Literature review: regulatory economics and performance-based ratemaking

prepared for the Department of Energy of Nova Scotia by London Economics International LLC ("LEI")

The literature review report covers four key areas: (i) Global experience related to the electricity sector restructuring and liberalization, (ii) Performance-based regulation ("PBR") – including discussion of various structures of PBR implemented globally and associated challenges, (iii) Performance and Accountability discussing performance standard measures used in the generation, transmission, and distribution sectors, and (iv) Customer and Service Provider Risks discussing various risks and how these may be impacted or mitigated through the energy market and regulatory structures. Each section presents a review of literature consulted (see bibliography for works consulted in Section 8) and examples from a variety of jurisdictions (both North American and global), culminating with best practices and key conclusions.

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Glossary

Benchmarking: methodological approach through which a firm's performance results are measured and compared either to the firm's own historical performance or to suitable comparators

Building blocks approach: framework where revenue requirements are "built up" based on the utilities' future estimated efficient costs and return of and return on an efficient asset base

Competition: arises whenever two or more parties strive for something that all cannot obtain

Competitive market: a market in which there is a sufficient number of buyers and sellers so that no single market participant has the ability to influence the price of the good or service

Cost-of-service ("COS") ratemaking regime: traditional form of utility regulation under which rates approved by regulators are directly linked to underlying costs

Deregulation: process of removing or reducing regulations, usually implemented to allow competition within the industry as an alternative means of controlling costs

Distribution: transfer of electricity over medium- and low-voltage lines to end-use customers

Divestiture: process of integrated utility selling assets as part of the restructuring process

Earnings sharing mechanism: mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers

I factor (inflation factor): annual adjustment to the utility's revenue or rates reflecting the level of inflation, as determined through a specified index, generally taking into account the actual inflation rate in the previous year

Incentive targets: targets set relative to service standards and efficiency gains, leading to rewards (penalties) for reaching (falling short of) those targets

K factor (capital factor): annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) or growth in customers

Liberalization: practice of introducing increasing levels of competition in the electricity sector and of improving incentives in segments where competition may not yet be practical

Open access: ability of third parties to use transmission to freely contract between eligible buyers and sellers of electricity in a manner that is non-discriminatory by the transmission service provider

Performance-based ratemaking ("PBR"): form of utility regulation which, by delinking changes in rates and costs, aims to strengthen the financial incentive to lower costs; usually also contains other targets to enhance non-price performance. Softer forms of PBR may also include blended cost of service models

Price cap: mechanism under which the rates charged by a utility are allowed to increase following a formulae consisting of several factors such as inflation, productivity, quality performance, etc.

Privatization: sale of government-owned generation, transmission, or distribution assets to private investors

Q factor (service quality factor): contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality as well as reliability and quality of supply

Regulatory period: time lag between two major reviews of the underlying components of the ratemaking regime; for PBR, the regulatory period follows a fixed pattern

Regulatory review/off-ramp: mechanism that allows, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime

Revenue cap: mechanism under which the revenues earned by a utility are allowed to increase following a formulae consisting of several factors such as inflation, productivity, quality performance, etc.

Restructuring: developing new companies/regimes in an industry sector by either splitting some functions or combining others; changing existing companies

Retail competition: the environment where different energy providers (retailers) can compete in the electricity market to sell residential, commercial, or industrial end use customers power at unregulated rates

Retailer: a company that sells electricity to end-use customers

RPI-X or CPI-X: form of either price or revenue cap regulation, using an inflation factor, such as the retail price index ("RPI") or the consumer price index ("CPI") minus a productivity factor ("X")

Stretch factor: mechanism to adjust the utility's revenue or rates each year to reflect firm-specific expected productivity gains in comparison to the gains expected for the industry as a whole. A percentage amount is added to or subtracted from the X factor

Transmission: transport of electricity from generators to local distribution networks through high voltage lines

True-up mechanism: provides for the possibility to review specific cost components under a COS regime, while the general ratemaking regime in place is PBR

Vertical integration: provision of generation, transmission, and distribution by a single entity

Wholesale market: market that enables trades between eligible bulk power purchasers and retail sellers of electricity

X factor (productivity improvement factor): annual adjustment to revenue or rates reflecting expected changes in terms of productivity; can be based on the utility's historical performance or on an external benchmark and may include a firm-specific target, or stretch factor

Yardstick competition: methodology for comparing utilities against either a hypothetical or an actual "efficient" firm

Z factor: contingent adjustment to revenues or rates in order to recover extraordinary costs that are outside of the company's reasonable ability to control

1 Executive Summary

While a review of electricity sector restructuring related literature indicates that there may not be a single package solution applicable to every jurisdiction, there are elements of reforms that are likely to work across jurisdictions (such as creating multiple number of generators if minimum efficient scale considerations allow, open access in transmission, transitional contracting mechanisms to manage volatility, well-designed performance-based/incentive ratemaking regime, minimal political intervention etc.). The review also shows that there are unique merits and challenges of various market design structures, including total cost of service ("COS"), performance-based ratemaking ("PBR"), and shifting to competitive wholesale generation markets. While COS regimes assure a guaranteed return to catalyze necessary investments, incentives to achieve efficiencies are lacking. By contrast, although wholesale competition and PBR regimes have incentives to reduce operating costs and improve efficiencies, timeliness of investments may be at stake.

We have analyzed the literature in four areas: global experience with electricity sector liberalization, PBR, performance and accountability, and customer and service provider risks. Below, we highlight some key points associated with each aspect.

Global experience with electricity sector liberalization: The electricity sector was historically organized as vertically integrated utilities and regulated under rate of return arrangements. Advances in generation technology and a propensity for over-capitalization by the utilities have prompted reforms with the goal of separating generation and retail supply as competitive markets from the regulated monopoly businesses of electricity transmission and distribution. Global experience with restructuring and liberalization of electricity markets indicates that liberalization is a process that evolves as issues arise, and transitional mechanisms to mitigate the potential initial price volatility are a critical component of the liberalization process. While multiple players in generation sector create efficient competition that ensures market sustainability, predictability of changes (by avoiding inconsistent policies that result in disruptive changes) is vital. Overall, success of electricity sector reforms and restructuring should not be judged solely by electricity price impact (unless it is the only objective), but instead by assessing level of achievement of goals/objectives that need to be laid out before implementation of reforms. In most cases, the three key objectives of restructuring are: improving efficiency and reducing prices, continuing to provide a reasonable opportunity for utilities to earn a reasonable return on investment, and providing reliable services to customers.

Performance-based ratemaking: For the aspects of the electricity value chain not conducive to competition, PBR is a regulatory approach that aims to provide incentives for regulated utilities to improve efficiency. The PBR approach has several potential advantages over a COS approach. Application of PBR is anticipated to motivate larger efficiency improvements among utilities than traditional COS. It is also expected to create lower rates for customers than a COS regime in the long run and also bring commercial success to those utilities where management is willing to strive for and exceed industry expectations on productivity. Furthermore, PBR can reduce the regulatory burden on both utilities and regulators by decreasing the need for frequent regulatory hearings. PBR is best conceptualized as a continuum, ranging from "soft" to "hard" mechanisms. Key success factors in PBR implementation include the PBR design's adaptability to changing environment, the provision of incentives to encourage cost efficiency and quality of service, having a clearly defined and efficient planning process for network investments, and a framework that supports funding of capital expenditure through rates.

Performance and accountability: There are different performance standard measures used in the generation, transmission, and distribution sectors; sector liberalization may strengthen, rather than undermine, these standards. Generation is most strongly incentivized by the energy market itself, because failure to run when needed means a loss of revenue. Common metrics used in the generation sector include availability and reliability metrics in terms of outages (such as forced outage rates, scheduled outage and service factors, unit capability and unplanned capability loss factors). In addition, North American regulators track generation performance for annual publication. In the wires sector, performance is measured in terms of the frequency and duration of outages, as well as by customer service in the distribution sector. A key feature of PBR is greater definition of performance expectations for utilities, so as to guide how maintenance should be targeted. For this reason, many regulators require regular reporting of outage information. This forms the basis of nonfinancial penalties. Other regulators also offer financial incentives in terms of either fines or, less commonly, rewards for reaching or surpassing pre-set performance standard targets.

Customer and service provider risks: For consumers, the highest magnitude risks include underinvestment, reliability issues associated with new technologies, and imprudent capital investments. Risks to consumers with lower magnitude, though arguably higher probability, include unsatisfactory service quality, poor customer service, fuel price increases, and environmental attribute requirements. Generally, consumers of unbundled utilities are less exposed to price and service quality risks, while consumers of vertically integrated utilities are better able to deal with reliability risks.

For utilities, high magnitude risks include insufficient recovery of stranded costs, inability to recoup extraordinary costs, and inability to recoup capital expenditure. Risks of lower magnitude but with arguably higher probability include insufficient productivity increases, lower load due to overall economy/conservation, and fuel price increases for power generation. These risks are greatest for utilities under performance-based ratemaking regimes; generally, utilities under cost of service are more able to shield themselves from these risks.

Finally, we explore risk factors related to setting a reasonable rate of return for utilities. In a cost of service regime, risks for the utility exist around the regulator setting an incorrect rate of return that doesn't reflect the true cost of capital; this in turn constrains the long term ability of the company to invest. However, in a deregulated market, customers face the risk that efficiencies gained through competition are not high enough to offset the higher return required for Independent Power Producers ("IPPs") to invest. A typical unregulated independent power producer may take on additional risk as compared to a regulated vertically integrated utility, which requires additional compensation.

2 Global experience with electricity sector liberalization

The term "liberalization", instead of "deregulation", best describes the practice of introducing competition at various points along the electricity sector value chain, and of improving the incentives compatibility of ratemaking in the case of those segments where competition is not yet practicable. While liberalization of the electricity sector provides stakeholders with a greater array of choices regarding how they produce, transmit, sell, and consume electricity, it does not mean the elimination of regulation. Instead, it requires the reshaping of regulatory regimes. For competitive segments, this process involves "writing the rules of the game" and creating "referees" who are able to identify, fairly try, and if proven penalize, inappropriate behavior.

For segments of the electricity value chain which remain regulated, liberalization is about refocusing regulation – in this case, on outputs rather than inputs. While moving from traditional cost of service ("COS") regulation frees utilities to think more about efficiencies and less about the minutiae of tracking individual costs, performance-based ratemaking ("PBR") often requires creation of new a new regulatory framework.

LEI conducted a literature review related to electricity sector restructuring and liberalization, issues surrounding the market design, challenges of implementation, various forms of regulation, and market organization.

The experience to date with restructuring and liberalization of electricity markets suggests that:

- **Liberalization** is a process that **evolves as issues arise**, and not an end in of itself;
- **Transitional mechanisms** to mitigate the potential initial price volatility **are a critical component** of the liberalization process;
- Existence of **multiple players in generation sector creates efficient competition** that benefits end users and ensures sustainability of the market; and
- **Predictability of changes is important** - it may be argued that sustained sub-optimal policy may sometimes be better than inconsistent policy that results in disruptive changes.

We note a number of key observations:

- Planning processes are an important component of the liberalization and restructuring efforts (forward looking capability by an entity with clearly defined responsibilities to see what is potentially needed to maintain the system reliability and adequacy);
- Market designers need to be pragmatic and recognize that there will be transitional costs. Theoretical perfection may not be an appropriate goal in practice depending on system size and costs of administration;

- Liberalized markets provide price signals that are more relevant to when an issue arises (COS causes a temporal disconnect between when the price signal occurred and when the underlying causes were evident);
- An increase in electricity prices and transmission/distribution costs, if it occurs, should not be viewed as solely the result of liberalization (input costs may increase independent of the market organization and regulatory regime; and prices for some customers may increase due to reasons such as elimination of cross-subsidies);
- Considering demand response from the beginning of the market design process helps address the issue of demand inelasticity;
- Large scale integration of intermittent resources may challenge energy-only market structures; and
- Location-based marginal prices may provide the best reflection of the true cost of supplying energy, but at the cost of additional complexity to the market design and operations.

Sections that follow discuss the experience of restructuring the electricity sector across the selected jurisdictions, including the rationale and motivation for restructuring, steps that were taken to achieve the liberalized status of the industry, as well as cases where restructuring has stalled or was reversed.

Jurisdictions covered: We have examined the experience of jurisdictions that were among the first to implement electricity sector restructuring and have gone through a complete process (although in some jurisdictions the process has evolved), including UK, Australia, Alberta, California and Norway. Additionally we touch upon features of restructuring efforts of some other jurisdictions that have implemented some of the aspects of the restructuring menu, but have not fully completed the process (e.g. continuing with COS regulation of wires networks, maintaining public ownership of generation assets, no retail competition allowed, etc.) – these include many of the states in the US and Ontario. In a separate deliverable by LEI (forthcoming), detailed case studies for specific jurisdictions will be presented.

Figure 1. Comparison of electricity statistics of selected jurisdictions

Jurisdiction	State of Restructuring	Installed Capacity (MW, 2013)	Peak Demand (MW, 2013)	Area (km^2)	Population (2012)	Population density (2012, ppl/km^2)
Alberta	Functional unbundling	14,568	11,139	661,848	4,000,000	6
Australia	Full unbundling	46,385	32,538	7,692,024	22,680,000	3
California	Restructuring stalled	50,177	45,097	423,970	38,040,000	90
New York	Restructuring stalled	37,922	33,956	141,300	19,570,000	138
Norway	Full unbundling	32,460	24,180	385,199	5,019,000	13
Nova Scotia	Restructuring efforts underway	2,730	2,033	55,283	948,700	17
Ontario	Full unbundling	34,946	24,927	1,076,395	13,510,000	13
United Kingdom	Full unbundling	89,200 (2012)	56,800 (2012)	243,610	63,230,000	260

Sources: Energy Information Administration, US Department of Energy; Australian Energy Regulator; Alberta Electricity System Operator; Independent Electricity System Operator (Ontario); California Independent System Operator; Norwegian Water Resources and Energy Directorate; National Grid PLC (UK); Statnett; New York Independent System Operator.

Restructuring efforts undertaken in Nova Scotia:

- In 1992, the Nova Scotia Power Privatization Act privatized the crown corporation, Nova Scotia Power, and created Nova Scotia Power, Incorporated ("NSPI").
- Nova Scotia Electricity Act passed in 2004 opened the power sector to wholesale competition, in that it allowed municipal utilities to purchase power from generators other than NSPI.
- To support open access for wholesale generators, the Nova Scotia Power System Operator ("NSPSO") is a functionally unbundled segment of NSPI, and operates the Open Access Same time Information System ("OASIS").
- The Electricity Reform Act passed in 2013 allows licenced generators to sell renewable power generated within the province directly to retail customers.
- Nova Scotia passed an energy efficiency legislation in April 2014, which removes the efficiency tax from electricity bills effective January 1, 2015, and introduces competition for Nova Scotia Power, requiring it to purchase cost effective, reasonably available energy efficiency from Efficiency Nova Scotia, a firm independent of Nova Scotia Power.

2.1 Rationale for moving from a vertically-integrated structure to a deregulated/liberalized structure

The motivation to liberalize the electricity sector can be triggered by different events. Such events may include, but are not limited to, significant increases in the price of supplied electricity[1] (US states, e.g. New York, Massachusetts, California), a revision of views of the role of the state (United Kingdom), and mismanagement of important functions (e.g. nuclear operations of Ontario Hydro).[2]

Under traditional COS (or rate of return) regulation of monopolies, firms tend to invest more than would be consistent with long run cost minimization. Such investments, while increasing profitability, may result in non-productive or less-productive capital allocations leading to mismanagement and increasing costs to final consumers. This phenomenon was first discussed by Harvey Averch and Leland Johnson, and is now known as Averch-Johnson effect.[3]

The objectives of restructuring focus on three main areas:

- **Improving efficiency and arriving at lower prices** than they would have been otherwise. Creation of a competitive market place for wholesale electricity (generators) and retail services (suppliers) has the objective of improving efficiency and reducing the end-user

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[1] S. Borenstein and J. Bushnell. Electricity Restructuring: Deregulation or Reregulation? *Regulation Magazine, The Cato Review of Business and Government*. Volume 23, No. 2. 2000

[2] Ontario Ministry of Energy, Science and Technology. *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario*. Toronto, Ontario. 1997

[3] Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review* 52 (5): 1052–1069. JSTOR 1812181

costs. PBR of monopoly businesses at wires level (distribution and transmission) mimics competitive pressures of an open marketplace and contributes to reducing the end-user costs by constraining the price increases of distribution and transmission services.

- **Providing reasonable opportunity to earn a return on investment.** Earning a return on investment ensures that the companies are financially sustainable and able to meet their financial and operational obligations. The companies are able to earn a return on their investments via competitive markets (generation and retail services) or as regulated monopolies (transmission and distribution networks).

- **Providing reliable services** to customers. The above two objectives need to be balanced with a third objective of ensuring the provision of reliable services to customers through reliability standards, often including reliability and customer service performance standards and incentive schemes.

Electricity is often treated as a special commodity that warrants distinct treatment due to its non-storable properties, being an essential social service that affects all the spheres of the economy and society.* Lack of real time price information and storage contribute to a vertical demand curve where sellers can command market power. In addition, the electric utility industry requires significant amounts of capital investment.

It was formerly thought that most aspects of the electricity sector value chain were natural monopolies, such that their average costs continue to decline indefinitely as throughput increases. Because each additional unit sold enables the next to be sold more cheaply, competitors face the prospect of losing significant amounts of money to match the price of an incumbent, implying few, if any, attempt to enter. Therefore, the electric utilities operated under a "regulatory compact" whereby utilities have an "obligation to serve"; in return, they are entitled to "just and reasonable" rates.

These views have evolved. Energy to produce electricity can be stored, albeit at great cost, and inelasticity of demand for electricity is the result of consumers not being exposed to full time differentiated costs, which can be addressed. At the same time advances in technology (information technology and telecommunications, engineering and greater understanding of materials science leading to more advanced and efficient designs of power plants) have lowered entry costs**,*** and allowed real-time trading of wholesale electricity and more efficient utilization of the electricity grid.

* M. Kopsakangas-Savolainen and R. Svento. *Modern Energy Markets*, Green Energy and Technology, DOI, Springer-Verlag, London, 2012 (Chapter 2)

** Joskow, P.L., Restructuring, competition and regulatory reform in the US electric sector. *Journal of Economic Perspective* 11 (3), 119-138, 1997

*** Newbery, D.M., *Privatization, Restructuring and Regulation of Network Utilities*. MIT, Cambridge, MA, 1999

Various jurisdictions have had different objectives for restructuring their electricity sector. In the case of the **United States**, the process was driven by federal and state regulators ***responding to relative prices with neighboring regions***. In the **United Kingdom** the restructuring efforts were driven by ***broader political objectives to restructure the wider economy and improve efficiency*** by privatizing utility services, including telecommunications and electricity sectors. **Norway**'s consideration in restructuring the electricity sector was to ***meet environmental goals by reducing excess capacity***;[4,5] lowering prices was not the goal of Norwegian restructuring efforts and the government expected and encouraged higher prices.[6]

While the objectives of liberalization and restructuring are clear, the design and implementation of the reforms have been challenging in many jurisdictions that undertook them. There are several aspects where the restructuring process can go awry, exposing problems and issues that may not always be anticipated or, as often the case may be, require solutions that involve substantial compromise.

2.2 Key success factors and barriers to success for restructuring/deregulation

Several challenges of successful restructuring are related to the unique characteristics of electricity (e.g. lack of efficient storing technologies and need for instantaneous balancing of supply and demand) that made the experience gained from restructuring other industries (natural gas, airlines, telecommunications) of tangential value.[7]

The structure and method of organization of the downstream value chain (transmission, distribution and retail supply) impact the operations and outcomes of the generation market.

- The presence of multiple players in the generation sector can be of consequence only if the transmission system allows for contestability of all load on the system;
- Transmission constraints that create load pockets also create market power for local generation;* and
- Access to distribution systems by retail suppliers is only meaningful if the ultimate consumers are not shielded from the market forces by regulated price plans* (e.g. standard offer service, default service).

The last point is an example of political considerations that often guide the decisions that may ultimately undermine restructuring efforts.

* 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

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[4] Bye, T. and E. Hope. "Deregulation of Electricity Markets – The Norwegian Experience," *Discussion Paper No. 433*, Statistics Norway. September 2005

[5] M. Kopsakangas-Savolainen and R. Svento. *Modern Energy Markets*, Green Energy and Technology, DOI, Springer-Verlag, London, 2012 (Chapter 2)

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

[7] S. Borenstein and J. Bushnell. Electricity Restructuring: Deregulation or Reregulation? *Regulation Magazine, The Cato Review of Business and Government*. Volume 23, No. 2. 2000

For instance, ***competitiveness in the generation sector is probably the single most important factor that will either lead to success or undermine the restructuring efforts downstream***.

'Success' of restructuring is based on factors that are important determinants of private sector involvement, such as the ***longevity*** of the restructured market design, ***low frequency of the intervention*** that result on major changes of the course, evidence of ***efficiency improvement***, and availability and effectiveness of ***hedging instruments***.

Similarly, 'barriers to success' include factors that impede the restructuring process, such as ***lack of due process*** (i.e. failure to subject policy changes to robust analysis), ***insufficient education for stakeholders***, ***overlapping jurisdictional authorities*** (e.g. the roles of California Energy Commission and California Public Utilities Commission), significant ***lack of goodwill among stakeholders*** (particularly when parties have a zero sum mentality). Moreover, ***over-ambitious targets/goals*** may also be a recipe for not achieving success – for instance, a "big bang" approach (implementing all the reforms at the same time without analyzing the impact of individual features and without sufficient time for stakeholders to recognize the new realities) can lead to restructuring challenges (see vignette on California on page 8).

It is important to recognize that electricity sector restructuring and liberalization is a process. It requires careful planning and pragmatic implementation, coupled with the openness to consider and the ability to adjust the approach to account for changing conditions.

While there is no perfect recipe for restructuring, the review of literature and experience to date suggests that there are several key factors that aid the transition process and help to create properly functioning competitive markets and regulated utilities:

- **Commitment to reforms and abstaining from politically expedient changes**: The experience of restructured electricity jurisdictions suggests that a key barrier to success is unwillingness to commit to the reforms and reluctance to expose customers to electricity price volatility.[8] These concerns exhibit themselves through price-protection schemes on the user side (default services at regulated rates) or price caps of the wholesale market on the generator side.

> While the concerns about price volatility are often legitimate, excessive restrictions on the acceptable price outcomes in the wholesale energy market stunt the incentives to invest in new capacity or for customers to hedge.
>
> Such disincentives potentially lead to serious challenges in maintaining system reliability, which have to be addressed either through intervention of the State via reliability contracts (as seen in Ontario, MA, CT, MD, NJ), or through institution of capacity markets (in ISO New England, PJM, and New York ISO).

[8] Joskow, P.L. "Lessons Learnt From Electricity Market Liberalization," *The Energy Journal*. Special Issue. The Future of Electricity: Papers in Honor of David Newbery. 2008

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- **Clear path for the restructuring program with well-defined milestones**: Defining a clear path for reforms with associated milestones allows investors to prepare for the changes in the marketplace. This creates an environment that facilitates investments in new generation capacity during the transition stage, where the market signals may not be fully transparent, or may not be sustained long enough to indicate the opportunity for private sector involvement.

- **Careful planning that includes proper tools to facilitate the transition**: The transition process (a period when stakeholders are starting to familiarize themselves with the new marketplace realities and new mechanisms and relationships are being established) is a critical stage in the restructuring process. The availability of transitional mechanisms is an important factor in ensuring the smooth and gradual change in the market dynamics (e.g. vesting contracts in the UK), that mitigate the risks that are difficult or impractical to hedge.

- **Creation of competitive markets that consist of multiple players and minimal regulatory barriers to entry**: Failure to create a competitive market with a sufficient number of players and minimal regulatory barriers to new entry is equally important for both generation and retail supply markets. This has been the experience in the UK and Ontario in the initial stages of the market evolution of the generation sector and in many states in the US on the retail side.

- **Availability of hedging instruments**: A wholesale market without the availability of proper hedging instruments is likely to test the stability of the market in the event of exogenous events (e.g. severe drought precipitated the California crisis). Hedging instruments should provide opportunity for sellers and buyers to limit their exposure to price volatility and help stabilize the prices when the market is experiencing extreme events (for example, during extreme cold or hot temperatures and transmission and power failures).

Defining success or failure of the electricity sector reforms and restructuring solely based on electricity price impact is challenging as it is necessary to isolate factors that result in different outcomes. For instance, changes in the cost of inputs (fuel, environmental attributes, capital and labour cost, etc.) are often driven by events independent of the electricity market; electricity prices could have been affected by these events regardless of restructuring.

2.3 Rationale for re-regulation, where deregulation efforts have been reversed

Reversal of restructuring has been driven by different factors (such as poor design choices and political considerations) in different jurisdictions. Generally, the triggers for reversing restructuring efforts have been unanticipated price volatility exacerbated by insufficient hedging capabilities and lack of political fortitude.

To focus on two well-known examples, poor design choices led to the collapse of the Power Exchange in California (see vignette), while political considerations have resulted in the market design changes that partially reversed the restructuring process in Ontario.

2.3.1 California

The infelicitous combination of "scarcity" in key input fundamentals (like a very dry hydrology period) and ill thought out features of the restructuring process (including the lack of contracts and the "must purchase spot" requirement on the California utilities, and rate freeze for retail customers) resulted in a situation of rising spot market prices[9] and an unprecedented divergence of collected revenues and costs for utilities.

In September 2001, the California Public Utilities Commission ("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. In 2008, the CPUC started exploring ways to again lift the freeze on retail rates and provide residential and large customers with competitive rates. However, ***long-term electricity contracts signed in 2001 to end the crisis remain a large impediment to such reform, since state law stipulates that retail competition cannot be implemented before the last of these contracts expires, which is estimated to be between 2015 and 2017***. The CPUC has 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

California Electricity Crisis

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, Pacific Gas and Electric ("PG&E"), the California Power Exchange ("PX"), and a number of small IPPs. The initial price hike was caused by high gas prices, higher environmental costs, high demand, low hydroelectric generating supply, and the lack of new entry. Apart from these factors outside the control of the CPUC, a series of design flaws plagued the final restructuring reform as there were a number of inefficiencies in the institutional framework and the trading arrangements. Furthermore, frozen retail rates and the absence of demand response programs insulated customers from the spot price, which led to the implosion of the system. Utilities with load serving obligations for default customers faced both the frozen retail rates and the volatile (and high priced) spot market prices, which led to the bankruptcy of PG&E and near bankruptcy of Southern California Edison ("SCE").

In addition to more favorable weather conditions, the crisis was halted through four main actions: (i) the state belatedly entered electricity procurement contracts on behalf of utilities, signing long-term contracts worth a total of $43 billion, extending up to 20 years and in effect ending the obligation for utilities to buy from the PX; (ii) wholesale energy prices were capped by FERC throughout the Western Interconnection; (iii) the approval process for new plants was streamlined enabling more capacity to quickly come online; and (iv) California retail rates were raised by an average of 19% for residential customers, which reduced the divergence between revenues and costs for utilities serving those customers. Some commentators believe that the rate hike was also an impetus to reductions in consumption.

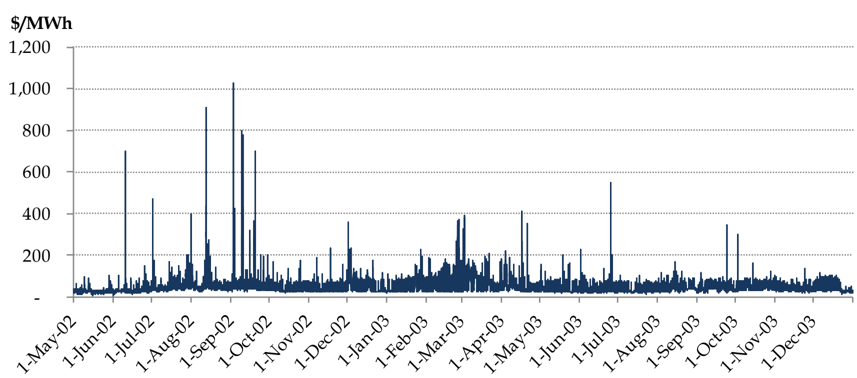
[9] Congressional Budget Office. *Causes and Lessons of the California Electricity Crisis.* September 2001.

incumbent's service territory.[10] For example, San Diego Gas and Electric's allowance for direct access is capped at 3,562 GWh and has been fully subscribed. CPUC required all California utilities to implement a lottery system for entities on the wait list for load that may become available.

2.3.2 Ontario

Shortly after opening in 2002, the wholesale electricity market in Ontario experienced price spikes, which led to freezing of end-user rates and large-scale intervention by the government in the form of a hybrid market structure. This hybrid structure is best described as a modified Single Buyer model, where future expansion of the generating capacity was supported through government mandated electricity contracts. The cost of such contracts was covered by all the users of electricity in the province, via a mechanism called Global Adjustment. The Global Adjustment is also used to finance the power procurement contracts signed with independent power producers prior to the sector restructuring and regulated payments to prescribed assets of Ontario Power Generation (see section 2.6.10 for further discussion).[11]

Figure 2. Hourly energy prices in Ontario (May 1, 2002 to Dec 31, 2003)



Source: Ontario Independent Electricity System Operator ("IESO")

The Ontario electricity market, while often characterized as a "hybrid" market, largely consists of the contracting activities of a principal buyer, the Ontario Power Authority ("OPA"), whose decisions are heavily influenced by the provincial government. While the provincially-owned generator OPG remains the dominant supplier, its role has diminished as the OPA contracted with new entrants. Although OPA contracting decisions are nominally based on the Long-term Energy Plan ("LTEP"), the LTEP has been overridden by provisions of the Green Energy Act ("GEA") and subsequent ministerial directives. The Ministry of Energy frequently issues directives that alter the course of market evolution without apparent public consultations with

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

11 IESO. Global Adjustment. <http://ieso-public.sharepoint.com/Pages/Ontario's-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx> Accessed on April 8, 2014

the IESO, the OPA, or stakeholders. Figure 3 presents a list of ministerial directives to OPA related to procurement.

Figure 3. 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 - launch standard offer programs to procure 50 MW for municipal hydroelectric projects; and 40 MW with non-utility generation facilities and Hydroelectric Contract Initiative contracted facilities
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 OPG for the conversion of Thunder Bay Generating Station ("TBGS")
December 16, 2013	100 percent Biomass - seek new contracts with the owners and operators of the Biomass non-utility generation ("NUG") facilities
December 16, 2013	Moving forward with renewable energy projects (large and those in remote First Nation communities) and energy storage
December 16, 2013	Letter requiring report back – Combined Heat and Power ("CHP")
March 31, 2014	Procuring Energy Storage - procurement of 50 MW of energy storage by the end of 2014
March 31, 2014	CHP – Agricultural Industry and District Heating Projects – develop a new standard offer procurement program to procure 150 MW of 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
March 31, 2014	2015-2020 Conservation First Framework - coordinate, support and fund delivery of CDM programs through distributors to achieve 7 TWh reductions in consumption between January 1, 2015 and December 31, 2020
April 24, 2014	Hydroelectric Projects – transfer 25 MW of unallocated capacity from the Hydroelectric Standard Offer Program (HESOP) to the 2014 hydroelectric procurement target for LRP
April 24, 2014	Industrial Electricity Incentive - establish the Industrial Electricity Incentive ("IEI") program to improve load management and the management of electricity demand

Source: OPA. "Directives to OPA from Minister of Energy." <http://www.powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure>

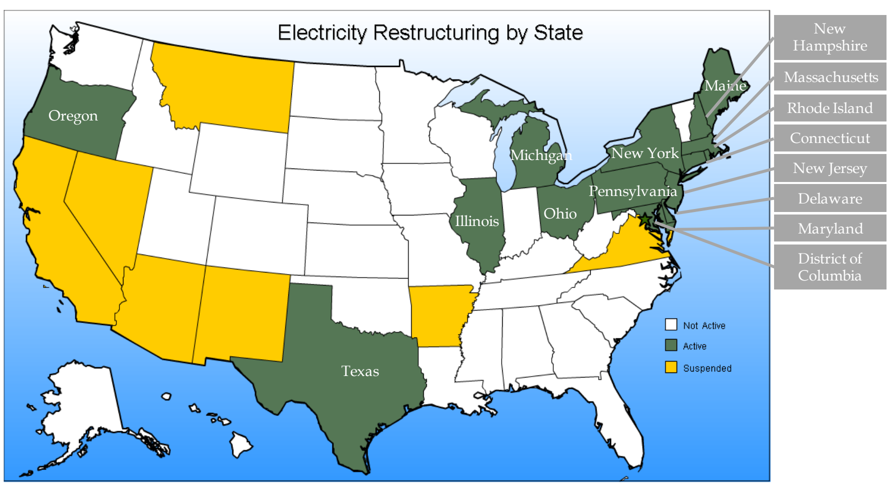
The Ontario IESO is the operator of the grid, coordinates dispatch and transmission flows, and operates spot markets, but repeated government interventions in the power sector have made investors wary about building generation capacity without an OPA contract. The Ontario Energy Board ("OEB") regulates a portion of OPG's generation capacity, but otherwise has limited oversight of generation markets and the OPA.[12]

Appropriate buffers between implementation entities and policymakers have yet to be developed to prevent ministerial directives from interfering with the day to day operation of key power sector institutions without due process.

2.4 Rationale for not deregulating, where deregulation efforts have stalled

Restructuring is a means to an end, not an end unto itself. When examining the electricity sector value chain, policymakers need to ask themselves not only whether restructuring *can* be introduced, but whether it *should* be. As discussed earlier in Section 0, restructuring is intended to provide consumers with the lowest sustainable long term prices, improving efficiencies, providing reliable services and reasonable opportunity for utilities to earn a return on investment. In jurisdictions with reliable service and relatively low rates, it may make sense not to restructure.

Figure 4. Electricity restructuring by state (as of April 2014)



Source: EIA

[12] Under the Ontario Energy Board Act, the OEB can only review OPA's activities related to conservation targets, and payments to and from distributors, retailers, or the IESO under the Province's regulations. OPA is required to assist the OEB by facilitating stability in rates for certain types of customers, and provide information relating to medium and long-term electricity needs, adequacy, and reliability of the power systems. OEB also approves annual fees of the OPA and reviews and approves the Integrated Power System Plan ("IPSP" – predecessor to LTEP) and the procurement process of OPA. Source: Ontario Energy Board website. History of the OEB. <http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Legislation/History+of+the+OEB>

US: The California crisis hit the headlines for several months in 2000 and 2001, and electricity deregulation stalled across the US as fears spread of an identical scenario in other jurisdictions. California's crisis was wrongly linked in the media with the concept of deregulation itself, and had a chilling effect on deregulating efforts in other US states and around the world. Figure 4 summarizes the current status of restructuring efforts at the state level across the US. In 1996, 44 states and the District of Columbia were either discussing the possibility of restructuring or in the process of passing such legislation.[13] However, as of 2006, 34 states had repealed, delayed, or suspended their restructuring efforts (in several cases, the reform was limited to opening retail access for large customers).[14] As of today, only 15 states and the District of Columbia have achieved some level of restructuring of their electricity sector.[15]

Europe: The European Union started the electricity market liberalization process via Electricity Directive EC/1996/92 that came into force in 1997, where the EU required functional unbundling of generation from transmission and at least 33% opening of the market. The Second Electricity Directive EC/2003/54 subsequently replaced the earlier legislation and put in place more explicit regulations, in particular regarding regulators, independence of grid operators and unbundling of distribution operations. The Third Electricity Directive (EC/2009/72) went further and presented ownership unbundling options for adoption at the national level.

While the restructuring process in the EU should not be defined as "stalled", it has nevertheless been slow and is certainly behind the original schedule, hindered by differences in national policies/approaches and challenges of coordination. The degree of restructuring of the electricity markets in the European Union is an ongoing process with some progress made on multiple fronts. However, the latest assessment of the progress notes that not all countries are compliant with the Second Electricity Directive's deadlines for implementation and some countries have already shown resistance to the provisions of the Third Electricity Directive.

For instance, France's state-owned EDF still directly controls most of the generation assets and, through subsidiaries, transmission and distribution networks. In the generation sector, EDF controls 91% of the total capacity and the three largest generators (EDF, GDF-Suez and E.On-France) control 99% of the total capacity.[16] A similar picture is true for the retail supply market, where EDF controls over 90% of the market through its subsidiary. France's slow pace of restructuring its electricity sector is driven by active role of the French state in the economy in general and a desire to maintain a "national champion" in the electricity sector.

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[13] Hickey and Carlson. "An Analysis of Trends in Restructuring of Electricity Markets". *The Electricity Journal.* June 2010, vol. 23, Issue 5. P.49.

[14] Hickey and Carlson. "An Analysis of Trends in Restructuring of Electricity Markets". *The Electricity Journal.* June 2010, vol. 23, Issue 5. P.48.

[15] Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas. EIA web site. *Status of Electricity Restructuring by State.* Accessed April 9, 2014. <http://205.254.135.24/cneaf/electricity/page/restructuring/restructure_elect.html>

[16] EU. *Energy Markets in the European Union in 2011.* 2012

Figure 5. Indicators of electricity market restructuring status for selected EU members

Indicators	UK	France	Germany	Italy	Spain	Netherlands	Poland
Number of companies representing at least 95% of net power generation	19	>5	>450	217	N/A	7	68
Number of main power-generation companies (1)	9	1	4	5	4	5	5
Market share of the largest power-generation company	20.00%	86.50%	28.40%	27.50%	24.00%	N/A	17.00%
Number of electricity retailers	22	177	>1,000	342	202	36	146
Number of main electricity retailers (2)	6	1	3	3	4	3	7
Switching rates (entire electricity retail market)	N/A	2.00%	6.30%	5.90%	7.40%	8.90%	0.05%
Regulated prices for households – electricity	No	Yes	No	No	Yes	No	Yes
Regulated prices for non-households – electricity	No	Yes	No	No	No	No	No
HHI in power-generation market (3)	947	8,880	2,021	1,087	1,361	1,811	1,835
HHI in electricity retail market (3)	1,768	4,000	N/A	1,763	2,543	2,264	2,000
Electricity market value (bn €) (4)	46,824	43,579	88,054	49,501	31,806	13,661	13,565

Note: Appendix B (Section 7) shows status of restructuring across EU member states.
Sources: Eurostat, CEER, National Regulatory Authority, EC calculations.
(1) Companies are considered as 'main' if they produce at least 5% of the national net electricity generation.
(2) Retailers are considered as 'main' if they sell at least 5% of the total national electricity consumption.
(3) The Herfindahl-Hirschman Index ("HHI") is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers (the higher the index, the more concentrated the market). Moderate concentration: 750-1,800; high concentration: 1,800-5,000; very high concentration: above 5,000.
(4) Market value is an estimation of the size of the retail electricity markets. It is calculated using data on electricity consumption in the household and non-household sectors and annual average retail prices.

The following two sections discuss common approaches followed to implement restructuring, and relevant international experience.

2.5 Process to implement restructuring

Electricity sector restructuring requires a comprehensive approach that ensures cohesion across the value chain.

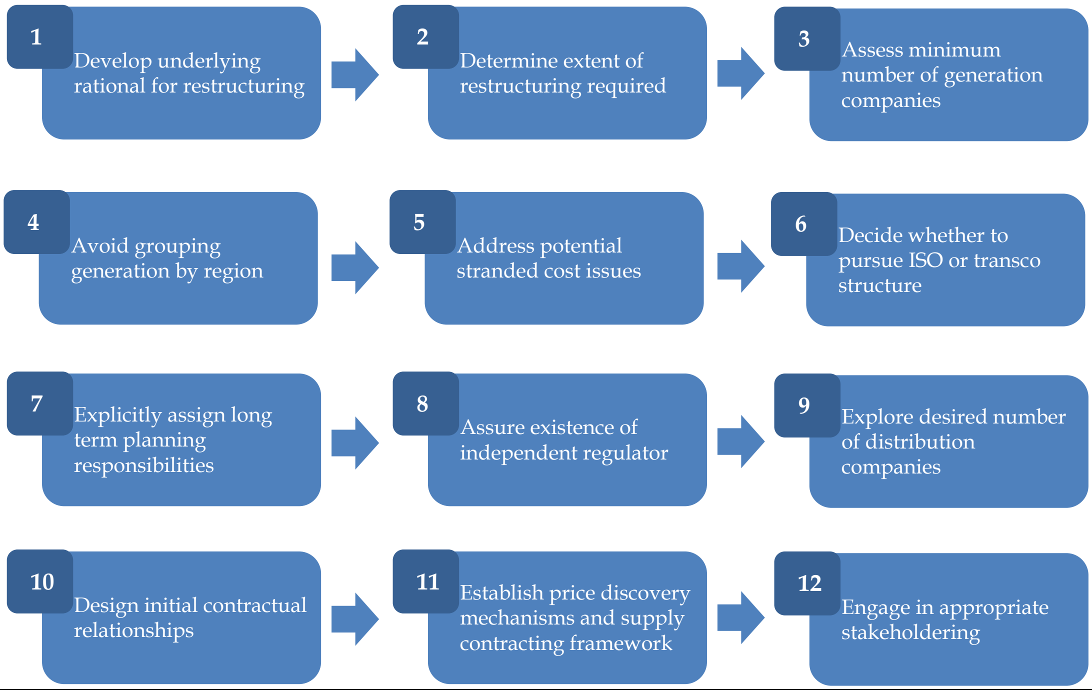
Figure 6 presents a step-by-step process for policymakers considering restructuring, which is elaborated in text below.

1. **Develop underlying rational for restructuring**: As discussed earlier in Section 0, underlying objectives for restructuring can vary from reduction of prices to achieving broader political goals.

2. **Determine extent of restructuring required**: In the case of unbundling a vertically integrated utility, it is important to determine whether the objective is full ownership unbundling, legal unbundling or functional unbundling (as defined later in Section 2.6.2). If some degree of mixed vertical ownership continues, an affiliate code of conduct may also be required.

3. **Determine number of generation companies**: Assessing minimum number of generation companies required to assure competition is necessary.

Figure 6. Step by step process for policymakers considering restructuring



4. **Avoid grouping of generation**: It may be helpful to avoid grouping generation by region, so as to prevent creation of local monopolies.

5. **Address potential stranded cost issues**: It is important to determine stranded costs upfront, converting the amount of the stranded costs to a financial asset on the utility's books, and a plan for recovering from customers over time. The length of the recovery period may be adjusted so as to manage costs on customer bills.

6. **Decide whether to pursue ISO or transco structure**: In the event of continued joint generation and transmission ownership, an ISO is likely required. We discuss various models further in Section 2.6.3.

7. **Long-term planning**: There is a need to explicitly assign long term planning responsibilities to appropriate entity.

8. **Independent regulation**: For both competitive and monopoly aspects of business, it is essential to assure that an independent regulator exists.

9. **Determine number of distribution companies**: In contrast to generation, regional grouping may be desirable for distribution.

10. **Contracts:** Designing initial contractual relationships between generators and distribution companies will assist in providing revenue and supply price stability for each, thereby smoothing transitional period.

11. **Price discovery**: Establishing price discovery mechanisms and supply contracting framework for the period following transition is important.

12. **Stakeholdering**: Engaging in an appropriate stakeholdering process prior to issuing final restructuring plan will minimize issues going forward.

Finally, policy makers need to identify appropriate timing and criteria for periodic review of restructuring outcomes. This also assists in proposing methods for improving the framework going forward.

2.6 Characteristics of various restructured models after reform implementation

Policy-makers and regulators face a range of options covering the main features of the regulatory regime and electricity sector organization. These choices dictate the restructuring models and their characteristics after reform implementation. The key features are listed below and discussed briefly thereafter.

- Regulatory framework;
- Form of unbundling (functional, legal, or ownership);
- Scope of unbundling (whether it only covers generation or retail as well);
- Size of largest player on the generation/retail markets;
- Share of government-owned versus investors-owned assets;
- Market model (energy/capacity, day-ahead/real-time, etc.);
- Transfer of grid operations to an independent system operator;
- Planning process;
- Process to maintain reliability of supply in case of extreme event;
- Treatment of stranded assets;
- Treatment of strategic assets; and
- Existence of a default customer program at the retail level.

2.6.1 Regulatory framework

The regulatory framework refers to rule-making activity of the government or its regulatory agencies. Government agencies involved in regulatory process include a range of institutions, such as those tasked with policy-making responsibility (e.g. ministries or departments), creating and enforcing rules for implementation of the policies (e.g. regulatory bodies) and may also include other government agencies responsible for different tasks (e.g. power authorities to actively manage the sector development).

There are two dimensions that may need to be considered when settling the regulatory framework: ***what are the specific roles and responsibilities of the institutions***; and ***how will***

these institutions function? When answering these two questions, the overarching objective of the regulatory framework is to ensure that the potential benefits outweigh associated costs of regulation.

The first issue regarding the role of institutions needs to be addressed in a fashion that results in clear delineation of the responsibilities and duties of involved institutions, ensuring that there are no overlaps of or gaps in the regulatory oversight. There are examples of institutions with overlapping responsibilities that have resulted in unintended consequences. For example, in the run-up to the California electricity market collapse, its power sector was subject to regulation and oversight by a multitude of bodies: Federal Energy Regulatory Commission ("FERC"): federal authority in charge of wholesale energy trade, including oversight of competition practices; CPUC: main regulatory body overseeing the utilities and independent power producers; California Energy Commission ("CEC"): long-term planning, licensing and permitting of power plants; California Independent System Operator ("CAISO"): operator of the transmission grid; and California PX: wholesale energy trading entity.

As a remedy to solve the energy crisis, California added power procurement responsibilities 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, it was shut after 3 years, without building a power plant or buying transmission assets. California continues to suffer from a plethora of state entities with overlapping mandates in the power sector.

Delineation of responsibilities also aids in creating goodwill among the stakeholders and agencies involved in the regulatory and planning processes, which in turn promotes congruency and coherence of policies and regulations. For example, on a state level CEC and CPUC are considered historically hostile agencies, and on a federal level, FERC's jurisdiction over the financial products traded on wholesale competitive markets for electricity puts FERC at odds with US Commodity Futures Trading Commission ("CFTC").[17]

Independence of regulatory bodies is a universally acknowledged pre-requisite to successful regulatory framework. Such independence can be achieved with fixed-term appointments of, for example, commissioners, where the appointments' cycle does not coincide with the elections' cycle. For instance, the grounds for dismissal of commissioners should be limited to health (physical and mental) and criminality, and not tied to political affiliations.

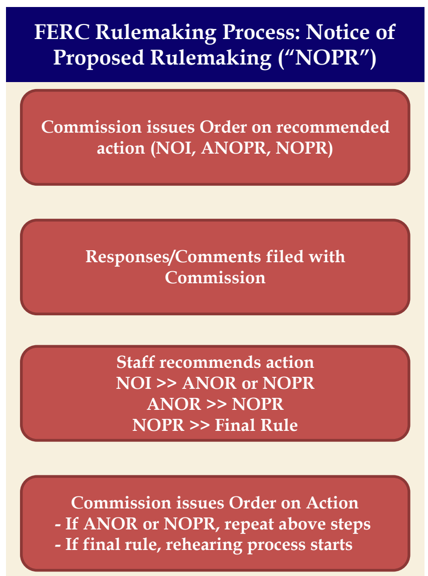
The second dimension of the regulatory framework design is related to how the regulatory analysis and deliberations are conducted. The US is a good example of the consultative approach to any changes in the rules or policies, where all stakeholders have the opportunity to view evidence and express their views. The consultative process to reach decisions on policy

[17] In early 2014, FERC and CFTC have signed two Memoranda of Understanding to address circumstances of overlapping jurisdiction and to share information in connection with market surveillance and investigations into potential market manipulation, fraud or abuse. See CFTC Press Release <http://www.cftc.gov/PressRoom/PressReleases/pr6816-14> January 2, 2014.

changes and rules of implementation include multiple stages and relatively lengthy processes, which produces outcomes that under most circumstances are a compromise that meet the needs of various stakeholders.

Best practice for rule changes in a regulatory setting usually involve a draft, comment, revise and issue approach, with final rule change subject to appeal. Mid-period rule changes are generally ill advised, and regulator should only initiate such proceedings on stakeholder request and only in limited cases. Moreover, all rule changes should be subject to comment period, and as such, rapid changes are almost always detrimental. Political factors however sometimes override a regulator's ability to act independently.

Figure 7. FERC NOPR process

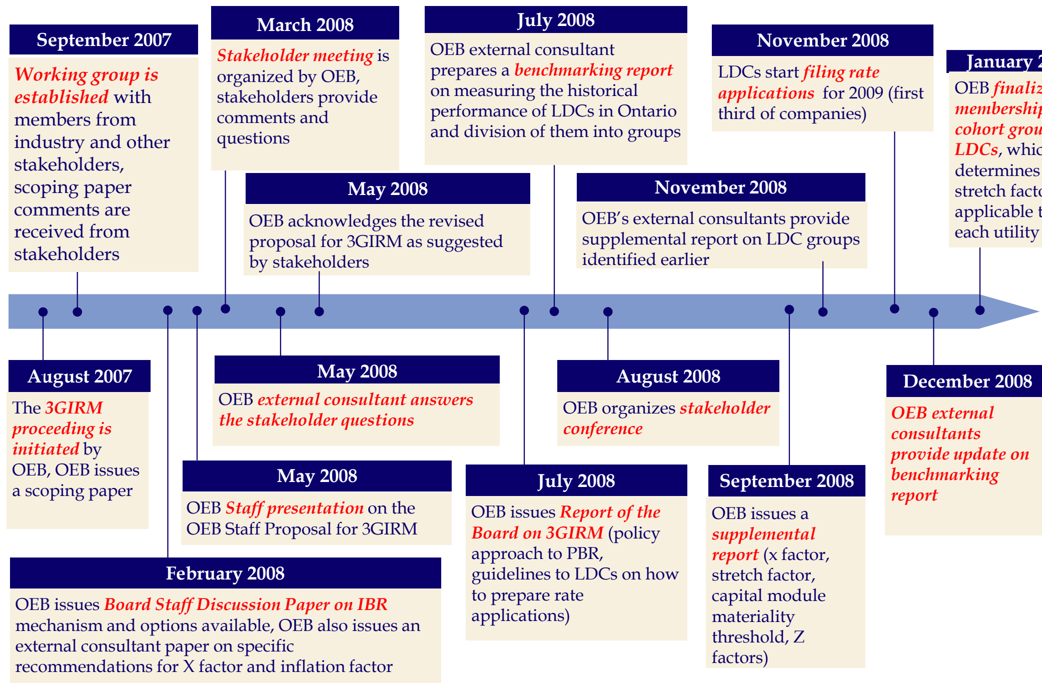


Notes: NOI = Notice of Inquiry; NOPR = Notice of Proposed Rulemaking; ANOPR = Advance Notice of Proposed Rulemaking; ANOR = Annual Notice of Review

Figure 7 presents FERC's Notice of Proposed Rulemaking ("NOPR") process. While there is no official timetable for the NOPR process, even without opposition to a new rule, the process usually takes between one to two years.

Figure 8 presents the 3rd generation incentive ratemaking ("IRM") process in Ontario, which took 17 months of consultation, study and review for implementation. While Ontario has followed reasonable regulatory processes, it should do so on the policy side as well, rather than acting via Ministerial Directives (as presented earlier in Figure 3) without meaningful public consultation.

Figure 8. 3rd generation IRM regulatory process in Ontario



Source: OEB.

2.6.2 Unbundling

Unbundling refers to a process in which the utility sector is gradually disaggregated into its constituent parts, in an attempt to achieve efficiencies through the introduction of competition, transparency, and achievement of horizontal economies of scale.[18] Unbundling results in a vertically integrated utility being divided into several new companies. For example, generating stations may be grouped into multiple new companies (gencos), or sold off individually to new owners. The transmission network may be split off into a separate company, and an independent system operator (or ISO) created. A power exchange may be created. Several new distribution companies may also emerge. The number of new companies created depends largely on the size of the previous incumbent; provided each is above minimum efficient scale, four or more gencos may be created, while the number of distribution companies may depend on factors such as geographic cohesiveness, the desire for multiple comparators for regulatory purposes, and a balance between minimum efficient scale and a size at which constant returns to scale are reached. In more advanced cases of unbundling, even businesses such as metering may be separated out.

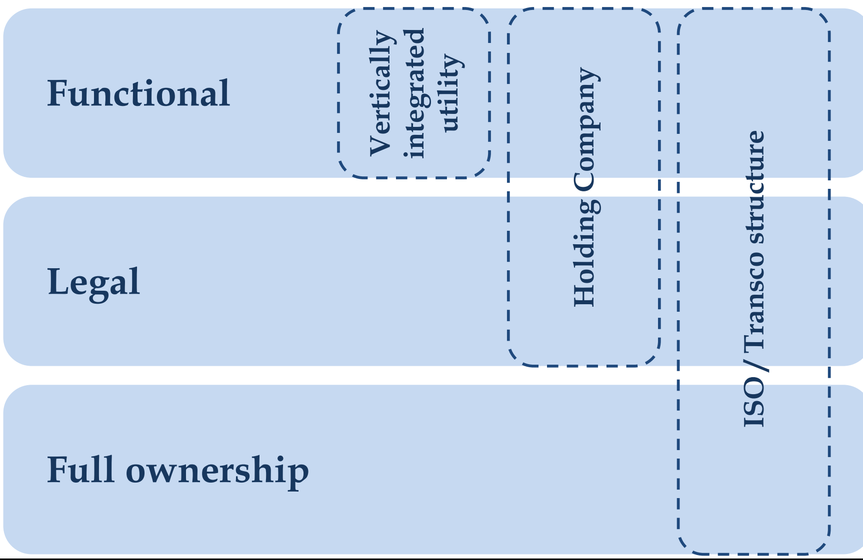
> Nova Scotia's relatively small market size (over 2,000 MW of peak demand) may make some options unfeasible, when minimum efficient scale is considered.

[18] Horizontal economies of scale may arise, for example, in a jurisdiction where, after unbundling, distribution companies are able to outsource billing systems or call centers more readily than they would have been inclined to do in their previous holding company structure.

Furthermore, under various form of unbundling, retail competition has also been introduced. Although the distribution utility in some cases served as a default service provider or provider of last resort to those customers that did not switch to competitive suppliers, the distribution and retail service businesses can be segregated. Indeed, most utilities had to competitively procure for the retail service business in order to assure their regulator that they are getting the best (market-based) price and product for their default customers

The textbook case of electricity sector restructuring envisions full unbundling of the generation, transmission, distribution and supply functions, where ownership ties are severed through divestiture and re-organization.[19] However there are different forms of unbundling, as discussed below (and presented in Figure 9).

Figure 9. Different forms of unbundling



- **Functional/accounting unbundling** is the least substantial form of unbundling as it takes place only at the accounting level; the company itself is unchanged (remains vertically integrated), and no separate corporate identities are created for individual pieces of the value chain. For example, as presented later in Figure 10, the 1st Liberalization Directive in the European Union resulted only in accounts unbundling.

- **Legal unbundling** is a less profound form of unbundling that sees the creation of individual companies, but maintains some or all of them within a common ownership structure. Energy Future Holdings in Texas and National Grid SA within the Saudi Electricity Company in Saudi Arabia are relevant examples for such unbundling.

[19] Joskow, P.L. "Lessons Learnt From Electricity Market Liberalization," *The Energy Journal.* Special Issue. The Future of Electricity: Papers in Honor of David Newbery. 2008

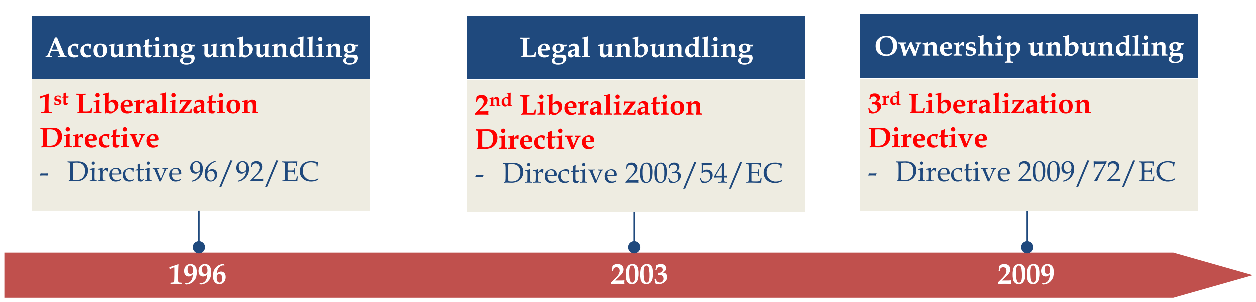
- **Full ownership unbundling** occurs when separate companies are created, with separate and distinct boards, legal identities, premises, staff, and shareholders. Under this model, the transmission network may be owned and operated by the same company (transco model) or ownership and operation of the transmission network may be separated (the ISO model). The ISO/transco models are discussed further in the next section (Section 2.6.3). Australia, Norway, Ontario and the UK are relevant examples of full ownership unbundling.

Proponents of full ownership unbundling usually argue that, compared with legal unbundling, it provides a stronger guarantee that the newly unregulated businesses will not be advantaged by potential ties to regulated affiliates. Under legal unbundling, both the regulated and the unregulated affiliates have common shareholders; some regulators have expressed concern that such a structure would lead to anti-competitive behavior and potential cross-subsidization of deregulated activities with ratepayers' funds from regulated business operations. Some regulators (as was the case in Texas) considered that this concern could be satisfactorily addressed by directing affiliated entities to adopt codes of conduct. The aim of codes of conduct is to behaviorally restrict the incentive to maximize profits through cross-ownership at the holding company level.

Such an incentive does not exist in an ownership-unbundled structure because each entity responds to different owners, without having to consider competitive objectives of any subsidiaries. In comparison with ownership unbundling, legal unbundling may also be viewed as providing the ability to allocate capital more efficiently between wires and generating assets.[20] However, under legal unbundling, regulated affiliates run the risk of being financially drained by the holding company, if not effectively ring-fenced.

In the European Union ("EU"), the process from requiring functional/accounting unbundling to full ownership unbundling took more than a decade (see Figure 10).

Figure 10. Timeline of unbundling in the EU



Source: EUROPA; Note: Appendix B (Section 7) shows status of restructuring across EU member states.

Unbundling is now almost universal across Europe in response to EU Directives. Some parts of Asia (China, most of India, and Singapore for example) are unbundled, Australia is mostly

[20] For example, borrowing at lower cost for regulated business with relatively low risk revenues and leverage unregulated businesses outside of the thresholds dictated by regulators for regulated business.

unbundled, as is New Zealand. Most of South America is at least partially unbundled, particularly the larger countries. In North America, the status of unbundling depends on the region; Mexico remains vertically integrated, parts of the United States are partially unbundled, and Canada ranges from fully unbundled in Alberta and Ontario to integrated structures in remaining provinces. Unbundling in Africa depends on the degree of external influence; the less interaction a country has with bilateral or multilateral aid agencies, the less likely it is to be unbundled.

2.6.3 Transfer of grid operations to an independent system operator

The universal feature of the restructured electricity sectors is the functional unbundling of network services and open access requirement to allow new generators and third-party suppliers to use transmission networks. Thus, there needs to be an entity to manage the complex short-term interactions on the network and monitor/maintain system reliability. As briefly discussed in Section 2.6.2, there are two options on how to organize the coordination and control of the transmission system:

- **ISO:** an independent system operator that has responsibility for managing use of the grid and coordinating the spot market, but does not own the transmission network (e.g. Ontario, NYISO, PJM and CAISO); and

- **Transco**: an independent company that combines ownership of the transmission network and responsibility for system operations; may be a for-profit or not-for-profit entity (e.g. National Grid Company in the UK).[21]

An ISO can also be structured to allow for separate operation of a power exchange (e.g. Power Exchange Central Europe ("PXE") that offers power trading for Czech, Slovak and Hungarian power[22] and the California Power Exchange, which, as discussed earlier, shut after the California Electricity Crisis).

