Alternatives for regulating prices associated with output from designated generation assets

Report prepared for the Ontario Energy Board by London Economics International LLC

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London Economics International LLC
409 Bloor St. East Suite 601
Toronto, Ontario
www.londoneconomics.com

contact:
A.J. Goulding/Bat –Erdene Baatar
416-545-0534
ajg@londoneconomics.com

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Although price regulation of generation is a new activity for the Ontario Energy Board, it has been the norm in a number of jurisdictions outside of Ontario for decades. As such, a range of approaches have been developed. These range from traditional cost-of-service regulation to arrangements which incorporate a series of targeted incentives based on the behavior the regulator wishes to induce. Best practice in regulation of generation suggests that regulators need to focus on a framework which allows for revenue sufficiency, incentives for efficiency and performance improvement, and appropriate sharing of risks between generators and consumers. While observed arrangements may need to be modified to reflect the unique characteristics of Ontario Power Generation (OPG)'s fleet, long term incentive based arrangements can be devised which minimize the regulatory burden, maintain OPG financial integrity, and protect the interests of Ontario ratepayers.

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1 Purpose and review of regulatory objectives

1.1 objective of paper

This report focuses on a range of regulatory arrangements that could be used to set prices for OPG's designated assets. OPG's designated assets include several of its hydro and nuclear assets, many of which have been in operation for several decades.

Figure 1. OPG designated assets[1]

Nuclear	MW	Hydroelectric	MW
Pickering A	1,030	Sir Adam Beck 1, 2, and pumping station	1,959
Pickering B	2,064	DeCew Falls 1 & 2	167
Darlington	3,524	RH Saunders	1,045
total:	**6,618**	*total:*	**3,171**

London Economics International (LEI) LLC's research is focused on regulation of generation and, at the client's request, is limited to one aspect of regulation: the setting of prices for output from installed and operational plants. An assessment of how to determine whether new investment decisions are being made and implemented according to least cost investment planning principles is outside the scope of this engagement.

This research is intended primarily as an exploration of concepts that will be used to spark discussion. As such, focusing on specific implementation details of any of the models discussed in this paper is beyond the scope of this engagement. In addition, our focus is primarily on how the revenues to generators are regulated. Allocation of the benefits of contracts with designated assets across customer classes is also beyond the scope of this engagement.

1.2 current arrangements for OPG designated assets

The identity of the designated assets and the payments to be made in relation to their output are set out in the *Payments Under Section 78.1 of the Act Regulation*, O. Reg. 53/05. The *Regulation* currently provides as follows:

- regulated hydroelectric facilities receive $33.00 per MWh for the first 1,900 MWh of production in any hour;
- additional production beyond 1,900 MWh in any hour from the hydroelectric facilities is paid the Ontario spot market price;

[1] The Beck tunnel project, expected to come online in late 2009, will also be included among the designated assets.

- output from the nuclear facilities receives $49.50 per MWh;

- OPG is required to establish a variance account to record costs incurred on or after April 1, 2005 associated with:

    - changes in hydroelectric electricity production due to differences between forecast and actual water conditions;

    - changes in nuclear electricity production dues to unforeseen changes in law or to unforeseen technological changes;

    - revenue changes from forecasted ancillary services sales;

    - acts of God; and,

    - certain transmission-related events.

- OPG is required to establish a deferral account to record non-capital costs incurred on or after April 1, 2005 associated with Pickering A restart.

According to OPG's 2005 Report:[2]

- the payment amounts referred to above were established by the Province based on forecasted production and operating costs, including a cost of capital and assuming an average 5% return on equity; and,

- although the current arrangements are expected to remain in place until at least March 31, 2008, the Province reserves the right to amend the payment amounts should fundamental changes occur in the underlying assumptions.

The current arrangements have both advantages and disadvantages. On the plus side, they are structured to provide incentives for OPG to efficiently manage its storage hydro facilities, and to increase output from those facilities. Unfortunately, the arrangements do not provide similar signals with regard to scheduling nuclear maintenance or seeking cost effective ways to safely increase output from the nuclear facilities. The variance accounts cover a broad range of items which are either within OPG's control or capable of being hedged. OPG has some limited incentives to improve its efficiency, in that rates serve as a form of a price cap. However, it is unclear the extent to which OPG costs have been subjected to an appropriate degree of public scrutiny, and whether the overall incentives embedded in the current arrangements are sufficient to spur OPG to superior performance.

