a view to eliminating potential market issues before they become problems.

2.2.3.2 Reliability

Alberta energy market participants must comply with NERC mandatory reliability standards via WECC. Through WECC and via the AESO's regional affiliation in the Northwest Power Pool ("NPP"), the AESO conducts coordinated reliability planning, including emergency reliability protocol, transmission planning, and regional resource adequacy, consistent with its role as the province's reliability coordinator. As a consequence for failure to comply with NERC reliability standards, Alberta market participants are subject to possible fines from the AESO.

On the generation side, the role of WECC (as NERC's regional affiliate and often via the AESO) is primarily monitoring and oversight of mandatory reliability standards. This is the same role played by the Northeast Power Coordinating Council in Nova Scotia, for example. Logistically, this often means reporting performance data. Examples of generation performance data include forced outage rates ("FOR") and energy availability factors ("EAF").

On the wires side, transmission owners must provide data relating to transmission operations and planning, facilities design, connections and maintenance, and communication as a preventative measure to ensure reliability. Similarly, NERC, via WECC, monitors the reliability efforts of Alberta's distribution entities.

To plan for future reliability needs, Alberta has also developed additional transmission regulations ("T-Reg"), to which the wires sector is subject. The EUA requires the AESO to assess current and future needs of market participants. Therefore, the government of Alberta has drafted T-Regs which require the AESO to make assumptions regarding expected load growth as well as the location and timing of future generation additions.[21] In so doing, the AESO is expected to make available the information needed to plan and address future transmission needs with the minimum criteria of ensuring that in-merit energy can access the market 100% of the time under normal operating conditions and 95% of the time under abnormal conditions (see Section 2.6 for the implications of T-Reg).[22]

2.2.4 Regulatory oversight of charges

Regulatory oversight of the Alberta power market resides primarily with the AUC, which was formed in 2008 following the split of the Alberta Energy and Utilities Board ("AEUB") into the AUC and the Alberta Energy Regulator ("AER"). The AEUB divided its roles between the AER, which regulates oil and gas exploration and production ("E&P"), and the AUC, which regulates the downstream energy market involving power markets and gas distribution.[23] The AUC is an independent quasi-judicial agency regulating investor-owned natural gas, electric and water utilities and certain municipally owned electric utilities "to ensure that customers receive safe and reliable service at just and reasonable rates."[24] The responsibilities of the AUC include:

- setting transmission and distribution rates;
- regulating transmission additions;
- issuing environmental and siting approval for new generation projects;
- fulfilling an adjudicative role investigating and ruling on regulated rate disputes between regulated utilities, over AUC decisions and orders, over AESO rules and over the rules issued by other Alberta energy market entities;

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21 Transmission Regulation s.8(a) and (b)

22 AESO. *Guide to Understanding Alberta's Electricity Market*. Accessed: April 30, 2014. <http://www.aeso.ca/29864.html>

23 The AUC derives its legal status from the Alberta Utilities Commission Act of 2007.

24 AUC. *Who Are We*. Accessed: April 29, 2014. <http://www.auc.ab.ca/about-the-auc/who-we-are/Pages/default.aspx >

- the establishment of mandatory, baseline quality of service standards pursuant to the Electric Utilities Act Rule 003 which delineates electric distribution performance standards;[25] and
- the regulation of competitive retail rates;

Of these, one of the most important responsibilities of the AUC is ruling on rate changes proposed by regulated electric transmission owners or distributors. Rate applications often include two phases. The first phase calculates utility revenue requirements to determine what constitutes a fair rate of return. The second phase determines how much revenue should be recovered from each rate class as well as reviewing terms and conditions of service. Since 2009 for ENMAX and 2013 for the rest of the distribution sector, the AUC has also been responsible for approving the PBR regimes applicable to the Alberta distribution sector. Figure 10 presents a list of utilities regulated by the AUC.

Figure 10. Businesses regulated by the AUC

Company	Ownership type	Distribution activities	Transmission activities
AltaLink	Investor-owned		X
ATCO Electric Ltd.	Investor-owned	X	X
FortisAlberta Inc.	Investor-owned	X	
ENMAX Power Corp.	Municipally-owned	X	X
EPCOR Inc.	Municipally-owned	X	X

Source: AUC. ("Who We Regulate." Accessed: April 29, 2014. <http://www.auc.ab.ca/about-the-auc/who-we-regulate/Pages/default.aspx>)

The majority of rate applications before the AUC are approved during the course of oral public hearings. The exceptions are those handled in a written process or in a negotiated settlement. Hearings are a quasi-judicial process, can take approximately 33 months, and typically adhere to the following steps:

- receipt of application;
- issuance of a public notice of hearing;
- interrogatories to applicant;
- intervener evidence;

[25] AUC. *AUC Information*. Accessed: April 29, 2014. <http://www.auc.ab.ca/about-the-auc/auc-information/Documents/AUC_Information/AUC_information_electricityAndtheAUC_02.pdf >

- interrogatories to interveners;
- possible rebuttal evidence;
- hearing; and
- argument and reply (usually written).

Figure 11. Key components of the PBR in Alberta

PBR components in Alberta			
PBR Component	ENMAX (First PBR)	Other electricity utilities	Other gas utilities
Form	Distribution -Price cap with going-in rates adjusted annually by I-X +/- other adjustments (Y, and Z factors) Transmission - Revenue cap with going-in rates adjusted annually by I-X +/- other adjustments (Y, and Z factors)	Price cap with going-in rates adjusted annually by I-X +/- other adjustments (K, Y, and Z factors)	Revenue per customer cap, adjusted annually by I-X +/- other adjustments (K, Y, and Z factors)
Going-in rates	Approved rates for 2006 with adjustments to include previously disallowed short term incentive plan costs	Approved rates for 2012 with adjustments that are in the nature of a correction to the going-in rates, and which are not rate adjustments made after-the-fact to reflect actual results will be considered	
Term	7 years (commencing 2014)	5 years (commencing 2013)	
I factor	50% of Alberta average hourly earnings index + 50% of Canada-wide Electric Utility Construction Price Index	55% of Alberta average weekly earnings index (from July of the prior year to June of the current year) + 45% of Alberta consumer price index (from July of the prior year to June of the current year)	
X factor	X= 1.2% (where 0.8% is the X factor and 0.4% is the stretch factor)	X = 1.16% (where 0.96% is the X factor and 0.2% is the stretch factor)	
K factor	"Distribution - None. Capex using revenues generated by the formula. Municipal rate rider is an option.Transmission - Annual G factor"	Based on forecasted capital expenditures subject to annual review and true-up; Capital trackers would be a means of addressing capital outside of the I-X mechanism	
Y factor	For recurring expenses outside of management's control		
Z factor	For recovery of extraordinary, one-off events outside of management control		
ESM	Asymmetrical mechanism: under-earnings are 100% borne by ENMAX; earnings above the deadband are shared 50/50 with customers. Deadband is equal to 100 basis points above the approved ROE	None	
Service quality	$2 million at risk for the performance penalties. No rewards for exceeding performance	Utilities are required to maintain their current levels of service quality throughout the PBR term and to continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties	
Offramps/ Reopeners	The following events would generally require a re-opening: if circumstances changed in a substantial or unforeseen manner; changes in regulatory status; changes to ENMAX's controlling ownership; or a misrepresentation by ENMAX	Commission to consider together the proposals made by parties for events that would result in either a re-opener or an off-ramp. Re-opening of the PBR plans is not automatic. Any re-opening of a PBR plan must be on application to the Commission	

Source: AUC Decision 2012-237 and AUC Decision 2009-035

In its 2009 approval of ENMAX's FBR application, two separate FBR regimes were adopted for distribution and transmission. Electric distribution is regulated under a price cap, while ENMAX's transmission business and gas utilities are regulated under a revenue cap. According to the AUC, this is justified by the difference in commercial arrangements to which distribution and transmission entities are subject to. Under a price cap regime, distribution revenues are allowed to increase with new customers and growth in demand from existing customers. The additional revenue provides additional funding for the increased capital and operating costs of serving new customers and additional load. On the other hand, ENMAX's transmission business deals with only one client, the AESO, and its revenues are not linked to a specifically measurable output.

The Alberta's PBR mechanism has several features relating to the I-factor, the X-factor, the treatment of capital expenditures, and the earnings sharing mechanism ("ESM"). The 2013 I-factor uses a blend of the Alberta consumer price index and Alberta's average weekly earnings index, while ENMAX's I-factor uses Alberta weekly earnings and Canada wide inflation index. ENMAX has an X-factor of 1.2%, while the others have an X-factor of 1.16%.

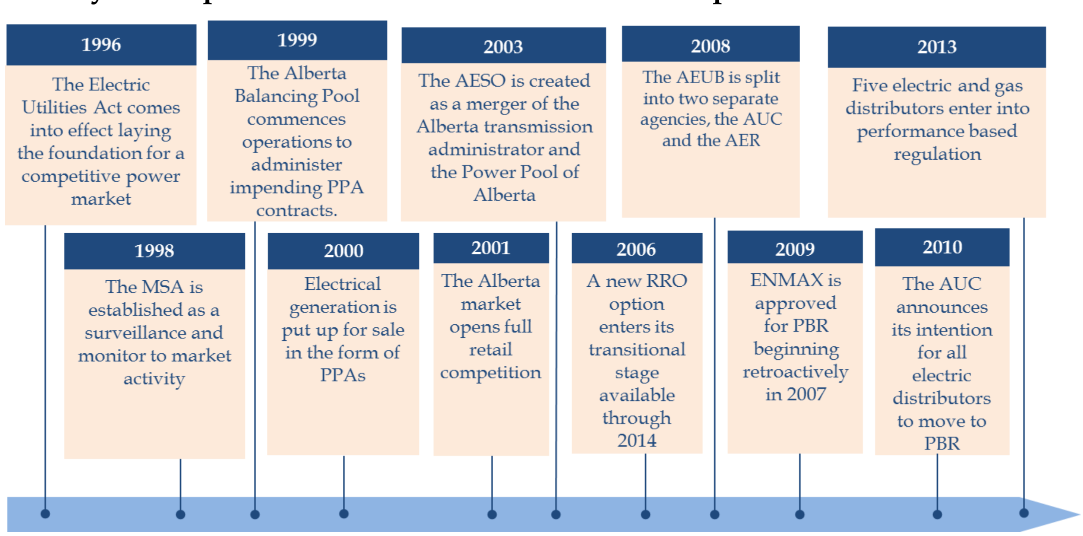
To ensure capex funding, the 2013 PBRs use "capital trackers" as a means of addressing capital expenditure ("capex") outside the I-X mechanism. For a capital investment to be qualified as a capital tracker, it has to meet **all** the criteria set by AUC:

- the project must be **outside of the normal course** of the company's ongoing operations to avoid double-counting;
- ordinarily, the project must be for **replacement** of existing capital assets or undertaking the project must be **required by an external party**; and
- the project must have a **material effect** on the company's finances. In addition, electric distributors are granted a target Y-factor comprised of flow-through to ratepayer items.

2.3 History of restructuring and recent developments

Alberta's electrical system evolved over time into a system of vertically integrated investor and municipally owned utilities controlling service territories and eventually to its current status as a competitive, energy-only wholesale electricity market. Figure 12 summarizes this transition.

Figure 12. Key developments in the evolution of the Alberta power market



Source: ADOE

2.3.1 Pre-1996 cost of service regulation

From the 1970s to the 1990s, Alberta's power system was controlled primarily by three vertically integrated utilities which controlled approximately 90% of the province's generation capacity.[26] Two of these utilities were privately owned, while the third was owned by the city of Edmonton.[27] Together, these vertically integrated utilities ran the power system as an integrated whole with individual utilities assuming the role of system controller in their territories. Since different utilities controlled different geographic territories in Alberta, price differences began to develop between different geographic regions with some geographic territories paying considerably more for power. To address regional price disparities, the government of Alberta created the Electric Energy Marketing Agency ("EEMA") in 1982. EEMA was responsible for pooling the wholesale cost of electricity and averaging generation and transmission costs across the province and thus equalizing rates by consumer class.[28]

The practice of equalizing prices across the province continues today in that unlike many other competitive power markets (but similar to Ontario), Alberta does not have locational prices. In the event of congestion, either additional must run payments are made or certain generators are prevented from running, thus increasing the system wide price relative to what it otherwise would have been.[29]

In 1993, responding to arguments advanced by utilities and independent power producers that the structure of the power market provided a disincentive to improve costs, the AMOE directed the ADOE to develop a new structure for the Alberta power market. To accomplish this, the ADOE established a multi-stakeholder committee to examine potential power market structures. Eventually, the recommendation was a market modeled after the UK and Australian markets with bid-offer power pools. While the ADOE agreed that transmission and distribution should remain regulated and that new generation should be deregulated, an issue was the treatment of existing, regulated generation and who should capture stranded benefits. Consumer advocates argued that some stranded benefits should flow to consumers, while utilities argued that residual values should reside with plant owners, see Sections 2.3.2 and 2.5.[30]

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[26] The two investor-owned utilities were Alberta Power (part of the ATCO Group and hereafter referred to as ATCO) and TransAlta. The major municipally owned supplier was Edmonton Power (hereafter, EPCOR). Of these three TransAlta was the largest with over 50% of the provincial power supply. For more information see: Daniel, Terry, Doucet, Joseph and Plourde, Andre, El*ectricity Industry Restructuring: The Alberta Experience*. May 2001. pp. 4-5.

[27] Hrab, Roy and Trebilcock. Michael J. *Electricity Restructuring: A Comparative Review*. March 2004. p. 52.

[28] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. pp. 219–220.

[29] Market Surveillance Agency. *2012 State of the Market Report: Alberta Wholesale Market*. August 30, 2012. p. 2.

[30] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. p. 221.

2.3.2 Implementation of the Electric Utilities Act

The legislative jurisdiction for the current deregulated power market is derived from the *Electric Utilities Act ("EUA")*, passed in 1995 and implemented in 1996. The legislation laid the foundation for the current market structure. As part of the legislation, a competitive power pool was created and referred to as the Alberta Power Pool. The Alberta Power Pool established an energy spot market and coordinates the operation of the province's separately owned transmission systems.

The legislation required vertically integrated utilities to unbundle into separate operating entities. The transmission, distribution and retail sale of electricity remained regulated by the AEUB (later split into the AER and AUC, see Section 2.2.4), initially under traditional COS regulation. New generation was deregulated. For existing generation, a system of legislated hedges was mandated by the EUA. The intention of the legislated hedges was to ensure shareholders were able to recover the costs of their investments while ensuring that consumers did not have to pay higher prices for electricity generated from existing plants.[31]

The hedges worked by forcing Alberta's distributors to pay generators a regulated monthly fee to cover the generators' fixed costs. In addition, generators received the market price for the power provided into the Alberta Power Pool. If this price was greater than the generators' average operating costs, as estimated by the regulator, the surplus was returned by the generators to the Power Pool Administrator who distributed the surplus back to the distributors.[32]

The result of this system of mandatory hedges was twofold. First, the price that distributors (and thus Alberta consumers) paid for power closely tracked a generator's power production costs. At the same time, generators recovered both their fixed and variable costs and did not face the risk of stranded investment in the facilities they had built.[33] Secondly, on a system-wide basis, the effect of legislated hedges was to set the price for 85% of the generation traded in the power pool. When combined with a lack of financial markets in forwards and options contracts, Alberta's system of mandatory hedging suppressed prices and led to poor price discovery.[34]

In 1997, one year into the deregulation of the Alberta electricity market, the ADOE began to register concern with the system of legislated hedges. Specifically, the system of hedges was recognized to be skewing the market and contrary to the province's original purpose for

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31 Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta September 2012. p. 220.

32 Ibid.

33 Ibid.

34 Chi-Keung Woo, D. Lloyd, and A. Tishler. "Electricity Market Reform Failures: UK, Norway, Alberta and California," *Energy Policy*, No. 31. Elsevier. 2003 p. 1110.

drafting the EUA. In effect, the price for most generation had remained regulated and markets were not providing appropriate incentives to build new generation.[35]

2.3.3 Power Purchasing Arrangements ("PPAs")

In 1998, the government of Alberta amended the EUA to establish the BP to administer the Alberta power pool's impending sale of PPAs.[36] The purpose of the PPAs was to stimulate competition and further develop an open power market in Alberta. Of additional benefit was that the PPAs resolved the question of who would retain the residual value of regulated generation in a deregulated market by guaranteeing existing generators cost recovery, while granting to consumers the excess value created by the PPAs (the PPA price paid which at times was negative) which they had a right to expect in a deregulated market.[37]

Alberta PPA details

Alberta PPAs typically include the following:

- **O&M payments are made monthly**. The PPAs contain provisions regarding maintenance planning, but final decisions on plant maintenance remains with the owner.
- **Availability Incentive Payments ("AIP") are made to plant owners**. PPAs set availability factor ("AF") targets. Payments are made to the plant owner (or PPA owner) when AF performance is either above (or below) the target. AF performance is based on a thirty day rolling average and divided between peak and off peak hours.
- **Plant owners maintain operational control of the assets**. Thus, plant owners also bear operational risk. Force majeure provisions apply to both PPA counterparties.
- **"Excess energy" or any plant's capacity in excess of the "Committed Capacity" remains with the owner**.[1] Initially, these values were small, but with plant uprates, "excess energy values" have grown. Typically, the "excess energy" offer right is combined with the offer decision of the PPA buyer.*
- **Assets revert to plant owner control at the end of the PPA period**. Typically, this date is 2020. At this time, many plants are expected to still have considerable asset life. This will have an effect on Alberta power market dynamics. For more information on the expiration of PPAs, see Section 2.4.2.[1]

*Note: Committed Capacity is the capacity listed in the PPA under offer control of the PPA buyer.
Source: Market Surveillance Agency. *2012 State of the Market Report*: *Alberta Wholesale Mark*et. August 30, 2012. p. 5.

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[35] Government of Alberta. Minister of Energy. *Power to the People: Report Summary: Retail Market Review Committee*. September 2012. p. 221.

[36] As noted in Section 2.2.2, the BP receives its jurisdiction from the Electric Utilities Act, which was created in 1998 and received independence from the AESO in 2003.

[37] AUC. *Alberta's Energy Market*. Accessed: April 19, 2014. <http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx#energymarket>

PPAs and the BP are the mechanisms to accomplish these goals. The PPAs are mechanisms by which the physical power output from the previously regulated coal and gas-fired generation is auctioned off for sale in Alberta's now competitive market. The result was virtual divestiture in which plant owners retain ownership of the plant and are ensured cost recovery, but are not allowed to bid into the competitive power market. That right is purchased by the PPA owner. As such, it is the right of the PPA owner to determine the amount of energy to bid into energy markets.[38] For hydro assets, all controlled by TransAlta, PPAs were considered financial PPAs so the right to make an offer decision was retained by TransAlta.[39]

In 1999, the BP commenced operations and in 2000 conducted thermal auctions. Each PPA was offered in its entirety without breaking up the capacity into smaller strips. Major generation owners placing assets up for auction included ATCO, TransAlta and EPCOR. Of the thermal plants originally auctioned in August 2000, three plants (Cover Bar, Genesee and Sheerness were unsold, so control of plant production reverted to the BP.

Subsequent Market Achievement Plans ("MAP") were developed using financial swap contracts to transfer the energy market exposure incurred by the BP by taking on the three unsold PPAs, beginning in December 2000 with MAP I. Contracts for shorter durations (primarily for one year but also two and three year contracts) were made available. Contracts were also offered in smaller 2 MW blocks. As a consequence of MAP I and later MAPs II and III, the BP was able to eventually sell the Sheerness capacity in its entirety to TransCanada and terminated the Clover Bar PPA. As of 2013, the Genesee PPA was the only PPA remaining under the control of the BP.[40]

Proceeds from the auctions are being returned to Alberta customers. Generating plants before the 1996 EUA were built "with support from the power rates customers paid under the regulated system. As such, customers had a claim on some of the value of these plants." Proceeds from the PPA auctions allocated to customers were compensation for the rates paid by customers before 1996.[41]

2.3.4 Regulated Rate Option

In 2001, the Alberta power market opened to full retail competition. Regulated electric transmission and distribution companies are required to make their systems available to

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[38] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. p. 221.

[39] Market Surveillance Agency. *2012 State of the Market Report: Alberta Wholesale Market*. August 30, 2012. p. 4.

[40] Ibid.

[41] Cooper, David J. and Taft, Kevin. *Change and Opportunity: EPCOR in a De-regulated electricity environment*. Parkland Institute. 2000. p. 12

retailers on a non-discriminatory basis. The result was that Albertans were given the option to purchase power from electric retailers. In addition, for those who decided not to choose an electric retailer, the AUC made available transitional regulated rate plans. The transitional regulated rate plans were designed to be available for a defined period of time of usually three years for small industrial and business customers and five years for residential and farm customers. These transitional rates were set via energy price-setting plans which were the result of negotiations between consumer groups and rate providers and approved by the AUC. Included in the long terms rates, typically, were hedges to protect customers from price variability. However, the plans also had the effect of stifling competitive retail market development.[42]

Recognizing that the transitional regulated rate plan option was scheduled to end in 2003 and 2005, the ADOE convened the Wholesale Market Policy Taskforce in 2004 to conduct stakeholder consultations to review Alberta's competitive market and, in part, to assess the potential for establishing a permanent regulated rate option ("RRO"). Following over a year of consultations, in 2005, the ADOE released a policy framework outlining the new extended RRO to be available through 2014.[43]

Beginning in 2006, the RRO was gradually phased into the Alberta power market over the course of over four years ending in June 2010. During this 2006-2010 implementation period, one-month forward hedges replaced long-term hedges for a growing portion of the RRO supply. Consumers gradually became exposed to month-to-month price fluctuations. Following the implementation period, all RRO options were based on one-month forward hedges. The result is that Alberta now has two separate retail pricing programs: default supply service[44] and RRO.[45] The RRO program is open to residential, small commercial, lighting, farm, irrigation and oil and gas customers with demand not exceeding 75 kW. The second option, the default supply service, is open to all customers with the rates based on the actual market prices in the Alberta Pool.

2.3.5 Regulatory reform

Before 2003, the Alberta market was structured such that there was a Transmission Administrator ("TA")[46] and the Alberta Power Pool which was comprised of the system

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[42] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. p. 222

[43] Ibid. p. 223

[44] EPCOR. *Default Supply Tariff*. Accessed: April 30, 2014. <http://www.epcor.com/power/rates-tariffs/TermsConditionsService/Terms Conditions-DefaultSupplyCustomers.pdf>

[45] EPCOR. *Regulated Rate Tariff*. Accessed. April, 30, 2014. <http://www.epcor.com/power/rates-tariffs/RegulatedRateTarrifsFortis/Regul atedRateTariff-2014-04.pdf>

[46] The Alberta Transmission Administrator was created in 1996 as part of the EUA.

controller, the MSA and the BP. Beginning in 2003, the Alberta power market entered into a period of regulatory change. Principally, the AESO was founded as a merger of the Alberta Transmission Administrator and the Power Pool of Alberta to be an independent system operator of the Alberta Interconnected Electric System ("AIES"). The result is that the Alberta electricity market is structured with three principal entities, the BP, the MSA and the AESO, which is comprised of the TA and the system controller as shown in Figure 13.[47]

Among the regulatory changes were modifications to the market rules, changes to the legal status of current market participants and the addition of new market participants. The changes to the market rules in 2003 consisted of the enactment of the following ADOE regulations:

- The **Code of Conduct Regulation** clarified the expected behavior of distributors and their associated retailers;

- The **Distribution Tariff Regulation** finalized the process by which distribution rates were to be approved and set;

- The **Roles, Relationships and Responsibilities Regulation** detailed the mutual obligations owed between default suppliers, distribution owners, and customers; and

- The **Tariff Billing Code (Rule 004)** came into effect later in 2006. The new code standardized the format by which electric distribution owners provided billing information to retailers for pass through to consumers.[48]

Other regulatory changes occurring in 2003 included the changing of the EUA included the separation of the BP from the Power Pool making the BP an independent entity. Additionally, the government of Alberta established the Office of the Utilities Consumer Advocate. This new entity operates under the Ministry of Service Alberta.[49]

Later, in 2008, the AUC was created following the split of the responsibility of the AEUB into separate regulatory entities, the AUC and AER, see Sections 2.2.4 and 2.2.3.[50]

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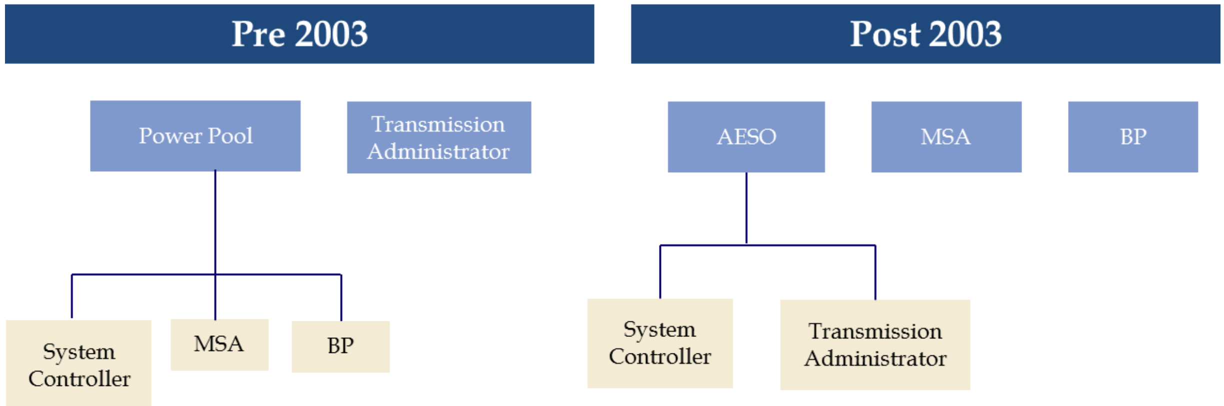
[47] AESO. *Guide to Understanding Alberta's Electricity Market*. Web. Accessed: April 30, 2014. <http://www.aeso.ca/29864.html>

[48] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. p. 223.

[49] Ibid.

[50] Ibid.

Figure 13. Evolution of the Alberta market structure (before and after 2003)



2.3.6 Performance based-ratemaking

Beginning in 2009, the AUC approved ENMAX's proposal to be regulated under a PBR framework. ENMAX's formula-based ratemaking ("FBR") plan was approved by the AUC on March 25, 2009, retroactively effective starting 2007.[51] It was considered to be a first step by the AUC as a critical input for determining a new regulatory regime which would be applied more widely to the electricity and gas sectors.[52]

Following the approval of ENMAX's FBR plan, on February 25, 2010, the AUC announced the commencement of its first stage of PBR regulation applicable for the electric and gas distributors. The case to approve ENMAX's FBR application lasted almost two years. The application was filed on May 11, 2007 and the approval decision was issued on March 25, 2009. The AUC's move towards a PBR ratemaking regime stemmed from criticism of the existing COS regulation, which was seen as "increasingly cumbersome."[53] With the completion of the ENMAX FBR application, the AUC came to further favor a PBR regime judging that it would be effective in achieving the two following objectives: (i) creating incentives for regulated utilities to become more efficient while ensuring gains from improved efficiency are shared with

[51] AUC. Decision 2009-035, *ENMAX Power Corporation 2007-2016 Formula Based Ratemaking*. March 25, 2009.

[52] The Commission will use the PBR plan approved for ENMAX in Decision 2009-035 as the model to be employed for adjusting the distribution service rates of both the electricity distribution companies and the natural gas distribution companies. [AUC. *Rate Regulation Initiative Round Table. Letter to Interested Parties.* February 26, 2010. p.3.].

[53] "[COS] regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings." [Alberta Utilities Commission (AUC). *Bulletin 2010-20 – Regulated Rate Initiative – PBR Principles.* July 15, 2010]. Also see Grieve Willie. *Address to the Calgary Chamber of Commerce.* Calgary Chamber of Commerce. May 27, 2008.

customers; and (ii) increasing the efficiency of regulatory resources in order to allow the AUC to focus more of its attention on both prices and quality of service important to customers.[54]

In March 2010, the AUC held a roundtable with interested parties to discuss general steps and established principles to which PBR regimes were expected to adhere. The AUC, in consultation with the stakeholders, came up with key principles with respect to which PBR applications should be developed: mimicking competitive pressures, ensuring cost recovery and a fair return for utilities, being administratively easy and transparent, recognizing the unique circumstances of each utility, and leading to shared benefits for customers and utilities.[55]

By September 2010, the AUC hired consultants to conduct total factor productivity ("TFP") studies for the purpose of determining X-factors. By July 2011, companies were required to file PBR proposals. In 2012, PBR applications for five electric and gas distributors were approved[56] and by 2013 PBR plans were installed.[57]

2.3.7 Recent developments

There are a number of current events with the potential to further shape the Alberta power market, including the review of a system of clean energy standards ("CES"), a changing generation fuel base, increasing interconnections with Alberta's neighbors and an ongoing regulatory debate.

2.3.7.1 Clean Energy Standards

Regarding the potential development of clean energy standards, a May 21st, 2013, white paper was issued by the Pembina Institute (the "CES White Paper").[58] As described in the White Paper, key characteristics of the CES would include:

- an emissions intensity standard, set to decline over time;
- a requirement that retailers bear the responsibility to meet the CES;

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54 AUC Rate Regulation Initiative web site: <http://www.auc.ab.ca/items-of-interest/Rate-Regulation-Initiative/Pages/default.aspx>.

55 Accordingly, a PBR regime should (i) mimic the efficiency incentives experienced on a competitive market while maintaining service quality, (ii) provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return, (iii) be easy to understand, implement and administer and should reduce the regulatory burden over time, (iv) recognize the unique circumstances of each regulated company relevant to a PBR design, and (v) lead to shared benefits for customers and regulated utilities. [AUC. *Bulletin 2010-20 – Regulated Rate Initiative – PBR Principles.* July 15, 2010].

56 The five electric and gas distributors approved for PBR in 2012 were AltaGas, ATCO Electric, ATCO Gas, EPCOR and FortisAlberta.

57 AUC Decision 2012-237.

58 Thibault, Ben and Weis, Tim. *Clean Electricity Thought Leader Forum: A Made-in-Alberta Proposal to Green the Grid*. Pembina Institute: Edmonton, Alberta. May 21st, 2013.

- the CES would be technology neutral;
- alternative compliance payments which would be charged to retailers who do not meet the CES through direct purchases; and
- the CES would complement the Specified Gas Emitters Regulation.

The CES White Paper provides little detail about how the CES would be implemented.[59] However, other environmental initiatives include the debate regarding the increase of Alberta's carbon tax on large industrial emitters. Central to the discussion was a hypothetical increase in the greenhouse gas emissions levy to $40/tonne of carbon emissions targeting a 40% emission intensity reduction.[60]

2.3.7.2 Coal to gas switching

As a consequence of Alberta's clean energy standards and greenhouse gas emissions levy, Alberta is preparing for over 800 MW of coal retirements at the Sundance, HR Milner and Batter River plants. Currently, coal-only fired generation makes up approximately half of installed generation capacity. Market planners expect a combination of new wind and natural gas fired generation to replace the retired coal capacity. In particular, the AESO is expecting the completion of ENMAX's 800 MW gas fired Shepard Energy Centre generating station in 2016 and TransCanada's 350 MW gas-fired Saddlebrook Generating Station in 2018.[61]

2.3.7.3 Transmission interconnection developments

In terms of new interconnections, in 2013, the 230kV AC Montana Alberta Tie-Line ("MATL"), which filed for approval for construction with the former Energy and Utilities Board as early as August 22, 2006, was finally brought online. The project now supplies Alberta with up to 300 MW of wind powered generation from Montana and allows Alberta's supplies to flow into the US Northwest. In addition, the implementation in 2011 of the Load Shed Services for imports ("LSSi") increased the maximum import available transfer capability ("ATC") on the BC intertie to 700 MW. This represented an increase of 75 MW over the maximum import ATC in 2011. Lastly, the ATC of the Alberta-Saskatchewan line has not experienced changes since the upgrades completed in 2010. Since then, the Saskatchewan intertie has been operating with maximum import ATC equal to its original design capacity of 153 MW.

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[59] While working papers associated with the Thought Leader's Forum explore a novel regime in which customers would pay an advance deposit for clean energy purchases, with retailers obtaining refunds or paying supplements depending on their performance relative to the CES, this does not appear to have been a consensus proposal endorsed by the entire forum.

[60] Vanderklippe, Nathan. "Alberta's carbon-tax windfall dilemma". *The Globe and Mail.* Web. 9 April 2013. <http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/albertas-carbon-tax-windfall-dilemma/article10959863/>

[61] Commercial Database and *AESO. Long-Term Adequacy Metrics.* August 2013.

2.3.7.4 Bidding Behavior

In an attempt to discuss and define *Fair, Efficient and Open Competition* ("FEOC") standards in relation to market participants, the MSA has developed its Offer Behavior Enforcement Guidelines ("OBEG"). The OBEG are controversial, however, because they clarify that, as long as there is no collusion, generators can use high priced offer strategies to raise power pool prices in order to ensure sufficient generation investment and long term market competitiveness. The implication that high generation bid offers are tolerated has been controversial in Alberta.

Moreover, there are concerns that the OBEG is encroaching into the AUC jurisdiction. In 2011, the MSA drafted the OBEG under jurisdiction of the *Alberta Utilities Commission Act* which "allows the MSA to make guidelines, essentially providing its views to further enunciate analytic principles and meaning given to provisions".[62] As such, the OBEG exist in an attempt to, but in so doing can also appear similar to the role of the AUC. The similarities between the roles of the AUC and the OBEG have also sparked debate.

2.4 Rationale for specific design elements and pros and cons of selected design

Alberta's power market design has evolved over time from a relatively autonomous, provincial system dominated by vertically integrated utilities into a competitive, energy only wholesale market. The purpose of key design elements and LEI's assessment of each design element's pros and cons are summarized in Figure 14.

Figure 14. Summary of selected design elements

Design elements	Rationale	Pros	Cons
Energy only market structure	To focus competition in one market and simplify potential payment options relative to markets with capacity auctions	There are greater revenue earing opportunities and the market structure is simpler	Could disincentivize new entry if long term contracts are not available
PPAs	To foster competition in the generation sector	Increased the number of generation operators in the Alberta market	Control of unsold PPAs has reverted to the BP causing concerns about conflict of interest
RRO	To shield consumers from potential spot market volatility	Helps to create better forward rate certainty for ratepayers	Has the potential to limit the depth and liquidity of the spot market
PBR	To simulate competition in the distribution sector	Can incentivize efficiency possibly leading to increasing profits and lowering rates	Concerns about full and timely funding of necessary capex

2.4.1 Energy-only market structure

By contrast to Alberta's energy only market structure, some US markets – including PJM, CAISO, New York Independent System Operator ("NYISO"), and New England Independent System Operator ("ISO-NE") – operate capacity markets in which generators clearing a capacity auction are granted payments for their existence, provided they are able to run when called

[62] MSA. *Offer Behavior Enforcement Guidelines*. January 14, 2011. p. 7.

upon, as an insurance mechanism ensuring resource adequacy. Since this additional revenue stream does not exist in Alberta, generators are dependent on energy sales in bilateral contracts or in the spot market.

In theory, an energy-only market structure can provide strong incentives for new capacity. With less efficient generators unable to rely on a payment to exist, they must fully compete with new entrants which are often more efficient, use new technology, and have lower heat rates. Moreover, the energy market structure can increase competition relative to a system in which less efficient generators are afforded a payment to exist.

As discussed in the Literature Review, for an energy-only market to be effective, its market structure must allow for energy markets to achieve peak prices which are truly reflective of the value of generation scarcity in times of resource adequacy concern. If a market is unable to reach peak prices, it may not properly incentivize new entrants and may eventually experience shortages. Concerns about not reaching peak prices occur when a price cap is enacted which is set below the value of lost load ("VoLL"). Price caps can potentially be political and create a need for capacity markets if politics demands a price can that is too low. In such cases, a price cap event is likely to occur and capacity markets are needed to capture this "missing-money."

In Alberta, therefore, the concern about an energy-only market is that there will be price-cap events and "missing money" created when energy prices reach the Alberta power market price cap of $1,000/MWh. According to AESO data, the pool price settled at the offer cap during 35 hours in 2013.[63] This was an increase from 2012 and 2011 when the pool price settled at the offer cap in just 6 and 11 hours, respectively[64] and leads to the conclusion that the price cap is set at an appropriate level.[65] However, the price cap has been in place, unchanged since 1996. There could be a time when $1,000/MWh is not adequate to reach peak prices. To the extent that generators are concerned about this and consequently "missing-money," this could begin to affect decisions to build.

2.4.2 PPAs

By auctioning off over 7,000 MW of capacity in 2000 via PPA contracts, market planners introduced competition into the market. Having evolved from a system where several large, vertically integrated utilities controlled most of the generation, the PPAs served as a way to introduce competition in the Alberta generation market. Prior to the auction, market manipulation by generators could have been an issue since much of the capacity was controlled by a few market entities. By separating the control of the plant from the resulting energy, many new market entities were introduced to the market thereby increasing competition.

63 AESO. *2013 Annual Market Statistics.* February 13, 2014. p. 4.

64 AESO. *2012 Annual Market Statistics*. February 2013. p. 5.

65 Aksomitis, Kris, Program Manager, AESO. *Price Cap and Floor in Alberta*. 2011.

Of additional benefit to consumers, the PPAs were able to remunerate consumers the "stranded benefits" associated with lower cost generation built by regulated generators before 1996. At the same time, Alberta market planners were able to remunerate customers while ensuring cost recovery for previously regulated generations built before 1996.[66]

During the 2000 PPA auctions, seven bidders participated. After the auctions, five available generation plants remained unsold. This left the BP in control of four PPAs with an aggregate capacity in excess of 2,000 MW. Since PPAs were offered in their entirety, without breaking down either the term or the capacity on offer, the results of the auction indicated that the sizes of the contracts may have been too large and the terms too long. This resulted in higher perceived risks associated with purchasing some PPAs causing the Genesee, Sheerness and Clover Bar PPAs to remain unsold. Consequently, control of the unsold PPAs reverted to the BP which resulted in concern regarding conflict of interest. The BP exists to administer the PPAs, but following initial PPA auctions also became a market participant with significant market power. This is a unique position for a market administrator. There is a concern among some participants that the BP would be unable to remain a disinterested, neutral third party and that the BP may bid its plants in a way that would suppress prices. To mitigate the BP's market power, a second auction was held that involved the development of "unit" contracts associated with the Clover Bar PPA and "strip" contracts associated with the Genesee and Sheerness PPAs. The "unit" and "strip" contracts effectively created smaller capacity and reduced the BP's participation in the market.

The PPAs are scheduled to expire in 2020, upon which control of the assets would revert back to the asset owner. In many cases, the assets are expected to remain economic past 2020.[67] Among some Alberta power market participants, the is some concern that the asset owners would in fact be able to exercise control in light of potential market concentration after 2020.

2.4.3 RRO

In 2006, a new RRO pricing option was extended through 2014 following the expiration of the similar transitional regulated rate option. For many Albertans, this was an important policy to maintain since they were concerned with the possibility of paying rates based on the potential volatility of the spot power markets. As a consequence, consumers were extended the option of paying a regulated price for their power. The RRO had the additional benefit of transitioning forward hedges to shorter duration one month forward contracts. The transition from longer to shorter duration hedges had the intended effect of ensuring price certainty but acclimating

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[66] Daniel, Terry, Doucet, Joseph and Plourde, Andre, *Electricity Industry Restructuring: The Alberta Experience*. May 2001. p. 11.

[67] Market Surveillance Agency. *2012 State of the Market Report: Alberta Wholesale Market*. August 30, 2012. p. 5.

consumers to more price volatility than would have been the case with longer term hedges. As of 2014, 40% of Albertans had switched their retail provider.[68]

As a consequence, the spot market may not have developed the depth and liquidity which it otherwise would have. Moreover, by choosing the RRO, retail customers may be locking in higher regulated prices for the duration of their load serving entity's month long hedge. According to Alberta's Retail Market Review Committee ("Committee"), the presence and prevalence of the RRO "is a significant impediment to the development of a competitive retail market."[69] Therefore, the Committee recommends that the RRO be replaced with a more limited, "provider of last resort" service available to consumers who have lost electrical service by accident and through no fault of their own.[70] This would have the effect of helping to develop and increase competition in the spot market.

On the generation side, new generation signals are dependent in part on the size of the Alberta spot power market. The less load participating in spot markets, the less likely markets are to experience the scarcity price spikes needed to entice new generation. This could have the effect of de-incentivizing new entrants and in the long run could potentially diminish system reserve margins.

2.4.4 PBR

As mentioned in Section 2.3.6, PBR began in Alberta in 2009 retroactive to 2007. ENMAX's rationales for filing an FBR application were "to (i) streamline regulatory oversight and (ii) provide increased rate predictability to customers and revenue predictability to ENMAX while maintaining safe and reliable service at just and reasonable rates."[71] Then, recognizing the limitations of cost of service approach, the AUC stated its intent to move to PBR. The objectives of the PBR for the electric and gas distribution utilities, as laid out by the AUC, include (i) to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers and (ii) to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.[72]

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[68] Distributed Energy Financial Group. *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS). 2014.

[69] Retail Market Review Committee. *Power for the People*. Report and Recommendations for the Minister of Energy, Government of Alberta. September 2012. p. 2.

[70] Ibid.

[71]. Alberta Utilities Commission. *ENMAX Power Corporation. 2007-2016 Formula Based Ratemaking*. March 25, 2009. p. 3.

[72] Alberta Utilities Commission. *Rate Regulation Initiative. Distribution Performance-based Regulation*. September 12, 2012. P. 3.

Based on the PBR experience, utilities in Alberta have been able to introduce a level of long term price certainty. Since rate plans are seven or five year terms, transmission and distribution rates are clearly delineated in the PBR formula. In addition, there are incentives to reduce costs to consumers. Since all Alberta gas and electric utilities under PBR have X-factors set above 1.15%, consumers should expect to receive power at lower costs than they otherwise would as a consequence of the X-factor. All Alberta PBR's have I-factors set based on relevant and partially local cost drivers including the Alberta average hourly earnings index and Canada's Electric Utility Construction Price Index.

Despite the theoretical benefits of PBR, utilities and industry participants have also raised the following concerns:

- **There were concerns in the industry about the potential disadvantages of using an industry-specific (customized) input-specific inflation index**. Specifically, ENMAX's I-factor makes use of a Canada-wide index tracking utility costs. There are concerns that this does not truly reflect costs in Alberta. Moreover, deflationary pressures were observed in 2009 due to the economic and financial crisis, which particularly affected the input indices used by ENMAX.[73] There is a belief amongst some stakeholders that similar issues will repeatedly arise in the future and increase rate volatility should ENMAX continue to use a Canada wide utility based I-factor. Subsequently, Albertan PBRs only use Alberta based inflation indexes.

- **There are profound concerns around the treatment of capital expenditures ("capex") under a price cap or revenue cap regime.** Although the distribution segment of ENMAX has not encountered serious issues regarding the recovery of its capex needs to date, the absence of an explicit capex component similar to the one included in the transmission revenue cap formula is perceived by some utilities as a substantial additional risk in contrast to traditional COS.[74]

- **ENMAX's regulatory burden has remained higher than expected.** Despite the principle that PBR should reduce regulatory interactions, there remain concerns regarding the amount and detail of information requested by the AUC and interveners in determining the earnings sharing amount. For instance, the AUC has added new auditing requirements as a result of the ESM, to which ENMAX was not subject prior to the FBR. Utilities also expressed concerns that the asymmetrical sharing mechanism may result in interveners being overly suspicious about the possibility that a utility would unfairly

[73] Deflationary pressures in recent years have been evident: (i) in 2009, average hourly earnings decreased by 0.4% in Ontario and only increased by 0.6% in Alberta; and (ii) the Electric Utilities Construction Price Index ("EUCPI") rate change reached 0.5% and 0.6% lows in 2009 for distribution and transmission, respectively. Sources: Statistics Canada. *Average Hourly Earnings for Employees Paid by the Hour*. Table 281-0030. Accessed: May 2, 2014 and Statistics Canada. *Electric Utilities Construction Price Index (EUCPI)*. Table 327-0011 Accessed: May 2, 2014.

[74] AUC Decision 2012-237.

minimize its net income in order to stay within the dead band. The calculation of net income has been an important subject of discussion ever since ENMAX's FBR application. However, there is also a broad recognition of the tangible benefits offered to consumers through an ESM.

- **Restrictive criteria on capital trackers.** Utilities were concerned that although the PBR mechanism provided a capital tracker, the criteria for a capital investment to qualify under the capital tracker treatment is limiting.

- **The approved X factor was too high.** Utilities were concerned that the approved X factor to be used in the PBR formula is so high that it will be difficult for them to meet obligations to customers while earning a commercially reasonable return to support necessary investments. During the PBR application period, several utilities proposed a negative or zero X factor. They believed that their rates need to increase during the PBR term, driven by expected capital spending for the next five years. They also argued that capital investment needs are growing at a much faster pace than inflation and volume growth, in order to maintain service and meet their statutory obligations to provide service.

2.5 Transitional challenges and remedies adopted

As a power market formerly dominated by three vertically integrated utilities under both public and private ownership, Alberta faced a number of transitional challenges while evolving into a competitive market. Among these challenges are: uncertainty regarding the possible treatment of stranded benefits for regulated generation, introducing competition, and determining the appropriate pace of deregulation, see Figure 15.

Figure 15. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Ensuring competition	Auctioned PPA contracts and has simulated competition in the distribution sector using PBR
Treatment of stranded benefits	Created by generation capacity now deregulation but built before 1996, stranded benefits are being returned to ratepayers
Pace of deregulation	Deregulated slowly using legislated hedges to gradually increase competition. Full retail competition was not introduced until five years following the implementation of deregulation

2.5.1 Ensuring adequate competition

Distinct from other jurisdictions including the UK, Alberta did not require divestiture of assets. However, in so doing, it did face the dilemma of ensuring competition in the generation sector. As a system where prior to deregulation, 90% of generation was controlled by three firms under both private and public ownership, ensuring competition was a challenge.

To ensure adequate competition, the Alberta power market took three important steps: (i) it auctioned PPAs to sell off the rights to generation output; (ii) unbundled the transmission, distribution, and generation sectors themselves; and (iii) the unbundling ensured that potential new entrants had the opportunity to access downstream markets on an equal footing as the traditional vertically integrated entities.

Using the PPA structure allowed the AMOE to inject competition into the power market; this has reduced the market concentration of the previously vertically integrated utilities and reduced concern that any single generation entity could exercise market power. Similarly, over time, the use of PPAs has increased the volume of generation that has the price set in the market.[75]

Equally important, the AMOE has organized the downstream value chain in such a way that the power market can benefit from the increased generation competition. For example, the existence of the AESO has ensured that the transmission system provides for the full contestability of all load in the system. There has developed a system of incentives and payments to eliminate transmission constraints which tend to create local market.[76]

PBR mimics competition. Thus, since 2009, Alberta electricity market planners have also been able to use PBR to simulate competition in the distribution sector. Using an (I-X) price cap framework, the AUC has designed incentives for distribution companies to improve productivity and cost performance, while maintaining performance standards. Thus, in lieu of literal competition in the distribution sector, it has designed PBR regulations.

2.5.2 Treatment of stranded benefits

A second challenge experienced during Alberta's transition to a competitive power market was ensuring appropriate remuneration for historically regulated assets. This was particularly challenging on the generation side. Generation had been guaranteed cost recovery plus a rate of return on assets which were paid for by Albertan ratepayers. The regulated generation assets were also the some of the largest, base-load plants best equipped to thrive in a competitive power market. The deregulation created stranded value to which customers argued they were entitled.[77]

To strike the appropriate balance, generation owners were guaranteed cost recovery plus their promised rate of return in the PPAs. However, stranded costs, raised via the sale of PPAs, were returned to ratepayers in an upfront payment and via reductions to rates over time.

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[75] Chi-Keung Woo, D. Lloyd, and A. Tishler. "Electricity Market Reform Failures: UK, Norway, Alberta and California," *Energy Policy*, No. 31. Elsevier. 2003. p. 1110.

[76] Johnsen, T.A., Verna, S.K., Wolfram, C., "Zonal Pricing and Demand-Side Bidding in The Norwegian Electricity Market," *Program on Workable Energy Regulation (POWER)* PWR-063. UC Berkeley, CA. 1999

[77] Government of Alberta. Minister of Energy. *Power to the People: Report Summary: Retail Market Review Committee*. September 2012. p. 5.

2.5.3 Pace of deregulation

Contrary to the experience of Ontario which undertook a "big bang" approach to deregulation, Albertans were concerned about being exposed to market volatility too quickly. Many ratepayers preferred paying a guaranteed, fixed price rather than a potentially volatile price. For smaller generators, there was a concern that they may not maintain financial viability when forced to compete immediately in competitive power markets against the traditionally vertically integrated utilities. Over time, this would undermine the level of competition which Alberta market planners hoped to incent.

The Alberta power market was opened to competition gradually. The AMOE initially legislated a system of financial hedges that covered 85% of generation sold in the power pool. Although units bid into the market and received the pool price, financial hedges ensured that owners received payments to cover fixed costs.[78]

In the retail market, it maintained an option for customers to receive a regulated rate despite opening up the market to full retail competition. In doing so, it both protected consumers from potential market volatility and ensured that load serving entities continued to demand one month forward power contracts from generators. This has further served to protect generation from full and immediate competition and complete reliance on spot energy markets for cost recovery.

2.6 Implications for Nova Scotia

The AMOE has described the benefits of a competitive market as primarily "better services at lower prices." Competition should force markets to be more efficient, cost effective and creative. In the longer run, a competitive power market will provide Albertans with more choices at the lowest possible prices.[79] A number of important lessons have been learned along the way:

- **State the goals of deregulation clearly and from the very beginning**. For the Albertan government, these goals were clear: it wanted to improve efficiency and reduce prices while guaranteeing a fair rate of return and cost recovery. Were Nova Scotia to deregulate, it would be important to consider its own goals upfront also.

- **Create competition in the generation sector**. Evolving from a market previously dominated by a few vertically integrated utilities, gradual, controlled deregulation worked well for Alberta. As a market with a dominant, privately owned vertically-integrated utility, Nova Scotia can learn from the experience of Alberta issuing PPAs for the capacity owned by the dominant players and thus fostering competition.

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[78] Chi-Keung Woo, D. Lloyd, and A. Tishler. "Electricity Market Reform Failures: UK, Norway, Alberta and California," *Energy Policy*, No. 31. Elsevier. 2003. p. 1112.

[79] Government of Alberta. Minister of Energy. *Power to the People: Report Summary: Retail Market Review Committee*. September 2012. p. 5.

- **Move at a gradual pace.** For the generation sector, the slow introduction of competition into the Albertan market could prove an important lesson for the residents of Nova Scotia. Currently, Nova Scotia does allow competition in its wholesale sector, with IPPs owning about 10 percent of generation capacity. There is no retail competition in Nova Scotia, except for sales of renewable power directly to retail customers. There is no spot power market, which could be difficult to create in a small market such as Nova Scotia. On the wires side, planning for future needs occurs gradually and well in advance of potential reliability issues, via the T-regs. However, T-regs can be a source of potential transmission overbuilds.

- **Maintain a regulated price for ratepayers**. Albertans were concerned about power bills being dependent on spot markets. Thus, Alberta introduced the RRO model. Should Nova Scotia choose to create full retail competition, an RRO could be an important method of ensuring Nova Scotia residents maintain an element of predictability in their monthly bills.

Finally, for Nova Scotia, there are important lessons to learn from Alberta in terms of designing an appropriate PBR:

- **The ESM is perceived as a regulatory burden.** Experience with ENMAX's PBR regime has created concern about the regulatory burden required to determine the earnings sharing amount, per the ESM. The amount and detail of information required by both interveners and the AUC can be onerous. The asymmetric nature of the ESM in which all loses is borne by ENMAX, but earnings above the deadband are shared equally with ratepayers has heightened suspicion on ENMAX and potentially increased regulatory burden further. Should Nova Scotia enact PBR, it should consider the potential regulatory burden caused by an ESM and drawbacks of an asymmetric mechanism.

- **The ability to ensure capex recovery in a complete and timely manner remains a concern.** Although distributors in Alberta can recover their capex through capital trackers, the criteria to qualify are very restrictive. For Nova Scotia, it should consider the concerns of the treatment of capital expenditures raised by interveners in Alberta and provide for mechanisms for utilities to recover the capital investments.

- **Productivity factors should be based on rigorous quantitative analysis.** Alberta has set X-factor values based on rigorous TFP analyses studying the experience of other relevant distribution utilities in North America. Should Nova Scotia choose to implement PBR in an (I-X) framework, it should likewise use rigorous TFP analyses to set the X factor.

3 California

California's electricity market is often characterized as a hybrid, designed to balance the best features of a wholesale market with regulation. California's restructuring of its electricity markets has evolved under influence from both of these features, as the state's regulators strive to improve the competitiveness and efficacy of the wholesale electricity market while furthering the state's environmental policy goals. The history of the formation of the California market as it was originally designed, the reasons for the market's collapse, and the details of the proposed new market, all afford an opportunity to gain insight into the various ways market design and implementation can go awry, and how things can be done better.

3.1 Overview of the California market

California's in-state generation capacity produces around 200 terawatt-hours each year which is transported over the state's 32,000 miles of transmission network. Approximately 70% of the electricity needs of California's 38-million-plus residents are met by in-state generation, and the rest is imported from the Pacific Northwest and the U.S. Southwest. In the 1990s, California became a US pioneer in deregulating its electricity market. California's approach relied on unbundling its three major utilities to create new economic entities to provide services to customers. Until 1996, around three-quarters of California was serviced by three major investor-owned utilities ("IOUs"): Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E"). These utilities currently fall under the footprint of the non-profit California Independent System Operator ("CAISO").

CAISO operates day-ahead and real-time energy markets, as well as various ancillary services markets. Currently, the CAISO operates the power grid and administers the wholesale electricity market in approximately 80% of California. The remainder of California is operated by local balancing authorities and utilities, including the Imperial Irrigation District, Western Area Lower Colorado, Los Angeles Department of Water and Power, Balancing Authority of Northern California, Turlock Irrigation District, PacifiCorp-West, and Sierra Pacific Power.[80] Plans to develop an Energy Imbalance Market that will allow CAISO to effectively dispatch generation from sources located in balancing authority areas outside of its footprint are currently underway and are discussed in more detail in Section 3.4.5 below.

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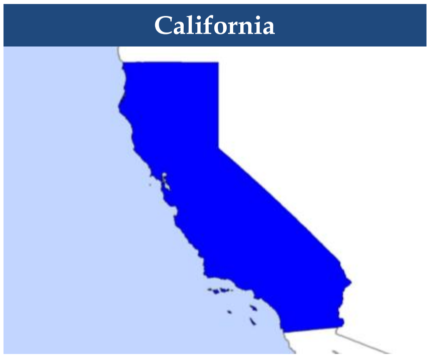
[80] California Energy Commission. "Map of Balancing Authority Areas in California." November 22, 2013. <http://www.energy.ca.gov/maps/serviceareas/balancing_authority.html>. Note: The Sacramento Municipal Utility District joined the Balancing Authority of Northern California, Valley Electric Association joined the CAISO, and Bonneville Power Administration is now included under the PacifiCorp-West balancing area.

Figure 16. California snapshot



Key facts	
Population (2013)	38.3 million
GDP growth (2012)	3.5%
Installed capacity (2013)	78,133 MW
Peak demand (2013)	75,503 MW
Generation (2012)	228,024 GWh
Load Growth (CAGR: 2009-13)	-0.10%

Source: Third party commercial database, California Energy Commission, LEI analysis

Figure 17. Installed capacity (2013) and generation (2012) by technology type

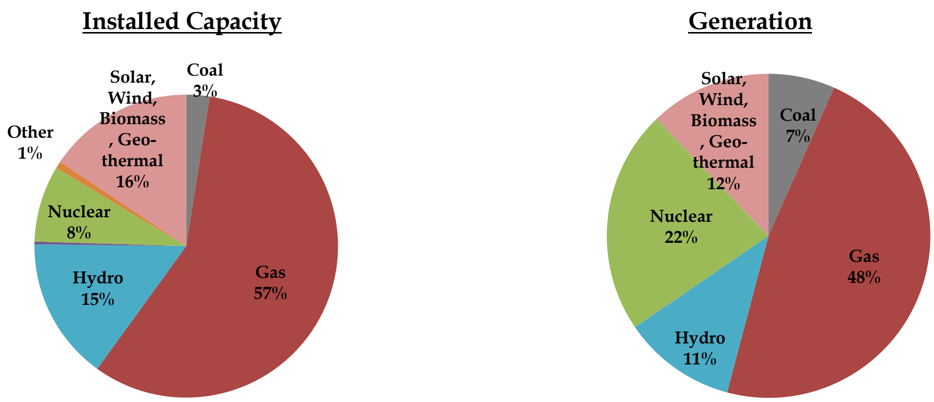
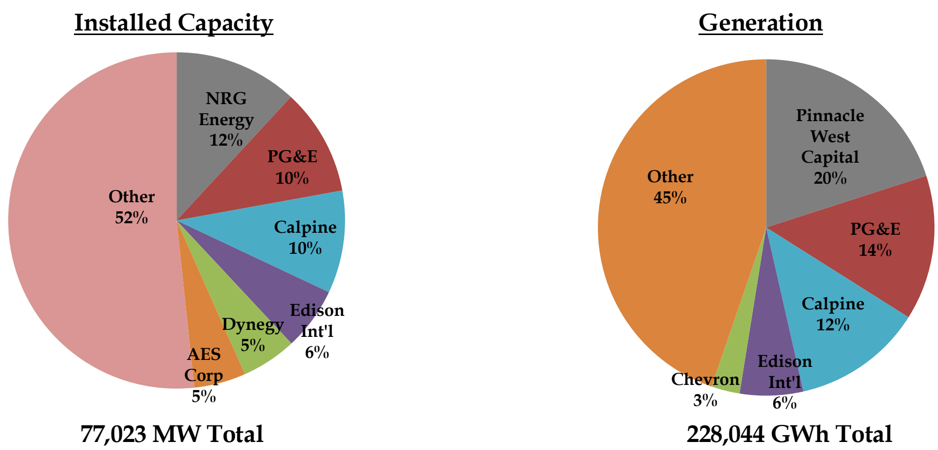


Figure 18. Installed capacity (2013) and generation (2012) by holding company



Source: Third party database provider. 2013 generation data not complete as of the report filing date.

As can be observed from Figure 17 (which includes remote generation), California is dominated by natural gas fired facilities, representing 57% of installed capacity. Hydroelectric generation capacity represents 15%, nuclear represents 8%, and renewables (including wind, geothermal, solar and biomass) represent around 16% of capacity.[81] California is highly reliant on import capacity, in particular from Arizona and the Pacific Northwest. Top holding companies include NRG Energy Inc., PG&E, and Calpine Inc. in terms of capacity owned, and Pinnacle West Capital,[82] PG&E, and Calpine Inc. in terms of actual electricity production.