The key objective of either structure is to assure reliability, which requires collaboration on the part of ISOs, transmission owners and electricity utilities. This includes coordination of existing system components and processes to guarantee delivery of electricity upon demand, cooperation in monitoring and coordinating generation and transmission, communications and information sharing among all system operators to identify and isolate problems as they occur, commitment by all electric utilities to continuously coordinate, cooperate, and communication to protect and ensure system balance.

In the ISO structure, in order to maintain reliability, certain responsibilities are performed by the ISO, while others remain with transmission owners, and as such, it may be important to identify appropriate ISO functions and transmission owner functions respectively. ISO

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[21] Hogan, W. *Restructuring the Electricity Market: Institutions for Network Services*. John F. Kennedy School of Government Harvard University. April 1999.

[22] Power Exchange Central Europe. <https://www.pxe.cz/dokument.aspx?k=Co-Je-PXE>

functions may include operational control of the transmission system, security coordinator for the region per NERC standards, administration of the ISO tariff, operation of Open Access Same time Information System ("OASIS"), allocation of available transfer capability, provision or coordination of ancillary services, involvement in transmission planning, implementation of congestion management procedures, coordination of transmission and generation, and maintenance scheduling. Transmission owners, on the other hand, may be responsible for maintaining ownership of transmission facilities, physically operating transmission facilities, maintain transmission facilities, power system analysis, conducting transmission planning studies, and constructing new transmission facilities.

In a transco structure, the transmission owner takes over all of the above-mentioned responsibilities. Under this structure, size and independence play a crucial role. First, the transmission owners need to be of a significant size – a small transco may not have sufficient system information gathering and control capability to ensure reliability. Second, with regards to independence, one of the principal requirements of an ISO is to be independent, and stakeholders (such as independently owned utilities, public power, rural electric cooperatives, and federal power marketing administrations) can participate in the governance of an ISO. Transcos can be independent affiliates, however, open governance may need to be demonstrated to ensure that stakeholders' interests are considered, and shareholders interests do not always prevail.[23]

While the transmission system can be owned by a large single owner, multiple transmission facility owners have been observed in jurisdictions, and recently, competitive procurement processes have also been initiated for transmission projects (for instance, critical transmission infrastructure ("CTI") projects are eligible for procurement under a competitive process in Alberta).[24] Similarly, the Ontario Energy Board initiated a process to select the most qualified and cost-effective transmitter to develop the East-West Tie line, one of the five priority transmission projects identified in the Ontario Long Term Energy Plan published in 2010.[25]

2.6.4 Size of the largest player

Market concentration determines the competitiveness of any market, including the generation market. From a regulatory perspective, the intervention options range from a laissez-faire (free market) position to actively pursuing a policy to reduce market power (usually in a market concentrated with very few large players).

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23 Electric Utility Consultants, Inc. *ISOs or TransCos: How to Choose?* March 1999.

24 Currently, 4 projects (~ $5.2 billion projected cost) out of the 53 transmission system projects (~ $13.5 billion) in the transmission pipeline (up to 2020) are considered CTI in Alberta. Source: AESO. *Long-term Transmission Plan*. June 2012.

25 OEB awarded the project to Upper Canada Transmission Inc. after a review of submitted applications and subsequent interrogatory answers and submissions. Source: OEB. *East-West Tie Line Designation. Phase 2 Decision and Order*. August 7, 2013.

The Herfindahl-Hirschman Index ("HHI") is often used to determine the market competitiveness level; the value of HHI of less than 1,000 is considered a sign of fully competitive market (i.e. at least 10 suppliers, each controlling 10% or less of the total supply in the market). HHI's values range from close to zero (large number of suppliers each controlling minimal share of the market) to 10,000 (complete monopoly). When re-organizing the generation sector, considerations of minimum efficient size may make creation of 10 players problematic. The presence of at least 5 players of equal or similar size without geographic concentration can be sufficient to achieve a reasonably level playing field.

FERC Guidelines

Market classification:
- Unconcentrated (HHI less than 1,500 - roughly equivalent to a market with 7 or more suppliers each with equal market share);
- Moderately concentrated (HHI is between 1,500 and 2,500 - roughly equivalent to a market with 4 to 6 suppliers each with equal market share);
- Highly concentrated (above 2,500; roughly equivalent to a market with fewer than 4 suppliers each with equal market share)

Changes in HHI potentially raising competition concerns in:
- Moderately concentrated market: over 100
- Concentrated markets: between 100 and 200

Changes in HHI presumed to enhance market power in:
- Concentrated markets: over 200

Source: Federal Energy Regulatory Commission. *Order Reaffirming Commission Policy and Terminating Proceedings (Docket No. RM11-14-000)*. 2012

Among the regulatory experience in addressing the competition level, the UK provides an example of an overly concentrated approach,[26] at least initially. The UK Government started the restructuring with organization and privatization of former state-owned power plants into three entities.[27] However, the first few years demonstrated that three entities were not sufficient to enforce levels of competition that would benefit consumers.[28,29] This prompted a series of actions to improve competition (resulting in divestitures).[30]

[26] UK introduced vesting contracts at the market opening, but largely to insulate both generators and distribution companies from market volatility. In Singapore, such contracts were designed to also reduce market power over the long term.

[27] The main motivation for creating three entities was driven by concerns of monopoly position of British Gas, which was privatized a few years earlier via stock flotation (Pond, R. *Liberalization, Privatization and Regulation in the UK Electricity Sector*, London Metropolitan University. 2006). However, more companies should have been created.

[28] Wolfram. C. "Measuring Duopoly Power in the British Electricity Spot Market," *American Economic Review* 89(4), 805-826. 1999

[29] Sweeting, A. "Market Power in the England and Wales Wholesale Electricity Market," *Economic Journal* 117 (520), 654-685. 2007

[30] Pond, R. *Liberalization, Privatization and Regulation in the UK Electricity Sector*, London Metropolitan University. 2006

Other approaches to address the competitiveness issue in electricity markets include the use of vesting contracts. Singapore instituted vesting contracts explicitly to limit the market power of the three largest generators, where the vesting contracts covered 85% of total electricity demand. Subsequently, the contract terms are revised every two years, where the covered volume is adjusted as new entries reduce the power of the incumbents, and the prices are set using the long-run marginal costs of most efficient technology that meets 25% of the demand.

Canadian Competition Bureau's Merger Guidelines

If merged firm controls 35% or more of the market, concern of **unilateral exercise of market power**.

If the largest four firms control 65% of more or a merged firm controls 10% or more of the market share, concern arises regarding **coordinated exercise of market power**.

The Bureau may calculate the HHI before and after the merger, but it does not use HHI to delineate any safe harbor threshold.

Source: Canadian Competition Bureau. *Merger Enforcement Guidelines*. 2011

Similar market power concerns in Alberta's generation market have led to Power Purchase Arrangements ("PPAs"), which are essentially dispatch rights for capacity (or strips of capacity) of large power plants that were sold via auction.[31]

In Ontario, market power was addressed via a negotiated settlement. The Market Power Mitigation Agreement ("MPMA") was designed to mitigate the market power of Ontario Power Generation ("OPG"). The MPMA included market share reduction targets (along with incentives to reach the targets) and a revenue cap for OPG.[32]

Some issues that need attention from a regulatory perspective when approaching the competitiveness of the market are as follows:

- estimates of market shares need to be developed as early as possible;
- consider a nuanced approach to estimating the market share (in case of generation, the market share could be considered across all hours, during peak hours, subset of other hours depending on the characteristics of demand and existing power plants; in case of retail: market shares could reflect type and number of customers being served by various retailers, and not just the entire market)[33];

[31] Alberta Balancing Pool. *Power Purchase Arrangements Information.* < http://www.balancingpool.ca/about-us/ppa-information/> Accessed April 26, 2014.

[32] Sioshansi, F.P. and W. Pfaffenberger. *Electricity Market Reform: An International Perspective.* Elsevier. 2006 (p.424)

[33] For instance, the market may have 20 retailers, however, if only one or two retailers are supplying to industrial consumers, it may be a concern.

- implement market power mitigation measures (divestiture and creation of multiple players is feasible in large systems; smaller systems would make vesting contracts an attractive choice); and

- if possible, there should be no specific timetable for how long the market power mitigation instruments are in place (UK originally set the vesting contracts for three years, and at expiry there was no interest from generation companies to continue with the contracts; Singapore, on the other hand, continues to use vesting contracts until there is certainty that absence of vesting contracts will not negatively affect the level of competition and lead to increase in market power).

Finally, the approaches to address possible market power issues when restructuring an electricity system should consider the specific characteristics of the market (such as features of demand and supply composition).

2.6.5 Share of government-owned assets

For jurisdictions where electricity sector assets are wholly or majority government-owned, one of the aspects of restructuring that needs attention is deciding whether the government needs to continue to own those electricity assets. From a regulatory perspective, the government may continue to own and operate such assets (subject to market power concentration discussed earlier) or it can choose to reduce its stake or completely withdraw from the sector.

There is a general consensus that state ownership of economic resources can lead to wasteful resource utilization and subordination of the purposes of such resources to a political agenda. Although government ownership may at times be justified if there is genuine market failure (rural electrification, for example), private ownership allows government resources to be reallocated to areas of higher social return, such as primary education. While reduced (or eliminated) government involvement is not a prerequisite for restructuring efforts, it is often expected that electricity assets in private hands may perform operationally better and capital is utilized efficiently through investment decisions that reflect economic and business sense, void of political considerations. As such, the share of government-owned assets generally decreases, and consequently, the share of investors-owned assets increases as the restructuring process evolves.

UK, Hong Kong, Australia and the US are among the proponents of private capital in the electricity sector. Continental Europe (particularly Northern Europe) has never viewed government ownership of electricity assets as an impediment to sector restructuring. There are, of course, options between the two extremes, e.g. Singapore has privatized the generation assets, but retained the ownership of wires businesses.[34] Also, Ontario's generation sector has reduced government ownership (via Ontario Power Generation), the major transmission company is owned by the provincial government, and vast majority of distribution utilities are owned by

[34] Energy Market Authority. *Introduction to the National Electricity Market of Singapore*. 2009 <http://www.ema.gov.sg/media/files/books/intro_to_nems/Introduction to the NEMS_Jul 009.pdf> Accessed April 26, 2014.

provincial and municipal governments. Ontario also has a transfer tax stipulation when a distribution utility is sold to private investors (33% of the fair market value), designed to protect payments made by distributors in lieu of taxes, which also creates serious challenges in attracting private capital into the distribution sector.[35]

There are a few issues that present themselves when considering privatization of electricity assets:

- When to privatize government entities? One logical step may be to privatize the government entities in the same process of re-organization and corporatization, so the market can start with a clean slate. However, that causes concerns regarding valuation of these entities, as there may not be much history in a corporatized form and the market does not yet have a basis for valuation. Privatization after market opening (providing better basis for valuation) may be fair and efficient for both the private investors (reduced chances of overpaying) and the government (better value for the asset).

- What control mechanisms should be in place after privatization? The UK had used the "golden share" mechanism (i.e. a nominal share that outvotes other shareholders) in the privatized firms to limit the opportunity by any private investor to obtain controlling shares; the underlying rationale was to enable the government to monitor and ensure that operations of the companies were not negatively impacted by the private interests.

Finally, the decision to maintain, reduce, or eliminate the share of government ownership in the electricity sector is, to some extent, dependent on the political leanings in the jurisdiction, on the sectors considered for privatization (entire sector, or only generation and retain wires businesses), whether the current ownership results in positive benefits to the government (it is easier to make an argument for privatization if the government has to support these entities from a given budget), and whether the current and future benefits of privatization (i.e. lump sum payments upfront and tax revenue stream in the future) outweigh future benefits of continued ownership (future profits).

2.6.6 Market model (real-time/day-ahead, energy/capacity etc.)

Once the generation sector is re-organized and a sufficient number of players exist, the next issue that needs to be addressed is determining the market model for wholesale electricity trading. There are a variety of ways markets can be organized, as discussed below.

A **Single Buyer** model is generally employed as a stepping stone towards a fully competitive wholesale generation market, and it has been used in many jurisdictions in Eastern Europe and Asia. While the Single Buyer model is better than the incumbent preference model, it accommodates only "one shot" competition; the wholesale centralized market, on other hand, requires competition across all dimensions (contracts, short-term operating costs, etc.)

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[35] Ontario Distribution Sector Review Panel. *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First* <http://www.energy.gov.on.ca/docs/en/LDC_en.pdf> Accessed April 26, 2014.

A **bilateral contracts-based market** may result in a less transparent market (unless provisions are in place to require disclosure of details of bilateral contracts), and buyers of electricity would pay differentiated prices based on their negotiating power, delivery terms, volumes, etc.

Pool-based markets allow greater transparency and clearer price discovery processes, where all the buyers are exposed to same prices; buyers also have the ability to separately hedge themselves via financial instruments. Energy trading in pool-based markets may be conducted as real-time or as day-ahead. While **real-time trading** requires matching of electricity offers and demand bids in real-time (e.g. NYISO, ISO-NE, PJM) on hourly intervals (or 5-minute or 15-minute intervals, depending on the market),[36] under a **day-ahead trading** structure, sellers and buyers agree on the deliveries for the following day, usually on an hourly interval (e.g. NordPool, APX Power NL, Electric Reliability Council of Texas).[37] The day-ahead market needs to be supplemented with the balancing market to trade in any energy needed to balance the real-time changes in the availability of power plants.

2.6.6.1 Energy-only vs. energy and capacity markets

North American wholesale electricity markets have evolved in one of two ways: **energy-only markets**, such as Alberta and the Electric Reliability Council of Texas ("ERCOT"), **or energy and capacity markets**, as implemented in California, New England, Midwest, New York and PJM (also summarized in Figure 11).

In an energy-only market, participant revenues are determined either by their participation in the spot market or by their bilateral contract position. Where deployed, capacity markets provide an additional revenue stream – a "payment for existence", which a plant receives even if it is not dispatched, provided that if it is called upon, it is in fact able to run.

For energy-only markets to work properly, they must be allowed to reach peak prices which reflect a scarcity value when appropriate, so as to provide price signals to new entrants. Competitive wholesale markets with price caps, particularly when those price caps are significantly below the value of lost load ("VoLL", the economic impact incurred as a result of an outage), may fail to provide such signals.

Capacity markets were put in place in some power markets to provide an additional means of signaling when new build is required. While we find that, when allowed to work properly, energy-only markets can be the most economically efficient design for competitive wholesale electricity markets, one of the key motivations for implementing capacity markets in the markets where they exist has been to replace the so-called "missing money" that arises when governments and regulators seek to artificially suppress peak prices, for example through price caps.

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[36] NYISO <http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp> Accessed April 26, 2014.

[37] NordPool Spot < http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/> Accessed April 26, 2014.

Figure 11. Selected ISO capacity market designs

ISO	Capacity market design summary
CAISO	▪ Spot capacity market, serves 1 state, since 2004* ▪ No centralized capacity market currently in place; System Resource Adequacy Requirement ("RAR") and Local RAR satisfied by utilities/LSEs on annual and monthly basis through bilateral trading of a capacity product defined by California Public Utilities Commission ("CPUC") ▪ LSEs issue long-term RFPs under longer-term procurement plans subject to Utility Long-Term Procurement Planning managed by CPUC
ISO-NE	▪ Forward capacity market, serves 6 states, since 2006 ▪ Use of 3-year forwards via Forward Capacity Auction ("FCA") with annual reconfiguration auctions ▪ Local requirement for import constrained areas; with commitment period start, LSEs and generators can also participate in seasonal and monthly reconfiguration auctions ▪ ISO-NE ′s December 2012 FERC compliance filing implemented a buyer-side offer floor mitigation mechanism, eliminating previous offer floor beginning in 2017/2018 ▪ Commencing with 2016/2017 proposes modeling four capacity zones: Connecticut, NEMA/Boston, Maine and Rest of POOL
MISO	▪ Voluntary capacity market, serves 11 states, since 2009 ▪ Starting in June 2013, an organized yet voluntary capacity market will be set up; nevertheless, most capacity transactions are still expected to be handled on bilateral basis ▪ Balancing Authorities ("BAs") within MISO will be divided among seven (7) Load Resources Zones ("LRZ") based on factors such as electrical boundaries and relative strength of interconnections between BAs ▪ Each LRZ will have a clearing price corresponding to its market conditions ▪ LSE are required to buy from supply resources (which participate) in order to comply with the resource adequacy requirement in their zones
NYISO	▪ Spot capacity market, serves 1 state, since 1999 ▪ Monthly Installed Capacity Spot Market Auction ▪ LSEs with unmet RA obliged to purchase capacity and offer excess capacity ▪ Locational: New York City ("NYC"), Long Island ("LI"), and Rest of State ("ROS") ▪ Local RA in LI and ROS due to transmission constraints ▪ Use of downward sloping demand curve ▪ New entrants cannot compete until they are operational
PJM	▪ Forward capacity market, serves 13 states and District of Columbia, since 2007 ▪ 3-year ahead Forward Capacity Market that relies on a downward sloping demand curve ▪ LSEs can use self-supply and bilateral contracts and residual capacity procured in competitive auction

Note: *CAISO System RAR instituted in 2004 and Local RAR in 2006
Sources: various ISOs

In energy-only markets, while an ISO may monitor projected reserve margins, the size of the reserve margin is largely left to the market. By contrast, in a capacity market, load serving entities ("LSEs") are required by the market operator to procure sufficient capacity (usually denominated in $/kW over a unit of time, such as a month) to meet a target reserve margin set by an ISO. Thus, an LSE will, in addition to procuring sufficient energy to meet its customer's needs, be required to calculate each customer's peak load and procure sufficient capacity to meet that peak load plus a reserve margin. If the customer peak load is 100 MW, and the target reserve margin is 15%, the required amount of capacity the LSE must purchase is 115 MW.

Zonal vs. nodal pricing

Price definition is one of the critical elements of how reflective prices are of the supply and demand balance. A mechanically simple approach is to use a single price for the whole market or zonal prices that reflect prevailing transmission congestions between zones across a single system. Zonal (or single market) prices therefore ignore transmission constraints within the zone, which result in prices not reflecting the true balance of supply and demand thus requiring side payments to dispatch needed but otherwise out-of-merit power plants in the zone. The increased costs of supplying transmission congested load are spread across the total zonal load. The true economic cost of supplying any load on the system can be calculated by using locational marginal prices ("LMP"), which reflect the local transmission constraints and are borne solely by customers at that node. LMPs, sometimes called nodal prices, are used in all US wholesale electricity markets, while Canadian and most of the European electricity markets rely on zonal pricing.

Capacity markets have faced several challenges. In initial capacity market designs, capacity prices were not known more than a year in advance, meaning developers needed to forecast future capacity prices and convince their bankers to consider the associated revenue stream in determining the debt carrying capability of the asset. Some capacity markets have been redesigned to allow for three year forward capacity markets. Capacity markets also tended to be binary – during periods of surplus, capacity was worthless, while when scarcity conditions arose, the price of capacity rose to the cap, usually set at the amortized cost of a new simple cycle gas turbine, which serves as a proxy for an economic means of meeting peak load. System operators have attempted to address the binary nature of capacity markets through the creation of floor prices and complex "demand curve" approaches which adjust minimum prices based on reserve margins and bids.

2.6.7 Planning Process

The key objective of the planning process is to assign necessary investments to maintain reliability. Under the vertically integrated structure, Integrated Resource Plans ("IRPs") are the norm, which are long-term plans prepared by a utility to guide future energy efficiency, generation, transmission, and distribution investments. Typically the regulators review the plans, order modifications if necessary, and approve it as the guidance document for future utility investment and operations decisions. The plan itself may not be 'approved' per se, but is found to be a reasonable guide to future actions.[38]

Under an unbundled structure, since generation companies are unbundled from the entity that manages the grid, the planning process requires careful consideration. There are multiple options for planning responsibility: (i) the remaining wires-only utility, (ii) an independent planning agency, (iii) the ministry, and/or (iv) the ISO (which usually is responsible for transmission and system reliability with input from transmission owners).[39]

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[38] The Regulatory Assistance Project. *Electricity Regulation in the US: A Guide*. March 2011.

[39] Specific reliability standards are discussed in further detail in Section 4 (Performance and Accountability)

Effect of renewable policies and demand response participation

An increased emphasis on renewable policies in recent years has also created additional challenges in the planning and design of energy markets. Wind and solar technologies by the virtue of their inherent design features are intermittent, where the output is dependent on factors that are beyond the control of the operator and as the result are non-dispatchable. Other renewable technologies that are dispatchable are either currently expensive (solar power with storage capabilities) or highly dependent on the input availability or location (biomass and geothermal). Due to cost drivers, wind power plants have emerged as the most prevalent form of renewable energy currently being developed. However, the intermittent nature of these resources also means that the system designers have to be cognizant of the need to maintain additional dispatchable and quick response (i.e. fossil-based) capacity and invest in transmission expansion to address any potential reliability issues.

Demand response ("DR") programs may help with balancing intermittent renewables and alleviate the need for some super-peaking power plants, if DR participants are provided with sufficient incentives for active engagement in the market. The demand response programs also address the issue of demand inelasticity, which contributes to market power of sellers in the energy marketplace.

As discussed earlier in Section 2.6.3, ongoing collaboration is required on the part of ISOs, transmission owners and electricity utilities. There have been concerns that there can be coordination issues between the system operator, transmission owners and generation asset owners that could lead to a decrease in reliability and capacity inadequacy.[40] However, the presence of ISOs and rules has generally been sufficient to date in maintaining reliability. Restructured markets have generally operated adequately and reliably.[41]

As discussed in Section 4 (Performance and Accountability), there are various levels of responsibility for reliability in North America (headed by FERC and NERC), and NERC reliability principles are followed by all markets, restructured or bundled. The few isolated reliability events that have been observed can be largely attributed to natural causes, which would have had similar consequences in a vertically-integrated industry.

Long-term reliability is maintained through a mixture of market and regulatory mechanisms (such as capacity markets, forward markets for transmission rights, auctions for forward reserves and capacity, and regional transmission expansion planning and other supply-demand forecasts). Over the long term, ISOs also play an essential informative role as they track generation and transmission proposals as well as demand levels.[42] These planning processes provide energy and capacity markets with extremely useful information, and serve to signal the need for new investment. They are also the basis for further actions by the ISO to address urgent needs that markets may fail to address in timely fashion.

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[40] Delgado, J. *The Blackout of 2003 and its Connection to Open Access.* American Transmission Company

[41] Harris, P.G. *Relationship between Competitive Power Markets and Grid Reliability PJM RTO Experience*. PJM

[42] For example, the NYISO conducts a 10-year outlook assessing system reliability and resource adequacy, the so-called Comprehensive Reliability Planning Process ("CRPP") on an annual basis. The PJM Interconnection also conducts an annual review of its bulk electricity transmission system, the Regional Transmission Expansion Plan ("RTEP"), identifying transmission expansion needs in conjunction with load and generation projections.

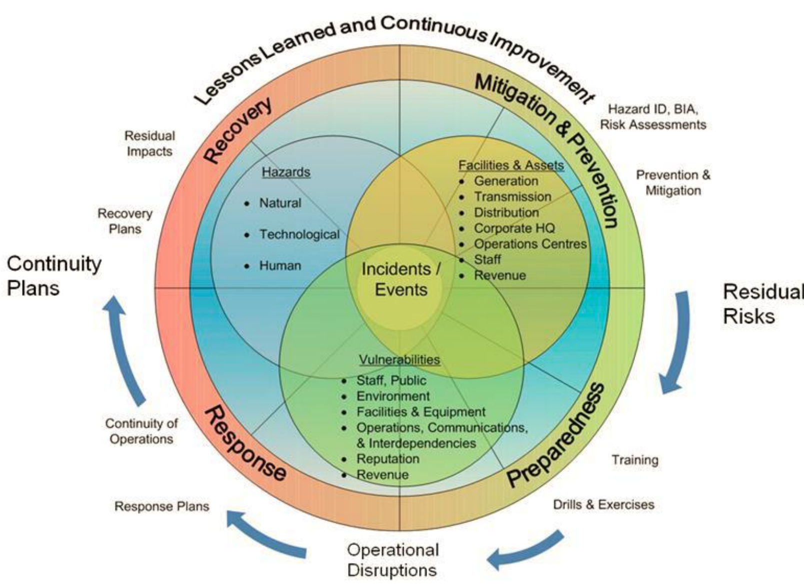
As discussed earlier in Section 2.2, overlapping jurisdictional authorities can sometimes be a hindrance in effective planning (for not only reliability, but also for generation procurement at least cost). As such, interaction of various authorities in Ontario's electricity sector (as discussed earlier in Section 2.3.2) is a relevant example.

2.6.8 Process to maintain reliability of supply in case of extreme event

When there is a threat of system reliability disruption due to extreme events, in a vertically integrated utility, the responsible departments respond. There are two entities that are likely responsible in an unbundled structure, and they are the successors to the departments that would have responded when vertically integrated), the ISO and the local distribution company. While the ISO is responsible for managing the transmission grid and system dispatch, the local distribution company is responsible for distribution level outages.

The ISOs maintain short-term reliability (i.e. emergency situations) by managing and triggering load relief, where the ISO notifies all transmission operators of impending actions, including curtailment of interruptible load, manual voltage reduction, curtailment of non-essential market participant load, voluntary curtailment of large load service entities customers, and public appeals. For instance, the IESO has an Electricity Emergency Plan,[43] which notes that the "*IESO and all market participants are required to prepare emergency preparedness plans to ensure grid reliability*." The Plan identifies various hazards, vulnerabilities and processes to follow under unexpected events (see Figure 12).

Figure 12. IESO emergency planning



Source: IESO

43 IESO. *Market Manual 7: System Operations. Part 7.10: Ontario Electricity Emergency Plan. Issue 7.0.* Accessed April 24, 2014.

Emergency load shedding in Alberta

On July 2, 2013 Alberta experienced demand levels rare for summer months and the Alberta Electricity System Operator ("AESO") was forced to issue a public appeal for voluntary reduction of electricity consumption. It also ordered transmission owners to shed 100 MW of load (excluding areas affected by flood, hospitals and emergency services).

At the local distribution company level, the extreme events that affect the system reliability are handled via emergency preparedness plans (or similar plans) designed to outline the steps for identifying and remedying the power shortage, in line with NERC standards, ISO guidelines and market rules. In the event there is insufficient power to supply all customers, utilities may resort to rotational load shedding. In terms of priority of restoring services, essential services (hospitals, water services, police, emergency services, etc.) receive power first, followed by industrial and commercial accounts, residential accounts and street lightning. The local utility would also assess if it has the required resources to deal with the emergency or if it should solicit help from neighboring utilities.

2.6.9 Treatment of stranded assets

One issue that arises during unbundling is cost-allocation. Utilities argue that under cost of service ratemaking they made investments in good faith based on the "regulatory compact," and that as such they are entitled to the promised associated returns provided the assets are operated according to good utility practice. Once competition is introduced, any guarantee of returns is eliminated. Generating stations may earn more, less, or about the same as they did under the previous regulatory regime. In the case where a generating asset earns less than expected under regulation, the difference between expected competitive returns and expected regulated returns is referred to as a **stranded cost**. The converse can also arise; generating assets that are expected to earn more than they would have under regulation give rise to **stranded benefits**.

From a regulatory perspective, the first step is to determine whether there are stranded costs. If stranded costs are identified and recognized, the regulator decides if the amount of stranded costs is of sufficiently large magnitude to warrant special treatment (i.e. need to be recovered). If indeed stranded costs need to be recovered, the next decision involves choice of recovery mechanism and responsibility (i.e. who pays for it: ratepayers, shareholders, or taxpayers).

Case Study – Western Massachusetts Electric Company (WMECo)

Massachusetts passed the Electric Industry Restructuring Act (the Act) of 1997, to foster competition, reduce retail prices and allow customers to choose their suppliers. A seven-year period through February 2005 was established as the transition period to transform vertically integrated industry into one driven by competition.

In late 1997, WMECo submitted its restructuring plan to the Massachusetts Department of Telecommunications and Energy (DTE). As part of the plan, WMECo identified transition costs, which were to be recovered through a non-bypassable charge applied to all distribution customers, including:

- the portion of the net book value of generating plants that is in excess of the market value;
- the portion of contractual commitments for purchased power in excess of market value;
- regulatory assets; and
- nuclear plant shut-down and decommissioning expenses

In September 1999, the DTE issued final ruling on WMECO's restructuring plan and approved the recovery of $785 million in stranded costs. The DTE disallowed any return on Millstone 2 and 3 (nuclear units) while they were out of service and disallowed a return on Millstone 1, although WMECo was allowed to recover its operating and maintenance costs.

The DTE required utilities to submit strategies to mitigate stranded costs and divestiture of generation assets was one of them. WMECo conducted a competitive auction to sell its 290 MW non-nuclear generation assets for $47 million to Consolidated Edison, Energy, Inc., the competitive subsidiary of Consolidated Edison Inc. The transaction was found to be consistent with the Act and was approved by the DTE in 1999. The proceeds from the divestiture were applied to reduce the amount of transition costs of WMECo.

Discussions regarding stranded costs can be complicated, but the solution is normally to determine what the stranded costs are, converting the amount of the stranded costs to a financial asset on the utility's books, and recovering it from customers over time (in case of recovery from ratepayers). The length of the recovery period can be adjusted so as to manage costs on customer bills. Such charges are often referred to as **competitive transition charges** ("CTC"s) and appear as a separate line item on customer bills. Because stranded cost proceedings have the potential to result in large rent transfers, utilities approach them aggressively. Utilities have an incentive to designate as many assets as possible as being "stranded," so as to convert as much of their future revenue stream from uncertain (market-based) to fixed (regulated). Utilities also have an incentive to argue for high stranded cost valuations. In regions where a market has yet to be created, such valuations are challenging, because no historical market information is available.

Where possible, policymakers have encouraged **divestiture**. Divestiture provides a clear, arms-length valuation through an auction of the assets; the difference between the auction proceeds and the book value of the assets represents the stranded costs. However, in some jurisdictions, regulators allowed the utilities to transfer assets to an unregulated affiliate at book value. In retrospect, regulators could have examined such transfers more carefully; the presence of information asymmetries between the utility and regulator regarding the value of the assets means that utilities making such a deal almost certainly believed the assets to be worth more than the book value; since ratepayers paid for the assets, some would argue that any increase in value of the assets as a result of competition should have been returned to ratepayers.

Another approach to stranded cost recovery which proved sub-optimal was **floating CTCs**. In these instances, utilities were allowed to retain the assets, and a benchmark projected market price was set to determine the level at which the CTC would be zero. As prices oscillated around the benchmark, the CTC would rise or fall. Although this arrangement had the advantage of avoiding setting the total amount of stranded costs to be recovered too high or too low, it also meant that customers were less able to perceive the impact of competition on their bills – during low market price periods, the CTC rose, erasing the gains, while during high price periods, the CTC was replaced by the higher cost of the power itself. While mechanisms to manage costs to consumers during the transition to competition are important, a mechanism which completely absorbs any market-based price changes may be ineffective in preparing customers for competition.

The decision on how to address stranded costs is contentious and requires careful analysis and deliberations with all stakeholders. Generally, a CTC approach is considered the best in terms of not interfering with the market, especially if the charge is set as fixed amount that applies to volumetric measure, i.e. electricity usage.

2.6.10 Treatment of strategic assets

Particular electricity sector assets are sometimes viewed as strategic because of their importance from a network reliability perspective, impact on consumer rates (e.g. distribution companies in the UK), a mix of political and economic reasons (e.g. legacy generation assets in Ontario) or even military concerns (e.g. nuclear technology). When restructuring the electricity sector, regulators may choose to treat strategic assets separately until they are assured that the competitive market forces will not result in undesirable outcomes (e.g. reliability failures, price increases). Methods deployed include maintaining government ownership over the assets deemed strategic, retaining government influence over the privatized companies, creating regulatory contracts to retain certain cost benefits, and restricting foreign control.

In the UK's case, the government retained a "golden share" to maintain a blocking control of the privatized distribution utilities to ensure that the pace of consolidation and the introduction of foreign ownership could be managed.[44] After a number of years, the golden shares were withdrawn, allowing for mergers and acquisitions of the distribution companies.

During the restructuring of Ontario's electricity sector, the government chose to set regulated payments to hydroelectric and nuclear assets of OPG. These assets became known as prescribed assets and the rationale for such regulated payments was:

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[44] Pond, R. *Liberalization, Privatization and Regulation in the UK Electricity Sector*, London Metropolitan University. 2006

- easing the burden on taxpayers;
- reducing price volatility and stabilizing electricity prices; and
- assuring that Ontario prices are competitive with neighboring jurisdictions.[45]

The prescribed assets are essentially legacy assets; ratepayers would make the argument that, over time, they have already paid for a portion of these assets through previous rates. Thus, during a transition to a competitive wholesale market, for valuable baseload assets, gains associated with a move to market based revenues, rather than cost based revenues, could result in a windfall to the incumbent unless mechanisms are put in place that retain these benefits for ratepayers. A decade later, there is no clear path for the government to reduce its stake in the generation sector (Ontario Power Generation) and regulatory payments for the prescribed assets continue. However, the provincial regulator has been exploring incentives-based regulation for the prescribed assets for a number of years now. For further related discussion, see Section 3 (Performance-based Regulation).

Similar to Ontario's legacy assets, the heritage contracts have been used in British Columbia and Quebec. BC's heritage contracts are designed to provide the benefits of low-cost hydroelectric capacity of BC Hydro to eligible consumers in the province. In Quebec, the heritage pool is the volume of energy that Hydro Quebec is obligated to provide at historical cost-based rates. The balance of energy demand is purchased from suppliers (including Hydro Quebec Production) on long-term purchase contracts.

Ownership restrictions are another way of dealing with strategic assets. The US Atomic Energy Act of 1954 prohibits the US Nuclear Regulatory Agency from issuing nuclear reactor licenses to foreigners, or any entities that is owned, controlled or dominated by foreigner, foreign corporation or foreign government.[46] This, however, does not mean that foreign entities do not have stakes in nuclear assets in the US.[47] A number of transaction involving US-registered corporations with foreign ownership have been approved after appropriate changes in the corporate structure ensured the foreign owners are separated from the management and decision-making process regarding nuclear assets. Generally the maximum for foreign ownership is 50%.[48] Vermont took a similar approach to transmission assets, arranging to have ownership of the transmission system transferred to a state-owned entity after local utilities were consolidated under Canadian control.

While strategic assets may provide important public function (especially when it is a politically sensitive issue of maintaining low electricity rates), prolonged reliance on strategic assets to

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[45] Ontario Ministry of Energy press release, 23rd February 2005, "Ontario Government Introduces Fair and Stable Prices for Electricity from Ontario Power Generation."

[46] US Atomic Energy Act. 1954. Section 103d.

[47] Matthews, J. *Foreign Investment in U.S. Nuclear Generating Assets: Mitigation of Barriers Presents Opportunity*. Morgan, Lewis & Bockius LLP. 2004(?)

[48] US Nuclear Regulatory Commission. *Standard Review Plan For License Transfer Applications Involving Potential for Foreign Ownership, Control or Domination*. 2003

achieve the political goals may ultimately result in potential price shocks when continuation of heritage contracts (or other similar arrangements) become infeasible (i.e. assets would reach their end of life at some point).

2.6.11 Existence of a default customer program at the retail level

If unbundling is chosen, and small customers are given access to competitive markets, policies need to be established to deal with those customers who fail to choose a supplier. Given that not all customers can or are willing to switch to retail suppliers, default service programs have been implemented to serve customers that have not made the switch. Under such programs the local distribution utilities procure energy on behalf of its customers and pass on the costs without a mark-up. These services are also used to meet objectives other than just providing energy at a reasonable cost, including consumer protection, income redistribution, immediate price reduction, etc., and as a result, default service tariffs may be sometimes set below wholesale market prices.

Default services can be provided by local distribution companies or allocated to retailers. Typically there are no qualification requirements to receive default service, however some jurisdictions (e.g. Alberta) have separate service options for residential and small commercial customers. Below, we describe default supply arrangements in Ontario, Alberta, and New Jersey.

Ontario's Regulated Price Plan ("RPP") is open to residential, small commercial and other general service customer with less than 50 kW of demand.[49] The eligibility of certain customer classes was gradually withdrawn (e.g. municipalities, universities and hospitals became ineligible after four years). Most customers under RPP are on time-of-use rates and smaller proportion are on tiered pricing plan (lower rate for the first 1,000 kWhs and higher for any consumption above the threshold). The prices are updated twice a year and are based on the forecast wholesale energy prices, global adjustment values, and any differences between forecast and actual prices in the previous period.

Alberta has two separate programs: default supply service[50] and the Regulated Rate Option ("RRO").[51] The default supply service is open to all customers who have not chosen a retail supplier and the rates are based on the actual market prices in the Alberta Pool. The RRO is open to residential, small commercial, lighting, farm, irrigation and oil and gas customers with demand not exceeding 75 kW. Services under both programs are available through local distribution companies or retail suppliers.

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[49] OEB. Regulated Rate Plan (RP-2004-0205) <http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Regulated%20Price%20Plan> Accessed April 24, 2014.

[50] EPCOR. Default Supply Tariff < http://www.epcor.com/power/rates-tariffs/TermsConditionsService/TermsConditions-DefaultSupplyCustomers.pdf> Accessed April 25, 2014.

[51] EPCOR. Regulated Rate Tariff < http://www.epcor.com/power/rates-tariffs/RegulatedRateTarrifsFortis/RegulatedRateTariff-2014-04.pdf> Accessed April 25, 2014.

New Jersey's Basic Generation Service ("BGS") is open to all customers who have not made a switch. BGS is available only as a fixed price option to residential and small commercial customers. Large commercial and industrial are given hourly-priced service. BGS rates are based on the outcome of an annual competitive procurement auction conducted by the distribution companies. There are separate auctions for fixed price and hourly-priced services.[52]

Availability of default services where the rates are set at or below the wholesale energy prices is likely to serve as an impediment to retail competition as retail suppliers are not likely to provide services at rates cheaper than such default services.

Even if default service tariffs reflected the wholesale market price of energy, retail competitors would often find themselves at a disadvantage as the costs of serving large number of low volume customers can add up quickly (advertising, billing, customer service, bad debts etc.), while the local distribution utilities have little additional cost for serving the same customers.

2.7 Impact of restructuring implementation

The following sections present a review of the impact of implementing reforms on various aspects of the power sector, such as number of players in the sector, share of customers in deregulated markets, electricity prices, total factor productivity, number of jobs and GDP, cost of regulatory processes and a few other potential effects.

While the number of players generally increases post-restructuring, retail sector consolidation is eventually observed. There is not a general consensus on whether wholesale and retail prices are lower post-reforms; having said that, there are often additional objectives for reforms, such as enhancing efficiency levels across the electricity value chain, which are generally expected to improve with competitive pressures. Sections below expand on each of these aspects along with discussing some further impacts.

2.7.1 Number of players in various segments of the power industry

As discussed earlier in Section 2.6.4, post-restructuring, the number of players generally increases. The restructured market creates space for independennt power producers, merchant transmission owners and multiple distribution companies.

After reform implementation, generation players usually increase substantially in number. For example, in Ontario, before the reforms, there was a crown corporation Ontario Hydro and over 30 non-utility generators on contract with Ontario Hydro. After restructuring of the sector, some generation assets were divested and new players entered the market via contracts with OPA; today, almost 400 generator licenses have been issued in Ontario.[53] Similarly, in the UK,

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[52] New Jersey Board of Public Utilities. BGS Acutions < http://www.nj.gov/bpu/about/divisions/energy/bgs.html> Accessed April 25, 2014.

[53] OEB. Licensed Market Participants (Generators) < http://www.ontarioenergyboard.ca/OEB/Industry/Licences/Licensed+Market+Participants> Accessed April 25, 2014.

where the state-owned generation assets were divided into three companies, which then eventually divested their holdings, and were joined by a number of new entries during the "dash for gas" phase. An exception to this case is Norway, where the number of generation companies had been large prior to the reforms.[54] After reforms, some regional companies and the state-owned Statkraft, the largest player, had grown through acquisitions.[55] As the market evolves, there are mergers and acquisitions that result in the consolidation of players, but in all cases the regulators carefully monitor the potential impact on market power concentration.

The transmission sector has also seen multiple transmission facility owners surfacing post restructuring. As discussed earlier in Section 2.6.3, competitive processes for assigning projects to most qualified and cost-effective transmission owners have been undertaken in Ontario and Alberta. In certain cases (e.g. the Cross Sound Cable and Neptune projects in the US Northeast) a number of merchant transmission projects have been implemented to relieve local transmission constraints. There are several examples of entrepreneurial transmission projects across North America, as presented in Figure 13.

Figure 13. Potential entrepreneurial transmission projects

Projects	Developer(s)	Capacity	Voltage/length	Origination	Destination	Targeted online date
Green Power Express	ITC Holdings	12,000 MW	765 kV/~3,000 miles	Upper Midwest	Midwest and East	2020
SMART	JV (AEP & MidAmerican)	n.a.	EHV	Midwest		n.a. (next 20 years)
LaSalle	LS Power	n.a.	345 kV/~160 miles	Northern Indiana	Northern Illinois	2014
Southern Cross	Pattern Energy Group	up to 3,000 MW	HVDC/~400 miles	East Texas	Southeast US	2015
SunZia	Multiple[1]	3,000 /4,500 MW	500 kV or HVDC/~460 miles	New Mexico	Desert Southwest	2015
Southline	Southline Transmission	750-1500 MW	230/345 kV/~225 miles	New Mexico	Desert Southwest	2014
NM RETA	NE RETA Goldman Sachs	1,200 /2,400 MW	345kV/~185 miles	Central New Mexico	Desert Southwest	2014
High Plains Express	Multiple[2]	1,500 /3,000 MW	500 kV/~1,300 miles	Wyoming	Desert Southwest	2020-2025
Zephyr	TransCanada	3,000 MW	HVDC/~1,000 miles	Wyoming	Desert Southwest	2015
Chinook	TransCanada	3,000 MW	HVDC/~1,000 miles	Montana	Desert Southwest	2015
TransWest Express	Anschutz Corporation	3,000 MW	HVDC/~725 miles	Wyoming	Desert Southwest	2015
Southwest Intertie	LS Power	2,000 MW	500 kV/~500 miles	Idaho	Desert Southwest	2012-2014

Source: Project websites; FERC; Developer press releases

[54] As discussed in Section 0, the underlying rationale for restructuring in Norway was to meet environmental goals by reducing excess capacity.

[55] Bye, T. and E. Hope. "Deregulation of Electricity Markets – The Norwegian Experience," *Discussion Paper No. 433*, Statistics Norway. September 2005

The distribution sector has experienced little change in terms of how companies operate in a given territory (i.e. continue as monopoly businesses). Many jurisdictions have experienced a consolidation trend that resulted in fewer companies For example, in the UK, the number of companies (14) stayed the same, but the ownership of these companies is now reduced to 6 entities.[56] Ontario's distribution sector was comprised of over 300 utilities, and now the province has 83 distribution companies.[57] In New York, seven distribution utilities consolidated into four, three of which are foreign owned. Such consolidation resulted in little, if any, concerns for market power concentration given the natural monopoly nature of the distribution business.

The retail sector has experienced growth, as it did not exist prior to the reforms. The evolution of the retail supply market was characterised by an initial explosion in the number of suppliers. Texas currently has 170 retail electric providers,[58] while Ontario and Alberta have 43 and 24 retail suppliers respectively.[59,60] As there are low barriers to entry and high potential for economies of scale in the retail supply business, the sector usually experiences eventual consolidation.

2.7.2 Share of customers purchasing their power on deregulated markets

The rate of switching is generally limited by the level of default tariffs and whether these tariffs allow sufficient margins for retailers to compete with incumbents. Texas is viewed as an example of successful implementation of retail competition: the default service tariffs were set at a level well above the wholesale market prices and were adjusted for changes in natural gas prices (which is the primary price setting fuel in Texas). Thus there was no narrowing or reversal of price differential between the default service tariffs and wholesale market prices.

Evidence suggests that large users of electricity are able to benefit from retail competition[61] (if the default service tariffs reflect wholesale energy prices, large users of electricity can benefit from retail competition by entering into hedge contracts that fix the electricity prices for a defined term). Figure 14 shows the switching rates across the US and Canada; large industrial and commercial customers have switched at higher rates when compared to medium industrial and commercial and residential customers.

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56 Ofgem. The GB electricity distribution network <https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network> Accessed April 25, 2014.

57 OEB. Licensed Market Participants (Distributors) < http://www.ontarioenergyboard.ca/OEB/Industry/Licences/Licensed+Market+Participants> Accessed April 25, 2014.

58 Public Utility Commission of Texas. *Alphabetical Directory of Retail Electric Providers* <http://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx> Accessed on April 29, 2014.

59 Ontario Energy Board. *Electricity Retailer Issued Licenses* <http://www.ontarioenergyboard.ca/html/licences/all_issuedlicences_read.cfm?showtype=Electricity%20Retailer> Accessed on April 29, 2014.

60 Utilities Consumer Advocate. *Competitive Price Companies* <http://www.ucahelps.alberta.ca/competitive-price-companies.aspx> Accessed on April 29, 2014.

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

It is less clear if smaller users (e.g. residential customers) can benefit from retail competition when considering the transaction costs, especially when compared to default service arrangements where local distribution utilities procure energy from the market through competitive procurement processes, as is done in a number of US states (e.g. New Jersey, Pennsylvania).

Figure 14. Switching rates across the US and Canada (top 12)

Jurisdiction	Large Commercial / Industrial	Medium Commercial / Industrial	Residential
Texas	100.0%	100.0%	100.0%
Pennsylvania	97.5%	85.5%	37.7%
Maine	95.6%	60.3%	28.0%
Illinois	93.9%	83.7%	68.5%
Maryland	93.8%	71.8%	26.1%
Alberta	93.8%	62.2%	40.0%
Massachusetts	89.0%	61.1%	16.9%
Connecticut	86.7%	78.0%	43.5%
New Jersey	85.7%	56.5%	16.0%
District of Columbi	83.5%	83.5%	14.6%
New York	83.1%	58.7%	24.0%
Ohio	79.3%	83.5%	50.2%

Source: Distributed Energy Financial Group. Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS). 2014

2.7.3 Wholesale and retail electricity prices

There is no general consensus on whether restructuring results in prices (wholesale and retail) that are lower than they would have been otherwise.

Proponents of restructured electricity markets, including Electric Power Suppliers Association ("EPSA"), have argued that:

- Restructuring was introduced because cost of service regulation did not work to contain costs;
- Electricity price increases are related to increases in fuel costs;
- Competitiveness of retail markets is determined by whether default services reflect the wholesale price of electricity;
- Customers have more choice in selecting their suppliers and products;
- There are inefficiencies in unrestructured states, where new power plants by IPPs are being idled because of poor power procurement policies and discriminatory transmission policies;

- Need for capacity payments is not a fault of restructuring, but the result of measures introduced to artificially lower the energy prices; and
- Competitive wholesale markets led to investments in more efficient and technologically advanced power plants.

While LEI is skeptical of their claims, critics of the restructured markets argue that the wholesale (and subsequently retail) energy prices are higher under the restructured model because of the following factors:

- **Absence of cost-based offers in the energy market**: generators can submit bids higher than their actual cost of running a power plant (though doing so evenutally attracts entry to push prices down);
- **Single-clearing price**: uniform prices do not differentiate lower cost power plants, thus the benefits do not go to consumers (but market incentivizes only the lowest cost plants to run, and punishes uneconomic investment);
- **Reliance on locational price signals**: instead of incentivizing new builds (power plants and transmission) where needed, higher prices may provide incentives to incumbents to keep the supply constrained, or ensure that price bids by new entrants remain high (rules on minimum price offers for new entrants are in place in PJM, NYISO and ISO-NE);
- **Barriers to entry**: incumbents have challenged arrangments to facilitate the development of new power projects by filing a suit in US District Court (though such state-sponsored arrangements may actually increase costs within those states); and
- **Complexity and lack of transparency**: markets introduce complex new markets and pricing policies to increase revenues to generators. Moreover, the existence of financial entities trading in virtual products adds to the lack of market transparency[62] (though virtual trading may actually reduce costs to consumers through temporal arbitrage).

The American Public Power Association ("APPA"), in its report,[63] has noted that the metrics for determining whether restructuring produced energy prices lower than would have been otherwise may include return on equity ("ROE"). APPA notes that FERC launched investigations of interstate transmission of natural gas because the ROE ranged between 18.50% and 21.75%, yet in the same period ROEs of merchant generation subsidiaries of Exelon, PPL Corp and Public Service Enterprise Group were 23%, 22% and 22%, respectively. APPA estimated the excess cost to consumers[64] by four largest merchant generators in PJM (Exelon, PSEG, PPL and First Energy) at about $3.2 billion in 2011. Another study also reached similar

[62] Caplan E. and S. Brobeck. *Have Restructured Wholesale Electricity Markets Benefitted Consumers?* American Public Power Association. 2012

[63] Ibid.

[64] The difference between the ROE of merchant operations and regulated businesses multiplied by the total equity.

conclusions.[65] LEI notes, however, that such studies fail to acknowledge the savings from the shifting of risk allocation from ratepayers to investors, and for the other market players whose realized returns were far lower.

While wholesale electricity markets may have some issues (need to address long term price signals, importance of generation and transmission separation, valuing resource diversity) that impact price levels, it is important to understand that there are normally other objectives of restructuring. In some cases, economic efficiency is best served when prices go up, for example when cross-subsidies are eliminated or an appropriate cost of capital is used. As discused earlier in Section 2.2, defining success or failure of the electricity restructuring solely based on electricity price impact may not be wise unless that is the sole objective of restructuring.

2.7.4 Total factor productivity ("TFP") level in the utilities sector

Generally, restructuring is expected to improve the productivity levels in the electricity sector as the competitive pressures stimulate generation and the transmission, distribution and retail sectors seek and sustain operational improvements. Moreover, under PBR-style regulations, as discussed in detail in Section 3 (Performance-based Regulation), utilities should be able to improve productivity greater than historically measured long term productivity improvements for the industry as a whole. In North America, a number of PBR forms are used (also elaborated upon in Section 3). In the UK, it was estimated that privatized utilities have increased labour productivity, and sometimes TFP, at rates faster than before the reforms, and achieved sustained improvements in level of service quality.[66]

TFP has been extensively studied, particularly in the wires businesses. US historical data (presented in Figure 15 and adapted from a TFP study prepared for the Alberta Utilities Commission) indicates a downward trend in productivity (of the distribution component) across electricity and combined electricity and gas utilities. Declining productivity growth trends can be due to a variety of factors, including the pace of technological change, the timing for its adoption, changing demand patterns, general economic conditions, regulatory changes, demographics etc.

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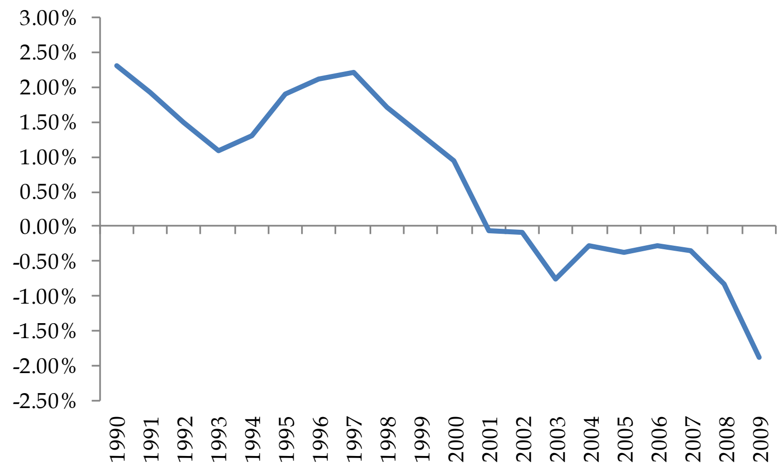
[65] Lenard T.M. and S. McGonegal. *Evaluating the Effects of Wholesale Electricity Restructuring.* Technology Policy Institute. 2008

[66] Holder, S. *Privatisation and Competition: the Evidence from Utility and Infrastructure Privatisation in the UK*. Twelfth Plenary Session of the OECD Advisory Group on Privatisation. OECD. 1998

Figure 15. US utilities* TFP trends over last 20 years (5-year rolling averages)



** Utilities include electric and combined gas and electric; the study measured the TFP of the distribution component; costs related to power generation and transmission, as well as general overhead costs, were not included in the study. Source: adapted by LEI from 'Total Factor Productivity Study for use in Alberta Utilities Commission Proceeding 566 – Rate Regulation Initiative.' Prepared by AUC Consultants. December 30, 2010.*

LEI has also conducted TFP studies for the Ontario local distribution companies ("LDCs"). LEI first examined the historical TFP trends of Ontario electric distribution utilities in 2007 for the Coalition of Large Distributors ("CLD") for the OEB 3rd Generation PBR proceeding,[67] using data for the 2002-2006 period. The Ontario TFP analysis was expanded to include three subsequent years (2007, 2008, and 2009) in the context of FortisAlberta Inc. ("FAI") proposal on PBR to the AUC in 2009.[68] Another extended study (with analysis performed towards the end of 2012) was prepared for ENMAX Power Corporation.[69] This study added two more years (2010 and 2011), bringing the total number of years under the extended study to a decade. The original Ontario LDCs TFP study from 2007 examined the data filed by 86 LDCs in Ontario. By 2009, due to mergers and amalgamations, the total number of LDCs declined to 78. By 2011 the sample size declined to 76.

The extended study results showed that over the last decade, Ontario's electricity distribution sector's TFP growth had been negative, ranging between -0.7% and -0.2%. These negative trends were primarily driven by the relative increase in the inputs (labor measured by OM&A and physical capital), which outpaced the growth in outputs (throughput, peak demand, and total consumers served).

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[67] Ontario Energy Board. *Written Comments on Board Staff and PEG Report Prepared by Julia Frayer, London Economics International LLC for the Coalition of Large Distributors and Hydro One Networks, Inc.* Proceeding EB2007-0673.

[68] Frayer, Julia. *Prepared Testimony of Julia Frayer for FortisAlberta Inc's Performance Based Regulation ("PBR") Proposal*. (Application No. 1606029, Proceeding ID 566). July 22, 2011

[69] Alberta Utilities Commission. *Total Factor Productivity of Ontario's Electricity Distributors: Extended Study*. Prepared by LEI for ENMAX Power Corporation as Additional Evidence for Formula Based Ratemaking Transmission Tariff Re-Opener Application (No. 1608905, Proceeding ID#2182). March 27, 2013

While distribution TFP studies can help inform discussions of transmission sector productivity growth (because of similarities in the institutional framework, business environment, and regulatory requirements), transmission-specific TFP studies have also been conducted. Recent studies in Australia have found productivity in the transmission sector to be negative. In July 2010, the Independent Pricing and Regulatory Tribunal ("IPART") conducted a study for New South Wales ("NSW") Government in Australia to review productivity performance of NSW state owned corporations. IPART found an annual average TFP growth rate of -1.49% (1998–2005) and -1.42% (2005–2009) for NSW's largest electricity transmission company TransGrid.[70] A few other transmission TFP studies are also summarized in Figure 16.

Figure 16. Transmission TFP studies

Jurisdiction	Timeframe covered by the TFP study	Avg. annual TFP growth rate	Consulting Firm and Source
New South Wales (NSW), Australia - TransGrid (largest electricity transmission company)	1997/98 - 2003/04 2004/05 - 2008/09	-1.49% -1.42%	Independent Pricing and Regulatory Tribunal for NSW Government (*Review of the ProductivityPerformance of State OwnedCorporations. Other Industries - Final Report.* July 2010)
Netherlands - TenneT (Dutch electricity transmission operator)	1979 - 2001	1.25% to 2.25%	Europe Economics Chancery House for DTe (*Research into Productivity Growth inElectricity Transmission and OtherSectorsA Report for DTe.* March 7, 2006)
United Kingdom - National Grid Company (national transmission company)	1991/92 - 2001/02	2.40%	Cambridge Economic Policy Associates (CEPA) report for Ofgem (*Background to work on assessing efficiency for the 2005 distribution price control review.* September 2003)[1]
New Zealand - Transpower (national transmission company)	1996 - 2002	2.30%	Meyrick and Associates report for New Zealand Commerce Commission (*Regulation of electric lines businesses. Resetting the price path threshold – comparative option.* 2003)[1]

[1] *Original sources, while the growth rates are transmission growth rate trends reported by Europe Economics (2006).*

On the generation front, there has been evidence in the UK of generators improving their operating costs and plant availability post-restructuring, particularly for nuclear assets.[71,72] Argentina's generation sector experienced similar improvements following the restructuring and foreign investments, where improvement in efficiency was estimated at nearly 20% with labour efficiency improvement at 23% in the first two years after private owners took over the power plants (privatized in 1992, estimates for performance improvements between 1993 and 1995).[73]

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70 Independent Pricing and Regulatory Tribunal for NSW Government. *Review of the Productivity Performance of State Owned Corporations, Other Industries - Final Report*. July 2010

71 Newbury, D. and M. Pollitt. "The Restructuring and Privatization of Britain's CEGB – Was It Worth It?" *Journal of Industrial Economics*, 45(3), 269-303. 1997

72 Kwoka, J. E. Transforming Power, Lessons from British Electricity Restructuring. *Regulation Magazine*, The Cato Review of Business and Government. Volume 20, No. 3. 1997

73 Omar Chisari, et al. *Winner and Losers From Utility Privatization in Argentina: Lessons From a General Equilibrium Model*. The World Bank. 1999

There have also been several international generation TFP studies. A US study[74] investigated the effect of incentive regulation on TFP growth of generation companies in the United States (covering the period 1986-1998), and showed that productivity improved at a rate of 1.5% per year in the studied firms. Another study found that the performance of nuclear plants improved 10% in terms of operational efficiencies as the result of restructuring and consolidation since the late 1990s.[75]

An Australian study[76] reviewing the 1961-1999 period aiming to provide a more realistic view of the change that occurred in the electricity industry after restructuring in the 1990s, concluded that there had been a substantial improvement in the performance of the industry since the mid-1980s. The study noted that the beginning of this improvement pre-dates the substantial restructuring of the industry in the early 1990s although the improvement in the productivity performance of the industry did speed up after 1991. Another study performed in India[77] explored how productivity had changed, given changes in capacity additions and deregulation (covering the 2003-2008 period) showed an annual TFP growth of 1.2%. A study conducted in Iran[78] analyzed performance of thermal power plants in light of restructuring (covering the period 2002-2008) concluded that improvements in efficiency and productivity in Iran had occurred with a positive relationship with restructuring.

TFP studies present a variety of empirical approaches, but they all share a common goal, which is to document the observed historical change in inputs and outputs over a given period of time, thereby capturing average trends in productivity over time. TFP studies, while potentially providing an indication of past performance, provide little insight into what is achievable in the future. It is questionable whether substantial incremental productivity gains can be reasonable expected where restructuring, particularly in the form of incentive ratemaking regulation, has been in place for extensive periods, and the least cost and/or most effective projects have already been implemented.

Moreover, TFP studies and the empirical results depend on the available historical data, length of the time series, selection process and assumptions made around data variables used to represent inputs and outputs, as well as the specific empirical techniques chosen. The results can also be the subject of much debate between regulators, utilities, interveners and other parties.

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74 Rungsuriyawiboon & Coelli. *Regulatory Reform and Economic Performance in US Electricity Generation*. 2004.