[2] Arrangements summarized from p. 3 of the report.

1.3 underlying regulatory theories

When focusing on existing assets, a regulator's concerns are threefold.

First, there is the question of *revenue sufficiency*: does the overall rate structure provide for sufficient revenue for the owner to meet its financial obligations on reasonable commercial terms?

Second, there is the question of *operational efficiency*: do the rates as structured provide for incentives for the efficient use of fuel, for the plants to be available at the times when they are most needed, and for the operators to prudently manage operating costs?

Third, we often must consider the extent to which any *risk sharing* is appropriate between the generator and the rate payer. For example, if the generator responds well to the incentives provided, then should some amount of the additional profits beyond a particular threshold be returned to ratepayers? Alternatively, if costs move in a direction unanticipated by the generator and beyond its control, then should ratepayers carry some of the burden?

The unique structure of the Ontario electricity sector raises further challenges for a regulator. These include:

- ***appropriate allocation of overall cost of capital*** – the designated assets are only a portion of the overall OPG portfolio; rates associated with these assets should, under standard cost-of-service ratemaking principles, not be used to subsidize the cost of capital for other OPG assets;

- ***determining whether a commercial equity return should be applied*** – OPG remains a provincially owned corporation, and its shareholder faces conflicting obligations to ratepayers versus taxpayers. As noted above, current rates for the OPG designated assets are calculated assuming a below-market 5% return on equity. Ratepayers may prefer a lower-than-market cost of equity to be applied, so as to avoid upward pressure on rates; such a policy represents a de facto subsidy from taxpayers, who might otherwise prefer higher dividends so that the proceeds can go to fund other government priorities, such as health care or education;

- ***efficacy of incentives*** – deployment of an incentives regime implies the imposition of rewards and penalties. Such a regime assumes that the application of such rewards and penalties will have meaningful consequences – shareholders will lose money or management their jobs. These assumptions may not hold true in a government-owned corporation under direct ministerial control. While global best practice suggests that regulators should deploy incentives whenever possible, monitoring and imposing the corresponding rewards and penalties takes effort on the part of both the regulator and the regulated company. If the incentive scheme is not genuinely going to change behavior – again, resulting in simply a series of transfers between ratepayers and taxpayers – regulators need to ask themselves whether the incentives are worth the trouble of implementing.

The various methods of regulating generation (and other regulated commodities and networks) described below take varying approaches to the questions of revenue sufficiency, incentives implementation, and the sharing of risks. After describing each alternative, we will then present some hypothetical arrangements tailored to reflect Ontario conditions.

2 Alternative models for regulation of generation

Despite the increased use of competitive wholesale markets for price determination for generators across the world, depending on the criteria one deploys, as much as half of the world's generation continues to operate under some form of rate of return regulation. While some of these regimes may be rudimentary, others contain quite sophisticated mechanisms designed to provide particular incentives to generators. Below, we provide conceptual details of four possible approaches for regulating generation. In subsequent sections we discuss examples of generation regulation from around the world.

2.1 traditional cost of service regulation

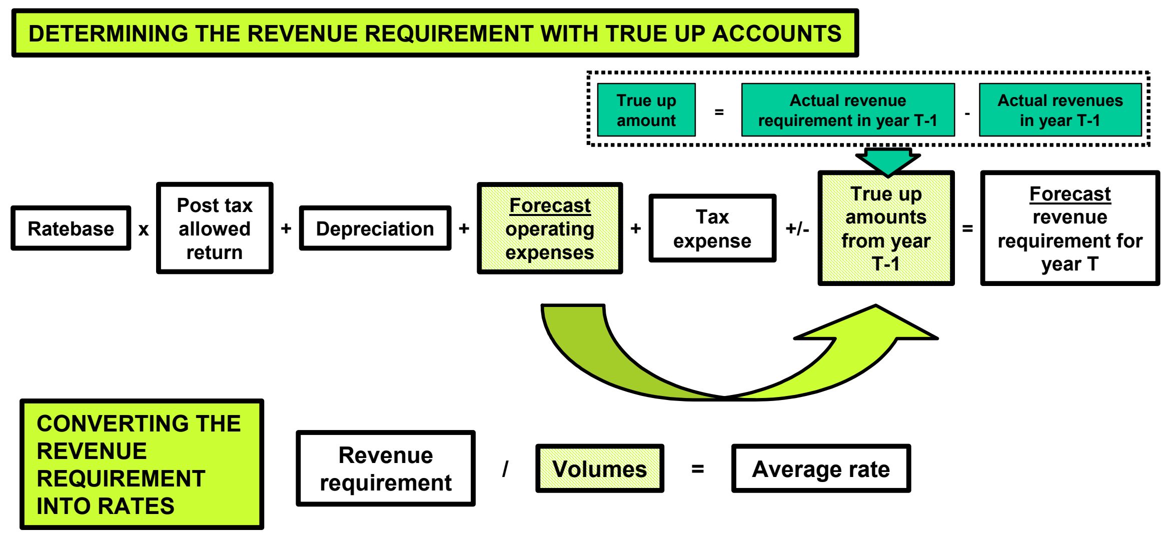
Traditional cost-of-service regulation consists of a multi-part process, starting with the calculation of the ***revenue requirement*** in which:

- the regulated asset base (RAB) is established;
- annual depreciation is determined;
- a return on ratebase is set;
- annual operating costs are projected;
- an annual capital expenditure budget is also projected;
- true-up amounts from previous year's under or over-recovery of the revenue requirement are calculated; and,
- the revenue requirement is calculated by multiplying the return on ratebase by the RAB, and adding depreciation, annual operating and capacity expenditures, and the true-up amount (which may be positive or negative).

To minimize the need for annual recalculation of all of the elements of the revenue requirement, regulators may fix most aspects of the equation, and (for fossil plants) use a fuel cost adjustment mechanism which changes according to a formula linked to fuel usage and changes in a relevant price index.

The second part of the cost-of-service rate calculation focuses on converting the revenue requirement into rates. Using principles of cost-causation (customers whose consumption activities caused particular investments to be made should be responsible for paying them), the revenue requirement is allocated among customer classes. It is then further divided among fixed and variable charges, which may vary seasonally or by time of day. True-up accounts are used to handle revenue volatility associated with load forecast error and changes in operating and capital costs.

Figure 2. Schematic of cost-of-service ratemaking process[3]



Cost of service regulation, with small variations, is used to set the price for regulated generation in those parts of the United States which have not transitioned to competitive wholesale markets. It is generally applied in a context in which the RAB includes the entire integrated utility; as such, the overall revenue requirement incorporates the cost of transmission and distribution, though with certain generation-related adjustments.[4] However, this does not mean that similar arrangements cannot be applied to generation in a stand-alone setting.

Cost-of-service regimes provide for a high degree of revenue sufficiency. Indeed, their main drawback – that they encourage utilities to over-capitalize their systems by "goldplating" new investments – would not be relevant in Ontario if cost-of-service were merely applied to the designated assets since they are essentially already built.[5] However, pure cost-of-service regimes provide no incentive for companies to seek out operating cost efficiencies (assuming such cost savings are fully recaptured by the regulator in subsequent reviews), and they also place the bulk of the risk related to asset performance on customers.

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[3] Shaded boxes represent forecasted values which cause potential for deviations in collections from the established revenue requirement, and which may necessitate a true-up account.

[4] For example, each state has different rules for sharing revenue from off-system sales, that is, sales of power which is economic to produce but surplus to the needs of regulated customers.

[5] There is currently no indication that the OEB will be regulating other OPG assets. OPG may make significant capital investments in the designated assets, particularly in nuclear refurbishment. Such investments, if made in designated assets, would presumably be under the OEB's purview. OPG is making a range of large capital investments in other types of non-designated generation assets without substantial regulatory oversight or market discipline.

2.2 efficiency target regulation

The best known form of efficiency target regulation is the inflation minus efficiency target approach used in the UK, Australia, and numerous other jurisdictions to regulate wires assets. Under this approach, initial rates are set in a fashion similar to the cost-of-service process described above. However, instead of changing over time in a fashion which directly reflects actual costs, rates change in a fashion designed to represent what rates would be were the company to be efficiently operated. As such, rates[6] increase year-on-year by an inflation factor (I), but decrease by an efficiency factor (X). This means that company returns may deviate from the allowed return established in the initial cost-of-service assessment. Companies which perform better than the X factor earn higher than their allowed return, while those which fail to meet the efficiency target embedded in the X factor face lower than expected profits.