California's resource mix has special bearing on market design efforts in the state. California's reliance on naturally variable hydro generation can be expected to increase spot price volatility. The market is also heavily dependent on natural gas-fired generation, with much of the gas supplied over relatively few pipelines entering from external markets.

California is significantly different from Nova Scotia in many respects. California's population of more than 38 million is thirty-eight times larger than that of Nova Scotia. Additionally, given that the state's economy is many times larger than most countries, California has substantially different electricity demand dynamics. California is also very well-interconnected to several regional electricity markets, most relevantly the Pacific Northwest and the Southwestern US, from where California imports a significant proportion of its electricity. As an island, Nova Scotia's interconnection with other markets is much more limited. California has also very different climatic conditions compared to Nova Scotia that are likely to play a critical role when evaluating the economic feasibility of certain types of electricity generation sources.

Energy Market:

California, like other electricity markets in the US, has real-time and day-ahead energy markets administered by an Independent System Operator ("ISO"), CAISO. The real-time market is a spot market which issues dispatch instructions every 5 minutes. The real-time market opens at 1:00 p.m. before the trading day and closes 75 minutes before the start of the trading hour, with results published about 45 minutes prior to the start of the trading hour. In contrast, the day-ahead market determines market clearing prices every hour. The market opens seven days prior to the trade date and closes the day before the trade date, with results published each day at 1:00 p.m.[83] Convergence bidding rules encourage markets to schedule power in the day-ahead market to minimize price uncertainty and volatility. CAISO has historically operated with a bid price floor of -$30/MWh, and bid cap $1000/MWh. Starting April 1, 2014, CAISO lowered its energy bid floor to -$150/ MWh which will increase the number of economic real-

[81] On a nameplate basis.

[82] Holding company for the Palo Verde and Four Corners plants that are based outside of California. Electricity from these plants is imported into California and falls under the CAISO footprint.

[83] CAISO website. "Market Processes." Last accessed on: April 29, 2014. <http://www.caiso.com/market/Pages/MarketProcesses.aspx>

time bids by covering the opportunity costs of not producing for many variable energy resources.[84]

Capacity Market:

California differs from other electricity markets in the US in that it does not have a Forward Capacity Market ("FCM") mechanism in place. California has a bilateral spot market for capacity, as part of the Resource Adequacy ("RA") program adopted in 2004 by the California Public Utilities Commission ("CPUC"). Unlike the FCM, the RA program is not regulated by the Federal Energy Regulatory Commission ("FERC"), but instead is administered by the CPUC. Under the RA framework, existing generators can sell their capacity on a month-ahead and year-ahead basis to load serving entities that must then show compliance with the RA program to the CPUC. The system RA requirement uses a 15% planning reserve margin of forecast load, although there are, in addition, local RA requirements in transmission constrained areas. The FERC-approved Capacity Procurement Mechanism ("CPM") allows CAISO to procure capacity if reliability is not achieved through the RA program, or when certain resources are at risk of retirement.

3.2 Institutional and legal framework

Currently, California's electricity system functions through a combination of market and regulatory instruments. California labels its electricity strategy a hybrid market approach, designed to "capture the best features of a vigorous, competitive wholesale market and renewed, positive regulation."[85] Although the state retains regulatory control over utility distribution systems, the FERC regulates the transmission system operations and transmission rates. In addition, the California Governor's office and the state's Legislature have both been very active in driving state energy policy and specific programs, particularly renewables. Figure 19 below summarizes the structure of the electricity market in California.

Four state-level entities are responsible for major aspects of California's electric industry: the CPUC, the California Energy Commission ("CEC"), the California Air Resources Board ("CARB"), and the CAISO. A host of other governmental units – most significantly the California Environmental Protection Agency and the California Water Resources Board – permitting agencies, federal agencies, and locally owned utilities also affect key aspects of the electric industry, particularly in renewable and distributed power development. During exceptional circumstances, jurisdiction of other regulatory bodies in the state has been extended to the electric sector, as it was done during the California crisis for the Department of Water Resources (see Section 3.5.1).

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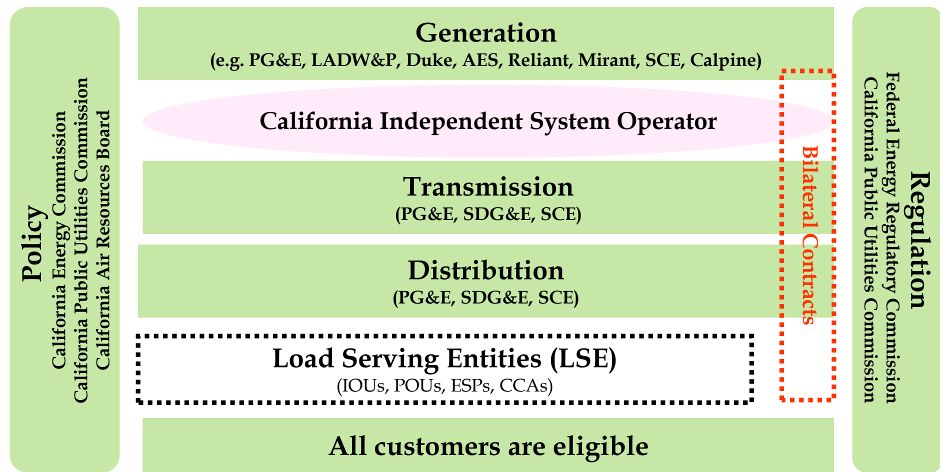
[84] FERC. "Order conditionally accepting tariff revisions." Docket No. ER13-2452-000. December 19, 2013.

[85] CEC. "Draft Energy Action Plan." 2003. p. 1

Figure 19. Overview of electricity market structure in California



Source: CPUC, CEC, CAISO

3.2.1 Regulation and policy setting

Three of the four state-level entities overseeing the institutional framework of the electricity sector in California – CPUC, CEC, and CARB – provide the regulatory and policy framework for the industry.

Established around 100 years ago, for more than 70 years CPUC was the only state-level energy agency in California. The CPUC derives its powers from the California state constitution, and is governed by five Commissioners appointed by the California Governor and approved by the state Senate. The Commission has plenary authority over the regulation of the three main investor-owned electric and natural gas utilities operating in California: PG&E, SCE, and SDG&E. It also regulates Electric Service Providers ("ESPs") and Community Choice Aggregators ("CCAs") that supply power in California, but not the Publicly Owned Utilities ("POUs"), such as the Los Angeles Department of Water and Power. The role of the CPUC is to set retail rates through traditional General Rate Cases ("GRCs") and allocating costs among utility customers in other types of proceedings.[86] The CPUC is also responsible for monitoring and enforcing safety standards in the industry, and allocating the billions of dollars needed to maintain and develop California's electric infrastructure. It also undertakes environmental assessments of proposed transmission lines, power plants, and other major electric facilities.[87]

Established by the Legislature in 1973, the CEC is California's primary energy policy and planning agency. It is the CEC's responsibility to forecast future energy needs and keep historical energy data, license thermal power plants of 50 megawatts or larger, promote energy

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[86] CPUC. *Regulatory Responsibilities of the California Public Utilities Commission*. April 2011. p. 1.

[87] Ibid.

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efficiency through appliance and building standards, develop energy technologies and support renewable energy, as well as plan for and direct the state's response to energy emergencies. While the CEC has no direct regulatory authority over other entities unless established in a specific law, many of California's renewable energy laws give a role to the CEC, generally in terms of overseeing renewable portfolio standards ("RPS") implementation by the POUs which do not fall under the jurisdiction of the CPUC.

A final state-level entity with a regulatory and policy-making role is the CARB, originally designed to deal with local air pollution regulations. Since the implementation of the Assembly Bill ("AB") 32, the Global Warming Solutions Act of 2006, and California's greenhouse gas ("GHG") reduction act, and given especially the recent launch of the California Cap-and-Trade program (see textbox below for the results of the cap-and-trade auctions), CARB's significance in California's energy efforts has grown in recent years.

California's Cap and Trade auction results

January 1, 2014 marked one year since the start of California's cap-and-trade program. Indications are that the program is working as planned. In the six auctions held by CARB thus far, all of the offered emission allowances usable for compliance in 2013 (and 2014 for the most recent auction) have been sold. Until the third auction held in May 2013, settlement prices rose incrementally above the floor price of $10 per metric ton, while allowances available-for-sale were decreasing. Settlement prices were buoyed by both a decrease in supply and increase in demand for carbon allowances. The last three auctions have seen a reversion to lower settlement price levels, and allowances available for sale have increased. The last auction in February 2014, which was the first one for 2014 Vintage Allowances, saw the settlement price remain the same as that of the previous auction held in November 2013 (the last auction for 2013 Vintage Allowances).

Figure 20. Cap-and-Trade Auction Results

Auction	Auction Date	Settlement Price ($/ton)	Allowances Available for Sale	Bid-to-Sale Ratio	Allowances purchases by compliance entities
1	Nov-12	$10.09	23,126,110	3.10	97.00%
2	Feb-13	$13.62	12,924,822	2.47	88.15%
3	May-13	$14.00	14,522,048	1.78	90.22%
4	Aug-13	$12.22	13,865,422	1.62	95.50%
5	Nov-13	$11.48	16,614,526	1.82	96.20%
6	Feb-14	$11.48	19,538,695	1.27	84.50%

Source: California Air Resources Board

3.2.2 Administration of the electricity system

The CAISO operates 80% of the power grid and wholesale electricity market in California and is overseen by FERC. CAISO functions as a non-profit entity, and though created by the state, is not subject to regulation or oversight by any state entity.[88] CAISO operates day-ahead and real-time energy markets, as well as various ancillary services markets. The energy markets (day-ahead, hour-ahead and real-time) use a full-network model that models transmission losses and reactive power load and produces prices at every point (node) in the system.

The day-ahead market determines hourly market-clearing prices and unit commitments, analyzes unit must-run needs and mitigates bids if necessary, with the ultimate goal of producing the least cost energy while meeting reliability needs. The day-ahead market is guided by three main processes: market power mitigation determination, integrated forward market, and residual unit commitment. Any bids failing the market power test are mitigated, and the system determines the minimal and most efficient schedule of generation to address local reliability needs. Day-ahead schedules form the foundation of energy used in real-time along with day-ahead bids and newly submitted real-time bids.

Key Characteristics

- CAISO, as a single-state Regional Transmission Organization ("RTO"), is less independent from state politics than a multi-state RTO e.g. New England ISO;
- California relies on imported energy from hydro resources, which can be variable and difficult to plan around in the long-term; and
- California has aggressive renewables targets (33% by 2020), which require CAISO to adjust its operations and planning to incorporate increasing amounts of intermittent resources.

The integrated forward market simultaneously analyzes the energy and ancillary services market to determine the transmission capacity needed (congestion management) and confirms the reserves required to balance supply and demand based on available bids. It ensures that the sum of generation and imports equals: load + exports + transmission losses; and that all final schedules are feasible with respect to transmission constraints and ancillary services requirement. When forecasted load is not met in the integrated forward market, the CAISO procures additional capacity from its residual unit commitment process by identifying the least-cost resources available.

The real-time market is a spot market to procure energy (including reserves) and manage congestion in the real-time, after all the other processes have run. This market produces energy to balance instantaneous demand, reduce supply if demand falls, offer ancillary services as needed, and curtail demand in extreme conditions. The real-time unit commitment designates fast- and short-start units in 15-minute intervals and looks ahead 15 minutes. In real-time, the economic dispatch process dispatches imbalance energy (energy that deviates from the

[88] Though it is required to obtain the approval of the CPUC in certain situations.

schedule), as well as energy from ancillary services. It runs automatically and issues dispatches every 5 minutes for a single 5-minute interval. Under certain contingency conditions, the ISO can dispatch for a single 10-minute interval.[89]

3.2.3 Regulatory oversight of charges

Prior to the restructuring, electric utilities in California operated under traditional cost-of-service ("COS") regulation. During the earliest discussions of restructuring strategies in the early 1990s, most industry observers agreed that contemporary COS regulation provided the utilities "weak incentives to operate efficiently,"[90] and the earliest proposals of restructuring strategies included proposals to shift to performance-based rate-making ("PBR") mechanisms. When CPUC's intention to restructure was first announced in April 1994 (referred to as the "Blue Book"), a PBR- based regulatory system was presented as the preferred post-restructuring framework. However, when the restructuring bill, AB 1890, was eventually passed, it essentially ignored most of the value-added component of the wires businesses. Although competition was allowed in some discrete areas of the distribution function, such as in billing and meter reading, there was no attempt to comprehensively adopt more profound PBR measures such as an RPI-X approach.[91]

Instead, the wires component remained under the regulatory jurisdiction of the CPUC, which approached (and continues to approach) rate reviews with the state's IOUs on a case-by-case basis. That is, tariffs are developed through a framework agreed upon by the IOU in question and the CPUC, which may or may not involve PBR elements. For several periods between 1994 and 2001, California IOUs were under a price cap form of PBR.[92] At present, however, all three electric utilities in California have reverted to a COS framework.[93] PBR mechanisms may play a new role within California's aggressive environmental policy, particularly with respect to the deployment of smart grid technology.[94]

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[89] CAISO website. "Market Processes." Last accessed on: April 29, 2014. <http://www.caiso.com/market/Pages/MarketProcesses.aspx>

[90] CPUC. "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future." Division of Strategic Planning. February 3, 1993 (known as "The Yellow Book"). p. 3. <http://www.ucei.berkeley.edu/ucei/Restructuring%20Archive/Yellow_book.pdf>

[91] RPI-X stands for Retail Price Index minus X. Under this form of regulation, distribution companies' tariffs are increased each year according to a calculation involving the rate of inflation, and reduced each year by the "X" factor, which represents expected efficiency gains.

[92] SCE between 1997-2001, and SDGE between 1999-2001. See CPUC. "Electric and Gas Utility Performance Based Ratemaking Mechanisms." September 2000.

[93] Based on conversations with Richard Myers, the author of the report in the previous footnote, which is the last such publication by the CPUC on PBR.

[94] Will McNamara and Jack Winter. *Resurgence of Performance-Based Ratemaking*. West Monroe Partners. 2012.

3.2.4 Monitoring arrangements

CAISO's Department of Market Monitoring ("DMM") keeps a close watch on the efficiency and effectiveness of the ancillary service, congestion management, and real-time spot markets. The primary object of the DMM is to monitor market performance to identify potential anti-competitive market behavior and market inefficiencies. In addition, the DMM identifies ineffective market rules or ISO operational practices, and recommends improvements to wholesale competition and efficient market outcomes. On a timely basis, the DMM conducts analysis of the structural competitiveness and efficiency of the California market, in particular analyzing the effectiveness of bid mitigation rules intended to prevent the exercise of market power. In the event of a violation, the DMM collects information on the violation and refers it to FERC for enforcement. The DMM will also coordinate with regulatory and legal entities to assist with any subsequent investigations undertaken in reference to the violation. Finally, the DMM ensures that the market is adequately providing signals for needed investment in generation, transmission, and demand response infrastructure.[95]

3.3 History of restructuring in California

The evolution of the electric power market in California is unique. First of all, as the ninth largest economy in the world (India is the tenth) with respect to gross domestic product in 2010 and international dominance of its entertainment and technology industries, California has an exceptionally high profile. As such, the state's initial reform of its power markets attracted considerable international attention. Secondly, no other restructured power market in the world has faced as profound challenges – a particularly noteworthy fact considering some aspects of the California market model were superior.

Challenges in the California market between 2000 and 2001 ("California crisis") were headline news across much of the world, entering immediately into regional market reform dialogues. This led to numerous calls for "re-regulation" in the US and abroad. Meanwhile, reformers in other markets point to California as an example of what to avoid in their own restructuring processes. Thus, the history of the formation of the California market as it was originally designed, the reasons for the market's collapse and the details of the proposed new market, all afford an opportunity to gain insight into the various ways market design and implementation can go awry, and how things can be done better.

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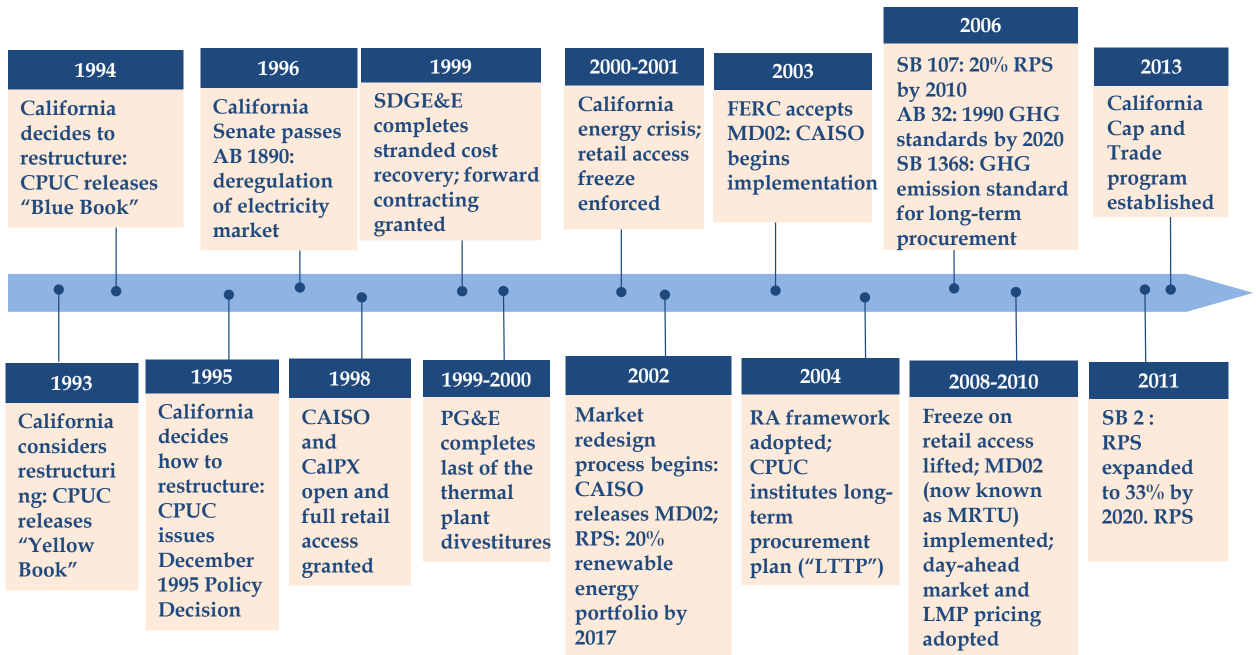
[95] CAISO website. Last accessed on May 1, 2014. <http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx>

Figure 21. Timeline of key events in California electricity market



Source: CPUC, CEC, and CAISO

3.3.1 Creation of a competitive market

California began the formal process of restructuring its electricity market in 1994, driven primarily by the high electricity rates compared to the national average. In 1991, the average electricity rates for California's IOUs ranged from 9-10.5 cents/kWh, which was 30-50% above both national average rates and the competitive cost of new supplies.[96] In response to mounting political pressure from various consumer lobbying groups, the CPUC in late 1992 began a comprehensive review of its regulated electricity industry, and an exploration of alternatives to the existing regulatory framework.

The review culminated in the release in February 1993 a document by the Division of Strategic Planning, entitled: "California's Electric Service Industry: Perspectives on the Past, Strategies for the Future."[97] In this document, that came to be referred to as the "Yellow Book," the Commission recommended regulatory reform that would increase reliance on market forces. It suggested four main strategies for reform of varying intensity that considered both cost-of-service and performance-based regulations. The Yellow Book release followed shortly after the

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[96] CPUC. "*California's Electric Services Industry: Perspectives on the Past, Strategies for the Future*." Division of Strategic Planning. February 3, 1993 (known as "The Yellow Book"). p. 122. <http://www.ucei.berkeley.edu/ucei/restructuring.html>

[97] Ibid.

passage of the Energy Policy Act of 1992 at the federal level, which set forth a long-term vision for the country's electric power industry that encouraged greater reliance on competition and market mechanisms.

The Yellow Book recommendations led to a series of proceedings, at the end of which the Commission released its "Blue Book" in April 1994. The Blue Book announced the Commission's intent to restructure the electric power industry, as well as the CPUC's decision to pursue a reform strategy. This reform strategy would give customers a choice among competing generation providers and would furthermore replace traditional cost-of-service regulation with performance-based regulation.[98]

About one year later, after numerous public hearings and testimony filings from hundreds of individuals and organizations, the Commission issued majority and minority "policy preference statements." Both statements fully supported restructuring with slight modifications; the majority's statement outlined the structure of the market that eventually came into being. A few months later, the CPUC issued the December 1995 Policy Decision in which it declared its plan for all electricity to be provided through the spot market except for retail customers electing direct access who could enter into bilateral contracts with generators and aggregators (wholesalers).[99] The reform process was then turned over to the state legislature to craft the required laws that would permit restructuring to proceed, and guiding the implementation and regulation of the market.[100]

The restructuring bill, known as AB 1890, was passed by the legislature unanimously at the end of August 1996 and signed into law by the governor shortly thereafter. California was hailed at the time as a pioneer by being one of the first states in the US, and one of the few jurisdictions internationally, to have created a competitive marketplace for electricity. The new market opened in 1998. The structure of the newly created market can be summarized as follows:[101]

- a competitive wholesale electricity market operated by a power exchange (the California PX) in which buyers and sellers bid for electricity;
- a non-profit Independent System Operator (CAISO) to implement the wholesale market energy transactions by managing and operating the high-voltage transmission grids owned by the utilities;

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98 CPUC. "CPUC Order Instituting Rulemaking R.94-04-031 and Order Instituting Investigation I.94-04-032." April 20, 1994 (known as "The Blue Book"). p. 1.

99 CPUC. "CPUC Decision D.95-12-063 ("The Preferred Policy Decision")." <http://www.ucei.berkeley.edu/ucei/restructuring.html>

100 Carl Blumstein, L.S. Friedman, and R.J. Green. "The history of Electricity Restructuring in California." *Center for the study of Energy Markets*. CSEM WP 103. August 2002.

101 Borenstein, Severin. "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster." *The Journal of Economic Perspectives* Vol. 16, No. 1 (Winter, 2002): pp. 191-211.

- limited utility unbundling, with IOUs required to sell half of all thermal generation assets, and to yield control of transmission assets to the CAISO;

- a retail tariff cut, with residential and small commercial customers receiving an immediate rate reduction with the retail price frozen at 90% of the 1996 regulated level; and

- full retail access, with customers allowed to elect a new electricity service provider of their choice, or to remain with the incumbent utility.

3.3.2 Market collapse

Although the reform initially worked well in the beginning, with low prices and abundant supply in the new market, in the summer of 2000 the market weakened, setting off what has come to be known as the California crisis. The causes of the California crisis revolve around two interrelated factors: bad luck and poor market design. The seeds of the crisis can be traced back, ultimately, to the postponement of new build by utilities during the protracted design and passage of the initial restructuring bill, owing to uncertainty about the final shape of the market. The effect of that postponement (system tightening) was aggravated by under-forecasts of demand due to an unexpected economic boom, permitting and siting delays for proposed new entrants, high gas prices, substantial exercise of market power, low snowmelt in the Pacific Northwest at inopportune times, key transmission failures, and major generator outages.

Additionally, two fundamental and related flaws in the design of the market exacerbated the problems created by system tightness. First, there was a complete disconnect between wholesale market prices and regulated prices. The disconnect resulted from the freeze on tariffs for a transitional period of up to four years, which meant that utilities were left exposed to – and customers were left immune to – higher wholesale energy prices over the period. This led to an increase in the perceived risk profiles of the IOUs, making it more difficult for them to obtain credit to be able to make the requisite investments in new capacity. Meanwhile, customers had no incentive to curtail their electricity usage as they were shielded from higher electricity costs by the rate freezes in place.

Second, a lack of emphasis in the market design on forward contracting by IOUs resulted in increased vulnerability to spot price volatility. This was aggravated by the fact that even though the restructuring encouraged the IOUs to sell half of their thermal generation, they ended up selling substantially more than that.[102] If IOUs had sold less of their thermal generation, they would have faced less financial distress from the high spot market prices. In addition, a limited duration forwards market was opened in 1999, well before high spot market prices

[102] The CPUC promised the IOUs 10 basis points higher return on their remaining generation assets (which remained under ratebase) for each additional 10% that they divested. In essence, the IOUs were incentivized to divest more than 50% of their non-nuclear thermal fleet. IOUs were allowed to take a bet on continued low spot market prices, and lost. See: Blumstein, Carl, L.S. Friedman, and R.J. Green. "The History of Electricity Restructuring in California." Center for the study of Energy Markets. CSEM WP 103. August 2002.

materialized. The IOUs were provided the opportunity to purchase up to 20% of their requirements in this forward market, for which they would be guaranteed cost recovery. This was about 50% of what became known as the "net short" (e.g., the difference between energy needs that were not covered by existing contracts and self-generation). IOUs were not prohibited from purchasing more energy under contract, but they were not guaranteed full pass through for amounts exceeding the 20% limit. When the market collapsed, SDG&E did not have any forward contracts, PG&E had used only a small fraction of its potential forwards, and SCE had used a large fraction of its guarantees.

In May 2000, the average wholesale electricity price was $50/MWh, higher than in any previous month. There were also numerous price spikes in the month, as prices reached the CAISO's $750/MWh price cap in either the real-time or ancillary services markets 23 times. By June, wholesale prices were averaging $132/MWh. Despite a series of decisions undertaken by the California regulators and FERC, the situation continued to deteriorate. Wholesale prices eased somewhat during the fall but then spiked dramatically in December. By the end of January, the collapse was complete. Blackouts occurred on eight days during the winter and spring even though demand was far below the summer peak. The California Power Exchange suspended operations and subsequently went bankrupt; PG&E filed for bankruptcy in April 2001. Between January and the end of May, the state government had spent $7.6 billion to buy wholesale power on behalf of consumers at an average price of $270/MWh because SCE and PG&E could not pay their wholesale energy purchase bills. See Figure 21 for a detailed chronology of events during the California crisis.

3.3.3 Subsequent market reforms

The California energy crisis during 2000 and 2001 was characterized by extraordinarily high prices and blackouts, requiring the governor to declare a state of emergency. The power shortages and high prices during that period led the state to drive contracting and force a market redesign.

Market Redesign

In mid-2001, when wholesale spot prices were finally coming under control (supported in large part by improving hydrology conditions and declining demand from the onset of a recessionary period), the CAISO began work on a comprehensive plan to re-design the market to address the main design flaws that had been identified.

Also in 2001, FERC, which has jurisdiction over many elements of market design through its oversight of transmission-related market design elements, initiated the Standard Market Design proceedings that heavily informed and guided the market redesign effort known at the time as California Market Design 2002 ("MD02").

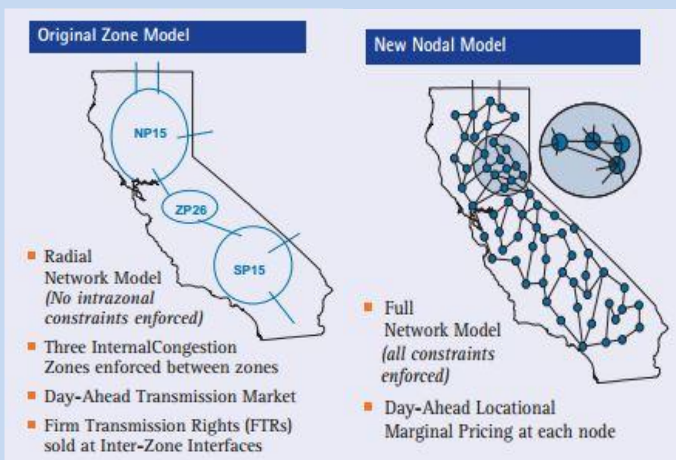
In October 2003, FERC issued an order accepting most elements of the MD02 proposal presented by CAISO.[103] In particular, FERC conditionally accepted and provided further guidance on: (i) CAISO's proposal to implement Locational Marginal Pricing ("LMP"); (ii) establishing an integrated forward market and a day-ahead market as part of redesigning its congestion management system; (iii) a residual unit commitment process that would allow CAISO to procure additional capacity when forecasted load is not met in the integrated forward markets.[104]

After further deliberation, in September 2006 FERC signed off on CAISO's market redesign initiative that eventually came to be known as the Market Redesign and Technology Upgrade ("MRTU"). The market redesign efforts are discussed in the textbox below.

Overview on the MRTU

The MRTU plan went online in April 2009 and introduced: 1) an integrated forward market and a day-ahead market both intended to improve market efficiency and grid reliability; 2) a nodal model, intended to provide better price signals and more liquidity in comparison to today's zonal pricing model had the following primary objectives; and 3) LMP, which, when fully implemented, would set wholesale electricity prices at 3,000 different system points (nodes) reflecting local generation and delivery costs. Figure 22 below shows the differences in the market design before and after the MRTU implementation.

Figure 22. How the implementation of MRTU changed the California market



Source: Direct Energy. "CAISO MRTU Frequently Asked Questions. <https://directenergybusiness.com/folder_icons/CAISO_MRTU_FAQ.pdf>

103 CAISO. "Comments by Market Surveillance Committee of the California ISO." June 6, 2003. Available at: <http://www.caiso.com/Documents/MSCMD02Presentation.pdf>

104 FERC. "Commission Accepts California ISO Concepts For Market Redesign, Provides Further Guidance." October 27, 2003. Available at: < http://www.ferc.gov/media/news-releases/2003/2003-4/10-28-03-caiso.pdf>

Retail Access:

Although California (along with Massachusetts and Rhode Island) was one of the first states to provide competitive retail access (allowing industrial and other types of customers to purchase directly from independent suppliers or vice versa), in the aftermath of the California crisis in September 2001, the CPUC suspended the right of new customers to contract with competitive electricity service providers (although customers that already had a contract with a competitive supplier were unaffected). However, in 2008, the CPUC started exploring ways to again lift the freeze on retail rates and has since re-introduced retail competition on a limited scale with only non-residential customers eligible and the maximum amount of electricity that may be sold by competitive suppliers capped for each year and in each incumbent's service territory.[105]

Resource Adequacy:

In 2004, the CPUC adopted a RA framework in lieu of a capacity market for electricity. Under this framework (still currently in place), the CPUC requires Load Serving Entities ("LSEs"), including the IOUs, to demonstrate that they have procured sufficient capacity to meet the 15% reserve margin on a monthly basis.[106] The RA program effectively established a bilateral spot capacity market. Trading of RA rights takes place bilaterally (and includes self-supply by the IOUs). If sufficient resources are not available, CAISO is empowered to take backstop procurement actions through the Capacity Procurement Mechanism. In addition to the RA program, in 2004 CPUC also adopted a Long-term Procurement Plan ("LTPP"), a long-term resource planning program under which CPUC reviews and approves plans for the three major IOUs to purchase energy. Recently, as part of the CAISO-CPUC Joint Reliability Plan adopted through a unanimous CPUC vote on November 8, 2013, reforms are being discussed to the existing RA program in place. More specifically, the Joint Reliability Plan has identified a set of steps to be undertaken by both agencies towards: 1) augmenting existing 1-year RA program to a 2- or 3-year program; and 2) developing an ISO-run market-based backstop procurement mechanism.[107]

Environmental Regulation:

Over the same period of time, California took aggressive steps to increase its renewable generation portfolio and reduce GHG emissions. In 2002, the Senate Bill ("SB") 1078 established a Renewable Portfolio Standard ("RPS") and set the goal for retail electricity providers to reach 20 percent of renewable energy in their portfolio by 2017. In 2006, SB 107 accelerated the 20 percent RPS target from 2017 to 2010. Finally, in 2011 SB 2, expanded California's RPS program

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105 SDG&E. Direct Access Background. <http://www.sdge.com/customer-choice/electricity/electricity> Last accessed on April 21, 2014.

106 For more information see: California Public Utilities Commission. "Resource Adequacy." February 5, 2013. <http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/>.

107 CAISO. "Memorandum: Decision on the Joint Reliability Plan." December 11, 2013. <http://www.caiso.com/Documents/DecisionJointReliabilityPlan-Memo-Dec2013.pdf>

yet again making it one of the most ambitious renewable energy standards in the country. At present, the RPS program requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.[108]

Similarly, in 2006, AB 32 set the goal to achieve 1990 GHG emission standards by 2020 and enacted the Global Warming Solutions Act of 2006, authorizing the state Air Resources Board to adopt market-based mechanisms to achieve the emission requirements. This culminated in the establishment on January 1, 2013 of the California's Cap-and-Trade Program, a market-based mechanism to curb GHG emissions. Also in 2006, SB 1368 required the Energy Commission to adopt a GHG emission performance standard for long-term procurement of electricity by publicly owned utilities (POUs do not fall under the jurisdiction of the CPUC).[109]

3.4 Rationale for specific design elements and pros and cons of selected market design

In the aftermath of the California crisis, a strong focus on securing adequate capacity and hedging against spot market prices has emerged. Currently, there is a high level of regulatory oversight of procurement and contracting, which is in part due to the fact that CAISO is a single state RTO, and is therefore more readily influenced by state-level politics. Having a single-state electricity system allows the CPUC and CEC to develop and direct state policies on the development of renewable energy resources and curbing emissions of greenhouse gases from generation of electricity. These are summarized in Figure 23, and discussed in more detail in the rest of this section.

3.4.1 Market Redesign and Technology Update ("MRTU")

As discussed in Section 3.3.3 above, market redesign reforms that commenced in the aftermath of the California crises culminated in the implementation of the MRTU tariff in April 2009. Implementation of the MRTU involved a comprehensive redesign and upgrade of the CAISO market structure and its supporting technology.

A full-network nodal model provides better price signals and more liquidity in comparison to the previous zonal pricing model. Moreover, moving to an LMP framework implies that wholesale electricity prices are now set at 3,000 different system points (nodes) reflecting local generation and delivery costs at each point. A key advantage of LMP is that it provides a platform for CAISO to address transmission congestion and improves the efficiency of the wholesale electricity market in the short-term by ensuring that cost of congestion is reflected in electricity prices. In addition, LMP helps relieve congestion over the long-term by promoting efficient investment decisions - energy prices in congested areas are higher than less congested

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[108] CPUC website. "California Renewables Portfolio Standard (RPS)." <http://www.cpuc.ca.gov/PUC/energy/Renewables/>. Last accessed on April 29, 2014.

[109] Ibid

areas, directing investments towards taking advantage of the price differential thereby relieving congestion. Presence of a day-ahead market allows for more opportunities for imports and exports to be scheduled ahead of real-time, and coupled with LMP, makes it easier for suppliers located within and outside of California to sell power into California at a competitive price.

In summary, a full-network model revealing the congestion a day ahead of time, the integrated forward market facilitating the most efficient way to manage that congestion, and LMP providing a full spectrum of costs of delivering electricity at each node, improves the efficiency of the electricity system, and allows for a reliable provision of electricity at lowest possible costs. It should be noted, however, that the aforementioned market redesign reforms, as beneficial as they may have been, were developed and finalized over a period of seven years, over which countless deliberations were held between the CPUC, CAISO, FERC, IOUs, consumer groups, and other stakeholders. Another potential disadvantage is that a full-network model is far more complex and requires substantially larger amounts of processing which translates into a greater commitment of time and resources.

Figure 23. Summary of design elements adopted

Design elements	Rationale	Pros	Cons
MRTU	• Establishing an integrated forward and a day-ahead market • Shift to a nodal pricing model	• Better price signals and increased liquidity • Improved congestion management	• Process of finalizing re-design reforms and implementation came at a significant cost and took most of the last decade
RA Program	• Provide a bilateral spot capacity market regulated by the CPUC instead of the typical FERC-regulated FCM product	• Allows the CPUC to push state-mandated policies for demand response, energy efficiency, distributed generations, and energy storage	• Has stalled the implementation of market-based backstop mechanisms and a Reliability Services Auction platform
Renewable Portfolio Standards	• Support state's environmental policy goals regarding renewables-based generation and reduction of emissions	• Fuel mix diversification • Reduce reliance on natural gas and hydro • Help achieve the state's emission goals	• Intermittent generation source • Integration requires investment in transmission infrastructure and energy storage
California Cap and Trade	• Provide a market-based platform to trade pollution/emission allowances	• Allows for the reduction of carbon emissions over time • Market forces determine price of carbon compliance	• California Chamber of Commerce has argued that the auction will raise energy costs in the state
Energy Imbalance Market	• Allow CAISO to dispatch generation from sources that are currently outside of its control area	• Centralized system expected to lower market participation costs • Regional energy imbalances offset through automatic re-dispatch generation every five minutes	• Raised concerns from adjoining balance authority areas who fear losing their autonomy to CAISO • Complicated governance structure may limit the market's efficacy

3.4.2 Resource Adequacy program

Unlike other electricity markets in the US that have a FERC-regulated Forward Capacity Market, California has a Resource Adequacy ("RA") program that essentially functions as a bilateral spot capacity market regulated by the CPUC. Reforms to the RA program are currently being deliberated that could see the existing program structure being improved through the incorporation of market-based mechanisms and procurement of forward capacity aside from bilateral procurements (See Section 3.3.3 above).

Despite continued calls for reforms to the RA program, the CPUC has insisted upon maintaining the existing structure out of fear that CAISO's administration of a market-based forward procurement mechanism would create a FERC jurisdictional market that may not emphasize state-mandated policies for LSEs pertaining to preferred resources. Preferred resources in California - including demand response, energy efficiency, distributed generations, and energy storage - have been a key focus for state regulators. Moreover, an essential motivation for a more formalized capacity market is that it can be used to supplement an energy-market that has an enforced price cap to address the so-called "missing money" problem. That is, a generator can turn to the capacity market for additional revenues, when energy market revenues are proving to be insufficient to cover its long-run marginal costs. The missing-money problem is less of an issue in California where most new build occurs through long-term power purchase agreements ("PPAs") awarded by utilities.

3.4.3 Renewable Portfolio Standards

California has one of the most ambitious RPS goals compared to any other state in the US. California regulators are working towards achieving the state's ambitious goal of having 33% of electricity retail sales met by renewable resources by 2020.[110]

With the 33% by 2020 target looming in the near future, new entry in California over the last few years has been dominated by wind and solar resources. Several of these resources are being financially incentivized by 15-20 year contracts awarded through utility-issued Request for Offers at above market prices, in addition to the generous tax credits and subsidies that they are already receiving at the federal and state level (e.g. Production Tax Credit and Investment Tax Credit).[111] In December 2013, CPUC approved the 2013 RPS Procurement Plan that will allow

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[110] Solar power generation has increased more than 44% from 2001 to 2013. In May, 2013, California accounted for 28% of total solar generation in the US. Both solar and wind reached record instantaneous peaks in 2013: solar generation reached a peak of 2,886 MW on September 26, while wind generation reached a peak of 4,302 MW on June 23. To give context, utility-scale solar generation in the state crossed the 1,000-MW threshold less than two years ago in August 2012, illustrating the rapid growth in solar generation across California.

[111] For example, the 420 MW Alta Wind project was made possible through a 20-year solicited contract with SCE at 2011 price of $86/MWh (average 2011 price in SCE zone was $31.3/MWh). Similarly, the 60 MW Agua Caliente solar project was awarded a 25-year solicited contract with PG&E at a 2012 price of $180/MWh (average 2012 price in PG&E zone was $29.2/MWh).

California's three utilities to conduct procurement aimed at replacing expiring contracts with projects in the utilities' RPS portfolios in an estimated amount of 4,876 MW (19,899 GWh) over the next ten years.[112]

This increase in renewables-based generation, while allowing California to achieve its environmental goals, poses current and future challenges in grid reliability. With a greater proportion of electricity being supplied by "intermittent" resources, California regulators have been forced to re-consider certain elements of their long term planning and operational policies. Two changes made recently were motivated by a desire to better integrate renewable sources into the California electric grid.

First, in December 2013, CAISO will lower its energy bid floor to -$150/MWh as of April 1, 2014 and improve overall market efficiency.[113] Lowering the bid floor from -$30/MWh to -$150/MWh will increase the number of economic real-time bids by covering the opportunity costs of not producing for many variable energy resources (renewables), and allow CAISO to rely on market-based curtailment during periods of over-generation instead of issuing dispatch instructions not based on economic bids.[114]

Second, CPUC issued an order requiring California's utilities to acquire 1,325 MW of energy storage resources by 2020, driven by three key principles: grid optimization, renewable integration, and greenhouse gas emissions reduction.[115] Other than the reliability benefit of energy storage, the drive for energy storage in California has in large part been fueled by the technology's ability to manage flows from intermittent renewable-based generation. By carefully timing the charging and discharging of stored energy with the rise and fall of expected inter-day load changes, an effective energy storage program will provide regulators the ability to mitigate inter-day load fluctuations.[116]

3.4.4 California Cap-and-Trade Program

The California Cap-and-Trade program was launched in January 2013 to provide a market-based platform allowing for the trade of carbon emission allowances. A key advantage of the California Cap-and-Trade program is that it allows market forces to set a price for carbon emissions compliance, while allowing the state to cap emissions at a certain level that is set to decline gradually into the future in line with state-mandated emissions standards. On the flip

[112] CPUC. "Decision conditionally accepting 2013 Renewables Portfolio Standard procurement plans and integrated resource plan and on-year supplement." November 20, 2013.

[113] FERC. "Order conditionally accepting tariff revisions." Docket No. ER13-2452-000. December 19, 2013.

[114] A negative bid signals to CAISO that a supplier is willing to decrease output as long as it is paid the amount of the bid.

[115] CPUC. "Decision adopting energy storage procurement framework and design program." October 17, 2013.

[116] Wolff, Eric. "Storing power: Could energy storage kill the California duck?" *SNL.* December 20, 2013.

side, concerns have been raised by certain market participants regarding the potential for such a mechanism to raise the cost of energy for the state in the event of a shortage of available allowances. While the reversion to lower settlement prices in the last three auctions has helped mitigate such concerns, prices may rise again in the future buoyed by market forces.

3.4.5 Energy Imbalance Market

CAISO is currently in the process of developing an Energy Imbalance Market ("EIM") along with PacifiCorp that will allow it to more effectively dispatch generation from sources that are currently outside of its control area. This particular market feature is motivated by the fact that the CAISO manages the flow of electricity for about 80% of California (and a small part of Nevada) – the rest is controlled by local balancing authority areas (See Section 3.1 above).[117]

The establishment of an EIM will lower market participation costs by relying on a centralized system for automatic re-dispatch generation to offset energy imbalances that occur on the grid, say due to sudden output changes from renewable generators. Under the approved EIM design framework, CAISO will automatically re-dispatch generation every five minutes both within its control area as well as between the balancing authorities controlled by PacifiCorp and any other market participants joining the EIM. The governance proposal approved in December 2013 will provide participants a meaningful voice in EIM decision-making as part of a transitional committee of nine members selected from a pool of ranked candidates representing utilities, public interest groups, renewable energy producers, EIM participants, governmental agencies, and generators. The committee size is expected to be expanded if more balancing authorities join the EIM at a later date. In essence, the governance rules being established are aiming to strike a balance to allow for the EIM to have the functionality of a regional transmission organization, while ensuring that balancing authorities maintain their autonomy.[118]

Testing for the EIM is currently underway in advance of a launch expected in October 2014. In addition to lowering wholesale costs by expanding the use of CAISO's advanced re-dispatch technology outside of its current footprint, the EIM will accrue positive externalities by improving reliability and enhancing renewable integration, as well as potentially enabling greater imports into California to meet the state's peaking flexibility needs. On the flip side, the governance structure is likely to become increasingly complex as other balancing authority areas choose to join the EIM.

3.5 Transitional challenges and remedies adopted

As discussed above, the restructuring process in California has not been straight-forward and has met with several challenges since the state first began to restructure its electricity market in 1992. The challenges encountered during the restructuring of the California market have arisen

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[117] CAISO. "The ISO Grid." Last accessed on April 30, 2014. <https://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx>

[118] UBS Electric Utilities & IPPs. "Integrating the Western Power Markets Through EIM." February 10, 2014.

both due to the adoption of certain ill-suited aspects of market design, as well as the unique positioning of the California market, for example with respect to its generation-mix (increased reliance on hydro and natural gas). The case of California is particularly meaningful considering that no other restructured power market in the world has the unique experience of being revived in part due to market redesign. These transitional challenges faced during the restructuring process, and the remedies undertaken to address the road-blocks encountered are summarized in Figure 24, and discussed below.

Figure 24. Summary of transitional challenges and remedy adopted

Transitional challenges	Remedy adopted
• California crisis (high prices, supply shortages, rolling blackouts, insolvency of state's utilities and electric market institutions)	• Price caps lowered in California; FERC imposed price caps in WECC • 19% average increase in residential customer retail rates • Long-term procurement contracts worth $43 billion for 20 years • Streamlining approval process for new plants
• Overlapping regulatory authority of various entities (CPUC, CEC, CAISO, and FERC)	• CAISO-CPUC Joint Reliability Plan adopted in November 2013 solidifies CAISO and CPUC's commitment to work together on future challenges facing the state's electricity system
• Overlapping RPS program structure	• No remedy has been adopted as yet to address this situation

3.5.1 California crisis

As discussed in Section 3.3.2 above, the California crisis, which lasted from approximately June 2000 to July 2001, was characterized by supply shortages and subsequent rolling blackouts, and ultimately, the bankruptcies of the state's biggest utility, PG&E, as well as the California Power Exchange and a number of small IPPs.

Numerous interim and emergency measures were implemented during 2000 and 2001 to attempt to forestall market collapse, and then to reduce the duration of the collapse once it had occurred. In an attempt to reduce what was widely perceived at the time as market manipulation to drive up spot market prices, wholesale price caps were lowered to $500/MWh in July, and then to $250/MWh in August. Subsequently, wholesale prices were[119] capped by FERC throughout the Western Interconnection. Other measures taken to curb the crisis included: 1) a requirement that imports bid into the market at $0/MWh; 2) a requirement that participating generators bid into the CAISO's real-time pool; 3) 19% (on average) increase in retail rates for residential customers to reduce the divergence between revenues and costs for

[119] Inappropriately, in LEI's view.

utilities serving those customers; and 4) streamlining approval process for new plants to enable more capacity to quickly come online.

Moreover, as some entities approached solvency and other institutions went bankrupt, energy purchasing responsibility was temporarily entrusted to the Department of Water Resources to enter into long-term power contracts in response to IOU insolvency. With this authority, the state belatedly entered electricity procurement contracts on behalf of utilities, signing contracts extending up to 20-years' and totaling $43 billion. These contracts in effect ended the obligation for utilities to buy from the California Power Exchange.

Whether as a result of these measures or simply improving circumstances (more hydro generation, resolved outage problems, falling gas prices, onset of a recessionary economic period) the situation began to improve by the latter half of 2001, and by 2002, total wholesale energy costs were more than 62% below the corresponding values for 2000 and 2001. In mid-2001, when wholesale spot prices were finally coming under control, the CAISO began work on a comprehensive plan to re-design the market to address the main design flaws that had been identified. The effort, called Market Design 2002 (MD02), eventually culminated in the MRTU which was implemented in April 2009 (see Section 3.4.1 above).

3.5.2 Overlapping regulatory authority

A continuing issue in California is its complex regulatory structure with a less than ideal delineation of responsibilities and duties. In the run-up to the California crisis, the state's power sector was subject to regulation and oversight by several bodies each operating under a different mandate – FERC, CPUC, CEC, CAISO, and the now defunct California Power Exchange. In the midst of the crisis, other regulatory institutions were provided supervisory authority. For example, power procurement responsibilities were entrusted to the Department of Water Resources. In addition, the Consumer Power and Conservation Financing Authority ("CPCFA") was established to invest in power assets for the purpose of stabilizing the market, however, CPCFA was shut down after 3 years, without building a power plant or buying transmission assets.

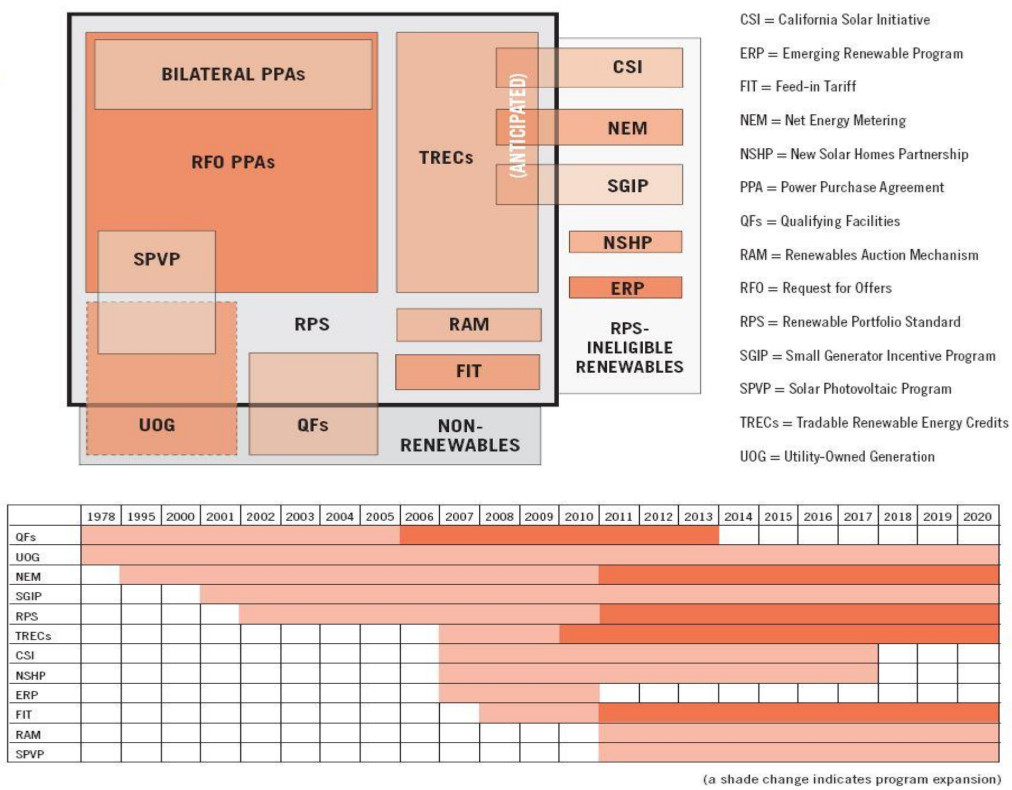
Overlapping regulatory authority and lack of clear delineations of responsibilities remain a challenge facing the California electricity sector. For example, no single person or government agency is in charge of integrating the renewables and distributed generation sources. Not surprisingly, no roadmap for achieving California's ambitious RPS goals of 33% by 2020 that clearly lays out the needed policy decisions, sources of funding, and schedule, exists. Moreover, the CPUC, CAISO, and CEC have been assigned key roles with respect to reliability, with redundant responsibilities, differing goals, limited staff, and no streamlined process for addressing interdependent decisions, despite extensive coordination efforts.

Steps have been taken in recent years to improve collaboration between various regulatory agencies in California. California regulators signed off on 2013 with the approval of the Joint Reliability Plan that solidifies the commitment of the CAISO and CPUC to work together on juggling an ambitious 33%-by-2020 RPS target, retirement of more than 12,000 MW of once-through cooling units, increasing penetration of distributed generation, energy storage procurement, and growth of intermittent renewable resources, among a host of issues changing the state's utility energy planning. Without a clearer delineation of specific responsibilities across the agencies, disputes are likely to continue to arise. Case-in-point is a bill passed by the California Senate on April 30, 2014, that would prevent the CAISO from moving forward with its proposed "reliability services auction" reform to the RA program unless given a direct approval by the CPUC.[120]

3.5.3 Overlapping program structure

As discussed above, California has one of the more ambitious RPS targets in the US. However, in the absence of a single authority with a specifically defined agenda to achieve the RPS targets, the renewable energy programs currently in place in California demonstrate a complex overlap in how they relate to each other, and whether they are RPS-eligible or not. Figure 25 below illustrates the complexity and overlap among the programs, as well as the large variation in the length of time authorized for each program.

Figure 25. Complex interrelation of California's renewable energy programs



Source: Hoover Institution. "Renewable and Distributed Power in California: Simplifying the Regulatory Maze – Making the Path for the Future." November 28, 2012.

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120 Jeff Stanfield. "California Senate Energy panel Oks bill grating PUC more oversight of CAISO." *SNL*. April 30, 2014.

3.6 Implications for Nova Scotia

There are several lessons from California's electricity market restructuring experience.

- **Transitional contracting**: First, with the benefit of hindsight it can be concluded that the California crisis could have been avoided, or at the very least its impact mitigated, if the California IOUs had been guaranteed full recovery of power procurement costs as a pass-through to ratepayers, and allowed to enter into long-term contracts. Had the restructuring been designed with contracts that matched the default supply obligations in price, customers and generators would have had a hedge, and the transition to market would have been cushioned.
- **Impact of regulatory policies on economic incentive structure.** Second, the California crisis emphasizes the importance of evaluating regulatory policies for their impact on the economic incentive structure of the market stakeholders. Rate freezes imposed soon after the market was first restructured were ineffective because they dis-incentivized consumers from watching their electricity consumption by shielding them from higher electricity costs. On the other hand, by preventing utilities from passing through costs to ratepayers, the rate freezes diminished their credit profile making it harder for them to finance new generation build. Similarly, provision of generous incentives to utilities to sell-off their thermal generation portfolio contributed in no small part to their inability to secure adequate supply during the California crisis.
- **Clear objectives and policies.** Finally, the California example showcases the point that an over-complicated regulatory structure prevents the clear delineation of comprehensive policy goals. This results in increased uncertainty for market participants translating into higher risk premiums, and creates roadblocks for the implementation of critical decisions. It is noteworthy that the system tightness leading to the California crisis arose out of postponement of new generation investment by utilities during the prolonged design and passage of the initial restructuring bill. This situation was aggravated by permitting and siting delays for proposed new entrants, which continues to be a problem in California today given the complex regulatory approval process involved.

The movement toward restructuring in California was born from a history of broad dissatisfaction with persistently high electricity prices at the time attributed to ineffective cost-of-service mechanisms that provided utilities weak incentives to operate efficiently. Nonetheless, as the California experience has shown, electricity markets have proven to be more difficult to restructure than was initially expected. Even though the earliest restructuring strategies were overwhelmingly in favor of instituting some form of PBR mechanism, the final restructuring bill left this determination to be more flexible by allowing the CPUC to decide for the utility in question on a case-by-case basis. After a brief flirtation with PBR mechanisms, all three California electric utilities are back on a cost-of-service framework. While providing for flexibility in choice of framework, this approach implies that lengthy CPUC proceedings are held each time a utility intends to amend its rates.

Finally, the California experience has shown that real-time retail pricing and long-term contracting can help control soaring wholesale prices, and can buy time to address other important structural problems that need to be solved to create a stable, well-functioning electricity market. These problems include creating a workable structure for retail competition, determining the most efficient way to set locational prices and transmission charges, implementing a coherent framework for investing in new transmission capacity, and optimizing least-cost procurement of reserve capacity.

4 FortisBC

FortisBC is a privately owned, vertically integrated utility located in south central British Columbia. It has been regulated under a performance based ratemaking ("PBR") structure twice since 1996, each time reverting back to cost of service ("COS") regulation following a regulatory period of at least five years. FortisBC's status as a vertically integrated utility and its varying uses of PBR mechanisms provide an important potential example for the Nova Scotia Department of Energy. Lessons learned relate to the use of a hybrid PBR regime to ensure capital expenditures are fully funded in a timely manner and to a rigorous, historical, and peer-based productivity study in setting productivity factors.

4.1 Overview on FortisBC

FortisBC is a regulated, vertically integrated utility, operating in the southern interior of British Columbia ("BC") and wholly owned by its parent company, Fortis Inc.[121] FortisBC's regulated generation assets consist of four hydroelectric generation plants on the Kootenay River with an aggregate capacity of 223 MW and an annual gross energy entitlement of approximately 1,591 GWh in 2013. FortisBC also owns approximately 7,150 kilometers of regulated transmission and distribution lines as well 65 substations. In addition to its generation assets, FortisBC has a number of long and short term PPAs with both BC Hydro and independent power producers ("IPPs").

In 2013, FortisBC had a peak demand of 699 MW compared to a historical peak demand of 746 MW reached in 2008. It serves about 163,800 customers, primarily in urban areas, and sold 3,211 GWh of electricity in 2013, as shown in Figure 26. Residential customers make up most of FortisBC's customer base. The remaining customer base includes commercial entities (24%), wholesalers (22%), and industrial customers (9%).[122]

FortisBC and Nova Scotia Power, Inc. ("NSPI") are both vertically integrated utilities which supplement in house generation with PPAs. Nova Scotia generates over 50% of its power from coal, whereas FortisBC has hydroelectric capacity and purchases power from BC Hydro and Independent Power Producers ("IPPs") whose resource base is also predominately hydroelectric.

FortisBC is smaller than NSPI in terms of asset size and number of customers served. NSPI owns approximately 2,423 MW of capacity, whereas FortisBC's generation capacity is equal to approximately 9% of NSPI's total generation capacity. NSPI owns over 30,000 km of

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[121] Fortis is a diversified international distribution utility holding corporation having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations. Included in the distribution assets is a gas utility company, FortisBC Energy.

[122] FortisBC Inc. *Annual Information Form For the Year Ended December 31, 2013*. March 14, 2014.

transmission and distribution lines, whereas FortisBC owns approximately 24% of NSPI's total amount of transmission and distribution lines.[123]

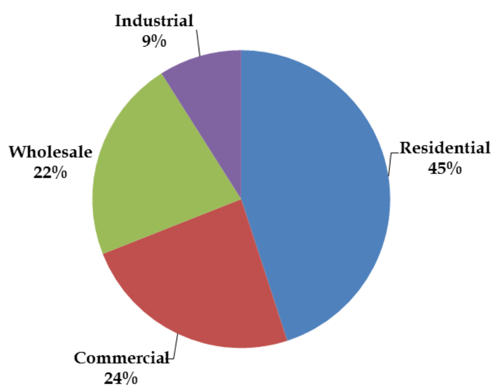
Both are members of the North American Electric Reliability Corporation. NSPI is the predominant entity in its provincial power market and has approximately 500,000 customers whereas FortisBC's customer base is equal to approximately 32% of NSPI's customer base.[124]

Figure 26. Snapshot of FortisBC

FortisBC

Key facts	
Customers (2013)	163,800
Provincial GDP growth est. (2014)	2.3%
Installed capacity (2014)	223 MW
Peak demand (2013)	699 MW
Production (2013)	1,591 GWh
Load growth (2012)	0.4%
Transmission and distribution lines (km)	7,150
Transmission and distribution substations	65

FortisBC Customer Base



Source: FortisBC

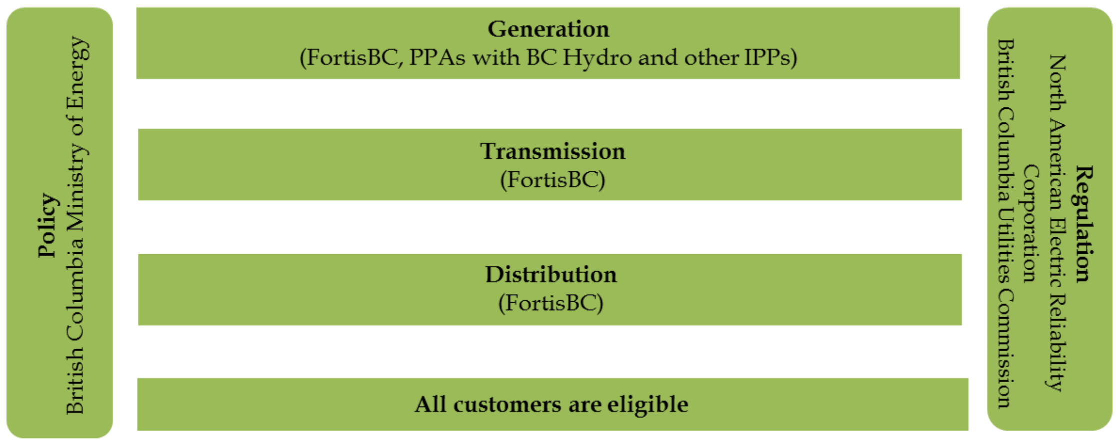
[123] Ibid.