75 Davis, L.W. and C. Wolfram. "Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power," *Working Paper 217.* Energy Institute at Haas. 2011

76 Abbott, M. *The productivity and efficiency of the Australian electricity supply industry*. Energy Economics. 2006.

77 Behera. *Productivity change of coal-fired thermal power plants in India: a Malmquist index approach*. 2011

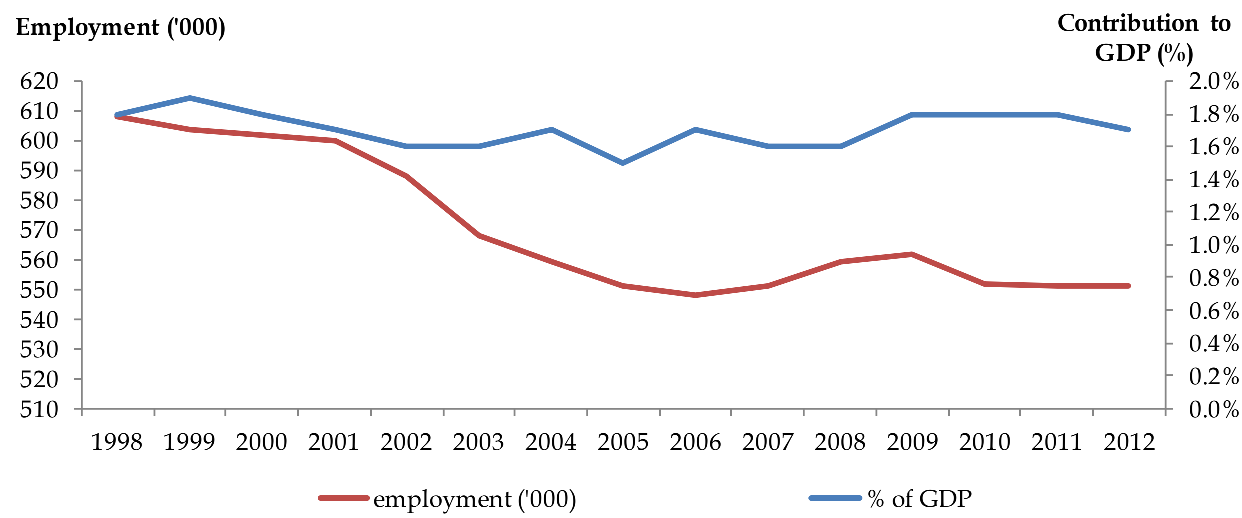
78 Hosseini. *Evaluating the efficiency changes of the Thermal Power Plants in Iran and Examining its Relation with Reform using DEA Model & Malmquist Index*. 2011

2.7.5 Number of jobs and gross domestic product attributed to power utilities

Restructuring often means evolution of employment while maintaining economic output in the sector. Opening of the generation sector generally results in reductions in jobs with the utility; however, some if not all of these jobs may be recovered in the IPP sector. There have been improvements noted in operational efficiencies through reduction of number of employees in the generation sector in the UK (nuclear power increased output by 50% while reducing the total workforce by the same percentage, thus doubling the output per employee).[79] Indeed, the expected improvements in operational efficiency (i.e. relying on fewer workers) have prompted strong reaction and opposition from labour unions in Thailand and Malaysia, that have contributed to stalling of restructuring efforts.[80]

Similar improvements have been noted for transmission and distribution companies in the UK, where operational improvements were noted in labour productivity (among other improvements such as service quality, cost of managing network congestion and balancing).[81]

Figure 17. US utilities sector employment and GDP contribution trends



Source: US Bureau of Economic Analysis

The US data on the utilities' sector employment and contribution to GDP (presented in Figure 17) demonstrates a declining trends in employment, while contribution to GDP has stayed in a similar range over the past few years.[82]

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[79] Kwoka, J. E. Transforming Power, Lessons from British Electricity Restructuring. *Regulation Magazine*, The Cato Review of Business and Government. Volume 20, No. 3. 1997

[80] Pelkmans, J. and N. Wagner. *Privatization and Deregulation in ASEAN and EC: Making Markets More Effective*. Institute of Southeast Asian Studies, 1990

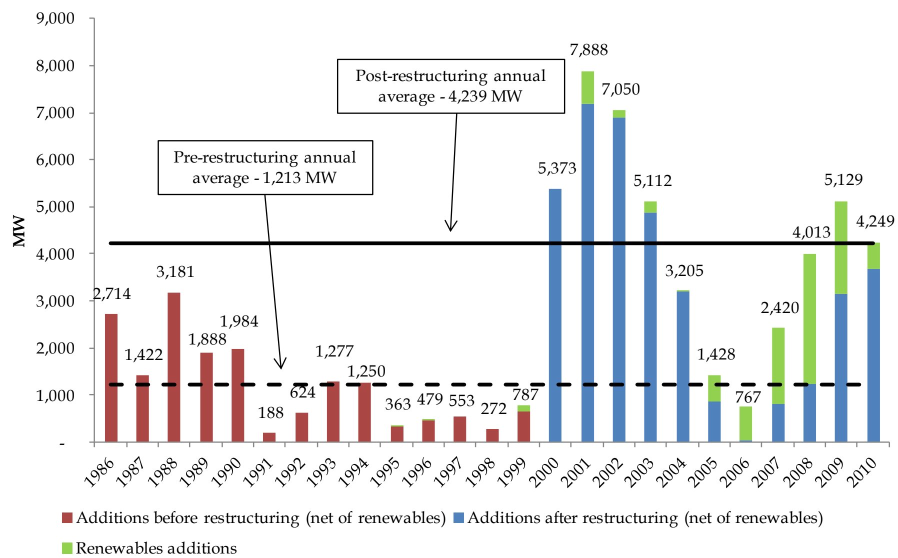
[81] Domah, P.D. and M.G. Pollitt. "The Restructuring and Privatization of the Regional Electricity Companies in England and Wales: A Social Cost Benefit Analysis," *Fiscal Studies*, 22(1): 107-146. 2001

The data also points to challenge of isolating the effect of any particular factor (e.g. restructuring) on the sector. For example, the reduction in employment may be attributed to changes in the type of power plants (e.g. natural gas-fired fired combined cycle gas turbine ("CCGT") units require fewer operators than coal-fired steam turbine power plants),[83] or to overall technology improvements, independent of the competitive pressures (e.g. automation, better logistics and fuel supply managements).

2.7.6 Level of investment in the various segments of the power industry

The level of investment post-restructuring generally depends on the state of the sector before reforms. Most jurisdictions that embarked upon restructuring efforts have been motivated by a high level and high growth rate of electricity rates, which can be caused by inefficient and large investments (e.g. nuclear energy in many US states), and subsequent overcapacity. Such jurisdictions are not likely to witness significant growth in investments post-restructuring, beyond the routine maintenance investments.

Figure 18. Generation sector investments in Texas



Source: Commercial database.

However, if a jurisdiction experienced high electricity prices due to tight reserve margins, the market should create opportunities for private capital to invest in the growth of the industry. Generally, restructured markets should result in a more efficient allocation of capital, thus

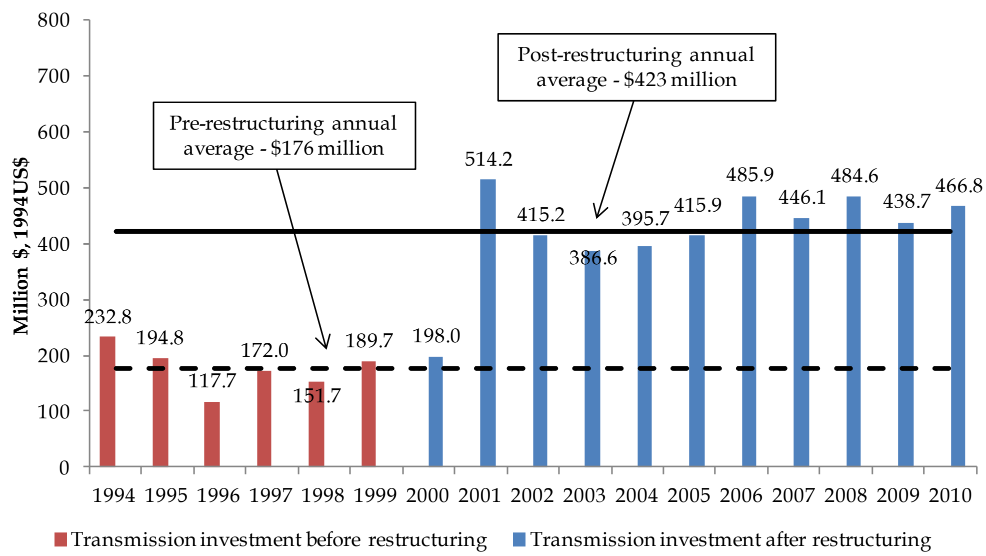
[82] It should be noted that this data includes statistics from non-restructured states as well. US state level data for employment in the electricity sector is not readily available.

[83] Although in certain cases it can be argued that the change in type of power plants was incentivized by the competitive pressures.

bringing overall economic benefits to the society as a whole. These trends can be identified in investment in the generation sector post-restructing in Texas for example (see Figure 18).

Transmission sector investments abide by the similar rules as generation (i.e. depend on the current state of investment around the timing of restructuring), but the fact that transmission is unbundled from former vertically integrated utilities creates opportunities to invest in the grid in a manner that benefits the whole system (all users of the grid). This is in contrast to the vertically integrated structure where investments in transmission may be ignored in favor of other business units (where transmission, distribution and generation assets compete for investment capital). Again, these trends have been identified in the case of Texas, where the average annual investments before and after restructuring show clear growth in the invested capital.

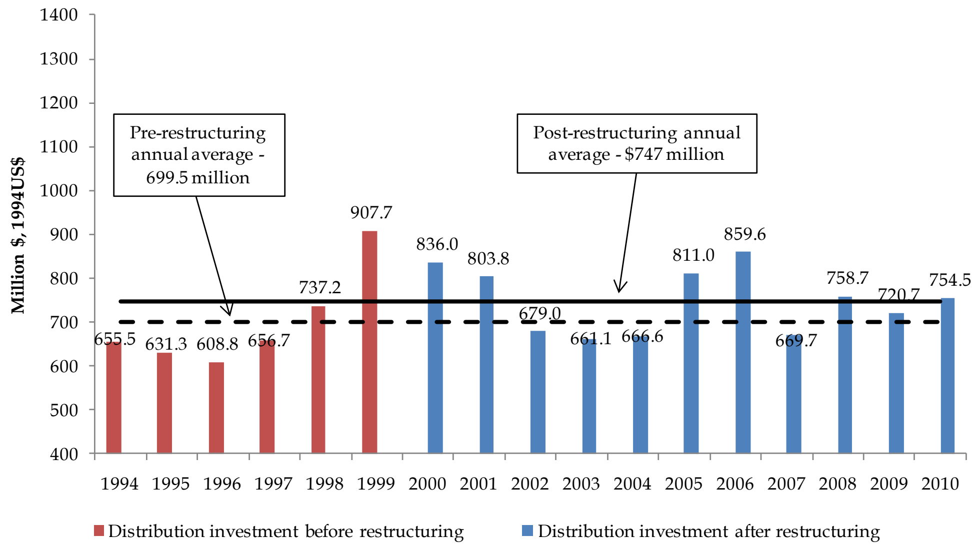
Figure 19. Transmission sector investments in Texas



Source: Commercial database.

As new transmission connections are needed to manage changes in flow patterns and new power plants connections, generally, the introduction of competition in the generation sector spur corresponding investments in the transmission sector. However, the impact of generation sector investments on the distribution sector are less pronounced, and investments in the distribution sector are primarily driven by expansion of the distribution network. Figure 20 presents distribution sector investments in Texas during the same timeframe.

Figure 20. Distribution sector investments in Texas



Source: Commercial database.

2.7.7 Costs of regulatory process

Regulatory costs can be associated with activities related to the ISOs, regulators and competition authorities. Figure 21 presents budgets for a selected sample related to regulation of the wholesale market.

Figure 21. Budgets and cost per MWh of energy for selected ISOs and surveillance authorities

Regulatory agency	Jurisdiction	Annual budget	Trading charge ($/MWh)	Year
Market Surveillance Administrator	Alberta	$ 4,065,944	$ 0.0319	2014 Approved
FERC (Market Oversight and Surveillance)	USA	$ 165,684,000	$ 0.0423	2014 Proposed
NYISO	New York	$ 160,000,000	$ 0.9560	2014 Proposed
IESO	Ontario	$ 129,900,000	$ 0.8030	2014 Proposed

Note: Trading charge is estimated using energy forecasts reported by respective ISOs. Trading charge for FERC is not levied; we have estimating it for comparative purposes using proposed budget (from FERC) and US energy forecast for 2014 (from EIA).

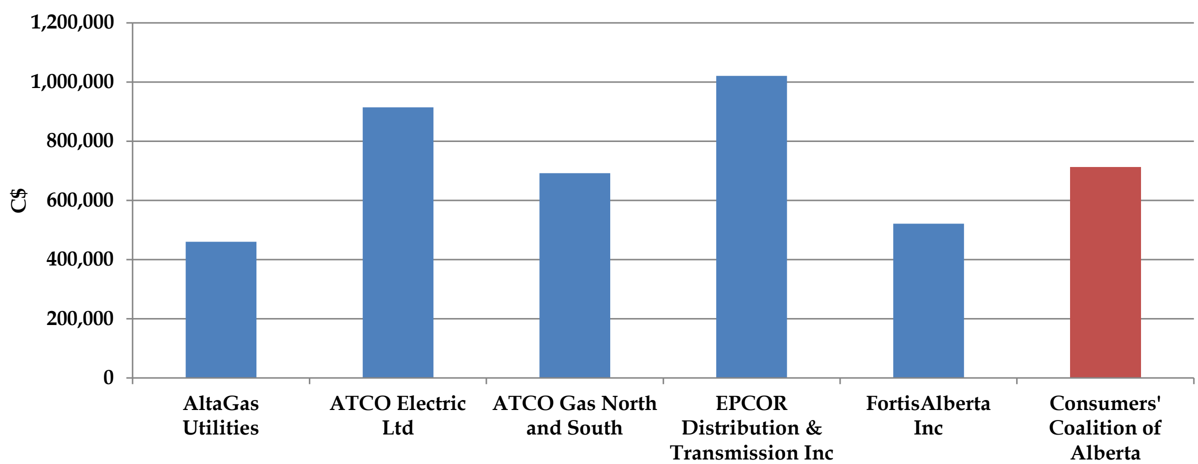
Source: Alberta Market Surveillance Administrator <http://albertamsa.ca/uploads/pdf/Archive/0-2013/MSA%202014%20Budget%20Approval%20131210.pdf>;
NYISO <http://www.nyiso.com/public/webdocs/markets_ operations/committees/mc/meeting_materials/2012-11-02/agenda_05__presentation_on_2013_draft_budget.pdf>;
FERC <https://www.ferc.gov/about/strat-docs/fy14-budg.pdf>
EIA. Annual Energy Outlook 2014 (Tab 08) <http://www.eia.gov/forecasts/aeo/index.cfm?src=Electricity-f3>

These costs are not necessarily new, or a result of restructuring, as these activities/functions continue to exist under vertically integrated structures as well. However, it is important to recognize that any increase in costs are envisioned to be offset by improvements in efficiency, resulting in net benefits for the power industry (more profitable) and consumers (rates lower than would be otherwise). For example, CAISO and PacifiCorp are set to start an expanded Energy Imbalance Market ("EIM") later this year; an analysis by Energy and Environmental Economics, Inc. suggests significant gains in efficiency.[84]

Turning to the wires sector, depending on the PBR term, ongoing regulatory costs may be lower under PBR-style regulation, avoiding frequent COS filings in front of the regulator.

Participating in the regulatory process can cost utilities several million dollars. Utilities are generally able to include regulatory costs in revenue requirement and recover from ratepayers. Under restructured models, costs may be similar to those incurred previously. For instance, traditional cost of service hearings and PBR hearings may be similarly expensive, however, a longer term of the PBR (5-7 years in some instances) may be more cost-effective than more frequent COS filings. Figure 22 provides regulatory costs borne by utilites (and an intervener: Consumers' Coalition of Alberta) in the first PBR proceeding in Alberta.

Figure 22. Utility costs for PBR proceeding in Alberta



Source: Alberta Utilities Commission (Decision 2013-051 – Rate Regulation Initiative Distribution Performance-Based Regulation Cost Awards)

In designing the regulatory process, regulators need to balance transparency, participation, and cost. While awarding funding to intervenors can level the playing field, it risks frivolous intervention. Regulators need to be attentive to in order to avoid focusing on details which have trivial impact on overall rates or important regulatory outcomes. Oral hearings can be

[84] The analysis estimates benefits of $21 million to $129 million for the year 2017. Preliminary cost estimates of setting up the EIM range from $3 million to $6 million, with an estimated annual cost of $2 million to $5 million, indicating that the two-party EIM would provide a low-cost, low-risk means of achieving operational savings and enabling greater penetration of variable energy resources. See Ren Orans et al. "Energy Imbalance Market Benefits in the West: A Case Study of PacifiCorp and CAISO," *The Electricity Journal*. 2013

burdensome and unnecessary, and are a unique feature of North American regulatory processes.

2.7.8 Other potential impacts of restructuring implementation

This section discusses a few other effects of restructuring, including potential impacts on: power sales and peak demand, energy efficiency and conservation, operation of generation assets and network lines, level of return on equity, reliability of power supply, greening of the industry, and aggregate cost savings for ratepayers/economy as a whole.

Power sales and peak demand: under most circumstances, energy consumption would reflect the level of economic activity. While it can be argued the total consumption of electricity would be largely independent of the market organization, one of the effects of restructuring is to provide consumers with clear price signals, which in turn, induces them to adjust their consumption. Competitive wholesale and retail markets create opportunities for product innovation, including rewards for energy conservation and demand response, which reduce both total energy consumption and peak demand.[85] For example, in one of the first capacity auctions in PJM, 963 MW of demand response cleared the market, an equivalent of a large power plant.[86] Figure 23 presents demand response levels in selected jurisdictions.

Figure 23. Demand response levels in selected jurisdictions

Jurisdiction	Demand Response (MW)	Peak Demand (MW)	DR as % of Peak Demand	Year
CAISO	2,322	46,846	4.96%	2012-actual
ERCOT	2,100	67,245	3.12%	2013-actual
ISO-NE	2,769	27,379	10.11%	2013-actual
MISO	7,197	98,556	7.30%	2012-actual
NYISO	1925	32,439	5.93%	2012-actual
PJM	10,477	157,508	6.65%	2013-actual

Sources: CAISO. 2013 Summer Loads and Resources Assessment; CAISO. Peak Load History 1998-2013; ERCOT. *Electric consumption increases 2.1 percent in 2013*. Press Release. January 17, 2014; ISO-NE website; MISO State of the Market 2012; NYISO. Power Trends; PJM State of the Market 2013

Energy efficiency and conservation gains: under COS, utilities prepare IRPs for regulatory approval, which include energy efficiency and demand response programs mandated by policy. During the transition to restructured markets, there was a temporary lull in the focus on energy efficiency, but the price signals in the competitive markets created conditions to determine the economic value of conservation and energy efficiency efforts, while distribution companies were also encouraged to develop programs. By exposing customers to transparent and

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85 Lesser, J.A. *The Benefits of Electric Restructuring to Pennsylvania Consumers*. EPGA/EPSA, 2007

86 PJM. *PJM Reliability Pricing Model Attracts More Generation, Demand Response.* Press Release, October 16, 2007 http://www.pjm.com/contributions/news-releases/2007/20071012-RMP-auction-results1.pdf (As reported in Lesser, J.A. *The Benefits of Electric Restructuring to Pennsylvania Consumers*. EPGA/EPSA, 2007)

comprehensive real time price signals, and appropriately pricing negative externalities, the market itself determines an equilibrium, and signals appropriate levels of investment in energy efficiency and conservation demand management.[87] Energy efficiency and conservation products' development at the wholesale generation and retail levels are driven by price signals, while these products' development at the distribution level is driven by policy. The examples of price signal-driven demand response and conservation programs and products include demand response aggregators, who manage demand response operations of a group of customers.

Nova Scotia passed an energy efficiency legislation in April 2014, whereby the Public Utilities Act was amended to include the addition of an energy efficiency and conservation section. The legislation removes the efficiency tax from electricity bills effective January 1, 2015, and introduces competition for Nova Scotia Power, whereby it requires Nova Scotia Power to purchase cost effective, reasonably available energy efficiency from Efficiency Nova Scotia, a firm independent of Nova Scotia Power. The Nova Scotia Utility and Review Board will provide regulatory oversight of efficiency programs and determine affordability.

Source: Nova Scotia Government (News Releases); April 7, 2014.

Similarly, in Vermont, Efficiency Vermont, operated by a private nonprofit organization, the Vermont Energy Investment Corporation, under an appointment issued by the Vermont Public Service Board, provides technical assistance, rebates, and other financial incentives to help Vermont households and businesses reduce their energy costs with energy-efficient equipment, lighting, and approaches to construction and major renovation. In addition, Efficiency Vermont partners extensively with contractors, suppliers, and retailers of efficient products and services throughout the state.

Source: Efficiency Vermont website: Accessed on April 28, 2014

Operation of generation assets: Some evidence suggests that the operational performance of generation assets improves after transitioning to the competitive environment. Competition provides strong incentives to improve availability (by reducing the down time due to forced and maintenance outages) of power plants. This has been experienced in international jurisdictions such as the UK and Argentina, as discussed earlier in Section 2.7.4.

Operation of network assets (line losses): The operation of network assets can be driven by factors that are not always related to the restructured state of the industry. For example, the amount of time expired since the previous investment cycle is likely to determine network performance. For instance, if the utility has just replaced most of its substations and wires, the performance measures are likely to be high, but if it has been thirty years or so since the last major overhaul, the system may perform less well.

However, unbundling of distribution and transmission assets creates opportunities for investments with clearly defined benefits and cost causality (investment costs are amortized to the users of the network through surcharges on tariffs). Privatization and market-based economic relations can provide strong incentives to improve the operations of wires businesses.

[87] Goulding, A.J. *A New Blueprint For Ontario's Electricity Market.* C.D. Howe Institute. 2013

Argentina's experience with restrucuring and privatization shows that dramatic improvements can be achieved, where the line losses were reduced from 26% in 1991 to 7% by 1999.[88] The PBR framework for transmission and distribution networks often includes explicit requirements to prevent deterioration of or to reduce the line losses. As discussed further in Section 3 (Performance-based Regulation), line losses of Hydro One in Ontario decreased gradually (by 1% per year on average) from 1,780 GWh in 2007 to less than 1,700 GWh in 2012.

Level of return on equity in various segments of the power industry: The competitive generation markets have impacted the risk/return profile of the generation business and changed how resource adequacy issues are addressed under the competitive power markets. This has been discussed in Section 5 (Customer and Service Provider Risks), specifically under Section 5.2 - risks faced by utilities. Few notable points are as follows:

- In a vertically integrated structure, the utility is considered to have a weighted average risk of individual risks associated with the generation, transmission, and distribution businesses. Under a restructured unbundled structure, cost of capital determination can be targeted to each of the three businesses independently.

- The unbundled generation sector will often require a higher return than a vertically integrated utility, commensurate with the higher risk level.

- In a competitive market, generators face price volatility and are not guaranteed to recoup their costs, in particular their investment costs. Competition increases risks to shareholders, and as a result of this transformation, the engineering component of the generation business has become less dominant while economic, financial and legal components have become increasingly important.

- From the perspective of ratepayers, risks related to generation investment have been shifted from them (the ratepayers) to generators.

- The basic fundamentals of estimating appropriate levels of returns on equity for transmission and distribution remain similar in unbundled and vertically integrated structures.

Figure 24 compares betas for a selected sample of vertically integrated utilities and independent power producers. Betas measure the element of non-diversifiable or market risk related to investment in a company's equity, with higher betas implying a higher level of risk. Related to this, Section 5 presents a comparison of weighted average cost of capital between IPPs and regulated companies.

[88] Center for Energy Economics. *Results of Electricity Sector Restructuring in Argentina*. University of Texas at Austin

Figure 24. Betas (levered) for selected sample of vertically integrated utilities and IPPs

2006-2013 average			
Utilities	**Beta**	**IPPs**	**Beta**
AEP	0.79	AES	1.09
Duke Energy	0.73	Boralex	0.76
Entergy	0.77	Calpine	1.08
Southern Co.	0.62	NRG	1.01
Xcel Energy	0.69	TransAlta	0.68
Average	0.72	Average	0.93

Source: Bloomberg

Reliability of power supply (reserve margin, outage frequency and duration): Reliability of power supply after transition to a restructured model is dependent on a number of factors, such as pace of demand growth, capacity surplus conditions prior to the reform, and access to interconnections.

The organization of the electricity market and the level of interference by regulators may also have an impact on the reliability performance of the system. As discussed earlier, energy only markets should produce sufficient price signals to incentivize new entry, and thus keep the reliability reserve margins at levels that do not cause serious concerns for reliability. However, due to the desire to maintain steady prices for end-users, policy makers often interfere to control the price spikes (e.g. through price caps) that may not reflect the economic cost of new entry, thus leading to tigher reserve margins and negative impact on the system reliability.

This has been the case in Texas, where ERCOT established price caps at the orders of the Public Utilities Commission of Texas ("PUCT"), a regulator. The generation owners have voiced concerns about insufficient price levels to induce new entry, and such concerns have materialized as the pace of new entries slowed down and the system experienced a number of blackouts due to tight reserve margins. ERCOT is projecting further deterioration in reserve margins. Although the price caps have been raised (and over 2,000 MW of capacity additions were announced as the result of price cap changes),* the fear is that the damage has been done as power plants require long lead time before they are operational. As the result, ERCOT and PUCT mull introduction of capacity markets.

* Source: ERCOT. *ERCOT Investment Incentives and Resource Adequacy*. Prepared by ERCOT Consultants. 2012

There were concerns that the transition to restructured market model may have left reliability management neglected in the complexity of new institutions and continually changing environment.[89] NERC in its 2004 Long-Term Reliability Assesement noted that "*Over the past decade, the increased demands placed on the transmission system in response to industry restructuring*

[89] Whitehead, J.T. *Analysis of The Blackout Of August 14, 2003*. A report prepared for TVA and US DOE. December 2003

and market-related needs are causing the grid to be operated closer to its reliability limits more of the time."[90]

Restructuring is a process, and as part of the process new institutions (i.e. Regional Transmission Organizations – "RTOs") were created to specifically address reliability through coordinated transmission planning. FERC, via Order 2000,[91] encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America. In the same Order, FERC noted: "*Regional institutions can address the operational and reliability issues now confronting the industry, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation*." As discussed earlier in 2.6.3, collaboration on part of ISOs (and RTOs), transmission owners and electricity utilities is key to assure reliability.

"Greening" of the industry: Restructured markets create opportunity to meet the preferences of diverse customers (over and above government mandates), including "green power." For example, competitive retail suppliers allow customers to procure carbon-free power to meet their social and environmental obligations. In theory, restructured markets allow for pricing of negative externalities (e.g. environmental, social and economic costs of carbon emissions), which should support the development of renewable technologies and products.

At present, greening of the industry is mostly driven by policy considerations, for example, Renewable Portfolio Standards ("RPS") across several states in the US – both restructured (RPS exist across all restructured states in the US) and non-restructured (e.g Kansas, Missouri, North Carolina, Arizona etc.). However, the presence of competitive markets allows for relatively more efficient utilization of capital and creates conditions to price the value of green products. Indeed, increase in market mechanisms led by liberalization create greater diversity of products, and incentives can be put in place to increase purchase of green power. For example, there are two markets for RECs: voluntary markets, and compliance markets for satisfying RPS goals. As presented in Figure 25, given that voluntary RECs have value indicates that some customers see benefit in voluntary green programs.

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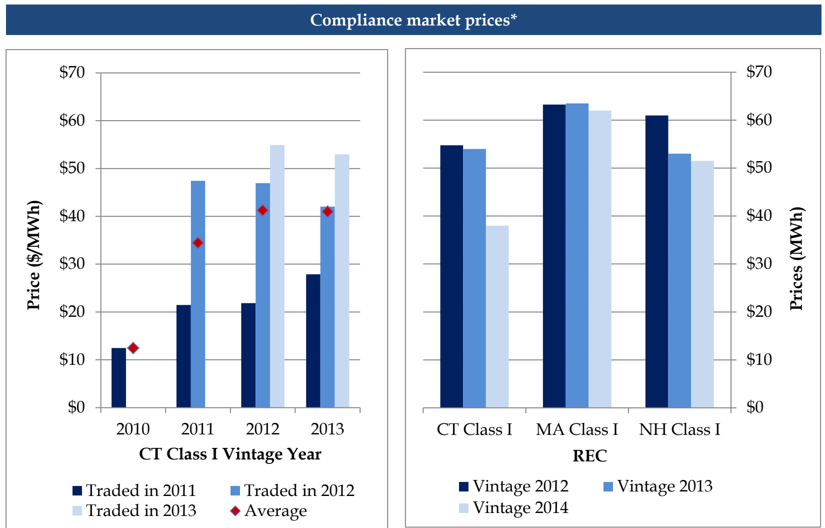
[90] NERC. *2004 Long-Term Reliability Assessment*. 2004

[91] FERC. *Order No. 2000 - Regional Transmission Organizations*. Docket No. RM99-2-000. December 20, 1999.

Figure 25. Market prices – Compliance and Voluntary RECs



Voluntary market prices ($/MWh)

REC	Term	2013 Price ($/MWh)
WECC WREGIS Green-e Certifiable Wind	Back Half 2011	$0.50
WECC WREGIS Green-e Certifiable Wind	Front Half 2012	$0.80
WECC WREGIS Green-e Certifiable Wind	Back Half 2012	$0.85
National Green-e Certifiable Any Tech	Back Half 2012	$0.70
National Green-e Certifiable Any Tech	Front Half 2013	$0.73
National Green-e Certifiable Wind	Back Half 2012	$0.70
National Green-e Certifiable Wind	Front Half 2013	$0.73

** As of March 2013; Source: commercial database*

In addition, there is a Zero Emission Renewable Energy Credits ("ZRECs") program in Connecticut, whose purpose is to provide 15-year revenue streams for small "behind the meter" renewable projects from the sale of renewable energy credits ("RECs") to public electric utilities.[92] Also, in Alberta, a Clean Energy Standard ("CES") proposal is currently being discussed, which is structured as a greenhouse gas emissions-intensity-based standard that would apply to electricity retailers and aims to reward a range of emission reduction activities in the power sector.[93]

Aggregate cost savings for ratepayers and the economy as a whole: A key challenge in comprehensively analyzing the aggregate cost savings - for both ratepayers and the economy as a whole - as a result of restructuring efforts, lies with the ability to control for all other factors and isolate the impact of reforms.

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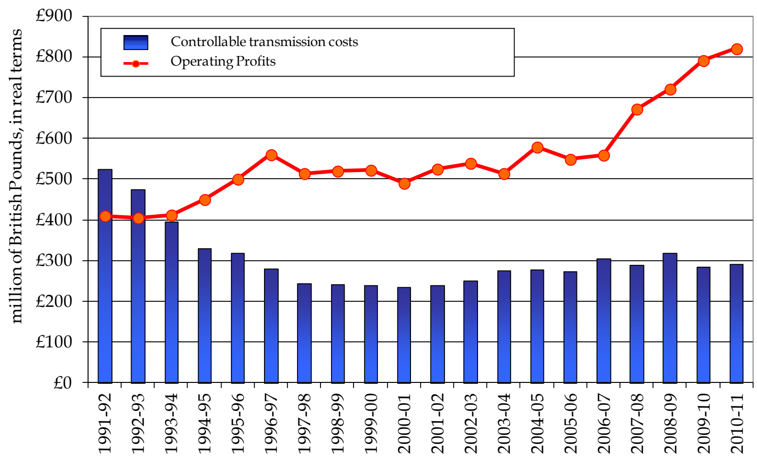
[92] Source: Connecticut Light and Power Company. <https://www.cl-p.com/Home/SaveEnergy/GoingGreen/Renewable_Energy_Credits>

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

Policy makers and regulators would be wise to refrain from promising lower rates to consumers as costs may increase anywhere along the value chain. Wholesale energy prices may increase reflecting the growth in demand and/or increase in the price of fuels, and distribution and transmission costs may increase if large scale capital investments are needed to replace aging assets.

Nevertheless, in an earlier discussion (Section 2.7.5), we discussed the impact of the utilities sector on the economy. The data suggests that the sector continues to provide steady contributions to GDP, while lowering total employment, which attests to the improved operating efficiency of the sector, thus positive impact on the economy.

Figure 26. Performance of UK's National Grid PLC since market opening



Sources: Ofgem Annual Transmission Reports; National Grid PLC Electricity Transmission Annual Reports

Figure 26 shows the declining trend of National Grid's (UK) controllable transmission costs in early years of restructuring, while the operating profits grew continuously and prices to customers fell in real terms.

While there is some evidence to suggest the positive impact on the economy, determining the benefits to final consumers have been more controversial. We have noted in earlier discussion (Section 2.7.3) that some studies have identified additional costs to consumers as the result of restructuring, while proponents of restructuring note that the benefits to consumers are in the form of greater choice stemming from competition and diversity of options as a result of innovation from market-based incentives.

To provide an illustrative example, if we assume the utilities sector achieves an efficiency of 1% per year, this would translate into $2.87 billion (corresponding to $0.74/MWh) in net benefits for the US economy (based on the 2013 estimate for utilities sector's contribution to the US economy of $287 billion[94] and US 2013 generation estimate of 3,896 TWh[95]). When attempting to review and provide analysis of the impact of restructuring efforts, one should be cognizant of the challenges outlined above. While certain metrics provide useful and objective indicators of the impact (e.g. operational performance of power plants), others often are a result of a multitude of factors.

2.8 Key conclusions

The experience of electricity sector restructuring to date informs that there may not be a ready-made one-for-all prescription, however, there are elements of restructuring that are likely to work across jurisdictions (such as multiple number of generators, open access in transmission, well-designed performance-based/incentive ratemaking regime, minimal political intervention etc.). We have noted a few key conclusions below, as takeaways for Nova Scotia:

- **It is important to be clear about objectives for restructuring upfront**. In most cases, the three key objectives of restructuring are: improving efficiency and reducing prices; continuing to provide an opportunity for utilities to earn a reasonable return on investment; and providing reliable services to customers.

- **Success of electricity sector reforms and restructuring should not be judged solely by electricity price impact.** Changes in electricity prices and transmission/distribution costs should not be viewed as solely the result of liberalization (many inputs do increase independent of the market organization and regulatory regime). In fact, “success” of restructuring is guided by factors that are important determinants of private sector involvement, such as the longevity of the restructured market design, low frequency of the intervention that result on major changes of the course, evidence of efficiency improvement, and availability and effectiveness of hedging instruments.

- **Key factors that aid the transition process and assist in creating properly functioning competitive markets include**: commitment to reforms and abstaining from politically expedient changes, clear path for the restructuring program with well-defined milestones, careful planning that includes proper tools to facilitate the transition, multiple players and minimal regulatory barriers to entry, and availability of hedging instruments.

- **Restructuring is a means to an end, not an end unto itself**. Before initiating discussions around forms of restructuring, policymakers need to ascertain whether restructuring is required at all. In jurisdictions where reliability of services combined with already reduced rates are observed, it may make sense not to restructure.

- **Reversal of restructuring reforms is likely a result of poor design choices and political considerations**. Generally, the triggers for reversing restructuring efforts have been

94 US Bureau of Economic Analysis

95 EIA. Annual Energy Outlook 2014 (Tab 08) <http://www.eia.gov/forecasts/aeo/index.cfm?src=Electricity-f3> Accessed on April 29, 2014.

unanticipated price volatility exacerbated by insufficient hedging capabilities and political fortitude.

- **A clear thought-out process to implement restructuring, and an independent body to proactively monitor the system adequacy conditions, are critical.** Electricity sector restructuring requires a comprehensive approach that ensures congruency and cohesion of all the steps in the value chain. Planning processes are an important component of the liberalization and restructuring effort, which involve forward looking capability by an entity with clearly defined responsibilities to see what is potentially needed to maintain the system reliability and adequacy.

- **Liberalization allows better indication of cost causality relationships**. Liberalized markets provide price signals that encourage behavior change when the situation arises (while under cost of service regulation, there is disconnect between timing of pricing signals and associated causes).

- **Considering impact of renewable development and demand response is important.** Planners and regulators should pay due attention to the impact of renewable development on the wholesale market and system reliability requirements. Large scale integration of intermittent resources may challenge energy-only market structure as greater capacity reserves are needed to mitigate the intermittent nature of renewable resources. Moreover, demand response market should contribute to better price discovery mechanisms. Considering demand response from the beginning addresses the issue of demand inelasticity and allows for wholesale energy prices reflective of economic value of electricity.

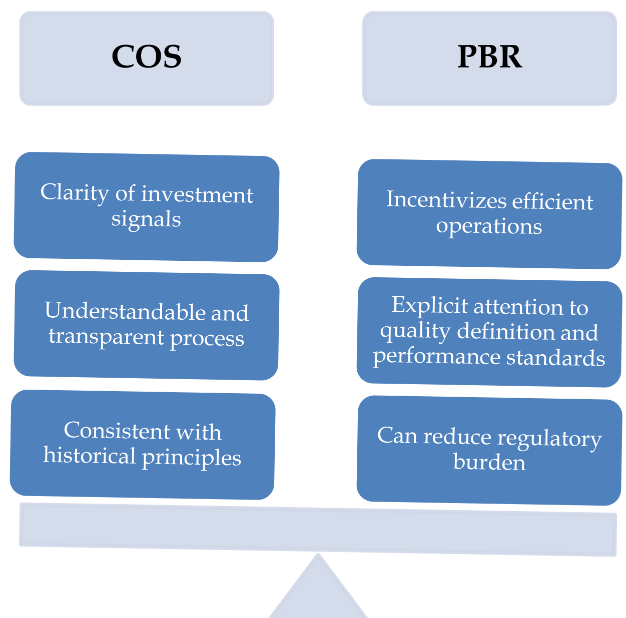
- **While reviewing best practices is important, each jurisdiction may have its own best fit depending on its objectives.** Policy-makers and regulators face a number of choices to make across a range of options covering the main features of the regulatory regime and electricity sector organization. Market designers need to be pragmatic and recognize that there will be transitional costs, and certain efficiencies may not be realized due to feasibility issues (e.g. location-based marginal prices may provide the best reflection of the true cost of supplying energy, but that usually involves additional complexity to the market design and operations).

3 Performance-based regulation

Performance-based regulation ("PBR") is a regulatory approach to rate regulation that provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs, and improve efficiency. It is best conceptualized as a continuum, ranging from "soft" to "hard" mechanisms, rather than a single type of regulatory regime.

While the PBR approach can have advantages over a cost of service ("COS") approach, there are evident merits of the COS approach, as shown in Figure 27. COS provides clarity of investment signals as well as an easy-to-understand transparent process. In addition, it is generally consistent with historical practices.

Figure 27. COS versus PBR



Stronger incentives within PBR imply more efficient operations and attention to quality definition and performance standards. Application of PBR - compared with the traditional COS - can motivate larger efficiency improvements among utilities. If properly designed, PBR should lead to lower rates for customers in the long run and bring commercial success to those utilities where management is willing to strive for and exceed industry expectations on productivity. Moreover, PBR is typically described as a regulatory framework that can – in principle - reduce the regulatory burden on both utilities and regulators by decreasing the need for frequent regulatory hearings.

When designing a PBR regime, careful consideration is needed in deciding the individual components of the PBR formula. These components, which could include an inflation factor, a productivity factor, an earning sharing mechanism, performance standards, and "off-ramp" triggers, among others, need to be viewed as a whole rather than individually. Collectively, the PBR formula needs to follow the key principles in ratemaking such as ensuring the financial stability of utilities and safeguarding their ability to earn a commercially reasonable rate of return, administrative simplicity, ease of understanding for ratepayers, and alignment of incentives between shareholders and ratepayers. Nevertheless, COS ratemaking principles continue to be relevant under a PBR approach, including those that facilitate the determination of "going in rates."

Key success factors in PBR implementation in jurisdictions that have adopted this regime since the 1990s (such as the UK and Australia) include the PBR design's adaptability to changing environment, the provision of incentives to encourage cost efficiency and quality of service, having a clearly defined and efficient planning process for network investments, and a framework that supports funding of capital expenditure through rates.

3.1 Rationale for moving from a COS to a PBR regime

There is strong rationale for favoring a shift to PBR from the traditional COS or rate-of-return ("ROR") regime. PBR, also known as incentive ratemaking mechanism ("IRM"), is a form of utility regulation that strengthens the financial incentives to lower rates and costs or improves non-price performance. Essentially, it allows the adjustment of utility revenues based on performance. PBR is normally adopted to correct the most common foundational problems observed in traditional COS regulation such as:

(i) weaker incentives for cost-efficiency;

(ii) lack of incentives to encourage prudent and efficient capital investment (e.g., higher risks towards 'gold plating' due to the information asymmetry between regulators and firms, whereby the regulator has limited ability to assess the reasonableness of proposed capital investment budgets); and

(iii) intensity of the associated administrative process.

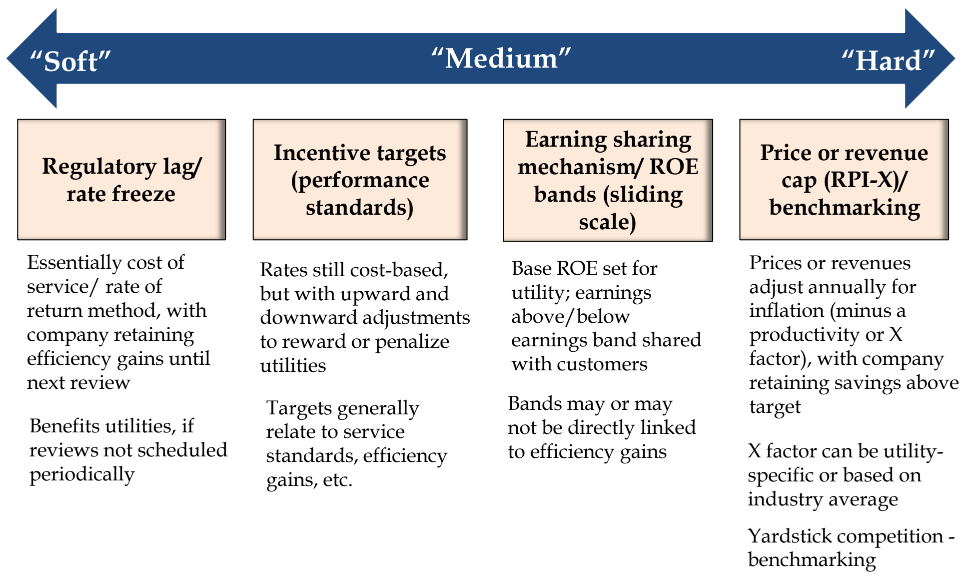
PBR aligns the incentives of the utility with those of the regulator and the consumer, unlike the typical capital-maximization objectives of a utility under the COS regulation. Therefore, in PBR, the focus shifts from cost accounting to productivity analysis.

Moreover, PBR allows the utility sufficient freedom to decide how to best optimize its resources given the targets and objectives. Meanwhile, the regulator does not need to frequently review the detailed cost accounts and capital expenditures for each utility.

PBR also addresses concerns about the achievement of an "optimal price" in sectors where there are natural monopolies. PBR mimics competitive pressures even in a monopoly environment. Theoretically, an "optimal price" based on the quality of service demanded at the lowest cost can still be achieved. Provided that the PBR has been strongly contextualized and well-developed, it allows firms to make decisions regarding costs and inputs to maximize output (relative to a given level of inputs) and ensure the most efficient allocation of competing inputs.

PBR regulation must be appreciated as a system that exists on a continuum with "soft" to "hard" mechanisms and not as a single type of regulatory regime (Figure 1). "Soft" mechanisms include minor modifications to the traditional COS regulatory approach. These may include regulatory lags, rate freezes, and efficiency audits and reviews. In these cases, the utility retains any gains only until the next regulatory review. "Medium" measures often include performance standards, where payments to utilities are adjusted based on their level of performance. "Medium to hard" PBR measures include earnings sharing mechanisms ("ESMs").

Figure 28. Continuum on PBR regulation from "soft" to "hard" mechanisms



ESMs normally set a return on equity ("ROE") threshold, allowing customers and the regulated company's shareholders to share earnings and losses depending on the deviation from the agreed level. At the "hard" end of the PBR continuum are the revenue and price cap regulations. Here, prices or revenues are adjusted annually for inflation (minus targeted productivity improvements) allowing the utility to retain any cost savings. This paper discusses these different mechanisms in detail in Section 3.4.

3.2 Nature and timing of the regulatory process under COS versus PBR

The nature and timing of regulatory processes under COS and PBR share common features as well as operate under slightly different procedures. As expected, both require submissions from utilities. The Commission is also the key decision-maker in both instances although both systems allow adequate consumer participation. However, the regulatory process under a PBR mechanism is usually longer. A primary reason is that PBR proceedings involve additional discussion and analysis of technical issues such as those related to productivity trends, inflation factor, and rewards and/or penalties for performance standards. This section offers a brief comparison of the regulatory processes under COS and PBR.

Under a COS approach, the revenue requirements and rates for the length of the term - generally between 1 and 3 years - is forecasted. Regulatory process under COS typically takes 12 to 18 months from the initial filing of the petition to the date of the issuance of the decision (Figure 29). Some states also stipulate that a decision has to be made within a certain period after the filing of a rate case or the utility can apply the requested rates subject to refund.[96] The COS regulatory process generally begins when a utility files a rate application, demonstrating the need for a rate adjustment.[97] Utilities normally request rate adjustments when costs have risen and the revenues collected no longer cover the cost of building, operating, and maintaining the system to meet customers' demand or to comply with new regulations. Moreover, the regulator (sometimes at the request of customer groups) may also initiate a case if rates are excessive.

> The regulatory process in Nova Scotia is similar to the COS approach (described in this section) where a public utility files an application and there will be an intervening period when the Board will ask for written information requests from applicant. There are also oral hearings. There is no set period for filing rate applications but the provincial electric utility is restricted to filing once per year only.
>
> There is also an annual hearing for the Fuel Adjustment Mechanism ("FAM") to address any over or under recovery of fuel costs and to establish the new base cost of fuel every second year.

The rate filing includes the estimates of expenses (such as operating expenses, taxes, return on investor-provided capital, and capital expenditures) and the reasons why the current rates are no longer sufficient. After the filing, interested parties (also known as interveners) submit requests to intervene in the proceeding. This period of intervention allows them an opportunity to question witnesses in the evidentiary hearing or file opposing testimony. Interveners include consumer groups, the state's public advocates, and environmental organizations. The Commission holds public hearings to generate feedback from customers and interveners about the utility's request to increase electric rates. The Commission then holds an evidentiary hearing to review the case. During this process, witnesses of the utility company are cross examined by interveners and respond to the questions from the commissioners. After the evidentiary hearing, the Commission issues its decision on the utility's request for a rate increase. The decision includes a summary of the issues and evidence presented in the case and explains the reasons for its decision. A utility can appeal the decision and apply for rehearing within a certain period of time after the issuance of the decision.

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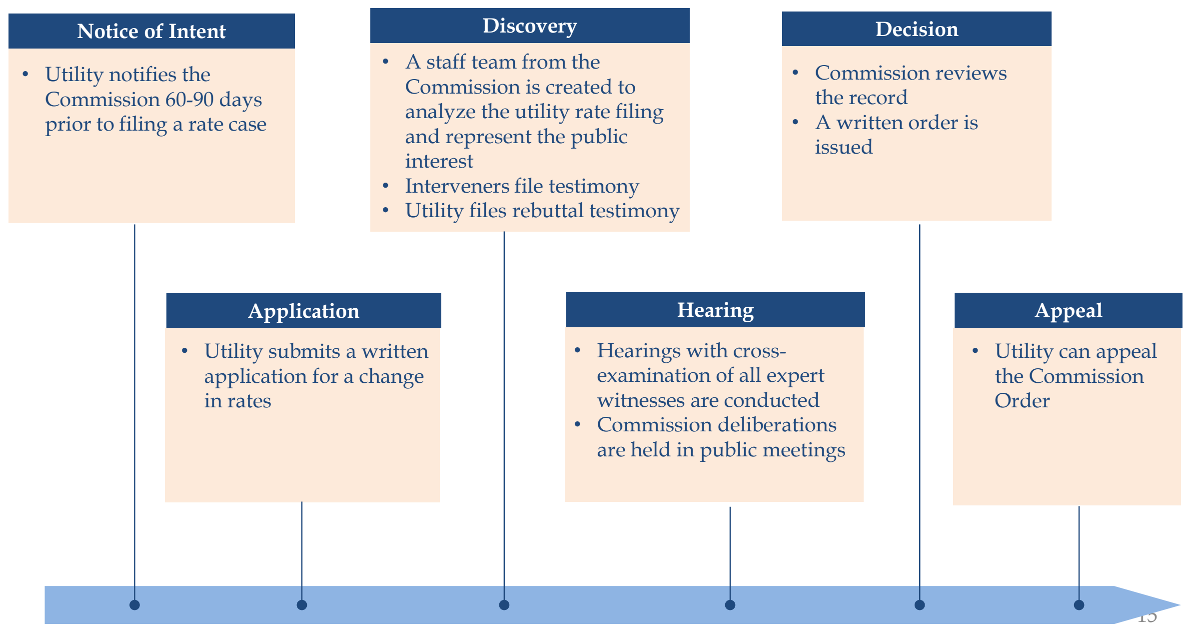
[96] An example of this is in Ohio where the Commission is required to issue a decision within 11 months after the filing.

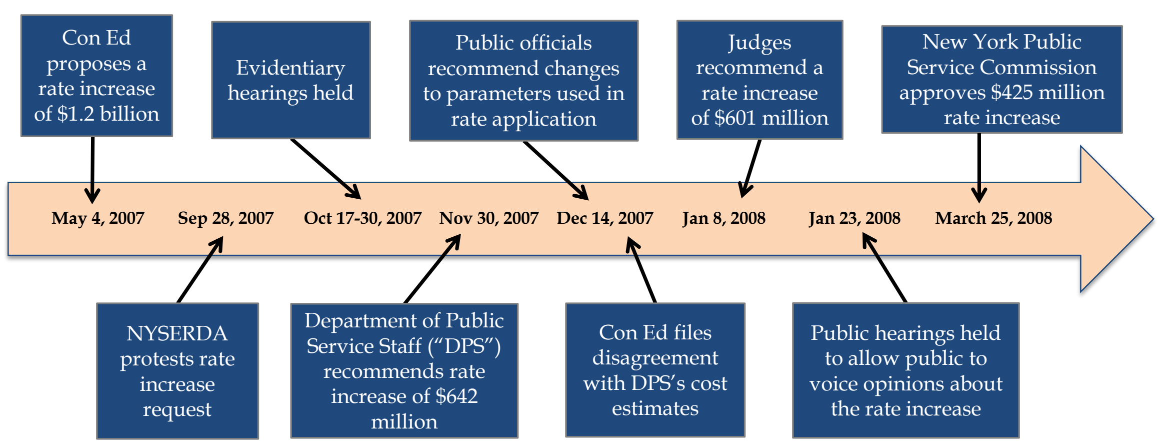
[97] In some jurisdictions, the utility needs to notify the Commission prior to filing its rates to allow the Commission to form a team of experts to review the utility's evidence.

Figure 29. Typical regulatory process under COS



Source: Various Public Utilities Commissions (Ohio Public Utilities Commission, New York State Public Service Commission, and Indiana Utility Regulatory Commission)

Figure 30. Example of a regulatory process under COS



Note: NYSERDA = New York State Energy Research and Development Authority
Source: NY Department of Public Service Commission Docket 07-E-0523

Based on the experiences of jurisdictions such as Alberta, Ontario, Australia, and UK, the regulatory process is longer under a PBR mechanism, usually requiring 17 to 32 months (Figure 31). The PBR process and timing are usually shaped by the number of utilities and interveners that participate in the regulatory process, the PBR framework that the jurisdiction is using (whether its I-X approach or building blocks approach), and the regulatory generation that it is in. Proceedings may take longer in the initial generation than in subsequent ones.

In some jurisdictions that implement the PBR approach using the I-X approach (such as Alberta and Ontario), the hearing process is quite similar to the steps of a COS approach. However, the key issue being deliberated under PBR is the formula and the components of the formula under which a utility may operate rather than the discoveries related to the COS process. Moreover, PBR proceedings involve discussions on and analysis of a broad range of technical issues such as but not limited to the estimation of industry productivity trends, determination of the right inflation factor, and establishment of the appropriate magnitude of rewards or penalties for performance standards. These will be discussed in detail in Section 3.5.

The regulatory process under a building blocks approach, as experienced by Australia and UK, is less adversarial than in the jurisdictions in North America. The building blocks approach, which will be discussed in detail in Section 3.4.2, is a PBR approach that sets a utility's revenue requirement amounts for each year of the regulatory term to determine the ultimate rate to be charged to customers. The name 'building blocks' comes from the approach taken to calculate the required revenue amount. To "build up" the revenue requirement, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each "block" of the revenue requirement for each year of the IR term. In Australia and UK, utilities use the "propose-respond" approach where utilities put a price proposal forward and forecast costs that eventually become the baseline, which the regulator responds to. There are no hearings heard in a formal legalistic sense. The processes in these two markets can be better characterized as workshops or roundtables with a high degree of flexibility in the exact format and structure.

Figure 31. Process and timing under PBR for selected jurisdictions

	Alberta	Ontario	Australia	UK
Framework	I-X approach	I-X approach	Building blocks approach	Building blocks approach
Generation (Distribution)	1st	3rd	3rd	5th
Number of electric distribution utilities	4	77	13	14
Process	Involves information requests and responses, oral hearings, and rebuttal	Involves information requests and responses, oral hearings, and rebuttal	"Propose-respond" model	"Propose-respond" model
Process name	PBR application	Incentive Rate Mechanism ("IRM")	Price determination	Price review
Timing	33 months	17 months	23 months	32 months

Source: Alberta Utilities Commission ("AUC"), Ontario Energy Commission ("OEB"), Australia Energy Regulator ("AER"), and Office of Gas and Electricity Markets ("Ofgem")

PBR filings require the ability to forecast additional elements that may have been less critical under a COS regime and for a longer period of time compared to a COS regime. Forecasting plays a central role in the building blocks approach where the utility needs to forecast components of the revenue requirements for the entire term of the PBR. These components include operating and capital expenditures, depreciation, customers and volumes, load growth, and rate of return.

COS analysis also continues to be relevant under a PBR approach. The PBR approach begins with a COS-based analysis of what the "going-in" rates should be. After this, rates or revenue requirements adjust annually during the term based on the PBR formula, which is composed of inflation, productivity, and other incentive mechanisms in place. The use of this automatic adjustment mechanism can reduce the frequency and scope of regulatory intervention, especially for utilities with regular cost of service rate cases.

However, the extent of the regulatory efficiencies achieved depends on the complexity of the selected individual components of PBR, intensity of the regulatory "settlement" process, and the extent of stakeholder inputs. Some regulators have also supplemented their internal capabilities with consultants who rendered technical expertise in analyzing efficiency. The scale of the regulatory burden under PBR depends on the duration of the PBR period and the complexity of the annual rate-setting process. Moreover, at each review, there will inevitably be a need for a detailed cost analysis and therefore, in reality, the savings associated with regulatory reviews will primarily be limited to the period between reviews. Nevertheless, administrative cost savings for utilities, regulators, and stakeholders should be expected to accrue over time, once the PBR learning process is settled.

3.3 Implementation process for moving to a PBR regime

Moving from a traditional COS to PBR can be a daunting task not only for the regulator but also for the utilities as well. It involves a tremendous amount of regulatory work and requires lengthy stakeholdering efforts to determine the appropriate PBR mechanism to implement and to allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation.

The first 'formal' step in the PBR process is when the regulator expresses its intent to implement a shift. In this step, the regulator is expected to explain the objectives clearly to all stakeholders as it embarks on the process. For example, in the case of Alberta, the Commission highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies to improve their efficiency while ensuring that the benefits from the increase in efficiency will ultimately benefit customers.[98] When deciding upon a regulatory regime or a

[98] Alberta Utilities Commission. *Rate Regulation Initiative Decision 2012-237.* September 12, 2012. P. 5. Available online at http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf

change in the regime, the following principles need to be collectively assessed to determine the goals of the move to PBR:[99]

- ***Incentives compatibility:*** Ratemaking should provide appropriate incentives to both companies and customers (although there may be some natural conflict there and tradeoffs need to be made).
- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and generating sufficient cash flow to support necessary investment.
- ***Administrative simplicity and transparency***: Rates should be straightforward for customers to understand; customers should be able to calculate their monthly bills themselves, and be able to understand why the rate is calculated in the prescribed fashion.
- ***Cost causation and avoidance of cross-subsidies***: To achieve the most efficient patterns of consumption, economic theory states that the customers that cause a cost to be incurred should pay for that cost.
- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions.

Experience and best practices dictate that the shift to a PBR mechanism requires the laying down of principles that should guide the stakeholders (particularly the utilities) in the development and implementation process. The establishment of principles will assist the regulator in the evaluation of and deliberation on the PBR proposals. Such principles should also guide the utilities in developing the most responsive and relevant proposals.

The move to PBR may also involve the hiring of an economic consultant to assist in determining the appropriate PBR approach, identifying the

Nova Scotia Department of Energy's internal PBR notes identified the following principles to consider:

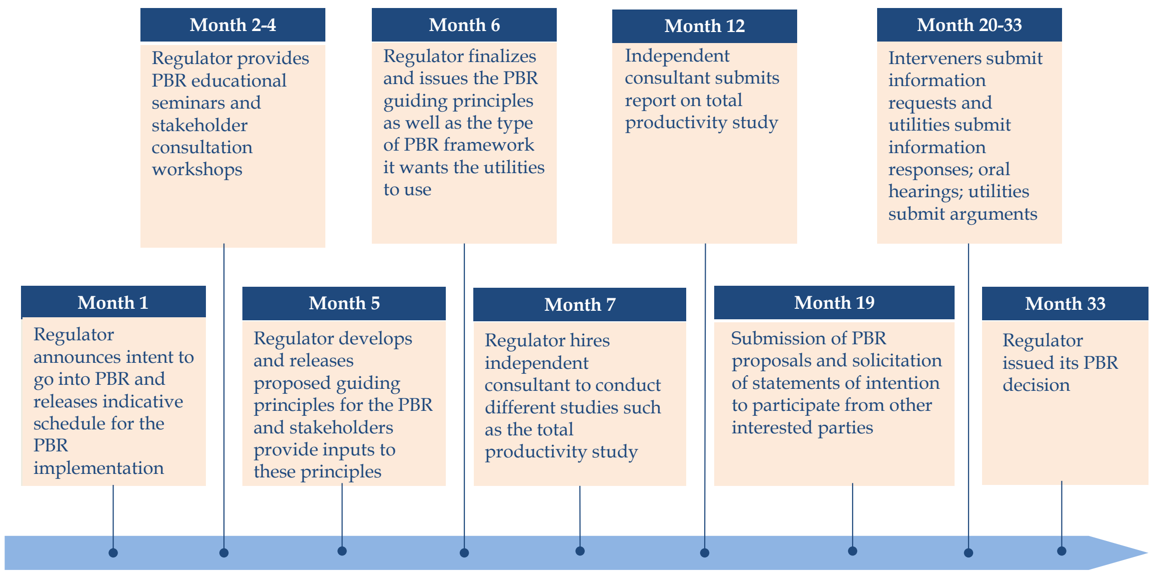
- consistency with legislation
- just and reasonable rates with provision to reset rates if needed
- create an environment that encourages efficiency
- simplicity (clear simple formula)
- rate predictability, flexibility (do deal with changing technology)
- uncontrollable costs, safe and reliable service
- streamlining regulatory oversight (reduce regulatory burden)
- know legacies and objectives
- have the right choice of timeframe/consistency
- benchmarking appropriately
- mandatory reliability standards,
- data collection on capital, reliability, and operational characteristics

[99]For more information, see: Bonbright, Danielson and Kamerschen. 1988. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, VA; Bonbright, Danielson. 1961. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, pp. 290-94); Weston, Fredrick. 1999. "Principles of Rate Design," www.raponline.org); and Woolf, Tim and Julie Michals, 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry," *The Electricity Journal*, Issue 8, Volume 8. October 1995.

appropriate components for the PBR such as incentives and magnitude of rewards or penalties for the performance standards, reviewing what data is currently available or providing a study of historical and forecasts of inflation and productivity trends. It is also crucial that the regulators and stakeholders be regularly communicating and on the same level of understanding. Workshops and technical conferences are generally conducted to familiarize stakeholders with the proposed PBR approach and to solicit feedback.