This form of I-X regulation is familiar to Ontarians; it has been applied in a simplified form to the wires sector in the province in the past, and may be more fully applied in the future as the sector stabilizes. Although some US states have tinkered around the edges of applying an I-X framework in an integrated utility setting, it is unusual to see it applied to generation on a stand-alone basis. That is not to say, however, that it cannot be done. Indeed, the nature of the portfolio of Ontario designated assets (hydro and nuclear), means that overall annual revenue requirement volatility will be less linked to the volatility of fossil fuel prices. This in turn would allow for the creation of an efficiency target mechanism with less need to isolate the impact of changes in fuel prices, or to set up separate mechanisms to encourage efficient fuel procurement.

Although the I-X formulation improves the incentives compatibility of rates relative to traditional cost-of-service, it poses risks for the regulator – X factors set too high may result in revenue insufficiency; set too low, and they result in rent transfers to regulated entities. Furthermore, X factors must be accompanied by performance standards; otherwise companies may be tempted to increase profits by reducing reliability. In the case of generation assets, performance standards usually devolve into some sort of availability standards, though additional performance standards can include environmental compliance or workplace safety. If the revenue requirement is set based on a particular availability expectation, and no true up is provided for outages except under narrowly drawn force majeure provisions, the availability standards effectively become embedded into rates.

2.3 price referential regulation

Price referential regulation represents a more light-handed approach to regulation than either cost-of-service or efficiency target formulations. Under price referential regulation, the regulator sets an overall maximum benchmark for prices, and allows companies to set prices at

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[6] I-X regimes can be structured either as a revenue cap or a price cap; under a revenue cap, companies have some flexibility to set prices as long as total revenue does not exceed the cap. Under a price cap, total revenue can grow if output grows.

any level below this threshold. Maximum benchmarks can either be based on some liquid, published index, or on a referent technology or service cost. This method is often used in markets where a transparent and competitive marketplace exists, but in which the regulated company has the potential to exercise market power.

Examples of price referential regimes include capacity markets in some US independent system operator territories, where those entities which are capacity deficient pay a penalty equal to the cost of a new peaking unit, plus some margin; this penalty price effectively serves as a ceiling on the capacity prices that large generation holders can charge. Massachusetts markets for renewable energy credits work in a similar fashion, though the purpose of the cap is to manage the overall price impacts of renewable portfolio standards rather than to combat market power. This latter objective – managing price impacts to final consumers – also underlies recent interstate compacts intended to deploy a tradable credits scheme for reductions in carbon emissions.

While the price referential approach is suitable in some settings, in the Ontario context it may not be appropriate to consider with regards to the designated assets. Setting the referent price at, say, the average of the previous year (or quarter, or month) hourly Ontario energy price (HOEP) would provide strong incentives for OPG to maximize production given the underlying marginal costs of the units.[7] However, it would provide for a greater degree of revenue sufficiency than ratepayers are likely to tolerate given that it would also mean moving a portion of customer demand to a more volatile market linked rate. Furthermore, since the hydro and nuclear assets have effectively been removed from the HOEP, the HOEP is likely to be slightly higher than it would have been were the designated assets participating fully on a shadow pricing basis in the market.

Although we have presented the price referential model here for the sake of completeness, we will not cover it among our hypothetical examples for Ontario, because we do not believe that it is politically feasible to implement.

2.4 regulation by contract

A fourth approach is to apply a form of regulation by contract, effectively negotiating a long term contract on behalf of the customers served by the designated assets. This contract would contain terms typical in private sector contracts, including performance standards, force majeure provisions, escalators, scheduling responsibilities, and contract capacities. Once the

[7] An intriguing alternative possibility for price referential regulation in Ontario would be to use any standard offer established by the Ontario Power Authority as a benchmark, perhaps with a discount to reflect the fact that the designated assets are partially depreciated. While such a proposal would likely find favor with OPG, critics would point out, with some justification, that any standard offer is intended to incentivize new generation, and thus may overcompensate existing assets.

contract was put in place, it would not be reviewed by the regulator again through out its life, except in extraordinary circumstances.[8]

Private sector power contracts often contain two parts: a capacity payment, designed to provide the generator with recovery of fixed costs and return on and of capital provided that it meets specified availability and performance targets, and an energy payment, paid only when the facility is used, and designed to reflect the variable operating costs of the plant. A subset of private sector power contracts, known as tolling contracts, transfers the responsibility (and risk) associated with fuel purchasing from the generator to the power purchaser. In such arrangements, the power purchaser provides the fuel, and the generator returns power in a specified ratio reflecting a target heat rate. This arrangement provides a strong incentive for the plant operator to maintain the plant in good condition, because if the plant operates at a lower fuel efficiency, the plant operator has to make up the cost of the additional fuel used.