[124] Emera Inc. *Annual Report 2013*. February 10, 2014.

4.2 FortisBC's institutional and legal framework

Institutional entities with jurisdiction in the BC electricity market include: the British Columbia Utilities Commission ("BCUC"); the British Columbia Ministry of Energy, Mines, and Petroleum Resources ("BC MOE"); the North American Electric Reliability Corporation ("NERC"); and NERC affiliate Western Electricity Coordinating Council ("WECC"). Provincially, the BC MOE is responsible for setting energy policy, while the BCUC is tasked with protecting the public interest as it relates to electric and gas utilities, as outlined in Figure 27.

Figure 27. Overview of FortisBC's institutions framework



4.2.1 Policy setting

At a high level, the policy direction of the BC electricity market is set by the BC MOE which determines energy and regulatory policy. For example, it is the decision of the MOE to legislate BC Hydro as a public Crown Corporation, to inject generation competition from IPPs, and, more fundamentally, to draft and legislate the key drivers of the BC electricity market via the 2007 Energy Plan and the *2010 Clean Energy Act*.[125] Included in the BC MOE's policy directives is the province's incentivization of clean energy and its participation with the Western Climate Initiative ("WCI"). Per the WCI, the BC government is expected to set caps on greenhouse gas emissions (though potentially at the WCI level as opposed to the provincial level), but as of March 2014, the exact details of the expected cap and trade program are still continuing to unfold.[126]

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[125] Government of British Columbia. *Summary of Ministry Responsibilities.* Accessed: April 22, 2014. <http://www.gov.bc.ca/premier/responsibilities/index.html>

[126] FortisBC Inc. *Annual Information Form For the Year Ended December 31, 2013*. March 14, 2014. p. 16

4.2.2 Reliability monitoring arrangements

FortisBC is responsible for compliance with the mandatory NERC reliability standards. Through the WECC and FortisBC's WECC sub-regional affiliation in the Northwest Power Pool ("NPP"), FortisBC conducts coordinated reliability planning, including the implementation of emergency reliability protocol, transmission planning, and regional resource adequacy.

Logistically, the role of WECC, as NERC's regional affiliate, to FortisBC is primarily to monitor and oversee mandatory reliability standards. This is the same role played by the Northeast Power Coordinating Council in Nova Scotia, for example. For FortisBC's generation assets, this often means reporting generation performance data. Examples of generation performance data include forced outage rates ("FOR") and energy availability factors ("EAF"). For transmission assets, FortisBC must provide data to WECC relating to transmission operations and planning, facilities design, connections and maintenance, and communication as a preventative measure to ensure reliability. Similarly, NERC, via WECC, monitors the reliability efforts of FortisBC's distribution assets. This requires FortisBC to provide data to WECC regarding its efforts to comply with critical infrastructure protection directives designed by NERC.

To ensure reliability in an emergency, FortisBC has responsibilities to provincial authorities. Specifically, this includes FortisBC's reliability coordinator, Peak Reliability ("Peak"). Peak is the highest level of operational authority for reliability and is the entity to which FortisBC is answerable in case of a reliability emergency. The role of Peak in BC is often fulfilled independently elsewhere, within a regional transmission organization ("RTO") like PJM.[127] In addition, much of the reliability directives which FortisBC would be responsible for enacting are passed on from Peak by FortisBC's balancing authority: BC Hydro.[128] In Nova Scotia, the role of reliability coordinator is occupied by the independently managed New Brunswick System Operator ("NBSO"), while the role of balancing authority is performed by the Nova Scotia Power Corporation.

4.2.3 Regulatory oversight of charges

Provincially, the BCUC acts as an independent regulatory agency operating under the BC *Utilities Commission Act*.[129] It is the primary responsibility of the BCUC to balance the interests of both utility customers and shareholders to ensure all relevant stakeholders are responsive to the energy needs of the province. To do this, the BCUC regulates the long term planning efforts of FortisBC, the setting of revenue requirements, designing rates, creating an integrated resource

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[127] NERC. *Reliability Coordinators*. Accessed: May 5, 2014 <http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx>

[128] As a Crown Corporation dominating the BC electricity market, BC Hydro serves as the balancing authority for the entire province of BC.

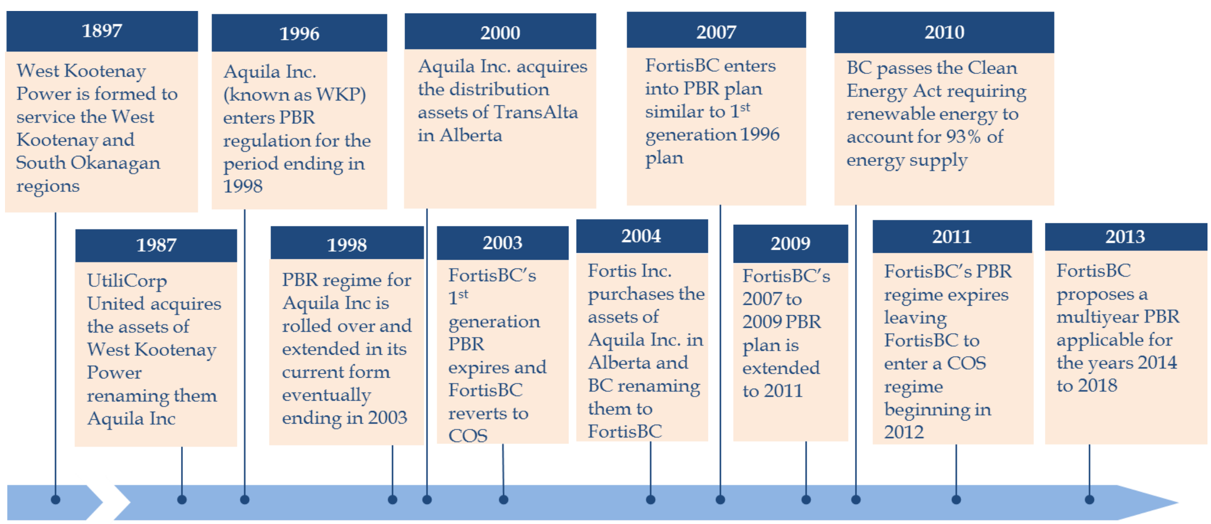
[129] BCUC also regulates BC Hydro and other BC investor owned utilities including: Croix Multi Utility Services, Inc., Hemlock Utility Services Ltd., the Yukon Electrical Company Ltd., and Silversmith Power and Light Corporation.

plan, constructing and expanding power facilities, and signing contracts for generation supply.[130] As such, the BCUC has the final authority regarding the rate-setting design (either a performance based ratemaking or cost of service rate structure) and specific rates. This will be discussed in detail in Section 4.4.

In setting rates, FortisBC is the only electrical utility that has been regulated under PBR in BC. To set rates under PBR, the BCUC typically relies partially on annual workshops and negotiated settlement processes ("NSPs") with interveners and interested stakeholders. NSPs take place two to three months before rates become effective on January 1st. Historically, workshops and NSPs have occurred annually as certain FortisBC revenue requirements under COS require updated forecasts. During the annual workshop, which is usually held in mid-November, FortisBC presents its preliminary revenue requirements for the upcoming year to the BCUC and provides explanations and justifications for its forecasts. Stakeholders then have the opportunity to review and provide comments on the Revenue Requirements.

4.3 History of restructuring and recent developments

Figure 28. Timeline of FortisBC's key developments



Source: FortisBC regulatory presentation

FortisBC was originally incorporated in 1897 as West Kootenay Power ("WKP"). WKP was a vertically integrated electric utility servicing the West Kootenay and South Okanagan regions of BC. In 1987, the assets of West Kootenay Power were acquired by UtiliCorp United and renamed Aquila Inc. In May 2004, Fortis Inc. purchased Aquila Inc.'s Canadian operations in

[130] British Columbia Ministry of Energy. *Utility Regulatory Framework*. Accessed: April 23, 2014. <http://www.empr.gov.bc.ca/EPD/PolicyRegulationLegislation/UtilityReg/Pages/default.aspx >

BC, renaming the assets FortisBC and transitioning FortisBC into an operation independent of its parent company, Fortis Inc., as shown in Figure 28.[131]

Figure 29. Overview and evolution of PBR regulation applied to FortisBC

A comparison of the PBRs regimes of FortisBC			
Topic	**1st Generation**	**2nd Generation**	**Proposed 3rd Generation**
Going in rates	Same process across generations: Rates are determined based on the revenue requirements of FortisBC divided by the forecast sales volume for the period.		
Regulatory period	1996-2003	2007-2011	2014-2018
Inflation ("I factor")	CPI- Canada and BC	CPI-BC	weighted average of the BC-CPI and Average Weekly Earnings
Productivity factor ("X factor")	4% in 1996; 4% in 1997, 3% in 1998 and beyond for Opex and 2% for all Capital Expenditures.	2% in 2007-2008; 3% in 2009, 1.5% in 2010-2011; should inflation be in excess of 3%, the excess is added to the Productivity Improvement Factor ("PIF"), which effectively caps the CPI at 3% applicable only to Opex	Proposed to be 0.5% across the board 2014-18 applicable across all years and to all controllable expenses such as O&M and capital expenditures
Capex Factor ("K factor")	No explicit K factor, capex was treated as operating expenses with revenues inflated based on an (I-X) index similar to the proposed 3rd generation.	Capex is not included in the PBR	Controllable capital revenues would be inflated based on an (I-X) index. Capex projects requiring a certificate of public convenience and need ("CPCN") would remain under COS regulation
Service Quality ("Q factor")	Proposed system of rewards and penalties based on performance compared to a target. Standards such as customer satisfaction, system reliability, safety and line losses are reviewed annually.		
Sharing Mechanism ("SM")	No collar: Variances between targeted and actual financial performance were shared equally between customers and the utility	The same across periods: 2% collar around the allowed ROE whereby variances as a result of actual financial performance will be shared equally between customers and the utility	
Extraordinary Items ("Z factor")	None	Similar and includes but are not limited to: (i) acts of legislation or government regulation, changes due to Generally Accepted Accounting Principles ("GAAP"), (iii) force majeure, (iv) directives of the BCUC or other regulatory agencies, and (V) others as agreed to by the parties	
Regulatory review and off-ramps	Annual review for the revenue requirements and submission of the Capital Expenditure Plan		

Source: FortisBC

FortisBC is a privately owned, vertically integrated utility which has alternately been regulated under both cost of service ("COS") and PBR regimes since 1996. WKP implemented its first multi-year PBR from 1996 to 1998. This plan was then "rolled over," extended in the same form through 2003. More recently, PBR regimes have been implemented by FortisBC in 2007 to 2009 and extended from 2009 to 2011.[132] Currently, FortisBC has an outstanding proposal with the

[131] Debienne, Don, VP Generation & Regulatory Affairs. *Performance Based Regulation ('PBR"): Streamlining the Process*. FortisBC Regulatory Presentation. Calgary, Alberta. 31 May 2006. Speech. p. 2.

[132] The 2007 to 2009 plan, later extended to 2009 to 2011 was actually approved as a 2006 plan on December 11, 2008 in BCUC Commission Order G-193-08.

BCUC for PBR for the years 2014 to 2018.[133] In the interim years (2004-2006 and 2012-2013), FortisBC has been regulated as a COS utility. Figure 29 provides an overview of the evolution of key elements relating to FortisBC's PBR regime.

4.3.1 PBR regime 1996 to 2003

Partially in an attempt to address inefficiencies arising from traditional COS regulation,[134] the BCUC approved FortisBC's application to enter PBR as part of FortisBC's 1996 revenue requirements application.[135] The plan was approved for a three year regulatory period. At the time, interveners such as the BC electrical consumers association voiced concern that PBR was relatively new, especially as it applied to electric utilities.[136] In the end, the BCUC determined that the expected incentives and reduced regulatory burden justified the deviation from COS regulation because PBR was broadly consistent with trends in the utility sector and noted that PBR had already been applied to BC Gas.[137] The plan was later rolled over and extended until 2003. Figure 29 highlights the important features of the 1996 PBR regime as well as highlighting its evolution.

Under the 1996-2003 plan, going in rates were determined based on the revenue requirements of FortisBC divided by the forecast sales volume for the period. The revenue requirements were determined "all-inclusive" and adjusted based on the cost components subject to PBR. This resulted in an "all-inclusive" rate increase.[138]

The PBR plan from 1996 consisted of 'targeted' cost categories with cost drivers, base costs, escalators, productivity improvement factors ("PIFs"), and a sharing mechanism. The PBR mechanism was selectively applied to capital expenditures ("capex"), operating and maintenance ("O&M") expenditures and non-financial performance measures; Figure 30 shows

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[133] The proposed multiyear PBR plan is still under review of the BCUC as of April 2014. In the interim for 2014, the BCUC granted a 3.3% rate increase over 2013 rates pending the approval of the multiyear PBR. See: FortisBC. *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018.* July 5, 2013.

[134] BCUC. *A Participants' Guide to the B.C. Utilities Commission*. July 2002. p. 5.

[135] FortisBC. *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*. July 5, 2013. p. 31.

[136] BCUC. *Revenue Requirement Application in the matter of West Kootenay Power Ltd.: Reasons for Decision*. July 19, 1996. p. 2.

[137] Ibid. pp. 2-3.

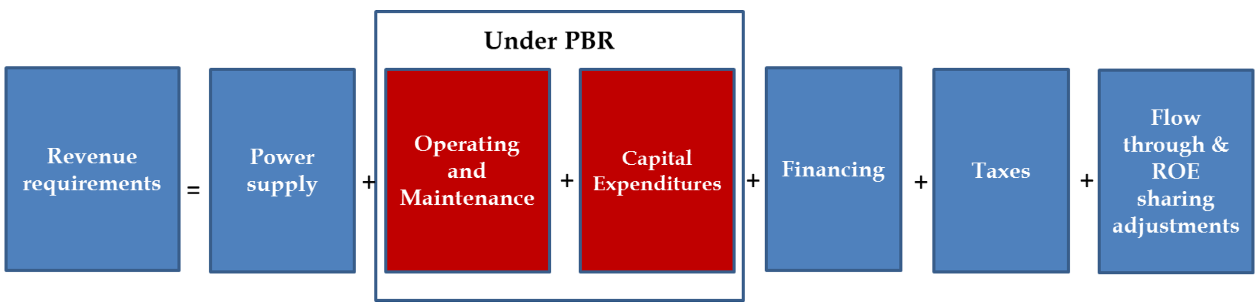
[138] "All-inclusive" refers to the practice of calculating revenues on a company wide basis. It is the sum of revenue expected to accrue from COS regulation and from PBR regulation. The O&M and capex revenue requirements are calculated on a company wide basis without breaking revenue requirements down into the generation, transmission and distribution sectors.

the components of FortisBC's revenue requirements.[139] PBR applicable components were designed to grow at inflation minus productivity improvement factors (or "I-X"). According to FortisBC's I-X formula, the X factor was actually referred to as a PIF which was the result of negotiations with the BCUC and the involvement of interveners. Eventually, the PIF was negotiated to be between 2% and 4% depending on the year and cost category.

Other features include the use of both a Canada-wide and a BC-based consumer price index ("CPI") for the inflation factor depending on the revenue component. For example, capex revenue requirements were inflated at the Canada-wide CPI measure while O&M expenses were inflated at the BC CPI. Capex, like O&M expenses, was treated under PBR.

There were performance targets (or a Q factor) based on performance standards which included annually-reviewed customer satisfaction, system reliability, safety, and line losses. The Q factor itself contained potential rewards or financial incentives which were based on a comparison of actual and targeted reliability and customer service performance. Of note, following the comparison, actual Q-factor rewards were provided at the discretion of the BCUC without a specific formula.

Figure 30. Components of FortisBC revenue requirements under PBR, 1996-1998



Source: BCUC. ("Revenue Requirement Application in the matter of West Kootenay Power Ltd.: Reasons for Decision." July 19, 1996)

In addition, there was a "sharing of variances from target" mechanism done on a line by line basis. Categories subject to the sharing mechanism included O&M, other income, capex, and financing in which volume variances from target were shared equally between customer and utility by deferring the differences to the following year's rates. There were no provisions for extraordinary items. There was an annual review of the revenue requirements and submission of an annual capex plan.

[139] Targeted cost categories refer to specific portions of FortisBC's revenue requirements to which PBR is applied. In the 1996 PBR regime, examples include O&M and capex expenditures. Similarly, the term "selectively" is used to refer FortisBC application of PBR to certain portions of the company's revenue requirements. Thus, PBR is "targeted" to certain revenue components and applied "selectively."

FortisBC has subsequently argued that the component-based PBR experience beginning in 1996 generally went well and that "PBR was not harmful."[140] There was a significant reduction in regulatory burden and that PBR was marginally beneficial in terms of financial performance. Indeed, O&M cost performance up to 2002 was positive. Additionally, it is believed that the annual review of revenue requirements went well.[141]

The challenge however proved to be the treatment of capital expenditures in a PBR context which did not provide adequate financing for necessary capex.[142] In addition, the lack of rebasing over the eight year period combined with a base year not adequately reflective of normal operating conditions contributed to a reversion to COS regulation.[143] Finally, the lack of an earnings sharing mechanism on a company-wide level proved complicated. Because the 1996-2003 PBR treated over/under financial performance on a "line by line" basis vis-à-vis a target before sharing the variance equally with consumers,[144] there were calculation errors.[145]

4.3.2 PBR regime 2007 to 2011

Following what were believed to be important cost improvement incentive mechanisms and reduced regulatory burdens, FortisBC again decided to apply for PBR regulation for the year beginning 2007. The treatment of capex was believed to have been fixed in the 2007-2011 PBR by moving its remuneration to COS funding. The 2004 change in ownership from Aquila to FortisBC, which had also been cited as a factor in the reversion to COS, was now settled.[146] Finally, the decision to revert to COS in 2003 had provided FortisBC the opportunity to rebase PBR relevant revenue components.

With the exception of capex being treated outside the PBR structure, the 2007-2011 PBR was similar to the 1996-2003 PBR regime. Under this term, FortisBC's PBR mechanism was changed to apply to the capitalized overhead, depreciation rates and return on equity ("ROE") risk premium in addition to O&M expenses and non-financial performance measures. Similar to the 1996-2003 regulatory regime, PBR relevant components were allowed to grow by an I-X index. However, capital-related costs were reviewed on a COS basis annually to capture capex

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140 Debienne, Don, VP Generation & Regulatory Affairs, FortisBC. *Performance Based Regulation ('PBR"): Streamlining the Process*. FortisBC Regulatory Presentation. Calgary, Alberta. 31 May 2006. Speech. p. 2.

141 Ibid. p. 2.

142 Ibid. p. 2.

143 Ibid. p. 2.

144 FortisBC. *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*. July 5, 2013. p. 31.

145 Debienne, Don, VP Generation & Regulatory Affairs. *Performance Based Regulation ('PBR"): Streamlining the Process.* FortisBC Regulatory Presentation. Calgary, Alberta. 31 May 2006. Speech. p. 5.

146 FortisBC. P. 31 *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*. July 5, 2013. p.31.

completely and immediately in rates. Revenue requirements were again calculated "all inclusively" from a formula-adjusted O&M and the return and depreciation expense based on annual ratebase adjustments resulting in an all-inclusive rate increase. Periodically, FortisBC conducts a COS study and rate design process to ensure that individual customer classes are paying their appropriate share of the revenue requirements. The plan was rolled over in 2009 in the same form as the original 2007 to 2009 PBR regime.

Another notable change was that the PIF factor was decreased. It was again the product of negotiations, but was set at 2% in 2007-2008, 3% in 2009 and 1.5% in 2010-2011, as compared to 4% in 1997. The inflation factor in the 2007-2011 PBR regime was solely composed of the BC CPI. An earnings sharing mechanism ("ESM") with a 2% collar was applied around allowed ROE. Finally, a Z-factor allowance for extraordinary items was added. The Z-factors included, but were not limited to, the following events:

- acts of legislation or government regulation;
- changes due to Generally Accepted Accounting Principles ("GAAP");
- force majeure;
- directives of the BCUC or other regulatory agencies; and
- others as agreed to by the parties.

FortisBC has stated that it "strongly believes that the PBR plan has been beneficial to FortisBC customers" having seen O&M per customer decline on a nominal basis.[147] This view is shared by the BCUC which noted that the shared earnings benefits flowing to both customers and shareholders totaled $67.5 million per year.[148] There were additional customer service (Q-factor) items which better gauged customer satisfaction. Additionally, the use of an ESM proved to be less complicated and resulted in fewer errors since financial performance was gauged on a company level, rather than a line-by-line basis. Unfortunately, after a five year period, it was believed that rebasing was needed.

4.3.3 Recent developments

Recently, macro level events in the BC power market have been driven by the 2010 Clean Energy Act. Accordingly, the *2010 Clean Energy Act* mandates that clean and renewable energy projects account for 93% of provincial electricity supply. Moreover, the 2010 Act mandated ambitious targeted reductions in greenhouse gas emissions, required rates to remain amongst the lowest in North America, and for BC to maintain electrical generation self-sufficiency.

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[147] FortisBC Inc. *Application for Approval of 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan*. June 30, 2011. p.1.

[148] BCUC Commission Order G-44-12, Reasons for Decision, p. 22.

Consequently, the *2010 Clean Energy Act* will dictate the type of energy which FortisBC must procure to ensure power to its customers.[149]

As of 2013, other recent developments include BCUC's approval of FortisBC's new smart meter program[150] and FortisBC's new five year PBR application applicable for the years 2014 to 2018. The application itself remains under consideration of the BCUC as of April 2014; Section 4.4.1 provides a more detailed discussion about this application.

4.4 Rationale for specific design elements and pros and cons

Currently, FortisBC is regulated under a COS model; however, rates from 2014 to 2018 would be determined through a PBR mechanism similar to the previous generations outlined in Sections 4.3.1 and 4.3.2. The proposed 2014-2018 PBR would calculate revenue requirements on an all-inclusive basis and apply PBR regulation selectively to certain revenue components. Similar to the previous PBR mechanisms, those revenue components proposed to be regulated under PBR would be inflated on an I-X basis annually. Likewise, generation O&M expenditures have been included in PBR regulation, however, the cost of financing is proposed to remain regulated under COS, as this is dependent on capital markets and deemed outside the control of FortisBC. Figure 31 presents the rationale, pros, and cons of select design elements in FortisBC's proposed 2014-2018 PBR regime.

Figure 31. Rationale, pros, and cons of select design elements in FortisBC's proposed PBR

Design elements	Rationale	Pros	Cons
Capex funded partially by COS regulation	To ensure complete, timely capex funding for projects larger than $5 million	Introduces incentives for FortisBC to deploy capex efficiently	Relative to PBR, the COS regulation could increase FortisBC's regulatory burden
X factor calculated using TFP analysis	To ensure an appropriate productivity target	Rigorous calculation based on the historic performance of relevant utilities	Using many non-BC and non-Canadian utilities may mean that the X-factor does not properly reflect FortisBC or its previous productivity gains
Performance Standards	To ensure continued attention is paid to customer service	Forces continued attention on reliability and service quality due to possible incentive to reduce O&M costs to meet productivity targets	Incentives for performance standards could increase O&M, harming FortisBC's financial performance, and potentially leading to increased rates

[149] Additional provisions included in the 2007 Energy plan include the reaffirmation of provincial support for a public ownership structure of BC Hydro and for there to be no nuclear generation in the province. For more information see: British Columbia. 2010: Clean Energy Act. Bill 17. 2010.

[150] The proposed smart meter program was approved as a COS revenue requirement in 2013 and defined as a project of public convenience and necessity as a $51 million, 20 year program intended to reduce customer cost on a Net present value basis of $13.9 million. See BCUC. *In the matter of FortisBC Inc.: Certificate of Public Convenience and Necessity for the Advanced Metering and Infrastructure Project*. Decision. July, 23, 2013.

4.4.1 Proposed multi-year PBR plan 2014-2018

FortisBC's move back to a COS regime for 2012/2013 was driven mainly by interveners. FortisBC experienced fairly large rate increases (more than 5 percent) and the interveners wanted a more thorough review process in order to feel more comfortable with the magnitude of the increases.[151] Interveners argued that COS would "allow stakeholders to take a better look inside the individual costs items for increased transparency,"[152] despite FortisBC's description of the 2007-2011 PBR experience as generally positive referring to its 2007 PBR plan as "successful".[153] As a consequence of the decision to go back to COS, FortisBC was afforded an opportunity to rebase and review productivity targets.[154]

Indeed, due to the positive experiences which FortisBC had in 2007-2011, FortisBC has proposed a PBR regime applicable for 2014 to 2018 which is modeled on the previous PBR regime.[155] Notable differences between the proposed PBR and the prior PBR, however, include the proposed X factor and the treatment of capex. For example, the 2014 to 2018 PBR proposal uses the term "X-factor," not PIF, which would decrease from 1.5% in 2011 to 0.5% beginning in 2014. This reflects prior productivity gains and is set based on a study of historical total factor productivity ("TFP") gains made by other utilities across North America. For the other half of the I-X index, the inflation factor would be changed to a weighted average of the BC-CPI and average weekly earnings index from one solely based on the BC CPI.

Additionally, the proposed 2014-2018 PBR would place controllable capex under PBR. Specifically, controllable capex does not include major projects for which Certificate of Public Convenience and Necessity ("CPCN") applications have been filed. By BC law, any proposed capex project greater than $5 million requires CPCN approval and therefore would remain under COS regulation. The result would be PBR regulation for capex projects less than $5 million, but COS for projects larger than $5 million. This reflects FortisBC's desire to reduce its regulatory burden and for additional incentives, while ensuring complete and timely funding for large projects of need via COS regulation.

Similar to the 2007-2011 PBR, there would be Z-factors and an ESM in the 2014-2018 PBR. It would also contain the same annual review of certain revenue requirements, as is the case in the 2007-2011 PBR.

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151 Email correspondence with Dennis Swanson, Director of Regulatory Affairs, FortisBC. December 14, 2011.

152 Ibid.

153 FortisBC. *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*. July 5, 2013. p. 23.

154 Ibid. pp. 4-5.

155 The 2014 to 2018 PBR proposal has not yet been approved by the BCUC.

The advantages of the proposed 2014 to 2018 PBR include its use of an X-factor, its treatment of capex, and its use of performance standards. For example, the X-factor is proposed based on a TFP study analyzing the historical TFP performance of a group of relevant peers. No longer would FortisBC use a PIF set based on negotiations between itself, interveners, and the BCUC. The X factor would now be in line with the industry productivity and efficiency. The treatment of capex for projects under $5 million ensures major projects of need will be funded completely and immediately, while also imposing incentives for FortisBC to deploy capex more efficiently. There would continue to be Z-factors to limit the exposure of FortisBC to events deemed outside its control. Finally, FortisBC's proposed PBR plan would continue its use of service quality indicators setting benchmark targets based on historical performance. This would ensure FortisBC's continued attention to customer service and reliability.

The plan would, however, keep the proposed base year in place for four years without an opportunity to rebase. In previous PBR regimes, the company has had an opportunity to evaluate and, if agreed upon, rebase following three years in the 1996-2003 and following two years in the 2007-2011 PBR. For the proposed 2014-2018 PBR, the period without an opportunity to rebase could be longer.

4.5 Transitional challenges and remedies adopted

In general, FortisBC has indicated a positive experience with PBR; however, there are a number of challenges which have been highlighted by both FortisBC and interveners. The first challenge is in ensuring adequate public involvement. To mediate the problem, FortisBC has adopted the negotiated settlement process, which occurs annually to review spending plans under COS regulation. During the negotiated settlement process, FortisBC has argued that it is important to remember that the process can be prescriptive, not just critical. In terms of lessons learned, FortisBC has stressed that the Negotiated Settlement Agreement ("NSA") should be voluntary, not litigated, and that it is important to remember that both sides want a deal.[156]

The second challenge is that of maintaining the appropriate level of capex. The 1996-2003 PBR regime treated capex in a PBR framework. The 2007-2011 PBR regime left capex to be funded under a COS regulatory model. During the 2011 capex review, the BCUC noted that a major concern for the commission was that of the "growth of capital expenditures, in recent years…as it relates to continued upward pressure on rates."[157] In response, the BCUC rejected as much as $14 million in proposed capex in 2011.[158] To mitigate this concern, FortisBC has proposed in its most recent filing to treat smaller capex (identified as less than $5 million) under PBR regulation.

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156 Debienne, Don, VP Generation & Regulatory Affairs. *Performance Based Regulation ('PBR"): Streamlining the Process*. FortisBC Regulatory Presentation. Calgary, Alberta. 31 May 2006. Speech. p. 11.

157 BCUC. *In the matter of FortisBC: 2011 Capital Expenditure Plan*. Decision. December 17, 2010. p. 2.

158 Ibid.

A third challenge is ensuring equitable tariff divisions among rate classes. In response, FortisBC periodically conducts a COS study and rate design process to ensure that individual customer classes are paying their appropriate share of the revenue requirements. The most recent study was conducted in 2009, resulting in a determination that derived revenue from each rate class should equal the same ratio of revenue to costs derived from each rate class.

Figure 32. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Fostering adequate public involvements	Annual negotiated settlement process involving interveners and interested stakeholders
Ensuring recovery of capex	Use of a hybrid PBR regime which funds large capex projects under COS regulation
Preserving an equitable tariff divisions among rate classes	Periodic rebalancing studies analyzing the rate design process

In transitioning to PBR, other challenges indicated by FortisBC include establishing an appropriate base year and structuring a suitable productivity factor that is sound, tested, and reflective of business as usual. The 1993-2003 PBR was criticized not being sound, tested and reflective of business as usual.[159] To help ensure an appropriate PIF, FortisBC has gradually reduced its productivity factor over time to take into account the "low hanging fruit" gains that have already been achieved. The 1996-2003 PBR targeted a 4% PIF for O&M expenditures in 1996. The 2007-2011 PBR regime began in 2007 with a 2% PIF, while the 2014-2018 PBR proposed an X factor which would be set for all years equal to 0.5%. The most recently proposed X factor is based on a TFP analysis of the historical TFP performance of relevant peer utilities.

4.6 Implications for Nova Scotia

FortisBC has generally had a favorable view of its own PBR regime, considering it to have been beneficial to both the firm and the customers.[160] According to FortisBC, performance metrics have generally improved and the firm believes it has been encouraged to operate effectively and efficiently. It has also been valuable to the customers as evidenced by the mitigation of the rate increase in 2010 and provision of incremental "Other Income," such as revenue from third party pole contacts, incremental transmission wheeling, and incremental tax saving.[161] The

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[159] Debienne, Don, VP Generation & Regulatory Affairs. *Performance Based Regulation ('PBR"): Streamlining the Process.* FortisBC Regulatory Presentation. Calgary, Alberta. 31 May 2006. Speech. p. 10.

[160] FortisBC Inc. *Application for Approval of 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan.* June 30, 2011. p. 1.

[161] FortisBC. *Preliminary 2011 Revenue Requirements*. October 1, 2010. p. 2.

other benefits of PBR recognized by the company in its *Application for Approval of Extension of Settlement Agreement for the 2007-2009 PBR Plan for 2009-2011* are:[162]

- lower cost of service;
- no interim rates translating to greater certainty;
- annual Reviews that allow customers to review costs and obtain information about the Company's operations;
- sharing mechanisms that encourage FortisBC to find additional areas of productivity and provide a financial incentive to both the Company and a benefit to its customers;
- performance targets to ensure that FortisBC does not earn a financial incentive at the expense of non-financial performance;
- FortisBC management is better able to focus their efforts on operating the utility; and
- the ROE Incentive Adjustment Mechanism has reduced revenue requirements by a total of $4.3 million for the combined 2007 and 2008 test years resulting in cumulative rate relief of approximately 2.1%.

One notable lesson from FortisBC's experience is that **capex concerns have been circumvented by the use of a "hybrid PBR"** where capital costs continue to be reviewed under COS. Having rebased following the 2007-2011 PBR, FortisBC has suggested that including some capex in PBR funding would ensure some productivity gains, while ensuring a moderation of negative pressure on its productivity performance and that only approved capital expenditures will be reflected in customer rates.[163] Moreover, FortisBC argues that excluding CPCN projects is appropriate and will result in a process akin to the adoption of a "capital tracker."[164]

However, despite the general successes noted by FortisBC, during the Workshop for the 2011 Revenue Requirements, some consumer groups[165] raised the issue of the increasing overall electricity rates and the impact on residential ratepayers, in particular on low and fixed income residential ratepayers. These groups noted that the BCUC's approval of FortisBC's 2011 Revenue Requirements, in combination with the significant BC Hydro flow through rate increase for 2011, could have resulted in general rate increases.[166, 167]

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162 FortisBC. *FortisBC Inc. Application for Approval of Extension of Settlement Agreement for the 2007-2009 PBR Plan for 2009-2011*. September 4, 2008, p. 3.

163 Ibid. p. 49.

164 Ibid. p. 55.

165 These consumer groups collectively known as the BCOAPO, include the BC Old Age Pensioners' Organization, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre.

166 BCUC. *An Application of FortisBC Inc.: 2010 Annual Review, 2011 Revenue Requirements and Negotiated Settlement Process*. Order Number G-184-10. December 9, 2010.

Other lessons learned from FortisBC in terms of designing a PBR mechanism include:

- **Flow through expenses, or ("Y Factors") should be re-forecast annually**. FortisBC's proposed 2014-2018 PBR regime would include a number of flow through items to consumers which are deemed non-controllable costs. For Nova Scotia, the use of Y factors would help to ensure the financial health of NSPI by ensuring it is only forced to pay costs within its control.

- **Z Factors help to ensure ratepayers only pay actual costs outside of FortisBC's control**. If Nova Scotia pursued PBR, the use of a Z-factor would allow NSPI to adjust rates or revenue and ensure that NSPI is not responsible unforeseeable, exogenous costs.

- **Use of locally based inflation measurements**. Similar to FortisBC's previous PBR regimes, an inflation factor should be based on a metric that is easy to calculate, easy to understand, and rely on readily available public data. It is also important that the inflation represents the utility's observed cost of behavior. FortisBC's use of locally composite labor and non-labor indices is "more reflective of company costs, which consist of both labor and non-labor components, than an economy-wide inflation measure such as CPI."[168] For NSPI, indexing costs based on local cost measurements ensures NSPI makes financial plans based on the most relevant estimates of future costs.

- **Involve stakeholders**. FortisBC has in the past (and proposes to continue) to conduct annual reviews of revenue requirements and on company performance. Determining revenue requirements annually involves a negotiated settlement process. This allows interested stakeholders the opportunity to participate in the ratemaking process and, for Nova Scotia, would help ensure popular acceptance of utility rates and planning.

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[167] Between 2011 and 2013, under which time FortisBC was regulated under both PBR (2011) and COS (2012-2013), the BCUC approved general rate increases of 5.9%, 4% and 6.9% respectively.

[168] FortisBC. *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*. July 5, 2013. p. 42.

5 Georgia Power Company

Georgia Power Company ("GPC") operates as a vertically integrated utility providing electricity to retail customers within its traditional service area across the State of Georgia and to wholesale customers in the Southeastern United States. Despite the momentum in many US states for unbundling vertically integrated utilities in favor of competitive markets, Georgia lawmakers and regulatory bodies decided against restructuring its electricity market following a number of public workshops and hearings in the late 1990s. This case study demonstrates how some existing characteristics may lead a jurisdiction to favor keeping a vertically integrated utility intact.

5.1 Overview of Georgia Power Company

GPC is an investor-owned electric utility ("IOU") that is fully regulated by the Georgia Public Service Commission ("PSC"). GPC is the largest electric utility in the state and is an operating subsidiary of the Southern Company. Currently, GPC owns 18 generating plants and 20 hydroelectric dams that serve approximately 2.4 million customers in 155 of Georgia's 159 counties.

In 2012, GPC had a total of 17,983 MW of generating capacity. This was more than seven times that of Nova Scotia Power.[169] However, similar to Nova Scotia's generation mix, GPC is heavily dependent on fossil fuels, which comprise over half of installed capacity. In 2012, the mix was approximately 51% coal, 11% nuclear, 6% hydro, and 32% split between diesel, combined cycle, and combustion turbines. GPC wholly owns numerous generating facilities and co-owns other generating facilities with other generators. GPC has wholesale contracts for capacity and energy with cogenerators and other providers both within and outside the State of Georgia. GPC typically issues requests for proposals ("RFPs") for new generation capacity. In addition to traditional PPAs, GPC also accepts asset purchase and sale agreements ("APSAs"), which is the purchase of an existing generating asset already in commercial operation.

Georgia has an Integrated Transmission System ("ITS"), jointly-owned by GPC, the Oglethorpe Power Corporation ("OPC"), the Municipal Electric Authority of Georgia ("MEAG"), and the city of Dalton. GPC owns approximately 12,606 of the 17,000 transmission line miles in the State of Georgia. Initially, GPC owned nearly all of the transmission lines. However in January 1975, GPC entered into separate contracts with each of the other utilities, selling them ownership interests and equal access to the transmission facilities before there was any federal mandate for an open-access transmission tariff ("OATT"). The ITS is also interconnected with neighboring utilities through transmission tie lines. Exporting generators that wish to interconnect with the ITS may interconnect to the Georgia Integrated Transmission System through any of the Georgia Integrated Transmission System participants: Dalton Utilities, Georgia Power Company (Southern Company), Georgia Transmission Corporation, or MEAG Power.

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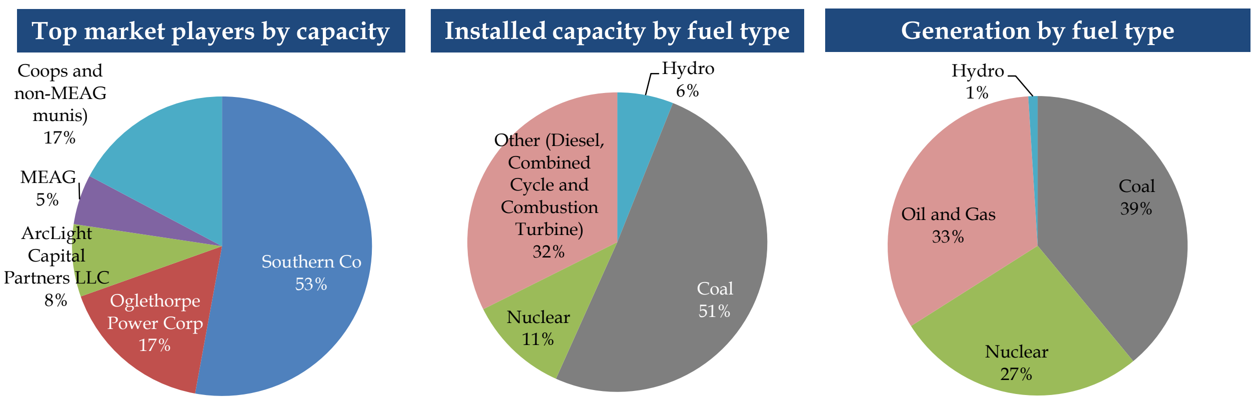
[169] Georgia was ranked 10th in net electricity generation and eighth in retail sales of electricity in 2013.

Figure 33. Georgia Power Company snapshot

Key facts	
Customers (2012)	2,359,333
State GDP growth est. (2014)	3%
Installed capacity (2012)	17,983 MW
Peak demand (2012)	24,636 MW
Compounded annual load growth (2009-2013)	-0.9%
Production (2013)	84.7 TWh
Distribution lines (2012)	72,774 mi
Transmission lines (mi)	12,606 mi



Source: Georgia Power Company, commercially available third party database

The ITS is located within the Southern Company Control Area and Southern Company Services is responsible for operating the control area in compliance with North American Electric Reliability Corporation ("NERC") and Southeast Reliability Corporation ("SERC") guidelines. At the local level, the ITS is operated by GPC through two Transmission Control Centers ("TCC"). The TCCs are the system operations agents for all of the owners of the ITS. One TCC is located in the northern region of the state, while the other is located in the southern region. The Transmission Control Center monitors bus voltage, transmission line loading and network status throughout the ITS. The TCC also reviews maintenance outage requests from the ITS owners to see if the transmission system can withstand any single contingency during scheduled maintenance activities.

For distribution, there are three types of electric utilities that provide retail electric service in Georgia. These include IOUs, customer-owned utilities ("cooperatives") and government-owned utilities ("municipals"). GPC is the only electricity IOU left in Georgia following the merger with Savannah Electric, another Southern Company subsidiary, in 2006. Southern

Company Services, also a Southern Company subsidiary, operates the Power Control Center ("PCC") in Birmingham, Alabama, which coordinates the integrated operations of the Southern electric system, including generation and transmission facilities in Georgia. The Georgia PSC fully regulates GPC, but has otherwise limited oversight of the remaining generators and distributors with regards to rate-making.

There are also electric membership corporations ("EMCs") and 52 municipally-owned electric systems in the state. Of the 42 EMCs, 38 distribute power received from OPC, one receives power from GPC, while the remaining three distribute power received from the Tennessee Valley Authority ("TVA"). Each EMC is owned by its customers and is self-regulating, with their rates set by the EMC's Board of Directors. Of the 52 municipally-owned utilities, forty-nine purchase their power from the MEAG. The municipally-owned utilities of Dalton, Chickamauga and Hampton remain unaffiliated with MEAG.

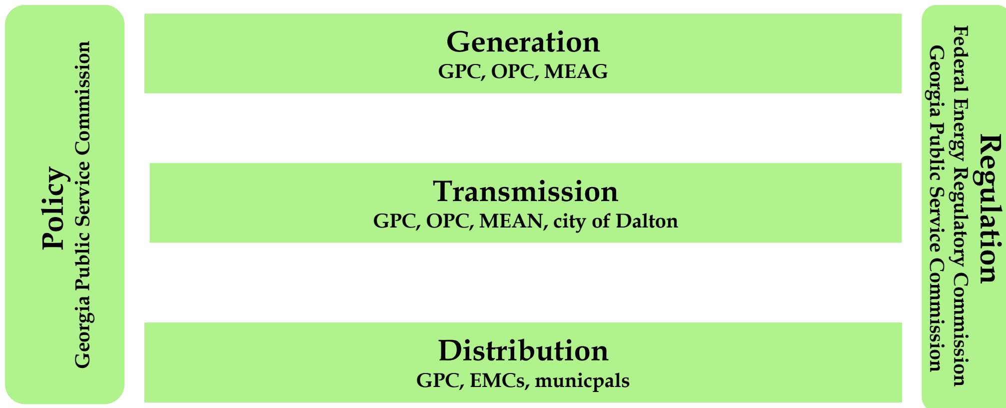
Some retail competition has been present in Georgia since 1973 with the passage of the *Georgia Territorial Electric Service Act* ("Territorial Act"). This Act enables customers with manufacturing or commercial loads of 900 kW or greater a one-time choice in their electric supplier for the life of the premise when they add a new load to the network. It also provides eligible customers the opportunity to transfer from one electric supplier to another provided all parties agree. The PSC resolves territorial disputes and customer complaints involving customer choice and approves requests for transfer of retail electric service.

Georgia clearly has a larger electricity market than any of the maritime provinces of Canada. In fact, the population of Nova Scotia, New Brunswick, and Prince Edward Island combined – roughly 1.82 million – is still less than the GPC's 2.4 million customers. However, GPC draws several parallels with Nova Scotia Power as a dominant privately-owned vertically integrated utility serving most of the power needs in the jurisdiction. In the New Brunswick case study, the importance of a privately-owned utility company (vs. current arrangements for NB Power) is clearly underscored. In this case study, it is useful to note the institutional and regulatory framework in Georgia and to understand the deliberation process that Georgia underwent in considering competitive electricity markets, which will be discussed in the following sections.

5.2 Current institutional and legal framework

As Georgia's only IOU, GPC is fully regulated by the PSC. This includes market administration, monitoring and rate setting. The Federal Energy Regulatory Commission ("FERC") is responsible for implementing and enforcing statues from the US Congress. Beyond that, generating and distribution entities in Georgia receive minimal oversight from the PSC. This section will focus specifically on the regulation of GPC.

Figure 34. Georgia market structure



Source: LEI

5.2.1 Regulation and policy setting

The principal economic and policy regulator at the federal level for the electric power industry is FERC, an independent regulatory agency within the US Department of Energy ("DoE"). FERC is charged with implementing, administering and enforcing most of the provisions of the statutes that regulate the electric utility industry passed by the US Congress. FERC oversees wholesale electric rates and service standards, as well as the transmission of electricity in interstate commerce. FERC ensures that wholesale and transmission rates charged by utilities are just and reasonable and not unduly discriminatory or preferential. It also reviews utility pooling and coordination agreements. Finally, FERC reviews rates set by the federal power marketing administrations, makes determinations as to exempt wholesale generator status under the *Energy Policy Act* ("EP Act"), and certifies qualifying small power production and cogeneration facilities.

At the state level, the Georgia PSC is responsible for overseeing electric power companies, and any "persons owning, leasing or operating public electric light and power plants furnishing service to the public."[170] Pursuant to the Integrated Resource Planning Act ("IRP Act") of 1991, the PSC has the responsibility to review and approve supply-side and demand-side resource options filed by the utility companies. Prior to enactment of the IRP Act, the PSC did not review a utility's management decisions pertaining to the need, planning, and construction of expensive electric generating facilities until the company applied for financing approval or filed for recovery of these costs in rate case proceedings after the plants were partially built or completed.

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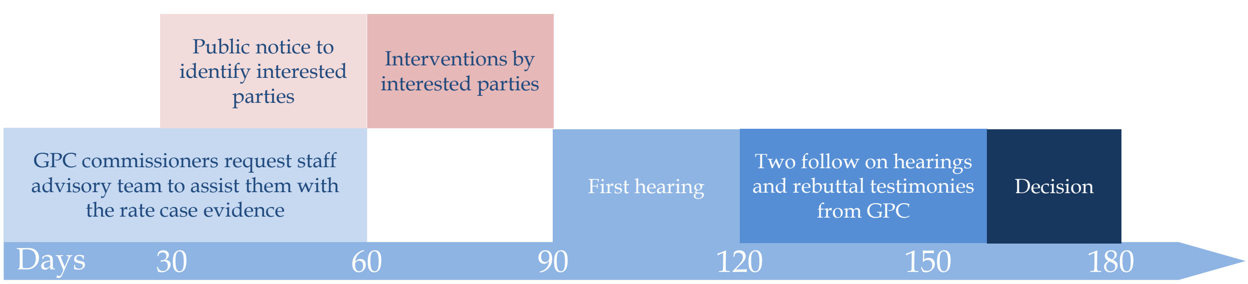
[170] Georgia Code. *Public Utilities and Public Transportation*. G.A. § 46-2-21.

5.2.2 Regulatory oversight of charges

Since 1996, GPC has followed an alternative rate plan ("ARP"), which predetermines increases in rates based on cost growth forecasts through a rate plan every three years. The PSC has exclusive power to "determine just and reasonable rates and charges to be made by any person, firm or corporation subject to its jurisdiction."[171] However, as noted previously, while the GPC is under full PSC rate-making jurisdiction, the PSC has limited authority with respect to cooperatives or municipals, who must only file their rate with the PSC. GPC also has an earnings sharing mechanism ("ESM"). Under this mechanism, if the GPC's actual earnings exceed the top end of the authorized earnings band, as determined in the Annual Surveillance Report, the GPC will directly refund to customers two-thirds of any earnings above the authorized band. Currently the earnings band is between 10% and 12%. While a rate case is submitted every three years, GPC will not file a general rate case in the interim period unless its projected earnings drop below 10%, in which case GPC may petition for an interim cost recovery ("ICR") tariff. The last rate case was filed in June 2013, with rate cases occurring every three years prior in 2010, 2007, and 2004. The rationale behind the ESM and the ICR tariff will be discussed in Section 5.4.3.

In order for GPC to increase or revise its rates, it must first file a rate case to the PSC. A separate staff advisory team is designated to support and answer questions raised by PSC commissioners. 30 to 60 days after the filing, GPC must publish a notice of hearing in newspapers of general circulation in its service area. The PSC then issues a scheduling order and may hold a pre-hearing conference with all interested parties. For 30 days following the first published notice of the proceedings, requests to intervene are considered by the PSC commission. The PSC commission grants the requests either at the pre-hearing conference or on the first day of the hearing. The interveners can request information from the utility, which GPC must provide.

Figure 35. Adjudication timeline for rate cases



Source: LEI

[171] Georgia Public Service Commission. *Staff Report on Electric Industry Restructuring: Docket Number 7313-U*. January 1998. p. 21.

GPC offers several non-traditional pricing options. For commercial and industrial customers, these include real-time pricing, price protection options, time-of-use rates, and a multiple load management rates. For residential customers, the company offers time-of-use, flat bill, and direct-load control options. The costs that customers receive include the current service charge, environmental compliance cost recovery ("ECCR"), nuclear construction cost recovery ("NCCR"), and municipal franchise fees. Current service charges recover fuel and other costs related to generation, transmission, and distribution of electricity from power plants to homes and businesses. These charges also recover the costs of various customer services – such as billing, customer support and call centers, and the costs of energy efficiency programs to help customers save money and energy. ECCR charges recover the costs of installing and operating environmental controls mandated by the government. NCCR charges recover financing costs related to the construction of the two new nuclear units at Plant Vogtle. Lastly, the municipal franchise fees charges recover fees paid to the cities for allowing GPC to conduct business within the city limits and on the cities' rights-of-way. All charges and fees are presented to the GPC for review, feedback, and approval before they are added to customer bills.

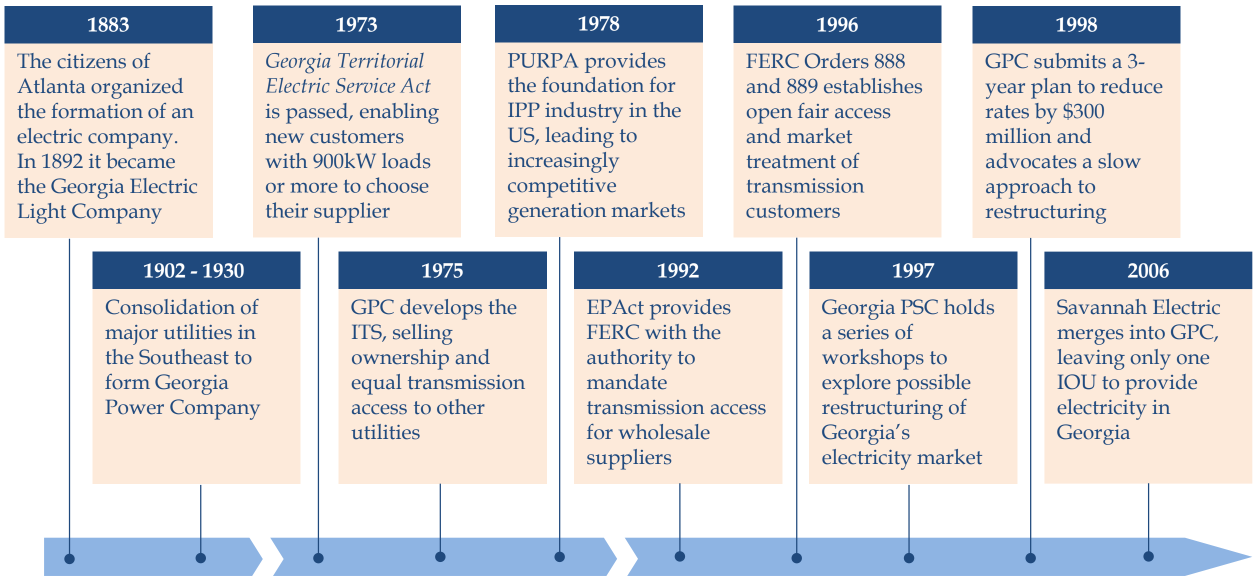
5.3 History of restructuring and recent developments

While GPC has never been restructured into separate generation, transmission, and distribution companies, national influence has led the PSC to launch proceedings to assess the viability of a competitive electricity market in Georgia. This section discusses the context behind those proceedings and why competitive restructuring failed to materialize.

5.3.1 Electricity restructuring in the United States in the 1990s

Beginning in the 1990s, a number of states undertook measures to require or encourage vertically integrated utilities to disaggregate into separate generation transmission or distribution entities. Also, participation in independent system operators ("ISOs") or regional transmission organizations ("RTOs") was encouraged at the federal level. The current transition of the electric power supply industry from a regulated monopoly structure to a competitive market environment was initiated by the enactment of the *Public Utility Regulatory Policies Act* of 1978 ("PURPA"), the *EP Act* of 1992, and FERC Order No. 888 in 1996. FERC Orders 888 and 889 established open access rules, setting of transmission access rates, disclosure of transmission capacity information, functional unbundling of transmission, and introduced the ISO concept. These Orders were the basis behind much of the restructuring in North America during the late 1990s and early 2000s.

Figure 36. Timeline of key events for GPC



Source: LEI

5.3.2 Proceedings on restructuring the electricity market

Beginning in April 1997, the Georgia PSC held a series of four informal workshops to examine issues related to restructuring the electric industry in Georgia. The purpose of these workshops was to bring about a heightened awareness of the issues involved in restructuring the electric industry and to examine the advantages and disadvantages of making such a change. The workshops also served to begin examination of the appropriate regulatory and legislative steps necessary for restructuring to successfully unfold. Presenters at the workshop included representatives from each sector of the electric industry, including: IOUs; municipals; cooperatives; independent power producers; and power marketers. Also present were: consumer advocates; environmentalists; various governmental agencies, including members of the State Legislature; and representatives from the residential, commercial, and industrial customer classes. Presenters focused their discussion on the structure of the industry in Georgia and what modifications may be necessary to establish a more efficient framework for the future.

After the workshops were completed, the Staff continued to compile data and information from the written comments, white papers, focus group reports, presentations, and transcripts. From the point of view of state policy makers, the regulatory system was working well in Georgia. At the time, electric rates were generally at or below the national average – a trend which continues to hold true. Due to the relatively low cost of electricity in the state, Georgia decided that there was no urgent need to restructure the electric industry. The ultimate decision also had to do with specific design elements, such as the ITS and the existing competition structure that developed out of the *Territorial Act* of 1973. The studies conducted by the PSC in 1998 essentially marked the end of restructuring efforts in Georgia.

5.3.3 Recent developments

GPC's rates have been determined on a cost of service ("COS") basis since its inception. Under this regime, GPC is allowed to recoup its capital costs from consumers and earn a set return on investment ("ROE"). In June 2013, GPC filed a rate case to increase rates by $1.46 billion. The PSC reached an agreement to increase rates by $873 million, 40% less than originally requested. This request was made to pay for GPC's coal-burning power plants and installation of smart grid technologies.

The Southern Company is also making major investments in Plant Vogtle 3 and 4, two 1,215 MW nuclear development projects in Georgia that are expected to come online in 2017 and 2018. These will mark the first new nuclear units built in the US over the last three decades. Additionally, in 2012, GPC announced its Advanced Solar Initiative ("ASI"), approved by the PSC, for the purchase of 70 MW of solar energy from new projects in Georgia each year for three years beginning in 2013. The 2013 process has been completed, and the 2014 process will commence soon. At the conclusion of GPC's IRP process in 2013, the PSC ordered Georgia Power to expand its solar energy capacity by 425 MW in addition to the ASI.

5.4 Rationale for specific design elements and pros and cons of selected design

This section evaluates and discusses the rationale behind three unique design elements that have largely shaped Georgia's views on competitive electricity markets. These include the ITS, the limited competition for new industrial customers that was articulated in the *Territorial Act* of 1973, and GPC's earning sharing and cost recover mechanisms.

Figure 37. Summary of specific design elements

Design elements	Rationale	Pros	Cons
Integrated transmission system	To increase coordinating and cost efficiency	Has made it feasible for limited competition to exist in Georgia	Transmission planning is carried out by transmission owners
Limited retail competition	To allow customers with large loads to select their electricity supplier	Reliable electric service at consistent rates	Does not allow small retail customers to choose electricity provider
Earnings sharing mechanism and interim cost recovery	To ensure that GPC delivers reasonable ROE and to prohibit intervention from excessive windfalls	Incentivizes GPC to deliver consistent ROE and provide accurate cost forecasts	No cost recovery is available if actual ROE is below 10%

Source: LEI

5.4.1 Integrated Transmission System

Several factors led to the creation of Georgia's ITS. During the early 1970's, OPC, MEAG, and the City of Dalton purchased generating capacity and an ownership interest in the transmission system from GPC. This made it possible to receive energy from the generating plants in which they had purchased an ownership interest. As such, the existence of a fully integrated transmission system has made it economically feasible for limited competition to exist in Georgia for the past 40 years. Owners of the system are able to compete for customer choice loads in accordance with the *Territorial Act*.

Although the transmission system is defined as jointly-owned, each transmission facility has a single owner. Each utility is responsible for maintaining its own facilities and develops separate maintenance standards for its respective facilities. These standards make no distinction between the facilities that serve the owner and the facilities that serve the other ITS participants. The cost of maintenance is the responsibility of the owner of the facility.

The utility's percentage investment in the system is equal to its peak load ratio.[172] If the utility's investment is not equal to its load ratio, it can consider the purchase or sale of transmission facilities from or to another co-owner.[173] In the event that a utility has more invested in the system than is required, then the under-invested utility is required to pay the over-invested utility the amount of the over-investment multiplied by the higher of the two utilities' carrying charge. However, paying this amount does not confer any ownership interest in the facilities.

The ITS arrangement is unique to Georgia. The ITS allows Georgia utilities access to power delivery systems for buying and selling available wholesale electric energy both within and outside of Georgia.

5.4.2 Limited retail competition

As mentioned earlier, the *Territorial Act* of 1973 established territories for serving residential and small commercial customers as well as initiating the (frequently disputed) customer choice provisions for large customers. Under the Act, every geographic area within the state was assigned to an electric supplier by the Commission. Customers with connected loads of less than 900kW must take electricity from the franchised supplier. However, if any customer with a load of 900kW or more locates within the corridors of an electric supplier's lines, that customer may choose its electric supplier. This means that a large load premises must be within 300 feet of the lines owned by the secondary supplier. For the few remaining areas still unassigned by the *Territorial Act*, any supplier may serve the premises if chosen by the large load customer. Once a customer chooses a supplier, the *Territorial Act* provides that the chosen electric supplier has the exclusive right to serve that customer for the life of the premises.