The shift to PBR often involves the steps and typical timeline that are shown in Figure 32.[100] This timeline is for a PBR launch; timing could be less for the succeeding regulatory period. More detailed examples of two jurisdictions' moves to PBR are provided in the textboxes that follow.

Figure 32. Move to PBR steps and timeline (Alberta)



Source: AUC Decision 2012-237

Note: The timeline above is for the regulatory proceeding for the distribution utilities in Alberta, except ENMAX

Nova Scotia's timeline could be compressed because there is only one major utility

Lastly, data availability is a critical element in the development of a PBR regime and will improve the functionality of PBR regulation over time. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. "Harder" forms of PBR require collating and employing multi-period information and data samples covering multiple firms. Over time, availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice"

[100] This list is mostly adopted from the chronology of events involved in the shift to PBR of Alberta. Note, however, that the steps and timeline in this list are indicative only and depend on various factors such as government regulations, timely submission of reports and proposals, number of utilities and interveners, and strong consumer opposition or involvement, to name a few.

forecasting tools can improve the functionality of the PBR process, thereby, facilitating analysis and negotiations of parameters for PBR factors, as well as benchmarking actual productivity achieved against prior targets.

Ontario's move to PBR

In anticipation of the Energy Competition Act, 1998 (Bill 35) being passed, the Ontario Energy Board ("Board" or "OEB") stated its intent in October 1998 to consider PBR as a new approach to regulation. The first step for the Board in establishing a framework for guidelines on PBR was to hold a series of seminars in October and November of 1998 to familiarize stakeholders with the concept. Stakeholders were able to provide input on the most appropriate approach to PBR for electricity distribution. These inputs were compiled into a report issued in December 1998 to provide guidance to the Board going forward.

Four task forces – coordinated by Board staff – were then established to address the following topics: cap mechanism, yardstick mechanism, implementation, and distribution rates. These task forces consisted of 83 volunteer stakeholder members representing various electricity distributors, gas utilities, customer groups and special interest groups. Task force meetings were conducted from mid-January 1999 through April 1999.

In the process, technical expertise on PBR and industry restructuring were provided to assist the task force. To address the diversity and large number of emerging issues on PBR and restructuring in general, working groups were formed within each of the task forces. The reports produced by these working groups were compiled by Board staff into task force reports and issued in mid-May, 1999. Individual task force member position papers were included as appendices to the task force reports. To provide updates on the process to members who were not participating in the task forces, a web site was set up by the Board.

A draft of the *Board Staff Proposed Electric Distribution Rate Handbook* ("the draft Rate Handbook") was distributed on June 30, 1999. This draft document contains a proposal for a regulatory framework for the Board to use in developing and administering electricity distribution rates in the Province. Regional seminars were held across Ontario to provide stakeholders with an understanding and clarification of the proposal.

The draft Rate Handbook contained proposed rate policies, guidelines and procedures to be used by the Board in the establishment and adjustment of electricity distribution rates in Ontario for a first generation PBR plan. A series of presentations and a technical conference were held to discuss about the draft Handbook.

On January 2000, the Board decided on a price cap framework. The proposed plan had a three-year term for the period 2000-2002.

Source: OEB website

Alberta's move to PBR

On February 26, 2010, the Alberta Utilities Commission ("AUC" or "Commission") announced that it would begin the first stage of performance-based regulation (PBR) for Alberta, as part of the AUC's rate regulation initiative. The first stage of PBR, however, only applied to the electricity and natural gas services of Alberta distribution companies under the AUC's jurisdiction.

The first step made by the AUC was to hold a roundtable with interested parties on March 25, 2010 to discuss the general steps, timelines, requests and concerns that parties had about the implementation of PBR. In response to the requests made by participants, the AUC engaged an independent consultant to conduct a PBR workshop on May 26-27, 2010 in order to educate participants about the issues, terminology and concepts raided by PBR. Also in response to the requests made by participants on March 25, 2010, the AUC initiated a proceeding from June 10-24, 2010 to solicit comments on the principles that should guide the development of PBR in Alberta. The submissions were reviewed in Bulletin 2010-20, and the following principles were established:

1. **Principle 1:** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
2. **Principle 2:** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
3. **Principle 3:** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
4. **Principle 4:** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
5. **Principle 5:** Customers and the regulated companies should share the benefits of a PBR plan.

On September 8, 2010, the AUC announced that it hired an economic consultant to prepare a total factor productivity ("TFP") study to determine the X factor in a PBR plan by December 31, 2010. Following the study, the filing date for PBR proposals was changed to July 26, 2011 so that companies had enough time to consider the evidence laid out by the consultant, with an eventual PBR start date of January 1, 2013.

Electric and gas distribution companies were required to file their PBR proposals by March 31, 2011, in accordance to the date that was agreed upon by those present at the March 25, 2010 roundtable. Parties were required to explain how their proposals were consistent with the Commission's five principles for PBR.

Following the submissions of the PBR proposals, the Commission received a number requests from companies and various interveners for some type of provision to deal with some capital costs outside of the I-X mechanism. After considering all of the submissions of the companies and interveners, the AUC decided to employ an I-X mechanism and a five-year term as part of its PBR plan, with a number of provisions where necessary to accommodate the unique circumstances of each regulated company. AUC intends to review PBR as it comes to the end of the first term and to consider extending the plans or incorporating other approaches if those can be demonstrated to better balance regulatory efficiency and regulatory effectiveness in a way that achieves AUC's objectives and satisfies its principles.

Source: AUC Decision 2012-237
Note: ENMAX was the first utility to implement PBR in Alberta. It filed its PBR application with the AUC on May 2007 and AUC issued its decision on March 2009. LEI advised ENMAX in this proceeding.

3.4 Types of PBR structures implemented

Variations of PBR have been adopted in many countries around the world. As mentioned in Section 3.1, PBR is not a specific regulatory formula but rather a broad regulatory approach that transcends a large continuum ranging from "softer" forms of PBR to "harder" forms. The choice of a soft versus hard PBR regime is linked with the risk appetite of the utility, the range of incentives that the regulator is willing to approve, and the demand of and feedback from interveners. Furthermore, when considering and evaluating the "soft" to "hard" spectrum of PBR regimes, it is important to keep in mind how the incentives amplify or change business risks and opportunities for the regulated utility.

3.4.1 Different forms of PBR

> The soft and medium forms of PBR can provide an intermediate step towards a full PBR mechanism.

Softer forms of PBR include regulatory lag and rate freeze. **Regulatory lag** allows for a delay in introducing new rates. The lag provides a utility a longer horizon to plan and operate and keep the benefits of the incentives provided in PBR. This means that the benefits of cutting costs and profit margins from increased sales would be retained by the utility for a longer period. **Rate freeze** is another feature of a soft form of PBR. Through a rate freeze, a utility's rates are held constant during the PBR term. A rate case moratorium is similar to a rate freeze in that it represents a commitment not to initiate a rate case designed to increase or reduce rates. Rate freeze and rate case moratorium can provide strong incentives while ensuring rate stability. Such mechanisms give strong incentives to reduce or control operating costs. Rate freezes are also commonly used to protect consumers during transition (i.e. transition to retail competition). However, without inflation adjustments, lengthy terms can impose risks on the regulated firm.

"Medium" measures of PBR include a COS approach with performance standards and ESM. Numerous markets have implemented a COS approach with **performance standards** to ensure that any cost reductions implemented by the utility do not lead to deterioration of service quality. With performance standards, payments to utilities are adjusted upwards or downwards in correspondence to their level of performance. Section 3.5.7 discusses this in detail. **Earnings sharing mechanisms** allow customers to share in a company's earnings in excess of pre-determined threshold ROE through lower rates in subsequent years. Some ESMs also require customers to bear a portion of any shortfall of earnings below certain ROE threshold. Section 3.5.9 has a more detailed discussion of ESMs.

Rate caps fall under the "hard" forms of PBR. In contrast to a rate freeze, rates under rate caps can change during the regulatory term based on the approved formula.[101] The two commonly used rate caps are the price and revenue caps. **Price caps** are also called price indexing or rate indexing. Under a price cap, the regulator approves a formula that determines how fast rates can increase. The regulator sets an initial price $(\text{PRICE})_{\textbf{Year1}}$ and the rates are adjusted for each

[101] Note that rate freeze is equivalent to a rate cap with zero inflation factor (I-factor) and zero productivity factor (X-factor), or where I = X.

year taking into account changes in inflation and productivity (or X factor). Although the formulas vary from plan to plan, the standard formula of a price cap is:

$$\textbf{(PRICE)}_{\textbf{Year1}} = \textbf{(PRICE)}_{\textbf{Year 0}} * \textbf{(1+(I-X))}$$

Where I is a measure of inflation and X is a productivity adjustment

Price caps are usually applied to any of the following: the utility's average price, the average prices for each customer class, or to each rate element of each rate schedule. This provides the utility a degree of flexibility in how to optimize specific customer rates and consider cost allocations. At the end of the regulatory period, costs are usually re-examined and prices are set based on an updated COS. At this "rebasing," the I-X formula may also be reviewed and revised if needed. This procedure may also include a revision of the indices that make-up the I factor, a re-setting of the parameter value for the X factor, and consideration of additional incentive elements.

In deciding the form of PBR to use, Nova Scotia should consider the availability of data as harder forms of PBR require collating and employing multi-period information and can require data samples covering multiple utilities.

Price caps have several advantages. First, price caps provide incentives for cost efficiency and cost reduction.[102] The cost-reducing incentives of price caps are fairly stable and viable because they can hold over a long period of time and they have built-in adjustments (I - X) that increase the regulatory commitment period.[103] Second, regulators under price caps do not need detailed information about the utility's cost functions to calibrate the price cap parameters.[104] Third, utilities under a weighted average price cap approach have the flexibility to change relative prices in the regulated basket of services. The use of baskets has *"provided utilit[ies] with the ability and incentive to rebalance their prices in the direction of allocatively superior prices and has allowed regulated utilities to compete with new entrants."*[105] Finally, price caps can provide incentives for utilities to meet and expand demand because revenues are not capped as they would be under a revenue cap approach. Utilities will have an incentive to increase sales as long as the marginal revenue accompanying the increased service provision is greater than the marginal cost of increased service provision. However, this contradicts demand management plans.

Such advantages are balanced by a limitation. The utility bears the volumetric risk or any shortfalls in demand under a price cap mechanism (although it is rewarded during periods of high demand growth). If demand is volatile, a price cap can also result in revenue instability, which in turn affects the volatility of the profit stream.

[102] Lantz, Björn. "Hybrid Revenue Caps and Incentive Regulation." Energy Economics 30 (2008) 688-695. September 25, 2006. Pp. 688-694.

[103] Vogelsang, Ingo. "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective." *Journal of Regulatory Economics*.22:1 5-27, 2002. P. 8.

[104] Ibid.

[105] Ibid.

In contrast, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, revenue requirement in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, taking into account changes in inflation and productivity. The formula of a revenue cap is shown below:

$$\mathbf{(REVENUE)_{YearT} = (REVENUE_{YearT-0} + Customer\ Growth\ Adjustment\ Factor * \Delta Cust) * (1+(i-x))+/-z}$$

Where $(REVENUE)_{Year1}$is the authorized utility revenues for in Year T; ΔCust is the annual change in the number of customers; I is the annual percentage change in prices (change in inflation index), X is the productivity offset; and Z is the adjustments for unforeseen events beyond management's control.

Revenue caps generally have a balancing account mechanism to capture the difference between the approved revenue requirement and the actual revenue. Revenue caps are best suited for utilities that face a high proportion of fixed costs and in industries where volume changes are predictable.

Under a revenue cap, there is no incentive for utilities to maximize sales but there is still an incentive to minimize overall costs (i.e., with revenues fixed, profits increase if costs are cut), making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Moreover, with a revenue cap, utilities are generally exposed to lower levels of risk related to changes in demand or sales.[106] Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes. Finally, the ability to make additional profits due to increased scale is removed under a revenue cap regime, along with any means to adjust revenue if costs increase with volumes.

Price cap and revenue cap regimes can converge if various true-up mechanisms are deployed. Price caps often incorporate measures to protect utilities and customers against weather and economic growth related volume fluctuations. Revenue caps may contain adjusters if utility experiences sustained and unexpected volume increases that require additional capital expenditure. Figure 34 provides examples of selected jurisdictions that are under price or revenue caps.

3.4.2 Approach to designing rate cap

There are generally two approaches for rate-setting under a price cap regime: (i) **a total factor productivity ("TFP") based I-X approach; and (ii) the building blocks approach.**

The **TFP-based I-X approach** was developed as a relatively simple mechanistic, yet empirically "rich" approach, to adjusting rate caps and providing incentives. The basic view that grounds

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[106] National Association of Regulatory Utility Commissioners. *Performance-Based Regulation for Distribution Utilities.* December 2000. P. 23.

most TFP-based applications of PBR models is that firms should be able to improve productivity consistent with measured long term productivity improvements (historically) for the industry as a whole. In North America, the TFP-based approach to an I-X rate cap is among a number of PBR forms used.

Under the TFP-based I-X approach, prices for the forthcoming period are set in relation to a historic productivity trend, which is generally obtained from statistical study of a group of comparator firms. The price that the utility can charge is fixed in advance for a certain period and price may increase by no more than the inflation less the X factor.

This approach is suited for utilities facing steady state of operating and capital investment profile as it provides for a reasonable steady rate of change in the price or revenue cap because the I factor is generally not volatile and the X factor is often fixed. Under steady state conditions, economists generally expect the utility sector to be able to gradually improve its productivity over time – driven by any or all of the following: technological change, allocative efficiency, improved capacity utilization, economies of scale, or elimination of efficiencies. However, from time to time, to the extent that the pace with which the utility is making investments in capital and deploying labor exceeds the pace of demand and customer growth, then the rate of change in productivity will take on a negative value. Furthermore, revenue requirements and adjustment parameters are often related to historical studies in which regulators determine parameters for the IR plan; these studies may have limited relationship to or fail to predict future trends.

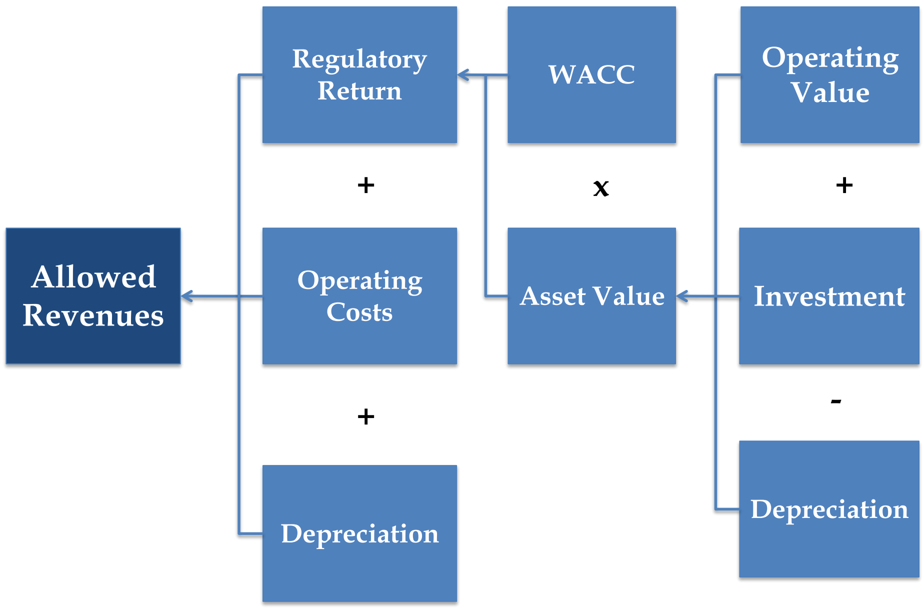
The **building blocks approach** has been the cornerstone of PBR in Australia and the UK for over 20 years now. First introduced in the early 1990s in the UK, the building blocks approach was developed to derive the components of the price cap regime (RPI-X) that the regulator wanted to apply to newly privatized, monopoly industries, commencing with telecommunications, and then expanding to other network industries in gas and electricity.

Under this approach, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory control period (i.e., IR term). The forecast takes into account productivity improvements and targets and necessary capital investment. After this procedure, these total costs are added together - "built up"- to an allowed revenue requirement for a utility based on estimates of the utility's expected capital and operating costs and return of and return on asset base (Figure 33).

The revenue requirement is then translated into a starting price (for the price or revenue cap) referred to as P_0 and an annual rate of change is estimated over the term of the PBR plan to adjust the price cap/revenue cap. The annual adjustment is referred to as I-X in Australia and RPI-X in the UK. The I factor is the inflation adjustment. Meanwhile, the estimated X factor reflects both the productivity target and the real price change required to support a utility's revenue requirement. This reference to an X factor can be confusing in the North American context because it is not solely a measure of productivity but reflects an aggregated view of efficiency trends across total costs and the need for efficient capital investment and (potentially) rate smoothing.

The revenue requirement that is forecasted for each year of the ratemaking period includes projections of efficient operating and capital expenditure. The efficiency or proposed costs are assessed using historical performance metrics, yardstick benchmarks of unit costs, and often industry-wide benchmarks (including industry TFP studies). For example, regulators and utilities in Australia and the UK normally commission independent expert reports to assess the proposed expenditures that make up the forecast revenue requirements for each firm.

Figure 33. "Building up" allowed revenues under the building blocks model



Source: Ofgem (2009) *History of Energy Network Regulation*

One of the greatest challenges associated with a building blocks approach is the reliance on forecasts. Related to this challenge is the difficulty on the side of the regulators to gather complete information about the costs of each utility; this weakens their ability to estimate the true level of the utilities' efficient costs. The utility may use this advantage during the regulatory review process to try to increase its profits. This could result in higher costs and prices, which can be set above the level indicative of efficient costs.

Another challenge of this approach is the need for extensive benchmarking analysis to set efficient costs. The building block approach can often become information-intensive, which can lead to significant administrative costs and make the process quite contentious as the regulator assesses the information provided by the utility. Although the building blocks approach naturally overcomes concerns about capex funding in PBR mechanisms, it is not recommended for a jurisdiction that is hoping to ease administrative burdens or where there is some discomfort with preparing and justifying longer term forecasts for operating expenses and capital expenses. Figure 34 includes examples of jurisdictions that are under building blocks approach.

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Figure 34. Forms of PBR and approaches of setting rates in selected jurisdictions

Jurisdiction	Company	Service Covered	Duration	Form of PBR	Approach to setting rate
Alberta	ENMAX Power (835,000 customers)	Transmission & distribution	2007-2013	Price cap (distribution) Revenue cap (transmission	I-X
	Other Utilities	Distribution	2013-2017	Price cap	I-X
Australia	All distribution utilities (Victoria)	Distribution	2011-2015	Price cap	Building blocks
British Columbia	Fortis BC (111,500 customers)	Generation, transmission and distribution	2007-2008	Revenue cap (hybrid)	I-X
California	PacifiCorp (1.8 million customers)	Generation, transmission and distribution	1994-1996	Price cap	I-X
	San Diego Gas & Electric (3.4 million customers)	Distribution	1999-2001	Price cap	I-X
	So. Cal. Edison (14 million customers)	Transmission & Distribution	1997-2001	Price cap	I-X
Maine	Bangor Hydro Electric (153,000 customers)	Distribution	1998-2000	Price cap	I-X
	Central Maine Power (560,000 customers)	Distribution	2009-2014	Price cap	I-X
Ontario	Ontario electricity distribution utilities	Distribution	2010-2012	Price cap	I-X
Philippines	All transmission and distribution utilities	Transmission and distribution	2011-2015	Revenue cap (transmission) Price cap (distribution)	Building blocks
UK	All transmission and distribution utilities	Transmission and distribution	2013-2021 (transmission) 2010-2015 (distribution)	Revenue cap (transmission) Price cap (distribution)	Building blocks

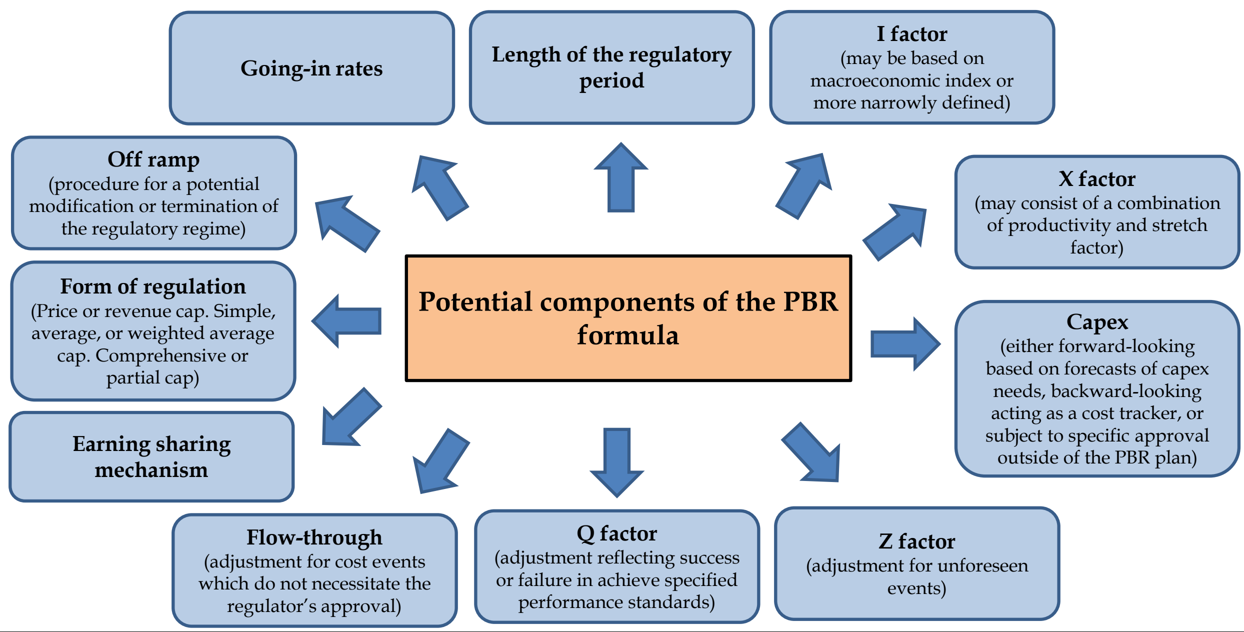
Note: Nova Scotia Power has 500,000 residential, business, and industrial customers across the province.

Sources: AER, AUC, British Columbia Utilities Commission ("BCUC"), California Public Utilities Commission ("CPUC"), Maine Public Utilities Commission ("MPUC"), OEB, Philippine Energy Regulatory Commission ("ERC"), Ofgem

3.5 Potential PBR regime parameters

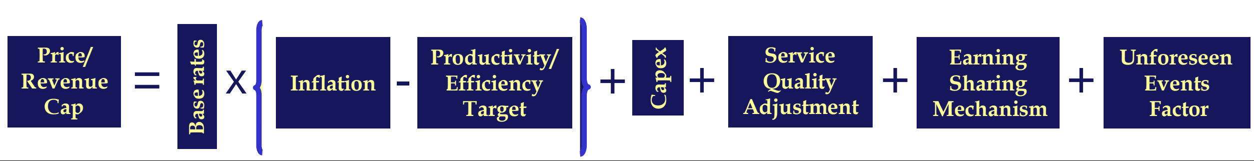
Deriving PBR formulas requires looking at a number of key components (Figure 35). These would normally include choice of an inflation factor, productivity or "X factor", treatment of (certain) capital expenditures, performance standards, earning sharing mechanisms, the treatment of unforeseen events, length of the regulatory period, and the triggers for an "exit" or "off ramp." Depending on a price or revenue cap regime, the rates or revenue requirement in the current year reflects the rates or revenue requirement in the previous year, adjusted for inflation and productivity target, and then adjusted for these other elements.

Figure 35. Potential components of the PBR formula



Determining the individual components requires careful consideration and such parameters are described in the subsections below. However, the components of the PBR formula need to be viewed holistically, thus, in determining the appropriate parameters and their combinations, choices of one parameter influence the others. For example, the X factor is not independent of the inflation factor because an inflation index using macroeconomic output-based measures takes some level of productivity gains into account. Moreover, an ESM will dampen the incentive for efficiency improvements. The term of the PBR regime should also be considered in the light of the X factor. Utilities will consider the term of PBR depending on how they perceive their abilities to perform vis-à-vis the X factor. For example, a well performing utility may assume that a longer term will provide a longer potential period for it to reap the "rewards" of cost gains, while utilities that are not confident about achieving their productivity target may view a shorter period as a lower risk proposition. Figure 36 shows the purpose of each key PBR component.

Figure 36. Key components to consider for a PBR formula



Components	Purpose
Going-in rates	Starting point of the PBR regulatory term. Rates usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period
Regulatory period	Scheduled time lag between two major reviews of the underlying components of the ratemaking regime
(I) - Inflation/ escalation factor	Annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year
(X) - Productivity factor / stretch factor	Annual adjustment to revenue or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or on external benchmark. May include a firm-specific target, or stretch factor
(K) - Capital expenditure or (G) Growth factor	Annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) needs or ex post approval of capex spending in the previous year
(Q) - Performance standards factor	Contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms or service quality as well as reliability and quality of supply
(ESM) - Earnings sharing mechanism	Mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers
(Z) - Unforeseen events factor	Contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict
Regulatory review / Off-Ramp option	Mechanism allowing to trigger, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime
(F) - Flow-through factor	Contingent adjustment to revenue or rates reflecting certain cost event which are automatically passed through to customers as they arise, without having to be approved by the regulator

3.5.1 Term of each price control period

Prescribing the right term or duration of the PBR regime is crucial. PBR requires that the system allows fixed or specific terms during which utilities can efficiently perform and their performance is reviewed and evaluated. A regulatory period is typically the time between a major review of underlying components of the determined rate regime (such as the allowed rate of return, the efficiency factor, performance standards, etc.) and the subsequent review. To allow enough time for the establishment of new institutions and/or facilitate the transition to a

Nova Scotia would examine the following elements in a periodic review

- Allowed rate of return
- Performance expectations
- Level of associated rewards/penalties
- Investment programs (past and future)
- Forecasting techniques
- Appropriateness of allowed operating costs

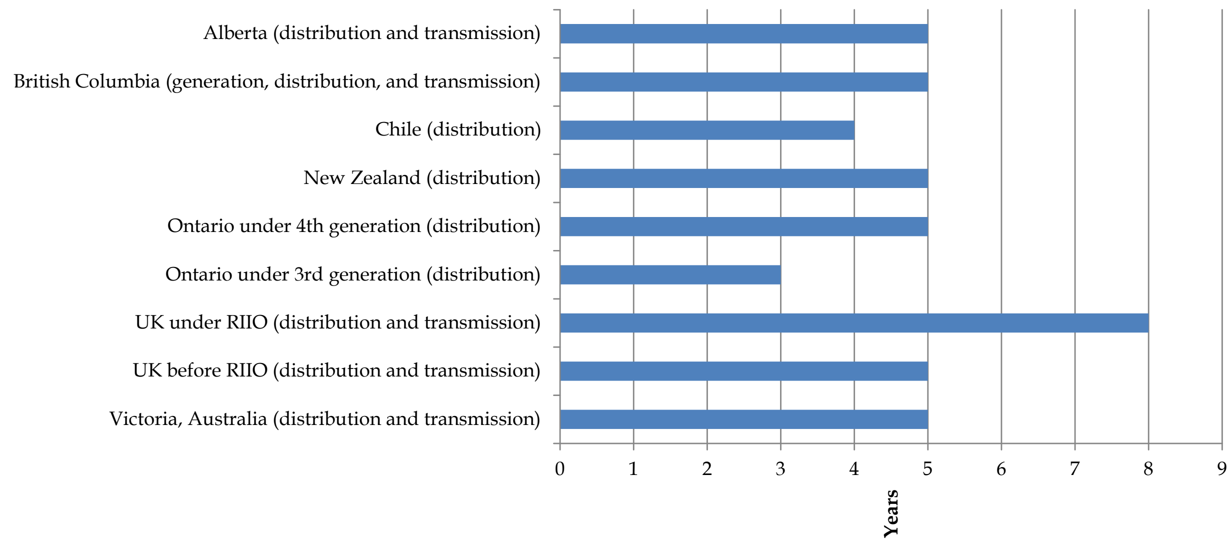
new type of regulatory structure, separate regulatory periods can also be devised for the first "generation" of PBR.

The length of the regulatory period should be governed by the need to balance competing pressures and interests. For example, a longer period can motivate a utility to adopt performance improvements and cost reductions further because the term will allow it to retain increased profits (barring an ESM). Similarly, a longer period will be beneficial especially for projects that require higher upfront costs, which can only be recovered in the longer term. On the other hand, longer periods between resets potentially increase the risk for regulators and utilities. For example, longer terms inherently allows the players to take their time in acting on or responding to changing circumstances in a more timely fashion. However, frequent resets may negatively affect utilities' investment planning. The relative preference for a specific term may also be affected by the degree of the utility's capital program. For instance, a utility may prefer a shorter term in order to have its capex added to its rates more quickly.

Based on industry experience, a PBR term of 3 to 5 years normally provides sufficient certainty regarding regulatory treatment. In this span of time, companies are motivated enough to implement long-term investment programs with or without lesser long run risks related to capital replacement. It also reduces the administrative burden typically associated with annual COS reviews. On the other hand, the utility may not have sufficient time to achieve target productivity/performance results if the regulation period is less than 3 years. Moreover, the utility would most likely not plan for a capital-intensive industry with long lived assets. Meanwhile, the utility will most likely assume that its longer term financial position will be compromised if it cannot change "unachievable" performance target levels under a regulatory period that is longer than 5 years. These may sound like simplistic views and assumptions but the PBR term should be guided by the industry's best practices.

Periodic reviews for issues such as rate of return and performance expectations may be combined with annual audited tariff reviews. In fact, this is already an industry practice. Elements are reviewed periodically in a PBR regime. Annual reviews in such a regime tend to focus primarily on assessing rewards and penalties related to service quality indicators and monitoring of capital expenditure. Figure 37 shows a comparison of the length of regulatory periods for electricity companies in various jurisdictions. The figure shows terms ranging from 3 to 8 years.

Figure 37. Length of regulatory periods under PBR for electricity companies in various jurisdictions



Source: AUC, AER, BCUC, OEB, Ofgem;
Note: PBR in British Columbia is for FortisBC. Initially, the PBR is from 2007 to 2009 and was extended to 2011.

3.5.2 Going-in rates

Going-in rates or "base rates" are the basis at the start of the PBR term to which the PBR formula is applied. Going-in rates are determined through the traditional COS calculations and derived independently from the PBR formula. Going-in rates as well as regulatory term will affect the level of risk borne by utilities and their financial viability during the PBR term.

3.5.3 Inflation factor

Questions that Nova Scotia may consider when choosing the I factor:

- Is it easy to calculate and understand?
- Does the index rely on readily available, public data from a reliable source?
- Does it represent the utility's observed cost of behavior?
- Is it exogenous to the firm?

The inflation factor (or the "I factor") provides a mechanism through which the utility's revenue or rates may be adjusted annually to reflect expected input cost increases. Two types of inflation parameters are typically used, namely, input-based and output-based measures (Figure 38).

An input-based measure reflects the change in price of ***inputs*** in the utility 'production' process over a certain period. The inflation rate is calculated through a weighted average, with the weights equal to the share of each input factor within the utility's cost structure. This measurement reflects the inflationary pressure faced by the company. This measure does not require any adjustment (such as estimating the difference between company-specific and broader national or industry conditions) because it tracks input price fluctuations better than an economy-wide measure. An example of an input-based measure is the producer price index ("PPI") which estimates the average change in the selling prices received by domestic producers for their output over time.

On the other hand, an output-based measure indicates the changes in prices for the final products produced by the utility, similar to the consumer price index ("CPI").[107] This measure is favored over the input-based measure because it is universally adopted, readily available, simple, and easy to work with and explain to stakeholders.

Figure 38. Input-based vs. output-based inflation measure

Types	Description	Advantages	Challenges
Input-based inflation measure	Weighted average of inflation metrics for each productive input	Does not incorporate efficiency gains. Reflective of price changes for inputs to distributor's production process	Not all inputs can be properly accounted for
Output-based inflation measure	Expected rate of change in prices for the final products produced by the utility or the economy as a whole (i.e., CPI)	Easier to calculate as data are more readily available, especially at the macro level	Includes average productivity gains across the sector or the economy which complicates setting the X factor

Two dimensions are considered when working with these measures, namely, geographical and sectoral scopes. The geographical scope may be national, provincial or local while the sectoral scope may apply to either the whole industry or just the utility. National statistics are often referred to because they are more readily available and easily understood. They are also more credible because they are calculated and issued by reputable government agencies. However, the national escalation index does not necessarily track the growth of the utilities' costs of operation in a particular jurisdiction so this is considered a weakness. Figure 39 presents a summary of the description, advantages and challenges of these dimensions.

Meanwhile, sectoral indices measure the usual inputs that are being used by the industry such as labor, materials, and capital. Industry statistics are generally preferred because they can be adopted for company-specific conditions with lesser need for adjustment. This means that industry-specific escalation factor mirrors industry price input patterns better than an economy-wide measure. An even narrower version of a sectoral index is a peer index, which focuses on a sample of firms in the sector only. These industry-specific measures contend with three

[107] The CPI looks at a basket of final products that are consumed across the economy, including food and beverage, housing, clothing, transportation, medical care, education and communications, and other goods and services. Electricity is typically only 2-3% of a national CPI index. Moreover, the price of electricity recorded in the CPI is the final price to consumers that bundles the transmission, distribution, and production of electricity. A true output-based inflation measures are more challenging to implement in the electricity distribution industry, as the definition of the output product is not clear. One possible approach could be the use of the price of delivered electricity, but the argument can be made that an electricity distribution company's "product" is the delivery of the electricity, not the production of electricity commodity itself.

challenges: (i) acceptance: it may be difficult to convince stakeholders that a particular industry index is the most appropriate especially if sectoral trends are not consistent with wider macroeconomic trends; (ii) liquidity: the index should not be driven by the costs of the regulated utility; otherwise, it will not serve its theoretical purpose; and (iii) volatility: a disruptive local event can have profound impacts on the index value because of the narrower scope of this index.

There is a tradeoff between relevance and simplicity in deriving the I factor. In a nutshell, national and output-based measures, if selected, are primarily chosen because of simplicity while input-based measures, especially tailored industry-specific input price indices, are preferred for relevancy. However, adjustments to the X factor must be made (assuming the X factor is based on historical productivity) if an output-based measure like the CPI is employed. An output-based inflation index indirectly incorporates the impact of average productivity improvements across whatever economic sectors the output-based measure covers. Therefore, the X factor, i.e. the productivity improvement target, must be measured to show the difference between the company's rate of productivity improvement and corresponding rate at the relevant national (or regional) level.

Figure 39. Dimensions of indices

Dimensions	Description	Advantages	Challenges
National measure	Inflation index that covers the entire economy or broad sectors of the economy	Simple and easily understood; data are readily available	Indices are not necessarily correlated with utility's related cost of operation
Sector measure	Measures inputs used by the industry such as labour, materials, and capital	Mirrors industry output price changes. Maybe closer aligned with utility costs than national escalation factors	Challenge in determining the appropriate sector-specific factor to use
Peer price index	Index made up of the prices charged by competitors	Better than the national or sector level measures	Limited availability of unbundled price data on all utility costs

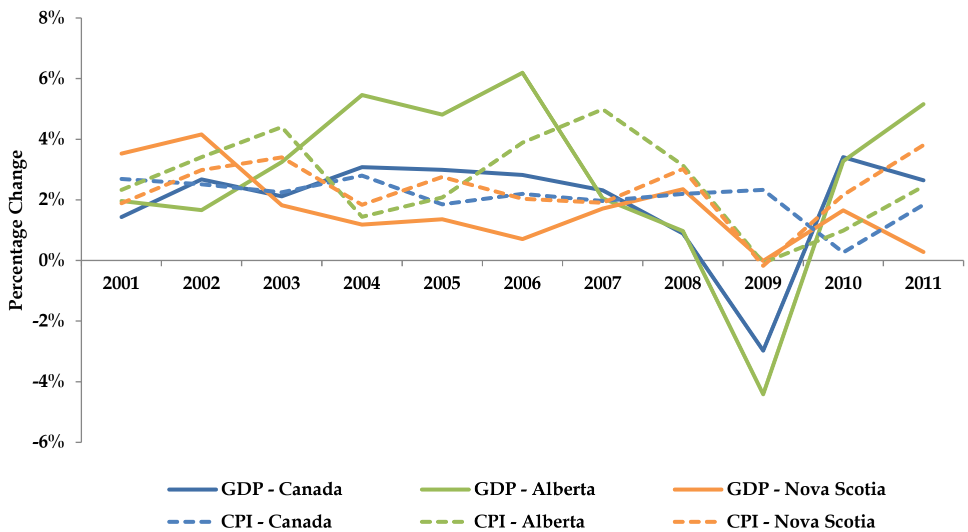
Determining the appropriate inflation factor is important because inflation indices can vary significantly. For example, Figure 41shows that Alberta (regional) inflation indices are more volatile than the Canadian (national) inflation measures. There are also specific periods when growth trends between Gross Domestic Product ("GDP") and CPI are opposite of one another. This can be observed in 2002, 2003 and 2011, when the GDP for Nova Scotia showed deflation while the CPI grew.

Figure 40. Examples of inflation factor used by selected jurisdictions

Jurisdiction	Inflation factor used	Term
Alberta (all electric distribution companies)	For ENMAX: Canadian EUCPI and Alberta Average Hourly Earnings (50/50 weighting) For the other electric distribution companies: Alberta average weekly earnings index and Alberta CPI (55/45 weighting)	For ENMAX: 2007-2013 For other utilities: 2013-2017
British Columbia (FortisBC)	CPI-BC	2007-2011
California (PacifiCorp)	CPI (Global Insight forecast)	2011-2013
Ontario	GDP-IPI for final domestic demand	2010-2013
Maine (Central Maine Power)	GDP-PI	2009-2013
Massachusetts (NSTAR)	GDP-PI	2007-2012

Sources: AUC, BCUC, CPUC, OEB, MPUC, Massachusetts Department of Public Service

Figure 41. Illustration of inflation measures in Alberta, Canada, and Nova Scotia



Inflation measure	10-year CAGR	Standard deviation
GDP - Canada	1.9%	0.02
GDP - Alberta	2.8%	0.03
GDP - Nova Scotia	1.7%	0.01
CPI - Canada	2.1%	0.01
CPI - Alberta	2.6%	0.02
CPI - Nova Scotia	2.3%	0.01

Source: Statistics Canada (Accessed on March 31, 2014)

3.5.4 Productivity factor

The X factor is the rate of change in efficiency that is expected or targeted.[108] There is a presumption that if the utility achieves the productivity equivalent to the X factor, then it will be able to earn its allowed rate of return. The X factor also serves as the mechanism by which customers reap the rewards of PBR (as it dictates the pace of real rate reductions). Therefore, there is a balance that needs to be preserved - the X factor needs to be feasible but also a challenging target, so that it can motivate cost reductions that are meaningful.

> **In determining the X factor, Nova Scotia may look into**:
>
> - how fast the efficiency frontier is shifting;
> - the location of company relative to the frontier (and whether it has exhausted or under-utilized its opportunity for cost reductions);
> - whether an additional stretch factor is warranted to further motivate the utility and to give consumers a greater share of benefits in productivity gains in the short term;
> - what type of I factor is used; and
> - length of regulatory period.

The X factor must be applied correctly and judiciously. It may be applied to total costs or to a subpart of total costs such as non-capital costs, e.g., operations, maintenance, and administration ("OM&A"). If the X factor is applied to the total cost base, then the relevant productivity measure is total factor productivity (or TFP), which measures overall productivity in the use of all inputs (i.e., both OM&A and capital). If the X factor were applied to OM&A only, then the relevant productivity measure would reflect partial productivity only (i.e., changes in the quantity of total output relative to changes in the quantity of OM&A).

The X factor is generally based on the regulator's assessment of the potential for productivity gains by the regulated firm or sector and reflects how the regulated firm or sector will perform in terms of productivity compared to the rest of the economy. To the extent analytical studies are performed, they typically look at productivity growth rates achieved historically. There are a number of techniques that are available to measure the relative efficiency of utilities and TFP or partial productivity (Figure 42).

[108] Improved efficiency may be expected through the use of better quality inputs, including the adoption of technological advances, improvement of the capacities of workforce, removal of restrictive work practices and other forms of waste, and better management through a more efficient organizational and institutional structure.

Figure 42. Commonly used methodologies in setting the X factor

	Average performance	Frontier performance	
Parameters	Price-based index number ("PIN")	Data envelopment analysis ("DEA")	Stochastic frontier analysis ("SFA")
Description	Index number measures the ratio of all outputs (weighted by revenue shares) to all inputs (weighted by cost shares)	Linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points and measures relative inefficiencies	Same as DEA but following econometric methods to estimate the efficiency frontier
Data needs	Quantity and price data on inputs and outputs for 2 or more firms	Quantity data on inputs and outputs for a sample of firms	Quantity data on inputs and outputs for a sample of firms
Advantages	Relatively simple and robust technique	Can be used without the need for price data. Can easily handle multiple outputs. Identifies peer firms (similar input and output mixes)	Accounts for "data noise" (data errors, omitted variables, etc.) and allows for the use of standard statistic tests
Drawbacks	Does not allow for identification of various factors of TFP change such as TE, SE, etc.	Sensitive to the way outputs and inputs specified. No measurement of errors	Requires large sample size for robust estimates
Examples	New South Wales (Australia), Ontario	Netherlands (until 2004), Norway, UK (DPRC5, TPRC4)	Sweden, New South Wales (Australia)

Source: Coelli, Estache, Pullman, & Trujillo

TFP - the ratio of the percentage change in unit of output to the percentage change in the unit of input - requires a time-series of data on prices and quantities of key inputs to and outputs of the electricity distribution or transmission utilities in a jurisdiction (or a representative sample of firms within a jurisdiction), preferably over the past decade.

Figure 43. TFP formula

$$\text{TFP} = \%\Delta \frac{\text{weighted sum of quantities of all outputs}}{\text{weighted sum of quantities of all inputs}}$$

INPUTS

Labour
- Physical: number of full time employees
- Monetary: Total salary cost
- Total labour costs divided by the quantity measures

Material, Rents, and Services
- Input variables other than labour and capital
- Examples include: power, office and vehicle expenses, rent expense, etc.

Capital
- Physical measure: length of kilometers
- Monetary: Depreciated or undepreciated replacement value; replacement value; nominal depreciated or undepreciated capital stock

OUTPUTS

Through-put
- Amount of energy supplied through the network

No. of customers
- Customer connections
- Network coverage

Peak demand
- Utilization of the system at peak

TFP studies, for purposes of setting the X factor, are typically more concerned in how the average level of productivity changes *over time* or the growth rate in productivity levels rather than at the business-specific costs (Figure 44). In more aggressive benchmarking or yardstick competition regimes, the X factor may be set with reference to how the efficiency frontier changes over time. An industry or a firm is becoming more efficient if it produces more output quantity over time with respect to the input quantities. Importantly, the examination of efficiency frontier trends and average productivity trends employs different methods of analysis.

For instance, a TFP analysis in the electricity sector takes the quantity of inputs to the quantity of outputs into consideration. Figure 43 presents the TFP formula and input and output factors that are often considered. Inputs into production (e.g., labor, material, rents, and services, and capital) are relatively easy to identify although measuring the quantity of said inputs (rather than their monetary value) is difficult.

An industry average productivity level represents a fitted line amongst the various firms' productivity levels, as depicted by the dotted blue line in Figure 45. The efficiency frontier represents the optimal output level given a set of inputs – therefore, the red curved line represents those firms that produce the most output per unit of input in the graph. Different X factors can be used. For instance, a single industry-wide X factor may be applied to all utilities while different X factors may be applied to specific firms or a group of firms in some jurisdictions. However, this differentiation is useful and necessary only if there is adequate information that can measure the differences in relative efficiency and an expectation that the firms will have different capabilities to achieve customized productivity targets. Therefore, different values of X may be set for different utilities, depending on where they are in relation to the productivity frontier.

Figure 44. What is productivity growth?

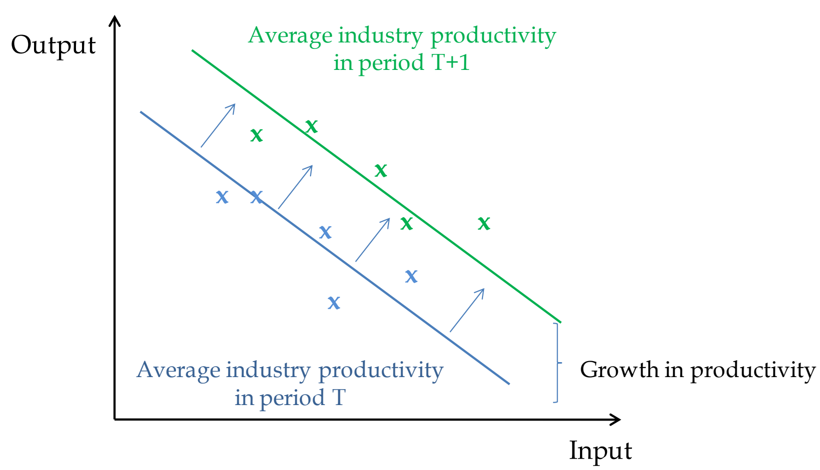
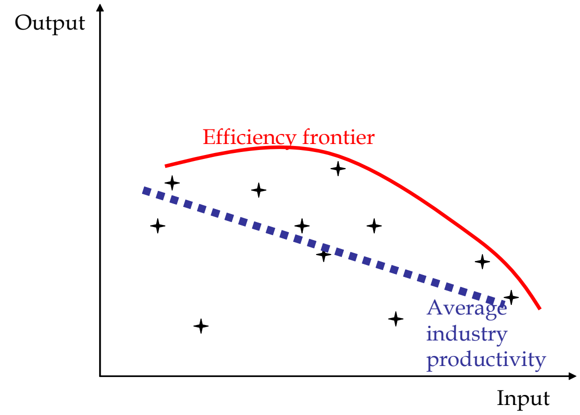


Figure 45. Illustration of the average industry productivity versus efficiency frontier



Some argue - in the case of differentiated X factors by firm - that relatively inefficient firms should have the capability to make greater productivity improvements (i.e., low hanging fruit) and motivated to "catch up" with firms on the efficiency frontier (resulting to a higher X factor for the less efficient firms). Others respond that a firm currently experiencing high productivity growth should be able to continue to excel and maintain its success (not jeopardizing its financial viability) despite being subject to a higher X factor. However, these arguments come with a caveat: regulators need to keep in mind that it is unreasonable to assume that a high productivity growth firm will indefinitely continue to outperform its peers because the "low hanging fruit" gains have already been achieved early on.

In addition to the X factor, a stretch factor is used by some jurisdictions. A stretch factor is an additional percentage applied to the X factor for the purpose of sharing with customers the benefits of the anticipated increase in productivity growth as the utility moves from COS to PBR.[109] For some underperforming utilities, the stretch factor is used to force them to "catch up" with the rest of the industry.

Ultimately, setting the X factor is as much of an art as of science. Productivity studies are useful inputs but they are not the only considerations. The goals and objectives of the PBR and data quality, including the inflator adjustor to be used, must guide the choice of methods that will be used in assessing productivity. Figure 46 shows the X factor used by different jurisdictions.

[109] AUC. *Rate Regulation Initiative Distribution Performance-based Regulation*. September 12, 2012. P. 96

Figure 46. X factor of selected jurisdictions

Jurisdiction	Company	Service Covered	Cap Type	X factor	Stretch factor	Duration
Alberta	ENMAX Power	Transmission & D	Price (distribution) Revenue (transmission)	1.2%	Yes	2007-2013
	Other Utilities	Electricity D	Price	0.96%	Yes	2013-2017
British Columbia	Fortis BC	Electricity G, T & D	Revenue	3.0%-4.% (O&M), 2.0% (Capex); 0% for all costs in last year	None	1996-1999
		Electricity G, T & D	Revenue	2.0%	None	2000-2002
		Electricity G, T & D	Revenue	2.0%	None	2007-2008
California	PacifiCorp	Electricity G, T & D	Price	1.4%	None	1994-1996
	San Diego Gas & Electric	Electricity and gas G, T & D	Revenue	0.9%-1.1%	None	1994-1998
		Electricity and gas D	Price	1.1%-1.4%	Yes	1999-2001
	So. Cal. Edison	Transmission & D	Price	1.2%-1.6%	None	1997-2001
	So. Cal. Gas	Gas T & D	Revenue	2.1%-2.5%	Yes	1997-2001
Maine	Bangor Gas	Gas D	Price	0.5%	None	2000-2009
	Bangor Hydro Electric	Electricity D	Price	1.2%	None	1998-2000
	Central Maine Power	Transmission & D	Price	0.5%-1.0%	Yes	1995-1999
		Electricity D	Price	2.0%-2.9%	None	2001-2007
		Electricity D	Price	1.0%	None	2009-2015
Ontario	Ontario electricity distribution utilities	Electricity D	Price	1.25%	Yes	2000-2002
		Electricity D	Price	1.0%	None	2007-2009
		Electricity D	Price	0.72%	Yes	2010-2012

Sources: AUC, BCUC, CPUC, MPUC, and OEB.
Note: G = generation, T = transmission, and D = distribution

3.5.5 Treatment of capital expenditure

The future of investments in infrastructure is critical when considering PBR. Current discussions on PBR worldwide are often centered on whether and how PBR regulation can lead to or spur continued investments in infrastructures. PBR, in theory, should allow for "normal" capital expenditure ("capex" or "K factor") funding. Utilities under PBR can have three sources of funds, namely, (i) the depreciation expense that is embedded in the base rate, (ii) the cash flow generated through productivity gains, and (iii) volume growth. Theoretically, such a scenario assumes a steady state environment where depreciation expense is sufficient to cover normal going forward capex. However, the real world involves practical realities that put the sustainability of capex into question, particularly under a price cap regime where the X factor is based on a TFP approach.

Accounting practices may undermine revenue sufficiency for capital expenditure. For instance, in an inflationary environment, the portion of rates related to depreciation expense is based on historical costs and these would be insufficient to fund replacement at current costs. Moreover, the cash flow that is generated through productivity gains may be insufficient to bridge the gap.

However, even if it was sufficient to bridge the gap, there would still be no additional profits left to incentivize further productivity gains from the perspective of management and shareholders.

Assuming that in certain cases when revenues may be recovered through higher consumption post-investment,[110] the additional billable units from load growth and wider customer coverage may still be insufficient to create a revenue basis to cover the entire cost of expansion-driven investments. This scenario is likely to occur because the added asset base does not affect the revenue requirement underpinning the rates until the next rate review.

Several approaches are being developed and employed around the world to address capex funding concerns (Figure 47). Some of these approaches and their advantages and disadvantages are discussed below.

Nova Scotia may consider the following in determining the right options for dealing with capex:

- Is the price cap sustainable financially for utility given projected capex? Can it support the necessary investments to provide high quality and efficient service?
- Do the design and implementation details of the PBR regime entail administrative burden to both the regulator and utility?
- How long is the regulatory period?
- Are there other safeguards (flow throughs, symmetric ESM)?

One approach is **embedding capex in the X factor**. Here, there is no explicit recovery mechanism beyond the I-X indexing formula where the X factor applies to all costs and incorporates some implicit growth in capital investment. This means that the X factor target is reduced to account for capex needs. For instance, an efficiency target of 0.5% and capital needs would amount to 2% of rates; the X factor then would be set at -1.5%. This means that rates would rise at inflation plus 1.5%. The use of negative X factors –- effectively embedded K factors –- is observed in Australia, New Zealand, and the UK. This approach is favored by users because it allows minimal involvement of the regulator and a provision for strong performance incentives. However, this approach subjects the distributors to the risk of having to wait until rebasing to recoup costs if growth in capex exceeds the funded amount. Moreover, this method necessitates some forecasting of future capex needs to establish the need and justify the additional adder embedded in the X factor.

Another approach employed is the **use of capital trackers**. The PBR formula, in most cases, cannot appropriately accommodate all the lumpy and capital-intensive projects that are common in the utility industry. To address this limitation, some regulators allow projects above a certain dollar threshold or those that meet specified criteria to be treated outside of the PBR plan. A capital tracker is an explicit mechanism that is used to track and recover certain capex. The provision of capital trackers is preferred by users because it provides certainty that capital costs will be recovered and reduces financing costs for distributors. However, this may require an active participation of and entail high administrative burdens to the regulator, utility, and stakeholders, during the rate planning stage.

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[110] Under a price cap, revenues grow as load increases, providing additional revenues to finance new investment.

Figure 47. Approach to capex of selected jurisdictions

Jurisdiction	Utility	Approach to capex
Alberta	ENMAX (transmission)	Explicit capex factor called the "G factor" (ex post COS)
	ENMAX (distribution)	Embedded in X factor plus a rate rider capped at $15 million per year
	All other distribution utilities	Embedded in X factor and capital trackers for projects that meet all of these criteria: (i) outside of the normal course of the utility's ongoing operations, (ii) for replacement of existing capital assets, (iii) required by an external party, and (iv) have a material effect on the utility's finances
Australia	All transmission and distribution utilities	Ex ante capex allowances are included in the building blocks approach
British Columbia	FortisBC (generation, transmission and distribution)	Capex not included in the X factor and is approved separately in a cost of service proceeding
Ontario	All distribution utilities	Embedded in X factor and an Incremental Capital Mechanism ("ICM") which is an explicit additional component of the price cap to meet extraordinary capital investment needs as long as the three criteria are met (materiality, need, prudence)
UK	All transmission and distribution utilities	Ex ante capex allowances are included in the building blocks approach

Source: AUC, AER, BCUC, OEB, and Ofgem

Some jurisdictions **apply the X factor to OM&A only**. Under this mechanism, only the OM&A will be under the X factor and the capex will continue to be recovered on a COS basis. FortisBC is an example of a utility that adopted this approach. This approach is favored by users because it allows certainty for capital recovery for distributors. This means better financing costs for the distributors. Nevertheless, this approach may require stringent regulatory intervention particularly in checking prudence and potential for over-investment. Moreover, it may skew incentives for management.

3.5.6 Adjustment for unforeseen events

As in any agreements or regulatory environments, players should always consider and prepare for unforeseen events. The exogenous factor ("Z factor") is a mechanism that allows for adjustment in case of occurance of events that are perceived as beyond the reasonable control of utility management, were neither foreseen nor foreseeable at the time a formula was set, and that have a significant impact on company finances.Figure 48 shows a list of examples of Z factors.

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Figure 48. Z factor criteria of events in select jurisdictions

Jurisdiction	Sector	Specified events or criteria?	Z factor eligibility
Australia	Distribution	Specified events	• Regulatory change • Service standard change • Tax change • Terrorism events • Insurer credit risk • Natural disaster, and • Network charge pass through events
British Columbia	Distribution (FortisBC)	Specified events	• BCUC or other regulatory agencies' directives • Acts of legislation or regulation of government • Changes due to Generally Accepted Accounting Principles ("GAAP") • Changes to actuarial evaluations • Force Majeure events; and • Other extraordinary events as agreed to by the parties in the negotiated settlement
California	Distribution	Criteria	• Event causing the cost must be exogenous to the utility • Event must occur after implementation of the PBR • Utility cannot control the costs • Costs are not a normal part of doing business. • Event affects the utility disproportionately. • PBR update rule must not implicitly include the cost • Cost must have a major impact on the utility • Cost impact must be measurable • Utility must incur the cost reasonably
Maine	Distribution (Central Maine Power)	Specified events	• Change in law • Environmental remediation • Extraordinary storms • Capital gains or losses
Ontario	Distribution	Criteria	• Unforeseen events outside of management's control • costs above a certain materiality threshold (0.5% of the total revenue requirement) • Materiality threshold is differentiated on the basis of the relative magnitude of the revenue requirements: for distributors with a revenue requirement below $10 million, the threshold is $50,000 and for distributors whose revenue requirements are above $200 million, the threshold is $1 million

Source: AER, BCUC, CPUC, MPUC, and OEB

Standards and criteria for Z factor are discussed and outlined before the start of the regulatory period. These standards and criteria are expected to guide decision-making after the occurrence of any incident. Specifications at the time of the setting of the formula are often made in the following areas:

- ***Areas considered outside the control of the utility***: Typically, they include but are not limited to (i) changes in regulatory requirements (particularly service standards); (ii) changes in law (such as accounting, tax and environmental regulations); and (iii) natural disasters.

- ***Financial impact:*** A minimum threshold for consideration for adjustment based on a Z factor is often determined. Such figures have varied widely across jurisdictions.

- ***Company contribution:*** Companies are sometimes required to cover a portion of the costs associated with incidences for which the regulators allow adjustment based on a Z factor. Such amounts, which are considered as similar to deductibles in an insurance context, vary widely across jurisdictions with respect to both structure (either fixed or a percentage of total costs associated with incidences) and amounts.

The Z factor can either be specific (including enumeration of qualified events)or broader as to include any occurrence that meets pre-established criteria or principles. Below are examples of criteria or events used by selected jurisdictions.

3.5.7 Adjustment for achieving specified performance standards

Performance standards are often used along with efficiency incentives to ensure that any cost reductions implemented by the utility will not cause the deterioration of service quality.

When properly designed, peformance standards should ideally meet a variety of different objectives:

- ensure a high level of service and protect consumers from hidden cost increases and poor service quality;

- align and rationalize incentives by offering financial rewards for service level improvements (if such improvement is desired by customers);

- allow corrective mechanisms such as penalties; such mechanisms should be set at a level which commands management attention and incentivizes the utility to fix the underlying problem in service quality rather than pay the fines;

- facilitate objective measurement, requiring relevant and accurate data for monitoring and evaluating performance; and

- allow utilities to meet standardsrealistically within the levels of capital expenditure which have been provided.

The actual benchmark levels need to be decided after determining the form of performance standards. Regulators will need to decide whether there is a demand for the service level to improve or just be maintained. Improvements in service often lead to monetary gains or rewards.

The identification of performance indicators that need to be incorporated within a PBR system normally depends on specific concerns within specific jurisdictions. However, they tend to be organized within three basic categories: reliability, customer service, and employee safety.

Because conditions vary widely among service territories, the idea of reasonableness is defined relative to a combination of two factors: past performance of the company at issue (indicating the current capacity of the company) and recent performance of other companies providing similar services in similar environments (indicating the range of possibilities).

Generally, a utility may be rewarded and/or penalized for performance relative to the expected level of a defined indicator in three ways:

Criteria that Nova Scotia should take into consideration when designing performance standards:

- Standards must be ***attainable*** – utility and regulation should cooperate to design challenging, yet realistic standards
- Standards must be ***measurable and verifiable*** – need relevant and accurate data for monitoring performance
- Standards must be ***based on industry-specific benchmarks***, relating to operations, customer service, and safety
- Standards must be consistent with customer needs or expectations and what customers are paying for

- ***Financial***: There are effective methodologies that directly impact company finances by including a parameter associated with defined performance indicators -- referred to as a "Q" (quality) factor -- within a PBR formula, thereby adjusting allowed prices based on performance relative to defined standards. Typically, a set of correspondence points (or ranges) is defined between (i) actual minus expected performance; and (ii) financial impacts (reward or penalty). The relationship can allow for the application of "penalties only" or "rewards only" or both. If both, the relationship can be symmetric (i.e., equivalent reward or penalty of actual performance equally better or worse than expected) or not. The specification of a relationship for any indicator needs to be customized based on the utility business. Therefore, it is often a product of a negotiation among regulator, utility, and affected stakeholders.