The fact that OPG's designated assets are nuclear and hydro does not in any way mean that such contracts cannot be applied. However, the tolling element is likely to be minimal. Instead, contract payments would focus on availability-linked fixed cost recovery mechanisms, coupled with price signals to guide maintenance scheduling and water temporal allocation signals.

Applying a regulation by contract approach in Ontario would require adopting aspects of tolling contracts and traditional private sector contracts, adapted to the characteristics of the underlying nuclear and hydro stations which make up the designated assets. As described more fully in later sections of this document, such an arrangement would include energy payments to OPG, with different payments for different asset types consistent with current arrangements. However, we envision the possibility of the payments being structured contracts for differences, similar to arrangements in use for some recent Ontario Power Authority (OPA) contracts.[9]

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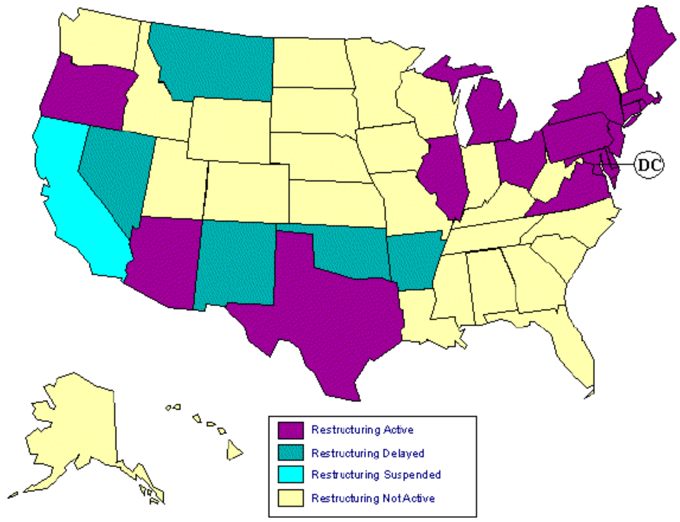
[8] The intent is to reflect as closely as possible contracting conditions in competitive markets. Competitive contracts are not reviewed every three to five years. Indeed, the costs from contracts entered into by the OPA will not be periodically reviewed. The point of this structure is to take the regulator out of the equation entirely, once initial costs have been reviewed and are reflected in the contract. If the concern is "excess" earnings, the contract can be structured to allow for revenue sharing above particular levels of profit.

[9] In a contract for differences framework, a counterparty receives the price available in the market, or a payment based on some relevant index. However, this price is then adjusted to meet some form of fixed price benchmark. Hence, in a two way contract for differences (CfD), a counterparty would refund the difference between the index and fixed price if the index was higher than the fixed price, and would receive top-up payments if the index was lower than the fixed price. To encourage counterparties to maximize output at higher price levels, the counterparty may be allowed to retain a portion of the difference between the index and the fixed price when the index is at a level higher than the fixed price component.

3 Examples of ratebase generation worldwide

Figure 3. Status of generation deregulation in the United States[10]



When seeking precedent for methods to regulate the designated generation assets, it is important to review experience in US jurisdictions where generation remains under ratebase, as well as sophisticated overseas regimes, such as Hong Kong, which have delayed the implementation of competition. While some regimes continue to use a fairly simple cost-of-service/rate of return approach for generation, others have deployed a number of mechanisms to attempt to better align incentives. Although fuel cost adjustment mechanisms may not be appropriate for the designated assets (seeing as they are predominately nuclear and hydro), they are an example of the way in which a regulated rate is used to provide some of the same incentives as competition would; some such provisions use a deemed heat rate and fuel price, putting the generator at risk if they either do not maintain their plants per specifications or do not engage in efficient procurement. Other jurisdictions allow for sharing of benefits from off-system sales as one means to incentivize generators to increase production and be available on peak. Still others engage in various forms of cost benchmarking, to provide some pressure to reduce operating costs within the regulated framework.

3.1 US states

As shown in the map above, about 50% of the United States by area remains under some form of regulation across all segments of the electricity sector value chain. To provide a diversity of examples, we present several case studies below. These include a traditional cost-of-service

[10] Map taken from US Energy Information Administration materials. Pale-colored states continue to regulate generation.

state (Georgia), a modified cost-of-service state (Kentucky), and arrangements prior to the transition to competition in New York.