The *Territorial Act* was the result of a compromise negotiated by all of the electric suppliers doing business in the State of Georgia during the early 1970's. A 900kW level was agreed upon as the load threshold for customer choice. This load level was chosen because a 900kW load was

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[172] Georgia Public Service Commission. *Staff Report on Electric Industry Restructuring: Docket Number 7313-U*. January 1998. p. 20.

[173] Ibid.

considered sufficient to justify the economics of the investment necessary to serve the load and foster competition for that load.[174]

Some advantages of the current structure have been to produce reliable electric service and provide that service at a price that is reasonable when compared to other states and the nation as a whole. For example, the current residential price of electricity in Georgia is 10.89 cents per kWh compared to the national average of 11.88 cents.[175] However, the drawback is that no one else can sell power, except to a utility – even an individual owning a few solar panels. This makes supply decisions for retail customers impossible, even at the micro level. There are two camps of thought on the issue of the *Territorial Act*. Some believe that the *Territorial Act* has worked well to foster price stability, while others believe that the *Territorial Act* should be repealed and the market should be allowed to develop without constriction.

The participants at the workshops and in the focus groups reached a general consensus for restructuring the electric industry. The consensus was that, if generation was opened to competition, territorial assignments for distribution lines should be kept and distribution service should remain as a state regulated service. However, no such actions have been taken.

5.4.3 Earnings sharing mechanism and interim cost recovery

As noted in Section 5.3.3, GPC is under a COS regime with an ESM. The rationale for the ESM is to motivate GPC's management to improve efficiency and to help avoid the possibility of unscheduled regulatory interventions due to windfall profits. In the most recent rate case filed in June 2013, a settlement with the Public Interest Advocacy Staff ("PIAS") of the PSC was reached on December 17, 2013. The settlement retains the ESM where the ROE was set at 10.95% and the GPC will refund customers two-thirds of the incremental earnings above 12% ROE. It was decided that if actual earnings fall below 10%, there would be no cost recovery. However, if GPC projects that its retail earnings will be below 10%, it may at any time files for the ICR tariff, which would adjust ROE earnings to 10%.

5.5 Implications for Nova Scotia

The Georgia electricity market contains unique characteristics. While GPC is a major power supplier in Georgia, it is not the only one. Municipals and cooperatives still constitute sizable generating capacity in Georgia. The market structure provides several interesting points of note for Nova Scotia:

- **The Georgia ITS predates FERC's open access mandate and continues to work well.** As the ITS is co-owned by all the generators, transmission is more cost effective by eliminating duplication of facilities and facilitating competition among utilities for new

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174 Ibid. p. 25.

175 EIA. "US Energy Information Administration Independent Statistics Analysis." Accessed April 2014. <http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a>

customers with loads of at least 900 kW. ITS members also share access to back-up equipment used in emergencies. Partly due to ITS and Georgia's cheap fuel sources, costs have remained below the national average. However, the ITS is a historical feature that Georgia pioneered based on the market structure at the time. As such, it may not be appropriate for all jurisdictions that have different transmission planning systems, needs, or constraints.

- **Incentivizing mechanism under COS helps retain adequate ROE.** The ESM that GPC must follow reduces the risk of excessive windfalls at the expense of customers. With the addition of ICR, the state ensures a reasonable ROE if cost forecasts are below the 10% band. This allows borrowing costs to remain manageable for GPC when investing in new assets.

- **Cheap energy sources have blunted sizable renewables investment**. Georgia currently has no renewable energy targets. One of the reasons for cheap electricity prices comes from the fact that fossil fuels comprise a significant portion of Georgia's energy mix. While GPC has made some progress in solar energy through its ASI, it remains the policy of GPC that renewable generation sources will be developed and purchased at a cost which is at or below the company's avoided cost. Any decision to purchase additional resources at prices above the company's avoided cost should be the decision of the PSC. This is different from Nova Scotia's goal of expanding its renewable energy capacity.

6 New Brunswick

New Brunswick's electricity system has undergone several major restructurings that have allowed it to experiment with both competitive and vertically integrated market structures. In October 2013, after nine years of limited competition in the generation sector, the Government of New Brunswick decided to amalgamate New Brunswick Power Corporation ("NB Power") back into a single Crown company that services most of New Brunswick's generation, transmission, and distribution needs. This case study discusses the conditions under which New Brunswick's provincial government based its restructuring decisions.

6.1 Overview of the New Brunswick market

New Brunswick's electricity market is serviced almost entirely by NB Power, a vertically integrated and provincially-owned Crown utility company responsible for most of the province's generation, transmission, and distribution. While NB Power has mostly served as a bundled utility since its inception, the Government of New Brunswick has also experimented with competitive electricity markets, starting by unbundling the company's generation, transmission, and distribution assets from 2004 to 2013. The decision to revert back to vertical integration was largely because a competitive electricity market failed to develop as policy makers had anticipated. This case study examines those failures in more detail, and discusses what the implications are for Nova Scotia.

At present, NB Power controls approximately 82% of New Brunswick's generating capacity, primarily through hydropower, nuclear power, and fossil fuels. Of this capacity, NB Power owns 12 hydro, coal, oil, and diesel-powered stations. The network of conventional generating stations has an installed net capacity of approximately 2,853 MW comprised of 1,439 MW thermal, 889 MW hydro, and 525 MW combustion turbine as of end of 2013.[176] In addition, NB Power also owns the 660 MW Point Lepreau Nuclear Generating Station, which provides nearly 35% of New Brunswick's electrical energy requirements. Point Lepreau is the only nuclear generating facility in Atlantic Canada. Like Nova Scotia, New Brunswick hopes to secure 40% of its energy from renewable energy sources by 2020.

NB Power is currently the sole developer and owner of the transmission system in New Brunswick. The transmission grid is approximately 6,849 kilometres long and includes high voltage lines at 345, 230, and 138 kV. As New Brunswick is situated between several other jurisdictions, NB Power also operates a total of 15 interconnections with Hydro-Québec, Nova Scotia Power, Maritime Electric in Prince Edward Island ("PEI"), and the ISO New England network in the United States. Figure 39 shows the intra-area transmission capacity limits in all of the jurisdictions in the Maritimes region as of 2013.[177] It is worth noting that the areas of Nova Scotia, PEI, and northern Maine are each connected only to New Brunswick.

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[176] NB Power. *Annual Report 2012-2013*. 2013.

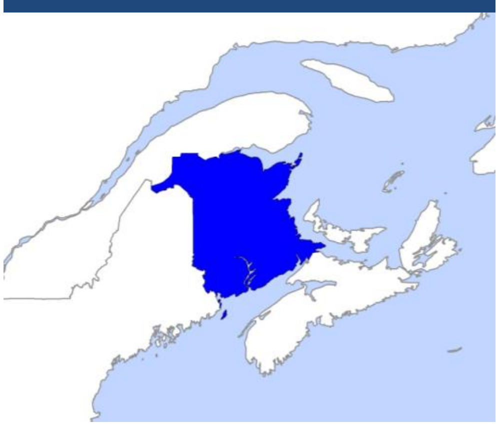
[177] Northeast Power Coordinating Council, Inc. NPCC 2013 Maritimes Area Comprehensive Review of Resource Adequacy. September, 2013.

There are three municipally-owned utilities that distribute electricity in New Brunswick, within the municipal boundaries of Saint John, Edmundston, and Perth-Andover – Saint John Energy, City of Edmundston Electric, and the Perth-Andover Electric Light Commission, respectively. In accordance with the *Edmundston Act, 1998* and the *Municipalities Act*, these municipal utilities are not allowed to extend distribution of electricity beyond their territorial limits. Other than a 30-day filing requirement with the Energy and Utilities Board ("EUB") however, their rates are set without any formal regulatory process. NB Power serves all other areas of the province and its rates must be approved by the EUB following a public hearing.

New Brunswick shares a number of similarities with Nova Scotia. With approximately 756,100 residents, New Brunswick's customer base is similar to Nova Scotia's. Consequently, New Brunswick and Nova Scotia share a similar level of generation capacity relative to other provinces in Canada. While Nova Scotia Power is a privately owned company, much like NB Power, it dominates nearly all of the generation transmission and distribution services in the province of Nova Scotia. Lastly, both provinces currently have dependencies on fossil fuels relative to many other jurisdictions in North America. With a requirement of 40% of electricity to be derived from renewable energy sources by 2020 however, Nova's Scotia's renewable portfolio standard ("RPS") is in line with New Brunswick's renewables target.

Figure 38. New Brunswick snapshot

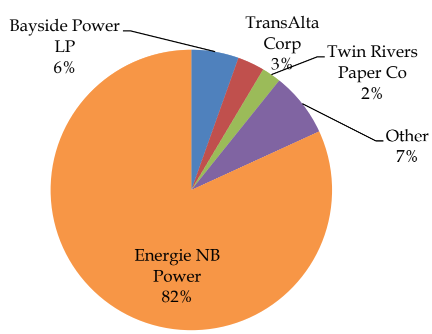
New Brunswick



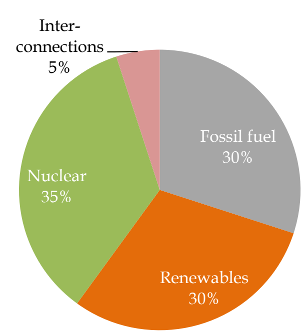
Key facts

Population (2013)	756,100
GDP growth est. (2014)	0.9%
Installed capacity (2013)	4,839 MW
Peak demand est. (2013)	3,200 MW
Compounded annual load growth (2009-2013)	1.8%
Production est. (2010)	13 TWh
Number of distributors	4
Number of transmitters	1

Top market players by capacity

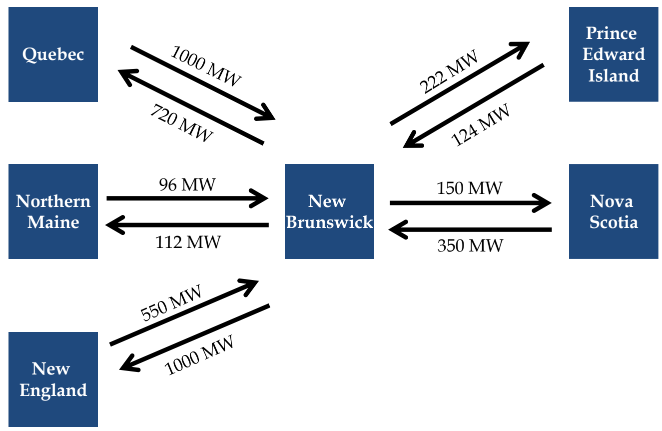


Installed capacity by fuel type



Source: New Brunswick Department of Energy and Mines, NB Power

Figure 39. Maritimes area transmission capacity limits

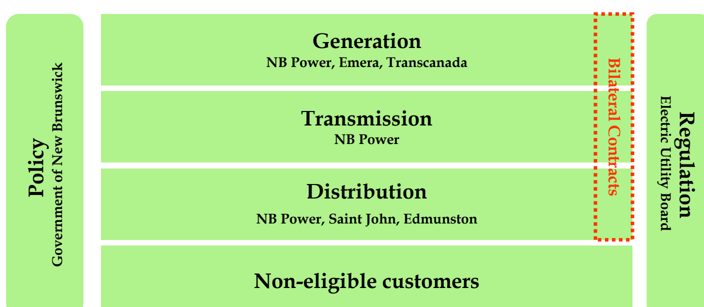


Source: Northeast Power Coordinating Council, Inc. NPCC 2013 Maritimes Area Comprehensive Review of Resource Adequacy. September, 2013. p. 8.

6.2 New Brunswick's current institutional and legal framework

Multiple restructurings of New Brunswick's electricity system have shifted regulatory responsibilities over time, leaving a legacy on the current design of the current institutional and legal framework. Under the current framework, generator risk is permanently assigned to utility customers and their protection will be a combination of government scrutiny for new investments and regulatory oversight. This section describes the various regulating institutions found in New Brunswick today and what their responsibilities are in administering the electricity system.

Figure 40. New Brunswick market structure



Source: LEI

6.2.1 Regulation and policy setting

The Government of New Brunswick is responsible for setting electricity policy within the province. In October 2012, the Minerals and Petroleum Development Branch and the Geological Surveys Branch of the Department of Natural Resources joined the Department of Energy to form the new Department of Energy and Mines. The Policy, Planning and Regulatory Affairs

Division within the Department is responsible for policy matters relating to the electricity sector (including NB Power and the system operator), downstream petroleum and natural gas, pipelines, the EUB, renewable energy, energy efficiency, and emerging energy technologies. This includes legislative and regulatory policies in relation to the *Electricity Act*, the *Gas Distribution Act*, the *Pipelines Act*, the *Petroleum Products Pricing Act*, and the *Energy and Utilities Board Act*. The Executive Council of New Brunswick (of which the Minister of the Department of Energy and Mines is part) may, at any time, issue directives which NB Power's board of directors must adhere to.

The EUB is an independent quasi-judicial board charged with regulating public utilities. Specifically, the EUB's mandate includes approving rate increases for NB Power Distribution customers, regulating the system operator, approving any changes to the Open Access Transmission Tariff ("OATT"), ensuring the Point Lepreau Deferral Account is recovered in rates, reviewing applications to participate in the electricity market, and resolving disputes regarding market rules. The Board's regulatory functions are carried out through both written and oral proceedings and representative groups are encouraged to participate in the process. Board hearings, which resemble court proceedings, are conducted by a panel of three or more Board members. The Board members then deliberate and issue a written decision, usually within 45 days of the hearing.

6.2.2 Administration and monitoring of the electricity system

Two entities administer the electricity markets, and are responsible for market evolution and design: NB Power and the EUB. Before NB Power was reintegrated in 2013, the New Brunswick System Operator ("NBSO") was mandated to take over the electricity system operation functions. NBSO is now dissolved and the system operation functions previously performed by the NBSO are now performed by the Transmission and System Operator ("T&SO") within NB Power. NB Power also undertakes planning to maintain and ensure the adequacy and reliability of the integrated electricity system for present and future needs.

However, monitoring and enforcing reliability standards, which were also the responsibilities of NBSO, are independently reviewed outside of NB Power by the EUB. The EUB has authority comparable to the Federal Energy Regulatory Commission ("FERC") to approve, monitor, and legally enforce reliability standards. The current regulatory framework recognizes the North American Electric Reliability Corporation ("NERC") as a standards development body and also authorizes the EUB to delegate monitoring functions to the Northeast Power Coordinating Council ("NPCC").

6.2.3 Regulatory oversight of charges

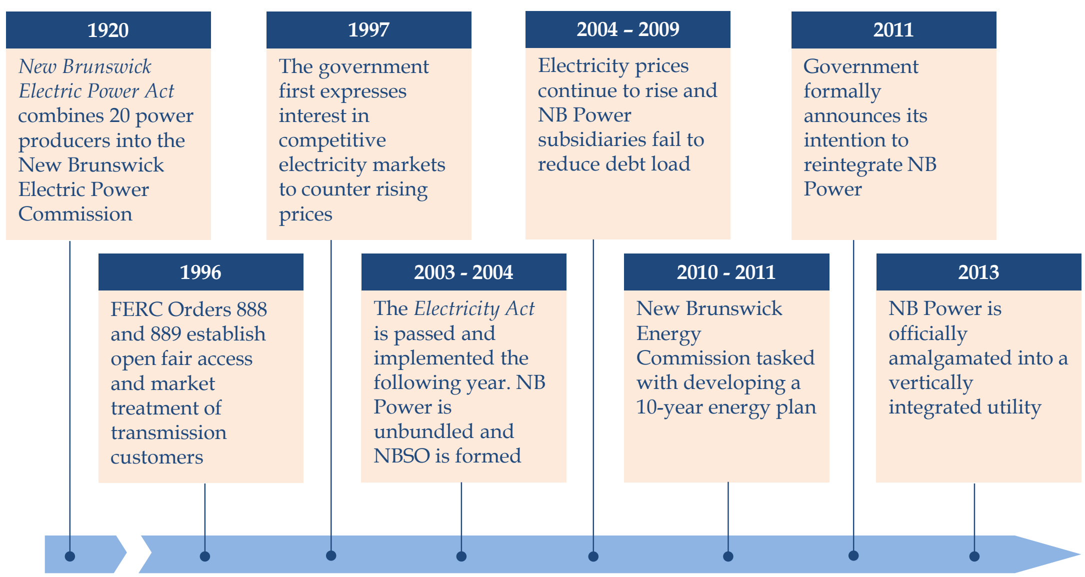
NB Power is required to demonstrate its costs and revenues across the entire company when requesting rate changes. Before the reintegration of NB Power, rate changes of less than 3% were exempt from any regulatory scrutiny. This is no longer the case; the current rules subject NB Power to regulation through public hearings for any rate increase, even if it is under 3%. In addition, NB Power is required to assess electrical system requirements through an Integrated Resource Plan ("IRP"). This process intends to utilize the principle of least cost procurement, economic and environmental evaluations, determine appropriate risk values for future electricity requirements, and the best options to meet them. The results of this IRP process are shared with NB Power's customers and stakeholders by submitting the IRP to the EUB at three year intervals or more frequently if directed by the EUB.

In addition to submitting the IRP, NB Power was also required to file a 10-year strategic, financial, and capital investment plan with the EUB during its first year as an integrated utility, and will provide annual financial forecasts to be used by the EUB in the rate-setting process. NB Power is now also required to issue quarterly financial statements and the utility, as represented by the CEO and the Chairman of the Board, must appear annually before the New Brunswick Legislature's Crown Corporations Committee.

6.3 History of restructuring and recent developments

Two major restructurings have occurred in New Brunswick over the last decade. In 2004, NB Power was broken up into five separate companies. With unsatisfactory levels of competition in the power market for nine years following restructuring, the government decided to reintegrate NB Power into a bundled utility in 2013. This section discusses the context behind those restructuring decisions and how its current regulatory institutions developed.

Figure 41. Timeline of key electricity restructuring events in New Brunswick



Source: LEI

6.3.1 Internal and external pressures on vertical integration emerge

On April 24, 1920, the government enacted the *New Brunswick Electric Power Act* which amalgamated approximately 20 power producing organizations into what became the New Brunswick Electric Power Commission. Over the next 84 years, very little changed with regards to the institutional structure of New Brunswick's electricity system, and the company continued to provide nearly all of the generation, transmission, and distribution requirements in the province. In 1996, FERC issued Order 888, which promotes wholesale competition through open access non-discriminatory transmission services by public utilities. The Northeast US was a major export market for NB Power, representing 18% of its revenues from power sales at the time. [178] However, New Brunswick's access to the Northeast markets was limited since NB Power did not provide wholesale access and its transmission tariff was not subject to regulatory review. As a result, transmission services in many Canadian jurisdictions, including New Brunswick, did not satisfy FERC's reciprocity requirements. In addition, the cost of domestic coal was twice the price of imported coal and both NB Power and the municipal utilities industrial rates were rising quickly in the 1990s.[179] These two developments were the largest drivers behind restructuring.

In May 1999, the Select Committee on Energy ("Select Committee") issued a report entitled *Electricity Restructuring in New Brunswick* ("Select Committee Report"). The Select Committee recommended that the province pursue a "deliberate and controlled" restructuring policy that would allow for the gradual transition of the electric industry from its monopoly structure. A market design committee was then established to address the development of the electricity market including its design, structure and rules, and make recommendations to the government by April 2002.

6.3.2 Experimentation with competitive electricity markets

In 2004, New Brunswick implemented the *Electricity Act*, which was passed one year earlier. Pursuant to this legislation, NB Power was divided into five separate companies, providing a legal and financial structure to support a decentralized organization: NB Power Holding Corporation ("Holdco"); NB Power Generation Corporation ("Genco"); NB Power Nuclear Corporation ("Nuclearco"); NB Power Transmission Corporation ("Transco"); and NB Power Distribution and Customer Service Corporation ("Disco"). Figure 42 illustrates the corporate organization of NB Power following restructuring. In addition, Genco had two subsidiary companies: NB Power Coleson Cove Corporation ("Colesonco") and NB Coal Inc. Disco and Transco were the only NB Power companies that were regulated, meaning that many of NB Power's other operations – including all of its generating facilities and most of its head office activities – were not subject to economic regulatory oversight.[180] At the time of reorganization, an interim governance structure was established with the NB Power companies sharing a common Board of Directors and a common CEO. The plan was that this structure would evolve

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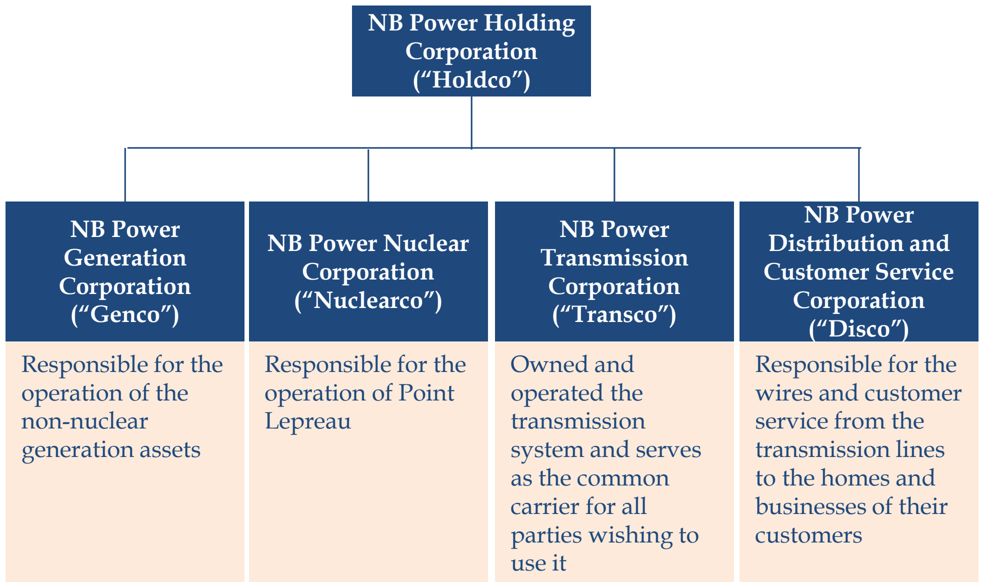
[178] Statistics Canada figures indicate that New Brunswick's exports to the Northeast States of the US accounted for 56% of its total exports in the late 1990s. 66% of New Brunswick's GDP was dependent on foreign and inter-provincial exports.

[179] Adams, Thomas. Borealis Energy Research Association. "New Brunswick's Power Failure: Choosing a Competitive Alternative." *Atlantic Institute for Market Studies*. October 2006.

[180] New Brunswick Department of Energy. The New Brunswick Energy Blueprint. New Brunswick: October 2011. <http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/201110NBEnergyBlueprint.pdf>

as the competitive electricity market evolved and separate Boards and CEOs would be established for each NB Power company.

Figure 42. The corporate structure of NB Power following restructuring



Source: LEI

Historically, New Brunswick's bulk electricity system operation functions were performed by NB Power Commission. The *Electricity Act* implemented in 2004 established the NBSO. The NBSO was a not-for-profit, Crown Corporation with an independent board of directors, which was mandated to ensure the security and reliability of the electricity system, to oversee access to the transmission grid and administer New Brunswick's OATT and the market rules. The NBSO also established a market advisory committee that included representatives from a wide range of interested parties. Any changes to the market rules must first be approved by the market advisory committee.

New Brunswick Electric Finance Corporation ("EFC") was also created as independent organization in part, to take on a portion of NB Power's debt in order to reduce debt levels in the NB Power companies to a more commercially appropriate level. All companies apart from Transco were funded entirely by debt.[181]

Point Lepreau's CANDU-6 reactor was completed in 1981 and was scheduled to be taken out of commission in 2008. Public debate on the future of the plant began as early as 2000. Despite being denied a federal grant to fund the project, NB Power announced in July 2005 that it was

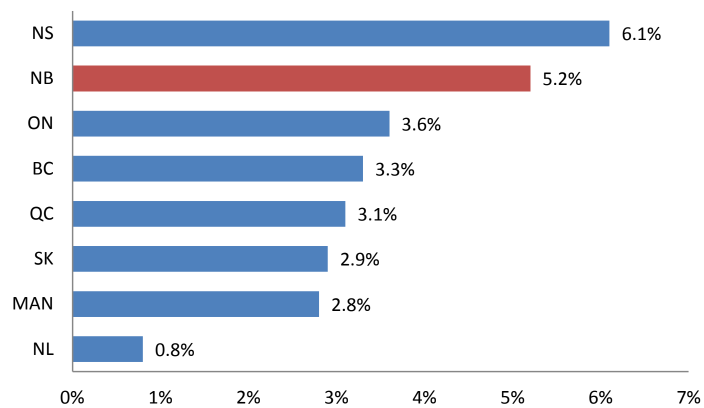
[181] Ibid.

awarding a C$1.4 billion contract for refurbishing the generating station. After many delays and cost overruns, the refurbished Point Lepreau started commercial production in November 2012.

6.3.3 Failed competitive markets and the reintegration of NB Power

The benefits envisioned before restructuring did not materialize the way that the government intended. From 2003 to 2009, NB Power had the second fastest increase in industrial electricity costs of any province in Canada and well above the median increase among US states as shown in Figure 43. In 2009, industrial electricity rates in New Brunswick were well above the median in Canada and the United States and 40%-90% higher than areas that directly compete with New Brunswick firms in the forestry industry.[182]

Figure 43. Average annual increase in industrial electricity costs (2003-2009)



Source: Manitoba Hydro, Survey of Canadian Electricity Bills – May 1, 2009. Based on 50,000 kW/kVa 31,000,000 kWh – 100% Power Factor

There was an absence of participants competing on the new generation side, which left New Brunswick dependent on NB Power's "heritage assets" for power generation. For reasons discussed in greater length in Section 6.4, NB Power's de facto dominance of the separate businesses quickly became a major barrier to entry for new market participants in terms of costs and grid access. Unbundling also did not solve the growing debt levels from the holding company's subsidiaries. In fact, the government nearly decided to sell off most of NB Power's assets – including Point Lepreau – to Hydro-Quebec in a controversial deal.[183]

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182 Atlantica Centre for Energy. "A Regional Vision for Sustainability and Competitive Industrial Rates." Atlantica Centre for Energy. June 2010. <http://www.atlanticaenergy.org/uploads/file/Electricity_june2010.pdf>

183 In October 2009, the Quebec and New Brunswick governments unexpectedly announced the acquisition of most of NB Power's assets by Hydro-Quebec. This would have resulted in the first takeover of a provincially owned utility by another one. This plan would have provided price and supply security for New Brunswick, and lucrative access to the US market for Hydro-Quebec. However, the transaction was cancelled in March 2010

In October 2011, the government released a 10-year "Energy Blueprint" with the goal of reintegrating NB Power into a fully regulated and vertically integrated utility, citing the failure of a competitive market to develop and the need for cost reductions as the main causes. In October 2013, the *Electricity Act* was amended and all the companies separated in 2004 became amalgamated in NB Power once again. The responsibilities of NBSO and EFC were either dissolved or shifted to NB Power.

6.4 Rationale for specific design elements and pros and cons of selected design

Figure 44. Summary of design elements

Design elements	Rationale	Pros	Cons
Reintegration of NB Power	Weak potential for wholesale competition and retail competition was never viable	Some administrative and cost synergies in merging	End of any potential wholesale competition for New Brunswick
Dissolution of NBSO	Not required given limited market	Reduces costs previously incurred by NBSO	Reduces impartiality of the transmission system and missed leadership opportunity if Maritime Provinces move towards a regional market
Transmission system compliance	Comply with FERC regulations in order to export to Northeast US	NB power continues receiving revenues from electricity exports	Transmission system is not independently operated

Source: LEI

The Government of New Brunswick's lack of commitment to privatize NB Holdco, resulting in several important dynamics in terms of how the electricity system developed. This section discusses the contextual rationale behind reintegration, the dissolution of NBSO, and features of the transmission system that make it compliant with FERC regulation.

6.4.1 Reintegration of NB Power

The rationale for reintegrating NB Power largely had to do with what the Government considered a weak wholesale and retail competition environment. A key objective of restructuring in 2004 was to foster wholesale competition to allow new generators to enter the market, as well as some retail completion limited only to large industrial customers with a

likely due to the possibility of further costs and the reluctance of the province to cede control over one of New Brunswick's prime assets.

minimum contract of 750 kW.[184] The alleged (and likely illusionary) benefit from reintegration was administrative and cost synergies from merging several companies that were controlled by the same holding company. The downside is that this action marks the end of potential wholesale competition. The sub-sections below outline the government's view on the potential for competition in New Brunswick.

6.4.1.1 Wholesale competition

A significant challenge for New Brunswick in creating a competitive wholesale market is the limited size of its market. In the government's feasibility evaluation of creating such a market, the premise was that the minimum efficient scale of a generation portfolio ranges from 3,400 MW to 8,000 MW.[185] At the time, peak demand was under 3,000 MW which presented a challenge to achieve a minimum efficient scale. With this conviction, the government made the decision to only functionally unbundle generation, transmission, distribution, and create a system operator under one holding company, all in compliance with FERC regulations. Because the government explicitly stated that the holding company will remain a Crown corporation, its subsidiaries were not privatized.

As for the generation portfolio, the government separated Point Lepreau and kept the remaining generating assets under Genco. The government's white paper entitled *New Brunswick Energy Policy* suggests that, based on economic theory and recent experience, at a minimum, approximately five equally sized firms are required to achieve a workably competitive market.[186] Moreover, the maximum market share of any one supplier generally should not be more than 35%.[187] To achieve such a workably competitive market within New Brunswick, Genco's generation portfolio had to be broken up. However, the government was reluctant to do this due to the risks of sacrificing its economies of scale, which it believed would result in higher costs for New Brunswick's consumers. Consequently, with the exception of Nuclearco, NB Power's generation portfolio was kept intact, reducing the number of market participants.

6.4.2 Retail competition

Full retail competition for small business and residential customers was considered unlikely to result in a vibrant retail market since few retailers were expected to participate in the market. In addition, retail competition for small business and residential customers required the elimination of the cross-subsidy in a relatively compressed timeframe, which could have created rate shocks for some customers. For a variety of historical reasons, NB Power's rate

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[184] Hydro Quebec. *Comparison of Electricity Prices in Major North American Cities*. April 2013. p. 74.

[185] Government of New Brunswick. *New Brunswick Energy Policy White Paper*. 2000. p. 16.

[186] Ibid.

[187] This is the standard that is often used by the Competition Bureau to evaluate whether a proposed merger should be challenged as potentially being uncompetitive.

structure results in cross-subsidization between commercial and residential customers. Residential customers pay approximately 90% of the actual costs that the NB Power incurs to serve them, whereas general service (institutions, schools, hospitals, offices, stores and other businesses) and industrial customers pay an average of 115% of the actual costs incurred to serve them.[188] In effect, institutional and small business customers are subsidizing residential customers. As such the government made no effort of developing a structure to foster retail competition.

6.4.3 Dissolution of NBSO

The NBSO was largely created to meet the FERC reciprocity requirements and to adopt and maintain rules for the power market. NBSO was the reliability coordinator for not only New Brunswick, but also PEI and Northern Maine.[189] NBSO operated a balancing market and contained no central organized wholesale market with spot prices.[190] As such, by following FERC guidelines, the NBSO was likely designed to provide more services than were required in practice because of the limited market that developed.[191] In this light, the government decided to reduce the NBSO's scope and believes that open and non-discriminatory transmission access can be still be achieved through a vertically integrated utility. However, if the interconnections of the Maritime Provinces develop into a regional market, it would offer New Brunswick a chance for a profitable, leadership role. The drawback of losing the NBSO is that such a regional market would require an impartial operator, and NBSO would have been the logical candidate for this role.

6.4.4 Transmission system compliance

As discussed, the rationale for an open transmission system is to allow New Brunswick to continue exporting to the Northeast US. FERC requirements for open access must now be met on the NB Power system, allowing at least the potential for US-based suppliers to serve wholesale customers, such as the province's municipal utilities in Saint John and Edmundston. Outside suppliers are not accorded access to retail customers unless those customers are allowed by provincial law to purchase from sellers other than NB Power. In addition, open access must permit others to be allowed to cross the transmission system for power generated and delivered elsewhere. For NB Power to provide open access, it must build new transmission

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188 Government of New Brunswick. *New Brunswick Energy Policy White Paper*. 2000.

189 The electric grid in Northern Maine is only connected to the New England grid by going through New Brunswick. AS such, the wholesale market there is dominated by NB Power, which also serves as the balancing authority and reliability coordinator. However, market administration is the responsibility of the Northern Maine Independent System Operator.

190 ISO/RTO Council. *2009 State of the Markets Report*. 2009. <http://www.isorto.org/Documents/Report/2009IRCStateOfTheMarketsReport.pdf>

191 Atlantica Centre for Energy. "A Regional Vision for Sustainability and Competitive Industrial Rates." Atlantica Centre for Energy. June 2010. <http://www.atlanticaenergy.org/uploads/file/Electricity_june2010.pdf>

when requested by users for whom the existing system is inadequate. The downside of not having an independent system operator is that the system operator under NB Power is not scrutinized by the market to efficiently perform.

To reconcile FERC's guidelines and NB Power's sole control of the transmission system, the cost of service ("COS") of the transmission system is currently separated from the remainder of NB Power's. The guidelines currently ban the mingling of transmission and generation costs. The separate COS and related rates is intended to comply with the requirement that prohibits funds flowing with a common owner between generators competing in the US market and transmission. While FERC cannot require Canadian entities to comply with this rule, if a Canadian transmission owner voluntarily seeks to use US facilities for its exports, as NB Power does, it must observe it.

6.5 Transitional challenges and remedies adopted

In New Brunswick's 2011 "Energy Blueprint", the government states that "given what has occurred in British Columbia, Ontario and elsewhere where competitive electricity markets have also failed to thrive - there is little likelihood that it will happen [in New Brunswick]."[192] This conclusion, however, hides some important facts; namely, that poor market participation largely developed out of the poor availability of financing for developers without long-term utility PPAs and the merely functional breakup of NB Power. This section discusses the challenges that the government faced during the transition to competitive markets with regards to these facts.

Figure 45. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Securing financing was difficult	Government pursues reintegration
Dominance of incumbent	Government pursues reintegration

6.5.1 Securing financing was difficult

When NB Power was unbundled, it was believed that market forces would take over and market participants would rapidly enter the generation market. In reality, developers found it very difficult to secure financing for new projects because financial institutions and other investors would not finance an independent power project without a long-term utility PPA in place as a secure source of future revenues. Overall, new generating facilities would not have been cost competitive with existing heritage assets, as heritage assets were priced on a historical cost basis. As such, no new generating stations were constructed during this time.

192 New Brunswick Department of Energy. The New Brunswick Energy Blueprint. New Brunswick: October 2011. <http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/201110NBEnergyBlueprint.pdf> p.14.

6.5.2 Dominance of Genco

The breakup of NB Power was more perceived than reality. The intention was that each separated unit would be run more efficiently as a business when subject to market competition. However, all parts of the company remained under central management with a common board and president. Because NB Power's generating portfolio was left intact, Genco's market power created significant barriers to entry for potential competitors that could not obtain long-term contracts or financing. In short, competition never happened mostly because the incumbent companies undermined it.

Following reintegration, the government maintains that NB Power will still be expected to operate as a business. Acting as the utility's owner, the government determines virtually all utility policy by law, appoints its board, and also appoints its regulator, making it capable of naming appointees who will follow its policies. In jurisdictions which aspire to some appearance of business-like operation, the government distances itself from the utility, but does appoint the regulator. The utility is under independent control and, if investor owned, it has a profit motive. An example of this model is Georgia Power, which is the dominant vertically integrated utility in the State of Georgia, but is privately owned by the Southern Company. Following New Brunswick's model of government ownership and control is far removed from the business model that it purports to maintain.

6.6 Implications for Nova Scotia

New Brunswick's experience between 2004 and 2013 has shown that the province has faced challenges and barriers associated with being a small jurisdiction and a small electricity market. The current government states that the competitive electricity market model has not worked for New Brunswick because these features preclude a competitive electricity market from thriving. However, as discussed in this case study, reassembling parts of NB Power only makes sense because the utility had never truly been split apart, so the unrealistic appearance of separation did little more than impact costs.

In sum, New Brunswick's restructuring experience offers a number of key implications for Nova Scotia:

- **There was a lack of transitional mechanisms to secure financing for new entrants.** New market entrants could not secure financing for new generation without long-term contracts with utility providers.

- **The potential for wholesale and retail competition was weak to begin with.** This fact resulted in the retaining Genco's generating portfolio and hindered privatization of its assets.

- **The incumbent generation company retained market power**. Because NB Power remained as the holding company, the de facto structure of the market hardly changed. Potential competitors had trouble gaining access to transmission and the ancillary services required to offer a complete supply package.

- **Government interference may continue to impede business efficiency.** Despite the intention of the government to ensure that NB Power runs itself as a private business, it is fully subject to government interference that may not result in least cost solutions and can possible continue to drive rates higher in the future. It also permanently transfers investment risk to the customers.

7 New England

The New England electricity market covers six states in the Northeastern US. It is an unbundled market that largely separates ownership of generation, transmission, and distribution sectors; however, there are exceptions in certain states. Interstate wholesale and transmission of electricity is regulated by the Federal Energy Regulatory Commission ("FERC"). ISO-NE is the independent system operator and administers the market on a daily basis. Distribution of electricity is governed by state regulators and regulation varies across states, with some states adopting Performance-Based Ratemaking regimes, while other states use cost-of-service regimes. For Nova Scotia, the experience from New England offers insights in capacity market design such as avoiding using a vertical demand curve, and transitional issues such as pitfalls in using negotiated settlements.

7.1 Overview of the New England market

The New England electricity market is a generally unbundled market that covers six states in northeast US. Most of the states have a fully unbundled electricity market with separate ownership for generation, transmission, and distribution companies. Two states continue to have vertically integrated utilities, however all generation participates in a centralized wholesale electricity market.[193] This is a very different market structure compared to Nova Scotia's, where a single utility dominates the province's generation, transmission, and distribution systems.

The New England Independent System Operator ("ISO-NE") oversees and administers the competitive wholesale electricity markets in New England. ISO-NE operates day-ahead and real-time energy markets, as well as a forward capacity market ("FCM"), an ancillary services market, and a market for financial transmission rights ("FTRs").

These markets are coordinated to ensure reliable power service to the region's 6.5 million households and businesses, or 14 million people in total. ISO-NE's footprint spans six states in the northeastern region of the United States (Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island). The energy market is currently divided into eight load zones mainly based on state boundaries.

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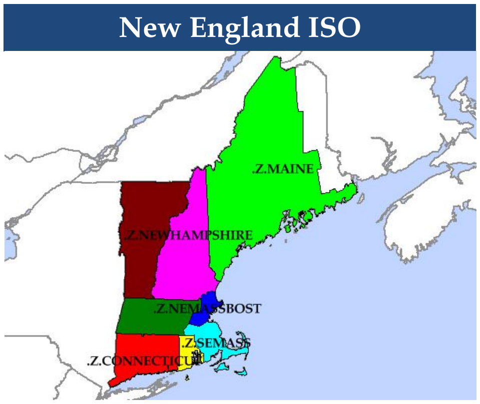
193 There is also a small market that is not connected to ISO-NE in the northern part of Maine. The system, administered by the Northern Maine Independent System Administrator ("NMISA"), is electrically connected to the New Brunswick system. This report focuses the ISO-NE system and does not cover the NMISA administered system.

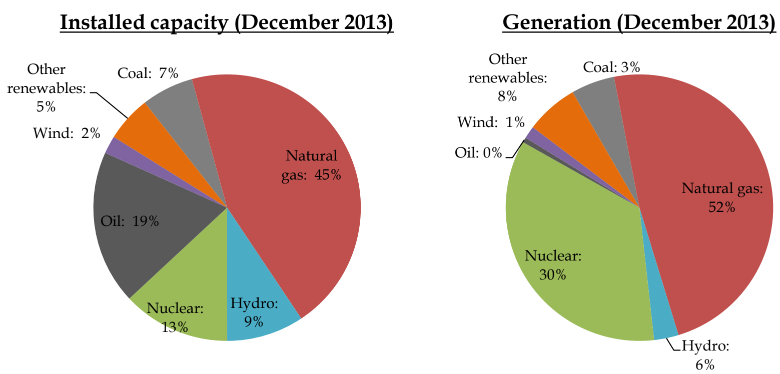
Figure 46. New England snapshot



Key facts	
Territories served	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
2013 Installed capacity	29,923 MW
2013 Summer peak demand	27,379 MW
2013 Generation	93,780 GWh
Load growth (2009-2013 summer peak load CAGR)	2.2%
Markets	• Two wholesale energy markets (day-ahead and real-time) • Forward Capacity Market • Ancillary services market (regulation and locational forward reserves) • Market for Financial Transmission Rights

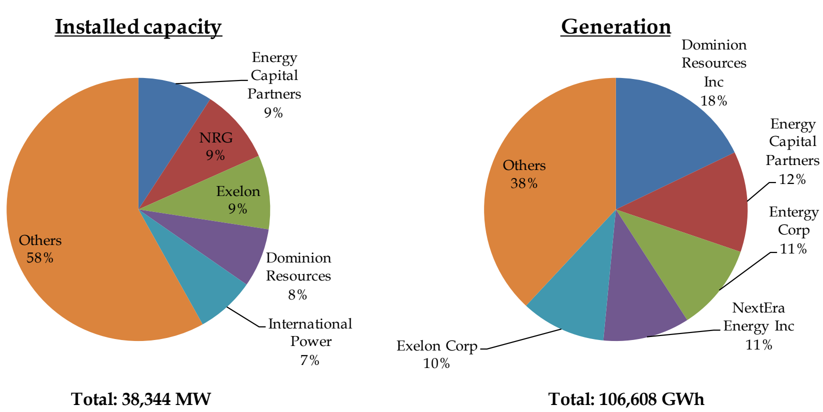
Source: Commercially available database, ISO-NE, LEI analysis

Figure 47. Installed capacity and generation



Source: Commercially available database

Figure 48. Installed capacity and generation



Source: Commercially available database

As shown in Figure 47, ISO-NE generating capacity is diversified, with natural gas being the dominant type of generating capacity, at 45% of total installed capacity. In terms of annual generation levels, gas-fired capacity dominates at 52%, followed by nuclear at 30%. Unlike Nova Scotia, which continues to have a coal-dominated system, most of ISO-NE's coal-fired generation fleet is retired or in the process of retirement. Over 11,000 MW of capacity is built after wholesale market operations in 1999, meaning that approximately 28% of capacity in New England today is constructed post-restructuring.

Similar to Nova Scotia, most of New England's electricity market value chain is privately owned, with the exception of municipal utilities. However, the ownership is more diverse in ISO-NE.

Figure 48 shows that the top five suppliers in ISO-NE own more than 40 percent of generating capacity in ISO-NE and provided roughly 60 percent of total generation (from December 2012 to November 2013). These suppliers built IPPs and acquired asset portfolios divested by the incumbent utilities as a result of deregulation and electricity market restructuring.

<u>Energy Market</u>

ISO-NE, like other Regional Transmission Operators ("RTOs") in the US, has a day-ahead and real-time market. The day-ahead market is a financial market where power is bought and sold based on forecast demand and supply expectations, and the market is cleared on the basis of demand bids (using the demand forecasts) and supply offers (for expected, available supply).[194] Based on the offers and bids received in the day-ahead market, RTOs create a dispatch schedule for the operating day and commit resources.[195] Energy prices settled in the day-ahead market are financially binding.

The real-time market is a physical market that reflects actual conditions, including flows, outages, and demand. This means that real-time prices are based on the actual power system output. Since many events that impact supply and demand cannot be predicted with certainty, there may be discrepancies between the day-ahead and real-time market prices. Any real-time discrepancies – e.g., higher than forecast demand or a forced outage of a supply resource that was previously committed to operate in the day-ahead market - are resolved in the real-time market at real-time prices, which may differ from the day-ahead market clearing prices, but typically not by a significant amount. In 2013, the average difference between day-ahead and real-time energy prices was around 1.4%.[196]

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194 In ISO-NE, increment offers and decrement bids (virtual supply offers and demand bids) can be submitted, into the day-ahead market without any generation or demand to back them up. They are useful as they allow price differences between the day-ahead and real-time markets to be arbitraged away.

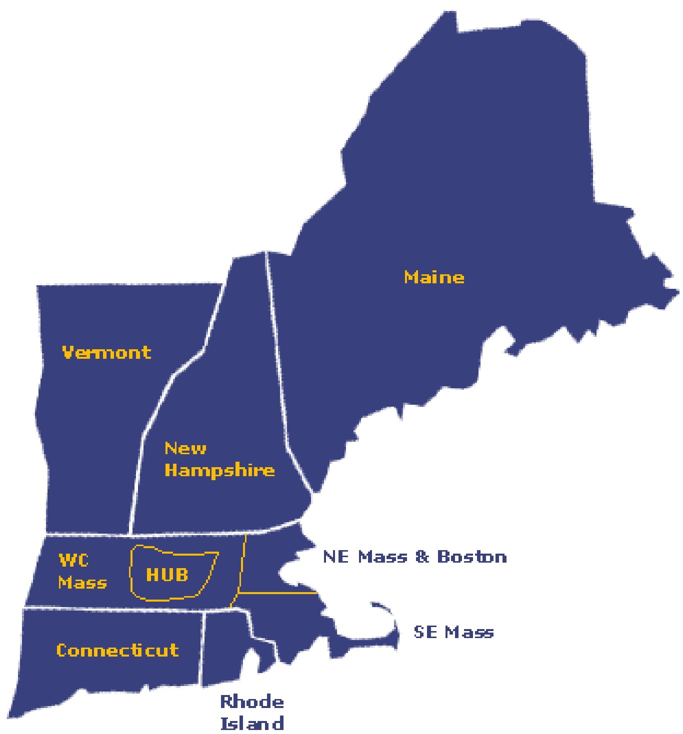
195 ISO-NE has an offer cap in place at $1,000/MWh.

196 ISO-NE *Hourly Zonal Information*.

Since 2003, ISO-NE has been using a locational marginal price (or "LMP") model to determine prices at different locations within its control area, in order to explicitly account for marginal costs of transmission congestion and marginal losses. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period due to transmission constraints. To fulfill the load, a higher-cost energy source will then be dispatched, resulting in a higher local price than the rest of the system. Generators are paid for their production based on their specific location price (node), while load pays for energy based on a load-weighted price over multiple nodes. Load zones where established as part of the LMP market design and can be changed, subject to stakeholder approval.

Under ISO-NE's market design, energy prices are first calculated at more than 900 pricing nodes that represent locations where generators inject power into the system or where demand withdraws from the system.

Figure 49. Load zones in New England



Source: ISO-NE

ISO-NE utilizes a LMP design for its day-ahead and real-time energy market. At each pricing node, the energy price is composed of three components – the energy component that is identical across the wholesale market, the congestion component calculated based on price differentials caused by congestions through transmission interfaces, and the loss component calculated based marginal cost of system losses specific to each location. If the system was entirely unconstrained and there were no losses, all of the LMPs would be equal to the energy component of the LMP.

Generators are paid nodal LMPs. However, load pays a related but different price calculated for eight load zones, which are aggregations of pricing nodes. New England is divided into the following eight load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, West/Central Massachusetts, Northeast Massachusetts (which includes Boston), and Southeastern Massachusetts. The prices calculated for load zones are a load-weighted average of the nodal price within each zone.

Congestion charges drive the differences between the system marginal price ("SMP"), which is uniform for all areas within the system, and the LMP. Depending whether the local area is upstream or downstream to the congestion, congestion charges could be positive or negative.

The New England system has been generally recognized as uncongested under normal operating conditions. The congestion costs decreased from roughly $37 million in 2010 to $29 million in 2012.[197]

<u>Capacity Market</u>

The FCM is built around a Forward Capacity Auction ("FCA"), which takes place annually, and three and a half years in advance of the delivery period. This timeframe for the FCA allows for new, yet unbuilt, power plant project developments to participate in the auction for capacity on equal footing with existing qualified supply.[198]

The FCM is divided into sub-areas according to two transmission constraints, which define separate Capacity Zones as: 1) any sub-area that has an import constraint that could affect bidding in the auction, and that does not have enough local capacity to meet its Local Source Requirement ("LSR"); or 2) any sub-area that has an export constraint that could affect the bidding in the auction, and whose local capacity exceeds the maximum amount of capacity (Maximum Capacity Limit, or ("MCL") that can be procured from this sub-area to meet the Installed Capacity Requirement ("ICR"). Price separation can occur for each designated Capacity Zone in the FCA, depending on the round at which an LSR (for import constrained) or MCL (for export constrained areas) is satisfied. This is the mechanism through which locational and siting elements are incorporated into the auction: Capacity Zones that need more investment will clear at a higher auction price for capacity, giving developers incentives to build additional capacity in the capacity-constrained area.[199] In the scope of the FCM in New England, capacity is characterized as a system resource available to meet the system's ICR, which is an ISO-NE estimate of the resources needed to supply the system's peak load within an acceptable probability of not meeting that demand.

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[197] ISO-NE *Regional System Plan 2013*.

[198] In addition, an annual configuration auction is set up in such a way to allow for the adjustment to purchases based on load forecast alterations and to allow suppliers to back up or unwind their capacity obligations.

[199] Historically, ISO-NE has three zones but in FCA#7, four areas were introduced and an import constrained zone cleared significantly higher than other zones for the first time. FCA #7 took place on February 4, 2013.

ISO-NE'S FCM

Forward auction - As discussed previously, FCM is a forward market where auctions held in this year will have capacity product delivered 3.5 years in the future. This market design allows projects that are currently not in commercial operation to participate in the auction, and if such projects cleared the auction and obtained capacity obligation, they will proceed to implement the project.

In order to increase the financial ability of capacity revenue, ISO-NE's market rules have a provision allowing new resources that clear in a capacity auction to lock-in the capacity clearing price for five years. In the proposal submitted to FERC implementing a downward sloping demand curve for the capacity market, ISO-NE proposed to increase the five-year lock-in provision to a seven-year lock-in.

Capacity zones - While ISO-NE's energy market has nodal pricing, and that load pays according to a topology of eight load zones, the FCM has only four capacity zones. There are two import-constrained zones, Connecticut and Boston, where ISO-NE sets a LSR for these two zones before each auction, indicating the demand for capacity for these two zones due to transmission limits of sending power into these areas. There is one export-constrained zone, Maine, where ISO-NE sets a MCL to indicate the upper bound of capacity that ISO-NE is willing to purchase within this zone, as transmission constrains limit the amount of capacity Maine can export into the rest of the New England system. Finally, the Rest-of-System zone covers area that is not an import-constrained zone or an export constrained zone.

While load zones for energy prices are set according to state borders, capacity zones are created based on transmission interface limits. The purpose of having multiple capacity zones is to create price signals for capacity resources on the location of capacity demand. For example, if LSR is not met in an import-constrained zone where there is sufficient capacity to clear the overall market demand, called the ICR, the import-constrained zone will have a higher capacity clearing price while the resources located in the Rest-of-System zone will receive a lower capacity payment.

Vertical demand curve - The amount of capacity resources procured by ISO-NE in each capacity auction for the whole market is called the ICR. The ICR is calculated based on the amount of capacity required to meet a LOLE of 1 day in 10 years requirement. In practice, this is generally around 12%-13% over the expected 90/10 peak load of the capacity delivery year.

Under the current market design, ISO-NE will only procure capacity up to the last unit where the cumulative capacity procured is greater than the ICR. Any unit that bids higher than this marginal unit will not be cleared in the auction and will not receive any capacity payments in the corresponding capacity delivery period. This essentially means the FCM has a vertical demand curve that is inelastic to capacity prices. A vertical demand curve design results in high price volatility in the capacity market when the balance between demand and supply is tight. The FCM has cleared at its price floor for the first seven auctions as the market began with excess supply when it was first formed. These recent events indicate the shortcoming of a vertical demand curve in the capacity market. First, it shows that the market failed to retain sufficient capacity to meet its reliability requirement. Second, the level of price volatility does not create an environment where capacity revenue can be used to obtain financing for new investments. In light of these shortcomings, FERC has ordered ISO-NE to propose a downward sloping demand curve for its next capacity auction.

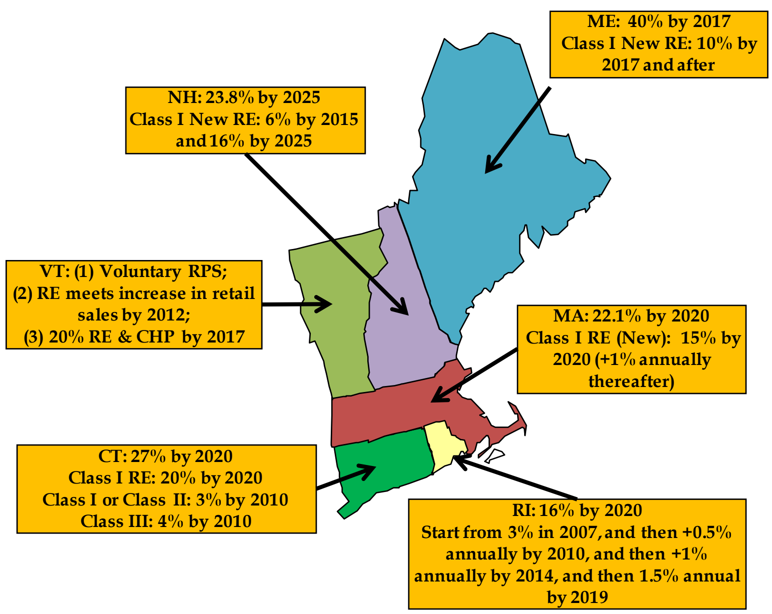
Descending clock auction - ISO-NE's FCM uses a descending clock auction to determine the capacity clearing price in each auction. Each FCA operates as a multi-round descending clock auction, where an auctioneer starts at a high capacity price and removes offers that clear over the ICR in each round. The auction will continue until after a price decrease, there are insufficient offers to meet the ICR. The auction will conclude at the offer price of the last unit that clears the ICR. For each auction, ISO-NE's Internal Market Monitor ("IMM") sets a technology specific offer floor for new resources, and also a bid cap for existing resources wanting to delist. So far, offer floors have been higher then delist bid caps.

In this case, the ICR is the estimate of the amount of capacity that will result in a loss of load evaluation ("LOLE") of no higher than one (1) day in ten (10) years (0.100 days per year). The ICR can be satisfied by a variety of different resources: electrical generating capacity with various characteristics, imports into the system over transmission ties, demand response (curtailments by consumers during times of system need), or even ongoing reductions in consumer demand. The textbox below provides a more detailed discussion on the FCM.

Renewable Portfolio Standards

Similar to Nova Scotia, New England States have also adopted RPS. RPS requires a minimum percentage of a utilities' retail load to be served by qualified renewable resources. Most ISO-NE states have adopted a two-tier system for renewable energy sources, with differences in classification criteria.

Figure 50. RPS requirements for ISO-NE states across

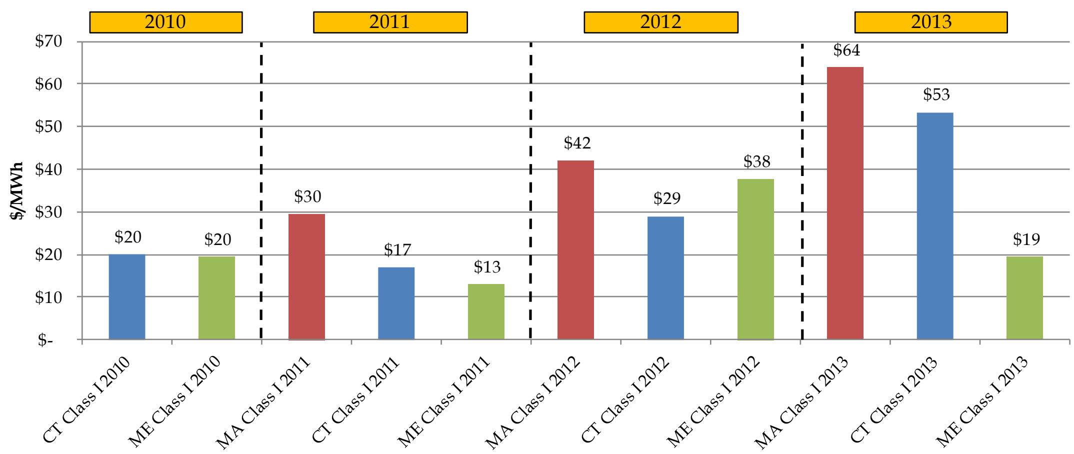


Note: RE=Renewable energy; CHP=Combined heat and power
Source: Database of State Incentives for Renewables & Efficiency ("DSIRE")

In most ISO-NE jurisdictions with RPS, qualified renewable generating units earn one REC per MWh generated. Utilities, load serving entities and other market participants subject to RPS purchase these RECs to fulfill the requirements. Thus, RECs serve as an additional revenue source for renewable generating units. Although critical for qualifying resources, REC prices have little impact on market clearing prices for energy. However, most renewable resources in the model are considered price takers, reducing market-clearing prices when the resources run.

Figure 51 below presents historical REC prices (for both new renewables) in selected New England states across different vintages (or compliance year periods). MA Class I (new renewables) REC for 2013 traded at around $64/MWh, while Class I (new renewables) REC prices for 2013 in CT traded at around $53/MWh, while those in ME traded at around $19/MWh.[200] The existence of REC price differences between states is due to differences in each state's RPS requirement in terms of generation (i.e. MWhs) and difference in available renewable capacity supply certified by each state. However, once a REC is sold, it cannot be re-classified to meet another states' RPS. Therefore, in the short-term, different supply-demand balances for RECs may affect each state's REC price.

Figure 51. Price of selected Class I non-solar RECs within ISO-NE ($/MWh)



Source: Bloomberg, accessed on August 6, 2013. 2013 Data are year-to-date averages. There is no MA Class I data for 2010.

Transmission Rights

Transmission congestion occurs when lower-cost resources cannot be dispatched fully due to limited transmission capability. To fulfill the load, higher cost energy sources will then be dispatched, resulting in a higher local price than the rest of the system. Congestion charges are the differences between the cost of energy or SMP, which is uniform for all areas within the system, and the LMP (before considering losses). Depending on whether the local area is upstream or downstream to the congestion, congestion charges could be positive or negative. In addition, generators electrically close to the load have a positive marginal loss component while generators electrically distant from the load have a negative marginal loss component.

FTRs can be acquired in three ways:[201]

- **FTR Auction** – ISO-NE conducts monthly FTR auctions to enable bidders to acquire and sell monthly and long-term FTRs.

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200 To put this into context, average annual energy price was $49/MWh in 2010, $46/MWh in 2011, $36/MWh in 2012, and $71/MWh in 2013.