- ***Non-financial***: In some cases, the utility's reputation rather than finances is put on the line. In these instances, performance results are publicized, relying on the assumption that the dynamics of public relations will force a utility to improve its performance (or maintain or further improve its good performance).

- ***Customer payments***: For certain performance indicators, it may be better to impose a financial penalty on the company for unacceptable performance and direct it to award the payment of the penalty to those customers who had been specifically affected rather than implement the penalty through a broader rate reduction for all customers (or a defined customer class). This approach applies only to company penalties for poor performance and not rewards for superior performance. This approach is particularly effective and beneficial as it allows companies to provide direct compensation to those harmed by the poor company performance.

Section 4 (Performance and Accountability) will discuss in detail the different types of penalties and rewards and how these are determined by different jurisdictions.

3.5.8 Flow through or pass through elements

Unlike the Z-factor, a flow through cost is an item that is beyond the utility's control but can be anticipated and thus pre-approved by the regulator during the review. Most PBR plans have flow through factors. They are contingent adjustments to revenues or rates reflecting certain cost events which are automatically passed through to customers as they arise, without having to be approved by the regulator. Figure 49 shows the flow-through criteria used by some jurisdictions.

Nova Scotia's Fuel Adjustment Mechanism can be considered a pass through cost. The FAM has a capped incentive adjustment where a portion of the actual versus forecast fuel cost difference is allocated to Nova Scotia Power ("NSP"). For variances up to $50 million, 90% of the savings or increase (over or under recovery) is passed on to ratepayers while 10% remains the responsibility of the utility. Any variance in excess of $50 million is passed on to ratepayers. Therefore, the total maximum effect on the utility in any given year is capped at $5 million. All of this is subject to an audit and hearing process.

Source: Fuel Adjustment Mechanism Plan of Administration

Figure 49. Examples of flow through costs

Alberta (ENMAX)	Australia	British Columbia	UK

• cost elements that are not unforeseen one-time events
• Uncontrollable costs that arise in the normal course of business
	• significant costs that the approved revenue allowance is no longer appropriate
	• limited to events which are beyond the control of the utility
		• uncontrollable costs such as:
		  • power purchase expenses
		  • water fee,
		  • harmonized sales tax savings
		  • true-up from the forecast to actual previous year incentive
		  • cost of removal tax savings
			• uncontrollable costs such as:
			  • elements of transmission connection point charges that are outside their control
			  • Ofgem license fees

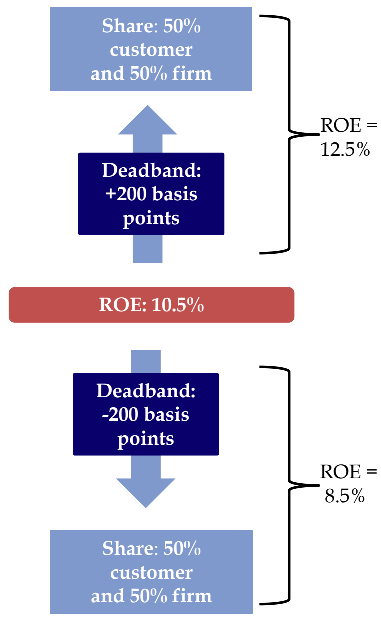
3.5.9 Earning sharing mechanism

Earlier, it was mentioned that PBR, among other goals, aims to motivate management to improve efficiency by weakening the connection between incurred costs and allowed prices. However, earnings above particular thresholds may be politically unacceptable, undermining the PBR framework. ESMs are designed so that the extraordinary earnings (or losses) are shared amongst the company and its customers rather than retained (or absorbed) entirely by the company if formulae-driven price adjustments result in a too wide divergence between prices and costs.[111] An ESM can also be stand-alone or be part of a PBR plan.

ESMs generally involve three elements, namely, a target ROE, a deadband around that ROE in which no sharing takes place, and sharing of gains or losses, which are outside of the dead-band. Deadbands and sharing percentages can either be symmetrical or asymmetrical. Under the "symmetrical" system, the customers share both upside and downside risks equally or proportionally, while under an "asymmetrical" system, the customers or the regulated utility are taking on a disproportionate portion of the risk.

Moreover, sharing percentages may be gradated. For instance, customers or the firms may gain a greater proportion of savings or bear a greater proportion of costs as profits increase or decrease. Incorporating gradated sharing is often determined by considering whether the added complexity in the formula outweighs the incentive gained in doing so. Some believe that as efficiencies become more difficult to achieve, firms should be allowed to retain a higher percentage of the savings. Others contend that higher levels of savings can lead to supernormal returns (in excess of the normal or average returns) for the firms if these are not disproportionately shared with customers.

Figure 50. ESM design elements



[111] Such mechanisms serve the same basic purpose – ensuring prices do not get too distorted or deviate too much from actual costs – as in the case of clawbacks within a traditional COS system. In the context of indexation formulae, an alternative and a more drastic one to an ESM is an exit ramp, which triggers an automatic end to the current formulae application period (and thereby initiates a COS rate review) if prices deviate too much from costs.

Figure 51. Selected jurisdictions and their ESM provisions

Company Name	US State	Term	Associated with X factor?	Sharing Mechanism
Central Hudson Gas & Electric	New York	Jul 1, 2010-Jun 30, 2013	Yes	Actual regulatory earnings in excess of 10.50% and up to 11.00% will be shared equally between ratepayers and shareholders. Actual regulatory earnings in excess of 11.00% and up to 11.50% will be shared 80/20 (ratepayer/shareholder). Actual regulatory earnings in excess of 11.50% will be shared 90:10 (ratepayer/shareholder).
Central Maine Power	Maine	2001-2007	Yes	ESM on a 50:50 basis where earnings with 350 basis points above or 350 basis point below the target ROE are shared.
CLECO Power LLC	Louisiana	Sep 2005-Sep 2006	No	If earnings exceed target ROE (12.25%) but remain less than 13.0%, the company shall return 50% of its earnings to ratepayers, while earnings in excess of 13.0% are to be returned to ratepayers 100%.
Consolidated Edison Co.	New York	Apr 1, 2005-Mar 31, 2008	No	Earnings above 11.4% (ROE target) and up to 13% are shared 50:50, 75% of earnings in excess of 13% will be deferred for the benefit of customers and the remaining 25% will be retained by the company.
Florida Power & Light Co.	Florida	2006-2009	No	FPL's shareholders will receive a 1/3 share, and FPL's retail customers will receive a 2/3 share.
Narragansett Electric	Rhode Island	Feb 1, 2013-Jan 31, 2014	Yes	Earnings between 9,5% and 10.5% are shared 50:50 between the utility and its ratepayers, while earnings in excess of 10.5% return are shared 25:75.
NSTAR	Massachusetts	2007-2013	Yes	ESM dead band is 8.5%-12.5%. If ROE is above/below the dead band, the earnings are shared 50:50.
San Diego Gas & Electric Co.	California	2009-2013	Yes	The sharing mechanism contains a symmetrical 50 basis points "inner dead band" and six sharing bands between 50 and 300 basis points above or below the authorized ROR. Shareholders receive 25 percent of the earnings above or below the authorized ROR in the first band, increasing by 10 percent in each subsequent band. Also, shareholders receive 100 percent of the earnings above or below 300 basis points of the authorized ROR.
United Illuminating Co.	Connecticut	Jan 11, 2006-Dec 31, 2009	No	ESM is based on sharing of earnings above target ROE (9.6%) where 50% is retained by the shareholder, 25% goes to customers through bill credits and the remaining 25% goes to reduce the customer's balance of standard costs.

Sources: State of New York Public Service Commission, Maine Public Utilities Commission, Louisiana Public Service Commission, Florida Public Service Commission, Rhode Island Public Utilities Commission, Massachusetts Department of Public Utilities, California Public Utilities Commission, State of Connecticut Department of Public Utility Control

However, there are also some identified drawbacks to ESM. First, an ESM can complicate the administration of a PBR system. For instance, ENMAX was concerned with the information and detail requested by the intervenors and the Commission in the process of determining the earnings sharing amount. Second, it blunts the efficiency incentives created by shifting to PBR. Some argue that a successful PBR implementation does not require an ESM. However, many believe that by allowing customers to share in benefits--which arguably would not occur in absence of incentives--the overall political acceptability of a PBR plan may also be increased. For instance, true-ups under a symmetrical ESM mechanism can neutralize the perceived impact of rate increases in the re-basing or review stage.

An ESM may also help avoid the possibility of unscheduled regulatory interventions, such as windfall profits taxes, which distort patterns of investment and returns. While some jurisdictions are not in favor of ESMs –-such as OEB and AUC because of the two concerns cited above–- they are adopted in other jurisdictions, including in the US. A sample of provisions of these ESMs across the US is shown in Figure 51.

3.5.1 Procedure for potential revision or termination of the regime ("off-ramps")

Under PBR regimes, plans typically include or prescribe mechanisms for modifications or even termination. A reopener provides an opportunity for revision or modification of a particular component in the PBR plan before the end of the regulatory period. On the other hand, an off-ramp allows for the review and possible termination of the entire PBR plan. These two mechanisms safeguard both the utilities and the customers against unexpected outcomes in the implementation of the PBR plan. Circumstances that may trigger an off-ramp or re-opener are defined prior to PBR implementation. These are usually events that are out of management's control. However, unlike the events covered under the Z factor, utilities must present solid justification for the review or the termination of the PBR plan and demonstrate that the ratemaking regime in place is unsustainable and will likely cause a material impact on either the firm or the customers. Figure 52 shows examples of events that can qualify for off-ramps.

An example of a utility that initiated an off-ramp request is ENMAX in Alberta. On October 15, 2012, ENMAX submitted an application to reopen the transmission component of its PBR plan on the basis that its 2011 and 2012 ROE had fallen below the reopener threshold level. ENMAX requested approval of remedial adjustments to the capital growth factor (G factor) and the productivity factor (X factor) components of its FBR plan. On November 2013, the Alberta Utilities Commission approved the request for a reopener to determine whether the reported ROEs are evidence of an issue with the structure of the PBR plan that must be remedied by the Commission.[112]

Figure 52. Examples of events that may qualify for off-ramps

Jurisdiction	Sector	Re-opener or off-ramp triggers
Alberta	Distribution	***ROE-*** If utility earned ROE that is 500 basis points above or below the approved ROE for one year or 300 basis points for two consecutive years *Change in service area* - material contraction and expansion of customers or service territories *Substantial change in circumstances* - material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan
California	Distribution	***ROE*** – An ROE of 300 basis points above authorized earnings for at least two consecutive years and an ROE of 175 basis points below approved earnings for two consecutive years make the PBR subject to a motion for voluntary suspension
Ontario	Distribution	***ROE*** – If utility earned ROE that is 300 basis points above or below the approved ROE for one year
UK	Distribution	***Above the capex allowance*** – if total spending on a high-value project is 20% over the total ex-ante allowance, and all outputs are met, this project will be eligible for a reopener.

Source: AUC, CPUC, Ofgem and OEB

[112] AUC. *ENMAX Power Corporation 2012 Formula-Based Ratemaking Transmission Tariff Reopener Determination*. (Decision 2013-399). November 4, 2013. P. 5.

3.6 Impact of PBR regime implementation

PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[113] timely consumer benefits, lower administrative/regulatory costs, and greater compatibility with a rapidly changing industry.

PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[114] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers. The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, BCUC noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[115]

Moreover, during the 2004-2009 period, FortisBC *"exceeded the O&M targets by an aggregate amount of $87 million over the six years. Customers received 50 percent of this or $43.5 million back via the ESM."*[116] O&M savings during the PBR period benefit customers in two ways: (i) through reduced rates during the term of the PBR via the ESM and (ii) through rebasing of the savings into opening O&M as the starting point for setting rates after the PBR has ended.

Similarly, in the UK, Ofgem stated that the RPI-X regulatory framework has brought benefits to electricity customers over the last 20 years and has *"delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices."*[117] In fact, *"since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization."*[118] Ofgem also believed that the implementation of PBR *"has led to significant improvements in quality of service. Between 1990 and 2009, the number of duration of reported outages fell by around 30 percent."*[119]

With performance standards in place under a PBR regime, distribution line losses also improve. In Ontario, line losses of Hydro One decreased steadily for the past six years: by 1% per year from 1,780 GWh in 2007 to less than 1,700 GWh in 2012. Hydro One is the largest transmission

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113 Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

114 Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

115 British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, page 22.

116 Ibid.

117 Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

118 Ibid.

119 Ibid.

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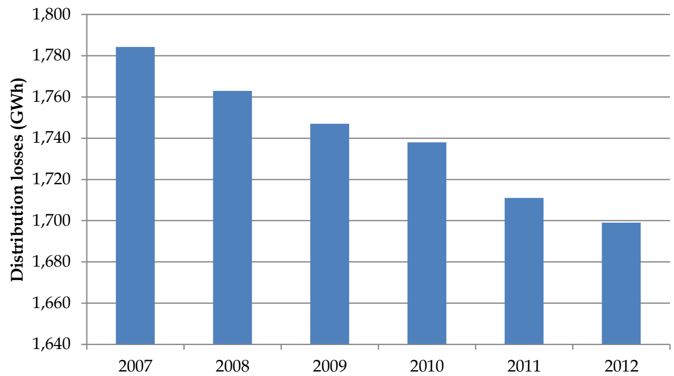
and distribution company in Ontario. Its distribution system is the largest in the province spanning approximately 75% of the province, serving 25% of customers.

Figure 53. Hydro One's distribution line losses (2007-2012)



Source: OEB. Yearbook of Electricity Distributors (2007 to 2012)

In addition, PBR regimes are usually expected to lead to an overall reduction in the regulatory burden mainly because of a lower frequency of regulatory proceedings (when compared with markets under a COS approach) and a less fastidious review of costs.[120] Reduced regulatory costs under PBR are a result of PBR's recognition of the information asymmetry between the regulatory and the utility. Under COS, regulators spend a considerable amount of time and expense to bridge the information gap. In contrast, PBR does not try to rectify this information gap. Rather, under the PBR regime, the regulator does not need to know the costs for each O&M item but only needs to know the range of possible costs from which the regulator can approve a PBR plan that can elicit maximum efficiency from the utility.[121] In addition, regulators benefit from PBR to the extent that it eases them of the demanding task of micro-managing the activities of the utility. For the utilities, reduced regulatory micro-management allows them to respond more quickly to technological and competitive challenges. For customers, this may mean lower prices.

Furthermore, a PBR regime does not necessarily lead to a fall in capital investments. Indeed, capital additions of electric distribution and transmission utilities in Ontario have increased by an average of 12% per year from 2005 to 2012 (Figure 54). Likewise, a recent review by Ofgem has found that the PBR in UK has *"… served consumers well, delivering lower prices, better quality of service and more than £36bn in network investment since privatization twenty years ago."*[122]

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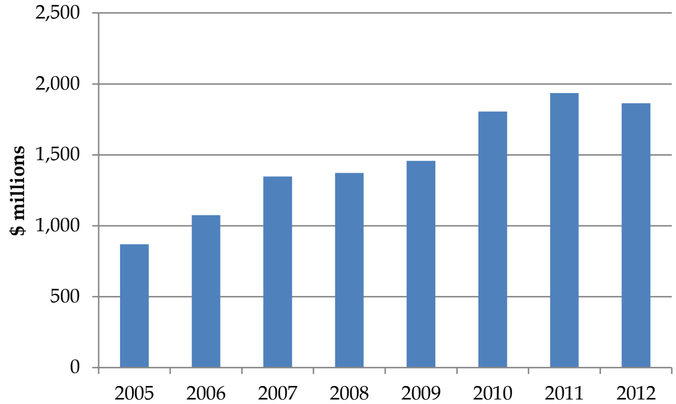
[120] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[121] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 6.

[122] Ofgem. *RIIO: A New Way to Regulate Energy Networks Final Decision*. October 2010. P. 2.

Figure 54. Capital additions of transmission and distribution utilities in Ontario



Source: OEB. Yearbook of Electricity Distributors (2005 to 2012)

Finally, PBR can also serve both as a transitional mechanism to restructured and more competitive electricity markets and as a substitute for actual competition.[123] According to Comnes, *"competition and restructuring often increase the complexity of allocating utility facility costs common to both competitive and noncompetitive services. Thus, sticking to COS ratemaking in such an environment perpetuates incentives for resource inefficiency and increases the cost of regulation… PBR is an effective transitional pricing mechanism for industry segments that are becoming more competitive over time. On balance, one may see the association of PBR with competition and restructuring as a way for regulators and the industry to (1) provide captive customers with reasonable rates without resorting to increasingly complex, contentious rate hearings and (2) increase the incentives for improved productivity in light of the possible future deregulation of utility prices."*[124]

3.7 Jurisdictional review of where PBR has been adopted for power utilities

The goal toward "efficiency improvements" has been motivating many jurisdictions throughout the world to varying forms of PBR particularly for electricity distribution and/or transmission utilities as well as for other monopoly infrastructure businesses. Jurisdictions like Abu Dhabi, Alberta, Austria, Australia, Brazil, Chile, Colombia, Finland, Ireland, Malaysia, the Netherlands, New Zealand, Norway, Ontario, Oman, the Philippines, Portugal, Spain, Thailand, the United Kingdom ("UK") and several jurisdictions in the US have already adopted PBR. Figure 55 shows jurisdictions where PBR has been adopted and the specific forms that they have taken.

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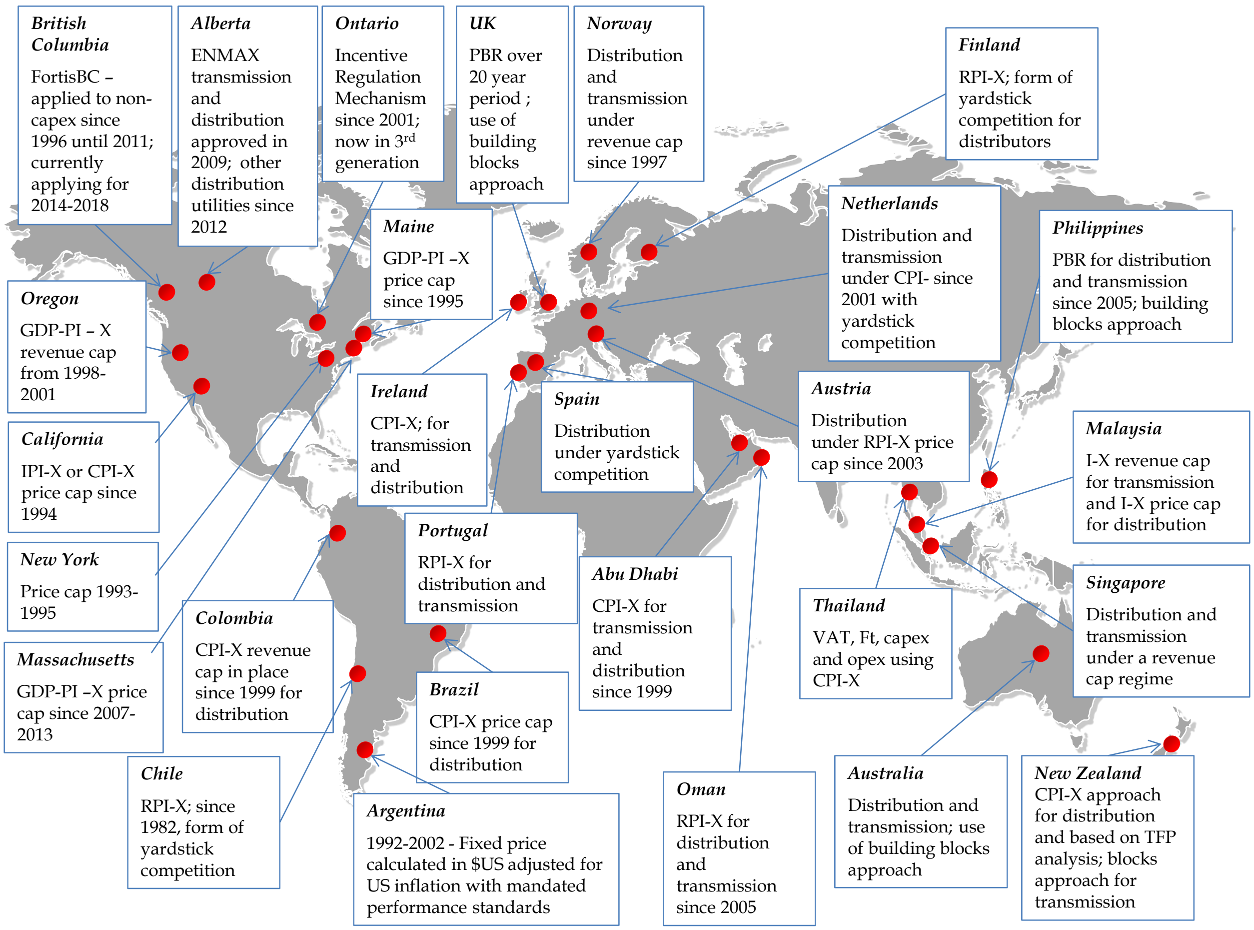
[123] Sappington, David. *White Paper on Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan.* February 1, 2000. P. 11.

[124] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 8.

Figure 55. Sample of markets where PBR has been adopted



Source: Various regulatory dockets

In Australia (where PBR has gradually become more uniform across the states in recent years), the experience with price cap and revenue cap regimes -- based on a building blocks approach-- has been viewed positively. The regulatory regime in place has allowed a high level of adaptability in the utility-specific determinations made by the regulator. Moreover, the treatment of capex –- based on forward projections of efficient capital outlays (similar to the UK system) -- has been supportive of the development of an efficient network and has led to the approval of significant capex allowances. The X factor has been negative in many instances for one or more years consecutively, leading to rate increases in real terms, but greater network investment. Furthermore, the regulator has encouraged utilities to reveal their true level of efficiency by implementing incentives to improve efficiency through ESM and a "glidepath" that transcends the fixed term of PBR.

In Canada, with the exception of regulatory lags that occurred from time to time as a result of rate freezes, British Columbia was the first province to adopt a harder and more explicit form of PBR in 1996. However, it was applied to the operations and maintenance expenditures, capitalized overheads, depreciation rates, ROE risk premium, and non-financial performance measures of FortisBC only. PBR (known more commonly as Incentive Regulation Mechanism or IRM in Ontario) has been in place in the province since 2001 and is now in its third generation. In Alberta, ENMAX was the first transmission and distribution utility to propose PBR in the province before the AUC decided to introduce the approach to the other electric and natural gas distribution utilities in 2011.

PBR has generally been considered a success in motivating efficiency and creating benefits for ratepayers in the UK (where PBR has been implemented for electricity transmission and distribution utilities for more than two decades). PBR design has adapted to the changing environment, although the underlying principle of "building blocks" has not changed. The building blocks approach relies heavily on forecasts of future efficient operating costs and capital expenditures and this has allowed the British distribution utilities to avoid the capital expenditure issues that some utilities are now facing. Moreover, the incentives for innovation and efficiency given to utilities have encouraged them to continue to provide high level of service quality while minimizing costs. Notably, the next generation of PBR for distributors -- under the RIIO model (or the "Revenue set to deliver strong Incentives, Innovation and Outputs" model) -- is expected to extend from the historical 5-year time span to 8 years.

3.7.1 Vertically integrated utilities under PBR

There are several examples of vertically integrated utilities that have adopted the PBR approach in North America. From 1994 to 1996, PBR was applied to San Diego Gas and Electric's ("SDG&E") gas and electric businesses. On the electric side, SDG&E is a vertically integrated generation, transmission, and distribution utility. SDG&E used a "revenue indexing" method where the utility's annual revenue requirement was adjusted using formulas for the revenue requirement associated with operating and maintenance expenses and determination of authorized capital expenditures. SDG&E's PBR originally allowed nuclear O&M expenses plus appropriate overheads. However, capital additions and nuclear O&M expense were removed from the SDG&E PBR in 1996. In addition to this Base Rate PBR, SDG&E also had a generation and dispatch PBR, which was intended to provide incentives to make power purchases and operate power plants efficiently. SDG&E was rewarded or penalized based on the actual versus expected performance on targeted cost factors, including fossil unit forced outage and maintenance outage rates, economy energy costs, and firm contract costs. Because of PBR, SDG&E's operating costs and capex were lower than projected from 1994 to 1996.[125] Its O&M was reduced by $15-19 million below the authorized level and this savings accounted for more than 50 percent of the utility's excess return in all three years.[126]

Central Maine Power ("CMP") is another example of a vertically integrated utility that was under a form of PBR, referred to as the Alternative Rate Plan ("ARP"). CMP is an electric utility serving more than 500,000 customers in Maine. CMP's ARP was composed of a price cap (Gross

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125 Biewald, Bruce, Tim Wolf. *Performance-Based Regulation in a Restructured Electric Industry*. November 8, 1997. P. 27.
126 Ibid.

Domestic Product Price Index – Productivity Factor) with an associated ESM.[127] The ARP was first implemented in 1995 and in effect for five years. It covered all aspects of CMP's operations, including generation. CMP was still a vertically integrated utility at the time. As the utility was unbundled, the generation subsidiary became deregulated. CMP's distribution business remains under a form of PBR until 2016.

Another example is FortisBC, which is a vertically integrated utility in British Columbia. FortisBC was under a partial form of PBR from 1998 to 2001 and from 2004 to 2009.[128] The 1998-2001 PBR plan focused on pursuing operating and maintenance cost efficiencies which included a limited capital incentive mechanism and a series of service quality standards that were tracked to confirm that service quality was being maintained throughout the term. The 1998-2001 PBR plan was based on the previous PBR plan and had additional features such as a 50/50 ESM between customers and shareholders, a longer term period, service quality standards that were more results oriented, and an Efficiency Carry-over Mechanism, which was designed to encourage the company to continue to pursue efficiency gains throughout the PBR term.

3.7.2 Generation-only utility under PBR

OEB is in the process of establishing the PBR for Ontario Power Generation's ("OPG") prescribed assets. OPG is one of the largest energy producers in North America with over 19,000 MW of electricity generating capacity from its two nuclear, five thermal, and sixty-five hydroelectric generating stations. Certain hydroelectric and nuclear assets owned and operated by OPG are regulated (also called the "prescribed assets"). The total prescribed assets total approximately 9.900 MW of in-service capacity and represent over 50% of OPG's total production capability. The price received by OPG for generation from the Prescribed Assets is regulated under the Ontario Energy Board Act of 1998 and Ontario Regulation 53/05.

Currently, OEB uses a COS regulation to establish the prices for OPG's Prescribed Assets but desires a move to a PBR methodology. OEB established a working group to determine the PBR details. Moreover, a TFP study is being conducted to determine the productivity factor that will be used to determine the revenue requirement for the prescribed hydro assets. OPG is scheduled to file its PBR application for prescribed hydro assets by 2015.

3.8 Rationale for moving back to a "soft" PBR or a COS regime from a "hard" PBR regime

The energy sector has seen utilities in three jurisdictions (California, Massachusetts, and British Columbia) moving from a "hard" form of PBR to its "soft" form. There are various reasons for this shift but it is generally driven by capital investment concerns. Although some level of capital investment is represented in the basic I-X price cap formula, the basic price cap formula cannot guarantee that capital investment needs will be met completely during the term of the PBR particularly for a firm with circumstances that are not consistent with "steady state"

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[127] ESM provides for a 50/50 sharing of profits or losses outside the 350 basis point bandwidth of the return on equity of 10.559 percent.

[128] The 2004-2009 PBR was extended to 2011.

conditions. Revenue sufficiency in the theoretical constructs of PBR is achieved because theory makes implicit assumptions about the pattern of capital investment – namely that the capital investment has been smooth and consistent with the pace of depreciation, such that the rate base remains stable over time. Even in the case of revenues recovered through higher consumption post-investment, the additional billable units from load growth and customer additions may not be sufficient to create a revenue basis that can cover the entire cost of expansion-driven investments because capital investment in transmission and distribution sectors is lumpy. It is also unlikely that the new capital--which will be deployed--will be fully utilized immediately. This has been observed when the National Grid terminated its 10-year PBR plan in 2010. Changes in the business and regulatory environment created undue capital cost recovery risk under the previous comprehensive PBR plan of the National Grid.[129] In its application, National Grid stated that as of December 31, 2009, its earned return was only 0.31%, which does not meet the standard for just and reasonable rates. It proposed for a partial rate adjustment plan where only the O&M costs would be subject to inflation adjusted mechanism, which, according to National Grid, was more appropriate given the circumstances that it was confronting at that time.[130]

The shift to a softer form of PBR can also be attributed to changes in the utility's corporate structure. NSTAR, an electricity and natural gas company in Massachusetts, was under PBR from 2009 to 2012. When the merger was announced in 2010, one of the merger settlement agreements offered by the merging parties was to freeze the base distribution rates of NSTAR for the next four years or until January 1, 2016.[131] The freezing of rates is a common proposition that merging companies normally make to get the Commission's approval for the merger case.

Another reason why a utility moves to a COS is to refine some elements of the PBR components. For instance, in 2009, FortisBC Inc. and the BCUC agreed that FortisBC will revert to COS in 2012 and 2013. FortisBC experienced fairly large rate increases (more than 5%) in 2011 and the interveners wanted a more thorough review process in order to appreciate the magnitude of the increases. Interveners argued that COS would "*allow stakeholders to take a better look at the individual costs items for increased transparency*."[132] Under the PBR, some items such as the O&M, capitalized overheads, and depreciation were set by the I-X formula. The move to COS also allowed for a rebasing of costs which brought the efficiencies achieved by FortisBC during the PBR period into the rates along with setting rates for 2012 and 2013.[133] Nevertheless, FortisBC has proposed to return to PBR for 2014-2018.

Therefore, utilities that have adopted a PBR regime did not move back to the traditional COS because the PBR mechanism did not work. These utilities moved back to either a softer form of

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[129] National Grid. *Initial Brief* submitted to the Massachusetts Department of Public Utilities, September 7, 2010. Available online at http://www.env.state.ma.us/dpu/docs/gas/10-55/9810nginbf.pdf.

[130] This phenomenon is similar to the ENMAX transmission experience in Alberta.

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

[132] Email correspondence with Dennis Swanson, Director of Regulatory Affairs, FortisBC. December 14, 2011.

[133] Email correspondence with Katie Berezan of the Office of the Commission Secretary, BCUC. April 11, 2014.

PBR or to COS for a short period of time to improve components of the PBR so they can adapt to the changes in the business environment.

3.9 Key conclusions

PBR, while challenging in certain aspects, offers potential advantages over a COS approach (Figure 56). For instance, the PBR approach may reduce administrative and regulatory costs due to fewer regulatory proceedings. PBR also leads to more stable rates for customers[134] because rates under an I-X approach will only increase by inflation less the productivity factor plus other flow-through mechanisms. Moreover, utilities are encouraged to operate more efficiently so they can achieve or surpass the productivity targets. Reliability can also be safeguarded under a PBR regime, especially for plans that have mandated performance standards, which in some jurisdictions also entail a system of penalties and rewards. Meanwhile, sufficiency of capex funding under a PBR approach can be a concern if there are no other capital incentive mechanisms in place other than the I-X formula or if the explicit capital incentive mechanism provided is very restrictive. Including a capex mechanism within the PBR formula or, at a minimum, incorporating a hedging feature to reduce regulatory risks associated with capital outlays beyond the control of management may, in fact, provide for increased stability and ensure longevity of a PBR mechanism.

Figure 56. Comparison of COS and PBR approaches

Parameter	COS approach	PBR approach
Regulatory process	• 1-2 years (depending on jurisdiction) • requires to go through regulatory proceedings every rate adjustment • more frequent regulatory proceedings	• longer than COS (2-3 years) • can be tedious as it involves analysis of technical issues related to PBR components • rates adjust within a regulatory term without going through a regulatory proceeding • reduces administrative and regulatory costs due to fewer number of regulatory proceedings
Rate stability	• rates adjusted through hearing process • rates based on costs will fluctuate with forecast costs	• rates are set annually by a formula in an I-X approach or during the hearing • fluctuation of rates is based on the PBR components (i.e. I factor, X factor, etc.)
Efficiency	• short regulatory term may be a deterrent for long term investment	• provides greater incentive for utilities to operate efficiently
Reliability	• ensures reliability and safe electric supply	• ensures reliability and safe electric supply • performance standards in place will provide comfort that reliability will be maintained
Capital expenditure funding	• utilities could recoup capital investments	• has been a concern in some jurisdictions such as Alberta and Ontario • according to some utilities, I-X price cap formula in Alberta and Ontario might not provide sufficient financing for capital expenditure • the inclusion of capex mechanisms or hedging features may help reduce regulatory risks (associated with capital outlays beyond the control of management)

134 Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

Similar to any other regulatory framework, the implementation of PBR regime also involves specific issues and challenges (Figure 57):

Figure 57. PBR issues and solutions

PBR issues	PBR solutions
Forecasting challenges and errors	• **Benchmarking and trend analysis** can be used to compare differences in actual costs from proposed costs and to inform regulatory decisions to adjust up or down utilities' forecast expenditures • Include an **ESM** so that earnings (or losses) above (below) forecasts after a certain dead band are shared between the company and its customers • **Re-opener** provides opportunity for revision of modification of the PBR • **Flow through costs** are approved cost categories that do not necessitate regulatory approval and are automatically flowed through to customers • **True up** allows to revisit costs from previous year and adjust the next year's revenue requirement for the forecast error between actual revenue and allowed revenue in year t-1 • **Reset or rebase** can be used during a PBR term if actual costs and forecasts become extremely divergent • **Construction Work In Progress ("CWIP")** provides utilities with cash flow upfront when new capex occurs
Data availability	• **Early and systemic collection** and **data quality checking** make filing process easier
Funding for capital investments	• **Ex-ante review approach** to treating investments may secure adequate investment • Provide some **mechanisms to ensure that utilities can cover their investments** such as providing capital trackers, adjusting depreciation, project-specific ROE, project-specific capital structure, and construction work in progress
Timing and type of cost savings	• **Eliminate distinction** between capital expenditure and operating expenditure • Including an **efficiency carry over mechanism** will provide a utility to operate efficiently throughout the entire regulatory period and will also provide a balanced incentive for the type of efficiencies undertaken
Cost-cutting to achieve productivity target	• Mandated **performance standards** ensures reliability and service quality will not suffer

- **Forecasting requirements and challenges.** The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[135] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting on the side of the utilities can also lead to potential additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts can significantly deviate from actual figures so the PBR design must include mechanisms that will provide a degree of protection to both the shareholders and ratepayers. These mechanisms may include re-openers, ESM, true-ups, rebasing, and flow-throughs.[136]

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135 Items to forecasts include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

136 In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

Benchmarking and trend analysis can also be used to compare differences in actual costs and proposed costs and guide regulatory decisions, for example, in increasing or reducing the utilities' forecast expenditures.

- **Availability, accuracy, and consistency of data**. Data is often inconsistent or even unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes and differences in accounting techniques, and mergers and amalgamations, to name a few. As mentioned earlier, data availability is a critical element in PBR. Harder forms of PBR require collating and employing multi-period information and data samples covering multiple utilities. Ensuring data consistency and credibility requires configuring systems and processes correctly. The utility can review current systems and record-keeping practices and configure them to capture the data required for filing. Appointing a Chief Data Officer--who can ascertain data accuracy and consistency--would be useful to prevent errors.

- **Funding requirements and financial viability.** Sources of funding in an I-X regime might not be sufficient under a non-steady state. Utilities are concerned that their financial viability may be undermined if there will be substantial capital expenditure requirements, which are not usually recognized in a timely manner in the PBR formula or if actual conditions depart from "test year" or historical conditions. Some regulators have addressed this issue by prescribing forward capital planning. Regulators are also dealing with such challenges through capex incentive mechanisms although such mechanisms complicate the administration of the PBR regime. In the same breath, some jurisdictions have incorporated adjustment factors within the PBR formula to address capital cost issues or have modified the PBR design so it becomes a cross between COS and "harder" forms of PBR.

- **Treatment of rewards for efficiency.** There is a concern that utilities will likely target efficiency gains in the early years of a regulatory period under PBR. This behavior is likely caused by the declining reward for efficiency over the regulatory period (in an I-X regime) and the practice of using the later years as the base year when resetting the rate for the next regulatory period. Furthermore, the practice of rewarding one type of cost savings and not the other often motivates utilities to change their spending profile to maximize returns. To address these concerns, an efficiency carry-over mechanism ("ECM") is included in the PBR design. An ECM provides utilities with an ongoing incentive to operate efficiently throughout the entire regulatory period by allowing them to carry over the incremental earnings from efficiency gains into the next regulatory period. Utilities in Alberta (except for ENMAX) and Australia have ECMs. Another solution that removes the trade-off between operating and capital expenditures in economically inefficient ways is the elimination of the distinction between these two types of costs. UK has done this in its 5th generation PBR (2010-2015) and treated both costs into "one pot." This new approach has allowed utilities to select the incentive that best suits their business.

- **Service quality vis-à-vis incentives for savings.** There is a common concern from ratepayers and regulators that the PBR's focus on the bottom-line and incentives for cost-cutting may lead to poor quality of service. Therefore, it has become increasingly common to require performance standards in the PBR formula. However, as will be discussed in the next section, setting the criteria and financial incentives for performance requires additional administration and management.

> If adopted in Nova Scotia, a simple form of PBR would be the best approach.

In addition, the size of jurisdiction affects the type of PBR regime that one will implement and the issues that may arise. The I-X approach is preferred in jurisdictions with relatively higher number of utilities such as Ontario while the building blocks approach is normally favored in markets that have fewer utilities such as UK and Australia. A primary reason is that the I-X approach can be implemented more economically for a large number of distributors compared with the building blocks approach. Moreover, utilities differ in terms of size of service territory, customer number, and customer type in jurisdictions with more utilities such as Ontario. This poses as a challenge to the regulator because PBR is expected to recognize the unique circumstances of each regulated utility. To address this concern, the OEB recently established the Renewed Regulatory Framework for Electricity Distributors, which provided utilities three options in the setting of rates.[137]

PBR also need not be as complex as the I-X approach or the building blocks approach. As discussed earlier, PBR is a spectrum with different forms. A simple ESM is also considered as a form of PBR and can create incentives for regulated utilities to perform efficiently.

To conclude, Nova Scotia can learn from the experiences and key success factors from other jurisdictions that have effectively implemented the PBR regime:

- **Open and transparent regulator**. Such openness and transparency allows for better handling and meaningful consideration of customer insights and feedback. The success of PBR in many jurisdictions had also been fueled by the strong participation of all stakeholders including the consumers.

- **Adaptation to the business and regulatory environment**. The regulator should be familiar with the business and regulatory environment and adapt to changes when necessary. For instance, in UK, Ofgem has routinely made modifications to the PBR

[137] These options include (i) a price cap index, (ii) a customized index with distributor-specific rate trend for the plan term to be determined by the Board and informed by the distributor's forecasts, the Board's inflation and productivity analyses, and benchmarking, and (iii) existing rates are adjusted by an annual adjustment mechanism. See OEB. *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.* October 18, 2012.

regulations after each regulatory period to improve a particular mechanism that did not work as anticipated or to adapt to changes in the environment.[138]

- **Reasonable rates for the protection of future investments**. Jurisdictions that have successfully implemented PBR set rates at a level which enables a utility to meet its obligations to customers as well as earn a commercially reasonable return to support necessary investments. PBR recognizes that any system should allow utilities to have sufficient funds for capital investment programs during the regulatory term. This recognition is anchored on the presumption that a reduction in returns to shareholders to levels below regulatory allowed targets may lessen their capital financing capabilities in the future because the cost of capital would increase (e.g., due to perceived additional risk for utility operation and lower returns).

- **Balanced targets for efficiency, productivity, and financial viability**. The targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. The X factor should also be informed by the consideration of opportunities for further productivity gains and cost reductions, customer growth, and capital funding.

- **Appropriate mechanism to manage risks**. In successful PBR regimes, the regulator has provided appropriate mechanisms to manage risks to customers and the utility for factors that are beyond the utility's control. These mechanisms include flow-throughs, Z factors, off-ramps and reopeners.

- **Fair incentive and penalty mechanisms**. When adding explicit incentives to a price or revenue cap, the penalties and rewards should be commensurate with (i) the savings of the utility after reducing costs and (ii) the costs of the utility after improving performance.

- **Contextually developed and relevant models**. There is no "one size fits all" PBR formula. Stakeholders (regulators, regulated entities, and consumers) must work together and recognize their needs and develop their own path to PBR. A regulatory framework from another jurisdiction or utility may not work as well in another utility because of numerous factors such as inherent economic and market differences, business practices, policy-driven obligations, and regulatory or institutional requirements. Therefore, a PBR design needs to be customized to the specific

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[138] For example, in the current regulatory period, the UK regulator decided to apply the same incentives to all network-related expenditures (capital expenditures and operational expenditures). In its review of the prior generation of PBR, the regulator noticed that differences in the treatment of incentives for capex and opex were distorted and incentivized the utilities to adopt more capex, rather than opex, solutions. The regulator also observed that utilities recorded expenditure in the areas with the highest rates of capitalization even if the expenditure was not in that area (Ofgem. *Electricity Distribution Price Control Review Final Proposals - Incentives and Obligations*. December 7, 2009. p. 107). Therefore, the regulator decided to neutralize these effects by equalizing incentives.

environment and circumstances of the regulated utilities. The regulator needs to take the utility's unique characteristics, type of customers served, and underlying economy into account.

- **Flexible mechanisms in addressing uncertainties.** Finally, stakeholders must recognize that there are uncertainties in moving to a "new" regulatory regime. Therefore, there should be some built-in flexibility for addressing those uncertainties if and when they develop. For instance, providing mid-term review, especially for long regulatory review, and re-openers is a typical approach that other jurisdictions have implemented to make PBR regimes more realistic, adaptable, and resilient to uncertainties and unexpected events.

4 Performance and Accountability

To analyze electrical performance and accountability,[139] it is important to distinguish between generation performance standards and performance standards for the wires sector, which include the transmission and distribution sectors. Generation performance is typically measured in terms of efficiency and availability and, in restructured markets, is largely incentivized by the competitive market. Incentives are supplemented by oversight from market institutions. The more a generator is available to produce electricity when called, the more revenue it accrues. The more efficient it is at operating, the greater its profits. To complement this incentive, system operators and power purchasing agreements ("PPAs") often design further generator incentives vis-à-vis minimum reliability and availability targets.

Power market liberalization has been accompanied by more precise definitions of performance, accompanied by new institutions and procedures for monitoring and accountability.

In the wires sector, performance is typically measured in terms of the frequency and duration of outages over time as well as by customer service metrics. Distinct from generation, and especially for utilities regulated using a performance based ratemaking ("PBR") tariff structure, the wires sector must balance operations and maintenance ("O&M") cost efficiencies against the need to maintain reliability, customer service, and employee safety. To encourage this, regulatory authorities have designed, implemented, and continue to monitor electric performance and accountability standards.

Figure 58. Overview of institutions responsible for reliability oversight and enforcement mechanisms

Activity	Institution	Mechanism
System Reliability	NERC	Fines/penalties
Generation	ISO, PPA counterparty	Market rules, PPA provisions
Transmission	NERC, ISO, regulator	Fines/penalties, performance standards
Distribution	Regulator	Performance standards

Largely considered the core value of electricity service provision, reliability is by far the most important performance indicator in electricity transmission and distribution. Reliability measures the ability of the network to continuously and securely meet consumer demand and includes the bulk electrical system's[140] ability to withstand sudden disturbances such as electric

[139] While market power and competition oversight is another form of accountability, this issue is covered in Section 2 (Global experience with electricity sector liberalization).

[140] NERC's definition of the bulk electrical system was defined according to the "bright-line" principle in FERC's Order 773 ruling RM14-2 as a subset of the bulk power system, which defines the outer limits of FERC's jurisdiction. Neither term includes the local distribution system.

disruptions or an unanticipated loss of system elements.[141] Therefore, many regulators prioritize indicators measuring reliability.

More generally, reliability is considered one portion of a range of parameters which encompass performance standards. These other important performance standard parameters include customer service or service quality standards as well as health and safety standards. Typically, service quality standards can include call center response times, average time to answer calls, emergency response times, and/or billing accuracy. Relevant health and safety measures include injury/illness severity rates.

4.1 Levels of responsibility for reliability

While levels of responsibility for ensuring reliability and performance standards differ by jurisdiction, this section focuses on North America.

The North American Electric Reliability Corporation ("NERC") was established in 2005 as part of the Energy Policy Act of 2005 ("EPAct 2005") to develop and enforce mandatory electric reliability standards as overseen by the Federal Energy Regulatory Commission ("FERC"). NERC oversees both traditionally regulated and liberalized power markets. Prior to the EPAct of 2005, NERC was known as the National Electricity Reliability Council and was responsible for developing voluntary reliability standards. NERC was formed as a response to the Northeast blackout of 1965. Following the 2003 blackout, a US-Canadian Power System Outage Task Force was convened and made "recommendations regarding measures to reduce the risk of future power outages and the scope of any that do occur."[142] The transition to mandatory reliability standards originated as a result. The blackout itself was not a consequence of wholesale market competition, but wires maintenance.

To better tailor reliability standards to regional needs, NERC subsequently delegated the development of regional standards (in addition to the mandatory NERC standards), compliance monitoring of mandatory reliability standards, and reliability assessments to the eight regional entities (or regional Electric Reliability Organizations ("ERO") enterprises) as shown in Figure 59.[143] Additionally, NERC responsibilities include conducting annual assessments of seasonal and long-term reliability, monitoring the bulk power system through system awareness, and education of industry personnel.

The highest level of authority responsible for reliability implementation within the bulk electrical system lies with the reliability coordinators. At the next level, the transmission

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141 Karlak, Janice Stroup. *Measuring Commercial Quality between Distribution and Supply: How To Allocate Indicators*. USAID and the National Association of Regulatory Utility Commissioners Licensing/Competition Committee. Kiev, Ukraine 11 September 2008. Speaker P. 3.

142 Dawson, Kelly and McAlister, Levi. "Restoring Faith in the Bulk-Power System: An early Assessment of Mandatory Reliability Standards." *The Electricity Journal* 23.2 (March 2010): P. 19-20

143 North American Electric Reliability Corporation. *Improving Coordinated Operations Across the Electric Reliability Organization Enterprise.* February 2014. P. 3.

operators report to the reliability coordinators. Load serving entities, the regional balancing authorities and generation operators comply with the transmission operator's reliability directives, as presented in Figure 60.

Figure 59. Levels of federal reliability standards development responsibility

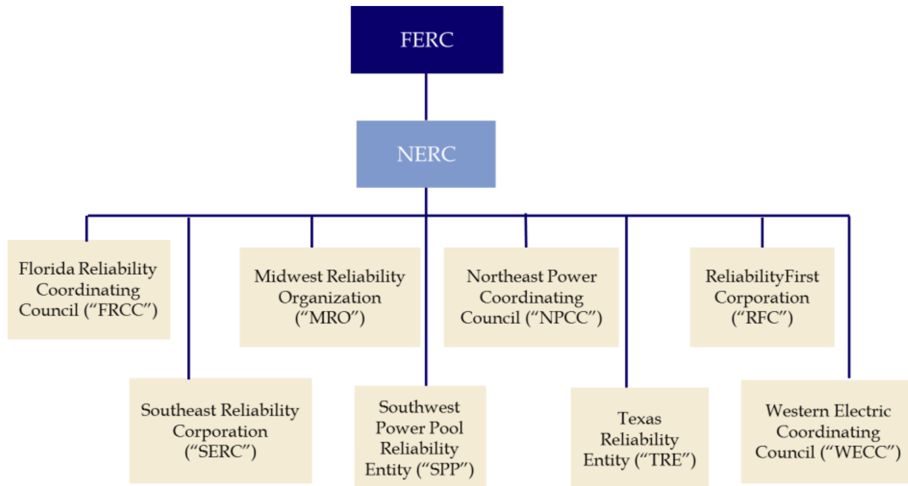
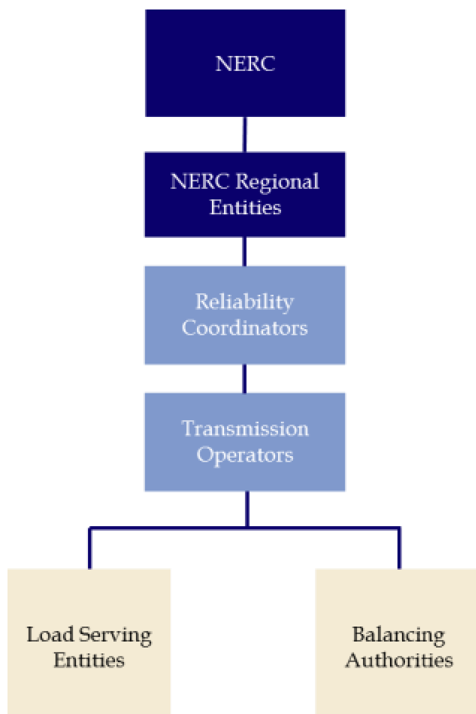


Figure 60. Levels of performance standard responsibility



According to NERC, the reliability coordinators have a broad mandate to prevent or mitigate emergency operating situations in next-day analysis and real-time operations with responsibility over both transmission and balancing operations.[144] Where relevant, this function lies with the regional transmission operators ("RTOs"). A complete list of reliability coordinators is presented in Figure 61.[145]

The next level of reliability responsibility rests with the transmission operator. Again, where relevant, this operational role typically occurs inside an RTO. In the event of a real-time or anticipated emergency, the transmission operator informs the reliability coordinator and makes efforts to avoid and/or mitigate the emergency. According to reliability responsibilities delineated by NERC, the transmission operator has the responsibility and clear decision-making authority to take all actions necessary to ensure the reliability of its area and to alleviate emergencies. These actions could, for example, entail curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. and are designed to both prevent reliability incidents from occurring and to alleviate their severity.[146]

Figure 61. List of US and Canadian reliability coordinators

Reliability Coordinators	Abbreviation
ERCOT ISO	ERCOT
Florida Power and Light	FRCC
Hydro Quebec, TransEnergie	TE
ISO New England Inc.	ISO-NE
Midcontinent Independent System Operator	MISO
New Brunswick Power Corporation	NBPC
New York Independent System Operator	NYISO
Ontario – Independent Electricity System Operator	IESO
PJM Interconnection	PJM
SaskPower	SPC
Southern Company Services, Inc.	SOCO
Southwest Power Pool	SPP
Tennessee Valley Authority	TVA
VACAR-South	VACS
Peak Reliability	PEAK
Alberta Electric System Operator	AESO

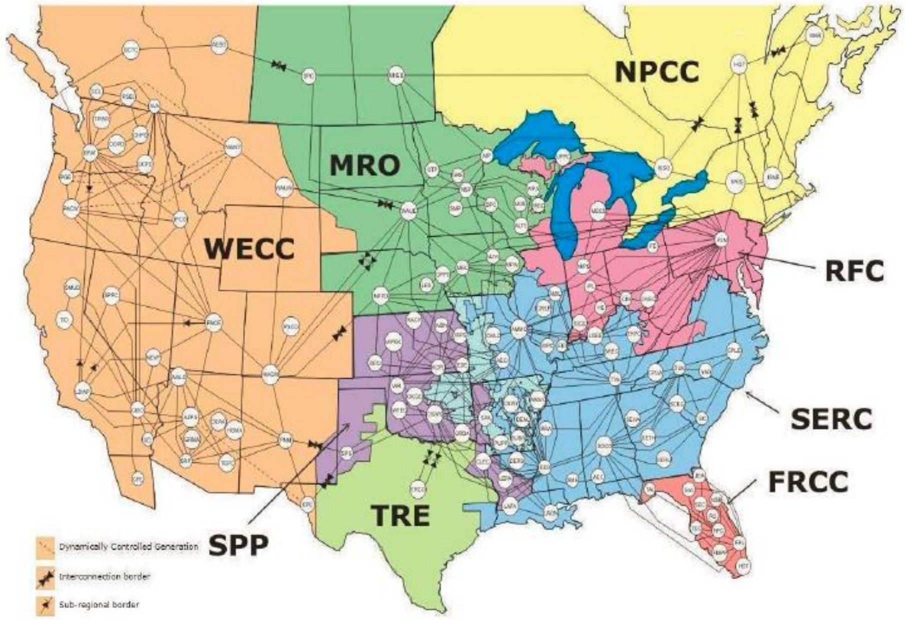
Source: NERC. Reliability Coordinators

144 NERC. *Reliability Coordinator Compliance Analysis Report*. May 2013. P. 6.

145 Ibid.

146 See NERC Reliability Standard TOP-001-1a – Reliability Responsibilities and Authorities.

Figure 62. NERC regional entities and balancing authorities



Index of Terms	
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
WECC	Western Electric Coordinating Council
TRE	Texas Reliability Entity
SPP	Southwest Power Pool Reliability Entity
SERC	Southeast Reliability Corporation

*Note that the white dots represent balancing authorities while the ERO entities are written in capital letters and colored
Source: NERC website

Reliability Coordinators – Nova Scotia

The New Brunswick Power Corporation serves as the reliability coordinator for the Nova Scotia electricity market. NERC however does not have the ability to fine Nova Scotia Power for reliability violations. Moreover, there are no official reliability or customer service targets.

Sources: NSURB, NSDOE

Responding to the reliability directives issued by the transmission operator are the electric balancing authorities, the distribution providers, and generators – which are all at the last line of reliability responsibility. As of 2012, there were over 90 balancing authorities in the USA and Canada as shown in Figure 5. The balancing authorities, generators, and distribution companies typically carry out the emergency directives of the transmission operators.

4.2 Transmission

At the transmission level, owners and operators are obligated to maintain compliance with NERC's mandatory reliability rules. In so doing, operators are typically the middle men issuing reliability directives to balancing authorities, distributors and generators. For the transmission sector, which has limited customer interaction, reliability metrics (rather than customer service) are the most important measure of performance. To ensure compliance, NERC has developed a system of annual self-reporting data to prove compliance and regularly audits to further monitor for compliance. As a last line of defense, NERC has the authority (in the US) to levy fines for up to $1 million per infraction per day.

ISOs also play a role in transmission performance monitoring. As it applies to transmission, specific information that the ISOs monitor ranges from, but is not limited to, resource and demand balancing to emergency preparedness and operations to interconnection scheduling and coordination to voltage and reactive power information. For example, part of the Alberta Electric System Operator's ("AESO") mandate is to carry out the compliance monitoring function of reliability standards. To this end, AESO has established a Compliance Monitoring Program ("CMP") applicable to any entity (including transmission) subject to any of the Alberta Reliability Standards ("ARS").[147] More generally, any transmission operator, such as ISO New England, is responsible for monitoring and reporting to regional NERC affiliates its efforts to comply with reliability standards outlined above. To this end, ISO-NE underwent an audit in March 2012 by the Northeast Power Coordinating Council ("NPCC") to demonstrate its compliance with thirty two NERC reliability standards.[148] Overseas, transmission PBR regimes also include performance standards and penalties based on interruption frequency and duration.

4.2.1 Transmission performance standards

While there are several components of performance standards, reliability is the regulatory focal point. Challenges to maintain reliability include weather and the grid's exposure to potential cyber related attacks. For instance, according to NERC's annual *State of Reliability* report for 2012, weather-related issues posed the main reliability concerns for the ten days when reliability was under greatest threat.[149] Going forward, NERC has indicated that weather could become an even greater cause for reliability concerns, primarily due to the increase in state renewable

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[147] Alberta Electric System Operator. *Alberta Reliability Standards*. Accessed: April 22, 2014

[148] ISO-New England. *2013 Regional Electricity Outlook.* 2014. P. 34-35

[149] North American Electric Reliability Corporation. *State of Reliability 2013*. P. 9-10

portfolio standards ("RPS"). RPS incentivize renewable production while simultaneously, many jurisdictions are retiring older thermal plants. Since thermal plants are typically closer to load (relative to renewable generating units), NERC has expressed concern that transmission lines will be extended farther, increasing their exposure to weather related problems.[150]

In addition to weather, the US government and particularly the Department of Homeland Security ("DHS") are becoming increasingly concerned about the potential threat that cyber security could pose to reliability. Between October 2011 and September 2012, 41% of all cyber incidents reported to the DHS involved the energy sector. In 2013, President Obama issued an executive order on cyber security (currently in the implementation stage), which is expected to bring significant changes to the cyber security regulation of the electric industry in terms of increased preventative measures in order to better ensure reliability.[151]

NERC reliability principles

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards;
2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand;
3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably;
4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented;
5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems;
6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions;
7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis; and
8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Source: NERC, Reliability Principles, Accessed March 24, 2014

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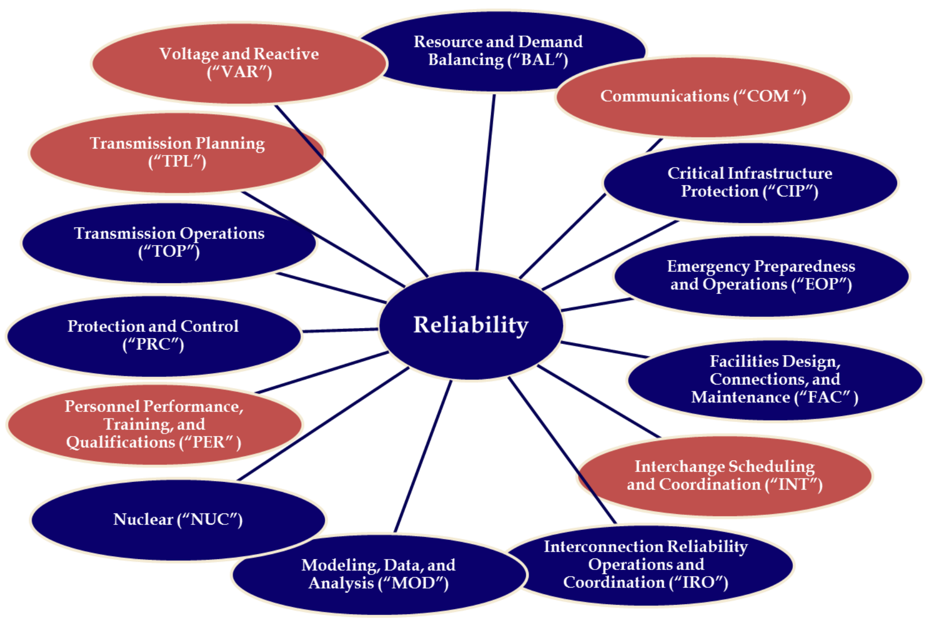
[150] North American Electric Reliability Corporation: *Special Report: Electric Industry Concerns on the Reliability Impact of Climate Change Initiatives*. November 2008. P. 11-13.

[151] Skees, Daniel J. and Spina, Stephen M. "Electric Utilities and the Cybersecurity Executive Order: Anticipating the Next Year." *The Electricity Journal* 26.3 (April 2013) P. 62

With the intent of delivering an adequate level of reliability, NERC has outlined eight fluid reliability principles as shown in the textbox. The reliability principles are designed to ensure that bulk electrical systems are planned and operated with consistent power quality standards and information sharing between electrical systems. Moreover, the principles are designed to ensure that emergency operation protocols are developed and maintained, adequate electrical system training is provided, security is assessed on a system-wide basis covering many interconnected systems, and adequate protection is available to counter cyber-attacks.