3.1.1 case study of a state with cost of service/rate of return regulation – Georgia

Georgia is not a deregulated market, and continues to set rates using the classic cost of service/rate of return regulation. In Georgia, investor-owned utilities (IOUs) continue to operate vertically integrated monopolies. The utilities own the generation, distribution, and transmission systems in their service areas, and charge customers regulated prices.

To set prices, Georgia's two IOUs, Georgia Power and Savannah Electric and Power (both subsidiaries of Southern Company) file periodic rate cases with the Georgia Public Service Commission (GAPSC). The GAPSC then makes a determination about the asset base of the firm, and sets an allowed rate of return on equity that the utility is permitted to make. Rates for end users are then set to allow the firm to make the profit projected.

Fuel and other operating costs are generally estimated in advance, and the estimates used in rate setting. Generally speaking, if changes in operating costs prevent the utility from making their allowed profit, they will be allowed to true-up the difference by increasing rates in subsequent years (excess earnings are returned to customers by rate reductions in subsequent years).

In the most recent rate cases, the allowed returns on equity were set at between 9.75% and 11.75% for Savannah Electric and Power (10.75% in the first year), and between 10.25% and 12.25% for Georgia Power (11.25% in the first year).

Although the utilities essentially pass operating costs directly through to the customers, the state regulator does have the ability to disallow the recovery of costs or investments if they are deemed to be imprudent. Regulators encourage efficient behavior with the threat that inefficiencies will be deemed imprudent after the fact.

3.1.2 case study of a state with an earnings sharing mechanism - Kentucky

The Kentucky Earning Sharing Mechanism (ESM) is based on a target 11.5% ROE with a 100 basis point dead band above and below the allowed ROE target. The Kentucky utilities are required to remit 40% of earnings above the dead band back to customers. Similarly, the Kentucky utilities are allowed to increase rates to collect 40% of any under earnings from customers. Any effects from the utilities' allowed environmental surcharges are excluded, as are the effects from fuel adjustment clauses.

Kentucky's ESM was the result of the "PBR Case"[11] in 1998. PBR refers to performance-based ratemaking. At the time the Public Utility Commission had approved the merger of two major utilities in Kentucky, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU). On October 12, 1998, the two utilities filed applications with the Commission for the approval of a Performance Based Ratemaking regulatory structure in Kentucky, initiating the "PBR Case". The PBR structure proposed by the utilities provided for measurement of company performance based on three indices: fuel costs, generation performance, and service quality. The companies would receive rewards for performance exceeding the defined indices.

The Commission rejected the plans but offered an optional ESM plan issued on January 7, 2000. The companies were ordered to either continue under traditional regulation or to accept the ESM plan. In explaining its rationale for advocating the use of an ESM plan rather than a full-fledged PBR approach, the Commission stated that:

"ESM plans are typically and appropriately used when an industry is beginning the transition from a monopolistic to a more competitive structure. …ESMs also provide the utility incentives to alter its behavior and take on additional risks by providing a limited safety net in case new efforts result in failure. In addition, ESMs can reduce business and regulatory risk and serve as an automatic means of keeping earnings within acceptable bounds. Sharing revenues allows captive ratepayers as well as shareholders to directly benefit from successful company initiatives."[12]

Evaluations of the Kentucky ESM have found it to be "an effective alternative to traditional cost of service regulation" and that it accomplishes the original objectives in the PBR Case Orders of reducing business and regulatory risk, stabilizing the utilities' ROEs, providing incentives to increase efficiency, and allowing both customers and shareholders to benefit from successful customer initiatives.[13]

3.1.3 case study of a state with targeted incentive bonuses – Niagara Mohawk in New York State

From January 1, 1991 though May 30, 1994, Niagara Mohawk[14], a New York utility providing electricity and gas supply to its service area, operated under a targeted incentive PBR program entitled Measured Equity Return Incentive Term (MERIT). The program allowed the company to earn an equity premium upon meeting certain performance standards and performance

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11 LG&E Case No. 98-426 and KU Case No. 98-474.

12 Barrington-Wellesley Group, Inc. "Focused Management Audit of Louisville Gas and Electric's and Kentucky Utilities' Earning Sharing Mechanisms" Report to the Kentucky Public Service Commission, August 31, 2003.