201 Available online at <http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/ftrs_arrs/index-p2.html>

- **Secondary Market** - The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or sold on a bilateral basis.
- **Unregistered Trades** - FTRs can be exchanged bilaterally outside of the ISO-administered process. However, the ISO only compensates FTR holders on record and does not recognize business done in this manner for settlement purposes.

ISO-NE collects FTR auction revenue, which is then distributed through Auction Revenue Rights ("ARR"s). ARRs are essentially entitlements to the auction revenues from selling FTRs. Auction revenues are allocated first to those who pay for transmission upgrades, if the upgrade makes it possible to award additional FTRs by increasing transfer capability. These proceeds are called Qualified Upgrade Awards ("QUAs").

After QUAs are allocated, any remaining auction revenues are distributed to entities that pay congestion costs associated with supplying power to serve load. These revenues are allocated in relation to the amount of load served in the separate load zones and to where congestion occurs.

Carbon emission regulation

Regulation of greenhouse gas emissions in ISO-NE has two layers. On the federal level, the Environmental Protection Administration ("EPA") is creating rules to regulate emissions of CO_2 from stationary sources under the Clean Air Act. On the state level, all of the states within ISO-NE are participants of the Regional Greenhouse Gas Initiative ("RGGI"), which creates a cap and trade system for CO_2 emissions from power generation facilities.

The RGGI was the first market-based regulatory program in the United States to reduce greenhouse gas emissions. Member states of RGGI have capped and will reduce CO_2 emissions from the power sector by 10% by 2018 relative to 2009 levels. From 2012 to 2014, the RGGI cap is 165 million short tons of CO_2 per year and starting 2015, the cap will decrease by 2.5% per year.[202] All of the states in New England are participants of RGGI.

On September 20, 2013, the EPA proposed a new Carbon Pollution Standard for New Power Plants, which sets emission rate limits on fossil-fuel fired electric utility generating units ("EGUs").[203] The rule proposes to define an EGU as a boiler which is able to combust more than 250 MMBtu/h heat input of fossil fuel, supplies more than one-third of its potential output electric output to the grid, and supplies more than 219,000 MWh to the grid on an annual basis. The 219,000 MWh threshold is used in place of the common 25 MW net-electric output threshold, but the EPA claims that the two are equivalent. Oil and coal fired units covered by

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[202] *See* RGGI. *About the Regional Greenhouse Gas Initiative*. Available online at http://www.rggi.org/docs/Documents/RGGI_Fact_Sheet_2012_09_28.pdf

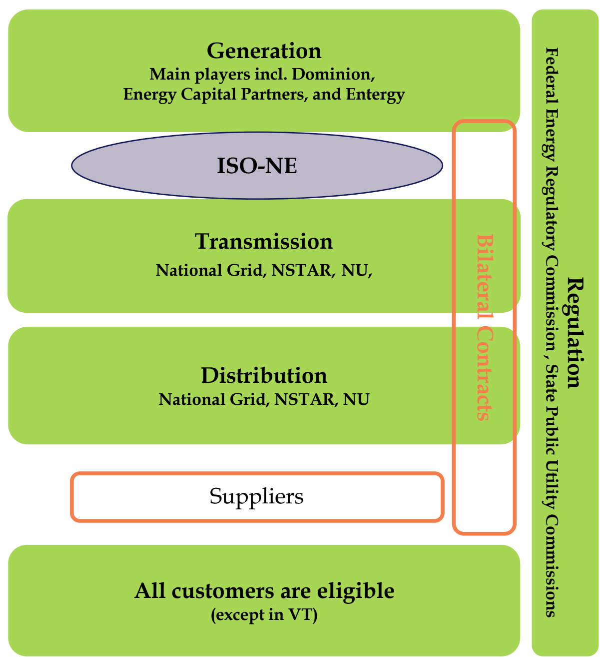
[203] *See* EPA Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units. Available online at http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf

the rule have to achieve an emission limit of "1,100 lb. CO_2/MWh gross over a 12-operating month period" or "1,000-1,050 lb. CO_2/MWh gross over an 84-operating month (7-year) period."[204] Natural gas fired units have to achieve an emission limit of 1,000 lb. CO_2/MWh if their heat input is greater than 850 MMBtu/hr., and 1,100 lb. CO_2/MWh otherwise. It is expected that new natural gas combined cycle power plant units should be able to meet the proposed standard without add-on controls, while coal- and oil-fired units would need to incorporate technologies such as carbon capture and storage ("CCS") to comply with the standard.

7.2 New England's current institutional and legal framework

As the New England market spans over six states in the US, both federal and state institutions, regulations, and laws shape the framework of New England's electricity market. In general, interstate activities, such as transmission and wholesale market, are regulated by FERC, while in-state activities such as distribution and retail are regulated by state utility regulators.

Figure 52. Overview of electricity market structure in New England



Note: NU refers to Northeast Utilities.

On top of regulations that govern the functioning of a competitive electricity market, the New England electricity market is also shaped by federal and state level environmental regulations. On the federal level, federal laws such as the Clean Air Act, and the US Environmental

[204] *See* EPA Fact Sheet: Reducing Carbon Pollution From Power Plants. Available online at http://www2.epa.gov/sites/production/files/2013-09/documents/20130920factsheet.pdf

Protection Agency ("EPA") regulations, apply to all New England states. On a regional level, all New England states participate in the Regional Greenhouse Gas Initiative ("RGGI"). Except for Vermont, all New England states have their own Renewable Portfolio Standards ("RPS") that set a target percentage of load met using renewable energy by a fixed timeframe.

7.2.1 Regulation and policy setting

FERC is the US federal agency that regulates interstate transmission of electricity, natural gas, and oil. From the perspective of the New England electricity market, FERC is the regulatory body that oversees the operation of the wholesale electricity market, and approves tariffs charged by the interstate transmission system.

FERC's legal authority comes from the Federal Power Act ("FPA") enacted in 1920 and followed by many subsequent amendments. In particular, the FPA states that the extent of FERC's power covers the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. However, it does not cover other sales of electric energy. FERC also has a major role in implementing the Energy Policy Act of 2005 ("EP Act"), which includes establishing rules for incentive-based rate treatments for transmission and determining provisions for electric market manipulation.

Reliability standards for the New England market are set by the North American Electric Reliability Council ("NERC") and the Northeast Power Coordinating Council ("NPCC"). ISO-NE has lead responsibility to meet these standards.

The New England Power Pool ("NEPOOL") is a voluntary association formed in 1971 through a participant's agreement to establish a bulk power pool. NEPOOL has more than 430 members, and its participants include all of the electric utilities using services under ISO-NE's Transmission, Markets and Services Tariff, independent power generators, marketers, load aggregators, brokers, consumer-owned utilities, end users, demand resource providers, developers, and a merchant transmission provider. Under provisions accepted by FERC, members of NEPOOL act through NEPOOL's Participant's Committee. Essentially, NEPOOL's Participant's Committee is the principal governing body of the New England wholesale electric power system, except for input from state regulatory authorities, through advisory voting on ISO matters and the selection of ISO Board members.

Formed in 2006, the New England States Committee on Electricity ("NESCOE") is a not-for-profit organization representing the collective interests of the six New England states on regional electricity matters. NESCOE is directed by managers appointed by the six New England Governors and advances policies that represent state interests. NESCOE makes policy determinations with a majority vote weighted to reflect electric load of each state within the region's overall load. NESCOE participates regularly in NEPOOL's various committee meetings, and also in ISO-NE's Planning Advisory Committee and Consumer Liaison Group meetings. Furthermore, NESCOE interacts directly with federal regulators, including filing for hearings and made comments to FERC and ISO-NE proceedings.

Local state policies and issues related to distribution, such as tariff structure of distribution companies and RPS, are set and governed by state legislatures, departments of energy, and public utility commissions. Figure 53 presents the list of New England state energy policy agencies and utilities regulators.

Figure 53. List of New England state energy policy agencies and utilities regulators

State	Energy policy	Utilities regulator
Connecticut	Department of Energy and Environmental Protection	Public Utilities Regulatory Authority
Maine	Governor's Energy Office	Public Utilities Commission
Massachusetts	Department of Energy Resources	Department of Public Utilities
New Hampshire	Office of Energy and Planning	Public Utilities Commission
Rhode Island	Office of Eneryg Resources	Public Utilities Commission
Vermont	Public Service Department	Public Service Board

7.2.2 Administration of the electricity system

As stated previously, ISO-NE is the system operator of the majority of New England's electric grid. A much smaller grid located in Northern Maine is administered by NMISA.

ISO-NE is an independent, not-for-profit corporation. According to ISO-NE, its role as New England's RTO has three primary responsibilities:

- Minute-to-minute operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the New England's interstate high-voltage transmission lines to ensure reliability of electric supply;

- Development, oversight and fair administration of New England's wholesale electricity marketplace; and

- Management of comprehensive bulk electric power system and wholesale markets' planning processes.

ISO-NE does not own any power plants or transmission lines, and cannot directly require resources to make infrastructure investments or take action to improve their performance. In order to achieve its goals of providing reliability supply of electricity at competitive wholesale cost, it relies on market mechanics and creates incentives, such as setting different levels of penalties/rewards for under-/over-performance. To cope with changes in energy policies, market conditions, and technology, ISO-NE constantly solicits views from stakeholders and files market rule changes to FERC.

ISO-NE is a nonprofit entity without equity. Its operating budget relies on collections from its tariff. In 2014, ISO-NE's total operating budget is $169 million, which translates to approximately $0.86 per month on the average New England electricity consumer.[205]

7.2.3 Regulatory oversight of charges

As ISO-NE is a multi-jurisdictional market, distribution companies are regulated at the state-level and each state has different regulatory regime. For example, distribution companies in Connecticut are regulated under a "softer" form of PBR with an earnings sharing mechanism ("ESM"), while distribution companies in Maine are regulated using an Alternative Rate Plan ("ARP"), which is a "harder" form of PBR.

As stated in the PBR section of the literature review, PBR is a spectrum with different forms. In New England, similar terminologies are applied inconsistently among state regulators, leading to potential confusion where one state has an ARP that is effectively in the form of an ESM, while another state's ARP is closer to a form of PBR based on I-X. Figure 54 summarizes the general form of rate regulation for electric distribution companies in each New England state.

Figure 54. Summary of electric distribution companies rate regulation in New England

State	Distribution company economic regulatory regime
Connecticut	ESM
Maine	ARP in form of PBR
Massachusetts	NSTAR had PBR, but is currently under rate freeze
New Hampshire	Cost of service
Rhode Island	ESM
Vermont	ARP in form of ESM

In this section, we use the PBR plan in Maine and Massachusetts as an example for discussion.

7.2.3.1 Central Maine Power ("CMP")

CMP is the largest electric distribution utility in central and southern Maine. It serves approximately 600,000 customers and covers 11,000-square-mile of service area. On July 1, 2008, MPUC approved CMP's application for the APR 2008. The APR took effect in January 2009 and was implemented over a five year period (until 2014). The distribution rate is adjusted annually based on inflation less a productivity offset of 1%. The APR also has performance standards measures namely the (i) Reliability Improvement Program to address distribution system reliability issues and (ii) a set of service quality provisions to ensure system reliability and customer service performance. As discussed in the Literature Review (Performance and Accountability), there are penalties whenever CMP performs below the set performance targets. The APR also has flow throughs for costs that are beyond the management's control.

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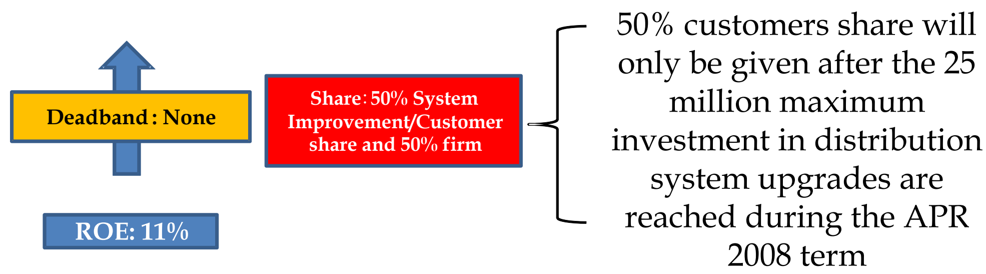
205 ISO-NE. *ISO-NE Regional Energy Outlook 2014*.

Figure 55. Illustration of CMP's ESM



APR 2008 also contains an ESM with a symmetrical sharing scheme. Under this sharing provision, distribution earnings in any year, up to 11%, will be retained by CMP shareholders. When CMP's actual ROE for its distribution business exceeds 11.0% in any year during the APR 2008 term, the excess will be allocated 50% to the System Improvement/Customer Share and 50% to the CMP share as shown in Figure 55. The following provisions apply to this sharing scheme:[206]

- The first $2 million of the System Improvement/Customer Share during the APR 2008 will be retained by CMP as partial recoupment of the Trees in Contact trim amount actually expended;
- An amount equal to the System Improvement/Customer Share in any calendar year will be invested in incremental distribution system upgrades in the following year, up to the maximum investment of $25 million over the APR 2008 term;
- When the $25 million maximum investment is reached during the APR 2008 term, distribution amounts earned in excess of 11.0% will be subject to a 50/50 sharing between customers and CMP and the System Improvement/Customer Share shall be determined accordingly, and shall be deferred and returned to customers in the following year's annual price adjustment.

7.2.3.2 NSTAR

NSTAR was under PBR until it merged with Northeast Utilities. NSTAR was an investor-owned electric and gas utility in the US with revenues of approximately $3 billion.[207] NSTAR transmits and delivers electricity and gas to 1.1 million electric customers in 81 communities. When it was under PBR, NSTAR Electric's rates were adjusted based on an annual inflation and a productivity factor. Rates were based on the Rate Settlement Agreement, which was in effect

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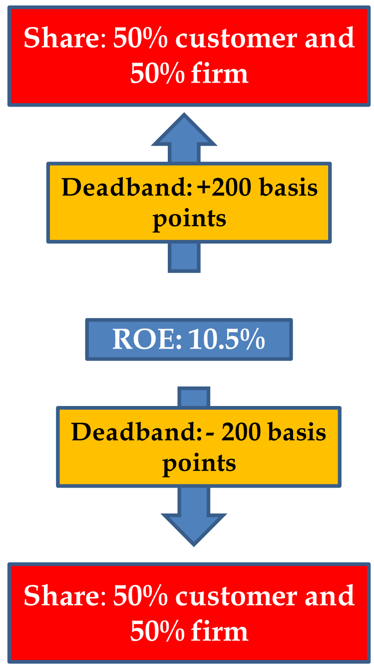
[206] Excerpted from the Maine Public Utilities Commission, *Order Approving Stipulation of Central Maine Power Company Chapter 120 Information (Post APR 2000 Transmission and Distribution Utility Revenue Requirements and Rate Design, and Request for Alternative Rate Plan (Docket No. 2007-215) and CMP Annual Price Change Pursuant to the Alternate Rate Plan 2000*. July 1, 2008. p. 14.

[207] NSTAR website. Accessed on June 14, 2011.

from 2007 to 2012. NSTAR Electric also had performance standards to comply with and was required to report this annually to the Commission. Penalties up to 2.5% of total distribution revenues were imposed for failure to meet the performance benchmarks.

Figure 56. Illustration of NSTAR's ESM



NSTAR also had a symmetrical ESM for both the dead band and sharing percentages. If NSTAR Electric's aggregate ROE for distribution service (excluding any incentive payments and penalties under the service quality plan) exceeded 12.5%, ratepayers and NSTAR Electric would share the excess ROE with the customers equally. On the other hand, if NSTAR Electric's aggregate ROE for distribution service (excluding any incentive payments and penalties under the service quality plan) fell below 8.5 percent, ratepayers and NSTAR Electric would share equally in the deficiency. NSTAR's approved ROE is 10.5%. Thus, there was a dead band of 200 points. Figure 56 below illustrates NSTAR's ESM. Any earning sharing adjustment was subject to investigation and a full adjudicatory hearing. NSTAR Electric did not exceed the 12.5% or fall below the 8.5% ROE. Currently, NSTAR's rates are frozen until January 1, 2016.[208]

7.3 History of restructuring and recent developments

The New England market has gone through multiple iterations of market design since the unbundling process began in the 1990s, including formation of the ISO, development of a wholesale energy market, usage of LMPs, and implementation of a capacity market.

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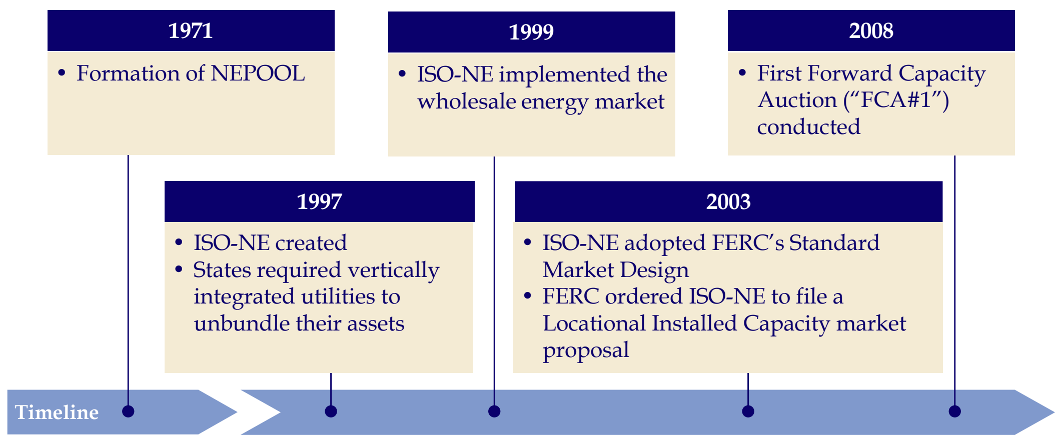
[208] Massachusetts Department of Public Utilities. *Decision Order Joint Petition for Approval of Merger between NSTAR and Northeast Utilities*. April 12, 2012. p. 18.

The New England market is constantly evolving due to changes in market conditions and energy policies. Recent and upcoming changes in the market include changes in the capacity market design to a downward sloping demand curve and continued unbundling of assets.

Figure 57. Key events in history of New England electricity market



7.3.1 Formation of the New England Power Pool and ISO-NE

NEPOOL was formed by the region's private and municipal utilities in 1971 as an effort to enhance reliability after the Great Northeast Blackout of 1965. The structure of NEPOOL was a regional grid that fostered cooperation and coordination among utilities, rather than an organized wholesale electricity market.

The lack of competition among regional monopolies leads to an aging electric infrastructure, high prices, and construction of expensive nuclear units that lead to bankruptcy of a utility. By the 1990s, New England's electricity rates were among the highest in the US. FERC's effort in promoting a competitive wholesale electricity market led to restructuring of New England's in the 1990s. In 1997, FERC approved creation of ISO-NE to manage the regional bulk power system and new wholesale markets, and to ensure open access to transmission system. Also, five of the six states in New England (with Vermont being the exception) required utilities to sell off power plants and gradually eliminate regulator-set rates to allow for market determined prices.

In 1999, ISO-NE implemented the wholesale energy market. In 2003, it adopted the "Standard Market Design" that includes features such as a Day-Ahead Market in order to reduce price volatility.

7.3.2 Developments in capacity market

In the early 2000s, FERC encouraged locational capacity markets as part of its Standard Market Design initiative. In 2003, FERC issued the Devon Order, directing ISO-NE to file a Locational Capacity Market proposal to implement a capacity market. Eventually, ISO-NE filed a Locational Installed Capacity market proposal with FERC, but continuing litigation between

ISO-NE and generators forced a FERC administered settlement process, which resulted in the FCM. In 2008, the first FCA was conducted for the 2010-2011 Capacity Commitment Period.

The original FCM design used a vertical demand curve where no additional capacity revenue would be paid to generators bid into the market at a price higher than the last unit that clears the ICR. This led to the first seven capacity auctions (FCA#1 to FCA#7) clearing at the price floor due to excess supply, and FCA#8 clearing at the price cap as capacity exited the market, creating insufficient supply in the market. In order to reduce price volatility, on January 24th, 2014, FERC ordered ISO-NE to develop a sloped demand curve for the ninth capacity auction by April 1st, 2014. It is expected that a downward sloping demand curve will be implemented in FCA#9, for delivery in 2018/19.

7.3.3 Unbundling of transmission and distribution assets

On the transmission level, the New England transmission system is owned by eight transmission owners ("TOs"), with the largest being Northeast Utilities (which also owns NSTAR Electric Co.) and National Grid. Under the requirement of having a non-discriminatory open-access transmission service over the New England transmission system, the transmission system is operated by ISO-NE. The TOs recover their transmission revenue requirements through formula rates included in ISO-NE's Open Assess Transmission Tariff ("OATT"). Both the Regional Network Service ("RNS") and Local Network Service ("LNS") revenue requirements for all New England TOs are calculated using a single base Return on Equity ("ROE") set by FERC. The current effective ROE for TOs is 11.14%. However, there has been an on-going complaint at FERC since 2012 claiming that this 11.14% ROE is unjust and unreasonable, seeking to reduce the ROE to 8.7%.

On the distribution level, the regulatory environment varies from state to state. For example, the two major distribution companies in Connecticut, Connecticut Light & Power ("CL&P") and United Illuminating ("UI") are regulated under a cost-of-service ("COS") regime with an authorized ROE set by Connecticut's Public Utilities Regulatory Authority ("PURA"). In Maine, Bangor Hydro Electric Company's ("BHE") and Central Maine Power Company's ("CMP") distribution rates are determined by an Alternative Rate Plan ("ARP"). ARPs are agreements between utilities and Maine Public Utilities Commission ("MPUC") with a multi-year price cap approach that places an upper limit on the utility's rate increase, while allowing the utility to retain savings it accomplishes through improved efficiencies. Details of the specific designs of Performance Based Ratemaking ("PBR") elements in Maine are covered in PBR section of the Literature Review.

On the other hand, some states in New England have followed a slower pace in restructuring its electricity market.

New Hampshire planned to restructure its electricity market in 1995, with the passage of Senate Bill 168, followed by House Bill 1392 in May 1996 directing a restructuring committee to develop an electric restructuring plan. However, the vision of full divestiture of generation assets owned by Public Service of New Hampshire ("PSNH") was scaled back due to backlashes from the 2000-2001 California energy crisis. Therefore, as of today, PSNH remains a vertically integrated utility within New Hampshire (although its generation participates in ISO-NE's wholesale energy market) serving approximately 70% of retail customers in New Hampshire, and owns about 1,150 MW of generation, while three other unbundled distribution companies provide services in areas not covered by PSNH. In April 2013, the New Hampshire House of Representatives passed House Bill 1602, which would give New Hampshire's Public Utilities Commission the ability to force divesture or plant retirement if it finds it beneficial to the state. The Bill is currently under debate in the state's Senate.

Vermont is the only state in New England that has chosen not to restructure its electric industry and the state currently has no retail competition. However, since Vermont utilities do not own all of the generation resources to meet their load and the generating assets owned by the utilities participate in the New England electric wholesale market, they share many characteristics with distribution companies in other New England states that have restructured.

7.3.4 Recent developments

In recent years, developments in natural gas markets have created profound changes to the relative economics of different type of generating units. New England, located at the end of the US gas pipeline system, has experienced both a decrease in natural gas prices, as well as more price spikes during winter periods. At the same time, developments in renewable energy have also created opportunities and challenges to the electricity market. These issues contributed to the recent developments in the New England electricity market as discussed in this section.

7.3.4.1 Capacity downward sloping demand curve

On January 24th, 2014, FERC issued an order to ISO-NE to file a proposed downward sloping demand curve for implementation by FCA#9. The goal of having a sloped demand curve is to have a uniform clearing price instead of two separate prices (one for new resources, and one for existing resources). In addition, ISO-NE has stated that a sloped demand curve would reduce price volatility and improve market efficiency. According to the FERC filing from ISO-NE on April 1st, 2014, the key features of the demand curve to be applied in FCA#9, which will be conducted on 2015 and pending approval from FERC, would have the following features:

- usage of cost and expected revenue of a new CCGT to set the net cost of new entry ("CONE");
- a downward sloping demand curve with no "kink" in the slope;
- maximum capacity clearing price at 1.6x net CONE when LOLE is 1 day in 5 years; and
- floor price of zero when LOLE is 1 day in 87 years.

The proposal is currently subject to regulatory proceedings at FERC. Due to time constraints, a *zonal* sloped demand curve design will not be implemented in FCA#9, but is expected to be implemented in FCA#10.

7.3.4.2 Capacity resources performance incentives

In October 2012, ISO-NE issued a white paper proposing a new FCM Performance Incentive in response to the challenges it faces due to performance issues related to capacity supply obligations ("CSOs").[209] In the report, ISO-NE states that the non-hydro generating fleet delivered less than 60% of additional power requested by ISO following the 36 largest system contingency events between 2009 and 2012. Furthermore, the increased natural gas-fired generation in New England, which relies on a just-in-time fuel delivery system, creates greater need for flexible supply resources, investments in fuel delivery infrastructure, and more reliable fuel arrangements. ISO-NE believes that changes to FCM can improve incentives for participants to undertake these investments.

On January 17th, 2014, ISO-NE and the NEPOOL filed a "jump ball" filing to FERC with two different proposals for a Performance Incentive ("PI"). Two proposals were filed with FERC because the ISO-NE's Participants Agreement requires ISO-NE to make a "jump ball" filing when at least a 60% Vote of NEPOOL Participants Committee supports a Market Rule change that is different from an ISO-NE proposed Market Rule change.[210]

ISO-NE's version of the Market Rule change proposed a fundamental change in the compensation that resources would expect from the FCM. First, ISO-NE is proposing to change the metric against which compliance is measured from availability (currently measured through the "must offer" requirements) to actual performance in real-time, measured in MWh of energy and reserves delivered. In addition, all exemptions would be removed, and generators exposed to potential significant net losses in the FCM. Second, ISO-NE proposes to change the capacity revenue stream. Under the PI, resources in the capacity markets would get paid a base payment (i.e., FCA clearing price x CSO, similar to the capacity payments under the existing FCM), and will also be receive (pay) a performance payment (penalty) based on their energy market operations during Scarcity Events. Intentionally, ISO-NE has designed the PI so resources may face penalties that exceed the base payment.

NEPOOL's proposal consists of two changes to the energy market and the FCM. With regards to the energy market, NEPOOL proposes to increase the current system-wide Reserve Constraint Penalty Factor ("RCPF") values for the thirty minute operating reserve ("TMOR") product from $500/MWh to $1,000/MWh and for the ten minute non-spinning reserve ("TMNSR") product from $850/MWh to $1,500/MWh. In addition, NEPOOL proposes to replace the Scarcity Event mechanism with a performance mechanism based on a forced outage metric referred to as the Peak Equivalent Forced Outage Rate, or ("EFORp").

As of May 20th, 2014, FERC has not made a decision on the version of performance incentive it would approve.

7.3.4.3 Possibilities surrounding the future of PSNH generators

As presented earlier in Section 7.3.3, PSNH is a vertically integrated utility in New Hampshire that has not been completely unbundled during the electricity market restructuring process in

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[209] ISO. *FCM Performance Incentives*.. October 2012.

[210] NEPOOL. *NEPOOL Proposed Revisions to Market Rule 1 of the ISO-NE Tariff*. January 17th, 2014. p. 3.

the 2000s, and continues to operate under a COS regime that covers both its generation and regulated rate services.

On June 7th, 2013, the New Hampshire Public Utilities Commission ("NHPUC") published a report related to generation ownership of PSNH.[211] The report states that the status quo is not a viable option going forward, and that PSNH in its current form indicates the incompleteness of New Hampshire's electricity market restructuring.

On March 25th, 2014, the House of Representatives of New Hampshire passed the bill (H.B. 1602) authorizing New Hampshire's Public Utilities Commission to determine whether all or some of PSNH's generation assets should be divested or retired. A report of the findings should be filed to lawmakers by the end of 2014.

If all of PSNH's generating assets are retired or divested, New Hampshire would become a fully unbundled state.

7.3.5 Procurement of large scale hydro and renewables through long-term contracts

With five out of six states in New England having Renewable Portfolio Standards ("RPS"), the demand for renewable energy in the region has been increasing and would increase significantly in the near future. Furthermore, legislative mandates to reduce the amount of carbon emissions also increase demand for energy from low-carbon emission sources.

However, due to the price uncertainty of Renewable Energy Certificates ("RECs") and transmission system limitations in interconnecting more wind power to the grid, many New England states, such as Connecticut, Massachusetts and Maine, concluded that long-term contracts are needed to help development of renewable energy. Also, in light of possible insufficiency renewable energy sources, these states are considering importing hydropower from neighboring regions through long-term contracts.

These long-term contracts may lead to a return of a less competitive wholesale energy market, which may undermine the restructuring effort of the electricity market over the last 20 years.

7.4 Rationale for specific design elements and pros and cons of selected market design

The multi-jurisdictional nature of New England's market adds unique features to the region's electricity market design. The market structure has to cope with inconsistent policy goals in different states, while the region shares a common electric infrastructure and system operator. Features such as locational marginal price and zonal capacity market attempt to allocate cost according to regional demand, while state-level policies such as RPS and regulation of distribution companies add complications to the functioning of the market. This section discusses the rationale and evaluates the design of key features in New England's electricity

[211] "IR 13-020. Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impacts on the Competitive Electricity Market". Public Service Company of New Hampshire. June 7th, 2013.

system. Figure 58 summarizes the pros and cons of specific design elements discussed in this section.

Figure 58. Summary of design elements

Design elements	Rationale	Pros	Cons
Multi-jurisdictional power pool	• Reliability support from multiple interconnected utilities	• Economies of scale • Diversity of resources	• Inconsistent regulations and interests among states create difficulties when making changes
Locational Marginal Prices	• To pay generators and charge consumers the appropriate price based on system constraints	• Prices reflect system constraints and attract investments in congested zones	• Administratively complex • Requires large computational power • Additional instruments required for hedging
Forward Capacity Market	• Create market to provide revenue for capacity resources that have low load factor	• Reduces very high energy prices during scarcity • Provide additional revenue stream to generators to cover their fixed costs	• Heavily administered market that does not always reflect true economic value • Vertical demand curve recreates volatile prices
Renewable Portfolio Standard	• Increase usage of renewable energy	• Market determined prices for environmental attributes unbundled from the energy generated from renewable resources	• Uncertainty in REC prices limit their use in getting financing for new projects • Differences between state legislation creates intricacies in REC trading
Performance-Based Ratemaking	• Decouple utilities revenue from energy volume • Mimic competitive forces in markets to induce efficiency improvements	• Potential to increase the operating efficiency of utilities • Rate stability to consumers	• Flaws in incentive designs over- or under-compensate utilities
Regional Greenhouse Gas Initiative	• Reduce greenhouse gas emissions through a market mechanism	• Improves the economics of low-emissions generators	• Level of emission cap is sensitive to economic and political forces, causing uncertainties in emission allowance prices

7.4.1 Multi-jurisdictional power pool

The New England electricity market is designed as a single market across multiple states. While this is not an uncommon feature in the US,[212] it is a structure that has not been adopted in Canada.

The reason New England adopted a multi-jurisdictional market design is reliability. Before formation of a single wholesale electricity market and operation of ISO-NE, utilities in New England region joined together to form NEPOOL in 1971. NEPOOL allows New England utilities to better cooperation during stress events, and allow pooling of resources to support one another during system imbalances. The effect of a joint power pool is higher reliability through economies of scale.

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[212] In the US, organized electricity markets such as PJM and MISO are also multi-jurisdictional.

7.4.2 Locational marginal prices

As discussed in Section 7.1, ISO-NE uses LMP, which is a market-based means of pricing the efficient use of the transmission system when constraints prevent economically priced power from flowing where it is needed.[213] ISO-NE believes that LMP improves the efficiency of the wholesale electricity market in the short-term by ensuring that cost of congestion is reflected in electricity prices. ISO-NE also believes that using LMP helps relieve congestion over the long-term by promoting efficient investment decisions, as energy prices in congested areas would be higher than less congested areas. Over time, investments would be made to take advantage of the price differential and relieve congestion.

A drawback in the use of LMP is that it can be administratively complex to design and to implement. Furthermore, with LMP, there is a need for financial instruments like financial transmission rights so that market participants have sufficient methods to hedge the additional risks created by LMP. Another drawback of implementing LMP instead of using a single price for the whole market is the need for more computational power for the market operator to calculate prices in real time.

7.4.3 Capacity market

Since 2008, ISO-NE has conducted FCAs that have delivery dates approximately 3.5 years ahead.[214] The objective of the FCM is to purchase sufficient capacity for reliable system operations for a future year at competitive prices.

The reason a capacity market is required is to complement the competitive energy market design that has a price cap. Under ISO-NE market rules, offers into the energy market are subject to a price cap of $1,000/MWh. Furthermore, as ISO-NE has admitted, a competitive energy-only market would result in "missing money" problem where revenues from energy market would be insufficient to cover the long-run marginal cost of a generator.[215] As such, without complimentary revenue to resources, an energy-only market would result in insufficient revenue to cover long-run marginal cost of existing units and to attract new investments.

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213 ISO-NE. "Locational Marginal Pricing – What are the Benefits?" <http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index-p4.html

214 FCAs are usually held in February, and the relevant capacity commitment period begins in the June 3 years after the FCA.

215 ISO-NE. "FCM Performance Incentives" October 2012. Available online at <http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf>

7.4.4 RPS

As discussed in Section 7.1, all states in New England, except for Vermont, has RPS. However, as RPS is based on individual state legislations, there are differences in renewable energy targets and qualification criteria of being renewable energy among states.

A tradable RECs regime designed to incentivize development of renewable energy allows policy makers to create quantity certainty through market oriented prices. By setting the amount of renewable energy utilities required to procure each year, and creating a market that unbundles energy and the associated "green attributes" created from renewable energy sources, policy makers can allow the market to decide the premium for green attributes associated with renewable energy.

The downside of a tradable RECs regime is the uncertainty of REC prices. In New England states, RPS requirement is designed based on a fixed percentage of energy demand of a year. Since energy demand in a year depends on external factors such as performance of the economy, weather pattern, and fuel prices, the final amount of REC demanded is uncertain until the end of the year. The supply of renewable energy credits in each year is also uncertain, as conditions such as wind pattern and hydrology could vary from year to year. Furthermore, if REC demand in a particular year is higher than expected, there could be insufficient installed renewable generation capacity to meet the demand. On the flip side, unless there is a REC banking provision, oversupplied RECs will not get compensated. All these uncertainties lead to volatile REC prices, as presented in Figure 51. In generally, renewable generation technologies, such as wind, have higher levelized cost of energy than non-renewable generators such as combined cycle gas turbines. Revenue from RECs could compensate for the difference. However, the volatility in REC prices decreases the value of REC revenue in securing financing for construction of renewable generators.

Finally, as RPS are state level policies, each state has its own definition and qualification criteria of which type of resources constitutes as a renewable energy source. For example, hydroelectric plants of up to 100 MW of capacity can be qualified as renewable resources in Maine; however the capacity limit for hydroelectric power is 30 MW in Massachusetts. At the same time, all New England states with RPS allow qualified renewable generators located in other New England states to sell RECs into their own state. The difference in definition of renewable energy sources, coupled with allowing cross selling of RECs between states, create intricacies in relationships between different states' REC prices.

7.4.5 Performance-based ratemaking ("PBR")

As discussed in Section 7.2.3, some states in New England have used PBR to set distribution rates. The PBR mechanisms that were implemented in CMP and NSTAR have a set productivity factor, flow through mechanisms, service quality and performance standards, and ESM. These mechanisms provide strong incentives for the utilities to increase performance and improve their productivity. In addition, with performance standards (with penalties) in place, consumers and regulators are assured that reliability and service quality will be maintained. Flow throughs also provided the utilities to manage their risks for factors that are beyond their control. Furthermore, with PBR, there is reduction in the regulatory burden because of lower frequency of regulatory proceedings, compared with other states in New England that are under a COS approach).

Nevertheless, PBR can be tedious as it involves analysis of technical issues such as determining the appropriate productivity factor to use and the suitable deadband for ESM, for example.

7.4.6 Carbon emissions regulation

As discussed in Section 7.1, all of the states in New England are participants of RGGI. RGGI states sell emission allowances through sealed bid, uniform price auctions on a quarterly basis. Since the product being sold are emission allowances, generators that emit greenhouse gases would need to purchase allowances in order to generate electricity. In contrast, as the product is not an "emission reduction certificate," non-carbon emitting generators do not get extra revenue from carbon credits. Therefore, although RGGI creates relative cost change between greenhouse gases emitting and non-emitting generators, they do not create extra revenue stream for non-emitting generators in parallel with REC revenues.

7.5 Transitional challenges and remedies adopted

New England's electricity market design has been a work in progress since inception. For example, the design of a well-functioning capacity market is still evolving, while the unbundling process of vertically integrated utilities in Vermont and New Hampshire are incomplete. These transition issues, present since the 1990s, continue to challenge ISO-NE and regulators. In this section, we cover the background and outcome of three of these challenges.

Figure 59. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Reliance on reliability must-run contracts leading to a heavily contested capacity market design process	Negotiated settlement where stakeholders agree on a capacity market design, and seek FERC approval
Certain states failed to fully unbundle the market due to specific circumstances within the state and uncertainties facing utilities and consumers in light of California's energy crisis	Vermont and PSNH in New Hampshire stopped their restructuring process. Generators in non-restructured states continue to participate in the ISO-NE wholesale energy market Efforts in unbundling PSNH have resumed
Slow pace of small customers switching to competitive retailer	Continued use of standard rate of service procured through a competitive process

7.5.1 Transition to the FCM

Before the implementation of the FCM, ISO-NE (and previously NEPOOL) imposed an installed capacity ("ICAP") requirement on load-serving entities, requiring them to procure specified amounts of ICAP based on their peak loads plus a reserve margin. Prior to the widespread unbundling of the generation, transmission and distribution functions of most New England load-serving entities (which in many cases included state-mandated divestiture of generating assets), if a utility did not have sufficient resources to meet its ICAP requirement, it could either obtain ICAP from an entity in the pool with a surplus or pay the deficiency charge.

Beginning in 1998, ISO-NE began operating a bid-based market for ICAP. In 2000, as part of the region's development of wholesale power markets and market-based rates, however, the ICAP market did not address locational requirement of installed capacity, and a number of out-of-market Reliability-Must-Run ("RMR") contracts are signed between ISO-NE and individual generators to keep the units online.

In April 2003, FERC rejected four RMR agreements and allowed collection of only going-forward maintenance costs through a bidding mechanism named as the Peaking Unit Safe Harbor ("PUSH") mechanism, and ordered ISO-NE to develop a Locational Installed Capacity ("LICAP") market or deliverability requirement by 2004. This created a long negotiated settlement process between generators, load, and other stakeholders.

Key contention areas include the topology of capacity zones (e.g. how many zones should there be), shape of the demand curve (ISO-NE's original proposal has a downward sloping demand curve, but the resultant agreement ended up with a vertical demand curve), level of transitional payments for capacity, capacity payments to new versus existing capacity resources, and arrangements to phase out existing RMR agreements.

The settlement process involved 115 parties, with over 30 formal settlement conferences held over a four month period. The result is a settlement agreement that created ISO-NE's FCM. Only 8 parties formally opposed the settlement agreement, and the NEPOOL Participants Committee voted for the agreement with over 78 percent support. However, it should be noted that while many parties, including load representatives and generators, opposed individual components of the settlement agreement, they accepted the settlement agreement as a whole as the settlement is the product of a complex and difficult negotiation and represents an interconnected balancing of interests.

7.5.2 Challenges during unbundling of vertically integrated utilities

As presented in Section 7.3.3, not all states in New England have fully unbundled their electricity market. Most notably, Vermont decided not to restructure their market in 2002, and PSNH in New Hampshire remains a vertically integrated utility with ownership of both generation and distribution facilities and divested only of their generating assets.

There are state specific and non-state specific reasons causing the incomplete unbundling process in Vermont and New Hampshire.

The main non-state specific reason is the California energy crisis in early 2000. Both New Hampshire and Vermont initiated their restructuring effort in the mid-1990s, with laws passed in the state legislature creating special committees or granting public utilities commission mandates to analyze the impact of unbundling the states' electric utilities. By late 1990s, both New Hampshire and Vermont had decided to restructure their market. In the case of Vermont, in 1999, the two utilities filed a joint restructuring plan by consolidating two companies into a single distribution company and selling their generating assets. In New Hampshire, the restructuring study commission issued a final restructuring plan in 1997 recommending unbundling of utilities including PSNH. However, both states' plans were scaled back or halted when the California energy crisis struck in 2000-2001, which caused concerns in states about the potential outcome of a restructured market.

For state-specific reasons, Vermont utilities signed long-term contracts with Hydro-Quebec in the early 1990s with at prices of around $65/MWh. However, by 1995, energy prices remained low in the region ranging from $35/MWh to $40/MWh. With these unprofitable long-term contracts, the competitive position of Vermont's utilities would be unfavorable and therefore in Vermont's restructuring plan, contract costs with Hydro Quebec would be paid down with state-backed loans. However, by 2002, Vermont Public Service Board decided that there is too much uncertainty following a restructured market, and stopped the restructuring effort.

In New Hampshire, the restructuring plan proposed by the Retail Wheeling and Electric Utility Restructuring Study Committee was heavily litigated by the owner of PSNH as soon as the plan was released. It took four years of negotiations before a negotiated settlement agreement was agreed between PSNH and the state, which resulted in the divestiture of one of the generating assets. However, by the time when the restructuring process began, the California energy crisis hit and derailed the restructuring.

7.5.3 Pace of market opening to small customers

In all New England states, except for Vermont, restructuring the electricity markets includes opening up competitive retail access to consumers. Competitive retailers have entered into the New England states but have achieved varying levels of success, both geographically and in the type of customers they are able to attract. Figure 60 presents the percentage of consumers that have switched their electricity supplier since market restructuring in a different New England state, and the percentage of load switching suppliers by customer type.

Figure 60. Percentage of consumer that has switched electricity suppliers as of 2013

	Residential customers	Small business	Large business	Total load
Connecticut	44%	78%	87%	66%
Maine	28%	60%	96%	59%
Massachusetts	17%	48%	89%	55%
Rhode Island	N/A			34%

Note: Data for New Hampshire is not available. Vermont has not opened up retail access.
Source: Distributed Energy Financial Group. Annual Baseline Assessment of Choice in Canada and the United States ("ABACCUS"). January 2014

In Maine and Connecticut, standard offer services are provided to residential customers that have not switched to a competitive retail supplier. In both states, the standard rate is determined through a competitive procurement process where suppliers submit bids to provide the service specified by the state's department of public service.

One reason for a relatively low switching rate for residential customer is the availability of a low standard service rate. For example, when markets opened in Massachusetts, the standard offer service rate was too low for competitors to enter the market, thereby stifling the competitive retail market. In 2005, Massachusetts let the standard offer service expire and transferred customers that were on a standard offer service to a "basic service" provided by distribution companies. However, this has not significantly increased the speed with which customers are switching retail service providers, and Massachusetts remains one of the states with the lowest numbers of customers switching among unbundled New England states.

7.6 Implications to Nova Scotia

New England's history in restructuring its electricity market from many vertically integrated utilities into a single energy and capacity market offers important lessons for Nova Scotia.

While New England's electricity market has a functioning wholesale energy market with prices generally representing the marginal cost of production, the capacity market has yet to demonstrate its ability to retain needed capacity and attract new investments.

On the distribution side, different states in New England have developed different regimes to regulate their distribution companies, ranging from traditional COS, to ESMs, to typical I-X regimes. The nature of a multi-jurisdiction energy market allows each state to decide the appropriate regulatory regime that suits the state's need. At the same time, a regional energy market allows the states to enjoy the benefits from the larger economies of scale of a regional wholesale energy market.

Based on the historical and current experience of New England's electricity markets, the following lessons would be relevant to Nova Scotia:

- **While negotiated settlements are a process efficient way in market design, it does not necessarily create an economically efficient market design**. Both during the development of FCM and unbundling of vertically integrated utility, stakeholders litigated against the proposed market design or restructuring plan, which resulted in negotiated settlements. In both cases, the resulting market structure ended up requiring further restructuring.

- **Over-handling of bid/offer rules may create artificial prices.** As a result of concerns of market participants exercising market power, the capacity market rule design has incorporated a bid/offer cap and a floor, and allowed ISO-NE's IMM to reject certain bids based on perceived cost of market participants. This resulted in capacity prices being set seven times in a row at price floor, and a sudden jump to the price cap in the eighth auction. With less interference from artificial prices, it is possible that more retirements and new entry would have happened with market participants being able to observe market driven prices.

- **Whether prices would be lower after restructuring should not be the only determining factor of the success of restructuring.** In many FERC dockets related to

New England's electricity market, parties filed to FERC arguing whether a tariff or market structure is "just and reasonable" based on whether the post-restructured price would be lower or equal to the existing price levels, or whether cost to consumers would be lowered. While potential changes to price levels and consumer cost are an important factor to consider in electricity market restructuring, whether prices are "just and reasonable" should not be judged relative to current prices. Instead, it should be determined by considering whether the level of profit would be sufficient to attract continued investments into the electric sector.

8 New South Wales

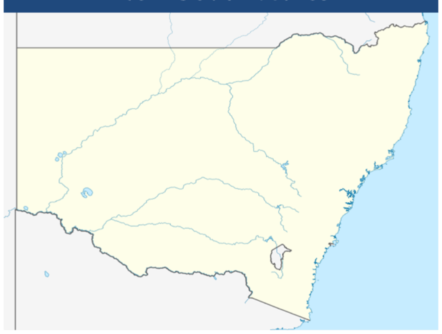
The New South Wales ("NSW") electricity market has completed its restructuring and deregulation and is currently privatizing. NSW's generation, transmission, and distribution networks fall under state jurisdiction. NSW participates in the National Electricity Market ("NEM"), the wholesale market in eastern and southern Australia. NSW provides valuable lessons to Nova Scotia particularly on its gentrader model and vesting contacts, which address transitional challenges in privatization.

8.1 Overview of the New South Wales market

New South Wales ("NSW") is an Australian state bordering Queensland to the north, Victoria to the south, South Australia to the west, and the Tasman Sea to the east. It is Australia's most populous state with 7.4 million residents. Its installed generation capacity is 17 GW with coal comprising more than 60% of the fuel mix. NSW and Victoria are pioneers in Australian electricity restructuring. While Victoria has privatized its electricity assets and deregulated its retail price, NSW has just started to privatize generation assets under the previous gentrader model and expects to fully deregulate its retail price by mid- 2014.

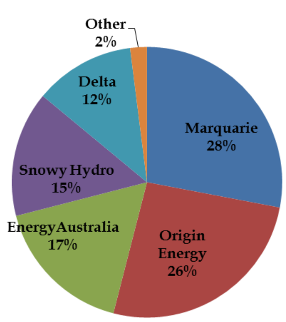
Figure 61. NSW snapshot

New South Wales

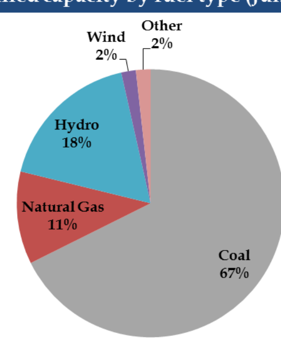


Key facts	
Population (June 2013)	7.41 million
GDP growth (2013)	2.4%
Installed capacity (June 2013)	17,000 MW
Generation (2013 estimate)	68,834 GWh
Peak demand (2013 estimate)	13,946 MW
Load growth (2005/06-2012/13)	0.6%
Number of distributors	3
Number of transmitters	1

Top market players by capacity (2013)*



Installed capacity by fuel type (June 2013)

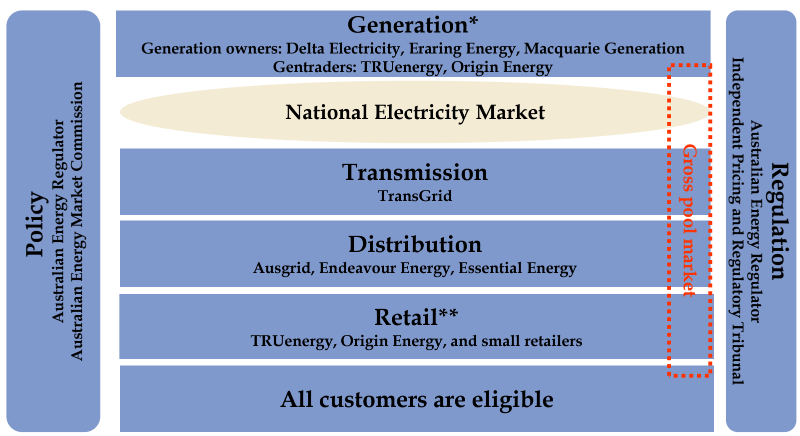


*Top market players shown in the pie chart above are based on dispatch rights of the capacity and not plant ownership.
Source: Australian Bureau of Statistics, Australian Energy Market Operator ("AEMO"), TransGrid

Although the NSW Government **owns** as much as 90% of state generation capacity, most of the generation capacity is **controlled** by gentraders (see Section 8.4.2).[216] The transmission and distribution networks are also owned by the state. The transmission network in NSW is owned and operated by TransGrid[217] while the distribution utilities are owned by Ausgrid, Endeavour Energy, and Essential Energy.[218] TRUenergy and Origin Energy, both private companies, purchased the retail operations and the brand name of the former state-owned retailers and hold a significant share in the retail sector. Vertical integration exists in NSW to a certain extent because there are ownership links between generators and retailers while operations are separated through "ring-fencing" agreements.[219]

The National Electricity Market ("NEM") is Australia's wholesale electricity market. The NEM operates an interconnected transmission network in eastern and southern Australia from Queensland to South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.[220] NEM operates as an energy-only market in NSW where generators sell electricity through a gross pool, spot market. Figure 62 shows the key players in NSW's electricity market.

Figure 62. Key market players in the electricity value chain



* The generation owners are government owned entities while Delta Electricity and Eraring Energy sold their generation electricity output to private entities TRUenergy and Origin Energy via the gentrader model.
** TRUenergy and Origin Energy purchased the retail operations and brand names of the former government owned retailers.
Source: NSW Auditor-General

216 AER. *State of the Energy Market 2013.* December 2013. p. 29.

217 TransGrid. *New South Wales Transmission Annual Planning Report 2013.* June 2013. p.11.

218 NSW Auditor-General. *New South Wales Auditor-General's Report: Financial Audit focusing on Electricity*. 2011. Vol 4. p. 6.

219 AER. *State of the Energy Market 2010.* December 2010. p. 93-94.

220 AER. *State of the Energy Market 2013.* December 2013. p. 6.

The installed capacity and generation of NSW are seven times larger than those of Nova Scotia's. However, both markets have a similar fuel mix where coal is the dominant fuel type accounting for more than 50% of the capacity. Other major fuel types include natural gas, hydro, and wind. Moreover, both markets implement a quota program that drives the investments in renewable energy, the renewable portfolio standards for Nova Scotia, and the renewable energy target for NSW.

8.2 NSW's current institutional and legal framework

8.2.1 Regulation and policy setting

The National Electricity Law lays the foundation for the current regulatory regime governing electricity networks.[221] It aims to foster efficient investment and operation of the electricity market and is responsible for setting the ratemaking regime of regulated businesses in the network. The main industry regulators are the Australian Energy Regulator ("AER"), the Australian Energy Market Commission ("AEMC"), the Australian Competition and Consumer Commission ("ACCC"), the Australian Energy Market Operator ("AEMO"), and the Independent Pricing and Regulatory Tribunal ("IPART").

The **AER** is responsible for regulating and monitoring the wholesale market. It produces weekly reports on the spot and forward market in the NEM, and conducts investigations towards extreme price events if warranted.[222] The AER monitors the regulation of the transmission and distribution in the NEM under the National Electricity Law ("NEL") and the National Electricity Rules ("NER").[223]

AEMC conducts independent reviews of the electricity market and is accountable to the Council of Australian Governments, which established the electricity reform in Australia.[224]

ACCC derives its regulation power from the *Competition and Consumer Act 2010.* It promotes competition and consumer protection and fair trade, prevent anticompetitive conduct, and monitor the price in the energy markets.[225]

AEMO delivers planning advice and operates the energy markets and systems.[226]

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[221] AER. *State of the Energy Market 2013.*December 2013. p.64.

[222] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 22.

[223] AEMC, AER, ACCC. *Memorandum of Understanding*. July 2009. p. 3-4.

[224] Ibid.

[225] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 22-23.

At the state level, **IPART** was established in 1992 as an independent regulator to review and regulate the electricity, gas, water, and transport sector in NSW.[227] IPART is responsible for the economic regulation of the transmission and distribution networks in NSW while AER monitors the regulation. Under the *Electricity Supply Act 1995*, IPART is responsible for setting the retail tariffs and monitoring the electricity licenses in distribution and supply.[228] Moreover, IPART administers the Greenhouse Gas Reduction and the Energy Saving Schemes.[229]

8.2.2 Administration of the electricity system

The **NEM** is the national wholesale spot market operating in eastern and southern Australia. It is an energy-only market that does not provide additional payment to generators for capacity, unlike North American markets such as New York and New England. Generators sell electricity through the NEM while retailers buy electricity for their customers in the industrial, commercial, and residential sectors.

The wholesale price is determined by supply and demand. Generators offer bids in the volume and the price that they intend to sell ahead of each trading day.[230]**AEMO** will dispatch the generators from the lowest to the highest price offers for each five minute dispatch period.[231] The dispatch price is set based on the highest bidding offer needed to meet the NEM demand, which is the marginal offer. Generators are paid at the average dispatch price over the 30-minute period regardless of their bidding price.[232]

The **AEMC** is responsible for reviewing the reliability standards of the NEM and sets the wholesale spot price range from a floor of -$1,000 to a cap of $13,100.[233]

Figure 63 illustrates how the NEM dispatches generation and sets the wholesale price in a 30-minute trading interval from 4:00 to 4:30 pm. In this example, five generators offer different price ranges to the market. At 4:20 pm, the fifth generator is dispatched to meet the demand at its offer price of $62 per MWh. The wholesale price is determined every 30 minutes at the

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[226] AEMO's Board." *AEMO.* Web. 30 April 2014. Available at http://www.aemo.com.au/About-AEMO/Board-and-Governance/AEMOs-Board

[227] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 23.

[228] Ibid. p. 23.

[229] Ibid. p. 23.

[230] AER. *State of the Energy Market 2013.* December 2013. p. 33.

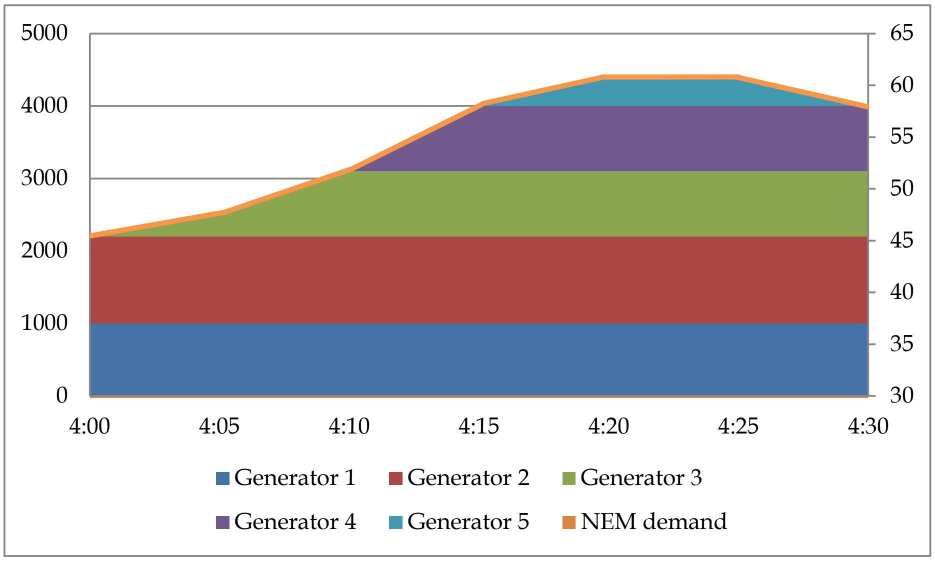
[231] Ibid. p. 33.

[232] Ibid. p. 33.

[233] Ibid. p. 33.

average of the dispatch price every five minutes. This is the price received by all dispatched generators and paid by the retailers in this period.

Figure 63. Generator bid stack



Source: AER

8.2.3 Regulatory oversight of charges

Under the National Electricity Law ("NEL") and the National Electricity Rules ("NER"), the AER is responsible for the economic regulation of the electricity transmission and distribution services. On the other hand, the **IPART** is responsible for regulating the prices for the retail sector.

Similar to UK, NSW is using a building block approach in its price regulation in the transmission and distribution sectors.[234] The regulator determines efficient cost components and uses these costs to determine a maximum revenue requirement in retail price regulation. The transmission networks are regulated under a revenue cap while distribution networks are regulated under weighted average price caps. NSW's PBR includes service quality standards with rewards and penalties, ex ante capex allowances, and a symmetric efficiency carryover mechanism with 30% of efficiency gains or losses retained by the utility. Figure 64 provides a summary of the key components of the NSW PBR mechanism.

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[234] Ibid. p. 129.