Consistent with NERC reliability principles, and to avoid future blackouts, NERC has established legally binding reliability standards, as presented in Figure 63. Two immediately obvious mandatory reliability categories that affect the transmission sector are the transmission operations and transmission planning. Effectively, however, all of the fourteen reliability standards pertain to either the transmission or the distribution sector.[152]

Figure 63. Components of mandatory electric reliability standards



Key	
Red	Relevant to transmission only
Blue	Relevant to transmission and distribution

Source: NERC Mandatory Reliability Standards

152 In total there are over 50 current mandatory standards which pertain to the transmission sector and distribution sector. Each of the standards typically has at least five associated rules. More are currently pending. Source: NERC. *Mandatory Reliability Standards for the Bulk Electrical Systems of North America*. Updated: April 3, 2014

The mandatory NERC reliability standards are further categorized by their violation risk factor and the likelihood of posing a reliability threat. Among the most prominent are the reliability standards which apply to vegetation management, protection system performance, and coordination and critical infrastructure mandates as they pertain to cyber security:

- ***Vegetation management program:*** all transmission owners and operators of lines above 200 kV must establish and document plans for monitoring the height and encroachment of trees and other vegetation, maintain sufficiency clearance for lines and report any vegetation-related outages to regional reliability organizations;[153]

- ***Protection system performance and coordination reliability standards:*** all transmission owners are required to institute programs that regularly test all transmission system equipment and perform the requisite maintenance. Moreover, in the event of equipment misoperation[154] (or equipment failure), transmission owners are required to conduct extensive analysis regarding the cause of the equipment failure and develop correction action plans designed to prevent future mishaps.[155] In the 2013 NERC State of Reliability Report, system "misoperations are identified as the leading cause to disturbance events (other than weather and unknown);"[156] and

- ***Transmission reliability standards:*** since the implementation of transmission reliability standards, transmission owners are required to identify critical assets, institute security management controls, and train personnel in the use of the security management controls. Moreover, there are requirements for some level of physical protection of transmission assets, reporting of cyber security incidents, and for recovery plans in the event of a cyber security attack.

As indicated, much of NERC's monitoring of compliance is done through their regional entities, which have the option to implement reliability standards which exceed that of the baseline NERC standards. All regional entities (with the exception of the Southwest Power Pool Reliability Entity ("SPP"), the Midwest Reliability Organization ("MRO"), and the Florida Reliability Coordinating Council ("FRCC")) have instituted some additional regional reliability standards.

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[153] For further information, please refer to: Reliability Standards FAC-003-01 – Transmission Vegetation Management Program.

[154] LEI has chosen to spell misoperations as it appears in the NERC reliability standards understanding that it is grammatically questionable so as to prevent confusion if the reader later sees the word in other NERC statutes. It is defined as a failure to operate equipment properly.

[155] For further information, please refer to: Reliability Standard PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations and Reliability Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing.

[156] North American Electric Reliability Corporation. State of Reliability 2013. P. 13

Nova Scotia: Levels of reliability responsibilities and provincial reliability standards

As a consequence of Nova Scotia's membership in NERC and NPCC, Nova Scotia maintains full compliance with the NERC and NPCC reliability standards as operationally implemented by the Nova Scotia Power System Operator (existing as a functionally unbundled part of Nova Scotia Power), its balancing authority Nova Scotia Power's Control Centre Operations Unit and by its reliability coordinator; the New Brunswick System Operator.

In addition, the Nova Scotia Utility and Review Board ("NSURB") has outlined Standards of Conduct (written in 2003 and updated in 2005). Ultimately, these reliability standards contribute to an outline of best practice, which is implemented by the reliability coordinator, the New Brunswick System Operator, and its local balancing authority, Nova Scotia Power's Control Centre Operations group.

Source: NS DOE, NSUARB

In Western Electric Coordinating Council ("WECC"), there are additional transmission maintenance and inspection requirements placed on transmission owners,[157] and in NPCC, transmission owners are required to undertake additional efforts to install sequence of event recorders which monitor a system event.[158]

As mentioned earlier, NERC's method of developing reliability standards is input-based meaning that it attempts to directly affect the manner in which reliability planning is conducted. By contrast, state public utility commissions ("PUC") and provincial regulators, which have jurisdiction over distribution reliability, have developed output standards or standards that reflect measureable results. Since distribution reliability is the purview of state and provincial regulators, performance standards for distribution utilities vary among different states and provinces. However, it is common for states to require utilities to maintain a minimum level of reliability based on metrics (as presented later in Figure 70). In the event of poor reliability performance, most states require detailed analyses of the causes of poor performances and a small number impose fines (as discussed later in Section 4.4.3).

4.2.2 Enforcement of transmission performance standards

For transmission, NERC's efforts to ensure compliance with mandatory reliability standards are extensive. Thus, the compliance efforts necessitate that affected entities maintain a

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[157] FAC-501-WECC-1 specifically states that: "Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled 'Major WECC Transfer Paths in the Bulk Electric System.'"

[158] PRC-006-NPCC-1 states that "Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3."

comprehensive "risk management" department which coordinates participation from several corporate departments including operations, finance, risk management, regulatory, training and external affairs.

A risk management department is necessary because for each of the mandatory NERC reliability standards there are sections delineating NERC's compliance monitoring program and the type of data which the relevant utility is required to track in order to be considered compliant. Separate compliance monitoring and data retention efforts are therefore necessary for each reliability standard. While the compliance monitoring requirements differ by reliability standard and depend on the likelihood of a reliability violation, it is typical for NERC to require annual self-certification and for NERC to conduct random and scheduled audits of reliability compliance efforts.

A combination of self-certification and audit is the most common method utilized for NERC compliance monitoring. Usually due annually to the regional NERC entity, self-certification is the process whereby registered entities are required to submit forms with relevant data (sometimes referred to as evidence) for the reliability standards in question. In response, the regional NERC entity will either declare the registered entity in compliance, or not in compliance, at which point, the regional entity will begin a preliminary screen for potential noncompliance.[159]

An additional crucial component of NERC's compliance monitoring is the NERC audit process. These are conducted either on a periodic basis, scheduled in advance on a triennial basis, or on a spot basis, conducted at any time with up to thirty-days notice. In 2013 for example, the MRO scheduled 19 compliance audits.[160] An audit consists of a detailed and thorough review of documentation across multiple dimensions in which the audited entity provides the appropriate "evidence" to support its claim to compliance.

NERC provides detailed audit worksheets documenting what it is looking for in a successful audit.[161] However, in general, an audit has three components to determine compliance: performance based requirements, risk-based requirements, and competency requirements. Performance-based elements in an audit target bulk power system performance and look for observable evidence and system testing results that demonstrate reliability outcomes. Risk-based elements in an audit require performance trends, require the audit to specify any risk targets achieved, and provide performance logs and any studies or models tied to strategic objectives. Competency-based elements in a NERC audit require evidence of internal

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[159] For further information, please refer to: NERC. Compliance Monitoring and Enforcement Program. Appendix 4c to the Rules of Procedure. Effective: June 25, 2013.

[160] Midwest Reliability Organization. NERC Compliance Monitoring and Enforcement Program. September 2012. P. 4

[161] Jacobi, Jeri, Lyons, Cristin and Starkweather, Rick. "NERC Standards and Standards Compliance: Still a Work in Progress?" The Electricity Journal 21.3 (April 2008): 29-39. P. 33-34

trainings.[162] Finally, NERC relies on the threat of sanctions to further ensure compliance with mandatory reliability standards.

PBR regimes also assist in enforcing transmission performance standards, which are particularly common in Australia (see vignette on Australia) and in the United Kingdom. For example, the UK's Transmission Price Control Review 4 ("TPCR4") PBR regime included a network reliability incentive scheme providing rewards/penalties for over/under performing against target levels of unsupplied energy or target numbers of loss of supply events. Specifically, the UK uses metrics for transmission reliability known as customer minutes lost ("CML") and customer interruptions ("CI"), which function similarly to System Average Interruption Duration Index and System Average Interruption Frequency Index (as discussed later in Section 4.4.2).[163] Fines for transmission assets in PBR regimes are similar to fines for distribution in PBR regimes (as discussed later in Section 4.4.4).

4.2.3 Magnitude and type of transmission incentives

The EPAct states that *"any person who violates any provision…of this title or any provision of any rule or order thereunder shall be subject to a civil penalty of not more than $1,000,000 for each day that such violation continues."*[164] This "per day, per violation" standard was upheld in FERC Order No. 672. However, NERC also reserves the right to utilize other less severe penalties depending on the nature of the performance standard violation and the degree of utility cooperation. Indeed, utilities are encouraged to self-report violations of mandatory reliability standards. NERC has made clear that it will look favorably upon self-reporting utilities in determining an appropriate penalty for a violation of reliability standards.[165]

The regulation of performance standards in Australia

In Australia, the entity responsible for setting the reliability standards for the distribution sectors vary by jurisdiction. In some jurisdictions (such as Northern Territories, South Australia, Tasmania, and Victoria), the "regulator" oversees the reliability standards while in other jurisdictions such as Queensland and Western Australia, the state minister is responsible for administering the reliability standards. Starting 2014, the Australian Energy Regulator ("AER") will be responsible for setting the reliability incentives. These reliability incentives will be part of the price review determination.

In the transmission sector, the AER is responsible for monitoring reliability through the service target performance incentive scheme ("STPIS"). The STPIS sets both network reliability and transmission congestion targets. The reason for targeting outages and congestions is both due to its effects on customers and due to the negative consequences outages and congestion can have on generation dispatch.

Source: AER

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162 Patterson, Jason. *Introduction to Auditing*. NERC. February 2012. P. 16-21.

163 For more information see: UK Ofgem: *Strategy for the next transmission price control - RIIO-T1 Outputs and incentives*. 31 March 2011. P.34

164 NERC. *Appendix 4B: Sanction Guidelines of the North American Electric Reliability Corporation*. P. 9-10.

165 NERC. *Compliance Monitoring and Enforcement Program. Appendix 4c to the Rules of Procedure*.

One prominent example of the application of fines for violations of mandatory reliability standards is that of Florida Power and Light. On January 26, 2008, in what has become known as the "Florida Blackout," Florida Power and Light experienced a loss of 22 transmission lines, 4,300 MW of generation, and 3,650 MW of load in the middle of the afternoon. As a consequence, NERC alleged that Florida Power and Light violated seven reliability subsections including transmission planning, transmission operations, emergency preparedness and balancing. While Florida Power and Light never admitted wrongdoing, it did settle civil charges with NERC and the federal government for $25 million, of which $5 million was appropriated to reliability enhancement measures.[166] Florida has not liberalized its power markets, nor has it implemented extensive PBR measures. This demonstrates that COS regimes also face reliability issues.

4.3 Generation

To measure generation performance, common metrics include availability and efficiency, which are often measured in terms of forced outages and heat rates. Outside of the spot market, it is common for PPAs to outline minimum levels of requisite generation performance. Performance can be benchmarked against annual NERC Generating Availability Data System ("GADS") reports.

4.3.1 Generation performance standards

Generation performance indicators are designed to ensure that generators have made the committed capacity available and can supply electricity and system support services when directed. As operating conditions vary widely among countries and regions, cross jurisdictional comparisons must make allowances for local conditions.

Over the past few decades, benchmarking of traditional performance indices has become a key tool in assisting most top performing generating companies in enhancing performance improvement efforts. There remains substantial room for improvement, however, as indicated by the analysis of generating plant performance by the World Energy Council which found a significant gap between the worldwide average performance and that being achieved by top performing plants. It has been estimated that eliminating the gap would result in savings of US $80 billion per year.[167] Some common categories of generation performance include:

Availability

Availability is defined as the percentage of time a generation unit is available for use, whether or not it is utilized. Some common availability metrics include:

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[166] Federal Energy Regulatory Commission. US Department of Energy. Florida Blackout. 129 FERC ¶ 61,016. Docket No. IN08-5-000. October 8, 2009 P. 1-4.

[167] "Performance of Generating Plant: New Realities, New Needs." *World Energy Council*. Web. August 2004. <http://www.worldenergy.org/documents/pgp04.pdf> P. vii.

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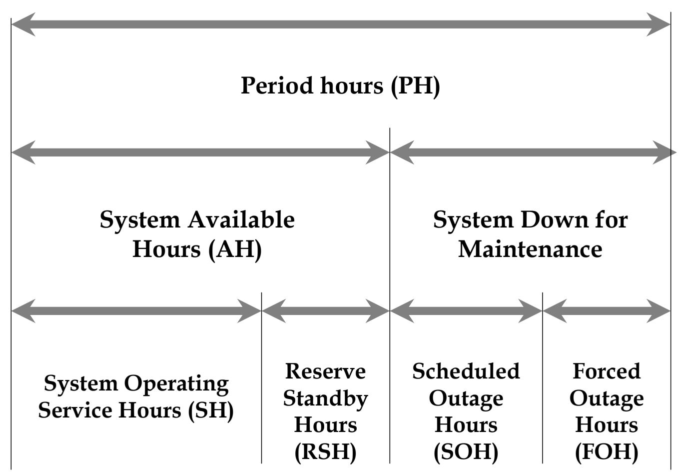
- **Energy Availability Factor ("EAF"):** expressed in percentage, equal to 100 – EUF. A similar indicator, Availability Factor ("AF"), is defined by the NERC GADS database as the unit's "could run" capability impacted by planned and unplanned maintenance which is calculated based on the following formula: AF = available hours/period hours x 100 (see illustration in Figure 64 for the time variables); and

- **Energy Unavailability Factor ("EUF"):** the energy unavailability factor over a specified period is defined as the ratio of energy that could have been produced during this period by a capacity equal to the unavailable capacity, and the energy that could have been produced during the same period by maximum capacity. Total energy unavailability comprises the unavailability factor due to planned maintenance work, or planned unavailability factor ("PUF"), and the unavailability factor due to all other reasons, or unplanned unavailability factor ("UUF"), so that PUF + UUF = EUF.[168]

Figure 64. Time variables in a generation process



Source: Energy and Environmental Analysis

Reliability

Reliability is often defined as the ability to maintain flexible generation with few outages. In the short run, this can be measured by outage rates and by generator ramp rates. Some common reliability metrics include:

- **Unit Capability Factor ("UCF"):** the percentage of maximum energy generation that a plant is capable of supplying to the electrical grid, limited only by factors within the

[168] Unavailability is classified as planned if it is foreseen well in advance, generally at the time when the annual overhaul program is established, and if the beginning of the unavailability period can largely be controlled and deferred by management. All other unavailability is classified as unplanned.

control of plant management. A high UCF indicates effective plant practices in minimizing unplanned energy losses and optimizing planned outages, thus maximizing available electrical generation;

- **Unplanned Capability Loss Factor ("UCLF"):** the percentage of maximum energy generation that a plant is not capable of supplying to the electrical grid because of unplanned energy losses (such as unplanned shutdowns, outage extensions or load reductions due to unavailability). A low value of this indicator implies that important plant equipment is reliably operated and well maintained;

- **Forced Outage Rate ("FOR")** – portion of downtime due to unplanned factors; calculated as forced outage hours x 100/(system operating service hours + forced outage hours);

- **Scheduled Outage Factor ("SOF") –** percentage of time set aside for planned maintenance which is calculated using this formula: SOF = scheduled outage hours x 100/period hours; and

- **Service Factor ("SF") –** percentage of total period hours the unit is online. It varies due to site related or economic factors, and calculated as follows: SF = system operating service hours x 100/period hours.

Fuel conversion efficiency

Fuel conversion efficiency is an important measurement of the efficiency by which a generator is able to convert fuel to power. A common fuel conversion metric is **heat rates** which are usually expressed in million British thermal units ("MMBtu") per net MWh generated.

The introduction of market mechanisms appear to coincide with improvements in heat rates. As an example, in Alberta, the wholesale generation market has been in operation for over 15 years. A paper prepared for the Independent Power Producers Society of Alberta ("IPPSA") noted that average market heat rates fell following deregulation, reflecting continued operational improvements, the effect of competitive pressure on prices, and the addition of modern and efficient new generating capacity.[169]

Similarly, Catherine Wolfram found that following divestiture of generation from utilities, plant heat rates tend to come down. The results were particularly robust in states defined as being located in an electricity market. Specifically, analyzing data from the US Energy Information Agency and the US Environmental Protection Agency for the years 1997 to 2001 for over 300

[169] Wellenius, Kevin. "Assessing Deregulated Power Prices in Alberta: an update to the 2003 report." *Prepared for the Independent Power Producers Society of Alberta*. September 2004

divested plants, heat rates have on average decreased by 2% - 2.5% following divestiture for plants operating at a minimum of 40% capacity.[170]

Other generation performance metrics

Fuel purchasing metrics measure the efficiency of generator fuel procurement and appropriateness of fuel costs. Fuel purchasing can be measured in terms of average unit fuel cost and compared to spot prices over a relevant time period. In general, multiple years of average fuel costs are required to gain an adequate understanding of long term fuel purchasing trends. Of note, fuel cost pass-through mechanisms are not required in jurisdictions which have spot power markets as spot markets enforce generation fuel purchasing efficiency.

Evaluating efficient fuel purchase practices can be contentious. Some argue that utilities should not pay more than spot prices for fuel; however, there is often a need to hedge the risk of rising fuel prices and to facilitate long term planning. In January 2014, for example, when day ahead spot natural gas prices peaked in New York City at over $100/MMBtu, hedging could have reduced fuel purchasing costs.

Across the US, many states employing cost of service regulation also provide generators an opportunity to pass through fuel costs to customers when actual fuel costs exceed forecasted costs. The Tennessee Valley Authority ("TVA") has a fuel cost adjustment which allows TVA to recover largely uncontrollable fuel costs driven by either global factors or by weather.[171] Similarly, the state of Minnesota has a fuel cost recovery mechanism known as the Fuel Clause Adjustment which assures generators a stable rate of return by allowing fuel costs used as an electrical generation input in excess of forecasted to be passed onto consumers.[172] The state of Arkansas also has a fuel pass through mechanism for its generators known as an Energy Cost Recovery Charge.[173]

Performance standards in the generation sector employed by Nova Scotia

Nova Scotia Power ("NSP") has a fuel adjustment mechanism ("FAM") built into its rate structure. Annually, NSP forecasts expected fuel expenditure which forms the basis for a fuel target. Throughout the year, the Nova Scotia Utility and Review Board ("NSURB") subsequently provides a detailed, thorough and ongoing review of NSP's fuel costs and procurement practices.

Source: Nova Scotia UARB

170 Wolfram, Catherine. "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants." *University of California Energy Institute. Center for the Study of Energy Markets. Work Paper 140*. March 2005.

171 Tennessee Valley Authority. *Frequently Asked Questions About TVA's Fuel Cost Adjustment*. November 2008.

172 Public Utilities Commission of Minnesota. *Report to the Legislature: Utility Rates Study as Required by Laws of Minnesota, 2009, Chapter 100*. June 2010. P 5

173 Arkansas Public Service Commission. *Frequently asked questions – Electric.* April 21, 2014

Performance at extreme temperatures is also an important metric for generation performance. It measures the degree to which a generator is able to meet contractual obligations during extreme temperatures. At times of extreme cold, gas scarcity can put a strain on a gas plant's ability to procure fuel. It is therefore important for system operators, and those procuring power through PPAs, to monitor and incentivize the performance of a generator to ensure that it is able to meet obligations when inputs are most scarce for the purposes of system reliability.

Typically, regulators can design generation performance monitoring and incentive structures into the tariff filings based on the above metrics. Similarly, those entering PPAs also often design monitoring and incentive structures into the contracts to ensure generator performance as discussed further in see Sections 4.3.3 and 4.3.4.

Performance at extreme temperatures –PJM, MISO and ERCOT

On January 8, 2014, PJM announced forced outages approaching 40,000 MW or 20% of total generating capacity. During the same period, MISO lost 28,736 MW or 22% of total generation. In both of these regions, up to 88% of the forced outage capacity was either oil or gas fired capacity. On the same day, ERCOT reported 3,700 MW of forced outages in addition to nearly 10,000 MW of planned outages (or about 18% of total capacity). This resulted in prices in ERCOT of $5,000/MWh.

Source: Marrin, Peter. "Outages Highlight Power Grid Pitfalls Amid Epic Cold Snap". *SNL News.* Web. 24 January, 2014.

A recent example of an effort to monitor generation performance standards is that of the ISO-NE. On January 14, 2014, the ISO-NE submitted to FERC a proposal to make changes to the incentive structure of the forward capacity market design. The approach, called "Pay for Performance," will strongly link capacity payments to resource performance during scarcity conditions. The ISO-NE is concerned that recently, there have been increasing outages, poor responses to contingencies, and failure to maintain liquid oil inventory among the existing generation fleet in New England. ISO-NE believes that the present FCM design provides little incentive for generators to invest in secure fuel arrangements or to undertake other investments that would assure their resources will perform when needed. Under proposed Pay for Performance mechanism, a resource will earn its capacity market revenue based on the amount it delivers during scarcity conditions. Furthermore, under this mechanism, a resource that provide more than their share of the system's requirements during scarcity events will be paid by those that provide less.[174]

4.3.2 Enforcement and reporting of generation performance standards

In North America, generation performance standards fall under NERC and ISO jurisdiction, as well as on contract counterparties. In monitoring generator performance, NERC has long recognized the value of benchmarking generation performance. Other entities, including the

[174] ISO-NE. ISO-NE Inc. and New England Power Pool filing of Performance Incentives Market Rule Changes. January 17, 2014.

Europe-focused EURELECTRIC and the World Energy Council, also benchmark generation performance indicators. As with the wires business, different jurisdictions track performance using different indicator definitions and formulas which vary to various degrees. Comparative generation performance across jurisdictions must also be cautiously interpreted given other aspects that may affect performance outcome such as different types, conditions, and sizes of the plants included in the data.

Generators are required to file a performance report containing availability and reliability data to NERC. This data is included in an annual GADS generating availability report ("GAR"). Items that generators need to file in the data reporting include availability and reliability metrics such as AEF, FPR, SOR, and service factors.

The GAR report can be an important indicator of general generation performance to which individual generators can be compared when incentivizing generation performance both when structuring a PPA and for regulators when structuring individual generator incentives. Figure 65 presents a sample of some of the information reported by fuel type and contained in the GAR summary published annually by NERC.

Figure 65. Generation performance indicators (US and Canada)

	2008 -2012						2004 -2008					
Unit type	Number of Units	AF (%)	FOR (%)	SOF (%)	SF (%)	EAF (%)	Number of Units	AF (%)	FOR (%)	SOF (%)	SF (%)	EAF (%)
Fossil, all fuel types, all sizes,	1,600	85.88	7.54	9.36	58.45	83.46	1,478	87.36	5.98	8.47	65.53	85.03
Nuclear, all types, all sizes	105	88.83	3.34	8.1	88.81	87.19	114	90.34	2.21	7.62	90.26	88.37
Gas turbines, all sizes	939	90.92	63.09	4.96	2.4	88.54	1,006	92.44	50.63	4.39	2.90	90.10
Hydro, all sizes	1,103	84.85	5.79	11.01	59.69	84.61	1,023	85.95	5.51	10.24	56.79	85.67

Source: NERC GAR

Liberalization does not necessarily diminish reliability of service

Liberalization forces performance standards to be codified and measured, but there is no evidence of reduced reliability. However, there is a need to have the right institutions and contracts in place. PPAs generally hold generators to higher standards than the standards to which customers can hold their utilities.

At the ISO level, generators also need to meet certain standards and obligations. For instance, system operators typically require technical studies to be completed by generators in order to confirm that proposed new generation projects can meet the generation performance standards before joining the interconnection queue. To ensure the reliability of the bulk power system, the New York ISO requires proposed generation projects to undergo detailed feasibility and system reliability impact studies before joining the interconnection queue.[175] In addition, ISOs enforce similar performance standards on an ongoing basis. For instance, AESO, in its generation and load standards, notes requirements related to power quality, voltage level and range, generator reactive power capability requirements, power factor requirements, insulation coordination, fault levels, generator data re-validation etc.[176]

Performance standards have also been used by state regulators to incentivize generators to operate efficiently in regulated regimes. Performance standards are also common features of PPAs.

4.3.3 Performance incentives to generation in regulated regimes

Incentives for vertically integrated generation are similar to the incentives provided in PPAs as discussed below. Regulators often offer a combination of rewards and potential penalties for a failure to perform, based on availability metrics and, in some jurisdictions (such as British Columbia), based on health and safety records. Below outlines two common examples of regulators designing incentive schemes for generation:

British Columbia instituted generation performance rewards targeting safety and reliability metrics for FortisBC, but at the discretion of the BC Utilities Commission ("BCUC").[177]

Figure 66. FortisBC performance standards, 2010

Performance Standard	Target	Actual
All Injury Frequency Rate	1.92	2.00
All Injury Severity Rate	17.53	12.88
Generation Forced Outage Rate	0.35%	0.12%

**Note: actual results reflect calculations as of the end of September 2010*
Source: FortisBC, 2011 Revenue Requirements

Specifically, the BCUC and FortisBC have established thirteen performance standards to determine eligibility for additional financial incentives, though not all are applicable to generation. The generation performance standards for FortisBC are generation forced outage rate, all injury frequency rate, and the injury severity rate, which were established with the goal of improving FortisBC's reliability and safety record. Each performance standard has a target. During the annual review, performance is evaluated against performance targets to determine if targets were achieved and if FortisBC is eligible for financial incentives. Failure to meet

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175 New York ISO. *Appendix G 2010 ISO/RTO Metrics Report*. Accessed: April 22, 2014 P. 217

176 AESO. Generation and Load Interconnection Standards. September 2006.

177 In BC, the electricity sector is dominated by the vertically integrated British Columbia Hydro ("BC Hydro") which is under a COS regulatory regime. However, there are other investor-owned generation utilities, such as FortisBC, which are regulated under a regime with some PBR mechanisms including generation performance standards.

performance standards does not necessarily constitute unacceptable performance and thus there are no financial penalties for a failure to reach performance targets.[178]

Louisiana has historically provided generation rewards or penalties based on generation performance standards. Louisiana Public Service Commission finalized plans in 2006 to reward electric utilities for higher plant efficiency, and vice versa.[179] The plan, referred to as generation PBR ("G-PBR"), consisted of two incentive mechanisms that determined whether the company was rewarded or penalized based on its performance relative to its peers and a target efficiency level calculated using a formula.

Specifically, the first mechanism compared a utility's fuel and wholesale energy procurement performance to that of a peer group (and the utility was rewarded/penalized based on over/under performance relative to the peer group). The second mechanism sets a formula to calculate the amount of fuel and wholesale energy expenses that a utility could recover from ratepayers. The formula reflected a target efficiency level of fuel and procurement practices as well as the unique characteristics of the company. If the company reduced the fuel and energy expenses below the formula-based amount, it was allowed to fully or partially retain the discrepancy as savings. Conversely, if the company was inefficient and exceeded the benchmark level set by the formula, it was not be allowed to fully or partially recover the difference. The Louisiana PSC choose not to include the G-PBR mechanism in approving Entergy Louisiana's 2009 rate plan citing an increase in natural gas fuel allowances.[180]

4.3.4 Generation incentives in PPAs

In addition to ISO standards, generation performance requirements are typically outlined in a PPA between the buyer and the seller of electricity products. Throughout the contract term, generators are generally required to make exclusively available to buyers the contracted capacity, generated electricity, and ancillary services of the contracted resource. To provide an overall picture of the type of performance indicators that are generally contained in PPAs, we reviewed a handful of different PPAs and summarized some of their main points in the subsections below. The main generation performance indicators included in the PPAs consist of availability levels, outage rates, and maintenance, which are largely interrelated. Performance indicators in PPAs often result in penalties if the target levels are not achieved. In some cases, rewards are also earned for achieving superior performance as shown in Figure 67.

[178] British Columbia Utilities Commission. *2006 Revenue Requirements and Establishment of a Multi-Year Performance Based Regulation Mechanism.* FortisBC Inc. May 2006.

[179] Entergy Corporation and Subsidiaries. 2005 10-K. December 31, 2005. P. 273-274.

[180] Entergy Corporation and Subsidiaries. 2010 10-K. December 31, 2010. P. 74.

Figure 67. Treatment of availability and maintenance in selected PPAs

PPA Counterparty	Availability	Maintenance
DeSoto County Generating Company	Capacity payment include a performance adjustment payment based on an availability index ("AI") which is equal to the difference between requested energy and delivered energy for the month. Actual AI performance was compared to a target to determine potential rewards or penalties.	DeSoto was required to required to submit an annual maintenance schedule for planned outages of each unit at the plant throughout the contract years. There were also planed annual maintenance and outage limits.
Mountainview Power Company	Required to deliver 97% contract availability for any summer period and 92% for any winter period. The PPA also included a positive or negative availability payment based on the deviation of actual availability and contract availability multiplied by an incentive amount of $360,000 for summer periods.	Mountainview was to submit an annual maintenance schedule for planned outages of each unit at the plant throughout the contract years.
Ontario Power Authority	OPA has made payments to clean energy standard offer program ("CESOP") participants based partially on an on-peak performance incentive for generators who could control production.	Participants were required to submit an annual maintenance schedule for planned outage.

Sources: DeSoto County PPA; Mountainview Power Company PPA, and Ontario Power Authority ("OPA")

Availability

Generators or sellers in a power purchase transaction are expected to maximize availability and net electrical output of the generating units at their plants in accordance with Good Utility Practice.[181] Some PPAs specify the target contract availabilities for each season.[182] Since availability is one of the core elements of generation performance, such contract or target availability is frequently built into a bonus/penalty mechanism that affects payments received by generators in order to incentivize them to maintain or exceed their performance above the targeted level. This can be done in a variety of ways, but often target baseline availability metrics and base an incentive on any deviation from that target availability. Descriptions and examples are provided in Figure 67.

Maintenance and outage

The generating unit owner (acting as the seller in the agreement) is normally required to submit an annual maintenance schedule for planned outages of each unit at the plant throughout the contract years. This schedule must be provided no later than a certain number of days (typically in the range of 30 days to three months) prior to the beginning of each contract year. Some

[181] Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with good business practices, reliability, safety and expedition.

[182] Public Utilities Commission of the State of California. *2012 General Rate Case: Generation (Gas) Volume 8 – Mountainview Operations and Maintenance Expenses And Capital Expenses*. November 2010. P. 4

generators are required to provide reasons for the planned outages. Buyers typically have the right to request a revision of the proposed outage plan and may approve subsequent changes to the planned outage schedule made by generators.

In some cases, a PPA specifically sets the maximum duration of each maintenance period (e.g. less than 24 hours), the particular months when planned outages are allowed, the maximum number of units allowed to be unavailable at any time due to a planned outage, and/or the time limits for a planned maintenance outage per generating unit per year differentiated by type of inspection involved, as illustrated by one of the samples in Figure 68.

Figure 68. Example of annual planned maintenance outages limit per generating unit in a PPA

Operating Condition	Planned maintenance outage limits (per generating unit for each calendar year)
No minor inspection, hot gas path inspection or major inspection	5 days
Occurrence of a minor inspection	8 consecutive days
Occurrence of a hot gas path inspection	20 consecutive days
Occurrence of a major inspection	40 consecutive days
Occurrences of a minor inspection and a hot gas path inspection	20 consecutive days
Occurrences of a major inspection and a minor inspection and/or a hot gas path inspection	40 consecutive days

Source: DeSoto County Generating Company and Florida Power and Light PPA

Failure to perform

Unless considered force majeure, there is usually a compensation component linked to any failure to perform by the generator. In the sample PPA where Naniwa Energy, a Nevada generator, served as the seller, if it fails to deliver or cause to be delivered the scheduled contract quantity, then it must pay the buyer an amount for each MWh of such deficiency. Another Canadian PPA reviewed incorporated a different structure of compensation. For any degradation in the committed operating characteristics of the units, the generator must provide compensation to the buyer through the monthly incentive payments and the monthly operating characteristic penalty payments. Monthly incentive payment refers to the amount payable by the buyer to the generator or vice versa, in respect of any variance between target availability and actual availability for each month of the contract term. Monthly operating characteristic penalty payment represents the amount payable by the generator to the buyer in respect of any degradation of committed operating characteristics for each of month of the contract term.

4.4 Distribution

Distribution is regulated by state and provincial utility commissions to ensure both reliability and customer service. Unlike generation, distribution presently remains a natural monopoly. For the most part, distributors are the only sector with direct customer interactions. Performance is typically monitored on an output basis by evaluating outage data and customer service surveys. At times, states and provinces have legal targets for minimum distribution performance, at times not. Some states and provinces have instituted potential fines or rewards for performance while others have not. In general, most jurisdictions require some form of reliability reporting, while financial incentives for distribution performance are less common.

4.4.1 Responsibilities for distribution performance standards

Jurisdiction over distribution performance standards in the US lies with the respective states. Thus, the federal government, via NERC, does not in general have jurisdiction over the reliability standards applied to the distribution sector. The most obvious exception to this rule is where the distribution sector is classified as critical infrastructure requiring it to comply with cyber security related performance standards. The distinction between transmission and distribution assets is the subject of the NERC "bright line" rule.[183]

As indicated in Sections 4.1 and 4.2.1, the distribution sector is responsible for maintaining compliance with certain relevant mandatory NERC standards. This involves critical infrastructure protection, but also facilities design, connections, and maintenance ("FAC") and modeling, data, and analysis ("MOD"). Like the generation sector, the distribution sector is also responsible for complying with emergency operations procedures as dictated by the transmission operator. It too is part of the last level of reliability responsibility whose emergency responsibilities typically involve load shedding.

Distributors must also respond to state level performance standards.[184] Here, performance standards are typically separated into reliability and service quality standards by state PUCs who usually monitor performance standards on an output basis. In this way, state regulators ensure reliability via ex-post reporting and monitoring of performance results. In addition, state efforts to ensure reliability are often embedded in the rate setting procedure. In so doing, while the details of distribution reliability standards necessarily differ by state, often state PUCs are concerned with maintaining reliability metrics at least equal to those seen in the pre-deregulation era, without offering explicit instructions on how to best achieve minimum reliability standards.

Unlike in the generation and transmission sectors, performance standards in the distribution sector also include customer service metrics.

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183 Approved by FERC Order 773 RM 12-6 and RM12-7 NERC's "bright line" rule essentially makes most facilities operating or connected at 100 kV or above and that are not used in the local distribution of electricity as subject to mandatory reliability standards.

184 See Footnote 183.

4.4.2 Distribution service performance standards employed

Recognizing the need to guide utilities regarding desired reliability levels, several jurisdictions (including New York and Pennsylvania) have statutes in place to ensure minimum levels of distribution performance.

In analyzing distribution reliability, it is important to recognize that reliability challenges vary for distribution and transmission. Transmission systems have infrequent outages, which are usually short in duration but affect many customers. Distribution systems tend to have relatively more frequent outages, which last longer but affect only a small number of customers.

Several reliability standards are used worldwide. These indicators mainly measure the duration and frequency of supply interruptions and typically require Supervisory Control and Data Acquisition Technology in order to ensure accurate measurement. The most common standards are:

- **System Average Interruption Duration Index ("SAIDI")** measures the total number of minutes, on average, that a customer is without electricity per year (excluding momentary interruptions). SAIDI is estimated as the sum of the restoration time for each interruption event times the number of interrupted customers for each interruption divided by the total number of customers;

- **System Average Interruption Frequency Index ("SAIFI")** measures the average number of times a customer's supply is interrupted in a year, excluding momentary interruptions. SAIFI is estimated as the total number of customer interruptions divided by the total number of customers served;

- **Customer Average Interruption Duration Index ("CAIDI")** measures the average duration in minutes of each interruption a customer faces. It is calculated by dividing SAIDI by SAIFI, or the sum of customer interruption durations divided by the total number of customer interruptions;

- **Alternate approach to CAIDI (worst feeders)** is to focus on a specific portion of the service, for instance, the worst 10% and measure performance for that specific subsection;

- **Momentary Average Interruption Frequency Index ("MAIFI")** measures the average number of times a customer's supply is interrupted in a year for momentary interruptions. It is the total number of customer momentary interruptions divided by the total number of customers served. The duration of momentary interruptions is defined as less than three minutes, or less than one minute, varying by jurisdiction. The standard is increasingly monitored, as microprocessor-based electronic technologies widely used in both home and businesses are sensitive to such momentary interruptions.; and

- **Momentary Average Interruption Duration Index ("MAIDI")** is a measure of the total customer momentary interruption durations divided by the total number of customers.

Figure 69. Sample of jurisdictions requiring reliability reporting

Location	SAIDI	SAIFI	CAIDI	MAIFI
Alberta	√	√		
California	√	√		√
Chile	√	√		
Colorado	√			
Delaware	√	√	√	
Illinois	√	√		
Kansas	√	√		
Maine		√	√	
Massachusetts	√	√		
Mississippi	√			
New York		√	√	
New Zealand	√	√	√	
Ohio	√	√		
Ontario	√	√	√	
Oregon	√	√		
Panama	√	√		
Pennsylvania	√	√		
Texas	√	√		
United Kingdom	√	√		
Vermont		√	√	
Victoria		√		
West Virginia				
Wisconsin	√	√		

Source: Various Public Utilities Commission or Regulator websites

Utilities usually track two to three of these reliability indicators, SAIDI and SAIFI being among the most prevalent for transmission companies. CAIDI and CAIFI (Customer Average Interruption Frequency Index) are common performance indicators in the distribution sector, and are not applicable to the transmission sector.

Figure 70. Commonly used measurements of reliability

Reliability Standard	Calculation	Units	Good For
SAIDI	$\frac{\text{(Total Min. each customer is without service)}}{\text{(Total number of System Customers)}}$	Minutes per customer per year	Transmission
SAIFI	$\frac{\text{(Frequency that customer is without service)}}{\text{(Total number of System Customers)}}$	Outages per customer per year	Transmission
CAIDI	$\frac{\text{SAIDI}}{\text{SAIFI}}$	Minutes per outage	Distribution

It is common for reliability measurements to exclude "major events" which are deemed outside of utility control. However, the exact definition of a "major event" differs by jurisdiction, making cross jurisdictional comparisons difficult. For instance, the state of Pennsylvania defines a "major event" as an interruption of five minutes or longer caused by conditions beyond the control of the distribution company which affects at least 10% of the customers in its service territory. Other jurisdictions define a major event as unscheduled interruptions due to the maintenance of the adequacy and security of the electric system by a distribution company.

Reliability performance standards in Nova Scotia

The newly elected Liberal leader Stephen McNeil has indicated a desire to legislate minimum electrical performance standards, but nothing, as yet, has been implemented. Nova Scotia Power does however track the following reliability metrics: SAIFI, SAIDI, CAIDI and has allocated $20 million annually for vegetation management programs in an effort to improve reliability performance. Additionally, the NSURB has approved annual maintenance and system improvement efforts as part of the NSPI's 2013 – 2014 cost of service tariff filing.

Sources: NSURB, NSDOE

In addition, each utility must provide a description of the company's current reliability and power quality programs (including power quality complaints received during the year, the number of momentary interruptions recorded on a company-wide and operating division basis, and the number of power quality investigations conducted during the year as well as the findings) and any changes made during the reported year. Reliability reporting requirements can be considered a form of non-financial penalties, and certain state-specific reporting requirements are discussed later in Section 4.4.3

In addition to reliability measures, there are a variety of different indicators that can be measured to track customer service (as discussed below Figure 71, which presents a sample of jurisdictions requiring customer service reporting).

Figure 71. Sample of jurisdictions requiring customer service reporting

Location	New service connections	Appointments	Telephone accessibility	Written response to inquiries	Customer/ PUC complaints	Billing accuracy and/or meter reads	Customer Surveys	Safety/ Health
Alberta	√							√
California	√	√	√				√	√
Chile								
Colorado			√		√			
Delaware								
Illinois								
Kansas								
Maine	√		√	√	√		√	
Massachusetts	√	√	√		√	√	√	√
Mississippi							√	
New York	√		√			√		
New Zealand								
Ohio								
Ontario	√	√	√	√				
Oregon								
Panama	√			√	√	√		
Pennsylvania								
Texas								
United Kingdom		√		√		√		
Vermont	√		√		√		√	√
Victoria	√	√						
West Virginia	√				√	√		√
Wisconsin								

Source: Various Public Utilities Commission or Regulator websites

- **Number of customer complaints** to the utility or to the regulator can easily be tracked and categorized (by complaints about reliability, technical quality, customer service, etc.). This is a good indicator of customer satisfaction, although it is also necessary to integrate frequency of customer praise into assessment;

- **Customer satisfaction surveys** provide a more extensive understanding of customer satisfaction. This measure is, however, prone to bias and surveys can be expensive to conduct regularly;

- **On-time appointments or connections** can be measured through the percentage of connections not provided by the agreed upon date and the percentage of customer appointments missed by more than one hour;

- **Billing accuracy** is measured by percentage of bills that are adjusted for misreads or errors. This indicates performance of meters, meter reading, and billing;

- **Satisfaction with call center experience** can be tracked through one or more of the following: percentage of calls not answered within 30 seconds, percentage of calls abandoned, and number of call center overload events; and

- **All injury/illness frequency rate ("AIIFR")** compares lost time due to injuries and illnesses to total employee working hours. Often lost time is based on the regulated Occupational Safety and Health Administration's ("OSHA") reportable lost time frequency standard and is adjusted for personnel changes due to possible mergers.[185]

Note that customer service quality indicators and their exact measures vary substantially among jurisdictions, making it difficult to compare international or cross-jurisdictional performance on an "apples-to-apples" basis. This does not preclude comparisons within a jurisdiction.

Figure 72 presents a list of potential performance standards that can be used in PBR.

Figure 72. Components of performance standards that can be used under PBR

Reliability	Health and Safety	Customer service/Service quality
▪ System Average Interruption Duration Index ("SAIDI") ▪ System Average Interruption Frequency Index ("SAIFI") ▪ Customer Average Interruption Duration Index ("CAIDI")	▪ All Injury Frequency Rate ("AIFR") ▪ Injury Severity Rate	▪ Call center response time ▪ Average time to answer calls ▪ Justified credit and collections complaints ▪ Billing accuracy ▪ Emergency response time ▪ Completion time for new requests service connections

4.4.3 Enforcement of distribution performance standards

There are many different possible enforcement mechanisms for distributors. In general however, the distributor provides annual data to the state utilities commission and is subject to a possible audit should its performance not meet expectations.

Many jurisdictions thus have established a set of reporting protocols for the purpose of collecting accurate, timely, and comparable data from companies being regulated. Included in the reporting protocol are the definitions of each indicator, measurement methodologies, and a timeline for reporting the performance indicators. It is important that the information collected be comparable and thus consistency of data is an important aspect of the reporting protocol.

[185] California Public Utilities Commission (CPUC) (1999), *Opinion Regarding San Diego Gas & Electric Company's Distribution Performance-Based Ratemaking Mechanism*, Decision No. 99-05-030, Los Angeles. P. 15.

The regulation of performance standards – United Kingdom

The UK structure differs from those adopted in the United States in several respects, the most obvious being its design as a "pay-as-you-violate" system of penalties rather than an annual review and corresponding rate adjustment. In the UK, the UK Office of Gas and Electricity Markets ("Ofgem") conducts annual examinations of distributor reliability performance and publishes its findings; moreover, it requires each distributor to submit a large compendium of data on service quality every year, which is also made public for review by customers and competitors. But while these publications may motivate increased efforts by distributors lagging behind their rivals, they have had no bearing historically on annual rate determinations. Rather, distributors incur penalties throughout the year on a per-incident basis, whenever they fail to attain the benchmarks.

One prominent incentive Ofgem uses to set the incentive arrangements for distribution reliability is the Interruption Incentive Scheme ("IIS") which provides distributors with a financial incentive to improve reliability by rewarding or penalizing the distributors depending on how they perform relative to the targets set for them by Ofgem. The basis of the rewards and penalties is the result of a "Willing to Pay" survey. Similarly, the electricity transmission operators are incentivized to ensure a reliable system through reliability threshold, against which their actual performance is measured and they are rewarded/penalized for any out/under performance.

Source: Ofgem

In general, annual requirements have to be submitted two to three months after the annual period is complete and most jurisdictions also require monthly or quarterly submissions of certain indicators. Some jurisdictions have regulatory-designed templates that utilities are required to submit; other jurisdictions allow utilities to file their own reports as long as all relevant information is included. Utilities are usually asked to explain how the data was collected and analyzed and to identify any data discrepancies. In cases where utilities are reporting subpar performance, they are also required to propose a remediation plan. Below we highlight the reporting requirements in selected US jurisdictions.

Similar to the transmission sector, NERC and certain state PUCs rely on the threat of fines in order to enforce performance standards. The threat of financial penalty is also believed to be an important motivation for achieving and maintaining excellent performance standards. This will be discussed in detail in Section 4.4.4.

Figure 73. Reliability reporting in California and New York

	California	New York
Frequency of filing	Annual basis	Annual basis
When to file	Must file by March 1 of the following year	Must file by March 31 of the following year
Items to be included in the reliability report	• Reliability indicators • Information on any group of customers that experiences more than one five-minute (or more) outage per month on a rolling annual average basis • Identify the ten largest outage events and indicate whether any of them were excluded from the reported indices • For each major event that has been excluded, include the following information: number of customers affected, the number of customers without service at periodic intervals, the longest customer interruption, and the number of people used to restore service	• Overall assessment of the reliability performance in terms of interruption frequency and duration on a corporate-wide basis broken down by operating area • List of circuit performance by operating area for the year • Identify major capital investments and specific projects undertaken during the year to maintain or enhance reliability • Analysis of the interruption patterns and trends of the utility's operating area • Describe problems causing the inadequate performance, actions being taken to resolve them, and the target dates for completion of the corrective actions • Justify actions that are unwarranted

Sources: California Public Utilities Commission ("CPUC") and New York State Public Service Commission ("NYPSC")

4.4.4 Magnitude and type of distribution incentives

In general, regulators have designed three distinct methods of penalizing (or rewarding) utilities: nonfinancial penalties, customer compensation, and a system of rewards and fines. Nonfinancial penalties do not use explicit monetary threats, but publish performance results with the expectation that the dynamics of public relations will exert a salutary impact on performance. Regulators may also use enforcement mechanisms against underperforming companies.

The second potential method of penalizing underperforming utilities is fines. These can either be a direct financial penalty which a utility is expected to pay to either to affected customers as direct compensation for poor performance or a penalty payable to a governmental entity. A study from the Ernest Orlando Berkeley National Laboratory found that 35 states (including Washington DC) required some form of reliability reporting. Of these, less than 10 have systems penalizing performance for missing targets.[186]

[186] Eto, Joseph H. et al. *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions*. Ernest Orlando Lawrence Berkeley National Laboratory. October 2008. P. XI

The third manner of incentivizing performance is via rewards and punishments. Strong reliability and customer service performances would be rewarded and poor performance would be penalized. In practice, this is the least common method used to incent performance.

Penalties (or rewards) for performance standards are based on deviations (set in percentage terms or in standard deviations) from performance targets. Targets typically are set either based on historical performance or on established industry standards, when regulators believe historical performance does not set a stringent enough performance target. When setting the benchmark performance target, regulators most often benchmark the target to a rolling average of the utility's previous three to five years of performance by target (e.g. CAIDI, SAIDI or customer service) depending on the jurisdiction. In Australia, performance targets are set at a rolling five year average while Ontario uses three year rolling averages. In general, targets attempt to reflect "business as usual' and regulators must decide the point at which past results no longer reflect "business as usual." When setting a target based on industry performance (rather than by utility performance), a regulator must determine which utilities are deemed relevant. In practice, this can become contentious.

One example of a jurisdiction which sets both reliability and service quality standards is the State of New York. Under its reliability performance mechanism ("RPM"), failure to meet pre-specified reliability targets results in fines (negative incentives). Under the RPM, the NYPSC tracks SAIFI and SAIDI metrics; for Consolidated Edison only it also tracks:

- pole repairs;
- removal of temporary shunts;
- street light repairs;
- replacement of over duty circuits;
- a remote monitoring mechanism; and
- a system restoration metric.

Utility rates also include what the New York State Public Service Commission calls a customer service performance mechanism ("CSPM") based on customer complaints, customer satisfaction (per a survey), and call answer rates. The amount of potential penalties is proportional to the degree of variance from the utility's performance target. In the case of Consolidated Edison for example, the utility could face up to a maximum of $112 million in fines for reliability violations and an additional $40 million for service quality violations.[187] The targets are set based on a maximum revenue exposure methodology which equates to approximately 1.4% of its annual revenue requirement and 90 basis points on its return on equity for reliability violations and

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[187] New York Public Service Commission. Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service. CASE 08-E-0539 and Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers. CASE 08-M-0618. Order Setting Electric Rates (Issued and Effective April 24, 2009) P. 19-20, 34-35.

another 0.5% of annual revenue requirements or 30 basis points ROE for service quality violations.[188] In general, targets are designed to be individualized and stringent, yet realistic.

Once a performance target is set, regulators must design a transparent formula delineating potential fines (or rewards) for missing targets. In theory, any formula which sets out fines for missing performance targets should be great enough to deter poor performance and should at least exceed the cost savings that the utility derives from not devoting resources to maintaining and/or improving reliability and service quality standards. In the UK, for example, customer willingness to pay analysis by service and region influences the standards set.

Figure 74. 2012 New York State electric distribution reliability performance targets

Utility	SAIFI Target	CAIDI Target
Central Hudson Gas and Electric	1.45	150
Con Edison	0.495	122.4
National Grid	1.13	123
New York State Electric and Gas	1.2	124.8
Orange and Rockland	1.2	111
Rochester Gas and Electric	0.9	114

Source: NYPSC. 2012 Electric Reliability Performance Report

Setting a potential performance reward is also a balancing act. Rewards should be great enough to incentivize reliability and service quality, but should also reflect consumer willingness to pay. In general, fines (or penalties) are at times designed in a linear fashion, but may be designed exponentially in which larger performance deviations from targets are fined (or rewarded) disproportionately more than smaller performance deviations. Often there is either a cap for each individual potential fines (or rewards) or a cap on a utility's maximum total exposure to performance standard penalties (or rewards).

There is a great deal of debate about comparing these indices from one geographic area to another (e.g. rural areas or areas with high lightning activity are expected to have a higher number of outages than densely populated urban areas with network distribution systems) and exactly how the input data is to be applied in making the calculations. In addition, there are concerns about how to normalize the indices for adverse weather. Some state regulators believe that index comparison is of limited use due to differences in how the data is applied, system designs, weather differences, and differences in vegetation growth. However, if the calculation

[188] Ibid.

method remains consistent, the indices are useful within a specific geographic area in evaluating changes in reliability over time.[189]

Figure 75. An overview of distribution performance incentive schemes

	Consolidated Edison of New York	Central Maine Power	New Brunswick Power	San Diego Gas and Electric	Ontario
Term of Tariff Plan	2010-2013	2008 – 2014	2013 - present	1999-2002	2009-2011
Rewards, Penalties or Both	Penalties Only	Penalties only	Penalties Only	Both Rewards and Penalties	Nonfinancial Penalties
Explicit Formula (Yes/no)	Yes	Yes	No	Yes	No
Reliability Metrics	SAIFI, SAIDI, other reliability investment metrics	CAIDI, SAIFI	All mandatory NERC Standards	CAIDI, SAIFI, MAIFI	SAIFI, SAIDI, CAIDI
Service Quality Metrics	Customer complaints, customer satisfaction, call answer rates	Complaint ratio, calls answered (%), call center quality, meters read, new connections	No explicit service quality standards tracked and subject to fines from the Energy and Utilities Board	Customer satisfaction, call center response, all injury frequency rate	New connections, underground cable locations, telephone accessibility, appointments made, emergency and written responses
Max Penalty	$152 Million	$5 million	NA	$14.5 million	NA

Sources: CPUC, Maine Public Utilities Commission ("MPUC"), New Brunswick Energy and Utilities Board, NYPSC, and Ontario Energy Board ("OEB").

Figure 75 presents a range of relevant examples of distribution performance incentives reflecting the wide range of potential incentive structures. They demonstrate that PUCs most commonly threaten fines and less often offer rewards to incentivize performance. Additionally, explicit formulas are usually provided, but regulators less often explain the manner in which penalty formulas are set. Most commonly, regulators ask for a frequency and a duration index to measure reliability. Customer service is usually measured as a combination of complaints and satisfaction surveys. The exact range of potential maximum fines ranges considerably from $5 million in Maine over $150 million for Consolidated Edison of New York.

Below summarizes the methodologies used by selected jurisdictions to set penalties and rewards. All of the jurisdictions highlighted have set "deadbands." Utilities in the UK and California are exposed to rewards and penalties, while in Maine, Central Maine Power is exposed to potential fines only outside the "deadband."

California: For San Diego Gas & Electric, upon determining "deadbands" for customer service metrics and a cap to a utility's exposure to performance fines, formulas are set per performance metric to either reward or fine. Formulas differ, but each set a unit of change and a penalty per unit of deviation. This is done on a sliding scale. For example, for SAIDI and SAIFI metrics, San

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[189] John D. Kueck et al. *Measurement Practices for Reliability and Power Quality*. June 2004, p. 3.

Diego Gas & Electric was potentially rewarded or fined $250,000 per unit and per 0.01 unit deviation from SAIDI and SAIFI targets.

Figure 76. San Diego Gas and Electric performance incentives, 1999-2002

Performance Area	Indicator	Benchmark	Deadband (+/-)	Liveband (+/-)	Unit of change	Incentive per unit $'000	Maximum Incentive ($m +/-)
Safety	OSHA	8.80	0.2	1.2	0.01	25	3
Reliability	SAIDI	52 mins	0	15	1.0	250	3.75
	SAIFI	0.9 outages/ year	0	0.15	0.01	250	3.75
	MAIFI	1.28 outages/year	0	0.3	0.015	50	1
Customer Satisfaction	Very Satisfied	92.5%	0.5%	2.0%	0.1%	75	1.5
Call center response	Answered in 60 seconds	80%	0	15%	0.1%	10	1.5

Source: CPUC (1999)

Maine: Central Maine Power ("CMP") is regulated under an alternative rate plan using a CPI – X price cap.[190] CMP is potentially fined based on percent deviations from a target outside a target. More specifically, it is fined by performance standard on a sliding scale whereby fines start at $200,000 per performance category for deviations ranging from 2.5% to 6.25% for reliability violations, $400,000 per performance category for deviations ranging from 6.26% to 10.4% and $800,000 per infraction for deviations greater than 10.4%. There are seven performance categories and the sum of all fines cannot exceed $5 million.

Figure 77. Central Maine Power historical performance standard performance and 2008 - 2014 targets

Indicator	2001	2002	2003	2004	2005	2006	ARP2000 Baseline	ARP2008 Baseline
CAIDI	-	-	-	126.6	130.8	128.4	139.2	129
SAIFI	-	-	-	1.98	1.94	2.18	2.10	1.7
MPUC Complaint Ratio	.89	.94	.73	.72	.93	.74	1.17	1.00
Percent of Business calls answered (%)	82	85	85	85	82	82	80	80
Call center service quality	91	91	92	90	89	88	84	85

Source: MPUC Doc. Nos. (2007-215) and (2008-111)

Alberta: ENMAX Power Corporation ("EPC") has a total of $2 million per year (in 2007 dollars) of revenues at risk should it fail to meet specified performance standards. EPC's proposed performance standards include a measure of workplace safety, system interruption frequency,

[190] The Maine PUC actually uses GDP as a measure of inflation, not CPI.

and system interruption duration. These relate to well-established objective measures of reliability and safety measurement, described as: All Injury/Illness Frequency Rate ("AIIFR"); SAIFI; and SAIDI. EPC is subject to a minimum penalty of $200,000 apiece should it fail to reach threshold performance levels in any of the three categories.

Figure 78. ENMAX Reliability Targets for the 2007-2016 Formula Based Ratemaking Period

Performance Standard	Target
AIIFR	6.50
SAIFI	1.0
SAIDI	30

Source: Alberta Utilities Commission ("AUC")

United Kingdom: In the Distribution Price Control Review 5 ("DPCR5") in what is known as the Interruption Incentive Scheme ("IIS"), Ofgem has incentivized distributors individually based on planned and unplanned outages and disaggregates based on four voltage categories in the distributor's territory. Next, provisions are made for outages originating outside the distribution system. Ofgem weights planned outages 50% less than unplanned outages. Thus, combined with the four voltage categories, there are eight reliability categories which are aggregated into a single reliability benchmark.[191] Next, based on a willingness to pay study of affected UK customers, Ofgem determined that customers were willing to pay £4 per year per for a reduction of 1 frequency of outage unit.[192]

Jurisdictions that do not have explicit formulas for setting fines include New Brunswick and Ontario. **New Brunswick**, as a full member of NPCC, is an example of a jurisdiction which threatens reliability penalties only based on reliability performance vis-à-vis mandatory NERC reliability standards and regional NPCC standards. In so doing, New Brunswick's efforts to ensure performance standards closely mirror other NERC jurisdictions. Its performance standards are input based and compliance monitoring is similar focused on areas which pose the greatest risk to reliability. Additionally, the New Brunswick Energy and Utilities Board ("EUB") has the authority to impose financial penalties and sanctions on registered entities for reliability risks, per the Electricity Act (O.C. 2013-286). It does not provide monetary performance incentives.[193]

Ontario is an example of a jurisdiction where there are no rewards or penalties imposed to utilities for reliability and service quality performance. Since 2000, distributor service performance, including the reliability standards, has been monitored in Ontario as part of PBR. The province's energy regulator, OEB, requires local distribution companies to measure SAIDI,

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[191] Electricity Distribution Price Control Review Final Proposals - Incentives and Obligations P. 83-86.

[192] Expectations of DNOs and Willingness to Pay for Improvements in Service. P. 105.

[193] New Brunswick Energy and Utilities Board. Reliability Standards, Compliance and Enforcement Program. 2014 Annual Implementation Plan. December 23, 2013. P. 2-5.

SAIFI, and CAIDI. In calculating the indicators, all planned and unplanned interruptions of one minute or longer are taken into account.[194]

There are no province-wide performance standards for the three reliability indicators of SAIDI, SAIFI, and CAIDI tracked in Ontario. Instead, performance standards are set specifically for each distributor based on historical performance whereby utilities are expected, at minimum, to operate within the limits of their performance for the past three years. OEB has been contemplating the determination of appropriate standards for the indicators. In setting the standards, potential factors being considered include the periodicity of the reported data, as well as the use of performance data for identifying inadequate service for remedial reporting and for penalty/reward mechanism. Considerations may also be given to having differential standards for different classes of utilities. OEB consultants recommended (in 2013) maintaining utility specific historically based performance standards rather than setting Ontario wide performance targets (see Figure 79).

Figure 79. Key reliability indices of the six largest distributors for 2012 in Ontario

Distributor	SAIDI	SAIFI	CAIDI
Enersource Hydro Mississauga Inc.	42	1.71	0.41
Horizon Utilities Corporation	87	1.95	0.74
Hydro One Networks, Inc.	677.4	3.68	3.07
Hydro Ottawa Limited	98.4	1.81	0.90
PowerStream Inc.	69.6	1.70	0.68
Toronto Hydro-Electric System Limited	90	1.6	0.94

Source: OEB, 2013 Yearbook of Electricity Distributors

In Ontario, service quality indicators in terms of customer service are measured by percentage of completion of services within their minimum performance standards. These services include connection of new services, underground cable locates, telephone accessibility, annual appointments, annual written response to inquiries, and emergency response. Minimum customer service levels are set with the intention to maintain customer service quality, while providing the distributor with flexibility to set service levels to the demands of their customers above the minimum guidelines. A distributor is expected to achieve the minimum standards for a specified percentage of the time (see Figure 80).

[194] Ontario Energy Board. "2006 Electricity Distribution Rate Handbook." May 11, 2005. P. 140-141.

Figure 80. Minimum performance levels for customer service indicators in Ontario

Customer Service Performance Indicator	Minimum Standard
Connection of new services	New low voltages (<750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied; new high voltage (>750 volts) must be connected within 10 working days; standards must be met at least 90% of the time.
Underground cable locations	Underground cable locations must be completed within 5 working days of a customer's request at least 90% of the time.
Telephone accessibility	Incoming calls to the general inquiry telephone number must be answered in person by an operator within 30 seconds, at least 65% of the time.
Appointments made	The appointments with customers must be made at the appointed time at least 90% of the time.
Written responses to inquiries	The written response must be made within 10 working days following the receipt of request, at least 80% of the time.
Emergency responses	Emergency trouble calls must be responded to within 120 minutes in rural areas and within 60 minutes in urban areas. Each standard must be met at least 80% of the time.

Source: OEB

4.5 Impact assessment

Given the varied structures of performance monitoring and enforcement mechanisms, regulators are eager to understand the impact of performance incentives for utilities, relative to both other incentive schemes and to the status-quo. Specifically, it is important to analyze the degree to which service quality, utility investment, O&M expenses and profit, and retail rates are impacted by incentive schemes. The answer to many of these questions, however, will depend on the utility's starting point, how ambitious the performance target is, the strength of the potential fine (or reward) and the utility metric being analyzed.

Figure 81 summarizes the effects of performance standards on service quality, utility investment, utility O&M expenditures, utility profitability, and retail rates for selected utilities in the US.

Figure 81. Summary of selected utility performance under performance incentive schemes

Impact Assessment	Nonfinancial Penalties	Penalties	Rewards and Penalties
Example	PECO Energy	ConEd of NY, CMP	SDG&E
Service Quality	**Improving reliability performance** following the implementation of performance standards	**Improving CAIDI and SAIFI** performances by ConED since 2006	**Met performance targets** in 2000
Retail Rates	**Decreased** since 2010	**Increased** since 2008	**Increased** between 2000 and 2002
Investment	PECO has seen **flat CAPEX** since 2005	CMP and ConEd have both **increased CAPEX** since 2000	SDG&E **increased CAPEX** while under PBR regulation 1999-2002
Utility O&M	**Flat O&M** as a percent of revenue 2000-2010	**Decreasing O&M** as a percent of revenue since 2004	SDG&E **increased O&M** from 50% in 1998 to 75% (of revenue) in 2000
Profitability	**Flat** consistently hovering around 9.5% (net profit margin) since 2005	**Flat** consistently hovering around 8.3% (net profit margin)	**Flat** hovering around 12% (Net profit margin)

Source: CPUC, MPUC, NYPSC, PaPUC, and third party financial database.

Service quality

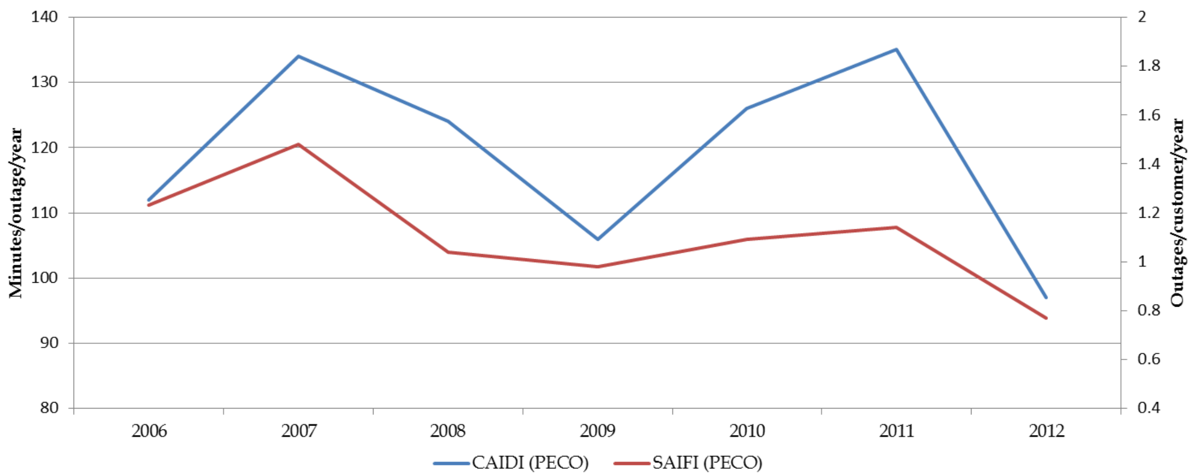
Regulators commonly ask whether performance standards actually improve utility reliability and customer service performance. However, scholars have noted that as yet only four states have adopted such metrics; the rest use varying definitions of reliability which make cross-jurisdictional comparisons difficult[195] Analyzing the service quality performance across the USA and Canada has yielded mixed trends depending on the jurisdiction. However, after attempting to standardize data using Institute of Electrical and Electronic Engineers, Inc. ("IEEE") metrics, researchers at the Lawrence Berkley National Laboratory have found that reported average annual outage SAIDI and SAIFI indexes have been increasing over the 2000-2009 timeframe in

[195] Eto, Joseph H. et al. *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions*. Ernest Orlando Lawrence Berkeley National Laboratory. October 2008. P. XI.

the US at an average annual rate of 2%.[196] These mixed service quality trends comes are partially a consequence of more reliable, consistent and more frequent reliability reporting.

By contrast, in Pennsylvania, where the PaPUC requires reliability reporting and closely monitors the results with the threat of audits, reliability metrics for PECO Energy[197] have improved since 2006 (see Figure 82).

Figure 82. PECO Energy reliability performance, 2006-2012



Source: PaPUC

In Ontario, which is another jurisdiction where distributors are faced with nonfinancial penalties comprised of compliance and customer pressure to exert pressure on utilities, the average reliability performance of all distributors has been mixed with both the frequency and duration of outages decreasing in 2009 and 2010 from 2008 levels but increasing again in 2011. Over the same period, on average Ontario distributors failed to stay below the three year annual average SAIFI and SAIDI goals in 2008 and 2011 (see Figure 83 and Figure 84).

In New York, where distributors face the possibility of explicit fines for missing performance targets (see Section 4.4.2), ConEd has gradually improved its CAIDI and SAIFI performances since 2006 (see Figure 85). ConEd failed to meet its benchmark performance targets in 2006, 2007, and 2011.

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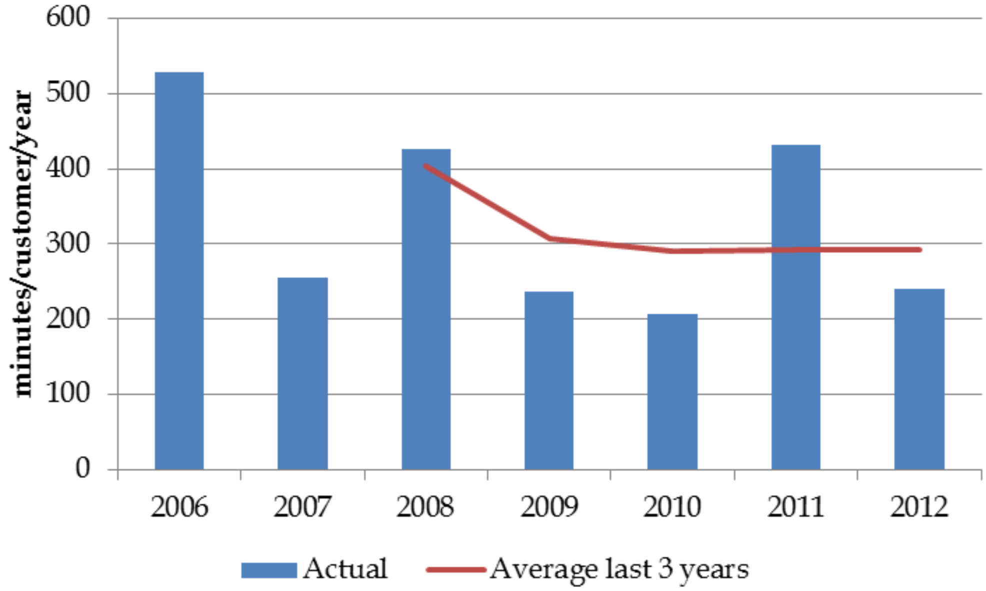
[196] Eto, Joseph H. et al. "Distribution-level electricity reliability: Temporal trends using statistical analysis." *Energy Policy 49* (2012) 243-252 P. 243.

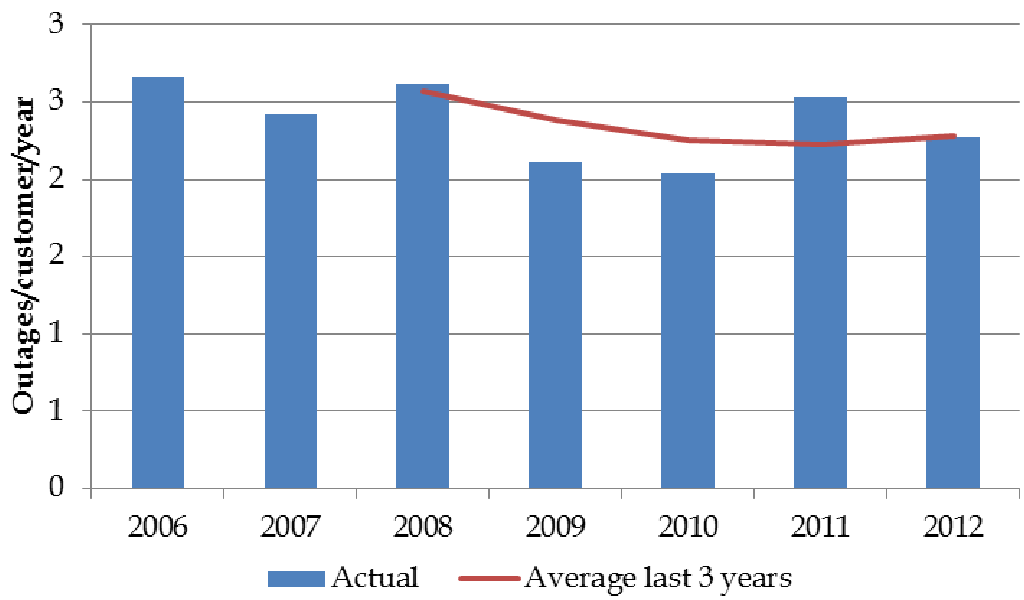
[197] PECO Energy is a large Philadelphia based electric and gas distributor. Here, reported results reflect only PECO's electrical business.

Figure 83. Ontario SAIFI actual and historical performance, 2006-2012



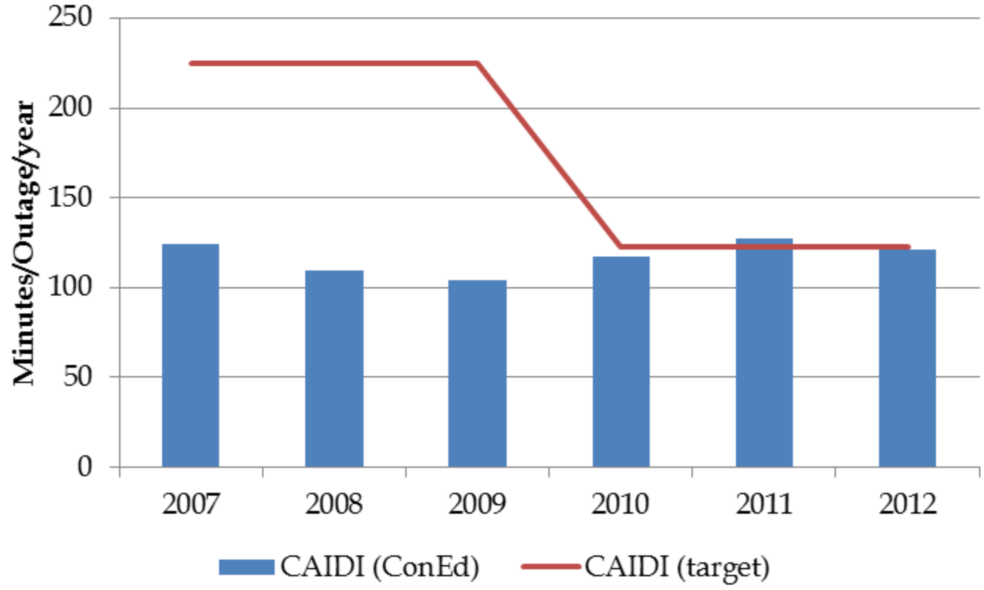
Source: OEB

Figure 84. Ontario SAIDI actual and historical performance, 2006-2012



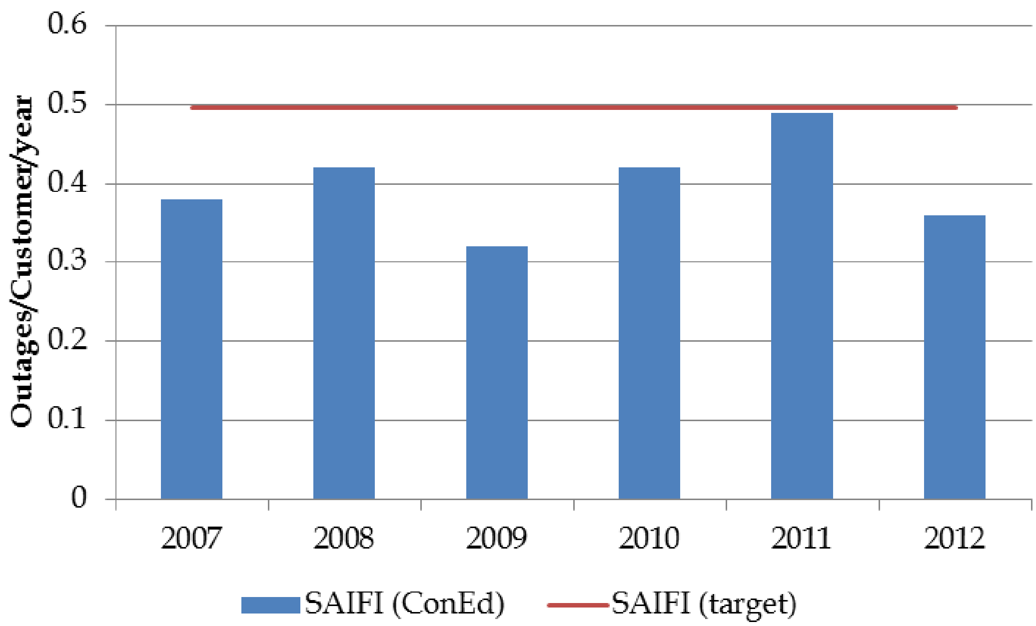
Source: OEB

Figure 85. ConEd CAIDI performance relative to target, 2007-2012



Source: NYPSC

Figure 86. ConEd SAIFI performance relative to target, 2007-2012

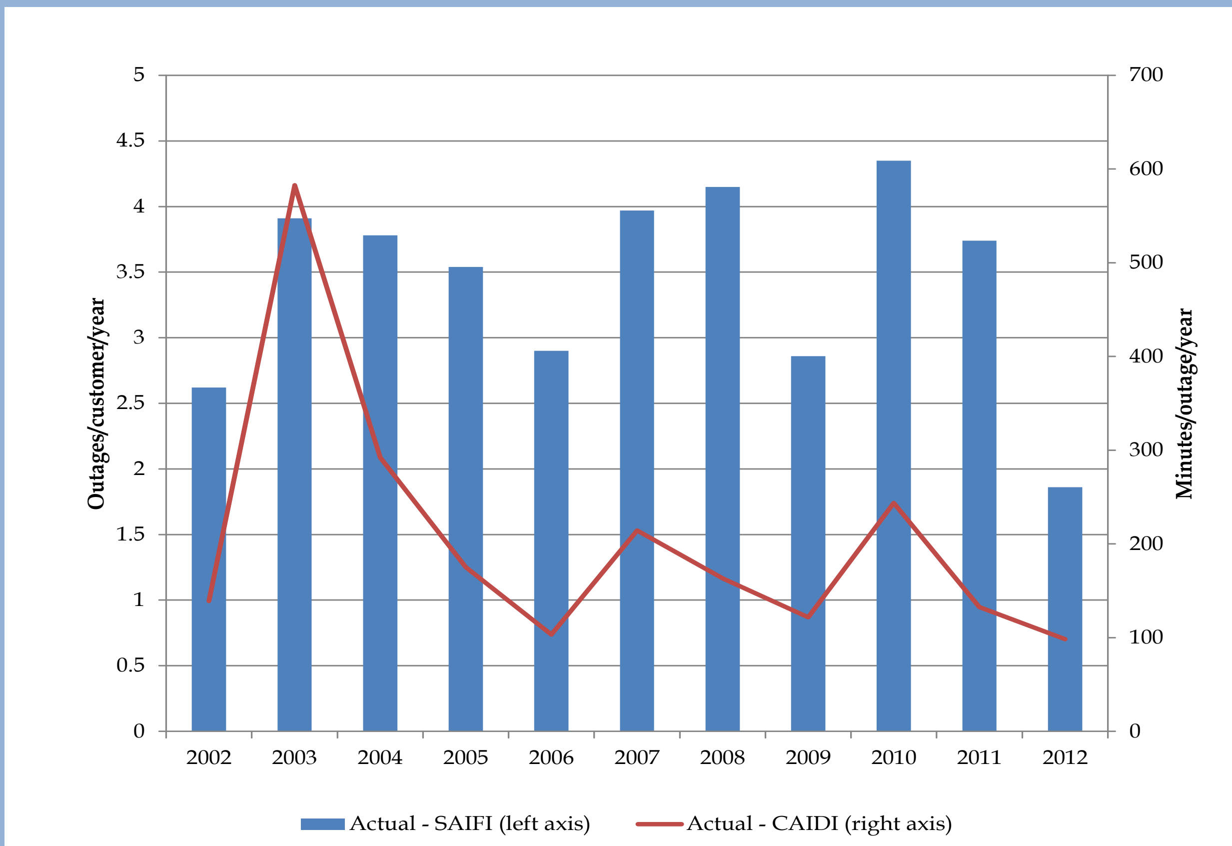


Source: NYPSC

Experience with reliability in Nova Scotia

For both CAIDI and SAIFI, Nova Scotia Power's performance has been relatively constant since 2002. The notable exception to the relatively constant reliability performance is 2003 following Hurricane Juan which caused extensive damage. As such, Hurricane Juan could be classified as a "major event". Following 2003, CAIDI has been trending down.

Nova Scotia Power's historical CAIDI and SAIFI performance, 2002-2012



Sources: NSP

Retail rates

There is generally a trade-off between reliability and retail rates. The more ambitious the reliability performance target, the greater the required investment, with a corresponding need to increase rates. The effect of a performance incentive scheme will however depend on the desired level of reliability and service quality and the starting point of the utility. However, if before beginning a performance scheme a utility has historically managed to achieve strong reliability performances, the effect of performance schemes on retail rates may not be as great as compared to mandating reliability standards on a utility with a weaker reliability history.

In practice, the effect of performance standards on retail rates differs based on the nature of the scheme. In Pennsylvania where there are no penalties or fines for missing performance targets but where the PaPUC monitors reliability standards, offered residential power prices are almost $0.09/KWh as of January 2014.

Profitability

The effect of performance standards on utility profitability can be broken down into direct effects and secondary effects which again depend on the strength of the performance target and the utility starting point. The immediate effect of performance standards on profitability is limited to the amount of the fine (or reward) and to the cost of compliance. Since in practice the threat of fines is more common than the possibility of rewards, the direct effect of performance standards on utility profitability is typically negative. Indirectly, it is possible for performance standards to incent investment that may positively affect profitability. In general however, for incentive schemes to have indirect effects, the size of the penalty must be great enough to affect behavior.

Figure 87. Net income (% of revenue) for selected utilities, 2007-2012

	2007	2008	2009	2010	2011	2012
Central Maine Power	10.1%	10.2%	8.5%	12.4%	18.0%	16.7%
ConEd	11.4%	10.0%	10.1%	10.7%	11.9%	12.4%
PECO	10.6%	6.8%	7.7%	6.7%	12.5%	14.3%
San Diego Gas & Electric	12.8%	13.2%	13.9%	14.1%	12.8%	13.0%

Source: Third party financial database

In practice, the effect of performance standards on profitability is limited. Since the PaPUC began tracking reliability without the threat of fines, the net profit margins of PECO Energy, one of the largest Pennsylvania electricity distributors has been consistently hovering around a fifteen year average of 9.5%. In Maine, where the regulator has threatened fines for utilities missing performance targets since 1995, net profit margins remained flat hovering around a long term average of 8.3%. This makes sense since the maximum penalty CMP has faced (in 2008) is $5 million, payable via a reduction in allowed revenue, compared to operating electric net income of over $55 million. In California, where SDG&E can be either rewarded or punished for reliability and service quality performance, SDG&E exceeded performance targets in 2000 and consequently received a net reward of approximately $10 million compared to 2000 net electric income of over $151 million.[198] Over the period, SDG&E's net profit margin also remained flat hovering around 12%.[199]

Operations and maintenance expenses

Compliance with mandatory reliability standards can require additional compliance staffing which tends to increase O&M costs. At the distribution level, reporting and compliance efforts are less onerous, typically requiring ex-post reliability and service quality results and thus may not increase O&M expenditures significantly. Again, however, the change in O&M expenditures as a result of performance standards depends on the strength of performance already in place at the relevant utility. If a utility has a strong reliability and customer service track record, O&M expenditures may not change. Additionally, if the strength of monetary incentive is not sufficient to change behavior, O&M expenses may either remain flat or decrease, as the incentive of competitive PBR regulatory regimes is to skimp on O&M expenses in order to increase competitiveness.

With a few exceptions, O&M expenditures as a percentage of revenue have remained flat or decreased for most utilities reviewed. In Pennsylvania, PECO Energy saw O&M expenses remain flat through the 2000-2010 period hovering around 60% of revenue. In Maine, CMP has seen its O&M expenditures decrease from over 80% of revenue in 2001 to 57% in 2012. In California, however, SDG&E during its reward and penalty PBR regime saw its O&M expenditures increase from 48% of revenue in 1998 to 60% in 2003. However, the size of the potential penalties or rewards for these utilities was less than 1% of equity and there are likely to be other factors influencing O&M trends.[200]

Figure 88. O&M (% of revenue) for select utilities, 2007-2012

	2007	2008	2009	2010	2011	2012
Central Maine Power	71.3%	75.0%	73.4%	62.9%	57.5%	57.0%
ConEd	64.0%	64.4%	60.4%	58.8%	55.4%	54.5%
PECO	60.3%	63.3%	61.5%	61.6%	71.5%	68.7%

Source: Third Party financial database

Capital expenditures

Performance incentives are designed to ensure reliability and service quality. To the extent that a utility is unable to meet performance targets, a utility will need to increase capital

[198] California Public Utilities Commission. *Electric and Gas Utility Performance Based Ratemaking Mechanisms*. September 2000. P. 12.

[199] Third Party financial database.

[200] Third party financial database.

expenditures; this, however, depends on the performance targets. Less stringent targets which a utility has historically been able to meet may not affect capital expenditures, whereas more ambitious performance targets often will require additional capital expenditures in order to reach performance targets.

An analysis of capital expenditures, as reported to FERC as construction work in progress ("CWIP"), notes that capital expenditures have increased for utilities facing the threat of performance based fines and for SDG&E during its performance based rate, but has remained flat for PECO Energy. This has been the case for both ConEd and particularly for CMP since 2000 whose investment levels have increased to over $600 million from about $12 million in 2005. Similarly, SDG&E reported a gradual increase in CWIP between 1999 and 2003. However, PECO, only facing stringent PaPUC reliability reporting laws, has seen its investment remain flat since 2005.[201]

4.6 Key conclusions

The transition from a vertically integrated COS utility model to a liberalized, incentives-based structure has left some system planners, regulators and consumer advocates concerned over potential effects on customers.

Setting appropriate performance targets is a key component in ensuring the targets are actually met; targets should adequately balance realism with ambition. Without targets, utilities are unlikely to be motivated to improve on their performance. Nevertheless, unrealistic targets could also lead to poor reliability and customer service if utilities see the targets as impossible to reach. The targets and fines should be transparent and be consistent with other utilities over time. Moreover, regulators should be adaptable recognizing that performance incentive schemes are often not perfect in their initial design and thus often will require changes to ensure optimal utility reliability and customer service performance.

In practice, many different performance standard compliance monitoring and enforcement mechanisms have developed, differing by generation, transmission and distribution. Generation performance standards are less common as generators are more often exposed to competition in some jurisdictions. However, those generator performance standards that do exist typically focus on reliability targets, like forced outage rates, to ensure that generation meets its obligations. For transmission, NERC has designed an input based system, delineating in detail performance best practice and incentivizes with the threat of fine for the failure to comply.

The distribution sector is where performance compliance and incentive schemes are most diverse. Electrical utilities in a PBR regime need clear performance standards to guide productivity improvement efforts. For this reason, regulators have long recognized the need for performance standards to ensure that utilities meet minimum reliability and customer service standards.

[201] Third party financial database.

Performance standards best practice

Generation

- ✓ Require generators to report availability and efficiency performance data
- ✓ Competitive energy markets themselves are the best way to incentivize performance
- ✓ Structure PPAs and design generator performance incentives for vertically integrated utilities based on realistic availability and efficiency metrics

Transmission

- ✓ Require reporting of reliability performance
- ✓ Maintain codes of best practice to help prevent reliability incidents
- ✓ Maintain ongoing data reporting and auditing system to ensure transmission is following best practice standards

Distribution

- ✓ Require distributors to report reliability and service quality performance
- ✓ Design realistic and achievable performance targets
- ✓ Use positive and negative incentive schemes to reward or punish
- ✓ Set caps on performance incentive exposure based on utility return on equity

In some states, there are no mandatory performance standards, in other states there are statutes mandating minimum reliability and/or service quality performance requiring utilities to report performance metrics annually. Any failure to meet standards can be met with extensive audits. In other states, like New York and Maine, state regulators require the reporting of reliability and customer service metrics and impose fines for failing to meet targets. Some jurisdictions, like California historically, have designed performance incentive schemes with fines and symmetric rewards, although this is a far less common methodology. Each approach has its strengths and weaknesses and lead to differing performance outcomes depending on the metric, starting point and the strength of the target.

Requiring utilities to report reliability performance to regulators for publication provides transparency to stakeholders, allowing the public to put pressure on utilities to improve service quality. However, at times, public pressure is not enough. As such, incentive plans can place important financial pressure on utilities to improve performance. Incentives need to be based on clear, realistic and achievable performance targets. The simplicity of a long run five year rolling average as applied in Australia is particularly appealing. By contrast, if setting a target based on industry averages, it is important to consider the applicability of each potential utility in that average. Performance targets based on industry averages require geographic consideration. Often, local geographies and conditions render certain utilities inapplicable when setting the performance targets of another utility.

Caps on the amount of exposure to performance fines set on the basis of return on equity are also important, as they act as an important insurance mechanism to ensure the utility's financial viability in the case of a poor reliability performance. Both fines and rewards need to be based on consumer willingness to pay for incentives. In addition, fines and rewards should be sufficient to incent behavior. In the UK, Ofgem's efforts to analyze local willingness to pay set a baseline marginal value for deviations from a performance target which formed the basis for distribution incentive schemes. Also, in designing the incentives, an evaluation of the utility's historical reliability performance is important as incentives themselves may not have a large impact if historically reliability and customer service performance has been strong. This represents best practice and a clear formulaic basis for performance incentives which, if done properly, should be an important deterrent for a utility to potentially avoid O&M expenditures to the detriment of electrical customers.

5 Customer and Service Provider Risk

The risks faced by customers and service providers depend on what services are being provided by the utility (bundled versus unbundled), and on how the utility is organized (vertically integrated versus unbundled). Consumers and utilities each face very different types of risks, which are both impacted by the structure of the market (competitive versus regulated).

> The introduction of competitive wholesale markets provides new tools for customers to manage risk. However, traditional cost of service regimes may provide greater opportunity to spread costs over longer periods. Policymakers considering a move to competitive markets need to weigh the costs of less coordination and increases in cost of capital against the potential benefits of increased efficiency, improved risk allocation, and greater customer choice.

5.1 Risks faced by consumers

Two key questions underpin the analysis of customer-related risks:

- Are customers paying the long run lowest prudently derived price?
- Are customers receiving adequate reliability and service quality?

The risks identified below are related to how various factors may result in higher prices and what factors may impact the reliability and service quality measures.

In a vertically integrated market (where generation, transmission and distribution functions are handled by a single company), consumers may face additional price risk related to overinvestment, as compared to those in which the generation sector is unbundled. Competition in the generation sector allows merchant companies to assume investment risk, which in turn reduces the exposure of ratepayers to imprudent capital investments. However, it can be argued that vertically integrated markets may be better positioned to address reliability and investment coordination issues associated with new technologies such as distributed generation and intermittent renewables.

A further step in liberalization of the energy market is the unbundling of retail access. Consumers in an unbundled retail market have the ability to purchase energy from competitive retailers, rather than from the distributor. Generally, consumers with retail access are provided additional tools, such as long term contracts, with which price risk can be mitigated. Consumers with bundled retail access lack the ability to manage exposure to future price increases except through the political process.

Risks for consumers have been organized in terms of their risk categories (price exposure, reliability issues, and service quality issues), however, they cover different types of market, regulatory and technology risks. These risks are faced by consumers of all categories (residential, commercial or industrial) and size. These risks would be generally more severe for larger consumers of energy, which are typically industrial. Price risks naturally have a greater impact to industrials consuming large amounts of energy, and reliability issues may affect production of goods. Both would cause significant economic consequences for industrial consumers, however, LEI notes that large industrial consumers may have a greater ability to move their operations to mitigate the risk, as opposed to residential or commercial consumers.

The following table is a summary of the risks which are discussed in greater depth in the rest of this section.

Figure 89. Risk summary for consumers

Types of risks	Risk mitigation: vertically integrated utility	Risk mitigation: unbundled utility
Fuel price risk: Increases in fuel prices for power generation can cause consumer energy prices to increase	Rolled-in nature of vertically integrated utility may allow rate impacts to be managed over a longer time period	Retail market unbundling allows for consumers to sign long term contracts, hedging their energy price exposure
Imprudent capital investments: Imprudent investments in regulated assets can cause electricity rates to increase	Effective regulation and oversight of the vertically integrated utility can mitigate this risk	Introduction of merchant competition shifts risks away from ratepayers, and towards the merchant companies
Environmental attributes: Requirements for generation companies to purchase environmental attributes can cause higher energy prices	Rolled-in nature of vertically integrated utility may allow rate impacts to be managed	Retail market unbundling allows for consumers to sign long term contracts, which may hedge their price exposure
Underinvestment: Lack of investment in generating capacity, transmission and distribution systems can cause reliability issues	Centralized capacity planning by the vertically integrated utility can be effective in mitigating underinvestment	Markets that provide the right economic incentives for new generation mitigate the risk of underinvestment
Reliability problems associated with distributed generation: Additional complexity for the distribution system due to distributed generation could cause reliability issues	Centralized planning by the vertically integrated utility can be effective in mitigating reliability issues in the distribution system	Thoughtful regulation and ISO planning can mitigate this risk
Reliability problems associated with intermittent resources: Challenges with respect to integrating renewables and procuring sufficient ramping capability could cause reliability issues	Centralized planning by the vertically integrated utility can be effective in meeting the challenges of intermittent resources	ISO planning around sufficient ramping capacity and thoughtful regulation can mitigate this risk
Unsatisfactory service quality provided by distributors: Distributors may offer poor service in terms of work performance or metering errors	Incentives for meeting service quality metric objectives are likely to provide greater service to consumers in both CoS and PBR regimes	
Unsatisfactory customer service provided by retailers: Customers may experience poor interactions with distributors or retailers	Incentives for meeting service quality metric objectives are likely to provide greater service to consumers	Retail market unbundling allows for consumers to switch to another retailer. Information clearing houses, standardized terms, strong oversight against "slamming", and lemon laws can also protect consumers

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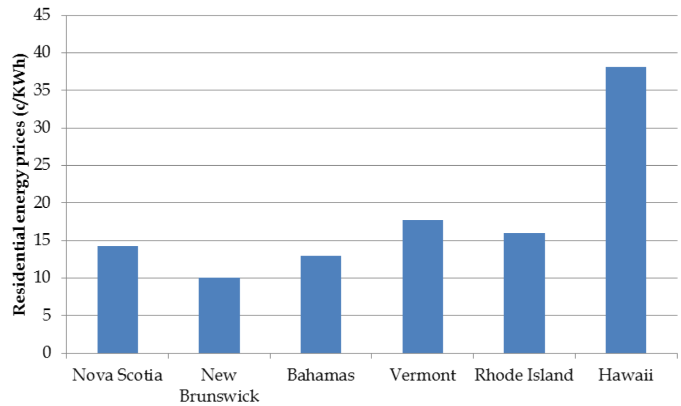
5.1.1 Price exposure

Figure 90. Delivered 2013 residential prices across select jurisdictions



Notes: All prices are in CAD (where 1 USD = 0.97 CAD; B$1 = 1 USD); Nova Scotia price is the 2014 Energy Rate; New Brunswick price is as of October 2013; Bahamas price is an average of three residential rate tiers; US prices are 2013 averages, and include fees as reported to the EIA

Sources: EIA, Bahamas Electricity Corporation, Nova Scotia Power, NB Power

One of the key risks to consumers is being exposed to paying prices which are higher than historical norms, or are not prudently derived. An indicative scan of smaller, more isolated, yet well-developed jurisdictions suggests Nova Scotia rates are not anomalous. Generally speaking, in terms of this price exposure, the further the market is unbundled, the more choice a customer has in terms of mitigating this risk. The following are specific risks that LEI has identified, which may contribute to consumers paying higher prices.

- **Fuel price increases for power generation**: Power prices are highly dependent on the underlying fuel costs. For example, high natural gas prices in the Northeastern United States in January 2014 caused significant spikes in prices in both New England and New York ISOs.[202] In terms of mitigating this risk, customers with unbundled retail markets will generally have the ability to purchase long term fixed price contracts, hedging their energy costs for a number of months or years.[203] With these contracts, customers in unbundled retail markets would be able to insulate themselves from fuel price increases. However, as discussed in the text box below, customers engaging in contracting to hedge price risk need to be aware of force majeure and change of law provisions.

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[202] EIA. *Northeast and Mid-Atlantic power prices react to winter freeze and natural gas constraints*. <http://www.eia.gov/todayinenergy/detail.cfm?id=14671>

[203] Alberta Retail Market Review Committee. *Power for the People*. September 2012. P 122. <http://www.rmrc.ca/RMRCreport.pdf>

First Energy Plans "Polar Vortex" surcharge

First Energy Solutions will charge residents of Rockford and 97 other municipalities in northern Illinois between $5 and $15 on their bills in June 2014 to cover unexpected costs incurred due to cold weather in January 2014. Rockford is the third largest city in Illinois after Chicago and Aurora, with approximately 220,000 customers in the affected area. This event marks the largest area supplier to seek to pass through the financial burden due to unusually cold temperatures in January, which caused temporary price hikes.

The price hikes were the result of the necessary power-purchasing costs made through PJM. In January, PJM lifted caps on the prices power plant operators could bid, since input costs had spiked. The total cost due to the rule change was approximately $500 million to all suppliers. Notably, some suppliers, such as Constellation and Integrys Energy Services, did not intend to pass through these costs.

Source: "FirstEnergy plans polar vortex surcharge on suburban electric bills." Crain's Chicago Business. Web. 25 March 2014 <http://www.chicagobusiness.com/article/20140325/NEWS11/140329887/firstenergy-plans-polar-vortex-surcharge-on-suburban-electric-bills>

In a vertically integrated market, consumers are not able to hedge, and in many cases, generators may also not be able to hedge their fuel contracts, which results in exposure to fuel prices for consumers. However, a vertically integrated utility may be able to manage any rate impacts by spreading the impact over multiple billing cycles – for example Nova Scotia Power has announced it will not increase fuel costs for 2015.[204]

- **Imprudent capital investments (generation, transmission, distribution)**: The risk of over-investment in generation, transmission or distribution systems, and their associated costs, impact consumers when these assets are regulated. Overinvestment can also take the form of investment in uneconomic technologies, an example of which can be found in the text box below. Imprudent capital investment can be an issue with vertically integrated markets, as merchant generation and transmission generally are not allowed to compete. As merchant generation and transmission are given opportunity to compete, risk is shifted from ratepayers to the merchant companies. Any losses associated with imprudent investment or cost overruns for a merchant project would be borne by the company, rather than the ratepayers. For vertically integrated utilities, this risk can be mitigated by effective oversight by regulators and lawmakers.

[204] Nova Scotia Power. *Nova Scotia Power: electricity rate stability through 2015*. April 1, 2014. http://www.nspower.ca/en/home/newsroom/news-releases/rates2015.aspx

Coal gasification plant had cost overruns of over $1 billion

In June 2013, Duke Energy commissioned the Edwardsport Indiana coal gasification power plant. Indiana remains a CoS state. Coal gasification is a new technology which converts coal into gas, removing sulfur dioxide, mercury and carbon dioxide, such that the plant produces pollution similar to a natural gas plant. The plant ended up costing $3.5 billion as compared to the original 2007 cost estimate of $1.9 billion, which will cause Duke's Indiana customers to see a 14-16% price increase. By contrast, a similar proposed plant in Illinois, an unbundled state, was never built because market conditions did not support it.

Source: Associated Press. *Troubled Indiana gasification plant begins operation*. June 10, 2013. <http://www.ibj.com/troubled-indiana-gasification-plant-begins-operation/PARAMS/article/41860>

Southern Company Issues RFP for Solar Capacity

In April 2014, the Southern Company's subsidiary, Georgia Power, issued a competitive RFP for up to 495 MW of solar capacity in the state. The Southern Company is one of the largest vertically integrated utilities in North America, and controls approximately 50 GW of capacity. Similar types of RFPs reduce the potential for overinvestment, as there is no preference for the incumbent. This is also a trend in transmission systems.

Source: Georgia Public Service News Release. *Commission Approves Release of Request for Proposals for the Georgia Power Advanced Solar Initiative.* New Release. April 18, 2014. < http://www.psc.state.ga.us/GetNewsRecordAttachment.aspx?ID=321>

- **Requirements related to environmental attributes**: Production of power from fossil-fueled sources produces negative externalities – costs to society which are not reflected in the price paid for the good or service. Emissions and effluents are a large portion of these negative externalities. Future environmental regulation may obligate CO_2 producing power plants to purchase environmental attributes; examples of these types of regimes are cap and trade systems or renewable portfolio standards ("RPS"). Although these regimes can vary greatly in their implementation, the resultant impact would likely be similar to a fuel price increase, as generators pass on additional costs associated with purchasing environmental attributes. It may be possible for costs to be mitigated through long term fixed price contracts; however, many contracts may have change of law provisions, which would still put price risk on consumers. Similarly, regulatory requirements for additional renewable generation would increase costs to consumers. In the case of a vertically integrated utility, rate impacts may be able to be managed over time in order to lessen the impact to consumers.

5.1.2 Reliability issues

Reliability risks include underinvestment, issues related to distributed generation, as well as those associated with intermittent resources.

- **Underinvestment in generating capacity and transmission systems**: Typically in a vertically integrated utility, underinvestment is not an issue, as the sector is centrally planned in order to be able to meet required reserve margins. However, as competitive entry is introduced into a market through deregulation, the pace of supply additions is unknown. Market forces are expected to attract generation capacity, and if market forces fail to attract sufficient investment, reliability issues could arise, affecting customers. For example, concerns had been raised in the Electric Reliability Council of Texas ("ERCOT") about the ability of energy-only market design to attract sufficient investment to meet target reserve margins and reliability objectives.[205] Proposals to implement scarcity pricing or a capacity market have been the result, though ERCOT continues to attract investment as an energy only market.

For transmission, levels of investment depend on ISO planning processes. As long as the ISO properly reflects future needs in its planning, costs of new transmission are passed through to customers in rates. Furthermore, jurisdictions can offer mechanisms for projects to receive regulated rates - for example, the NYISO's economic planning process allows costs of eligible transmission projects to be allocated through NYISO's tariffs.[206] Also, please refer to Section 6.1.4 for discussion regarding FERC incentives for new transmission projects.

NYISO Congestion Assessment and Resource Integration Study ("CARIS")

As part of phase 2 of the NYISO CARIS planning process, potential economic transmission projects with capital costs greater than $25 million can apply to have regulated cost recovery through the NYISO Tariff. Projects are eligible if the present value ("PV") of production cost savings is greater than the PV of costs for the first ten years of the project. Furthermore, the PV of the first ten years of locational based marginal pricing ("LBMP") load savings, net of Transmission Congestion Contract revenues and bilateral contract quantities, must be greater than the PV of the projected project cost revenue requirements for the first ten years of the amortization period.

- **Reliability problems associated with distributed generation**: Growth of distributed generation ("DG") and intermittent generating resources has been a risk to reliability posed by technological growth. Distributed generation can be described as small-scale generation facilities located close to loads, which contrast against the conventional paradigm of large generating facilities located far from load and transmitted via the high voltage transmission system. This will continue to cause challenges to jurisdictions integrating significant amounts of DG, as distribution networks which were traditionally

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205 The Brattle Group. *ERCOT Investment Incentives and Resource Adequacy*. June 1, 2012 <http://www.ercot.com/content/news/presentations/2013/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf>

206 NYISO. *2013 Congestion Assessment and Resource Integration Study*. November 19, 2013. P 22. <http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2013_CARIS_Final_Report.pdf>

passive will need to consider issues of system stability.[207] Like under-investment, it can be argued that a vertically integrated utility is better able to plan for such issues in terms of investment and coordination, though thoughtful regulation and ISO planning can also mitigate this risk.

ISO-NE Distributed Generation Forecast Working Group

In fall 2013, ISO-NE initiated the Distributed Generation Forecast Working Group ("DGFWG"), to address the challenge of additional DG growth. New England is expecting approximately 2,000 MW of mostly solar PV DG by the end of 2021. The mission of the DGFWG is to "to foster collaboration between ISO, state policymakers, state regulators, distribution companies and others possessing needed expertise to address the operational, planning, and market implications of high penetrations of DG."

Source: ISO- NE. *Regional Update*. December 18, 2013. <http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2013/final_meleg_post_dec18_13.pdf>

- **Reliability problems associated with intermittent resources such as wind or solar:** Renewable resources such as wind and solar may cause grid reliability issues due to their intermittent nature. As the relative share of these resources increases, changes in wind or solar conditions can cause significant changes to energy production on the grid. To compensate, jurisdictions have had to ensure sufficient ramping capacity to support these intermittent resources. NERC has published a report regarding integration of variable resources, highlighting that "PV systems can experience variations in output of +/- 50% in a 30 to 90 second time frame and +/- 70% in a five to ten minute time frame."[208] Multiple ISO's have published papers on this topic. For example, in CAISO, significant amounts of renewables have led to "short, steep ramps" identified as a particular operating challenge.[209]

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[207] Lopes, Hatziargyriou, et al. *Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities*. October 2006.

[208] NERC. *Accommodating High Levels of Variable Generation*. April 2009. P. 27. <http://www.nerc.com/files/ivgtf_report_041609.pdf>

[209] California ISO. *What the duck curve tells us about managing a green grid*. <http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf>

Selected recommendations from PJM Review of Industry Practice and Experience in the Integration of Wind and Solar Generation

- Sub-hourly scheduling and dispatch
- Install telecommunications and remote control capability to clusters of solar DG
- Include solar in variable generation forecasting
- Account for the impacts of non-metered solar DG in load forecasting
- Consider separating regulation requirements into regulation up and regulation down
- Have operating reserve requirements set by season or by level of expected variable generation
- Implement a centralized forecasting system for wind and utility-scale solar that offers day-ahead, very short-term (0-6 hours), short-term (6-72 hours), and medium or long-term forecasts (3-10 days)
- Require wind generators to be equipped with ability to limit ramps

Source: GE Energy. *Review of Industry Practice and Experience in the Integration of Wind and Solar Generation*. November 2012. <http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-task3b-best-practices-from-other-markets-final-report.ashx>

Like under-investment, it can be argued that a vertically integrated utility may be in a stronger position to address such issues, especially in terms of investment and coordination. In a deregulated market, strong regulation and ISO planning can mitigate this risk.

5.1.3 Service quality issues

Service quality risks to consumers include unsatisfactory service from distributors and retailers.

- **Unsatisfactory service quality from distributors:** Aside from reliability, electricity distributors may define service quality for consumers in various ways. For example, ENMAX Power Corporation in Alberta measures time (in years) of meter errors, prior to detection, and as a measure of work performance, days between a site energization order being created to actual site energization, amongst others.[210] Although consumers are not necessarily able to mitigate these risks, regulators can have incentives for meeting service quality metric objectives; this is discussed in depth in Section 4 (Performance & Accountability).

[210] ENMAX Power Corporation. *ENMAX Power Rule 002 2013 SQRP Annual report.xls* <http://www.auc.ab.ca/rule-development/service-quality-and-reliability/Documents/EPC%202013%20Annual%20report.zip>

Examples of service quality metrics

Consolidated Edison of New York: customer complaints, customer satisfaction, call answer rates

Central Maine Power: complaint ratio, calls answered, call center quality, meters read, new connections

San Diego Gas and Electric: customer satisfaction, call center response, all injury frequency rates

Ontario: new connections, underground cable locations, telephone accessibility, appointments made, energy and written responses

Unsatisfactory customer service from retailers: Retail customer service can also be defined in various ways, including "green" power, time of use billing, flexible payment dates, and retailing of other products such as natural gas.[211] However, different customer service experiences may be offered by various retailers in an unbundled retail market. In such a market, consumers can mitigate the risk of poor customer service from their retailer by switching to a competitor. In a bundled market, effective regulation of the vertically integrated utility can ensure quality customer service for consumers.

Regulated industries have less incentive to innovate or react to consumer preferences for customized goods and services that reflect personal tastes or needs.

Source: Alberta Retail Market Review Committee. *Power for the People*. September 2012. P 20.

Another aspect of customer service relates to taking advantage of consumers. The practice of "slamming", which is the illegal practice of switching retail customers to another provider without proper permission, is a risk to consumers in unbundled markets. Strict regulatory oversight is required to prevent this behaviour. Other ways that consumers can be protected is by providing standardized terms for retailers, offering information clearing houses to educate consumers about their retail options, or so called "lemon laws" which allow new customers to cancel their service.

"Slamming" before the Pennsylvania PUC

The Pennsylvania PUC investigated an agent of Pennsylvania Gas & Electric for falsifying verifications and attempting to unilaterally switch 319 accounts. In February 2014, the PUC rejected a proposed settlement of a $75,000 civil penalty and refund for any switched customers, due to the severity of the allegations and lack of additional mitigating actions. As of April 2014, a final penalty has not been imposed.

Source: Pennsylvania PUC. *Joint motion of Chairman Robert F. Powelson and Vice Chairman John F. Coleman,*

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211 Government of Alberta. *Power of Choice: A Guide to Help You, the Consumer, Better Understand Customer Choice in Alberta's New Restructured and Competitive Electric Industry*. 2000.

For conclusions and relative ranking of risks, refer to Section 5.4.

5.2 Risks faced by utilities

One key question likely underpins the analysis of utility-related risks: **can the utilities earn a fair return on their investment?** The financial and operating aspects of the utilities will have an impact on the ability to earn a fair return, which in turn can lead to issues of financing, among others. The risks below are identified based on how they impact the operational and financial performance of the utilities.

The impact and extent of the identified risk factors will depend on the regulatory environment in which the utilities operate. The utilities that are under a cost of service ("COS") form of rate regulation (where the utilities demonstrate the necessity and reasonableness of capital investments and operating costs to deliver the services), are most protected and able to shield themselves from adverse developments in the marketplace, regulatory or technological areas.

In a deregulated generation sector, generators would generally be subject to a greater amount of risk. As well, performance-based ratemaking ("PBR") regulation mimics competition for transmission and distribution companies, therefore exposing them to additional risk. The risks discussed in this section are broadly categorized into marketplace, regulatory and technological.

Utility and IPP Bankruptcies

In the US, the bulk of utility bankruptcies occurred under cost of service regimes. While the bankruptcy of PG&E is often linked to market opening, this was due to a regulatory flaw, namely the inability to pass through the full cost of power purchased on customers' behalf. By contrast, most major utility bankruptcies were due to investments later deemed imprudent by regulators, such as Long Island Lighting Company (Shoreham Nuclear Station) or catastrophic events (General Public Utilities Corporation (Three Mile Island) or Entergy New Orleans (Hurricane Katrina)). In some cases ratepayers continue to pay these costs. By contrast, while numerous IPPs have made trips through bankruptcy, ratepayers are not dunned for the costs of poor IPP investments. Even when bankruptcy does occur, in either case, assets remain in place providing service, as this is the best way for creditors to be repaid.

Figure 91 presents a summary of the risks which are discussed in greater depth in the remainder of this section.

Figure 91. Risk summary for utilities

Types of risks	Risk mitigation: Wires under PBR	Risk mitigation: Competitive generation
Insufficient recovery of stranded costs: Stranded costs may occur when a market deregulates. Improper recovery may impact returns	Regulators ensure that measurement and collection of stranded costs occurs in an appropriate manner	
Inability to recoup capital expenditure: Inability to recover large capital investments will impact cash flows	Mechanisms to recover capital investment in a PBR regime needs to be in place	Forward power and fuel contracts can help in mitigating the primary risks to competitive generators
Insufficient productivity increases: Inability to reach productivity goals may result in revenues which are too low	X-factor needs to be set with great care, with a balance between incenting efficiency and an achievable target	Competitive generators need to keep up with industry productivity increases, or risk lower revenues
Inability to recoup extraordinary costs: Force majeure situations can incur costs which would impact a utility's ability to make a fair return	An appropriate Z-factor put in place	Appropriate insurance may protect competitive generators against force majeure
Lower load due to overall economy/conservation: Volumetric rates can be at risk to lower volumes of energy sales	Appropriate adjustments or variance accounts applied	Baseload type power plants in a portfolio will be impacted to a lower degree
Fuel price increases for power generation: Fuel costs are generally passed through to consumers, however, rate freezes could impact returns	Appropriate fuel adjustments or variance accounts need to be in place	Competitive generators can hedge fuel exposure with forward contracts
"Cutting the cord": Lower load and number of customers connected to the grid, as a result of distributed generation	Appropriately design backup charges and minimize net metering	Compete both in wholesale and behind the meter markets

5.2.1 Regulatory risks

Regulatory risks include those associated with insufficient recovery of stranded costs (also discussed in Section 2 - Global experience with electricity sector liberalization) and inability to recoup capital expenditure.

- **Insufficient recovery of stranded costs**: Stranded costs, also known as stranded investments or stranded debt, are those costs that the utilities are allowed to recover through their regulated rates but the recovery of which may be impeded or prevented as the market transits from a regulated regime to a competitive, deregulated environment. The risk of stranded costs not being recovered properly may place a utility at a disadvantage compared to others, or impact the return earned.

Situations in which stranded costs can occur

Stranded costs can occur in a number of situations; for example, in jurisdictions moving from cost-of-service ratemaking for generation to competitive wholesale markets, stranded debt arises when facilities are found to be uncompetitive in an open access environment. These investments can include power generation facilities, transmission lines, etc. Another example is when formerly government-owned utilities are broken up and privatized, the new entities will only be able to be sold with a level of debt that reflects commercial realities. The debt which cannot be placed with the surviving companies then becomes "stranded", net of privatization proceeds, and mechanisms must be developed to assure its repayment. In the future, it is also conceivable that widespread success of distributed generation could lead to stranded distribution system costs.

To mitigate this risk, regulators must ensure that measurement and collection of stranded costs occurs in an appropriate manner. Methods of measurement differ by whether they measure stranded costs before or after restructuring takes place, whether they are based on the estimation or on actual market valuation of assets, and whether they value a company's assets individually or take a more aggregate, "top-down" approach.

Collection of these costs typically occurs by: (i) imposing an access charge on all customers who utilize the utility's electric system, (ii) charging only those customers who opt to buy power from a generator other than their incumbent utility, or (iii) implementing rate freezes, which charge higher prices for the components of the electricity market that are still regulated (transmission and distribution). For example, in Virginia, legislation passed in June 1999 proposed to allow recovery of stranded costs through utility rates that were to be capped through mid-2007. In addition, a specific exit charge on customers who chose to leave their incumbent utilities was imposed.

Nova Scotia Power exit fees ruled out by Utilities and Review Board

In 2012, Nova Scotia Power ("NSP") sought exit fees from municipal utilities who were seeking supply from third-party supplies. NSP requested $23.8 million in exit fees over five years from six utilities, but this was rejected by the Board. The Board cited a 2005 agreement which allowed municipal utilities to purchase electricity on the open market without exit fees, unless the business changed significantly.

Source: Nova Scotia Utility and Review Board. *2012 NSUARB 133.* September 6, 2012. <http://caselaw.canada.globe24h.com/0/0/nova-scotia/nova-scotia-utility-and-review-board/2012/09/06/nova-scotia-power-incorporated-re-2012-nsuarb-133.shtml>

Figure 92. Regulatory approaches for recouping capital costs in PBR regimes

Approach	Description	Advantage	Disadvantage	Examples
Embedded capex in X factor derivation (apply to total costs)	No explicit recovery mechanism beyond the I-X indexing formula. X factor is applied to all costs, including capex	Minimal involvement of the regulator. Provision for strong performance incentives	Utilities have to wait until rebasing to recoup costs if growth in capex exceed depreciation	Enmax (Alberta)
Capital cost tracker (i.e., adding K factor to IBR formula)	Addition of an explicit mechanism either external or internal to the rate indexing formula. Can either be forward-looking or backward-looking. Prudence review is usually required for this approach	Provides certainty that capex will be recovered. Reduces financing costs for utilities	Require active participation of and can entail administrative burden to the regulator	Forward looking – UK Backward-looking – ENMAX transmission
Capex reviewed under COS	Only non-capital costs will be included under the IBR formula with an I-X index, while capex would be reconstituted into ratebase using COS approach	Provides certainty that capex will be recovered	Provides no real incentives for allocative efficiency	FortisBC (British Columbia)

- **Inability to recoup capital expenditure:** The treatment of capital expenditures significantly impacts utility's cash flows. PBR theory assumes a steady state environment where depreciation expense should be sufficient to cover normal going forward capex; when significant capital spending needs to occur for future investments, solely revenues from a price cap regime would not be sufficient. This is particularly true as network system investments tend to be "lumpy."

  Utilities face risk if they build network system investments first and request a rate increase later, as it is possible the regulator can find the asset not to be "used and useful", placing significant financial stress on the utility. Figure 92 describes different regulatory approaches for recouping capital costs for PBR regimes.

  On the other hand, competitive generators recoup capital expenditures through market revenues, which are subject to the other regulatory, market and technological risks discussed in this section. Changes in electricity and commodity costs would be the most significant risks, though power and fuel hedges can be utilized to mitigate these risks.

5.2.2 Market risks

Market risks for utilities include insufficient productivity increases, inability to recoup extraordinary force majeure costs, lower load/customers due to overall economy, fuel price increases, and interest rate increases.

- **Insufficient productivity increases:** For competitive generators, productivity increases which lag other competitors would place it at a disadvantage, and ultimately impact profits. Appropriate attention to improving productivity is the only way to mitigate this risk.

  PBR regulatory frameworks (as discussed in detail in Section 3) are designed to mimic market forces. For example, a common framework is known as I-X, where a price or revenue cap is escalated by an inflation factor (I), though these increases are moderated with expected productivity gains, or the X factor. Clearly, a risk to the returns of a utility is not meeting the expected productivity gains, which in turn will result in the regulated rates being paid to the utility to be below the actual costs of the utility. To mitigate this risk, great care must be taken in setting the X-factor, which is typically set using a total factor productivity ("TFP") study, which measures the productivity growth (rate of growth in quantity of outputs relative to the rate of growth in the quantity of inputs) for an appropriate peer group. The X-factor should strike a balance between incenting efficiency and setting a reasonably achievable target.

- **Inability to recoup extraordinary force majeure costs:** In the case of a force majeure or natural disaster, significant costs would be incurred by the utility, which would affect its ability to make a fair return. In PBR plans, what is known as a Z factor is included to recoup extraordinary costs that are outside the company's ability to control (or forecast).

Z factors (as discussed in Section 3) will typically cover events such as force majeure, natural disasters, change in law and unforeseen regulatory or policy events. The final two types of events would also be considered a regulatory risk. For competitive generators, appropriate insurance can be purchased to protect against these risks, though cost may be an issue.

Examples of Z-factors

- **Alberta (ENMAX)** – specified events and provided criteria (i.e. change in law and force majeure)
- **New Zealand** – provided criteria for pass-through costs that are unforeseen (i.e. outside utility's control, cannot be accurately forecasted)
- **Ontario** – events will be subject to the three criteria of causation, materiality, and prudence and will be on application by next rate filing

- **Lower load/customers due to overall economy:** Regulated rates, both in COS and PBR frameworks, are often set on a volumetric basis, which may expose utilities to volumetric risks.[212] In case of a recession, if overall energy consumption and load falls, it can reduce the overall revenue for the utility. Note however, that regulatory constructs such as variance accounts can allow a utility to recover these lost revenues in future years. For example, the Alberta Utilities Commission approved a volume variance account for transmission access charges, given electricity distributors have little control over their transmission volumes.[213] Competitive generation utilities would also be impacted by lower overall energy consumption, though peaking plants could be impacted the most. A diversified supply mix, which includes baseload generation, would protect a generator from undue exposure to this risk.

- **Fuel price increases for power generation:** Generally speaking, in well-designed regimes, cost of service utilities are able to pass fuel prices through to consumers. A Fuel Adjustment Mechanism ("FAM") is one regulatory practice to allow for timely recovery of fuel costs. Nova Scotia Power has a FAM currently, which adjusts rates to account for the actual cost of fuel (rather than the forecasted fuel cost).[214] In a deregulated market, the risk of fuel price increases depends on the generators hedging capabilities and trading strategy.

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[212] MIT. *The Future of the Electric Grid*. December 2011. P 182. <http://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf>

[213] AUC. *Rate Regulation Initiative Distribution Performance-Based Regulation*. September 12, 2012. <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

[214] Nova Scotia Power. *Fuel Adjustment Mechanism (FAM)*. <https://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/rates/fam.aspx>

Commodities trader Cargill reported to have lost $100 million due to cold weather in 2014

Hedging and trading strategies can cause dramatic losses in abnormal market conditions. It was reported that the commodity trading company, Cargill, lost over $100 million due to the cold weather conditions of early 2014. The cold weather caused significant increases in electricity and natural gas prices, which would cause losses in short positions.

Source: Reuters. *Cargill loses $100 mln in U.S. winter energy trade –SparkSpread*. Feb 20, 2014. <http://www.reuters.com/article/2014/02/20/cargill-energy-idUSL2N0LP2LX20140220>

- **Rising interest rates**: Utilities are currently in a very low interest rate environment, as can be observed in the chart below. It is expected that interest rates will rise from these very low levels in the next several years,[215] which can bring about risks for utilities. Many utility stocks are valued for their yield for investors, paying high dividends with respect to the share price. As interest rates rise, these stocks are less valuable to investors, and the company would expect to see a decrease in value.[216] Furthermore, as discussed in greater depth in Section 5.3.1, interest rates are used to set the allowed return on the regulated asset base ("RAB") for utilities. The risk for regulated utilities is that the allowed cost of capital doesn't reflect the prevailing cost of capital, which constrains the long term ability of the company to invest. For unregulated companies, there is a risk for the value of their assets to fall on a net present value basis, as well as simply higher debt costs.

Figure 93. Historical Canadian interest rates

Source: Bank of Canada. *Bank Rate*. <http://www.bankofcanada.ca/wp-content/uploads/2010/09/selected_historical_page1_2_3.pdf>

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215 Wall Street Journal. *Bank of Canada Seen Standing Pat on Interest Rates; All Eyes on Inflation Outlook*. Apr 15, 2014.

216 CNBC. *Stock market already feeling sting of higher rates*. <http://www.cnbc.com/id/101012580>

5.2.3 Technological risks

Technological risks for utilities include lower load/customers due to conservation, loss of load due to distributed generation, and capital costs associated with disruptive technology.