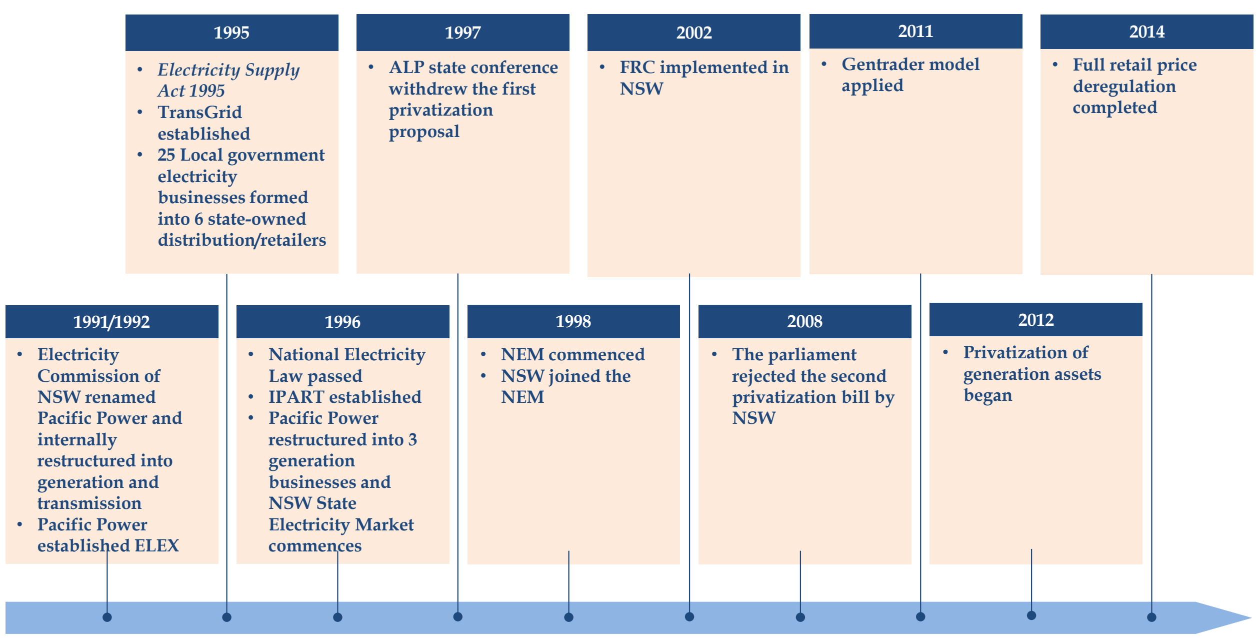
Figure 64. Key PBR components

PBR components for NSW utilities	
Form	Transmission networks are regulated under a revenue cap, while distribution networks are regulated under weighted average price caps
Approach	Building blocks approach
Going-in rates	Annual revenue requirements forecasted over the regulatory period on the basis of the building blocks approach
Term	5 years minimum
Inflation factor (I factor)	Quarterly CPI index
Productivity factor (X factor)	Specific for each year and utility. X factor is set to equalize (in present value terms) the revenue to be earned over the period to the total revenue requirements; X factor ranges between -13.3% to 0% depending on the distribution utility
Capital expenditure	Ex ante capex allowances are included in the building blocks approach through annual forecasts of rate base
Service quality (Q factor)	Capped rewards/penalties for specific performance targets. Targets set on the basis of a firm's historical performance . Not yet uniformly applied to all networks
Efficiency carry-over mechanism ("ECM")	Symmetric ECM with 30% of efficiency gains/losses retained by utility. Carry over mechanism (covers 6 yrs.). Currently applies to opex
Exogenous factors (Z factor)	Applies to specific events such as regulatory or tax change, disaster or terrorist event. General cost pass-throughs for costs beyond control of network that exceed minimum value
Off-ramps	Only for transmission utilities. Re-opener is available for events significantly altering the allowed level of capital expenditure

Source: AER

8.3 History of restructuring and recent developments

Figure 65. Timeline of key electricity restructuring events in NSW



Source: AER and LEI research

Electricity market restructuring in NSW was driven by inefficient investment and poor operational performance by state-owned generators. Early developments in the 1990s include establishing the state internal pool market, and the restructuring of generation, transmission, and distribution businesses. Privatization and deregulation efforts began in the late 1990s and subsequently faced transitional challenges. The full retail price deregulation was completed in 2014 and the privatization of generation assets is still ongoing. Figure 65 provides a timeline of key restructuring events in NSW.

8.3.1 Market restructuring and development

NSW is a pioneer in electricity restructuring in Australia. The restructuring from 1991 to 1996 involved establishment of three generation businesses, separation of the transmission assets into TransGrid, and consolidation of a fragmented distribution sector into six distribution businesses.

Prior to the commencement of the NEM in 1998, NSW established the Pacific Power Internal Pool Market ("ELEX") based on the first UK pool market in 1991/1992.[235] In 1998, NSW joined the NEM and operated in an interconnected network.[236]

8.3.2 Privatization of generation assets

There were two attempts to privatize the industry before 2011, but both failed to secure political support from the state. The first attempt was in 1997 when the Treasurer Hon. Michael Egan proposed to privatize the generation, distribution, and retail sector which was expected to raise $22 billion for the government.[237] However, the proposal was withdrawn by the Australian Labor Party ("ALP") State Conference.[238] The second attempt in 2008 failed when parliament rejected the Bill introduced by the NSW Government to lease the generation capacity, privatize the generators via Initial Public Offerings, and privatize the retail business.[239] The main opponents of the Bill were ALP parliamentary representatives led by the ALP State President Bernie Riordan.[240] The move toward privatization caused conflict between labor and trade

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[235] Ibid. p. vi.

[236] Ibid. p. vi.

[237] Ibid. p. 37.

[238] Ibid. p. 37.

[239] Ibid. p. vii.

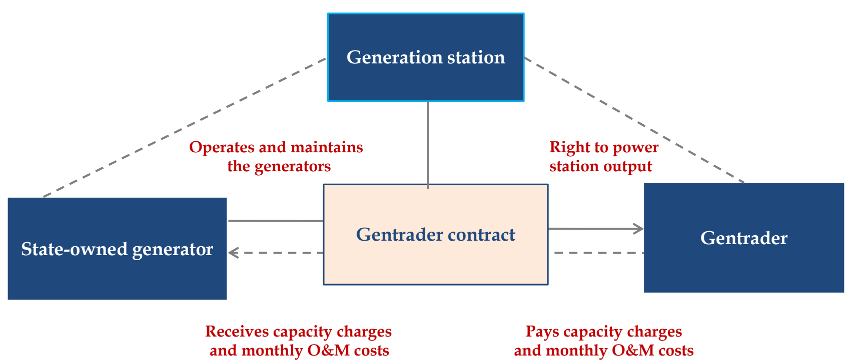
[240] "NSW Labor to fight Iemma on privatization." *Crikey.* Web. 18 February 2008. Available at http://www.crikey.com.au/2008/02/18/nsw-labor-to-fight-iemma-on-privatisation/?wpmp_switcher=mobile

union groups and NSW Premier Morris Iemma—who endorsed the move and was put in a difficult situation—causing further aggravation in the looming conflict over jobs and wages.[241]

8.3.3 Gentrader model

The several unsuccessful attempts to privatize the generation assets in NSW drove the government to adopt a gentrader model in 2011. The intent was to introduce competition in the wholesale market and reduce potential risks. Under a gentrader model, the government of NSW retains the ownership of and responsibility for the day-to-day operations of generation assets while retaining the right to trade electricity.[242] Under this model, the gentraders pay the Government two fees: (i) capacity charges to the State-owned generators over the life of the contract for having access to the capacity of the generation; and (ii) monthly fixed and variable costs such as maintenance, fuel, wages, capital operating expenditure, and any carbon liability that may emerge as a result of the introduction of a carbon tax or similar arrangement.[243] The State-owned generators remain as the contract counterparties to existing fuel contracts and pass the contract costs to the gentraders.

Figure 66. Gentrader model



Source: LEI based on the description in the Legislative Council

Each gentrader is allotted a set maximum available capacity, which the generator can dispatch into the NEM at any time on its behalf. A generator pays a penalty called the availability liquidated damages ("ALDs") to the gentrader if it is unable to deliver power when scheduled to do so and called upon. The ALD cap, set on a yearly basis, is equal to the capacity charge paid by the gentrader.

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[241] Ibid.

[242] It is similar to Alberta's Power Purchase Arrangements ("PPAs").

[243] Legislative Council. *The Gentrader Transactions. Standing* Order 231. February 23, 2011. p. 19.

In 2011, the NSW Government sold the electricity trading rights to TRUenergy (rebranded in 2012 as EnergyAustralia) and Origin Energy.[244] After the sale, the government entities dispatch rights of 28% and 12% were owned by Macquarie Generation and Delta Electricity, respectively, while private entities Origin Energy and EnergyAustralia owned 26% and 17%, respectively.[245]

8.3.4 Retail deregulation

NSW was the first to implement full retail contestability ("FRC") in Australia. Since January 1, 2002, all electricity customers in NSW have had the option to choose their retail electricity supplier or to remain with the Standard Retailer on a regulated tariff.[246] However, regulations still existed in retail prices charged by electricity distribution businesses as they remained as a monopoly. Moreover, the IPART set default tariffs for small energy retail customers.[247]

8.3.5 Recent developments

NSW is taking aggressive steps to privatize its generation assets although it still faces opposition from the union and challenges from antitrust regulators. In 2012, the state passed the *Electricity Generator Assets Act 2012* to facilitate the sale of the generation assets to gentraders.[248] Origin Energy acquired the Eraring and Shoalhaven power plants, which were previously under a gentrader agreement.[249] EnergyAustralia acquired the Mount Piper and Wallerawang power stations in September 2013, paving the way for further privatization.[250] In February 2014, AGL Energy agreed to purchase the state-owned generation company, Macquarie Generation, for AUS$1.5 billion. However, the deal was blocked by the antitrust regulators in March.[251] NSW is also considering privatizing the transmission and distribution networks worth AUS$34.5 billion. However, no transaction will be made before the next election in 2015.[252]

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[244] AER. *State of the Energy Market 2013.* December 2013.p. 29.

[245] Ibid. p. 29.

[246] IPART. *Recovery of Full Retail Contestability Costs By New South Wales Energy Businesses.* August 2001. p. 5.

[247] Ibid. p. 5.

[248] AER. *State of the Energy Market 2013.*December 2013.p. 29.

[249] Ibid. p. 29.

[250]"Mt Piper & Wallerawang Power Stations Project." *EnergyAustralia.* 2012. Available at http://www.energyaustralia.com.au/about-us/what-we-do/projects/mt-piper-and-wallerawan

[251] "New South Wales Considers Selling Electricity Network." *Bloomberg News.* Web. 27April 2014. Available at http://www.bloomberg.com/news/2014-04-27/australia-s-most-populous-state-to-mull-electricity-network-sale.html

[252] Ibid.

Furthermore, the government of NSW will remove the remaining regulation applicable to retail prices starting mid-2014.[253] Previously, the incumbent retailers had to offer service to residential and small business customers at a price regulated by IPART.[254]

8.4 Rationale for specific design elements and pros and cons of selected design

This section discusses the rationale and evaluates the design key features in NSW's electricity system, which includes privatization of generation assets, the gentrader model, retail price deregulation, and Performance-Based Ratemaking ("PBR"). Summary findings are shown in Figure 67.

Figure 67. Summary of specific design elements

Design elements	Rationale	Pros	Cons
Privatization of generation assets	To build a fully competitive market	• Improve productivity and foster efficient capital investment in sector • Generate additional revenue for the government to pay back its debt and to fund the public infrastructure • Save money on future electricity costs	• Short-term plan to fund public infrastructure
Gentrader model	To provide as an alternative to privatization	• Mitigate the government's risk in electricity trading	• Risks of additional costs borne by the generation owner
Retail deregulation	To foster retail competition	• Foster retail competition and lower the electricity price for small consumers because they can choose electricity products and retailers • Retailers earn profit margin comparable to a competitive market • Customers are generally satisfied with the retail service	• More transparency and information are needed for retail choice • More clarification on retail choice and time-of-use tariffs are needed
PBR	To facilitate an incentive based ratemaking, which will allow the accommodation of higher-powered incentives when needed	• Able to accommodate higher-powered incentives	• Add significant administrative costs as an information-intensive approach • A Total Productivity Factor ("TPF") approach provides more powerful incentives to improve efficiency in the network by reducing capital and operating expenditure and regulatory costs

253 Barry O'Farrell MP. Premier of NSW. Minister for Western Sydney. *Delivering Lower Electricity Prices for NSW Households.* Media Release. April 2014.

254 NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 15.

8.4.1 Privatization of generation assets

As we noted in the literature review, the reluctance of the government to give up ownership of electricity assets stems from the concern over possible market power concentration, from a regulatory perspective. However, private ownership is expected to improve productivity and foster efficient capital investment in the sector. Although privatization is not a prerequisite for electricity restructuring, the government of NSW views it as a critical component of a fully competitive electricity market and has made consistent efforts to privatize the sector. Despite the previous two failed attempts at privatizing, the government started to sell generation assets in 2012.[255]

The NSW Treasury advocates privatizing, claiming that it will generate additional revenue for the government, save money on future electricity costs, allow the government pay back its debt, and finance public infrastructure such as transport, school and hospitals.[256] More than AUS $400 million has been raised from asset sales. This money was returned to low-income energy customers in the form of rebates.[257] However, the Electrical Trades Union NSW argues that public ownership provides a stable revenue stream to fund public infrastructure.[258] This raised the question of whether the current and future benefits of privatization—including lump sum payments upfront and tax revenue stream in the future—outweigh future benefits of continued ownership. Opponents also argued (fallaciously) that the privatization would lead to higher electricity prices, saying that asset sales were a short-term, ill-conceived plan to fund the state infrastructure. Still, private sector buyers face several challenges when they consider acquiring the generation assets. These include antitrust regulations towards large private entities, additional costs paid to employees for job guarantees, and carbon taxes often required for power plants.

8.4.2 Gentrader model

Due to the political opposition against privatization, the government of NSW employed a gentrader model to contract the electricity dispatch rights to the private sector in 2011. The gentrader model is advantageous because it allows the government to get "out of the risky business of electricity generation and electricity trading."[259] In a privatized system, the usual role of the state-owned generator shifts towards ensuring that the asset is maintained in good

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255 AER. *State of the Energy Market 2013.*December 2013. p. 29.

256 "NSW Government to privatise electricity generators." *ABC News.* 15 November 2012. Available at http://www.abc.net.au/news/2012-11-15/nsw-government-to-privatise-electricity-generators/4372858

257 Ibid.

258 "Unions attack Labor over call for electricity sell-off." *The Australian.* 13, August 2012. Available at http://www.theaustralian.com.au/national-affairs/unions-attack-labor-over-call-for-electricity-sell-off/story-fn59niix-1226448735324#

259 Legislative Council. *The Gentrader Transactions. Standing* Order 231. February 23, 2011. p. 21.

condition and capable of meeting the requirements of the gentrader contracts. This means that the state's generating companies function as asset managers, while the energy market and trading risks are borne by gentraders.

Although gentraders pay monthly fixed fees (with some escalators built into the fees) over the life of the contract, there is still the risk that additional costs must be borne by the generation owner. During a stakeholder consultation, critics raised the issue that "the gentrader model exposes the generator state-owned corporations to on-going financial risks with respect to the operational performance of the generators while eliminating their ability to manage those risks through control over operational and maintenance strategies."[260]`Nevertheless, the government determined that dealing with the risks being faced by the state under the energy reform transactions and the gentrader model was better than maintaining the status quo.[261]

8.4.3 Retail deregulation

NSW implemented FRC in 2002 to open the retail choice to all electricity customers. However, the government plans to fully deregulate the retail price in mid-2014 when retail market competition is sufficiently robust. Increased network costs and climate change policies have led to a significant increase in retail electricity prices in NSW. With the privatization of retail businesses, more retailers were entering the market and customers were increasingly shifting their retailers to respond to the rising electricity price. Hence, retail price regulation impeded the competition in the retail sector. To foster innovation and competitive pricing, the AEMC put a package of recommendations forward including retail price deregulation, information sharing, consumer protection, and market monitoring.

The retail deregulation is generally considered a success though there are still several issues that need to be addressed adequately:[262]

- the deregulation fosters retail competition and lowers electricity prices for small consumers because they can choose electricity products and retailers;
- there are few barriers to entry for retailers. Small retailers are competing with large players. Origin Energy and EnergyAustralia lost significant market share when customers shift to small retailers;[263]
- the retailers achieve profit margin comparable to a competitive market;

[260] Ibid. p. 21.

[261] Ibid. p. 21.

[262] Ibid. p. v.

[263] AEMC. *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales.* October 2013. p. v.

- consumers are generally satisfied with the retail service but they demand more transparency and information to make retail choice; and

- the Standing Council on Energy and Resources is developing policies to clarify retail choice and encourage deeper understanding of the time-of-use tariffs offered by all retailers.

8.4.4 PBR

The electricity distribution regulation provisions of the National Electricity Rule outline objectives and principles, upon which distribution regulation is administered, which require, among others, the following outcomes:[264]

- an efficient and cost-effective regulatory environment;

- an incentive-based regulatory regime which provides equitable allocation of savings, a sustainable commercial revenue stream which includes a fair and reasonable rate of return, and consistency in the regulation of connection and distribution service pricing;

- an environment which fosters an efficient level of investment, operating and maintenance practices, and use of existing infrastructure; and

- regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions, and reasonable certainty and consistency over time of the outcome of regulatory processes.

From the very beginning of Australia's incentive-based regulation in late 1990s, there have been continuous arguments on whether the regulator should adopt the current building block approach or the Total Factor Productivity ("TFP") approach. Advocates of the current regime endorsed the building block approach because of its ability to accommodate higher-powered incentives. Moreover, the building block approach in NSW allows for the implementation of a clearly defined planning process for network investment and revenue certainty. Utilities are also certain that their capex plans will be reflected in the rates.

However, as discussed in the literature review, the building block approach is an information-intensive approach, which heavily relies on forecasts and extensive benchmarking analysis in setting the efficient cost. It can burden regulators with additional administrative costs, particularly in gathering adequate information from the utilities as they try to determine the appropriate revenue requirements. Furthermore, there were concerns that prices are increasing because of higher reliability standards and favorable appeal regime for utilities. Therefore, some experts endorse a TFP approach that creates more powerful incentives to improve productivity by reducing capital and operating expenditure and regulatory costs. The AEMC reviewed the TFP approach in its price regulation in 2011 and found that it will improve efficiency in the

[264] AER. Gas and Electricity Distribution Regulatory Guidelines. March 2006.

networks.[265] However, the Commission needs more data and analysis before considering the TFP approach.

8.5 Transitional challenges and remedies adopted

This section discusses the transitional models—which include the gentrader model and transitional design in the wholesale market—adopted in NSW's electricity restructuring. The summary of challenges and remedies adopted is in Figure 68.

Figure 68. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Failed attempts to privatize the generation assets	• Gentrader model
Transition to the NEM	• Vesting contracts • Transitional default tariffs

8.5.1 Gentrader model as a remedy to stalled privatization efforts

The gentrader model, discussed in Section 8.4.2, can be considered as an alternative policy that the government adopted in lieu of its failed efforts to privatize generation assets. The NSW Treasury first proposed a gentrader model in 2001 to contract the trading rights of state-owned generation and retail businesses out to the private entities.[266] In 2004, NSW Treasury produced a consultation paper proposing to contract the wholesale trading rights along with jobs and high risks to the private sector while leaving the fundamental role of "producing and delivering reliable and affordable electricity" to the state.[267] In 2007, Professor Anthony Owen raised the concern of public sector's ability to fund the projected baseload demand in the next decade.[268]After the 2008 Bill, which sought to privatize the electricity sector in NSW, was rejected by parliament, the government of NSW resorted to the gentrader model and considered it the sub-optimal option when the sale and long-term lease of the generation assets were no longer feasible.[269]

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[265] AEMC. *Review into the Use of Total Factor Productivity for the Determination of Prices and Revenues.* July 2011. p. i.

[266] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. vi.

[267] Ibid. p. vii.

[268] Ibid. p. vii.

[269] Ibid. p. viii

8.5.2 Mechanisms to transition to the NEM

As noted in the literature review, there are two market models in electricity wholesale trading, namely, bilateral contracts-based and pool-based markets. A pool-based market provides greater transparency, clearer price discovery processes, and the ability (for the buyers) to hedge separately via financial instruments. Prior to the commencement of the NEM in 1998, the NSW established a state pool market based on UK's gross pool model in the 1990s. The introduction of the pool market improved the financial performance of the sector and optimized the utilization of the capacity. Although Pacific Power continued to supply energy under a uniform bulk supply tariff ("BST"), it has been reduced due to the efficiency gains brought by the pool market. The reduction in BST decreased the cross subsidies (in retail tariffs) for small and medium business. The success of the state pool market had a significant impact on the introduction of the NEM, which adopted a similar pool model.

To address the transitional challenges brought by the NEM, NSW employed several specific designs, which include vesting contracts and transitional default tariffs.

The ***vesting contracts*** were structured as two-way hedges between the generators and retailers. The volumes were matched to the energy supplied to non-contestable customers and gradually reduced as the number of non-contestable customers fell. The form of the contract (a two-way hedge) meant that retailers were not exposed to any wholesale price risk for energy supplied under these contracts. The contract price was set based on pre-existing regulated retail tariff to manage the transition of retail prices.

Under the ***transitional default tariffs***, all customers had the right to remain on their previous regulated tariff for the first 12 months after choosing their retailers. The government provided greater protection for small customers (mostly household customers). It required IPART to set a standard tariff at which the default supplier[270] must continue to offer supply to small customers indefinitely. The default supplier can offer service at other unregulated tariffs but they must also offer the standard tariffs for small customers.

8.6 Implications for Nova Scotia

Important lessons in NSW's electricity restructuring can be learned from the transitional models that were adopted to privatize the generation assets and shift to a national wholesale market. The following are the most significant:

- **Gentrader model as an alternative to privatization.** Privatization in NSW has been receiving constant opposition, particularly from the labor and trade unions, since the 1990s. However, the government realized the importance of private sector participation in building a competitive electricity market so it employed the gentrader model to contract the electricity dispatch and trading rights out to the private sector. The model

[270] For example, the retailer/distributor who supplied the area in which the customer is located prior to the introduction of competition.

introduced competition in the market, helped eliminate the government's exposure to electricity trading risks, and paved the way for further privatization.

- **Mechanisms to ensure the smooth transition to NEM.** While UK faced problems such as price manipulation by major generators and issues related to long-term bilateral contracts between the generators and the suppliers (which eventually led to the decision to shift to a bilateral market in 2002), the pool market in NSW performed successfully and significantly influenced the establishment of NEM. NSW applied key transitional models when it established NEM. These included vesting contracts to mitigate the wholesale price risks and transitional default tariffs for customers (prior to choosing their own retailers). These specific design elements reduced market risks, especially for smaller consumers who may wish to remain regulated.

9 Ontario

Ontario's electricity system is often characterized as a "hybrid" as it contains elements of both a centrally planned and competitive electricity market. This characteristic is the direct result of how Ontario's incomplete restructuring policies evolved over time. Ontario's restructuring in 2002 represents an unsuccessful attempt by a jurisdiction to move from a regulated integrated government monopoly to a competitive market. A key lesson for other jurisdictions is that the failure to institute transitional mechanisms increases the risk of political influence in the event of price volatility. The current institutional structure alleviates some of the problems that arose following restructuring, but at the expense of genuine market competition and cost efficiency.

9.1 Overview of the Ontario market

Prior to restructuring, Ontario had a vertically integrated provincially-owned monopoly, Ontario Hydro, which was responsible for generation, transmission, and distribution. Currently, power generators bid into and receive dispatch instructions from a wholesale market administered by the Independent Electricity System Operator ("IESO") with retail choice at the consumer level. However, Ontario's electricity market still largely consists of a principal buyer, the Ontario Power Authority ("OPA"), which is heavily influenced by the provincial government.

Ontario has operated an energy-only wholesale electricity market since 2002, following the restructuring of the vertically integrated Ontario Hydro. Presently, the province's installed capacity consists primarily of nuclear (40%), natural gas (30%), hydro-electric (24%), and wind (5%). Approximately 47% of this generating capacity is controlled by the provincially-owned Ontario Power Generation ("OPG"), which holds the generation assets that remained of the former Ontario Hydro.

OPG's market share has been decreasing due to its coal-fired stations being retired and because of new entrants under OPA-backing contracts, including solar and wind power producers using a Feed-in Tariff ("FIT"), which will be discussed in more detail later. By April 2014, Ontario became the first market in North America to fully eliminate coal as a source of electricity generation.[271] OPG also has some unregulated power generating assets that operate on a merchant basis. The second largest player in Ontario's electricity generation is Bruce Power LP, which controls approximately 19% of generating nameplate capacity, mainly through nuclear plants, which are leased from OPG. The remaining asset owners typically control less than 3% of the overall market share each, but make up roughly 34% combined.

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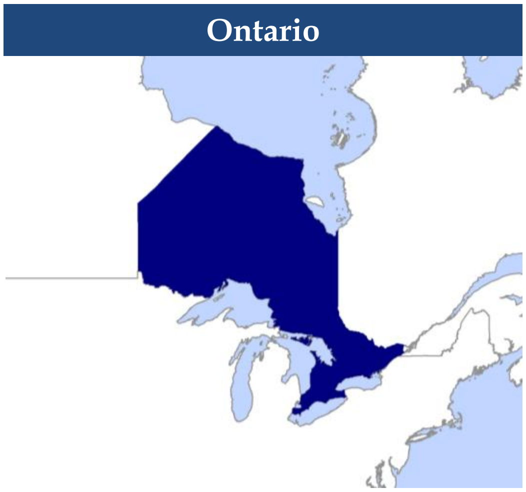
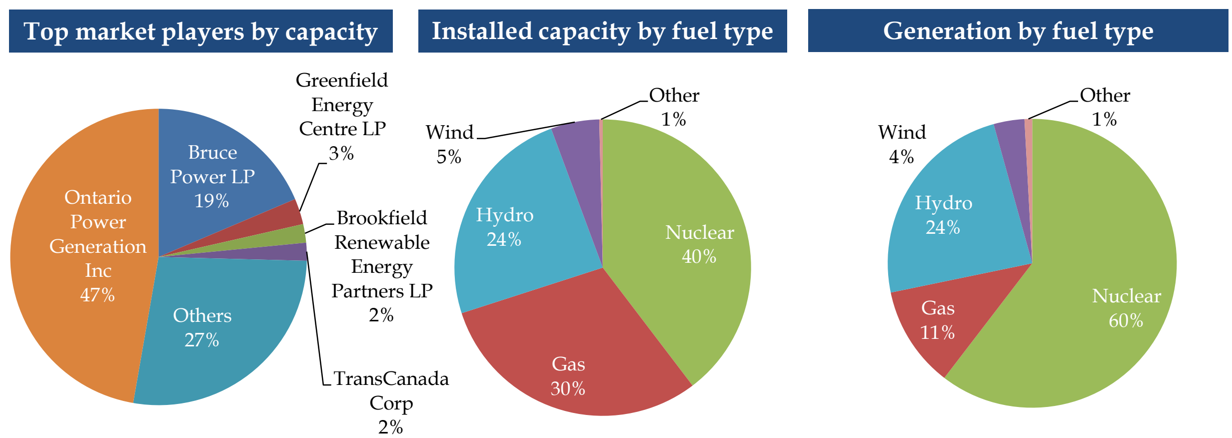
[271] Ontario Ministry of Energy. *Creating Cleaner Energy in Ontario – Province has Eliminated Coal-Fired Generation.* April 15, 2014. Available online at http://news.ontario.ca/mei/en/2014/04/creating-cleaner-air-in-ontario-1.html (Accessed on April 22, 2014).

Figure 69. Ontario snapshot



Key facts	
Population (2013)	13,537,994
GDP growth est. (2014)	2.1%
Installed capacity (2013)	32,961 MW
Peak demand (2013)	24,636 MW
Compound annual load growth rate (2009-2013)	-0.6%
Production (2013)	154 TWh
Number of distributors	77
Number of transmitters	13



Source: Ontario Ministry of Finance; IESO; third party data provider

Despite limited or negative load growth from 2009 to 2013 averaging -0.6% per year, Ontario's installed capacity has grown over the same period by 2.9% per year. While a portion of this capacity increase has been justified by the decision to close all of Ontario's coal-fired power stations, analysis suggests that continuation of current policies could result in excess supply through 2019.

Hydro One Networks, Inc. ("Hydro One") is the owner and operator of 97% of the transmission assets in Ontario. It is a wholly owned subsidiary of Hydro One, Inc., which is a Crown corporation that is also wholly owned by the province. Hydro One's transmission system is also connected to other transmitters, namely Great Lakes Power, Canadian Niagara Power, and Five Nations Energy, which represent the remaining 3% of licensed transmission facilities in Ontario.

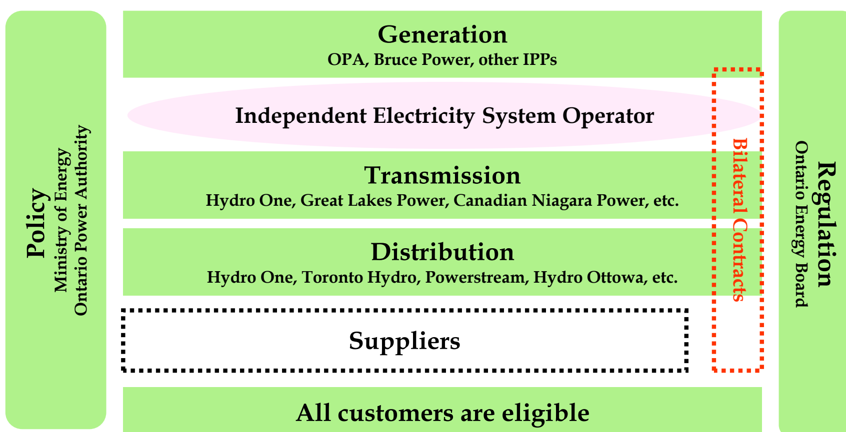
Hydro One is also the largest local distribution company ("LDC") in Ontario, serving over 29% of customers primarily living in rural areas. There are around 77 distribution companies in Ontario, which mostly serve urban customers and are largely municipally owned. The other major distribution companies by market share include Toronto Hydro (16%), Powerstream (7%) and Hydro Ottawa (6%).

Of course, the electricity market in Ontario is clearly different from that of Nova Scotia. With a population of 13.5 million, Ontario is a larger, more highly integrated market. Ontario is also linked to five adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York) through 26 interconnections. Lastly, Ontario faced a different starting point when it began restructuring. While Nova Scotia Power Inc. ("NSPI") is already a privately-owned company, Ontario started with a provincially-owned monopoly and took a "big bang" approach in which restructuring, deregulation, and unbundling occurred all at the same time. The transitional challenges using this approach are discussed in Section 5.

9.2 Ontario's current institutional and legal framework

The institutional arrangements in Ontario allow the provincial government to control market design and planning through ministerial directives. This section provides an overview of the regulatory bodies in Ontario's electricity system and their responsibilities in administering it. Figure 70 summarizes the key roles of all the entities in Ontario's electricity sector.

Figure 70. Key roles of entities in Ontario's electricity sector



Source: LEI

9.2.1 Regulation and policy setting

The Government of Ontario sets electricity policy and the Ontario Energy Board ("OEB") regulates Ontario's power market. While the Ontario Cabinet retains the legislative authority to set policy for Ontario's energy sector, daily oversight of Ontario's electricity system is conducted by the Ministry of Energy ("Ministry"). The Ministry has overall responsibility for Ontario's power market, which includes ensuring reliability and productivity of the electricity system and promoting innovation in the energy sector. Upon the approval of Cabinet, the Minister can issue policy directives to the OEB, the IESO and the OPA, and each is legally obligated to implement such policy directives. This feature is discussed more thoroughly in Section 9.4.1.

9.2.2 Licensing regime

The OEB is the ostensibly independent tribunal that is responsible for regulating Ontario's electricity and natural gas sectors. The OEB regulates both the IESO and the OPA, as well as transmission and distribution companies. However, while the OEB regulates the cost of power from certain OPG assets such as nuclear and large hydro plants, the cost of power agreements with non-utility suppliers are not subject to OEB regulation. The OEB also creates transmission system standards, manages rate hearings and evaluates appeals from stakeholders. Lastly, it sets prices for consumers under the Regulated Price Plan ("RPP"), issues licenses, and oversees electricity retailers.

9.2.3 Administration of the electricity system

Two entities administer the electricity markets and are responsible for market evolution and design: the IESO and the OPA. The IESO, (previously the Independent Electricity Market Operator or "IMO") is a not-for-profit corporation licensed by the OEB to operate the transmission system and balance the demand for electricity with supply. It also forecasts consumption throughout the province and dispatches plants based on offers from generators to provide the required amount of electricity.

The OPA is a not-for-profit government-owned corporation which is responsible for the long-term planning and procurement of Ontario's electricity supply, as well as for facilitating achievement of the province's conservation targets. The OPA's primary functions are to recommend preferred transmission systems, develop plans for a reliable and sustainable system, and ensure that consumers have enough power in the future by proposing new generation facilities in strategic areas.

9.2.4 Regulatory oversight of charges

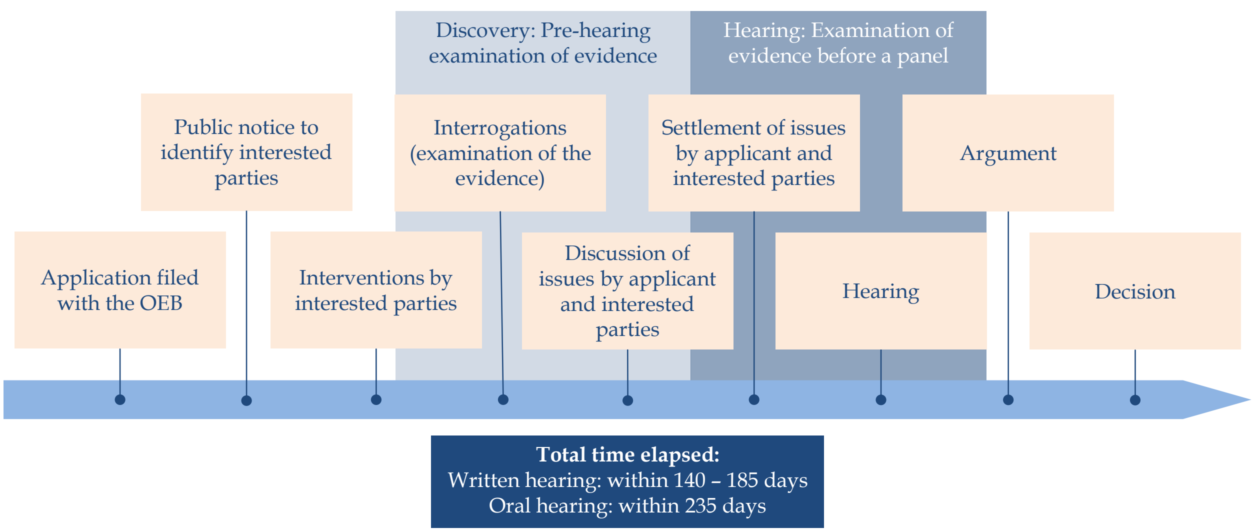
Before the breakup of Ontario Hydro, electricity rates were determined purely on a cost-of-service ("COS") basis, with no consideration about whether the costs incurred were reasonable or billed to consumers over an appropriate period. OEB at that time did not regulate electricity. Major cost overruns resulted in increasing prices in the early 1990s before the government froze the price of electricity for several years regardless of costs.

Currently, the OEB follows a quasi-judicial process that is open to public participation when setting rates. The regulatory process is summarized in Figure 71. For distribution, rates are determined using the incentive regulation mechanism ("IRM"). This will be discussed in detail in Section 9.2.4.1 below. However, for transmission, rates are calculated using COS, and IESO and the OPA operating costs are subject to annual reviews by the OEB. The OEB needs to assess projected operating costs and distribute capital investments between current and future consumers. This is largely based on reviewing forecasts and operational details submitted by OPG, Hydro One and utilities in a public forum. Entities that are regulated by the OEB are guaranteed a reasonable rate of return on their capital investments once the OEB approves their rates and deems the investment appropriate given future demand for electricity.

The total cost of electricity that Ontario consumers pay, however, is the sum of the Hourly Ontario Electricity Price ("HOEP") and the Global Adjustment ("GA"). The GA is a charge which covers the cost for delivering conservation programs and the payments made to participants under contracts with the OPA. The GA is calculated based on the differences between the market price and the rates paid to regulated and contracted generators and for conservation and demand management programs.

In 2005, the OEB initiated the RPP. As part of the RPP, the OEB sets tiered prices for customers not on time-of-use prices. As of May 1, 2014, eligible consumers will pay 8.6 cents per kWh up to a certain threshold each month and 10.1 cents per kWh for electricity used per month over this amount. The amount of electricity that is charged at the lower price changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to April 30th). Prices are reviewed and may change every six months based on an updated OEB forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

Figure 71. Adjudication timeline for rate-setting



Source: Ontario Energy Board

9.2.4.1 IRM for electric distributors

Figure 72. Key aspects of Ontario's IRM regime

	1st generation	2nd generation	3rd generation	4th generation*
Term	2001-2005	2006-2010	2011-2014	2015-2019
Form of regulation	Comprehensive price cap			
Going-in rates	Rebasing review or COS application at the beginning of each regulatory period for which distributors submit a projection of their rate base and revenue requirement for a forward test year			
Regulatory period	Rebasing year + 3 IRM adjustment years	Rebasing year + 3 IRM adjustment years	Rebasing year + 3 IRM adjustment years	Rebasing year + 4 IRM adjustment years
Inflation factor ("I factor)"	Ontario-specific Input Price Index (labor, materials, capital)	Macroeconomic index: the Canada Gross Domestic Product Implicit Price Index for final domestic demand	Macroeconomic index: the Canada Gross Domestic Product Implicit Price Index for final domestic demand	Inflation in non-labour prices will be indexed by Ontario distribution industry-specific indices while inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index
Productivity factor ("X factor")	Based on TFP for 48 utilities in Ontario. Uniform X factor of 1.5% for all utilities	Simple average of approved productivity factors across North America. X factor of 1% for all utilities	The X factor consists in two components: (1) the productivity factor at 0.72% and (2) the stretch factor (0.2% , 0.4% , 0.6% depending on the utility). Determined through arbitration between several TFP index studies	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor
Capital factor ("K factor)"	No explicit capital factor. Capex is embedded in the rate base test year.		No explicit capital factor. Capex is embedded in the rate base test year. Capex in excess of depreciation may be recovered under the Incremental Capital Module with three conditions: materiality, need, and prudence.	
Performance standards ("Q factor")	Mandatory standards for customer services. No mandatory standard for reliability			A regulatory review may be initiated if a distributor's annual reports show performance outside of the +/- 300 basis point earnings dead band or if performance erodes to unacceptable levels
Earnings sharing mechanism ("ESM")	No ESM			
Exogenous factor ("Z factor")	Adjustment for any extraordinary costs that meet criteria	Fewer criteria and limited to tax changes and natural disasters	Approval of a Z factor adjustment under 2 conditions: (1) event must be clearly outside of management's control and (2) costs must be above a materiality threshold of 0.5% of total revenue requirements (with a $50,000 floor and a $200 million ceiling)	

Note: *Under the Renewed Regulatory Framework for Electricity, which is discussed in Section 9.2.4.2, the utilities are given the option to choose the rate-setting mechanism that they want to adopt. The 4GIRM discussed above is just one of the options.

Source: OEB

Ontario is currently under the 3rd generation IRM ("3GIRM"). In principle, distribution rates are set annually based on a price cap that defines the maximum price that each distribution utility may charge.[272] Distribution rates are then periodically adjusted on the basis of a price cap index. The price cap index equals the inflation escalator minus the productivity and stretch factors. The price cap index applies to distribution rates (both fixed and variable charges) uniformly across all customer classes. In a departure from prior generations of IRM, the 3GIRM's target efficiency factor was differentiated amongst utilities. In addition to the industry productivity factor, each distributor receives a stretch factor that depends on the relative efficiency of a distribution company as compared to its peers. Figure 72 provides the key aspects of Ontario's 1GIRM, 2GIRM, 3GIRM, and 4GIRM. Renewed Regulatory Framework for Electricity Distributors ("RRFE").

Furthermore, the 3GIRM introduced an Incremental Capital Mechanism ("ICM") which is an explicit additional component to the price cap that distributors can elect to employ (with proper substantiation) to meet extraordinary capital investment needs. ICM allows distributors to request ex ante rate relief for non-routine capital investments not included in approved capital plans and/or not funded through existing rates. To be eligible for the ICM, the capital spending must respect certain criteria, specified in Figure 73.

Figure 73. Criteria for ICM eligibility

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold (which is based on a formula) and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers

Source: OEB

9.2.4.2 Renewed Regulatory Framework for Electricity Distributors ("RRFE")

On October 18, 2012, the OEB released its Renewed Regulatory Framework for Electricity Distributors ("RRFE"). Under the RRFE, an electric distributor is given three options on how to set its rates, based on method that will best meet its requirements and circumstances: (i) 4th generation incentive rate-setting ("IR"), (ii) custom incentive rate-setting ("Custom IR"), and (iii) annual incentive rate-setting index. Figure 74 below shows the different parameters of these three options. This new framework calls for distributors to focus on customer requirements and to demonstrate that their investment plans support cost-effective planning and operation of the distribution network.

272 This is in a normal, non-rebasing year.

Under the first option, rates are set on a single forward-test year COS basis and subsequent rates will be based on the price cap index formula under the 4th generation IRM ("4GIRM"). The term will be longer (5 years – rebasing plus 4 years) to "better align rate-setting and distributor planning, strengthen efficiency incentives, support innovation, and help manage the pace of rate increases for customers."[273] I factor will be based on an industry-specific price index while the X factor will be based on Ontario total productivity factor trends and stretch factor. All distributors will be subject to the same X factor. Similar to the 3GIRM, the stretch factor will be based on one of three efficiency cohorts based on the total cost benchmarking evaluation. The rules used for the ICM under the 3GIRM will continue to apply in the 4GIRM.

Figure 74. Key elements of the three rate-setting options

Setting of Rates	4th Generation IR	Custom IR	Annual IR Index
"Going-in" Rates	Determined in single forward test-year cost of service review	Determined in multiyear application review	No COS review, existing rates adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (i.e. Capital and OM&A)		
Annual Adjustment Mechanism – Inflation	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board based on: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
Annual Adjustment Mechanism – Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking	To assess reasonableness of distributor cost forecasts and to assign stretch factor		N/A
Sharing of Benefits	Productivity Factor		
	Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term
Z factors	Same as in the 3rd generation incentive regulation		
Performance Reporting & Monitoring	A regulatory review may be initiated if a distributor's annual reports show performance outside of the +/- 300 basis point earnings dead band or if performance erodes to unacceptable levels		
Appropriate for	Distributors that anticipate some incremental investment needs will arise during the plan term	Distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures	Distributors with relatively stead state investment needs

Source: OEB. ("Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach")

Under the **Custom IR**, rates are based on a five-year forecast of a distributor's revenue requirements and sales volumes. Distributors that opt for the Custom IR need to submit robust evidence of cost and revenue forecasts and detailed infrastructure investment plans for the term of the plan. Unlike the 4GIRM, there will be no ICM under this option as the distributors are

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[273] Ibid. p. 15.

expected to operate under their Board-approved multi-year rates. Distributors are also required to submit yearly reports of their capital spending.

The **Annual IR index** is simpler than the other two options. Rates are adjusted by a price cap index formula, so rates will be adjusted yearly by the growth of the I factor minus an X factor. All distributors under this option will have the same X factor. Similar to the Custom IR, there will be no ICM under this option as it assumes that the distributors will be under a "steady state" of operation.

Distributors also need to submit additional reports to the Board under the renewed regulatory framework. Distributors are required to file 5-year capital plans to support their rate application as well as reporting yearly on their key performance outcomes.[274] The Board will develop measures that will link to the performance outcomes on customer focus, operational effectiveness, public policy responsiveness, and financial performance.

9.2.5 Monitoring arrangements

The OEB is responsible for market monitoring and enforcing market rules. All generation, transmission, and distribution companies are subject to audits, compliance reviews, and monitoring for various aspects of financial operating performance. As discussed above, this serves as a basis for approving and setting delivery rates electricity distribution and transmission.

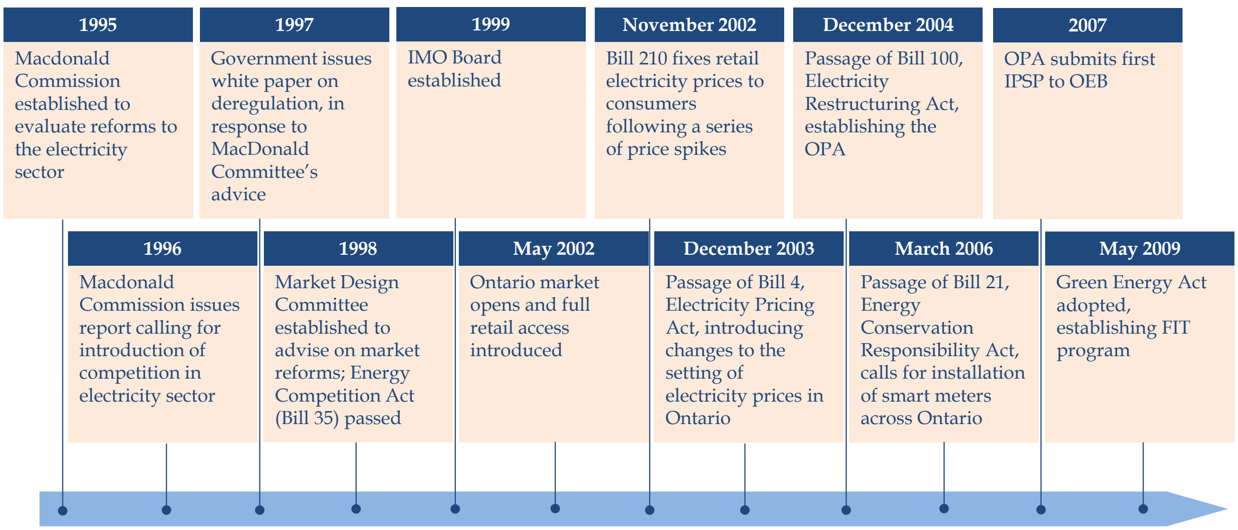
For the generation market, the OEB monitors, investigates, and reports on activities and behavior through the Market Surveillance Panel ("MSP"). The MSP relies on the IESO's Market Assessment Unit ("MAU") to monitor the market on a daily basis to identify anomalous conduct made by market participants and any other activities that may have an adverse effect on market efficiency. The MAU is administered within the IESO's Market Assessment and Compliance Division ("MACD"), which aggregates market data to investigate alleged breaches of the market rules. Where necessary, the MAU issues letters of non-compliance, imposes financial penalties, or pursues other sanctions against non-compliant market participants.

9.3 History of restructuring and recent developments

The Ontario electricity market has undergone a number of important developments in recent years, including the regulation of a large portion of OPG's generation assets, price caps for end-users, and solicitation of new electricity supply from various sources through the OPA. This section discusses the context behind Ontario's restructuring decisions and how its current regulatory institutions developed. Figure 75 provides a timeline of key electricity restructuring events in Ontario.

[274] Ibid. p. 3.

Figure 75. Timeline of key events in Ontario



Source: LEI

9.3.1 The decline of Ontario Hydro

Similar to NSPI, Ontario Hydro used to produce over 90% of the province's electricity and controlled the balance of supply through non-utility generation contracts. However, in the 1990s, Ontario Hydro suffered major cost overruns, excessive debt and poor nuclear performance.[275] As a result, electricity rates in the early 1990s rose by nearly 30%.[276]

Ontario first considered restructuring its electricity sector in 1996, when the so-called Macdonald Commission[277] issued its report called the "Framework for Competition: The Report of Advisory Committee on Competition in Ontario's Electricity System to the Ontario Minister of Environment and Energy." The report called for injecting competition into Ontario's electricity sector as soon as possible, and suggested the possibility of breaking Ontario Hydro into a number of competing generation companies, some of which would remain publicly-owned. The report noted that creation of between five and six equally sized firms might be necessary to establish a workably competitive market. Little action was taken along the lines suggested in the Macdonald report.

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[275] Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997. p. 1.

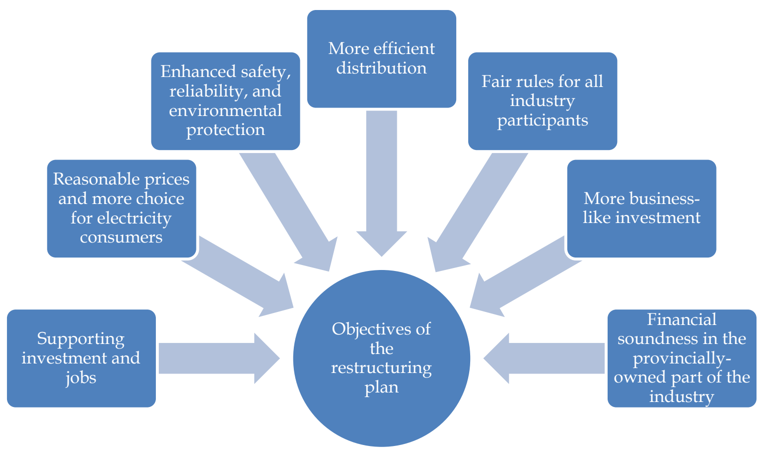
[276] Ibid. p. 5.

[277] This Commission was formally called the Advisory Committee of Competition in Ontario's Electricity Sector.

9.3.2 Phasing in competition in the electricity market

It was not until the crisis in Ontario Hydro's nuclear operations in late 1997 and the subsequent loss of public confidence in Ontario Hydro that a consensus for reform became evident. Consequently, the Ontario Market Design Committee ("MDC") was set up in January 1998. The MDC was composed of key stakeholders from the Ontario electricity sector, and was tasked with developing an implementation plan consistent with the provincial government's White Paper on Electricity Restructuring entitled, "Directions for Change." In this White Paper, the Government identified the two primary causes of Ontario Hydro's poor business performance. First, the problems associated with electricity monopolies which include higher prices, excessive debt, poor priority setting, and bureaucracy inefficiency.[278] Second, Ontario Hydro had an unclear relationship with the provincial government. More specifically, it had "a complex mandate as a commercial entity, an at-cost provider, and a regulator of other utilities."[279] The White Paper laid out the objectives of the restructuring plan which is shown in Figure 76.

Figure 76. Objectives of Ontario's restructuring plan



Source: Ministry of Energy, Science, and Technology ("Direction for Change – Charting a Course for Competitive Electricity and Jobs in Ontario")

As a result of the MDC's efforts, the *Energy Competition Act* of 1998 (also known as Bill 35) was passed, establishing the legislative framework for competitive electricity markets in the province. The MDC issued its final report in January 1999,[280] which finalized recommendations on market design, market rules, and transition issues and summed up its previous

[278] Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997. p. 7.

[279] Ibid. p. 8.

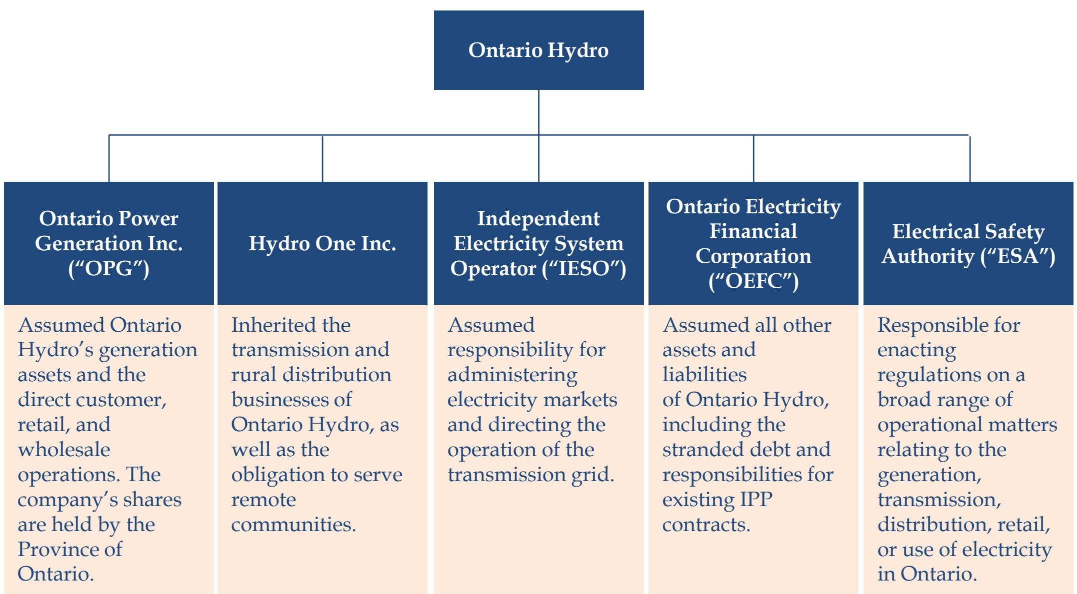
[280] Ministry of Energy, Science, and Technology. *Final Report of the Market Design Committee to the Minister of Energy, Science and Technology*, Toronto, Ontario: Jan. 29, 1999.

recommendations published in the Commission's three interim reports. Pursuant to the *Electricity Act* of 1998, Ontario Hydro was separated into the five companies shown in Figure 77.

The *Electricity Act* of 1998 also paved the way to codify the authority of the OEB to issue licenses to entities involved in the production, transmission, distribution, and sale of electricity. Moreover, under this Act, municipal utilities became business corporations with the municipality as the single shareholder initially. An Independent Market Operator ("IMO") was then established to run the market, with the Central Market Operations group of the former Ontario Hydro providing the nucleus for the new IMO.

The *Electricity Competition Act* of 1998 also brought significant changes to the electricity distribution sector. The Government directed the OEB to "examine, advise on, and subsequently implement a performance-based ratemaking approach to regulation."[281] In addition, Ontario's municipal electric utilities ("MEUs") were required to incorporate under the Ontario Business Corporations Act ("OBCA") as LDCs and operate on a commercial basis. The OEB allowed LDCs to earn commercial returns, but required improved efficiency. Consequently, the LDCs have been consolidating. At the time of restructuring, Ontario had nearly 300 municipal utilities, including some serving a very small number of customers. Although consolidation has reduced this number to fewer than 80, many remain quite small. Figure 78 shows the total number of customers for LDC as of 2012.

Figure 77. The deconstruction of Ontario Hydro on April 1, 1999



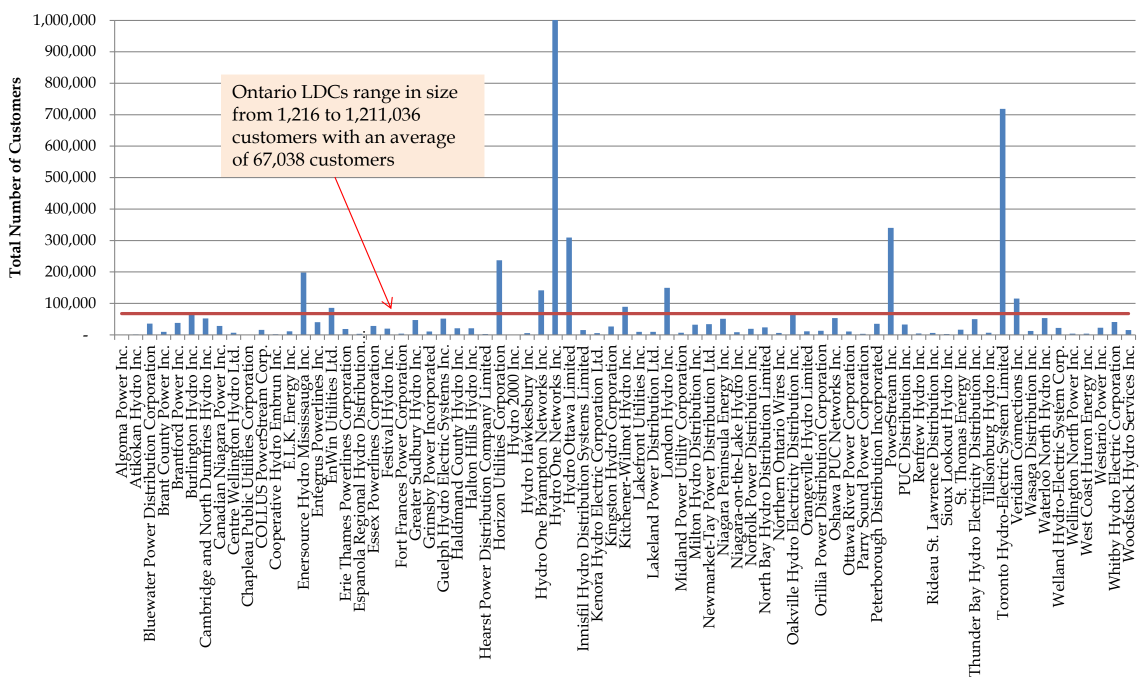
Source: LEI

281 Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997.

Another major development in the distribution sector was the adoption of an IRM regime. In 2000, the OEB issued Decision RP-1999-0034, which approved an IRM regime to regulate electricity distribution companies. The OEB believed that such regulation would offer two key advantages – first, it would provide companies with a strong incentive to continue and expand their efforts to control cost, increase efficiency, and maintain service quality and second, it would minimize the administrative burden; and the cost of regulation.[282] The 1st generation IRM ("1GIRM") was implemented on March 1, 2001.

It was not until May 2002 that a fully competitive wholesale and retail market was opened. However, Ontario's efforts at deregulation on the retail level were effectively unraveled with the price freeze in November 2002. During the summer of 2002, Ontario experienced extreme hot weather conditions causing tight supply conditions that led to price spikes in the wholesale market. The price spikes triggered a series of interventions by the Ontario government. On December 9, 2002, the Ontario government passed the *Electricity Pricing, Conservation, and Supply Act*, 2002 (Bill 210), which froze commodity prices to end-users at Cdn. 4.3 cents/kWh through 2006. The plan was retroactive to May 1, 2002. While these freezes have since been lifted, some elements of price smoothing and subsidies remain today.

Figure 78. Total number of customers by LDC (as of 2012)



Source: OEB. ("2012 Ontario Electricity Yearbook")

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[282] OEB. *Overview of the Electricity Distribution Rate Regulation Framework.* March 9, 2000. p.2-2.

9.3.3 Promotion of electricity supply and capacity

On December 9, 2004, the *Electricity Restructuring Act*, 2004 was passed. The purpose of this Act was not only to restructure the province's electricity sector, but also to promote the expansion of electricity supply and capacity, including supply and capacity from alternative and renewable energy sources; facilitate load management and demand management; encourage electricity conservation, and the efficient use of electricity; and regulate prices in parts of the electricity sector.[283] It also established the OPA to act as a creditworthy counterparty through which new generation could be procured by means of long-term power-purchase agreements ("PPA").

Today, Ontario energy policy is guided by the *Green Energy and Green Economy Act*, 2009 ("GEA") and the Long-Term Energy Plan ("LTEP"), which offer direction for the development of clean energy. The GEA was enacted to promote renewable energy development in the province through the implementation of a FIT program, which motivates renewables by streamlining project development and by offering long-term contracts at above-market rates for renewable generation.

The latest LTEP was released in 2013, which set out the direction for Ontario's energy sector in the next two decades. Broadly, the LTEP focuses on conserving energy rather than making new generation and transmission projects. However, while the OPA usually bases its contracting decisions on the LTEP, provisions of the GEA and subsequent ministerial directives have overridden previous versions of the LTEP.[284] This is a problem that will be discussed further in Section 8.3.5.

Figure 79. Key aspects of Ontario's Long-Term Energy Plan (December 2013)

Key aspects of Ontario's Long-Term Energy Plan (December 2013)

- Decreasing the need for new supply by implementing conservation programs and standards to offset most growth in electricity demand over the next 20 years;
- Expanding demand response programs to help achieve a 10% reduction in peak demand by 2025. This is equivalent to approximately 2,400 MW under today's forecast conditions;
- Moving ahead with nuclear refurbishment at both Darlington and Bruce Generating Stations, beginning at the end of 2016;
- Extending the phasing-in of wind, solar and bioenergy for three more years than estimated in the 2010 LTEP, with 10,700 megawatts online by 2021. By 2025 about half of Ontario's installed generating capacity will come from renewable sources; and
- Developing a new competitive procurement process with the Ontario Power Authority for future renewable projects larger than 500 kW.

Source: Ontario Ministry of Energy. *Achieving Balance: Ontario's Long-Term Energy Plan.* December 2013. <http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf>

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283 Government of Ontario. *Electricity Restructuring Act 2004.*

284 For a full discussion on Ontario's institutional inefficiency, see Goulding, AJ. "A New Blueprint for Ontario's Electricity Market." *C.D. Howe Institute* Commentary No. 389 (September 2013): Print.