- **Lower load/customers due to conservation:** Energy conservation efforts of all types, from efficiency programs to building design to demand response, target reduced peak load and overall consumption. Similar to risks due to lower load from the overall economy, volumetric rates may expose utilities to volumetric risks, though regulatory constructs can allow a utility to recover these lost revenues in future years. The risk associated with volumetric rates has been noted as a clear disincentive for utilities to pursue conservation and energy efficiency measures, and the regulatory mechanism often used to recoup related lost revenues is known as a Lost Revenue Adjustment Mechanism ("LRAM"). US states which have implemented an LRAM include Colorado, Kentucky, Louisiana, North Carolina, South Carolina, Ohio and Oklahoma.[217]

Conservation efforts

- **Ontario**: Ontario has conserved 8.6 TWh of energy between 2005 and 2013. The Long Term Energy Plan considers conservation as "the first resource to be considered", with a goal of 30 TWh of conservation in 2032
- **New York**: The New York State Energy Plan includes a goal to "reduce electricity use by 15 percent from forecasted levels by the year 2015 through new energy efficiency programs in industry and government"

- **"Cutting the cord"**: With the introduction of distributed generation, not only is there a risk of lower load, but also the risk that loads may disconnect from the grid entirely. The Edison Electric Institute ("EEI") published a 2013 report which highlighted the risk of DG capturing "market share" from utilities as a significant disruptive challenge.[218] Others in the industry have also taken notice, including David Crane, chief executive officer of NRG Energy, who is concerned that "utilities will get trapped in an economic death spiral as distributed generation eats into their regulated revenue stream and forces them to raise rates, thereby driving more customers off the grid."[219] In order to hedge this risk, NRG has identified growth areas in self-generation for businesses and homes,

[217] American Council for an Energy-Efficient Economy. *Incentivizing Utility-Led Efficiency Programs: Lost Margin Recovery*. <http://www.aceee.org/sector/state-policy/toolkit/utility-programs/lost-margin-recovery>

[218] Edison Electric Institute. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. January 2013. <http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf>

[219] Bloomberg Businessweek. *Why the U.S. Power Grid's Days Are Numbered.* August 22, 2013. <http://www.businessweek.com/articles/2013-08-22/homegrown-green-energy-is-making-power-utilities-irrelevant>

as well as more comprehensive off-grid solutions.[220] Competing in the distributed generation is a way for competitive generators to mitigate this risk.

- **Capital costs associated with disruptive technology:** There are a number of disruptive technologies which may influence the way that utilities do business. In Section 5.1.2, the reliability impacts of distributed generation and intermittent resources on consumers have been discussed. Another such technology could be the widespread use of electric vehicles ("EVs"); concern has been raised on the role of significant EV charging overnight, and the impact this would have to reliability and service life of the distribution system, due to the increased time that equipment operates at high temperatures.[221] Other studies raise concerns about increased load, citing that charges draw an electrical load equivalent to a house, and controlling times at which EV load is applied to the grid.[222] In terms of capital costs, a study conducted by PWC for the Austrian Climate Research Programme estimated that 2,800 charging points would be required for 1 million EVs to be introduced in cities, at a cost of $111 million euros (approximately $170 million Canadian dollars).[223] The risks posed by these technologies, assuming capital investments are made to address them, is that these capital investments would not be recovered. This risk has been discussed in Section 5.2.1.

For conclusions and relative ranking of risks, refer to Section 5.4.

5.3 Consideration of risks factors in setting a reasonable rate of return for utilities

Utilities face risks related to setting an allowed return on regulated asset base. If the allowed rate doesn't reflect the prevailing cost of capital, this constrains the long term ability of the company to invest. Furthermore, any changes to the rate of return of a utility impact consumers through price changes.

These risk factors can change depending on the structure of the market. Unbundling allows for more precise targeting of cost of capital determinations. Within a vertically integrated utility, there are individual risks associated with the generation, transmission, and distribution businesses. There are relative levels of risk associated with the various businesses across the value chain, where the vertically integrated utility can be considered to have a weighted average risk of all the businesses. Generally speaking, the unbundled generation business will have risks greater than the vertically integrated utility, while the transmission and distribution

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220 Utility Dive. *Facing decline, NRG Energy forges new business models*. March 4, 2014. <http://www.utilitydive.com/news/facing-decline-nrg-energy-forges-new-business-models/234896/>

221 Pacific Northwest National Laboratory. *Technical Challenges of Plug-In Hybrid Electric Vehicles and Impacts to the US Power System: Distribution System Analysis*. P. 3. January 2010. <https://www.smartgrid.gov/sites/default/files/resources/phev_distribution.pdf>

222 Silver Spring Networks. *How the Smart Grid Enables Utilities to Integrate Electric Vehicles*. <http://www.silverspringnet.com/pdfs/whitepapers/SilverSpring-Whitepaper-ElectricVehicles.pdf>

223 PWC. *The impact of electric vehicles on the energy industry*. <http://www.pwc.com/en_GX/gx/energy-utilities-mining/pdf/electricvehicles-austrianclimateresearch.pdf>

businesses will have lower risks than the vertically integrated utility. The higher risk businesses should expect to see higher return.

The way in which the wires business is regulated after deregulation can also impact risks levels. Certain utilities argue that PBR regulation subjects them to greater amount of risk. For example, Enmax Power Company has argued in regulatory proceedings that "variability of EPC's ROE for both Transmission and Distribution suggests that EPC's risk may have increased as a result of being subject to the FBR framework."[224] Utilities argue that this risk should result in a higher allowed ROE, while regulators argue that the opportunity to earn more than the allowed ROE (through an earnings sharing mechanism, for example) is sufficient compensation.

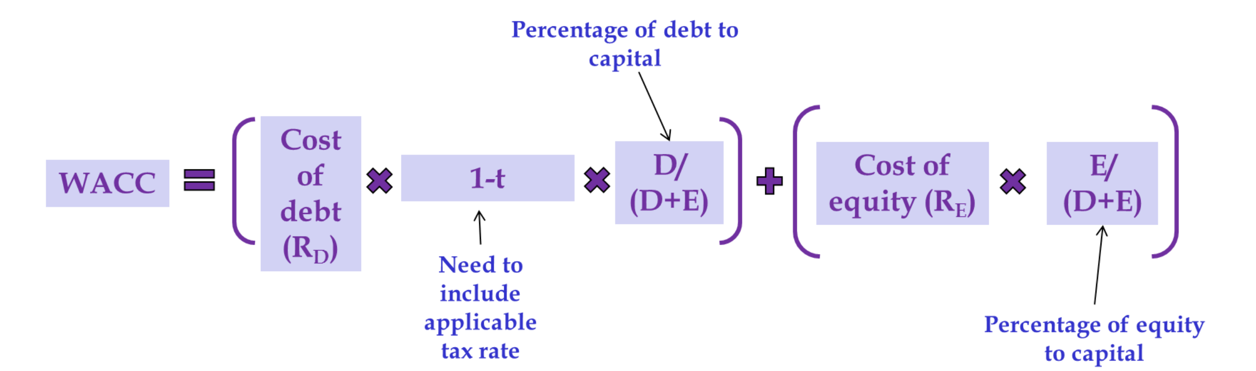
This section will discuss the calculation of WACC, the formulaic determination of return on equity, and highlight areas in which risk exist.

5.3.1 Weighted average cost of capital ("WACC")

The determined WACC is the allowed return on the regulated asset base for utilities. Utilizing WACC as an allowed return can be seen in both PBR and COS regimes. For example, in Australia, which is a PBR regime, the Australian Energy Regulator ("AER") applies a permitted WACC to regulate the return. In Hong Kong, which is a COS regime, the return on assets ("ROA") applied can be considered a form of WACC.

WACC rests upon four key components: the cost of debt, the cost of equity, the optimal capital structure, and the corporate tax rate. Both of the first two components, cost of debt and cost of equity, take risk factors into consideration.

Figure 94. Formula for calculating the post-tax weighted average cost of capital (WACC)



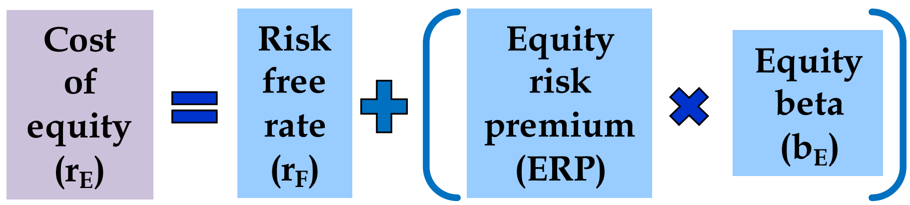
The first component, the cost of debt, is a simple summation of the risk-free rate and the debt premium for the distribution companies. For cost of debt, it is the debt premium which takes

[224] ENMAX Power Corporation. *Regulated Rate Initiative, Application No. 1606029, Proceeding ID. 566.* December 16, 2011. P 11.

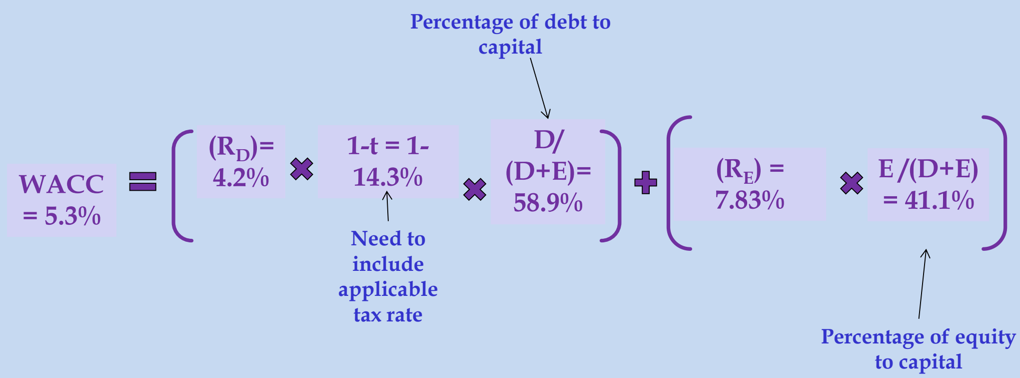
risk factors into consideration. The debt premium is the premium charged for a company with a similar risk profile to the electricity distribution company, relative to the risk-free rate. This premium can change depending on whether the company is vertically integrated or deregulated, where it would be expected that deregulated companies generally take on additional leverage due to stable cash flows but would have higher debt premiums.

The second component of the WACC formula is the cost of equity, which is calculated according to the Capital Asset Pricing Model ("CAPM"). This consists of the already calculated risk free rate, the equity risk premium and the equity beta.

Figure 95. The CAPM Model



Weighted Average Cost of Capital – Nova Scotia Power



Each WACC component is approved in a general rate structure, based on market conditions and appetite for risk. The effective tax rate is based on approved, forecasted total tax expenses as a percent of pretax income. Cost of debt is based on historical debt issuances, while cost of equity is based on historical equity beta and an equity market risk premium.

Source: Nova Scotia Power. *2013 General Rate Application.* July 23, 2013

The equity risk premium is defined as the rate by which equity market returns have historically exceeded the risk free rate, however, this is not related to a particular company's risk profile. Equity betas measure the element of non-diversifiable or market risk related to investment in a company's equity, with higher positive equity betas signifying a greater correlation between the returns from a company's equity and the returns in the market. The equity beta is the component which takes risk factors of the company into consideration, where it would be expected that deregulated companies have a greater beta.

To summarize, the debt premium and equity beta are the metrics in which risk associated with a company's regulated structure are captured. As an example, LEI has performed an indicative WACC calculation for a selection of large regulated companies, and compared that to the WACC calculation of a selection of competitive IPPs.

Figure 96. Assumptions used for large IPPs

Company Name	2006-2013 Beta	2006-2013 Average Debt/Equity ratio	2006-2013 Unlevered Beta*	Corporate Bond Rating
AES	1.09	2.09	0.42	BB-
Boralex	0.76	1.32	0.38	BB-
Calpine	1.08	1.66	0.48	BB
NRG	1.01	1.56	0.47	BB-
TransAlta	0.68	0.76	0.43	BBB-
Average	0.93	1.48	0.44	BB-

*** Assumes a corporate tax rate of 25%**

Figure 97. Indicative unregulated IPP WACC calculation

	Reference	Calculations	Unregulated IPP
Cost of Equity			
risk-free rate	a		5.0%
equity risk premium	b		4.2%
unlevered beta	c		0.44
relevered beta	d	= c x (1+((1-l))x (i / (1-i)))	0.92
Estimated pre-tax Cost of Equity	e	= a + (b x d)	8.8%
Cost of Debt			
risk free rate	f		5.0%
debt premium	g		2.6%
Estimated pre-tax cost of debt	h	= f + g	7.6%
Capital structure (debt/capital)	i		*60%*
Estimated pre-tax WACC	j	= (i x h) + ((1-i) x e)	8.1%
Estimated post-tax WACC	k	= (i x h x (1-l)) + ((1-i) x e)	**6.9%**
Other assumptions			
Corporate Tax rate	l		*25.0%*

For IPPs, AES, Boralex, Calpine, NRG and TransAlta were considered. To calculate WACC, LEI used the 15-year average return on 30-year T-bonds as the risk free rate,[225] US average premiums of US equities over US 10 year Treasury bonds as the equity risk premium, 10-year average yield spread for BB- rated companies for debt premium,[226] and the assumptions described above for beta and capital structure.

Figure 98. WACC calculations for regulated utilities in regulatory filings

	Duke Energy Carolinas	FortisBC	Southern California Edison	Average
Cost of Debt	5.06%	5.79%	5.53%	5.46%
Cost of Equity	9.00%	10.52%	6.69%	8.74%
Tax	40%	25%	22%	29%
% Debt	47%	60%	43%	50%
% Equity	53%	40%	57%	50%
Post-tax WACC	6.2%	6.8%	5.7%	6.2%

Sources: SC PSC, FortisBC, Southern California Edison

LEI then considered regulated WACC determinations, as described above. As expected, given the additional risk taken on in a competitive market, unregulated IPPs have a higher indicative WACC than regulated companies. ***For deregulation to be beneficial, efficiencies gained through competition must be greater than the higher return earned by unbundled generators.***

5.3.2 Size and liquidity premium

Returns can be adjusted for a size premium, which is the theory that smaller firms have higher returns than larger ones. The size premium was first identified in 1981 by Rolf W. Banz,[227] and shows that small companies have greater returns than even their greater beta risk (in the context of the CAPM model) would indicate.

[225] The 15 year average was used, given a 5 year average would have included only post-recession values, and a 10 year average includes the period between 2003 and 2005 for which 30-year t bonds were not sold.

[226] Averaged yield spread of BB and B rated companies.

[227] Rolf W. Banz. *The Relationship Between Returns and Market Value of Common Stocks*. Journal of Financial Economics, Volume 9. 1981.

Figure 99. Historical size premiums (1926 to 2010)

Decile	Beta	Size premium (return in excess of CAPM)
Mid-cap (3-5)	1.12	1.20%
Low-cap (6-8)	1.23	1.98%
Micro-cap (9-10)	1.36	4.07%

Source: 2011 Ibbotson Stocks, Bonds, Bill and Inflation Classic Yearbook. *Chapter 7: Firm Size and Return.* Table 7-6. P 103

Another adjustment to returns could be for the liquidity premium, which is the premium required for illiquid assets. It is the extra return an investor demands to hold a security that cannot be costlessly be traded; although this is similar to a transaction cost, it can also be considered to be related to the risk of having to transact quickly. A common way to calculate this is to add a liquidity premium into the discount rate, as it can be considered to cause a higher discount rate.

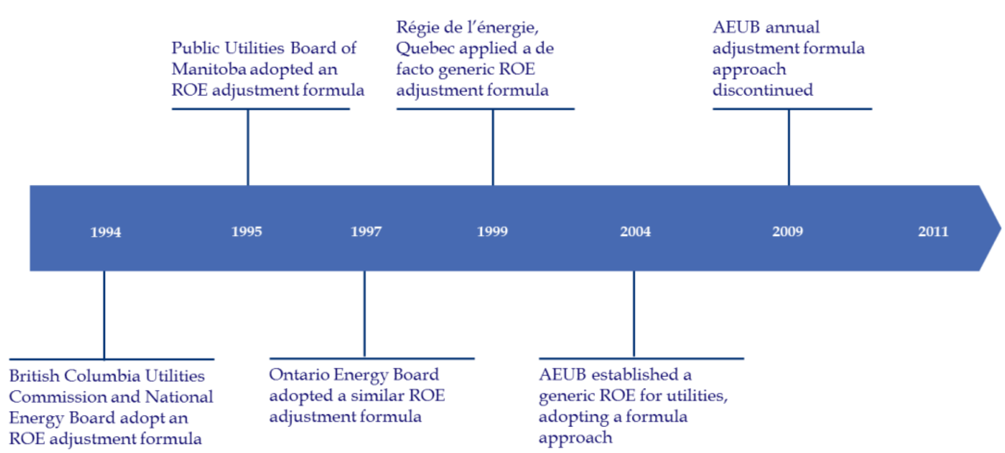
Figure 100. Historical returns of liquidity quartiles (1972 to 2010)

Quartile	Arithmetic mean of annualized raturns
1 - Less Liquid	17.94%
2	16.34%
3	15.04%
4- More Liquid	12.60%

Source: 2011 Ibbotson Stocks, Bonds, Bill and Inflation Classic Yearbook. *Chapter 9: Liquidity Investing.* Table 9-1. P **116**

5.3.3 Formulaic determination of return on equity

Figure 101. History of formulaic ROE in Canada



Many jurisdictions use or have used a formulaic approach for determining annual adjustments in generic ROE; in Canada, this practice was first utilized in 1994. These formulaic approaches are used to determine the subsequent generic ROE, based on the initial ROE and taking into account some change.

For example, in 2004, the Alberta Energy and Utilities Board ("AEUB") established a single generic ROE, and a formula approach for determining annual adjustments as follows:

ROE_{New} = Initial ROE + 75% × (Change in forecast 30-year Government of Canada bond yield)

However, this was discontinued in 2009, as the AUC concluded that the historical relationships upon which the formula was based had not been re-established after the financial crisis. The original formula was developed based on the expectation that the required rate of return for utilities moved in the same direction as the return on 30-year bonds. The AUC found that after the financial crisis, this expected relationship between interest rates and the required return on equities did not necessarily hold.

The risk that exists when a regulator chooses a formulaic approach in setting an ROE is that if the assumptions used are no longer true, the formula will set an ROE which is not appropriate for the market conditions, impacting the ability of the utility to earn a fair return on their investment.

5.4 Key conclusions and risk magnitude rankings

The purpose of this section was to introduce some of the risks which are faced by both consumers and utilities, and discuss how these risks might be impacted or mitigated through the energy market and regulatory structure. LEI also introduced methods in which reasonable rates of return are set, and highlighted which elements can be impacted by risk.

To conclude, the various risks have been ranked indicatively. The following figures show a graphical representation of LEI's indicative risk ranking, where risk factors at the top of the graphic may have the most severe consequences, while the risk factors at the bottom of the graphic may be least impactful. These rankings are indicative, as each risk factor could manifest itself in different ways, however, LEI has provided general ranges of magnitude. This is shown in graphical form in Figure 102 as well as tabular form in Figure 103 (where higher numbers have higher magnitude and probability).

For consumers, reliability related risks are those which have the greatest impact, and are therefore ranked as the risk with the greatest magnitude of impact. Imprudent capital investment in an extreme case can be a considered a high magnitude impact as well, as the significant capital costs associated with power projects can have a large impact on prices paid by consumers. However, in a more typical case, impact to consumers can be considered moderate. The prices of fuel would have a lower impact to prices than capital costs, due to the relative magnitude of fuel costs compared to capital costs, and environmental attribute costs are likely to have an even smaller impact. The risk factors with the lowest magnitude impact to consumers may be low service quality and customer service.

Figure 102. Indicative magnitude and probability of impact to consumers (chart)

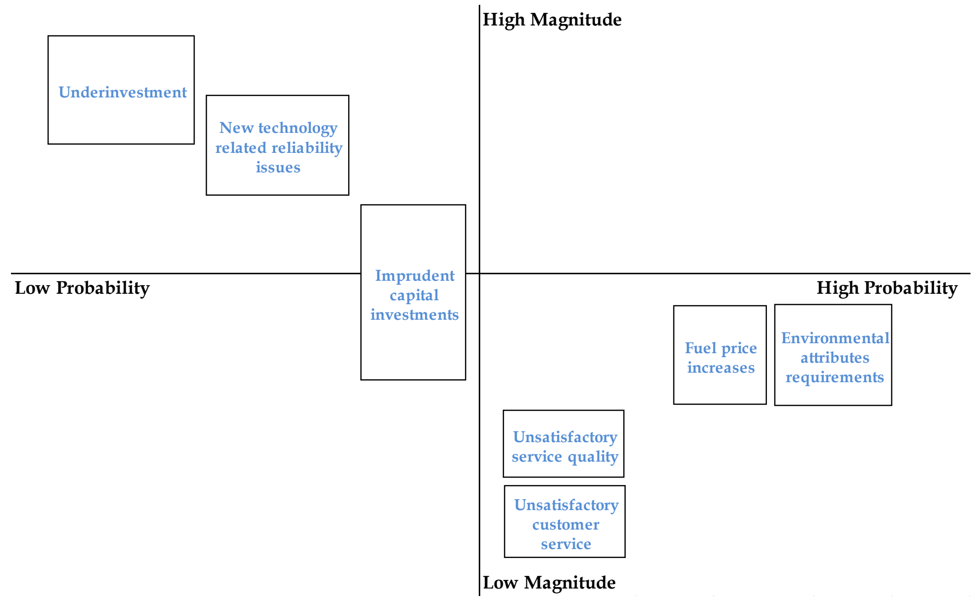


Figure 103. Indicative magnitude and probability of impact to consumers (table)

Types of risks	Probability (1-5)	Magnitude (1-5)	Indicative quantification ($ millions annually)	Description of indicative quantification
Fuel price risk	4	3	$28	In 2013, NSP fuel costs were $557 million. A 5% increase in fuel costs would cost consumers $28 million.
Imprudent capital investments	3	3	$33	Cost overruns of about $1 billion at Edwardsport Indiana coal gasification plant is used as an indicative imprudent capital investment. This cost was estimated to be spread over a 30 year asset life.
Environmental attributes	5	3	$35	Given 2013 NSP coal production of approximately 7 TWh, and average production of CO2 of 1 ton per MWh, and assuming carbon prices similar to the current RGGI price of approximately $5/ton.
Underinvestment	1	5	$63	ICF Consulting performed a New England Value of Lost Load ("VOLL") study, which analyzed the drop in economic output observed across states and urban and rural areas, relative to the amount of energy unavailable (in MWh). LEI has conservatively used the lower bound estimate of $10,000/MWh. Applying the peak Nova Scotia load of about 2,100 MW and an average increase of 3 hours of outages as a result of underinvestment, customers stand to lose about $63 million.
Reliability problems associated with distributed generation	2	5	$42	A increase of 2 hours of outages as a result of reliablity problems associated with distributed generation, based on the above indicated US VOLL, would be about a $42 million cost to consumers.
Reliability problems associated with intermittent resources	2	5	$42	A increase of 2 hours of outages as a result of reliablity problems associated with distributed generation, based on the above indicated US VOLL, would be about a $42 million cost to consumers.
Unsatisfactory service quality provided by distributors	3	2	$13	NSP reported $1.3 billion in 2013 sales. If total customer metering errors averaged 1% annually, it would result in $13 million in cost to customers.
Unsatisfactory customer service provided by retailers	3	1	<$1	The Pennsylvania PUC rejected a penalty of $75,000 for "slamming" techniques used by Pennsylvania Gas & Electric.

Source: AER, NSP, PaPUC, AP

In terms of probability of risk for consumers, the highest magnitude risks have the lowest probability, particularly when it comes to reliability issues. Fuel price increases and environmental attribute requirement risks have the highest probability.

The following figure shows LEI's indicative ranking of risk magnitude for utilities. The three risks with the largest magnitude are also those which are likely to involve significant amounts of capital. Inability to recoup extraordinary costs and capital expenditures are likely the largest risks. Insufficient productivity increases can be considered a moderate sized risk, while lower load and fuel price increases being the least impactful. The latter two are also most likely to have related variance accounts. These have also been quantified in terms of probability, where inability to recover of stranded costs and extraordinary costs are low probability, inability to recover capital costs and insufficient productivity increases are moderate, while low load and fuel price increases are relatively higher probability.

Figure 104. Indicative magnitude and probability of utility risks (chart)

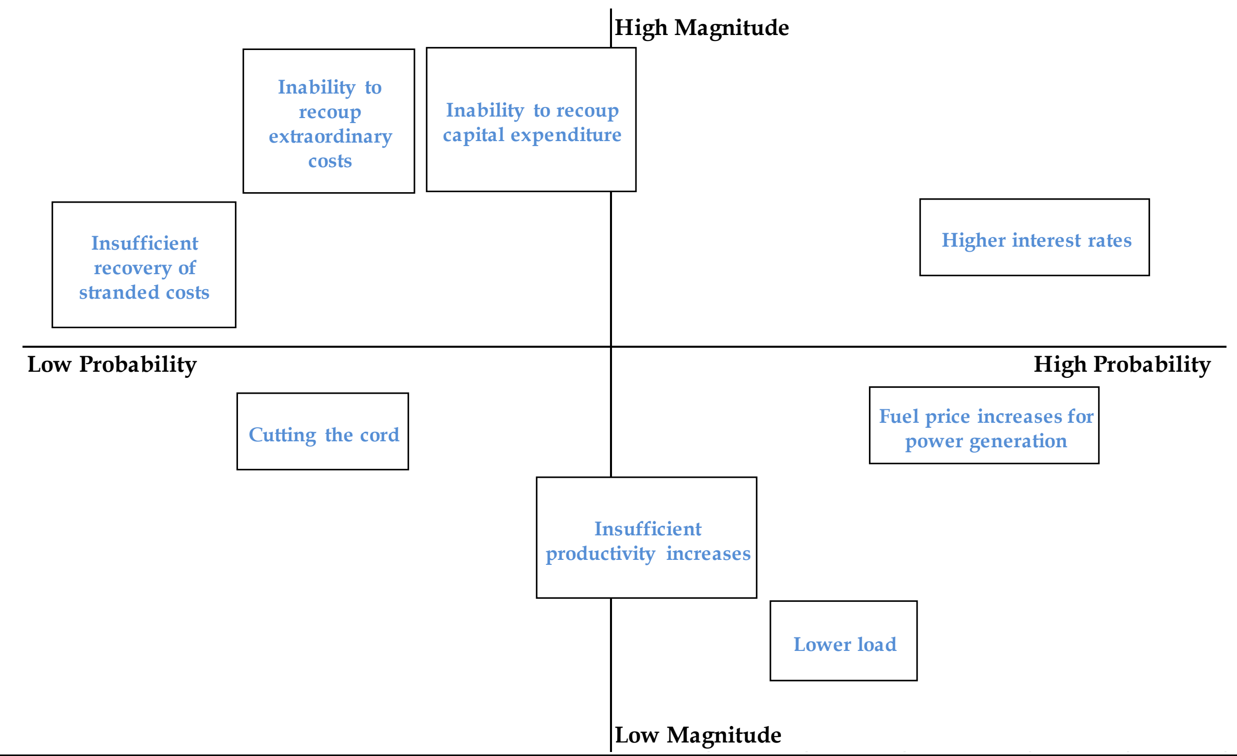


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Figure 105. Indicative magnitude and probability of utility risks (table)

Types of risks	Probability (1-5)	Magnitude (1-5)	Indicative quantification ($ millions annually)	Description of quantification
Insufficient recovery of stranded costs	1	4	$5	In 2012, Nova Scotia Power ("NSP") sought exit fees from municipal utilities who were seeking supply from third-party supplies. NSP requested $23.8 million in exit fees over five years
Inability to recoup capital expenditure	3	5	$10	Fortis Alberta is regulated under a PBR regime and without a K factor would have potential shortcomings of capital funding. For example, depreciation expense for electrical poles from the 1950s, reinvested to keep pace with inflation, would provide $390 per pole to replace a pole which now costs on average $2,250. In 2009, Fortis Alberta replaced about 5,500 poles. Without a separate K factor, Fortis would stand to lose about $10 million.
Insufficient productivity increases	3	2	$2	Central Maine Power is a CPI-X, PBR regulated utility. If its productivity comes in 0.5% below its targeted X factor of 1%, costs will be 0.5% higher than regulated revenues. With 2012 CMP total operating expenses of $429 million, 0.5% is $2.1 million.
Inability to recoup extraordinary costs	2	5	$10	In California, Southern California Edison had calculated a materiality threshold value of $10 million for extraordinary events in its PBR regime ending 2003.
Lower load due to overall economy/conservation	4	1	$1	NSP reported $1.3 billion in 2013 electricity sales. Assuming these are all volumetric, if 1% of a 10% decrease in sales was not captured through a variance account, the utility would lose $1.3 million.
"Cutting the cord"	2	3	$4	NSP reported $1.3 billion in 2013 electricity sales. If 1% of a 30% decrease in sales was not captured through a variance account, the utility would lose nearly $4 million.
Fuel price increases for power generation	5	2	$3	In 2013, NSP fuel costs were $557 million. Assuming a 5% increase in fuel costs would result in $28 million of additional costs. If, hypothetically, NSP were unable to recoup 10% of the increase in fuel costs, NSP would stand to nearly $3 million.
Higher interest rates	5	4	$6	In 2013, Boralex reported $977 million in total debt. Assuming a 2% increase in interest rates impacted the costs of 30% of all debt, this would result in additional costs of $6 million.

Sources: CMP, Fortis Alberta, NSP, CAPUC

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6 Appendix A – Experience for setting rate of return in other jurisdictions

The following section discusses experience in other jurisdictions for setting rate of return, and further highlights the importance of benchmarking for setting such a return. In the context of these international and domestic examples, LEI does not consider NSP's allowed return to be anomalous, both in terms of process and the outcomes.

6.1 International experience in valuing rate base and regulating permitted return

This section presents examples of regulatory regimes in electricity markets using different approaches in regulating permitted rate of return. It should be noted that these examples present only a single aspect of many possible designs within a certain regulatory approach.

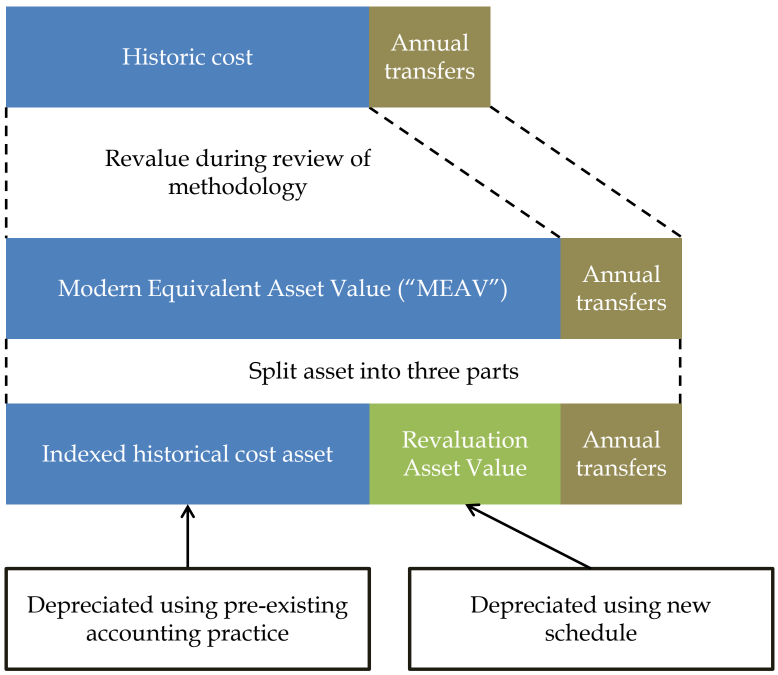
Figure 106. Valuing rate base – international examples

Jurisdiction	Asset valuation method	Details
South Africa	Depreciated replacement cost	- WACC - Actual borrowing cost of Eskom as the cost of debt - Cost of equity is calculated using the CAPM formula - Deemed debt-capital ratio of 60%
Australia	Depreciated replacement cost	- WACC, fixed for 5 years - Deemed debt-capital ratio of 60% - Cost of debt is determined at the beginning of a review period using the nominal risk free rate (yield on 10-year Australian government bond) plus the debt risk premium determined by the spread on 10-year BBB+ rated corporate bonds - Cost of equity is calculated by assuming the market risk premium, currently set at 6.5% and the equity beta of 0.8
United States	Historical test year rate base or a future year rate base	- Regulators set an allowed ROE for each utility during their rate review - ROE is applied to calculate the WACC - Cost of debt is usually based on the actual average bond yield of the utility - Company specific capital structure

6.1.1 South Africa

In an effort to review the multi-year price determination methodology used to regulate the electricity market in South Africa, the National Energy Regulator of South Africa ("NERSA") published a consultation paper with recommendations that Eskom, the *de facto* monopoly that generates 95% of electricity used in South Africa, should be regulated under a regulatory regime using depreciated replacement cost ("DRC") as the asset valuation method and a permitted rate of return based on WACC.

Figure 107. NERSA's proposal in implementing DRC



Note: Annual transfers relate to state-owned entities that are unable to cover their expenses through generation of income.

For the DRC valuation method, NERSA recommended the use of the Modern Equivalent Asset Value ("MEAV") approach, which is defined as "the current cost of acquiring a present day asset that could provide a similar level of service to the asset in question". Furthermore, to avoid shortening of asset lives, double dipping and front loading of depreciation, NERSA recommended that assets be split into three parts: (i) the existing indexed historical cost asset base, (ii) annual transfers to commercial operation, and (iii) the revaluation asset value.

Among the three parts, the existing asset base was to continue to depreciate using pre-existing accounting practice, and a new deprecation schedule was to be applied on the revaluation asset value, defined as the difference between the existing asset base and the revalued asset base. Figure 107 illustrates NERSA's proposal in implementing DRC.

For the permitted rate of return, NERSA recommended the use of a permitted WACC on the rate base. NERSA proposed to use actual borrowing cost of Eskom as the cost of debt input into the WACC formula with a deemed debt-capital ratio of 60%. The cost of equity is calculated using the CAPM formula. As the cost of debt would follow market conditions, and the capital structure is set by the regulator, this approach in regulating the permitted rate of return is essentially regulating the ROE of Eskom.

For Eskom's 2013/2014 to 2017/2018 Multi Year Price Determination, the following WACC was used:

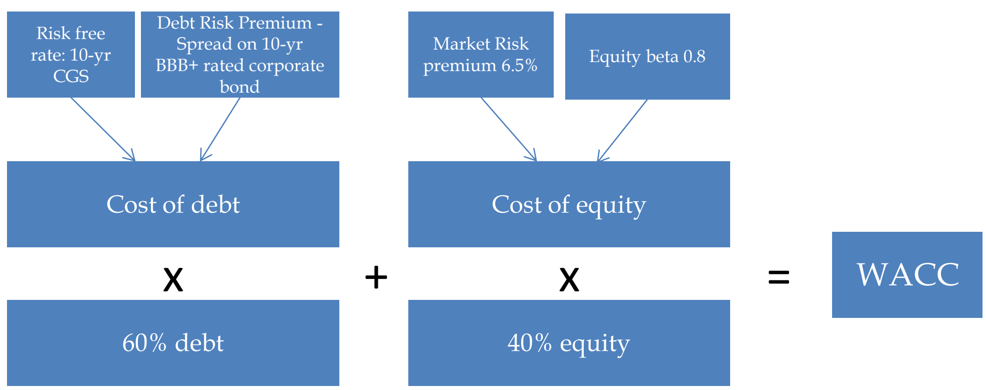
Figure 108. Eskom's 2013/2014 to 2017/2018 Multi Year Price Determination WACC

	2013/14	2014/15	2015/16	2016/17	2017/18
Real Pre-tax WACC	3.4%	3.8%	3.7%	3.9%	4.7%

Source: NERSA. *Revenue Application - Multi Year Price Determination 2013/14 to 2017/18 (MYPD3)*. P 12 <http://www.eskom.co.za/CustomerCare/MYPD3/Documents/NersaReasonsforDecision.pdf>

6.1.2 Transmission network in Australia's National Electricity Market

Figure 109. AER's method to calculate WACC



CGS: Commonwealth Government Securities, which are Australian government bonds.

In states and territories connected to the National Electricity Market ("NEM") in Australia (Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia and Tasmania), transmission networks are regulated by the AER. For regulations related to return on capital, AER applies the DRC approach to determine the rate base, and a permitted WACC to regulate the return.

For the DRC valuation approach, the asset base is calculated by rolling forward the asset base at the start of the period, and adjusting it for depreciation, capital expenditure, and Consumer Price Index ("CPI"). As such, the DRC valuation approach is in line with the CCV approach described earlier.

AER's method to calculate WACC is presented in Figure 109. For calculation of WACC, AER sets a deemed debt-capital ratio of 60%, and the cost of debt is determined at the beginning of a review period (usually every 5 years) using the nominal risk free rate, which is determined by the yield on 10-year Commonwealth Government Securities ("CGS", the Australian government bond) plus the debt risk premium determined by the spread on 10-year BBB+ rated corporate bonds. The cost of equity is calculated by assuming the market risk premium, currently set at 6.5%, and the equity beta of 0.8. This determines WACC, which is fixed over a 5-year review period.

In 2012, AER approved the nominal WACC of 8.6% for PowerLink in Queensland, while in 2009 AER approved the nominal WACC of 10.1% for TransGrid in New South Wales.

6.1.3 ROE in selected US states

In the US, where regulations on utilities differ from state to state, most regulators set an allowed ROE for each utility during their rate review. The ROE is applied to calculate the WACC, whereby the cost of debt is usually based on the actual average bond yield of the utility. To obtain the permitted return, the estimated WACC is applied to either a historical test year rate base or a future year rate base. When historical years are used, traditional accounting principles generally recommend using the average rate base as the valuation methodology.

For example, in May 29, 2008, the California Public Utilities Commission made the decision (Decision 08-05-035) to establish a uniform multi-year cost of capital mechanism ("CCM") for Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company. Before the decision, major energy utilities' capital structure and ROE were addressed in their respective general rate case applications. As these rate cases became more and more complex, the burden on reviewing rate cases on the Commission increased. A uniform multi-year CCM was implemented to simplify the ratemaking process and reduce the burden on the Commission.

Under the decision, the three utilities are required to calculate their cost of capital using the most recently adopted capital structure, and a dead-band of 100-basis points. The approved "*ROE is adjusted by one-half of the difference between the Aa utility bond average for AA credit-rated utilities or higher and Baa utility bond average for BBB credit-rated utilities or lower and a Moody's AA benchmark*."[228] Essentially, California has set up an automatic mechanism for determining the permitted ROE. Given the capital structure and actual cost of debt, the resulting cost of capital is the allowed rate of return on the rate base.

South Dakota is another example where fixed assets are used as rate base and permitted rate of return is based on a permitted ROE. In South Dakota, the applied rate base is calculated as a 13-month average of the rate base per book value for the test period.

During a rate case filing, in addition to submitting an ROE for approval, the company also has to submit a capital structure and a cost of debt. The company has to justify the reasonableness of the capital structure, for example, by comparing the proposed capital structure to a proxy group of companies. The company also has to justify its long-term cost of debt, e.g., by comparing the cost of its long-term debt issuance with a utility index. Analyzing these components underlying the cost of capital, the Public Utilities Commission decides on the reasonableness of the rate case.

Figure 110. Adjusting ROE in the California regulatory regime

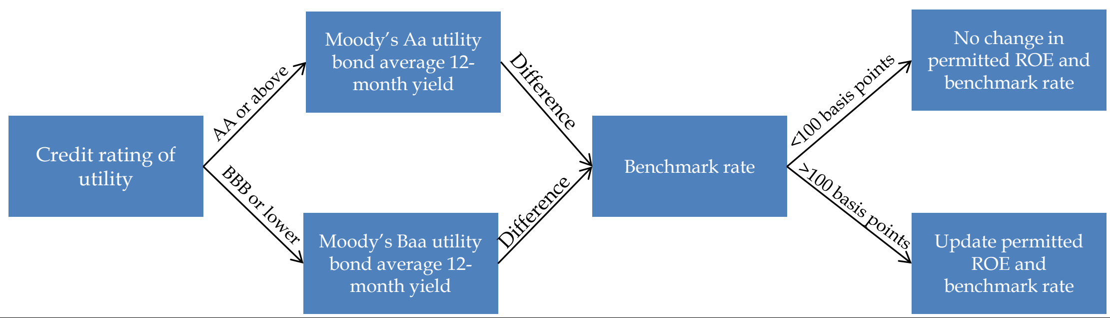


Figure 111 shows the authorized return on equity approved in the US since 2011. The average ROE has been 10.4%.

Figure 111. Authorized Return on Equity for US electricity utilities, since 2011

Order Date	Company	Docket or Document	Authorized ROE
1/5/2011	Public Service Co. of Oklahoma	201000050	10.2%
1/10/2011	Interstate Power & Light Co.	RPU-2010-0001, 287 PUR4th 201	10.0%
1/12/2011	Madison Gas & Electric Co.	3270-UR-117	10.3%
1/13/2011	Wisconsin Public Service Corp.	6690-UR-120, 286 PUR4th 341	10.3%
1/24/2011	Niagara Mohawk Power Corp.	10-E-0050, 286 PUR4th 401	9.3%
1/27/2011	Texas-New Mexico Power Co.	38480	10.1%
1/31/2011	Western Massachusetts Electric Co.	25842	9.6%
2/28/2011	PacifiCorp dba Rocky Mountain Power	PAC-E-10-07	9.9%
3/9/2011	Baltimore Gas & Electric Co.	9230, 288 PUR4th 25	9.9%
3/10/2011	Ontario Power Generation Inc.	ER-2010-0008	9.4%
3/25/2011	Southwestern Public Service Co.	38147	10.0%
3/25/2011	PacifiCorp dba Pacific Power & Light Co.	UE-100799, 287 PUR4th 333	9.8%
3/30/2011	Appalachian Power Co. & Wheeling Power Co.	10-0699-E-42T, 288 PUR4th 185	10.0%
4/12/2011	Kansas City Power & Light Co.	ER-2010-0355	10.0%
4/14/2011	Southern California Edison Co.	10-08-001	11.5%
4/25/2011	Otter Tail Power Co.	E017/GR-10-239, 288 PUR4th 490	10.7%
4/26/2011	Unitil Energy Systems	DE 10-055, 290 PUR4th 307	9.7%
4/26/2011	Central Vermont Public Service Co.	7694	9.5%
4/27/2011	Southern Indiana Gas & Electric	43839, 289 PUR4th 9	10.4%
5/4/2011	KCP&L Greater Missouri Operations Co.	ER-2010-0356	10.0%
5/5/2011	Pacific Gas & Electric Co.	09-12-020	11.4%
5/12/2011	CenterPoint Energy	38339, 289 PUR4th 289	10.0%
5/24/2011	Commonwealth Edison Co.	10-0467	10.5%
6/8/2011	Montana-Dakota Utilities Co.	PU-10-124	10.8%
6/17/2011	Oklahoma Gas & Electric Co.	10-067-U, 290 PUR4th 457	10.0%
6/17/2011	Orange & Rockland Utilities, Inc.	10-E-0362	9.2%
6/28/2011	NorthWestern Energy	D2009.9.129 et al., 290 PUR4th 189	10.3%
7/12/2011	Northern States Power Co.	U-16475	10.3%
7/13/2011	Union Electric Co. dba Ameren Missouri	ER-2011-0028	10.2%
7/28/2011	Public Service Co. of New Mexico	10-00086	10.0%
8/1/2011	Fitchburg Gas & Electric Co.	41944	9.2%
8/9/2011	Delmarva Power & Light Co.	09-414	10.0%
8/12/2011	Interstate Power & Light Co.	E001/GR-10-276	10.4%
8/15/2011	Lockhart Power Co.	2010-181-E	12.0%
8/22/2011	Municipal Light (Alaska)	U-10-31	10.9%
5/16/2012	Commonwealth Elec. (Commonwealth Energy)	97-111 186 PUR4th 1	9.5%
5/16/2012	Cleco Power, LLC	U-21496-J	11.3%
5/16/2012	Southern California Edison Co.	D.02-11-027	11.6%
5/16/2012	Cleco Power, LLC	U-21496E	12.3%
5/16/2012	Cleco Power, LLC	U-21496F	12.3%
5/16/2012	Cleco Power, LLC	U-214964	12.3%
5/16/2012	Cleco Power LLC	U-21496-K	11.3%
5/16/2012	Cleco Power LLC	U-21496-L	11.3%

Source: Public Utilities Fortnightly. ROE Survey Database. Accessed 4/8/2014 http://www.fortnightly.com/online-databases/roe-survey

6.1.4 FERC Transmission Return on Equity

FERC approves all transmission ROE calculations, which in turn are used to set transmission tariffs. The basis for any approved transmission ROE standard is the "just and reasonable" rate of return standard for transmission owners. To determine whether or not a transmission company's ROE is just and reasonable, FERC sets a final ROE which is equal to a base ROE plus any potential adjustments. The base ROE is set using discounted cash flow ("DCF") analysis based on a relevant historical time period and based on a relevant group of industry peers.

In practice, determining relevant time periods and relevant industry groups can be contentious. Taking on an adjudicative function in a dispute over transmission tariffs between the New England Transmission Owners and a group of ISO-NE regulatory commissioners in 2012, FERC decided that a group of 28 national transmission owners (excluding a Hawaiian transmission owner for relevancy), was appropriate proxy group for use in calculating DCF inputs.[229]

FERC Transmission ROE Policy – New England Transmission Owners

A recent, prominent example of FERC setting transmission ROEs is that of the New England Transmission Owners ("NETO") in 2012. Initially, the NETO proposed for the transmission owners to remain at 11.14%. Complainants primarily composed of state regulatory commissioners and attorney generals argued that the ROE should be no more than 9.2%. At issue was the composition of relevant utilities making up a benchmark of comparables and the number of years deemed relevant necessary to set inputs in the DCF model necessary to set the base ROE. Included in the NETO proposal was a 74 basis point adder to account for changes in capital markets, which complainants deemed unnecessary. On August 6, 2012, FERC issued a ruling recommending a transmission ROE for the NETO or 9.66%

Sources: Coakley v. Bangor Hydro-Electric Co., 139 FERC ¶ 61,090 (2012) and McMahon, Bobby. "US FERC judge orders lower transmission rate of return in New England" *Platts*. Web. 7 August 2013.

Following a DCF analysis to set a base ROE, FERC considers various riders to add to the base ROE before setting the final ROE. In the 2012 New England Transmission Owners case, the transmission owners argued for an additional 74 basis point upward adjustment to account for changes in capital market conditions, citing precedent.[230] Following the Energy Policy Act of 2005, FERC has begun to provide adders to transmission ROE calculations to incentivize membership in RTOs, to compensate for increased utility risk accrued as a result of using new technologies and to promote critical infrastructure corridors. As such, it allowed Atlantic Grid Operations A LLC to add 50 basis points for its status in an RTO in 2011.[231] Also in 2011, it allowed the Northern Pass Transmission LLC a 166 basis point ROE adder for the unique nature of its transmission projects and its unique commercial structure.[232] For the use of advanced

[229] See Coakley v. Bangor Hydro-Electric Co., 139 FERC ¶ 61,090 (2012) ("Coakley").

[230] Ibid.

[231] Atlantic Grid Operations A LLC, 135 FERC ¶ 61,144 (2011)

[232] Northern Pass Transmission LLC, 134 FERC ¶ 61,095 (2011)

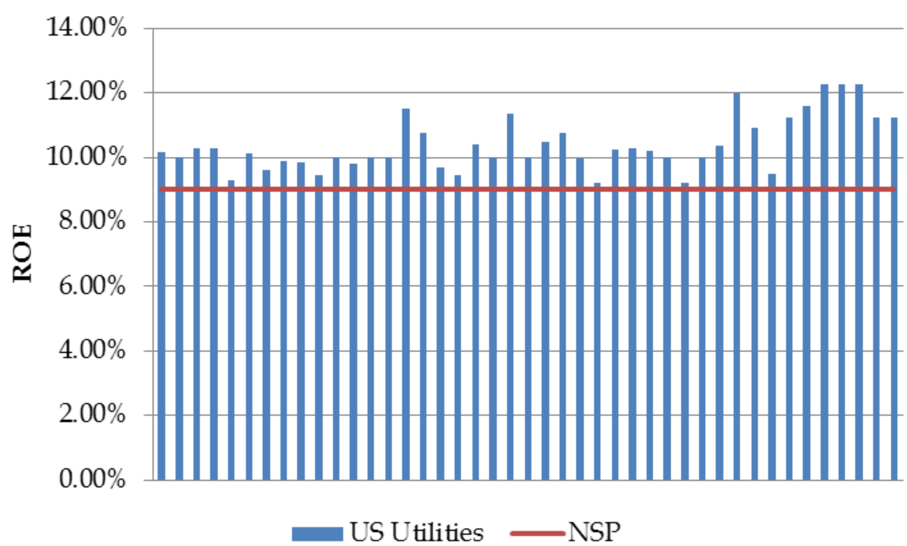
technologies, FERC also granted Desert Southwest Power to 50 basis point ROE adder.[233] In each of these examples, base ROEs were calculated using DCF analysis and supplemented with ROE adders to arrive at a final, approved ROE.

6.2 Benchmarking for setting reasonable rate of return

Benchmarking is defined as systematic use of data to assess relative performance, and involves choosing one or more evaluative parameters, and assessing own performance against that of others or oneself. For regulators, this can be a useful technique to develop appropriate metrics, to spot anomalies in submissions and flag for further analysis, or publish reports of regulated entities to focus attention on poor performers.

As stated by the Nova Scotia Utility and Review Board ("NSURB") in the Public Utilities Act, "every public utility shall be entitled to earn annually such return as the Board deems just and reasonable."[234] In NSP's general rate application for 2013 and 2014, the NSURB set the ROE at 9.0%, with a range of 8.75% to 9.25%.[235] As discussed in Section 6.1.3, the average approved ROE for US utilities since 2011 has been 10.4%. As shown in the figure below, the authorized return for NSP would not be considered anomalous.

Figure 112. Authorized Return on Equity for US electricity utilities versus NSP



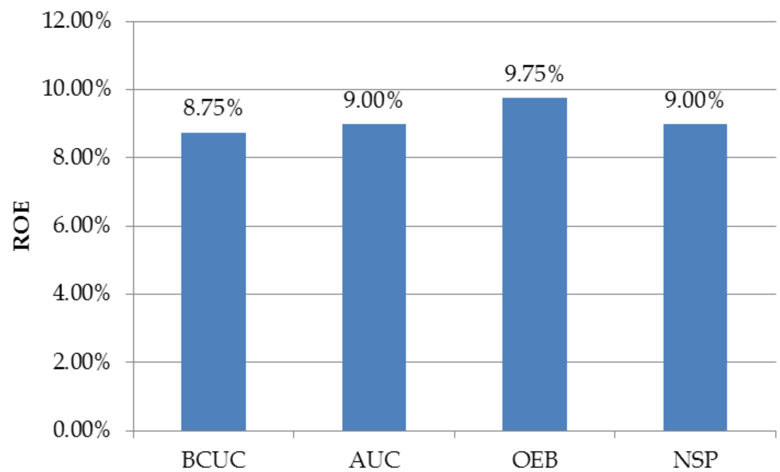
[233] Desert Southwest Power, LLC, 135 FERC ¶ 61,143 (2011)

[234] NSURB. *Public Utilities Act. S 45(1).* <http://nslegislature.ca/legc/statutes/public%20utilities.pdf>

[235] NSURB. *2012 NSUARB 227. M04972.* <http://nsuarb.novascotia.ca/sites/default/files/PDFs/nsuarb-212090-v1-decision_-_nspi_2013_gra.pdf>

LEI also considered NSP's ROE against that of Canadian utilities. In a review of the generic cost of capital proceedings by the British Columbia Utilities Commission ("BCUC"),[236] the Alberta Utilities Commission ("AUC"),[237] and Ontario Energy Board ("OEB"),[238] it is apparent that NSP's ROE is reasonable from a benchmarking perspective.

Figure 113. Return on Equity for Canadian electricity utilities versus NSP



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7 Appendix B - Status of restructuring in EU member states

Figure 114. Status of compliance with Energy Directives 2-3 in EU member states

EU countries	2nd Energy Package		3rd Energy Package	
	Electricity	Gas	Electricity	Gas
Austria	Cases Closed	Cases Closed	Non-Transposition Case Closed	Non-Transposition Case Closed
Belgium	Cases Closed	Cases Closed	Non-Transposition Case Closed	Non-Transposition Case Closed
Bulgaria	Cases Closed	One Case Pending	Non-Transposition Case Pending	Non-Transposition Case Pending
Cyprus	No Case	No Case	Non-Transposition Case Pending	Non-Transposition Case Pending
Czech Republic	Cases Closed	Cases Closed	No Case	No Case
Denmark	Cases Closed	Cases Closed	Non-Transposition Case Closed	Non-Transposition Case Closed
Estonia	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
Finland	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
France	Cases Closed	One Case Pending	Non-Transposition Case Closed	Non-Transposition Case Closed
Germany	One Case Pending	Cases Closed	No Case	No Case
Greece	One Case Pending	One Case Pending	No Case	No Case
Hungary	Cases Closed	Cases Closed	No Case	No Case
Ireland	One Case Pending	One Case Pending	Non-Transposition Case Pending	Non-Transposition Case Pending
Italy	One Case Pending	Cases Closed	No Case	No Case
Latvia	Cases Closed	Cases Closed	No Case	No Case
Lithuania	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
Luxembourg	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
Malta	Cases Closed	No Case	No Case	No Case
Netherlands	Cases Closed	Cases Closed	Non-Transposition Case Closed	Non-Transposition Case Closed
Poland	One Case Pending	Two Cases Pending	Non-Transposition Case Pending	Non-Transposition Case Pending
Portugal	Cases Closed	Cases Closed	No Case	No Case
Romania	Cases Closed	One Case Pending	Non-Transposition Case Pending	Non-Transposition Case Pending
Slovakia	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
Slovenia	Cases Closed	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
Spain	Cases Closed	Cases Closed	Non-Transposition Case Closed	Non-Transposition Case Closed
Sweden	One Case Pending	Cases Closed	Non-Transposition Case Pending	Non-Transposition Case Pending
United Kingdom	One Case Pending	One Case Pending	Non-Transposition Case Pending	Non-Transposition Case Pending

Note: The cases above refer to non-compliance investigations by EU related to Energy Directives 2 and 3.
Source: EU. Energy Markets in the European Union in 2011. 2012

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9 Appendix D - List of Acronyms

AER	Australia Energy Regulator
AESO	Alberta Electric System Operator
AEUB	Alberta Energy and Utilities Board
AF	Availability Factor
AIIFR	All Injury/Illness Frequency Rate
APPA	American Public Power Association
ARP	Alternative Rate Plan
AUC	Alberta Utilities Commission
BC	British Columbia
BCUC	British Columbia Utilities Commission
BGS	Basic Generation Service
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAPEX	Capital Expenditures
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CCGT	Combined Cycle Gas Turbine
CCM	Cost of Capital Mechanism
CEC	California Energy Commission
CES	Clean Energy Standard
CFTC	Commodity Futures Trading Commission
CGS	Commonwealth Government Securities
CI	Customer Interruptions
CLD	Coalition of Large Distributors
CML	Customer Minutes Lost
CMP	Central Maine Power
ConEd	Consolidated Edison of New York
COS	Cost of Service
CPI	Consumer Price Index
CPCFA	Consumer Power and Conservation Financing Authority
CPUC	California Public Utility Commission
CRPP	Comprehensive Reliability Planning Process
CSPM	Customer Service Pricing Mechanism
CTC	Competitive Transition Charges
CTI	Critical Transmission Infrastructure
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DEA	Data Envelopment Analysis

DG	Distributed Generation
DGFWG	Distributed Generation Forecast Working Group
DHS	Department of Homeland Security
DNO	Distribution Network Operator
DPCR5	Distribution Price Control Review 5
DPU	Department of Public Utilities
DR	Demand Response
DRC	Depreciated Replacement Cost
EAF	Energy Availability Factor
EEI	Edison Electric Institute
EIM	Energy Imbalance Market
EPAct 2005	Energy Policy Act of 2005
EPC	ENMAX Power Corp.
EPSA	Electric Power Suppliers Association
ERC	Energy Regulatory Commission, Philippines
ERCOT	Electric Reliability Council of Texas
ESM	Earning Sharing Mechanism
EU	European Union
EUB	Energy and Utilities Board
EUF	Energy Unavailability Factor
EV	Electric Vehicle
FAC	Facilities Design, Connections, and Maintenance
FAI	FortisAlberta Inc.
FAM	Fuel Adjustment Mechanism
FBR	Formula-based Ratemaking
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data Service
GAR	Generating Availability Report
GDP	Gross Domestic Product
G-PBR	Generation PBR
GEA	Green Energy Act
HHI	Herfindahl-Hirschman Index
IEEE	Institute of Electrical and Electronic Engineers, Inc.
IESO	Independent Electricity System Operator
IIS	Interruption Incentive Scheme
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
IPP	Independent Power Producer
IPSP	Integrated Power System Plan
IQI	Information Quality Incentive
IRM	Incentive Regulation Mechanism

IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
ITO	Independent Transmission Operator
LBMP	Locational Based Marginal Pricing
LDC	Local Distribution Companies
LEI	London Economics International LLC
LMP	Locational Marginal Price
LRAM	Lost Revenue Adjustment Mechanism
LPL	Liberty Power Limited
LSE	Load Serving Entity
LTEP	Long-term Energy Plan
MAIDI	Momentary Average Interruption Duration Index
MAIFI	Momentary Average Interruption Frequency Index
MAR	Maximum Allowed Revenue
MEAV	Modern Equivalent Asset Value
MFP	Multi-factor Productivity
MISO	Midwest ISO
MMBtu	Million British Thermal Units
MOD	Modeling, Data, and Analysis
MPMA	Market Power Mitigation Agreement
MPUC	Maine Public Utility Commission
MRO	Midwest Reliability Organization
MWh	Megawatt hours
NB	New Brunswick
NERC	North American Electric Reliability Corporation
NEM	National Electricity Market
NEMs	Net metering systems
NERSA	National Energy Regulator of South Africa
NETO	New England Transmission Owners
NGET	National Grid Electricity Transmission
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NSA	Negotiated Settlement Agreement
NSP	Nova Scotia Power
NSURB	Nova Scotia Utility and Review Board
NSW	New South Wales
NYISO	New York ISO
NYPSC	New York Public Service Commission
O&M	Operation and Maintenance
OASIS	Open Access Same time Information System
OEB	Ontario Energy Board

Ofgem	Office of Gas and Electricity Market
OM&A	Operating, Maintenance and Administrative
OPA	Ontario Power Authority
OPG	Ontario Power Generation
Opex	Operating Expenses
OSHA	Occupational Safety and Health Administration
PaPUC	Pennsylvania Public Utility Commission
PBR	Performance-based ratemaking
PG&E	Pacific Gas and Electric
PPA	Power Purchasing Agreement
PUC	Public Utility Commission
PUCT	Public Utilities Commission of Texas
PUF	Planned Unavailability Factor
PV	Present Value
PX	California Power Exchange
PXE	Power Exchange Central Europe
RAB	Regulatory Asset Base
REC	Renewable Energy Credit
RIIO	Revenue set to deliver strong Incentives, Innovation, and Outputs
ROA	Return on Assets
ROE	Return on Equity
ROR	Rate-of-Return
RPI	Retail Price Index
RPP	Regulated Price Plan
RPS	Renewable Portfolio Standards
RRO	Regulated Rate Option
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SF	Service Factor
SOF	Scheduled Outage Factor
SPP	Southwest Power Pool
STPIS	Service Target Performance Incentive Scheme
T&D	Transmission and distribution
TFP	Total Factor Productivity
TPCR4	Transmission Price Control Review 4
UCF	Unit Capability Factor
UCLF	Unplanned Capability Loss Factor
UF	Unavailability Factor

UK	United Kingdom
USA (US)	United States of America
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
WECC	Western Electric Coordinating Council
ZREC	Zero Emission Renewable Energy Credit