9.3.4 Recent developments

Recent developments in Ontario include the consideration of establishing a capacity market and locational marginal pricing ("LMP"), revisions to the FIT program, the OEB further developing its IRM approach, and the Ontario Electricity Support Program.

9.3.4.1 Capacity market

With the expected nuclear retirements and refurbishment as well as renewable generation and demand response integration in the system, IESO is looking for flexible, responsive mechanisms that could complement the future system needs. A capacity market is one approach being considered.[285] IESO acknowledges one of the benefits of capacity markets is that "they can make the system more flexible by better matching available resources with year-to-year changes in supply and demand conditions without the need for long-term contracts."[286] On April 8, 2014, the IESO conducted an information session on capacity markets to discuss how capacity markets work, lessons learned from the design and performance of other jurisdictions, and implications of having a capacity market in Ontario.

9.3.4.2 Consideration of locational marginal pricing

In 1998, the Ontario MDC recommended the use of uniform pricing for the market and that nodal pricing should be analyzed further.[287] Since then, IESO has had several reviews, with studies and stakeholder engagement ("SE") consultations, to further examine costs, feasibility, and implications of potentially moving from uniform to nodal pricing system in Ontario. Previous reviews did not result in major changes.

IESO launched a new consultation entitled the Energy Market Pricing System Review (SE-114) in August 2013, reviewing the issue for the fifth time in 15 years.[288] The review intends to identify areas of improvement to the current uniform pricing system and to consider alternative pricing systems (such as nodal) by performing system modeling and cost-benefit analysis of the alternatives. The results of SE-114 "will provide input into a broader IESO consultation that will prioritize potential enhancements to improve the efficiency and effectiveness of Ontario's electricity market."[289]

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[285] OEB. *Achieving Balance – Ontario's Long Term Energy Plan*. December 2013. p. 7.

[286] IESO. Electricity Markets in Ontario. Available online at http://ieso-public.sharepoint.com/Pages/Ontario%27s-Power-System/Evolving-the-Markets/default.aspx. (Accessed on April 23, 2014).

[287] IMO (now IESO). *Locational Marginal Pricing and Financial Transmission Rights.* Market Evolution Program ("MEP"), LMP Workshop Session 1. November 11th, 2003. <http://www.ieso.ca/imoweb/pubs/consult/mep/LMP_Workshop_2003Nov11_LMP_FTRs.pdf>

[288] The reasons that past investigations into 'nodal pricing' did not result in significant change to the uniform pricing structure are many and varied but are beyond the scope of this report.

[289] IESO. *Stakeholder Engagement Plan.* Energy Market Pricing System Review (SE-114). August 29th, 2013. <http://ieso.ca/imoweb/pubs/consult/se114/se114_SE_Plan_Draft.pdf>

IESO engaged a consultant to perform modeling of the current system and to test alternative scenarios. The modeling will project ten years starting from 2016, and will run 16 total model runs by testing four price setting scenarios under various situations such as different demand growth or natural gas price outlooks.[290]

Since the start of the consultation, two stakeholder sessions have taken place, and two more are planned. Market Reform's draft report to IESO will be submitted in Q1/Q2-2014, and the Final Report will be published in Q2-2014.[291]

9.3.4.3 Revisions to the Feed-in Tariff ("FIT") program

As discussed earlier, the Green Energy Act was enacted in 2009 to promote renewable energy development in the province through the implementation of a Feed-in Tariff ("FIT") program. The FIT program motivates renewables by streamlining project development and by offering long-term contracts at above-market rates for renewable generation.

The 2009 Green Energy Act FIT program obligates the OPA to contract with qualifying projects, even if the resulting capacity is not needed currently and irrespective of the LTEP. Recent updated FIT Program rules improved on previous arrangements by including a Procurement Targets provision establishing the maximum amount of MWs procured during an application period.[292]

The latest FIT Program, Version 3.0, had a Procurement Target of 70 MW, plus 53.5 MW from the previous application period,[293] for Small FIT and an additional 15 MW for pilot rooftop solar projects on unconstructed buildings.[294] During the FIT Program Version 3.0 procurement application window from November 4th, 2013 to December 14th, 2013, the OPA received 1,982

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[290] IESO. *The Energy Market Pricing System Review: Presentation on Modeling*. October 25th, 2013. <http://ieso.ca/imoweb/pubs/consult/se114/se114-20131021-Presentation.pdf>

[291] For more information and updates on the review, see IESO's Energy Market Pricing System Review (SE-114) page at <http://ieso.ca/imoweb/consult/consult_se114.asp>.

[292] OPA. *Directives to OPA from Minister of Energy.* June 12th, 2013. <http://www.powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure>.

[293] The first FIT program version to incorporate Procurement Targets was FIT Rules Version 2.0 (effective from August 10th, 2012). The Procurement Target was 200 MW for Small FIT and 15 MW for Unconstructed Rooftop Soar Pilot. During the application window December 14th, 2012-January 18th, 2013, the OPA procured 146.5 MW, determining that the remaining 53.5 MW will be added to the procurement target in the next application period.

[294] OPA. *FIT Program now accepting Applications*. November 4th, 2013. <http://fit.powerauthority.on.ca/program-updates/newsroom/newsroom-2013/november-4-FIT-Program-accepting-applications>.

applications representing a total of 493.71 MW (over 75% solar).[295] Results of the procurement will be announced by the OPA in the first quarter of 2014.

9.3.4.4 OEB exploring an IRM approach for OPG generation

OEB wants to use an IRM mechanism to establish the prices for OPG's Prescribed Assets. Figure 80 shows a list of OPG's Prescribed Assets. At present, prices for these assets are set using a COS regulation. A total factor productivity ("TFP") study is being conducted to determine the productivity factor to be used for the revenue requirement for the prescribed hydro assets. OPG is anticipated to file its first IRM application for the prescribed hydro assets by 2015.

Figure 80. List of OPG's Prescribed Assets

Plant Name	Fuel type	Capacity (MW)
Sir Adam Beck 1	hydro	417
Sir Adam Beck 2	hydro	1,499
Sir Adam Beck Pump	hydro	174
DeCew Falls 1	hydro	23
DeCew Falls 2	hydro	144
R.H. Saunders	hydro	1,045
Total hydro capacity		**3,302**
Darlington	nuclear	3,512
Pickering A	nuclear	1,030
Pickering B	nuclear	2,064
Total nuclear capacity		**6,606**
Total Prescribed Assets capacity		**9,908**

Source: OPG website

9.3.4.5 Ontario Electricity Support Program

Recently, the government announced that it is planning to give low-income residents discounted electricity through the Ontario Electricity Support Program, which will provide ongoing support directly on electricity bills to eligible consumers, beginning in 2016. Details with regards to who will qualify and the exact discount have not yet been finalized by the OEB.

This program is anticipated to help ease the sting of the end of the controversial Clean Energy Benefit, which will expire at the end of 2015. The Clean Energy Benefit is criticized for rewarding wealthier consumers who use great amounts of power by providing a 10 percent discount to all residential hydro users and some businesses up to 3,000 kWh a month.

[295] OPA. *FIT 3 Application Summary*. January 24th, 2014. <http://fit.powerauthority.on.ca/program-updates/newsroom/newsroom-2014/January-24-FIT3-application-summary>.

9.4 Rationale for specific design elements and pros and cons of selected design

Many of Ontario's current electricity market design features have developed as a response to public backlash and previously failed policies. Crucial to understanding the heart of the problem is to identify which of Ontario's current design features are sustainable and acceptable for the public going forward. In doing so, this section covers the institutional arrangements and contracts with the OPA, the GA mechanism, FIT, IRM, and the renewed regulatory framework.

Figure 81. Summary of specific design elements

Design elements	Rationale	Pros	Cons
Institutional arrangements and contracts with the OPA	• To offset the risk of wholesale market price suppression	• Generators receive full cost recovery through long-term contracts with OPA	• Ontario assumes risk for investment decisions • Does not consider least cost approaches
Global Adjustment Mechanism	• To offset the price difference between the market price and the rates paid to regulated/contracted generators	• Funds a number of conservation and demand management systems	• Distorts price signals • Lacks transparency
Incentive Regulation Mechanism	• To result in fewer rate reviews • provide greater incentive for cost reduction and productivity gains • To allow the Board to establish minimum service quality and reliability standard	• Reduced the regulatory burden for both the utilities and regulator • Provided appropriate mechanisms to manage risks	• "One size fits all" • Data availability • Restrictive ICM
Renewed Regulatory Framework for Electricity Distributors	• To better align reliability with customers' expectations • To provide incentives for continuous improvement and innovation • To better align timing of expenditure and cost recovery	• Provided 3 options for utilities to choose from based on their needs and requirements for the PBR term	• Regulatory process might take longer for the Custom IR option • Regulator needs to hire external consultants to review PBR plans of those that will do custom IR

Source: LEI

9.4.1 Institutional arrangements and contracts with OPA

The reason that *Electricity Restructuring Act* of 2004 required the creation of the OPA was in part because investors were reluctant to assume the merchant risk for new generation capacity given the frequent interventions of the government in market operations. However as mentioned previously, the Ministry is allowed to issue directives to the OPA. Between March 2005 and April 2014, the Minister of Energy issued 80 directives to OPA as shown in Figure 82. Out of these, over half directed the OPA with relation to procurement of power/capacity from OPG and other generators. Directives to the OEB and IESO are less frequent, but still occur. Repeated use of ministerial directives undermines the independence of these institutions and creates a lack of constancy in power sector policies that ultimately reduces the willingness of private investors to participate.

To offset the risk of wholesale market price suppression, the majority of Ontario's electricity generation receives full cost recovery through either a long-term contract with the OPA or regulation by the OEB. Unsurprisingly, around 91% of energy is either under contract with the OPA or rate-regulated by the OEB[296] with a small remainder bidding in the IESO-run market based on short-run marginal costs.

The consequence of government intervention is that the province replaces (directly through OPG or indirectly through OPA) private risk-taking. Without proper safeguards, this transfer of risk from private investors to ratepayers and/or taxpayers can result in inefficient capital allocations, as governments stray from commercial objectives and apply artificially low hurdle rates to specific projects, if indeed a hurdle rate is applied at all. Based on a study conducted by LEI for the C.D. Howe Institute, "Ontario consumers could expect to pay an additional $42 to $370 million per year above and beyond what is required to meet a 15% reserve margin between 2013 and 2015, before considering the costs of surplus baseload generation."[297]

The independence of OPA from the government would allow it to more effectively implement contracting according to long-term system plans on a technology and owner-neutral life cycle least cost basis, and fewer changes to the overall structure of the Ontario power sector would be necessary. If OPA would no longer be used as the principal buyer, risks can be reallocated appropriately, price signals made more transparent, and investment and consumption decisions improved. Relying solely on private capital for future investment will force consideration of least cost alternatives to meet power supply needs consistent with environmental laws, while necessitating the transition of rural development and jobs growth responsibilities back to those agencies most experienced and effective at them.

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[296] OEB. *Regulated Price Plan – Price Report, May 1, 2013 to April 30, 2014*. April 5th, 2014. p. 21. <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013_20130405.pdf>

[297] Goulding, AJ. A *New Blueprint for Ontario's Electricity Market*. C.D. Howe Institute Commentary No. 389. September 2013. P. 9.

Figure 82. List of ministerial directives to OPA related to procurement

Date	Directive
March 24, 2005	Execution and delivery of CES contracts and a DR contract in accordance with the terms of the 2,500 MW RFP
June 15, 2005	"Early Movers" - Negotiate and Conclude Contracts with Certain Generation Facilities
June 15, 2005	Immediate Launch of Procurement Processes to address needs in Downtown Toronto and Western Greater Toronto Area ("GTA")
October 14, 2005	Contracts for the Refurbishment of Bruce A at the Bruce Nuclear Facility Generating Station
October 20, 2005	GTA West Supply Initiative - Goreway Station Project
November 7, 2005	RES I RFP - assume OEFC's contracts
November 16, 2005	RES II RFP - enter intro contract with nine suppliers for 1,000 MW
December 14, 2005	Early Movers - Negotiate and Conclude Contracts with Certain Generation Facilities
February 10, 2006	Toronto Reliability Supply and Conservation Initiative - with respect to 2,500 MW RFP
March 21, 2006	Standard Offer Program - enter into contracts with small renewable generators
June 14, 2007	Clean Energy and Waterpower in Northern Ontario Standard Offer
August 27, 2007	Procurement of up to 2,000 MW of Renewable Energy Suppl
December 20, 2007	Hydroelectric Energy Supply Agreements with Ontario Power Generation Inc
January 31, 2008	Procuring Approximately 350 MW of New Gas-Fired Electricity Generation for Northern York Region
February 25, 2008	Procuring Electricity From Energy From Waste ("EFW") Pilot or Demonstration Projects ("PDPs")
April 10, 2008	Procurement for Electricity From Combined Heat and Power (CHP) Renewable Co-generation Projects
August 18, 2008	Southwest Greater Toronto Area (GTA) Supply - procure CCGT facility for generating about 900 MW in Oakville
December 19, 2008	Procuring Electricity from a Commercial Durham and York Region Energy from Waste ("EFW") Facility
December 24, 2008	Negotiating New Contracts with Early Movers Generation Facilities
January 23, 2009	Biogas Projects and Renewable Energy Standard Offer (RESOP)
May 7, 2009	Negotiating New Contracts with Hydro-Electric Generation Facilities
September 24, 2009	Develop a feed-in tariff ("FIT") program
January 6, 2010	Negotiate and execute a New Contract with Ontario Power Generation (OPG)
April 1, 2010	Negotiate one or more Power Purchase Agreement(s) ("PPA") with respect to the Korean Consortium projects
August 26, 2010	Atikokan Biomass Energy Supply Agreement ("ABESA") with Ontario Power Generation
November 23, 2010	Negotiating New Contracts with Non-Utility Generators
November 23, 2010	Combined Heat and Power ("CHP")
June 3, 2011	Bruce and West of London Transmission Areas -offer FIT contracts for up to 750 MW and 300 MW of renewable generation facilities
July 29, 2011	Korean Consortium's Haldimand Projects - direction to the OPA to negotiate power purchase agreements (PPAs) with Samsung C&T Corporation and Korea Electric Power Corporation
August 17, 2011	Thunder Bay Generating Station Conversion to Natural Gas
August 19, 2011	Procuring Electricity from Energy from Waste ("EFW") facilities
April 5, 2012	Continue the FIT and microFIT programs
July 11, 2012	Feed-In Tariff Program Launch
November 23, 2012	Renewable Energy Program Re-Launch
December 11,2012	Renewable Energy Program Re-Launch to Strengthen Community and Aboriginal Participation in the FIT program
December 13,2012	Southwest Greater Toronto Area (SWGTA) Supply - move TransCanada 900 MW CCGT plant to lands of Lennox GS
January 21, 2013	Hydroelectric Projects - confirming 9,000 MW of hydroelectricity contracts
June 12, 2013	Renewable Energy Program - stopping procurement of Large FIT and setting 150 MW target for Small FIT, and 50 MW for microFIT for each of the next four years
June 26, 2013	Hydroelectric Projects
August 16, 2013	Administrative Matters Related to Renewable Energy and Conservation Programs
October 25, 2013	Clarification re: Procuring Electricity From Energy from Waste ("EFW") Facilities Using Technologies That Have Completed the Ministry of Environment Pilot or Demonstration Project ("PDP") Initiative
October 28, 2013	Clarification re: Non-application to First Nation reserves of FIT Program restrictions relating to agricultural lands
December 16, 2013	Supply agreement with the Ontario Power Generation for the conversion of Thunder Bay Generating Station
December 16, 2013	100 percent Biomass Non-Utility Generator Projects
December 16, 2013	Moving Forward with Large Renewable Energy Projects, Renewable Energy Projects in Remote First Nation Communities and Energy Storage
December 16, 2013	Moving Forward – Letter Requiring Report Back – Combined Heat and Power ("CHP")
March 31, 2014	Procuring Energy Storage
March 31, 2014	Combined Heat and Power ("CHP")
March 31, 2014	Moving Forward with the Large Renewable Procurement ("LRP") Process
March 31, 2014	Continuance of the OPA's Demand Response Program under IESO management

Source: OPA. "Directives to OPA from Minister of Energy." <http://www.powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure>

9.4.2 Global adjustment mechanism

As discussed in Section 9.2.4, the total cost of a consumer's electricity bill is the HOEP and the GA. The GA reflects the difference between market price and the rates paid to regulated and contracted generators and for conservation and demand management programs. This includes: 1) the regulated rate paid to OPG's baseload generating stations; 2) payments made to suppliers under contract with the OPA; and 3) contracted rates paid to non-utility and other resources. The GA is also the mechanism used to recover the cost of a number of other OPA administered programs, including demand response and conservation initiatives.

The GA, taken together with government intervention, interferes with economically efficient decision making. Most obviously, it distorts pricing signals, because customers only know the amount of the GA assessment after they have made their consumption decisions. In some ways, the GA cancels out attempts by consumers to save money by altering their demand levels and patterns, as changes in wholesale prices due to lower demand levels are offset by the reciprocal increase in the GA to cover fixed obligations for supply. The GA makes consumer bills less comprehensible, potentially undermining consumer acceptance of power sector policies.

Programs for large users serve to further mute price signals to these customer classes, and blunt the incentive for bilateral contracting. The GA combines costs from achieving environmental objectives with those incurred as a result of reliability goals, and the lack of transparency prevents the customers themselves from signaling their desired levels (in excess of statutory norms) of each of these elements through the market. Finally, this very lack of transparency can lead to a tendency among policymakers to use the GA to hide the consequences of poor decisions.

9.4.3 IRM

As mentioned in the Literature Review, there are different ways to set the rates. In Ontario, the government decided to use the IRM which hopes to achieve the following goals:[298]

- IRM was expected to ***result in fewer rate reviews*** before the Board and hence, a lesser regulatory burden;
- IRM can ***provide greater incentive for cost reduction and productivity gains*** compared to those available under traditional COS regulation while protecting the interests of customers; and
- IRM would ***allow the Board to establish minimum service quality and reliability standards*** and require compliance with these standards.

[298] Excerpted from the *OEB Draft Policy on Performance Based Regulation*. October 2, 1998.

The Board also created a set of principles for the implementation of IRM that capture the changes in the Board's regulatory responsibilities as well as the changes in the Ontario energy market structure. These principles are shown in Figure 83.

Figure 83. Principles for the development of PBR

Principles for the development of PBR
1. PBR framework should **address all specific requirements of the legislation and regulations**
2. It should **protect customers** and results in prices for regulated services that are **just and reasonable**
3. It should **discourage cross-subsidization** between regulated and competitive services
4. It should **encourage greater economic efficiency** by providing the appropriate pricing signals and a system of incentives to maintain an appropriate level of reliability and quality of service
5. It should permit the utility an opportunity to **earn a reasonable return** on shareholder capital and to **maintain its financial viability**
6. It should be **transparent** and as **simple** as possible. The cost administering PBR, including costs imposed on all participants, including the regulated entity and the regulator, should **not exceed the benefits available from PBR**
7. It should **allocate the benefits** from greater efficiency fairly between the utility/shareholder and the customers
8. It should be **flexible** and able to **handle changing and varied circumstances**
9. It should **facilitate the use of efficient processes**

Source: OEB

Ontario's IRM has provided benefits to stakeholders. For one, given the number of utilities in Ontario, a PBR regime offers, in theory, the advantage of significantly reducing the regulatory burden compared to a COS regime. Another benefit is that the IRM provides appropriate mechanisms – such as flow-throughs, exogenous factors ("Z factors"), and off-ramps – to manage risks and uncertainties.

There were also challenges with the implementation of the 3GIRM. First, with the diverse utility size and customer type in the local distribution sector, distributors were worried about a one-size-fits-all IRM regime. However, the 3GIRM introduced some level of benchmarking into the price cap regime where the assigned overall target efficiency factor ranged from 0.92% to 1.32%. Nevertheless, utilities continue to be concerned about the efficacy of the technical analysis that underpins the stretch factors assigned, given that there is a significant diversity among utilities, with certain characteristics that are allegedly beyond management's control, for example in terms of network size, type of customers, topology and density of service areas, the age and design of legacy networks, including, for example, the proportion of underground assets.

The second challenge was data availability. At the time of the design of the 3GIRM, data on Ontario was limited in terms of scope (historical timeframe). Thus, the setting of the productivity factor was very controversial. This was compounded by the lack of comparable and sufficient data series on costs, output, and productivity for Ontario distributors. The approved productivity factor was based on the results from several studies and views of different consultants. Nevertheless, using data from other jurisdictions was also regarded as sub-optimal.[299]

Third, although the ICM provided for increased stability of the IRM mechanism and reduced regulatory risks associated with capital outlays beyond the control of management, its implementation was contentious and restrictive with some distributors opting out. Because ICM is reserved for unusual circumstances, aging assets and capex for replacement could not be addressed under the ICM.

9.4.4 RRFE

The RRFE was established to address some of the concerns raised by the distributors in the 3rd GIRM. More specifically, the rationales of the RRFE are:[300]

- to shift the focus from utility cost to value for customers,
- to better align utility reliability and quality of service levels with customer expectations;
- to institutionalize continuous improvement and innovation;
- to provide for a comprehensive approach to network investments to achieve optimum results;
- to better align timing and pattern of expenditures with cost recovery; and
- to provide a sustainable, predictable, efficient and effective regulatory framework.

As mentioned earlier, under the RRFE, an electric distributor is given three options on how to set its rates. OEB expects that providing these options will give "flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include lumpy investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time."[301]

The advantage of the RRFE is the flexibility that it provides to the distributors. As mentioned in the Literature Review, there is no "one size fits all" PBR formula especially for a market with distributors of different size and type of customers. In addition, the longer term for the 4th Generation IRM and the Custom IR provide sufficient certainty regarding regulatory treatment that distributors feel comfortable engaging in long-term investment programs as well as reduces administrative burden of annual COS reviews.

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[299] OEB. *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors.* September 17, 2008.

[300] Excerpted from the OEB's "The Renewed Regulatory Framework – An Overview (RRFE Information Sessions)".

[301] OEB. *Renewed Regulatory Framework for Electricity*. October 18, 2012. p. 10.

A potential drawback of the RRFE is the regulatory burden for the regulator. As mentioned earlier, there are more than 70 electric distributors in Ontario. Providing utilities multiple options to set rates requires more time for the regulator to review each PBR plan. A productivity-based regulation can be implemented relatively economically for a large number of distributors compared to the building blocks approach. Another challenge, more specifically for the custom IR option, is need for the distributor to be able to forecast its operating and capital expenses accurately. Poor forecasting can lead to potential additional costs that will affect the distributor's bottom line. Furthermore, custom IR can become information-intensive, which can lead to additional administrative costs and make the process contentious as the regulator assess the data and information provided by the distributor.

9.5 Transitional challenges and remedies adopted

Ontario experienced a number of transitional challenges during the period after restructuring. The main cause of this was the "big bang" approach whereby restructuring, liberalization, and unbundling occurred at the same time. This section specifically looks at the contextual challenges that Ontario faced, the lack of transitional hedging instruments, and remedies the government deployed.

Figure 84. Summary of transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Opening market during a period of high demand	None
Price volatility and lack of hedging instruments	Rate freeze
Corporatization of MEUs	OEB provides LDCs with smoothing mechanism

Source: LEI

9.5.1 Opening the market during a period of high demand

While the price hikes of 2002 were, to a large extent, policy induced, Ontario did have the misfortune of poor timing. Wholesale and retail price competition was originally scheduled to open in November 2000. However, market opening was delayed to May 2001 and later May 2002 to ensure system reliability and to allow testing of the hardware and software acquired by wholesale market participants, service providers, and retailers. The summer of 2002 was a period of very high demand and this was coupled with reduced levels of water available that year for hydroelectric generation, causing significant pressure on existing generation systems for power, which ultimately led to higher prices than average.[302] This of was made even worse

[302] When the market opened in May, the average hourly wholesale price was $30.1/MWh. Prices quickly escalated to $37.1/MWh in June, $62/MWh in July and as high as $103/MWh for 14 hours on September 14.

by the fact that retail prices were frozen for many years prior to restructuring, which in effect kept prices artificially low for consumers. The inability of customers to understand the true cost of power also highlights the inadequacy of public awareness leading up to the restructuring. The result, of course, was government intervention and the eventual decision to curtail genuine market competition in November.

9.5.2 Lack of vesting contracts during transition

Ontario's restructuring illustrates the risks that emerge in the absence of vesting contracts. These contracts serve to limit market power and hedge retailers against spot price volatility. Without proper hedging instruments, price volatility from unusually high demand and low poor hydroelectric performance from low water levels are exacerbated. In the example taken from the United Kingdom, vesting contracts were used for three years as a transitional mechanism before they were scrapped after there was no interest from generation companies to continue with the contracts.

9.5.3 Rate impact associated with the provisions of market returns embodied in the corporatization of the MEUs

As mentioned earlier, the MEUs were required to incorporate under the OBCA as LDCs and operate on a commercial basis. Twenty four large utilities filed application for new rates in May 2000 and these applications included revenue requirements increases to provide the utilities with the opportunity to earn market based returns and for payments in lieu of taxes.[303] Utilities requested increases in revenue requirements ranging from 5.3% to 12.1%.[304] Because of this impending increase in rates, the Minister issued a policy directive to the Board to give primacy to the objective "to protect the interests of consumers with respect to prices and the reliability and quality of electricity service."[305] The Board interpreted this directive as a reminder that during the transition period, consumer interests must come before maximization of returns.[306]

To address the concern of the potential bill increase, the Board provided the LDCs with a smoothing mechanism where the market returns are phased-in for three years without deferrals and without a sharing mechanism for any excess earnings.[307]

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303 OEB. *Decision with Reasons In the Matter of a Proceeding under sections 129(7) and 78 of the Ontario Energy Board Act, 1998 S.O. 1998, c.15, Sched. B to determine certain matters relating to the Minister's Directive dated June 7, 2000 (RP-2000-0069).* September 29, 2000. p. 1.

304 Ibid. p. 1.

305 Ibid. p. 2.

306 Ibid, p. 9.

307 Ibid. p. 15.

9.6 Implications for Nova Scotia

The experience with restructuring of the electricity sector in Ontario offers several lessons for Nova Scotia. In many ways, Ontario had the right objectives: developing full wholesale and retail completion of its power market, maximizing liquidity in the wholesale market through participation of merchant generators, and diverting investment risk away from consumers. However, the implementation did not offer adequate transitional mechanisms to consumers, which resulted in public backlash and ultimately, political intervention resulting in a partial reversal of government policy away from deregulation. This reversal is the main cause of policy uncertainty, which has been largely responsible for the poor levels of private investment that could have transferred more investment risk away from the public. Moreover, Nova Scotia is faced with the opportunity to assess early in the market design process whether the political landscape will support the development of an efficient market that will serve all stakeholders well. Ultimately, the conceptual design of any jurisdiction going down Ontario's path must recognize these political realities so that the political process will not thwart the intended outcome of the market.

- **Create multiple players and accelerate privatization**. There was a lack of government will to sell off OPG's generation plants to add more players and create a truly competitive structure, arising in part from the lack of public support for such a radical change from the long-standing crown corporation.

- **Create transitional hedges.** Spot market prices can be unpredictable and very high. Ontario demonstrates that restructuring without appropriate hedge strategies can be very risky, and vesting contracts have a role in restructuring to competitive markets.

- **Open market gradually, particularly to small customers**. Customers were exposed simultaneously to competition and as a result, small customers were hurt the most from price volatility.

- **Market timing is important.** The wholesale and retail markets were opened during a time of excessive demand. This was made worse by poor hydroelectric performance from low water levels and years of artificially low price freezes.

Finally, there are also lessons to learn from Ontario in terms of designing the appropriate PBR mechanism:

- **Availability of data**. Nova Scotia should consider the availability of data as part of its overall design process. This is particularly important to determine the industry productivity factor.

- **Scale of the regulatory burden under PBR depends on the duration of the PBR period and the complexity of the annual rate-setting process.** Thus, Nova Scotia should take this into consideration when determining the different components of the PBR.

- **COS analysis continues to be relevant under a PBR approach.** Ontario's IRM's "going in" rates are determined by COS analysis, determination of the total revenue requirement, and allocation of revenue requirement across customer classes.

- **Provide appropriate mechanism to manage risks and uncertainties**. The IRM has provided appropriate mechanisms such as flow-throughs, Z factors, off-ramps, and reopeners to manage risks to customers and the utility for factors that are beyond the utility's control.

- **No "one size fits all" PBR mechanism.** With the three alternatives provided to distributors under the RRFE, a distributor has the option to choose the most appropriate PBR mechanism that will suit its unique characteristics, type of customers served, and capital requirements for the term. With its limited number of distributors, Nova Scotia might be able to provide this option as well.

10 United Kingdom

Since privatization and deregulation in the 1990s, the United Kingdom ("UK") has experienced several iterations of market design and is currently structured around a bilateral market with a centralized balancing market. Its electricity retail market is also fully liberalized and consolidations between generators and retailers have created dominant energy companies. Moreover, the UK implemented a performance-based ratemaking ("PBR") mechanism two decades ago that has adapted to meet changing circumstances. Nova Scotia can learn from the UK's experience in successfully restructuring and privatizing its electricity market as well as effectively implementing a PBR approach for setting rates for the regulated sectors of the electricity industry.

10.1 Overview of the UK market

The UK[308] electricity market is a mature competitive market. It was among the first movers in power sector restructuring, and its market reform has generally been considered a success. Except for some old nuclear reactors, the entire sector is privately owned and fully unbundled, with privatization and unbundling beginning in the early 1990s. The current market design is structured around a bilateral market with a centralized balancing market. The electricity retail market is also fully liberalized, and consolidations between generators and retailers have created several large energy companies in the country. There are 80 generators in the UK, led by RWE Npower, Scottish and Southern Energy ("SSE"), British Gas, E.ON, Scottish Power, and Électricité de France ("EDF"), as demonstrated in Figure 85.

In 2012, grid-connected installed capacity in the UK was 84.9 GW with a peak load of 56.8 GW.[309] Generation in the UK is dominated by coal and gas-fired plants, with a combined generating capacity of 73% of the UK's total energy generation in 2012. Electricity demand has been decreasing at an annual average rate of -0.5% since 2001. Renewables, which have been growing in the past few years, are driven by the 2020 European Union targets,[310] and now supply nearly 10% of total generation (from 2.5% in 2000). Projected coal and nuclear retirements, future growth in offshore wind generation, and emphasis on sustainable development have created both opportunities and challenges in the UK electricity market.

The UK has a wholesale electricity market where generators sell electricity to suppliers through bilateral contracts, over-the-counter trades, and spot markets. It has been open to competition since 1990 with the creation of the Electricity Pool ("Pool"). The Pool was replaced with the

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[308] In this report, we refer to the electricity market in the UK, excluding Northern Ireland, which runs on a separate network.

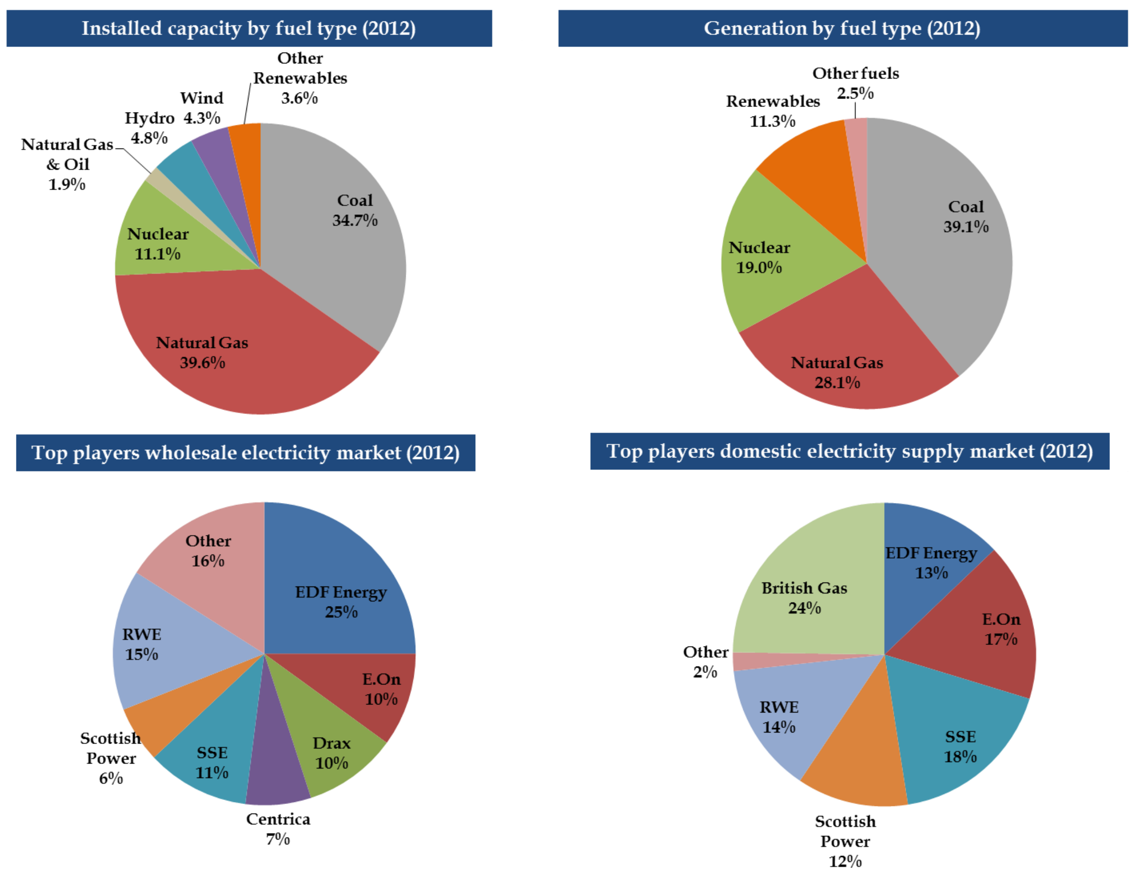
[309] Department of Energy & Climate Change ("DECC"). *Digest of UK Energy Statistics. Chapter 5: Electricity*. Available online at https://www.gov.uk/government/publications/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes. Accessed on April 25, 2014.

[310] 2020 EU targets imply around 110 TWh of renewable electricity.

New Electricity Trading Arrangements ("NETA") in England and Wales and subsequently by the British Electricity Trading Transmission Arrangements ("BETTA") in 2005, which extended the previous arrangements to Scotland (see Section10.2.2.1).

Figure 85. UK snapshot

Key facts	
Population (2012)	63.2 million
GDP growth (2013)	1.7%
Installed capacity (2012)	84. 9 GW
Peak demand (2012)	56.8 GW
Load growth (2009-2012)	1.8%
Generation (2012)	364 TWh
No. of electric distribution companies	14
No. of electric transmission companies	3

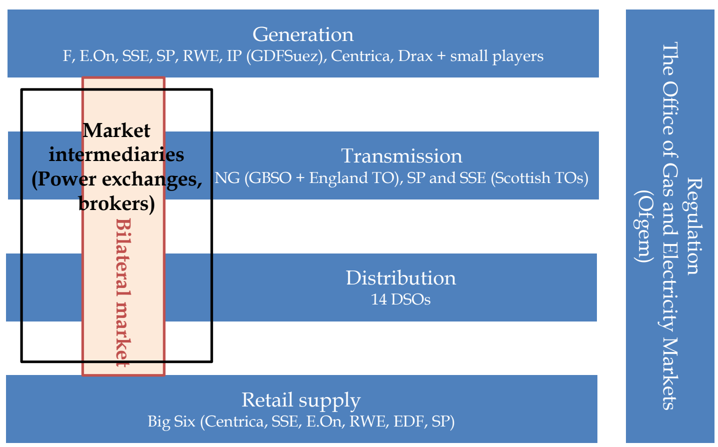


Sources: Office for National Statistics and Department of Energy & Climate Change ("DECC") Digest of UK energy statistics ("DUKES")

The transmission assets are owned and maintained by regional monopoly Transmission Owners ("TOs"), namely: National Grid Electricity Transmission ("NGET"), Scottish Power Transmission Limited ("SPTL"), and Scottish Hydro-Electric Transmission Limited ("SHETL").[311] These three TOs must ensure that sufficient transmission capacity is available to the UK transmission network. NGET is the sole System Operator of the electricity transmission and has the responsibility for ensuring that electricity supply and demand are balanced and the system remains within safe technical and operating limits.

Currently, there are fourteen (14) distribution network operators ("DNOs")[312] in the UK and each is responsible for a distribution service area. These DNOs are owned by six (6) different groups.[313] They are regulated by the Office of Gas and Electricity Markets ("Ofgem") through license conditions and price controls. Most DNOs are part of a holding company, which is also involved the generation and/or supply businesses.

Figure 86. Relationship of the different sectors in the UK electricity market



Source: National Grid

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[311] These are the three onshore Transmission Owners ("TOs"). There are also Offshore TOs.

[312] These DNOs include: Northern Powergrid (Northeast) Limited, Northern Powergrid (Yorkshire) plc., London Power Networks plc, South Eastern Power Networks plc, Eastern Power Networks plc, Electricity North West Ltd, Scottish Hydro Electric Power Distribution plc, Southern Electric Power Distribution plc, SP Distribution Ltd, SP Manweb plc, Western Power Distribution (East Midland) plc, Western Power Distribution (West Midlands) plc, Western Power Distribution (South West) plc, and Western Power Distribution (South Wales) plc.

[313] These six (6) groups composed of (i) Electricity North West Limited, (ii) Northern Powergrid (owns Northern Powergrid Northeast Limited and Northern Powergird Yorkshire plc), (iii) SSE (owns Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc, (iv) ScottishPower Energy Networks (owns SP Distribution Ltd and SP Manweb plc.), (v) UK Power Networks (owns London Power Networks plc, South Eastern Power Networks plc, and Eastern Power Networks plc,, (vi) Western Power Distribution (owns Western Power Distribution (East Midland, West Midland, South West, and South Wales).

Electricity retail supply is legally separated from distribution. The major electricity suppliers—comprising six large vertically integrated suppliers[314] with a total combined market share of 98%—include Centrica,[315] SSE,[316] E.On, RWE Npower, EDF Energy, and Scottish Power (also known as the 'Big Six').[317] Competition among suppliers was introduced to improve quality of service to consumers, encourage consumer switching, and create pressure for lower and more innovative tariffs.

There are some similarities between the UK and Nova Scotia markets. In both markets, coal has served as the dominant fuel since 2012. Moreover, both markets have increasing renewables in the energy mix in the past few years because of the introduction of environmental policies, such as the renewable portfolio standards ("RPS") in Nova Scotia and the Renewable Obligation ("RO") in the UK.

Nevertheless, there are also stark differences between the two. For one, the UK has a larger electricity market than Nova Scotia. Nova Scotia's total installed capacity in 2012 represented 3% of the UK's total installed capacity. Likewise, Nova Scotia's peak demand represented 3% of the UK's peak demand in 2012. In addition, the UK has fully competitive markets in the generation and supply sectors while Nova Scotia has a vertically integrated utility that dominates the generation sector and is the sole player in the retail market. Finally, the UK is an experienced market in terms of restructuring, unbundling privatization, and market reforms, after having gone through several iterations of market design. Nova Scotia, on the other hand, has undergone limited restructuring.

10.2 The UK's current institutional and legal framework

The energy sector in the UK is governed by the Department of Energy and Climate Change ("DECC"), a ministerial department. The electricity and gas markets are regulated by the Gas and Electricity Markets Authority ("GEMA"), which operates through Ofgem. This section provides an overview of the regulatory bodies in the UK energy market and their responsibilities.

10.2.1 Regulation and policy setting

DECC sets the electricity policies in the UK. It is responsible for ensuring that the market has secure supply of energy by promoting policies that encourage investments in the UK's energy infrastructure. It also ensures the delivery of low-carbon energy at the least cost to consumers.

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[314] Integrated generation and supply businesses.

[315] British Gas is part of the Centrica Group.

[316] Formed in 1998 with the merger of Scottish Hydro and Southern Electric.

[317] Ofgem.*2013 Great Britain and Northern Ireland National Reports to the European Commission – Monitoring Competition*. August 29, 2013. P. 59.

Ofgem is the executive arm and the independent economic regulatory body of the gas and electricity markets in the UK.[318] It is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derived its regulatory powers from the Gas Act 1986, the Electricity Act 1989, and the Utilities Act 2000.[319] Ofgem's functions include administering a price control regime for network operators, monitoring the quality of services by setting guaranteed standards of performance, and deciding upon proposed industry code changes. Ofgem operates under the direction and governance of GEMA, which makes all major decisions and sets policy priorities for Ofgem.[320] Ofgem also has the powers to investigate suspected anti-competitive behavior.

10.2.2 Administration of the electricity system

Since the introduction of NETA (and subsequently BETTA to incorporate Scotland), the UK electricity market has been structured into three components: the bilateral market, the short-term (generally day-ahead) bilateral markets, and the balancing market.

10.2.2.1 BETTA

BETTA has three aspects, namely, contract trading, physical operations and the settlement of imbalances (Figure 87).

Contract trading

Prior to gate closure,[321] electricity is traded through forward contracts via power exchanges or over the counter ("OTC"). A contract requires the seller and buyer to notify the central settlement system of BETTA of the contracted quantity of electricity to be delivered or taken for each half-hour settlement period.

Physical operations

Generators and retail suppliers must inform the system operator about their physical production and consumption plans for the half-hour settlement period in question before the gate closure. The notification is made through a final physical notification ("FPN") for each of

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[318] The Utility Regulator regulates the electricity, gas, and water sectors in Northern Ireland.

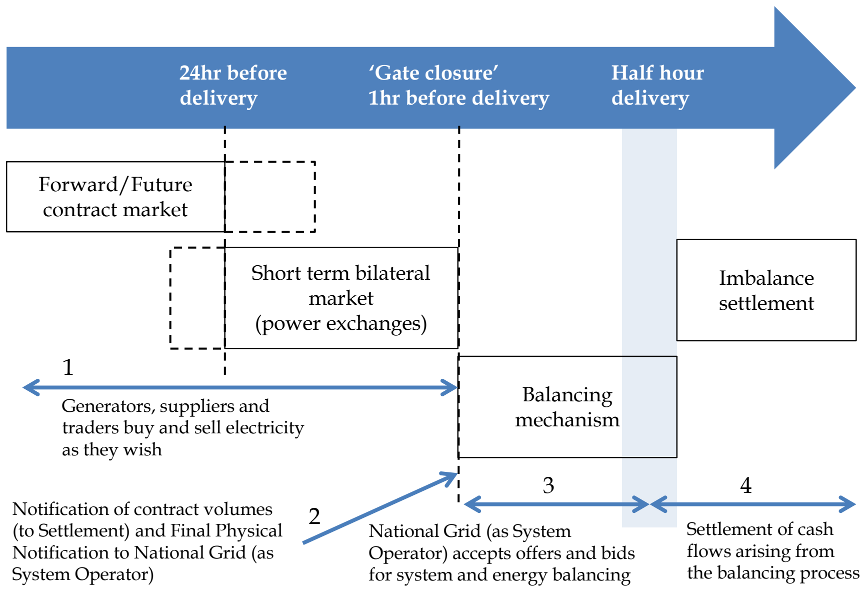
[319] Australia Competition and Consumer Commission. *Regulatory Practices in Other Countries Benchmarking opex and capex in energy networks.* May 2012.

[320] GEMA consists of non-executive and executive members. It determines the strategies, sets policies, and takes decisions on various matters such as price controls and implementation. Its powers are provided for under the Gas Act 1986, Electricity Act 1989, Utilities Act 2000, Competition Act 1998, and the Enterprise Act 2002.

[321] Gate closure is the point in time when participants must provide certain information to the system operator and the central settlement system with respect to each half hour settlement period (the settlement period is also called the dispatch period). Gate closure for a settlement period is the point in time exactly one hour prior to the start of the settlement period.

their generation and supply units. The System Operator receives the information contained in the FPNs. The participants may also submit bids and offers for individual generation and supply units to the System Operator with respect to the half-hour settlement period in question. Bids and offers take the form of prices and quantities. The System Operator may accept bids and offers through the Balancing Mechanism ("BM") to increase or decrease the output from individual generation or load units, allowing it to physically manage the supply and demand balance on the network and flow through the network.

Figure 87. Overview of BETTA market structure



Source: National Grid

Settlement of balances

After the settlement period has ended, metered output or consumption is compared to contracted output or consumption for that half-hour settlement period. This quantity comparison is done separately for each generator and supplier, i.e., in the case of a vertically integrated company, the imbalance quantity for the company's generation arm is calculated separately from the imbalance for the company's retail supply arm.

The imbalance between the contracted and metered quantities for a generator or supplier is settled at one of two energy imbalance prices calculated uniquely for each settlement period. The spread between the two imbalance prices places an incentive on market participants to balance their contractual and physical positions. This settlement process is called Imbalance Settlement. Energy imbalance prices do not vary geographically within the area covered by BETTA.

10.2.2.2 Independent transmission operator

NGET is the System Operator in the country and is responsible for balancing the supply and demand in real time. The Balancing Mechanism ("BM") is the mechanism where NGET accepts bids and offers to increase or decrease electricity to assist it in balancing the system. While generators and suppliers are required to be members of the balancing market operated by NGET, the volume settled through this market has been insignificant. Most of the transactions are cleared in the bilateral markets.[322] In the short-term bilateral market, power exchanges—such as the Amsterdam Power Exchange ("APX")—emerged to provide market places for trading, clearing, and information provision services.

There is a regulatory mechanism that encourages TOs to maintain a reliable and secure system. A target for availability, reliability, and for minimizing loss of supply events is set for each TO licensee as part of the price control. TOs are either rewarded or penalized according to their level of performance against the targets set by Ofgem. Moreover, the TOs are required to report on the security and quality of service of the national electricity system.

Likewise, DNOs are required by their license to ensure that their networks meet the requirements of Engineering Recommendation P2/6, which specifies the maximum supply interruption times for specified contingencies. DNOs are also required annually to provide Ofgem with data on their network's performance.

10.2.3 Licensing regime

In the UK, electricity transmission and distribution are both licensed activities. Ofgem issues the licenses and utilities are required to comply with the license conditions. Electricity transmission license conditions require unbundling in functional terms. Figure 88 shows the conditions required for a transmission operator. NGET is not allowed to own generators or suppliers so it will not have an incentive to discriminate between market participants. Another license condition is prohibition from giving cross-subsidies.

Similar to the transmission sector, regulation of the distribution sector is accomplished through the license conditions and price controls. The Electricity Act requires distribution and supply to be legally separated. Moreover, the licenses require managerial and operational independence to prevent suppliers' access to confidential information. This also ensures competition. Figure 88 shows the conditions in the distribution license.

All vertically integrated DNOs are legally unbundled and are operated through a separate subsidiary company, insulated from the competitive segments of the market. Those involved in the day-to-day operations of the generation or supply sector are not responsible for the management of the DNO. Nevertheless, there are still certain services within the holding

[322] Ofgem. *2013 Great Britain and Northern Ireland National Reports to the European Commission – Monitoring Competition.* August 29, 2013.p. 47.

company that the competitive businesses share with the regulated ones. These include legal, human resource, IT, corporate pension, and finance areas. Generally, DNOs are located in a separate location from the supply and/or generation subsidiary companies. There is also a compliance program to ensure that independence between the operations, rules governing access of personnel on premises, and penalties for violations for those rules are maintained. The regulator regularly monitors the compliance program.

Figure 88. Conditions of transmission and distribution licenses

	Transmission	Distribution
Ownership in other value chain	System operator not to own any electricity supply or generation interests	N/A
Evidence of compliance	Obligations on licensee to deliver evidence of compliance and in case where confidential info comes to the possession of the licensee it shall ensure it is treated as confidential Appointment of a compliance office	Appointment of a compliance officer
Cross subsidies	Prohibition of cross subsidies	Prohibition of cross subsidies
Ring fencing	Restriction on activity and financial fencing (licensee may only conduct transmission business; it may not hold or acquire shares or other investments of any kind)	Financial ring-fencing
Confidential information	Restriction on use of certain information	Full managerial and operational independence of distribution business and restricts the disclosure of confidential info
Non-discrimination	Requires non-discrimination in the provision of use of interconnectors; prohibition on engaging in preferential or discriminatory behavior	Obligation to ensure that they do not restrict, prevent, or distort competition in the supply of electricity or the generation of electricity

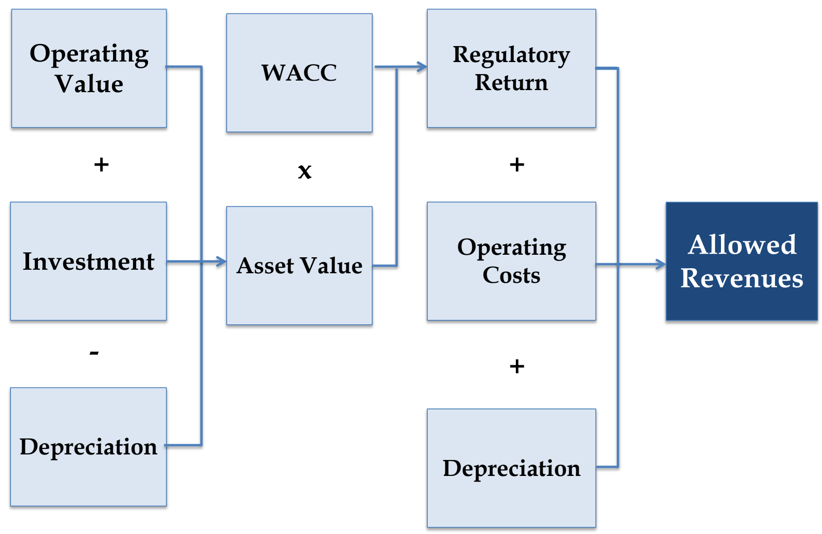
Source: Ofgem (License conditions are available online at https://epr.ofgem.gov.uk/Document

10.2.4 Regulatory oversight of charges

In addition to controlling the transmission and distribution networks through license conditions, **Ofgem** also regulates these two sectors through price controls. The UK uses an incentive-based regulatory regime (also called performance-based ratemaking, or "PBR") in setting these price controls for the natural monopoly networks. Introduced in the early 1990s, the PBR used by the UK is in the form of an RPI-X cap mechanism where the RPI is the inflation in the Retail Price Index and X is an efficiency factor. This means that rates are allowed to increase by inflation minus an efficiency factor. Until 2010, the RPI-X values for P_0 and X were predetermined and revenues were forced to conform to these annual changes. Beginning in the 5th distribution price control review ("DPCR5"), revenues were smoothed to ensure constant year-on-year changes. X is the derived value that achieves this end.

The UK's PBR has employed a "building blocks" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated utility over the term of the price controls. In particular, revenue requirements are set based on estimates of the likely capital and operating costs and return of and return on an efficient asset base. Actual allowed revenues for each utility vary depending on how well it performs against a number of incentives. Figure 89 shows the components of revenue requirements under the UK's building blocks approach.

Figure 89. Components of the Allowed Revenues



Source: Ofgem ("History of Energy Network Regulation")

In the UK, Ofgem uses the Information Quality Incentive ("IQI")[323,324] scheme to further encourage TOs and DNOs to reveal their efficient costs and discourage inflated capital expenditure forecasts through a reward and penalty framework.[325] It provides incentives for a TO or DNO to not only propose efficient and prudent costs as part of its regulatory review, but also to realize timely investment when needed (rather than to game the system so as to time investment with PBR terms). The IQI provides incentives by giving additional income to TOs or DNOs whose forecasts are close to Ofgem's assessment. This incentive is realized by providing TOs and DNOs with a higher incentive rate than those distributors with higher capex forecasts, thereby increasing their reward for outperformance.

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323 Also referred to as the "sliding scale incentive" in previous regulatory periods.

324 The IQI scheme was intended to mitigate the information asymmetry between Ofgem, the regulator, and the distributors in capex forecasting and provide incentives to distributors to provide the most efficient level of capex for the requirements of the network over the regulatory period. It aims to reduce the risk of under-investment, reduce the opportunity for distributors with high capex allowances to make high returns for underspend and reward distributors with low capex allowances for delivering against this.

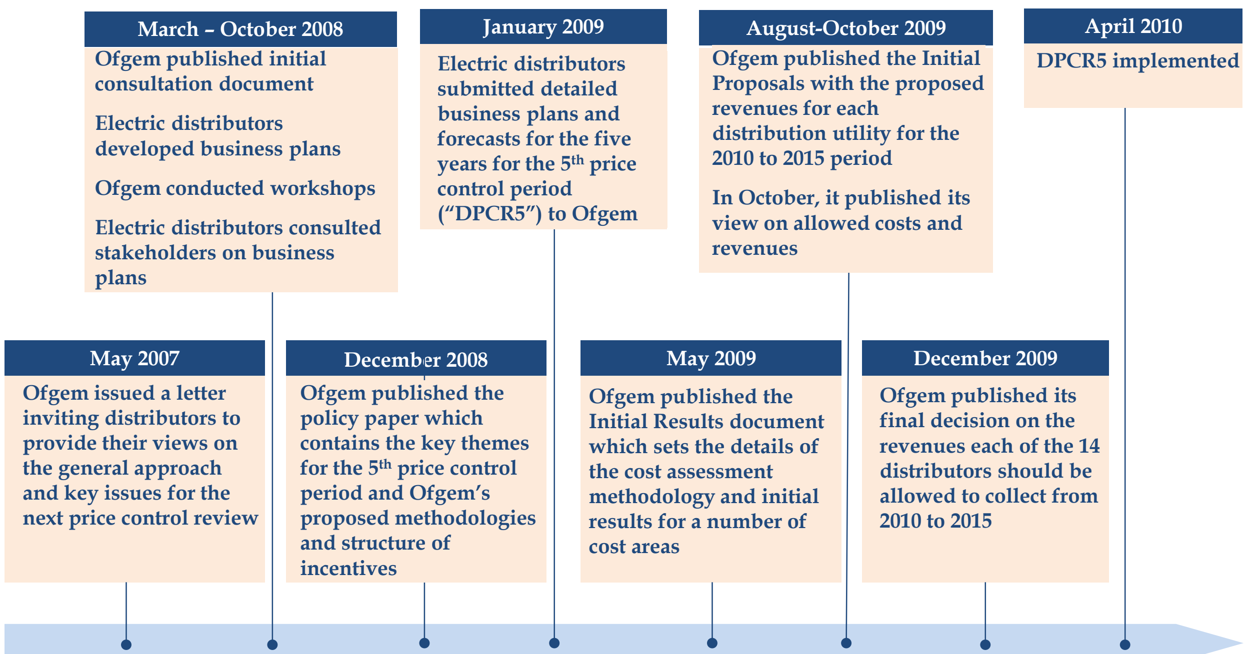
325 The Information Quality Incentive Mechanism is determined by the following formula:

(Allowed Expenditure – Actual Expenditure)*Efficiency Incentive + Additional Income

The IQI, which has become a key feature of the UK approach, specifically also addresses the information asymmetries problem that regulators have historically been concerned with under cost of service and also, to some degree, under the building blocks approach.

The ratemaking process in the UK typically takes more than 30 months from the time of Ofgem's issuance of key issues for the next price control review to the implementation of the PBR. Figure 90 shows the process during the 5th generation price control review for the distribution sector ("DPCR5"). During the price control review, each utility is required to submit detailed forward-looking business plans, which serve as the basis of analysis and review by technical experts at Ofgem.

Figure 90. Ratemaking process during DPCR5



Source: Ofgem ("Electricity Distribution Price Control Review Final Proposals")

10.2.4.1 Transmission sector under the RIIO model

Under the RIIO model, the transmission operators are expected to deliver outputs that are set during the transmission price control review. A list of these outputs is shown in Figure 91 below. Several of the incentives are linked to the percentage of allowed revenue.

Ofgem generally considers a TO's performance against its outputs on an annual basis. The productivity factor ("X factor") in UK is not the same as the X factor in North American markets. The X factor in UK's RPI-X is not the productivity target but instead the glide path in rates that allows the regulated utilities to recover reasonable return if - and only if - efficient costs are achieved. This glide path also allows for a smoothing of rates for customers.

Ofgem reviews the TOs' capex forecasts to ensure that projected investments are adequate to maintain the operation of the network and to ensure that customers do not carry the costs of unnecessary investment or any operational inefficiency. Prior to the start of the regulatory period, TOs (as well as DNOs) are required to submit business plans that include, among other data, the utilities' forecasts for network replacement and capacity additions for the next five years. For the forecasted network replacement, Ofgem evaluates each utility's forecasts against its own asset replacement policies in the past and against the expenditure forecasts of other distributors taking into account the age profile of assets on the individual networks.

Figure 91. NGET's outputs and incentive parameters under RIIO-T1

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive ("HSE")	Statutory requirements. No financial incentive A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs
Reliability	Primary output based on Energy Not Supplied ("ENS")	Incentive rate of £16, 000/MWH which is based on an estimate of the value of lost load ("VoLL"). A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues
Availability	Prepare and maintain a Network Access ("NAP")	Reputational incentive. Potential financial incentives if relevant during development and update of NAP
Customer Satisfaction	Develop customer/stakeholder satisfaction survey	Up to +/-1% of allowed revenue
	Effective stakeholder engagement	Up to 0.5% of allowed revenue via a discretionary reward scheme
Connections	To meet existing legal requirements	General enforcement policy
Environmental	SF_6 – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses	Reputational incentive
	Business Carbon Footprint ("BCF") – publish BCF accounts at business level annually over RIIO-T1	Reputational incentive
	Environmental Discretionary Reward Scheme ("EDR") scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentive	Positive reward available if achievement leadership performance across different scorecard activities.
	Visual amenity – to efficiently meet planning requirements for new infrastructure and deliver visual amenity outputs by mitigating impacts of existing infrastructure when it is located in designated areas	Reputational incentive in the context of its performance in the utilization of two mechanisms: (1) Baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent (2) Initial expenditure cap of £500m to reduce the impact of existing infrastructure in designated areas

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

Financial models are also used by Ofgem and its consultants to determine whether the regulated energy network is financeable under the proposed control. Financeability is assessed using a range of different financial ratios (similar to those used by rating agencies to identify a company with a comfortable investment grade credit rating). If there are concerns, adjustments can be made to the control to ensure that the network can finance its functions.

Figure 92. Key components of PBR for the TOs

PBR components for UK for the RIIO-T1	
Form	Revenue cap
Approach	Building blocks approach
Term	8 years
Inflation factor (I factor)	UK Retail Price Index
Productivity factor (X factor)	Expected productivity improvements are embedded in the revenue requirements
Capex (K factor)	Embedded into the revenue requirements. Capital additions are included in the Regulatory Asset Value in the year of purchase of the assets. There is no distinction between new capex and opex when added into the RAV
Service Quality Standards (Q factor)	Rewards/penalties for specific performance targets (see table on NGET's outputs and incentive parameters under RIIO-T1)
Off-ramps	Reopeners are available for costs related to delivering EMR measures or for enhancement of physical security
Exogenous factor (Z factor)	Deviations in generation capacity connections from annual baseline profile and deviations in from baseline profile of investment (due to unanticipated demand connections)

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

10.2.4.2 Distribution sector under DPCR5

The price control currently used by the distribution sector (i.e., the 5th DPCR) is not yet under the RIIO model. Under the current PBR mechanism, which has a 5-year term, DNOs need to make productivity improvements to be able to achieve their return on equity.

In the UK, there are several mechanisms in place to ensure that the DNOs do not focus on cost cutting at the expense of customer service. Some of the performance standards that are currently in place include customer interruptions, customer minutes lost through interruptions each year, customer satisfaction, speed of providing quotes, speed of completing work to connect existing or new customers to their networks, percentage of units that are lost in distributing electricity to customers, and efficiency of connection of distributed generation. Distributors are rewarded or penalized if the targets set for these standards are not met. In designing the rewards and penalties for the target results, Ofgem uses the return on regulatory equity ("RORE")[326] as a measure of the DNOs' performance.[327] For the current period, Ofgem

[326] The RORE is also used to determine the cost of capital.

[327] For instance (and as discussed in the *Ofgem Electricity Price Control Review Final Proposal*),[327] if all companies match the customer minutes lost performance currently achieved by the most efficient distributor, and were able to achieve their own best customer interruptions performance from the previous regulatory period in every year of the current regulatory period and earn the cap on losses and customer satisfaction, then they would

has also placed caps on the DNOs' exposure to each incentive, but it did not impose a cap on the extent to which DNOs can outperform the targets by being more efficient.[328]

In the UK, there are also re-openers or "logging up mechanisms" for distributors during special circumstances to ensure that both the distributors and consumers are protected from differences between the actual and assumptions underpinning the price control. [329] The PBR also has flow-through mechanisms to ensure that costs beyond the DNOs' control are covered and passed through to customers. There are also incentives to invest in technological improvements. Figure 93 shows some of the key components of the 5th DPCR period.

Figure 93. Key components of the 5th DPCR period

PBR components for UK for the 5th DPCR Period	
Form	Price cap
Approach	Building blocks approach
Term	5 years
Inflation factor (I factor)	UK Retail Price Index
Productivity factor (X factor)	Expected productivity improvements are embedded in the revenue requirements; X factor for distributors ranges between -11.1% to 4.3% depending on the firm
Capex (K factor)	Embedded into the revenue requirements. Capital additions are included in the Regulatory Asset Value in the year of purchase of the assets. There is no distinction between new capex and opex when added into the RAV
Q factor	Rewards/penalties for specific performance targets
Off-ramps	Reopeners are available for high value projects that are 20% over the total ex ante allowance and load-related expenditure
Flow-through	Non-controllable costs such as charges on transmission exit, wheeling charges, and license fees
Other incentives	Distributors are encouraged to invest in technological improvements. For instance, the Innovation Fund Incentive ("IFI") was introduced to partially fund technical research and development on distribution networks.

Source: Ofgem ("Electricity Distribution Price Control Review Final Proposals")

Currently, Ofgem and the DNOs are in the process of finalizing the allowed revenues for the DNOs for the next regulatory term (April 1, 2015 to March 31, 2023). This term, which is known as RIIO-ED1, will be the first term that the distribution sector will be under the RIIO model. Similar to the transmission sector, the RIIO-ED1 will set outputs for safety, reliability, customer satisfaction, and stakeholder engagement with strong incentives for efficient delivery. DNOs will also be incentivized to manage their carbon footprint and report on how their actions have contributed to broader environmental objectives.

be able to earn around another 110 to 220 basis points over the period. Given the WACC for the current regulatory period is at 4.7%, this would mean that shareholder returns at over 10% for all DNOs.

[328] *Ibid.* p. 56.

[329] Ofgem. *Electricity Distribution Price Control Review Final Proposals – Cost Assessment.* London: Ofgem, 2009, p. 6.

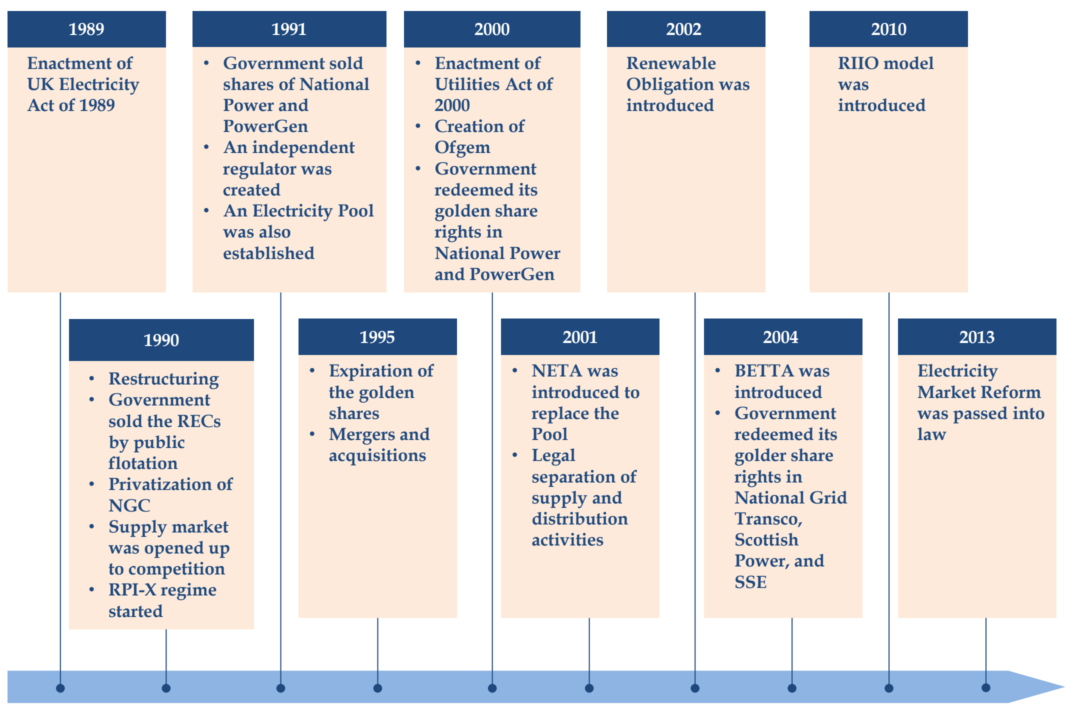
Although the RPI-X framework has worked well in UK, Ofgem acknowledged that this framework was designed under a different context and may not work well in the future. Electricity networks were designed originally to deliver power from large, centrally-located power stations to homes and businesses around the UK. In the future, electricity networks need to be set up in such a way that electricity will be able to flow to accommodate a much larger number of smaller renewable plants that will connect to the networks. An Ofgem document also listed some of the challenges that distributors are likely to face—connecting more home-based micro generators, linking more small scale renewables and combined heat and power ("CHP") to the low voltage distribution network, adapting to the impacts of climate change, and coping with active demand management.[330]

10.2.4.3 Generation and retail sectors

Unlike the transmission and distribution sectors, the generation and retail markets are fully liberalized with no price controls. Retail prices are set by energy suppliers based on their costs and other factors related to their business and market forces. Ofgem's role in these two unregulated sectors is mainly limited to monitoring, although it also approves or vetoes changes to market rules and transmission access and charges.

10.3 History of restructuring and recent developments

Figure 94. Timeline of key events in the UK's electricity market



Source: LEI research.

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[330] Ofgem, *Regulating Networks for the Future RPI-X 20 Emerging Thinking,* (London: 2010), p. 36 and Ofgem, *RIIO – A New Way to Regulate Energy Networks*, (London: Ofgem, 2010), p. 1.

The UK electricity market was one of the first to be restructured and unbundled in the world (after Chile, which reformed its market in the early 1980s). The full sector reform included restructuring, privatization, regulation, and competition. The UK's experience shows that having clear objectives for the restructuring program, providing for mechanisms to facilitate the transition, and establishing an independent regulator are vital components to restructuring efforts. This section discusses the context behind the UK restructuring decisions and how its current regulatory institutions developed.

10.3.1 Prior to restructuring

Pre-restructuring, the electricity industry structure in the UK was characterized by the vertical integration of generation, transmission, distribution, and supply. The Central Electricity Generating Board ("CEGB"), which owned and operated the generation stations and transmission system in England and Wales, dominated the nationalized electricity industry. Electricity produced by CEGB was sold in bulk to the 12 Area Boards, which were separate public corporation responsible for the distribution and retail of electricity in their respective region. There were two vertically integrated boards (called the Scotland Electricity Board or "SSEB") in Scotland.

An Electricity Council—composed of three full-time members, the chairs of the 12 Area Boards, and three representatives from the CEGB—played the primary role of coordinating matters of industry-wide concern. Its duties included advising the government on behalf of the industry as a whole, and promoting and assisting the maintenance and development of an efficient and economical system of electricity supply.[331]

10.3.2 Restructuring

On February 1988, the Government published its proposal to restructure and privatize the electricity supply industry in England and Wales. The restructuring was driven by broader political objectives to restructure the wider economy and improve efficiency by privatizing utility services, including telecommunication and electricity sectors.

The UK Electricity Act of 1989—enacted into law on July 1989—laid the legislative foundations for the restructuring and privatization of the electricity sector in the UK. Provisions in the Act included change in ownership (from the state to private investors) and the introduction of competitive markets.

The new structure was introduced on March 31, 1990. England and Wales restructured their electricity industry, and the twelve (12) Area Boards were transferred to the twelve (12) Regional Electricity Companies ("RECs"),[332] serving the same regional areas of England and

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331 Simmonds, Gillian. "Regulation of the UK Electricity Industry." *Centre for the Study of Regulated Industries*. May 2002.

332 REC means Regional Electricity Companies in the UK section and is different from the definition of REC in the other sections.

Wales. The CEGB's assets were split into three (3) generating companies (National Power, PowerGen, and Nuclear Electric)[333] and a transmission company (National Grid Company, or "NGC").

Scotland restructured its electricity market separately from England and Wales. The SSEBs were replaced by the ScottishPower and Scottish Hydro-Electric, while the nuclear stations were placed in a state-owned company called Scottish Nuclear.[334] Vertical integration was maintained in the new structure in Scotland.

10.3.3 Privatization

The Government sold the RECs in December 1990 by public flotation in the stock market. Fifty-five percent (55%) of the shares went to individual investors, thirty percent (30%) to institutional investors, and fifteen percent (15%) to foreign investors.[335] The government also retained some rights (which were referred to as the "golden shares") in the RECs until March 1995.

The NGC was also privatized on December 1990. Ordinary shares in the NGC were transferred to the RECs. The Government auctioned off its sixty percent (60%) share in the two generating companies—National Power and PowerGen—in March 1991. The Government held a 40% share in these two generation companies until March 1995 (which was extended until 2000). The two Scottish companies (Scottish Hydro-Electric and Scottish Power plc.) were also floated in June 1991.

10.3.4 Creation of regulator

The UK Electricity Act of 1989 established an independent regulator of the electric power sector headed by the Director General of Electricity Supply, which was supported by the Office of Electricity Regulation ("OFFER"). OFFER was created not only to regulate the newly privatized electricity industry but also to be an independent entity from the Parliament. This was done to protect OFFER's regulatory decisions from political control, subsequently providing long term regulatory certainty and encouraging market entry and investment.[336]

10.3.5 Establishment of the electricity pool

An Electricity Pool ("the Pool") was also established under the Electricity Act of 1989. It was set up to facilitate a competitive bidding process. NGC operated the Pool and administered its settlement system on behalf of pool members. Generators were required each day—on a day-

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333 Nuclear power stations were transferred to Nuclear Electric.

334 Scottish Nuclear became part of British Energy in 1996.

335 EIA. Electricity Reform Abroad and US Investment. September 1997. p. 24.

336 Department of Energy & Climate Change. *Ofgem Review Final Report*. July 2011. p. 8.

ahead basis—to provide details of the price at which they were prepared to make generation available. NGC provided a forecast of system demand on a day-ahead basis, prepared a schedule of generation to meet this estimate, and determined the pool price.

10.3.6 Acquisitions and consolidations

After restructuring the electricity sector by separating generation, transmission, and distribution, the Government focused on increasing the level of competition among generators. The generators divested some of their generating assets to new market participants to avoid referral to the Monopolies and Mergers Commission and to gain permission to merge with electricity retailers. Subsequently, horizontal and vertical consolidations in the market led to the creation of the "Big Six" energy suppliers in the UK.

10.3.7 Opening up of the supply market to competition

The supply market was opened up to competition in three phases:

- first wave (April 1990) - customers with a peak load greater than 1 MW were able to choose their suppliers;
- second wave (April 1994) - customers with peak load of more than 100 kW were able to choose their supplier; and
- third wave (September 1998 to May 1999) - the remaining part of the electricity market (customers with peak load below 100 kW) was opened up to competition.

10.3.8 Merging of the gas and electricity regulators into a single regulator

The electricity sector's institutional framework was further reformed with the enactment of the Utilities Act of 2000. Key provisions of the Act included the replacement of an individual regulator (the Director General of Electricity Supply) with a regulatory board, GEMA, and combining them into one regulatory office for both the gas and electricity sectors—Ofgem.

10.3.9 New Electricity Trading Arrangements ("NETA")

In 2001, NETA was introduced to replace the Pool.[337] NETA relied on bilateral contracts between generators and suppliers to provide power, with the NGC running a balancing market to settle real-time imbalances between generation and demand. The introduction of NETA aimed to solve the problem of perceived price manipulation by major generators and encouraged long-term bilateral contracts (between the generators and the suppliers).

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[337] Some of the key differences between NETA and the Pool include: (i) self-dispatch – each generator under NETA was responsible for determining the level of output from its generation units whereas under the Pool, the NGC scheduled on behalf of the generator, (ii) paid as bid – all trades were valued at the bid price for that trade rather than at the bid price for the most expensive trade for a given time period, (iii) ex-post price – the cash-out price was determined after the event rather than in the pool, to name a few.

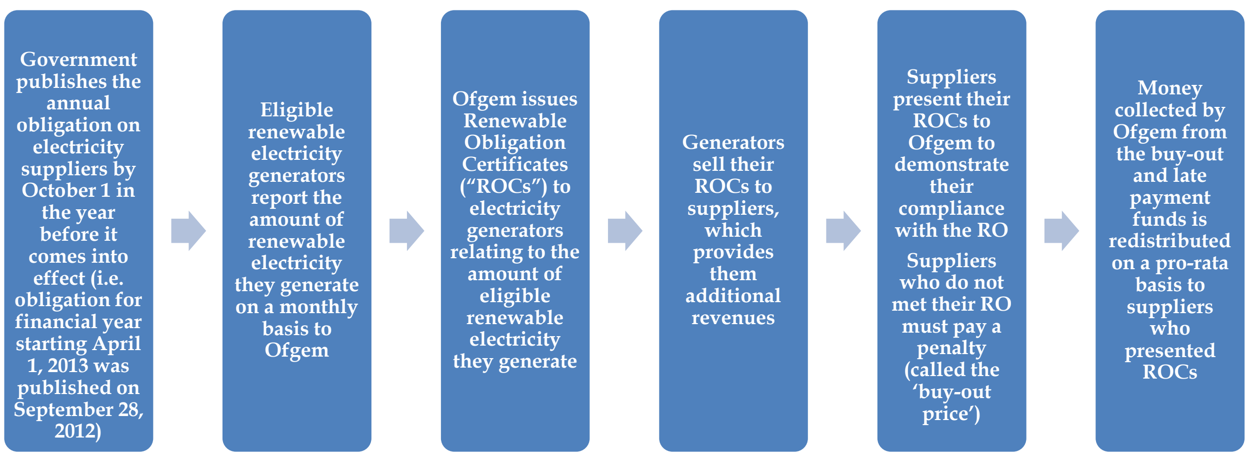
10.3.10 Legal separation of supply and distribution activities

The Utilities Act 2000 also split the supply and distribution activities, and required these businesses to be licensable separately. This means that the requirements for the companies to unbundle came not directly through legislation as such, but rather through a change in the conditions of their licenses. Furthermore, the Act introduced a UK-wide license and removed the use of public electricity suppliers ("PES") and second-tier licenses. This allowed all suppliers to supply customers nationwide.

10.3.11 Renewables Obligation

On April 2002, the Renewable Obligation ("RO") was introduced in England and Wales and Scotland. Under the RO mechanism, electricity suppliers are required to source an increasing proportion of electricity from renewable sources from a 3% commitment in 2012 to 15.4% in 2015/2016. This obligation can be achieved by presenting Renewable Obligation Certificates ("ROCs") or paying into a 'buy out' fund. The buy-out payment for 2013/2014 is set at £42.02 per ROC. Owners of renewable units can obtain ROCs for the renewable energy they generate through accreditation of their generating station and by meeting the requirements for ROC issuance. Figure 95 shows how the RO works.

Figure 95. How the RO works



Source: DECC website (accessed on April 30, 2014)

10.3.12 British Electricity Trading and Transmission Arrangements

The Energy Act 2004 enabled the expansion of NETA to include the Scottish transmission grid, forming the single UK-wide set of arrangements for trading energy known as the BETTA. NGC became the single system operator in England, Wales, and Scotland. BETTA was established to overcome the separation of the trading arrangements between England and Wales and Scotland and introduce a common set of wholesale electricity trading and transmission arrangements.

10.3.13 RPI-X cap regime

With the separation of the regulated (transmission and distribution) and unregulated (generation and supply) businesses, the regulator established a price cap mechanism called the RPI-X cap to protect customers in the transmission and distribution sectors where there is lack of competition. The RPI-X cap is set in such a way that utilities need to make efficiency gains to maintain profitability. Efficiency improvements achieved over and above those assumed in the price cap may be retained by utilities.

The framework for the electricity price control has changed significantly when compared with the regime that was put in place at privatization.[338] For instance, starting with the 5th price control review in the distribution sector, the revenues were smoothed to ensure constant year-on-year changes whereas in the previous price control reviews, values for P_O and X were predetermined and revenues were forced to conform to these annual changes.[339]

Furthermore, the objectives of the price control have changed and adapted to the needs of the time. In the past, the incentives in the UK were focused on improvements in cost efficiency. Over time, additional objectives—such as quality of service and environmental or social-related targets—have been introduced. A target is set *ex ante* and the utilities are rewarded (penalized) if they outperform (underperform) the goals set during the price review.[340] Moreover, Ofgem also provides several incentives to encourage quality customer service and efficient investments in infrastructure. These incentives include the low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, innovative funding incentive, and the information quality scheme ("IQI"). The details on the PBR currently used in the transmission and distribution sectors are discussed in Section 10.4.6.

10.3.14 RIIO model

Ofgem launched a comprehensive review of the RPI-X framework that it uses to regulate the electricity and gas networks on March 2008. The review concluded that there is a need for a new regulatory framework built on the elements of the previous approach while still incorporating new elements. Although the RPI-X framework was a success, Ofgem acknowledged that the existing regime does not provide sufficient incentives for the network companies to make adequate investments, which can accommodate future needs.

On October 2010, Ofgem introduced the RIIO model ("Revenue = Incentives + Innovation + Outputs"). It builds on the success of the previous RPI-X regime but meets the investment and

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338 For more information about the changes for each price control, see Ofgem's *History of Energy Network Regulation*. February 27, 2009. Available online at https://www.ofgem.gov.uk/ofgem-publications/51984/supporting-paper-history-energy-network-regulation-final.pdf

339 Email correspondence with Ofgem staff (Emma Davis).

340 DNOs will be rewarded or penalized according to the following parameters: (1) customer interruptions (customer minutes lost through interruptions each year), (ii) customer satisfaction, (iii) percentage of units that are lost in distributing electricity to customers, and (iv) efficiency of connection of distributed generation.

innovative challenge by placing more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network. Instead of incentivizing the regulated companies to improve their operating efficiency, RIIO is designed to "reward companies that innovate and run their networks to better meet the needs of consumers and network users."[341] The RIIO model measures key delivery outputs such as customer satisfaction, reliability and availability, safety, connection terms, environmental impact, and social obligations required by the government. Companies that deliver these outputs would earn a higher return relative to the current RPI-X regime. Poorly performing companies, however, would "face much more intrusive and heavy handed regulation and lower returns."[342] Ofgem completed the first price review of RIIO for the transmission companies in early 2013 and expects to implement RIIO for the distribution companies in 2015.

10.3.15 Electricity Market Reform

The Government argued that while the current system is working in delivering secure and affordable electricity, it faced challenges in the future. With anticipated 11 GW retirements of coal and nuclear plants in the next decade, the current market arrangements could struggle to deliver the investment at the necessary magnitude and pace. On May 22, 2012, the DECC published a draft Energy Bill, which put in place an Electricity Market Reform ("EMR") aimed to attract an estimated £110 billion in investments needed to replace and upgrade the existing electricity infrastructure in the UK. The EMR has three primary objectives, namely (i) energy security, (ii) decarbonisation, and (iii) affordability (Figure 96) and four main components: (i) Contracts for Difference ("CfD") for renewable energy; (ii) an Emissions Performance Standard to curb the most polluting fossil fuel power stations; (iii) a capacity market to ensure sufficient reliable capacity; and (iv) a carbon price floor to support low-carbon technologies (Figure 97). This was passed into law on December 18, 2013. Section 10.3.16 will discuss in detail some of the recent developments in these components.

In December 2013, the Government issued its first EMR Delivery Plan, which provides details on the CfD strike prices for renewable technologies for the 2014/2015 to 2018/2019, reliability standards for the capacity market, an outlook to 2030, and the next steps in EMR.[343]

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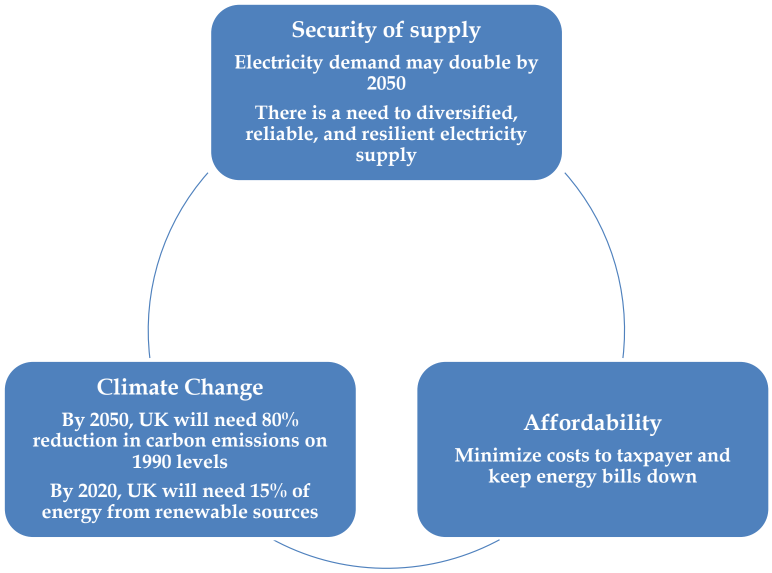
[341]Ofgem. *RIIO – a new way to regulate energy networks*. Factsheet 93. October 2010. p. 2.

[342]Ibid. p. 2.

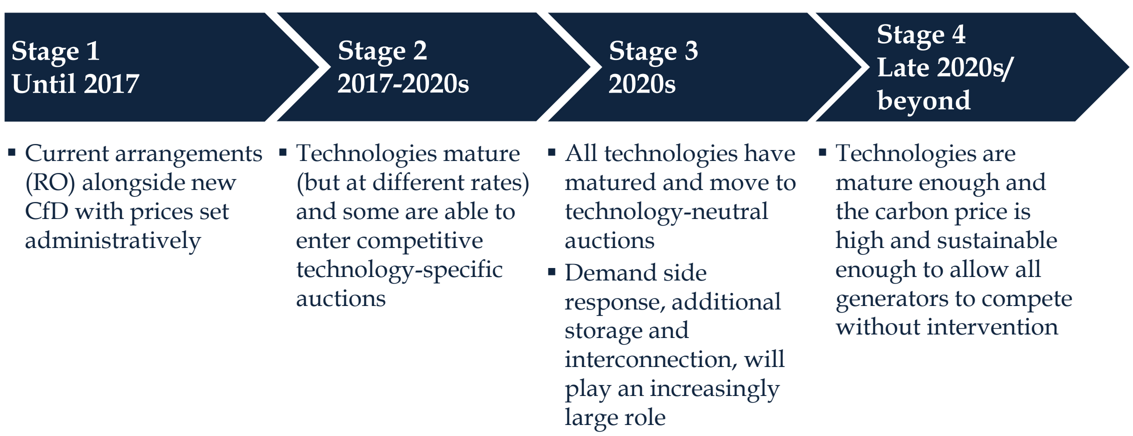
[343] The Government will publish an EMR Delivery Plan every five years.

Figure 96. Three key objectives of the EMR



Source: DECC. ("Electricity market reform: policy overview")

Figure 97. Four stages of EMR



Source: DECC. ("Electricity market reform: policy overview")

10.3.16 Recent developments

Recent developments in the UK revolve around the implementation of the EMR. To facilitate the vital investment needed under the EMR, the government provided two new mechanisms: the CfD and the capacity market, which will be discussed in detail in the following subsections. Another important development is the expected investigation of the 'Big Six' companies due to alleged price manipulations.

10.3.16.1 Contract for Difference

The CfD will eventually replace the Renewable Obligation, which is the existing financial support mechanism for large-scale renewable generation (Section 10.4.5 provides a discussion on this topic).

CfDs are intended to facilitate investment in low carbon generation by removing long-term exposure to electricity price volatility and providing price certainty through a long-term contract. In addition to receiving revenue from selling electricity into the market, generators will receive additional revenues when the market price is below the pre-agreed strike price. Conversely, the generators must pay the difference if the market price is above the strike price.

In December 2013, DECC issued the strike prices for the period 2014/2015 to 2018/2019. The strike prices are based on an analysis from the System Operator (National Grid), which was reviewed by an independent Panel of Technical Experts.[344] The strike prices have been set so that they are broadly comparable to the levels of support available under the Renewable Obligation. Figure 98 shows the announced CfD strike prices for selected technologies.

Figure 98. CfD strike prices, £/MWh for selected technologies

Technology	2014/15	2015/16	2016/17	2017/18	2018/19
Biomass conv.	£105	£105	£105	£105	£105
Landfill gas	£55	£55	£55	£55	£55
Offshore wind	£155	£155	£150	£140	£140
Onshore wind	£95	£95	£95	£90	£90
Solar PV (>5MW)	£120	£120	£115	£110	£100
Wave and tidal	£305	£305	£305	£305	£305

Source: DECC. ("Electricity Market Reform Delivery Plan")

10.3.16.2 Capacity market

The UK government perceived a risk to reliability in the future as around a fifth of existing capacity is expected to close over the next decade and more intermittent (wind) and less flexible (nuclear) generation would be built to replace it. Therefore, the government sees the need to design mechanisms that will ensure that sufficient, reliable capacity is in place to meet demand.

The capacity market will also address the investment challenges that the country is currently facing, particularly as it deals with market changes brought about by the call for more low-

[344] DECC. *Electricity Market Reform Delivery Plan*. December 2013. p. 11.

carbon electricity generating plants. The government sees this as an "insurance policy" against the possibility of blackouts in the future.

Based on the EMR Delivery Plan issued December 2013, the first auction for capacity market would be run by the System Operator, NGET, in late 2014 so that capacity will be in place by winter of 2018/2019.[345] The amount of capacity to be contracted will be guided by the reliability standards, which include a Loss of Load Expectation of 3 hours/year. The System Operator will set out how much capacity is needed and advise the Secretary of State, who will make the final decision on how much capacity to procure.[346]

Similar to the capacity markets in New York, PJM, and New England, capacity providers that successfully clear the auction will enter into agreements with the government, which will require them to provide electricity when needed in the delivery year. Failure to do so means facing penalties. Generation, demand response resources, and energy storage will be able to participate in the capacity market. The UK capacity market will also be run annually. Moreover, plants that receive CfD would be excluded from receiving capacity payments.[347]

DECC is currently consulting on the details of the capacity market design. It aims to complete the design by late spring 2014[348] and to legislate the necessary laws and ruling before summer recess of 2014.[349]

10.3.16.3 Investigation on the "Big Six"

Ofgem has called for the investigation of the top six energy suppliers, namely, Scottish and Southern Energy ("SSE"), Scottish Power, Centrica, RWE Npower, E.On and EDF Energy. These six companies generate about 98% of the UK's energy supply market.

The recommendation came after Ofgem suspected 'tacit co-ordination' on the size and timing of price increases by the six power generators.[350] Ofgem referred the matter to the Competition and Market Authority ("CMA") so the latter can conduct an investigation. The investigation will likely begin on June 2014 and is expected to take about 18 months.

Some consumers groups welcome this development as they view it as a signal of government desire to check and strengthen competition and encourage entry of smaller suppliers. However,

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345 DECC. *Electricity Market Reform Delivery Plan*. December 2013. p. 13.

346 DECC. *Electricity Market Reform Delivery Plan*. December 2013. p. 67.

347 DECC. *Electricity Market Reform: Capacity market – Design and implementation update*.

348 As of writing of this report, there are no new developments on the capacity market designs.

349 DECC. *Electricity Market Reform Delivery Plan*. December 2013. p. 95.

350 Ofgem. *Consultation on a proposal to make a market Investigation Reference in Respect on the Supply and Acquisition of Energy in Great Britain*. March 27, 2014.

the utilities are divided in their reaction. Some are concerned that this development may cause delays in investment in power generation in the next four years, possibly leading to blackouts around the time of May 2015 election. Others like Npower, EDF, and E.ON U.K. believe that the enquiry will restore public trust in energy companies.

10.4 Rationale for specific design elements and pros and cons of selected design

Figure 99. Summary of specific design elements

Design elements	Rationale	Pros	Cons
Energy-only market (until end of 2014)	• To provide signal when new build is required	• Simplicity • Reliability and generation investment is set by market participants	• Increased revenue risks due to price uncertainty/ fluctuations • Potential for regulatory intervention if prices too high
Capacity market (starting end of 2014)	• To ensure reliable capacity in the future • To address investment challenges	• Capacity market on a forward basis ensures energy supply in the future • Provides additional revenue stream to generators	• Regulatory complexity
Vertical separation between regulated and unregulated businesses	• To insulate regulated business from financial instability of the unregulated business	• Ensures no cross subsidies between regulated and unregulated businesses	• Need to provide ring-fencing conditions and mechanisms which involve additional costs to utilities • Entails monitoring from the regulator
Independent transmission operator	• To ensure that there is no discrimination between market participants	• Safeguards independence of the TSO	• Need to provide mechanisms to safeguard independence of TSO • Requires monitoring from the regulator
Single trading arrangement (BETTA)	• To have a single, integrated, and competitive electricity market	• Enables more competition to enter the Scottish market • Provides more access to the British market	• Not as transparent as a pool
Renewables Obligation	• To provide incentives for the deployment of large-scale renewables	• Diversifies the fuel mix	• Entails additional costs to consumers
PBR	• To ensure that customers in the transmission and distribution sectors where there is lack of competition are protected • To meet the investment and innovative challenges of the future • To ensure that service quality and performance standards are met	• Incentivizes utilities to operate efficiently to maintain its profitability • Ensures that there are no cost cutting through performance standards • Provides efficiency savings sharing • Includes reopeners and flow throughs to ensure that costs beyond the utilities' control are covered • Incorporates environmental objectives	• Regulatory process can be long and takes time • Requires utilities to prepare and justify longer term forecasts for operating and capital expenses • Need for extensive benchmarking analysis to set efficient costs

The UK energy market is one of the most competitive and liberalized in the world. However, as in the case of many other nations, it expects a future where older power plants will need to be replaced with new ones, while recognizing the impetus to be more environment-friendly as it secures a steady and reliable supply. UK tackles this multi-faceted challenge through various mechanisms and market designs. A deeper understanding of these key design features will facilitate the development and adoption of a system that will be appropriate, effective, and sustainable in the long run. This section then looks at the energy-only market approach, vertical separation, independent transmission operator structure, BETTA, Renewable Obligation, RIIO model (as applied to the transmission sector), and the 5th generation RPI-X framework.

10.4.1 Energy-only market until end of 2014

The UK will remain an energy-only market until late 2014, when it will have its first capacity market auction. Under an energy-only market, generators get paid only for the electricity they generate. The government has recognized that the market—under this mechanism—has performed well since privatization and liberalization. According to an Ofgem report, the UK market has delivered the nearly 30 GW of gas generation currently in operation and maintained an adequate capacity margin.[351] It has also resulted in comparatively lower electricity prices and supported the deployment of increasing amount of renewables from 3.1 GW in 2002 to 8 GW in 2009.[352] One of the advantages of an energy-only market is that reliability and generation investment is set by market participants rather than arbitrary rules.

However, one of the challenges of having an energy-only market is the uncertainty of future energy supply. Under the current arrangement, maintaining the level of security of supply is left to market forces.[353] The government acknowledged that there are a number of issues in the current market set-up and these could result in insufficient investment signals and hence pose risks to future electricity security of supply:[354]

- The peak wholesale electricity price may not increase enough to reimburse generators and, therefore, will not incentivize developers to invest in sufficient new capacity;
- Under the current arrangements, there is a risk that prices will not be sufficiently predictable and certain, allowing them to be used as the justification for investments in new generating capacity; and
- In the UK market, there is only a limited reference price over the longer term. As such, the case for new investment is weakened because of a lack of reliable price signals; this can deter new entry and competition in the sector.

Moreover, there is an anticipated closure of over 19 GW of power plants—including nuclear, oil, coal and gas plants—over the coming decade.[355] The UK also expects an increase in the

351 DECC. *Electricity Market Reform Consultation Document*, December 2010, p. 26.

352 Ibid. p. 26.

353 Ibid. p. 4.

354 Excerpted from DECC's *Electricity Market Reform Consultation Document*, December 2010, pp. 35-36.

355 DECC. *Electricity Market Reform Consultation Document*, Cm 7983, December 2010, pp. 20.

levels of intermittent generation while it tries to meet its obligation under the European Union's ("EU") target for renewable energy. Therefore, the government saw the need to attract investments from new entrants while encouraging incumbent companies to maximize their pace of investments. The government has identified that one way to ensure future energy supply is through a capacity market mechanism as discussed in Section 10.3.16.2.

10.4.2 Vertical separation between regulated networks and unregulated generation and retailing

Ofgem imposes strict regulations or ring fencing mechanisms to ensure that there is a separation between the regulated network business and the competitive market business, and to ensure that competition is not distorted. Ring fencing is a set of constraints placed upon the holding company that limits its ability to access the funds of its regulated affiliate in the event of holding company or affiliate financial distress. Companies comply with the legal and functional unbundling requirements through license conditions discussed in Section 10.2.3.

There are several advantages of separating the regulated networks from the unregulated businesses. First, the separation of regulated and unregulated businesses prevents franchised utilities with captive customers from unfairly subsidizing their unregulated affiliates at the expense of the captive customers. Second, this prevents affiliates from gaining improper advantages in their competitive markets. Third, lack of ring fencing measures would likely affect the credit rating of the regulated affiliate and eventually the ratepayers. In general, not being properly insulated from the parent company is an oft-cited argument for lowering the credit rating of regulated entities by rating agencies. Lastly, separating the regulated and unregulated businesses protects and regulates the sharing of customer's confidential information.

There are also several potential costs associated with ring-fencing. For example, complying with the strict regulations and implementing ring fencing mechanisms such as hiring a Compliance Officer responsible for compliance with the Standards of Conduct involves additional costs for the utilities. Smaller companies tend to be more impacted by the additional costs, which may undermine their ability to compete with larger suppliers. Moreover, the regulator also needs to monitor and to ensure that the utilities are complying with the license conditions.

10.4.3 Independent transmission operator

As discussed in the Literature Review, there are two options for organizing the coordination and control of the transmission system. The UK chose to have an independent transmission system operator structure where NGET is both the transmission owner and the System Operator of the electricity system. This structure has worked well in the UK because of the mechanisms put in place by Ofgem as well as the Directive 2009/72/European Commission of the European Parliament. Some of these mechanisms, which are listed below, ensure the independence of the TSO:

- TSOs are constrained from having any controlling interest, directly or indirectly, or the power to exercise any voting rights, in a firm that is performing any of the functions of electricity generation or supply.[356] Moreover, this restriction is cross-sector, meaning that a person holding an interest in gas production or supply firm cannot hold any interest or exercise any right over an electricity transmission system.[357]

- TSOs are prohibited from being appointed as members of any entity (such as the supervisory board or administrative board) representing a production or supply company and vice versa.[358] In other words, a person may not be a member of the managing boards of both a transmission system operator or a transmission system and a company performing any of the functions of generation or supply.[359]

- TSOs may not share commercially sensitive information with any of its generation or supply affiliates, as well as transferring its staff to generation or supply functions.[360]

Similar to ring-fencing, implementing these mechanisms entails costs to both the utility and the regulator.

10.4.4 BETTA: a single trading arrangement

The primary goal of BETTA is to have a UK-wide single, integrated, and competitive wholesale electricity market. It is designed to establish a common set of wholesale electricity trading and transmission arrangements to allow the free trading of electricity across Great Britain and introduce a common set of rules (for access to the transmission network) and charging (for use of the network).

A UK-wide market for the trading of electricity generation offers several advantages. First, it enables competitive prices. Prior to BETTA, Scottish customers were not benefiting from the competition in the wholesale market in England and Wales, where prices had fallen by 40% since the NETA reforms were proposed in 1998.[361] BETTA enabled more competitors to enter the Scottish wholesale and retail markets; such entry exerted more downward pressure on electricity prices, benefiting consumers and businesses.

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[356] *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC ("Electricity Directive 2009/72/EC")*. Article 9(b)(i) and (ii). Available online at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF

[357] Electricity Directive 2009/72/EC article 9(3).

[358] Electricity Directive 2009/72/EC, article 9(c).

[359] Electricity Directive 2009/72/EC (15).

[360] Electricity Directive 2009/72/EC, article 9(7).

[361] Ofgem. *The Betta Way Forward*. P. 2.

Second, it provides Scottish generators access to a wider British market where they can sell their electricity. Before BETTA's operation, Scotland produced 70%more electricity than it needed and it was difficult to sell to the wider British market.[362] Moreover, with BETTA, generators in Scotland have a greater choice of suppliers. It also provided all participants in England, Wales, and Scotland access to the same markets on equal terms.

Lastly, BETTA provided a more cost-effective way in implementing a single set of UK-wide arrangements.

Nevertheless, under BETTA, forward prices are the result of bilateral contracts either through over the counter (through brokers) transactions or through power exchanges; they are not generated by the balancing mechanism. Therefore, BETTA is not as transparent as an electricity pool market. Moreover, BETTA is for short-term contracts. The futures are too illiquid to provide limited price guidance.[363]

10.4.5 Renewables Obligation ("RO")

As mentioned earlier, in 2002, the UK introduced the RO to encourage investments in renewables. Similar to the renewable portfolio standards ("RPS") in the US, the RO requires electricity suppliers to source a specified proportion (known as the 'obligation') of the electricity they provide to customers from eligible renewables. Under the RO, the obligation is set each year and has increased annually.

One of the advantages of the RO is that it incentivizes generators to build renewables. Total capacity of renewables increased from 1,675 MW in 2002/2003 to 8,528 MW in 2010/2011, leading to an average increase of 27% per year as shown in Figure 100. This, in turn, creates greater diversity in UK's fuel mix.

A disadvantage is that the cost of compliance with the RO is passed on to consumers through their energy bills. According to Ofgem, the impact of the RO on an average household electricity bill was £30 in 2012 (in real 2012 prices).[364]The RO will terminate on March 31, 2017 and will be replaced with the CfD. However, electricity generation that is accredited under the RO will continue to receive its full lifetime of support (20 years) until the scheme closes in 2037. Currently, the Government is conducting stakeholder consultations to discuss the transition from RO to CfD.[365]

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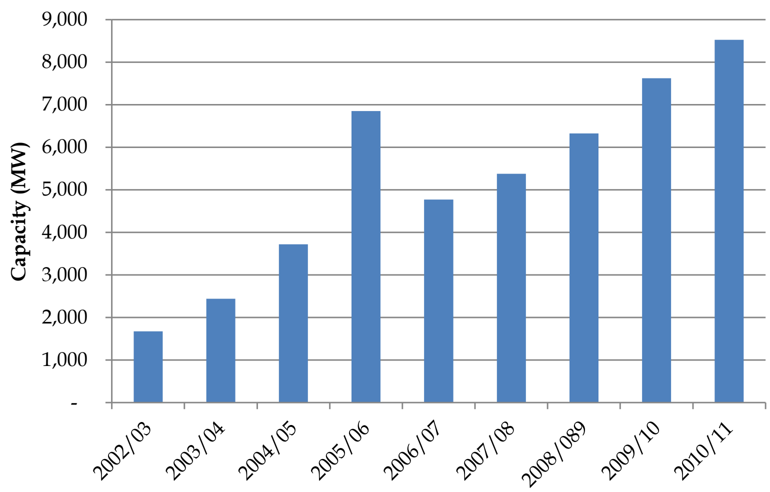
[362] Ibid. P. 2.

[363] Layton. Brent. Market Design Report International Practice Review Paper. August 2005. p. 7.

[364] Ofgem. "The Renewables Obligation."
Available online at https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro

[365] On March 12, 2014, DECC issued a report on the Government's response to the consultations on the RO transition and on Grace Periods. This report is available at

Figure 100. Total renewable capacity accredited (MW)



Source: Ofgem. ("Renewables Obligation Statistics")

10.4.6 PBR

As discussed in Section 10.2.4, the UK uses a PBR approach to determine rates. The rationales for implementing a PBR approach, more specifically the RIIO model, are the following:[366]

- To deliver output that reflects what consumers want and to meet the needs of a sustainable energy sector;
- To lengthen price control from 5 to 8 years to encourage utilities and Ofgem to focus on longer-term needs;
- To provide higher returns for utilities that deliver at a lower cost and lower returns for poor performing utilities;
- To stimulate innovation like smart networks with financial packages; and
- To ensure, through a long-term approach, that the cost of investment is spread fairly between present and future consumers, giving value for money.

UK's PBR mechanism is generally considered to be successful in terms of delivering lower prices and better quality of service and has several advantages. First, utilities are assured that they will be able to recoup their capital investments. Second, with the system of rewards and penalties tied to the utilities' performance, the regulator and the consumers are assured that the utilities will not be cutting costs or focusing only on the bottom-line that may lead to poor

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/289076/Transition_and_Grace_Periods_Government_Response_-_12_Mar_2014.pdf

[366] Ofgem. *Re-engineering Network Price Controls*. July 26, 2010.

service quality. Third, since privatization, allowed revenues have declined by 60% and 30% (in real terms) for electric distribution utilities and electric transmission, respectively.[367] Ofgem believes that these reductions were achieved without sacrificing capital investment.[368] In fact, according to Ofgem, capital investment in the electricity networks is higher, on average, than the period immediately prior to privatization.[369] More specifically, the UK's building blocks approach has increased investment by £35 billion for the past 20 years.[370] Lastly, PBR is believed to have led to substantial improvements in service quality and network reliability. For instance, the number and duration of reported outages fell by around 30% between 1990 and 2009.[371]

As mentioned in the Literature Review, one of the challenges in implementing a PBR mechanism similar to the UK's is the reliance on forecasts. Regulators also have to gather adequate information about the utility's costs. Another challenge is the requirement to have extensive benchmarking analysis to determine the efficient costs. Lastly, the PBR review process takes time as the regulator and its consultants need to review and to evaluate all the business plans and forecasts prepared by the utilities.

10.5 Transitional challenges and remedies adopted

The road to reform is not always well-paved. The transitional challenges are compounded by the difficulty of predicting the future particularly in a sector that is volatile and where utilities are always subject to intense public scrutiny. The UK dealt with the challenges during the transition period through several schemes and instruments such as vesting contracts, ring-fencing, and retention of government's "golden share." These schemes are explained below.

Figure 101. Transitional challenges and remedies adopted

Transitional challenges	Remedy adopted
Volatility in the pool market	Vesting contracts
Cross subsidies between regulated and unregulated businesses	Ring fencing mechanisms
Rate increase and unfriendly takeovers	Government's "golden shares" in companies

[367] Ofgem. *Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking*. London: Ofgem, 2010, p. 50.

[368] Ibid.

[369] Ibid.

[370] Ofgem. *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*. London: Ofgem, 2010, p. 2.

[371] Ibid.

10.5.1 Using vesting contracts as a transitional mechanism

From April 1, 1990 to March 31, 1993, the UK imposed vesting contracts as a transitional mechanism towards a competitive market.[372] RECs were obliged to purchase fixed amount of electricity from the generators at a price that would guarantee margins for both parties.[373] Vesting contracts protected the generators and distributors from high coal prices and the volatility in the pool market.

10.5.2 Protecting financial viability of regulated businesses through ring-fencing

Since privatization, distribution utilities were permitted to acquire generation assets to allow more competition in the generation sector. However, a restriction had been imposed: no REC-owned generation facilities can account for more than 15% of their individual electricity sales.

Allowing individual RECs to produce their own electric power also led to a surge in REC investment in independent power producers ("IPPs"). The regulator was concerned that companies were using their regional monopolies on distribution to subsidize their retail activities. Unregulated and commercial businesses are also riskier than network businesses. To ensure that network businesses did not run into financial difficulties due to financial losses in other parts of the holding company, they were required to separate their distribution and retail businesses, although they still continued to own both operations in 1997. Moreover, the RECs were required to ring-fence their distribution business from their generation and marketing businesses.

Ring-fence provisions are designed to safeguard the financial stability and viability of a license holder against pressure that might arise from its affiliates. They also ensure that the regulator has access to necessary information relating to the holding company. These ring-fence conditions include "conditions related to the conduct of its business, maintenance of adequate resources and of ready access to additional finance at reasonable costs,

Examples of the standard ring-fence conditions of PES license:

- Restricts the activities a PES may undertake in its distribution business, its first and second tier supply business, and other activities
- Prevents a PES from acquiring shares in affiliates except for shares in subsidiaries existing at the date the condition first took effect
- Requires a PES at all times to conduct its affairs so as to secure that it has sufficient management and financial resources to carry on its distribution and supply businesses
- Requires PES to provide Ofgem full financial statements for each twelve month period ending March 31
- Prevents a PES from incurring indebtedness, creating security or guaranteeing obligations of others unless for a 'permitted purpose'
- Prevents a PES from entering into any transaction with an affiliate

Source: Ofgem ("Electricity Distribution Licences: Initial Proposals on Standard Conditions for the Financial 'Ring-fence' – A Consultation Paper")

[372] Bower, John. *Why Did Electricity Prices Fall in England and Wales?* September 2002. Oxford Institute for Energy Studies EL 02.

[373] Ibid.

transactions with affiliates and avoidance of cross-default obligations and obtaining certain undertakings from its ultimate holding company or companies."[374]

10.5.3 Ensuring no rate impact during the transition through the government's "golden share"

When the UK government started to privatize its generation, transmission, and distribution assets, it retained a "golden share" in all the assets to ensure that there are no adverse impacts on ratepayers during the transition of the companies to private owners. By holding a "golden share" in each asset, the Government was able to maintain a blocking control of the privatized utilities (and exercise some control over corporate governance of the industry). This restricted any individual party from obtaining more than a 15% share in any privatized company.[375] During that time, the Ministers sought to safeguard competition by giving themselves the right to veto changes in the companies' ownership and structure.

The Government's golden shares in the RECs expired in March 1995, allowing for mergers and acquisitions of generation and distribution companies. The government's golden shares in the generation and transmission companies also expired in 2000 and 2004, respectively. Generally, the holding of golden shares is practiced to support national security; these shares allow time for the privatized company's management to restructure their company without having to worry about possible unfriendly buyouts or takeovers.[376]

10.6 Implications for Nova Scotia

Clearly, the long history of reforms in the UK energy sector points to the crucial role that policy plays in pursuing objectives. Policy reforms have been borne out of deeper market appreciation, more profound dialogue and consensus-building, and a stronger call for low-carbon development. The UK example presents a credible case for the merits of privatization. However, privatization and liberalization require an independent and transparent regulatory environment and the strong commitment and cooperation of system operators, utilities, and consumers. Nova Scotia can learn from the UK's experience in successfully privatizing and restructuring its electricity market as well as effectively implementing the PBR approach. Below are useful insights and recommendations, taking off from the UK experience:

- **Provide clear objectives for electricity reforms upfront**. The UK was clear with its objectives in its 1990 restructuring as well as the EMR. Providing a clear path for reform allows industry players to prepare for the changes in the marketplace.

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374 Ofgem. *Electricity Distribution Licences: Initial Proposals on Standard Conditions for the Financial 'Ring-Fence' A Consultation Paper*. December 1999. pp. 4-5.

375 EIA. *Electricity Reform Abroad and US Investment*. September 1997. p. 31.

376 Guislain, Pierre. *The Privatization Challenge: A Strategic, Legal, and Institutional Analysis of International Experience.* October 2001. P. 257.

- **Provide transitional mechanisms.** The three-year vesting contracts as well as the five-year "golden share" provided some time to develop the design, set up operations, and stabilize the functioning of the market.

- **Separate potentially competitive segments from regulated segments.** This will guard against cross-subsidization of competitive businesses from regulated businesses and discriminatory policies affecting access to the networks on which competitive suppliers depend.

- **Ensure that there is sufficient number of players.** In the initial stages of the market evolution of the generation sector, the UK market was unsuccessful in creating a competitive market due to the limited number of generators. As discussed in the Literature Review report, one of the factors that helps create properly functioning competitive markets is to have multiple players.

- **Ensure ring-fencing mechanisms are in place**. As the UK unbundled the generation, transmission, distribution, and supply businesses, it provided mechanisms to ensure that utilities did not gain an undue advantage as a result of their affiliations and to restrain regulated industries from subsidizing the activities of their affiliates.

- **Adopt a more technology-neutral approach.** UK has the RO to encourage the investments in renewables. In a way, the government is indirectly subsidizing generation from renewables. However, the amount of subsidy provided is not necessarily the same as the value of the environmental benefits of particular technologies. A better way to adopt a more technology-neutral approach is to price the negative externalities produced by fossil-fueled plants. Use of cap-and-trade mechanisms is a means of establishing a more technology-neutral approach to emissions reduction.

- **Establish performance standards and quality of service**. The UK's use of performance targets combined with a penalty and reward incentive system has improved the quality of service of DNOs.

- **Adapt to the changing environment.** The framework for the electricity transmission and distribution price controls has changed significantly as compared with the regime that was put in place at privatization. Ofgem routinely makes modifications to the PBR regulations after each regulatory period to adapt to changes in the environment or improve a particular mechanism that did not work as anticipated. However, some would argue that the changes have been too frequent without corresponding benefits.

- **Recognize what works and what does not work**. In the original provision of the price controls implemented at privatization, revenues for distributors were allowed to increase in line with the number of units distributed. However, Ofgem recognized that this arrangement had the unintended effect of incentivizing distributors to increase the volume of units distributed. To address this, changes to the revenue driver mechanism were implemented in the next regulatory period under which the influence of units distributed was reduced to a weight of 50% with the other 50% linked to customer numbers.

- **Provide incentives to encourage cost efficiency and quality service in its PBR.** Ofgem has put in place incentives for TOs and DNOs so they can continue to innovate, deliver services efficiently, and provide an appropriate level of network capacity, security, reliability, and quality of service. Some of these incentives include a low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, innovative funding incentive, and the IQI. TOs and DNOs are also able to keep some of the benefits if the business is able to operate at a lower cost or exceed target levels—of performance standards or customer service—at the same cost.[377]

[377] In fact, the Ofgem reported that for the 2010-2015 period, well performing distributors could earn up to 13% equity returns within the regulatory period.

11 Appendix A – List of works consulted

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12 Appendix B – List of Acronyms

1GIRM	1st Generation Incentive Regulation Mechanism
2GIRM	2nd Generation Incentive Regulation Mechanism
3GIRM	3rd Generation Incentive Regulation Mechanism
4GIRM	4th Generation Incentive Regulation Mechanism
AB	Assembly Bill
ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALD	Availability Liquidated Damage
ALP	Australian Labor Party
APSA	Asset Purchase and Sale Agreement
APX	Amsterdam Power Exchange
ARP	Alternative Rate Plan
ASI	Advanced Solar Initiative
BC	British Columbia
BC MOE	British Columbia Ministry of Energy, Mines and Petroleum Resources
BCOAPO	British Columbia Old Age Pensioners' Organization
BCUC	British Columbia Utilities Commission
BETTA	British Electricity Trading Transmission Arrangements
BHE	Bangor Hydro Electric Company
BM	Balancing Mechanism
BST	Bulk Supply Tariff
CAISO	California Independent System Operator
Capex	Capital Expenditures
CARB	California Air Resources Board
CCAs	Community Choice Aggregators
CCS	Carbon capture and storage

CEC	California Energy Commission
CEGB	Central Electricity Generating Board
CfD	Contracts for Difference
CHP	Combined Heat and Power
CL&P	Connecticut Light & Power
CMA	Competition and Market Authority
CMP	Central Maine Power Company
CONE	Cost of New Entry
COS	Cost of Service
CPCFA	California Power and Conservation Financing Authority
CPCN	Certificate of Public Convenience and Need
CPI	Consumer Price Index
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CSO	Capacity supply obligation
DECC	Department of Energy and Climate Change
DMM	Department of Market Monitoring
DNO	Distribution Network Operators
DoE	US Department of Energy
DPCR5	5th Generation Distribution Price Control Review
DUKES	Digest of UK Energy Statistics
EAF	Energy Availability Factor
EC	European Council
ECCR	Environmental Compliance Cost Recovery
EDF	Électricité de France
EFC	Electric Finance Corporation
EFORp	Peak Equivalent Forced Outage Rate
EGU	Electric generating units
EIM	Energy Imbalance Market

ELEX	Pacific Power Internal Pool Market
EMC	Electric Membership Corporations
EMR	Electricity Market Reform
EP Act	Energy Policy Act
EPA	Environmental Protection Agency
ESM	Earning Sharing Mechanism
ESP	Electric Service Provider
EU	European Union
EUB	Electric Utility Board
FCA	Forward Capacity Auction
FCM	Forward Capacity Mechanism
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
FOR	Forced Outage Rates
FPA	Federal Power Act
FPN	Final Physical Notification
FRC	Full Retail Contestability
FTR	Financial Transmission Rights
GA	Global Adjustment
GAAP	Generally Accepted Accounting Principles
GEA	Green Energy Act
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gas
GPC	Georgia Power Company
GRCs	General Rate Cases
HOEP	Hourly Ontario Electricity Price
I Factor	Inflation Factor
ICAP	Installed Capacity
ICM	Incremental Capital Mechanism

ICR	Installed Capacity Requirement
IR	Incentive Rate-setting
IESO	Independent Electricity System Operator
IMM	Internal Market Monitor
IMO	Independent Market Operator
IOU	Investor-owned Utilities
IPART	Independent Pricing and Regulatory Tribunal of NSW
IPP	Independent Power Producer
IQI	Information Quality Scheme
IRM	Incentive Rate Mechanism
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
ITS	Integrated Transmission System
I-X	Composite Price Index - Productivity Factor
K Factor	Capital Expenditure Factor
LDC	Local Distribution Company
LICAP	Locational Installed Capacity
LMP	Locational Marginal Pricing
LNS	Local Network Service
LOLE	Loss of Load Evaluation
LSE	Load Servicing Entity
LSR	Local Sourcing Requirement
LTEP	Long-Term Energy Plan
LTPP	Long-term Procurement Plan
MACD	Market Assessment and Compliance Division
MAU	Market Assessment Unit
MCL	Maximum Capacity Limit
MD02	California Market Design 2002

MDC	Market Design Committee
MEAG	Municipal Electric Authority of Georgia
MEU	Municipal Electric Utilities
MPUC	Maine Public Utilities Commission
MRTU	Market Redesign and Technology Upgrade
MSP	Market Surveillance Panel
NBSO	New Brunswick System Operator
NCCR	Nuclear Construction Cost Recovery
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NGET	National Grid Electricity Transmission
NHPUC	New Hampshire Public Utilities Commission
NMISA	Northern Maine Independent System Administrator
NPCC	Northeast Power Coordinating Council
NPP	Northwest Power Pool
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
NSPI	Nova Scotia Power Inc.
NSW	New South Wales
NYISO	New York Independent System Operator
O&M	Operating and Maintenance
OATT	Open Assess Transmission Tariff
OBCA	Ontario Business Corporations Act

OEB	Ontario Energy Board
OFFER	Office of Electricity Regulation
Ofgem	Office of Gas and Electricity Markets
OPA	Ontario Power Authority
OPC	Oglethorpe Power Corporation
OPG	Ontario Power Generation
OTC	Over the Counter
PBR	Performance-Based Ratemaking
PCC	Power Control Center
Peak	Peak Reliability
PEI	Prince Edward Island
PES	Public Electricity Suppliers
PG&E	Pacific Gas and Electric Company
PI	Performance Incentive
PIAS	Public Interest Advocacy Staff
PIF	Productivity Improvement Factor
POUs	Publicly Owned Utilities
PPA	Power Purchase Agreement
PSC	Public Service Commission
PSNH	Public Service of New Hampshire
PURA	Public Utilities Regulatory Authority (Connecticut)
PURPA	Public Utility Regulatory Policies Act
PUSH	Peaking Unit Safe Harbor
Q Factor	Service Quality Factor
Q factor	Service Quality Factor
QUA	Qualified Upgrade Awards
RA	Resource Adequacy
RCPF	Reserve Constraint Penalty Factor
REC	Regional Electricity Companies (UK)

REC	Renewable Energy Certificate
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIIO	Revenue = Incentives + Innovation + Outputs
RIIO-ED1	RIIO 1st Generation for Electricity Distribution
RIIO-T1	RIIO 1st Generation for Transmission
RMR	Reliability-Must-Run
RNS	Regional Network Service
RO	Renewables Obligation
ROC	Renewable Obligation Certificate
ROE	Return on Equity
RORE	Return on Regulatory Equity
RPI	Retail Price Index
RPP	Regulated Price Plan
RPS	Renewable Portfolio Standards
RRFE	Renewed Regulatory Framework for Electricity
RRO	Regulated Rate Option
RRP	Regulated Price Plan
RTO	Regional Transmission Organization
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SE	Stakeholder Engagement
SERC	Southeast Reliability Corporation
SHETL	Scottish Hydro Electric Transmission Limited
SM	Sharing Mechanism
SMP	System Marginal Price
SPTL	Scottish Power Transmission Limited
SSE	Scottish and Southern Energy

SSEB	Scotland Electricity Board
T&SO	Transmission and System Operator
TCC	Transmission Control Center
TFP	Total Factor Productivity
TMNSR	Ten minute non-spinning reserve
TMOR	Thirty minute operating reserve
TO	Transmission Owners
TSO	Transmission System Operator
TVA	Tennessee Valley Authority
UI	United Illuminating
UK	United Kingdom
VOLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WKP	West Kootenay Power
X Factor	Productivity factor
Z factor	Exogenous Factor