13 Ibid.

14 Ibid.

measurement criteria. The total revenues subjected to MERIT totaled $180 million, derived as follows:

- January 1, 1991 – May 31, 1991 - $30 million (1% on equity)
- June 1, 1991 – May 31, 1992 - $50 million (1.67% on equity)
- June 1, 1992 – May 31, 1993 - $50 million (1.67% on equity)
- June 1, 1993 – May 31, 1994 - $50 million (1.67% on equity)

MERIT's award for the previous period was collected in the following rate period and allocated 91% to electric and 9% to gas. The award was for fulfilling several performance standards on an annual basis. There were five major performance standards, each of which counts for 20% of the total funds granted that year. The five performance standards for 1991 were:

- **Reduction of Public Service Commission complaints:** Target of 7% reduction from January 1, 1991 through May 31, 19991 as compared to the previous year.
- **Reduction of layers of management:** By May 31, 1991, the company must reduce the electric customer service field organization by one layer of management as compared to the number of layers that existed on October 31, 1989.
- **Implementation of Activity Value Analysis (AVA):** The company must implement AVA with an expected annualized gross value of $37 million in savings by May 31, 1991.
- **Meeting of goals at Nine Mile 1 and 2 plants:** Net generation targets; minimum capacity load factor of industry average of 61.26%; reduction of corrective maintenance work requests by 200; and, minimize outage duration to 56 days.
- **Open Issue Report:** The company will file a report addressing concerns in the following areas: environmental, legal support, accountability, and company operational statistics during the self-assessment process, which will generate new ideas for subsequent periods.

While the specific issues mentioned above may not be relevant to the overall Ontario situation, the various incentive items can be modified to suit the particular circumstances of any jurisdiction. MERIT lasted until 1994, when it was replaced by a full-fledged price cap. It was, however, judged to be a success by the regulatory authorities and continues to be used as a case study.

3.2 Canadian heritage contracts

Heritage contracts refer to arrangements put in place to allow customers to benefit from low cost, long lived assets during the transition to competitive or rolled in pricing. Such contracts have the advantage of providing a high degree of certainty to stakeholders and reducing the regulatory burden. However, they do not provide strong incentives to the legacy operators to make plant available at times when output would be most valuable, or to reduce costs in a prudent fashion. Any incentives in this regard come from the possibility of export sales once the heritage contract quantities have been filled. Heritage contracts are in place in British Columbia (BC) and in Quebec; the arrangements in Ontario for the designated assets could also be viewed as a form of heritage contract, one which is in some ways superior to the arrangements in place in those provinces. It should be noted, however, that one clear advantage of the BC and Quebec arrangements over those in Ontario is regulatory certainty; generally speaking, arrangements in both provinces are expected to be in place for the foreseeable future.

3.2.1 British Columbia

BC Hydro owns and operates virtually all of the generation in British Columbia and coordinates it with its operation of the province's transmission and distribution systems. A BC Hydro subsidiary, Powerex, markets surplus BC Hydro electricity and trades power outside of the province. BC Hydro's Grid Operations, which operates the transmission system, was separated from the rest of BC Hydro on August 1, 2003. The Grid Operations unit is now a separate company named the British Columbia Transmission Company (BCTC). Generation is grouped under BC Hydro Generation (BCH Gen) and distribution under BC Hydro Distribution (BCH Dist). In 2005, BCH Gen controlled about 10,218 MW of hydro generation capacity.

BC Hydro uses a revenue requirements model to guarantee that consumers will continue to benefit from its "heritage" assets. This model is essentially a return to the traditional utility cost-of-service ratemaking. Under this model, BC Hydro rates will be reviewed and approved by the BC Utilities Commission (BCUC) subject to the conditions of the Heritage Contract. The BC Heritage Contract places electricity supply obligations on BCH Gen and payment obligations on BCH Dist in respect of the electricity supplied from the heritage assets. The supply obligations or "Heritage Energy" have been set at 49,000 GWh per year under average water conditions[15]. BC Hydro generates between 43,000 and 54,000 gigawatt hours of electricity annually, depending on prevailing water levels. The supply obligation also includes capacity and ancillary services as needed. BCH Dist has a priority call on the Heritage resources up to the maximum capacity available, as required to serve its customers. In other words, heritage resources must be used to serve native load first. Powerex may use any surplus capacity pursuant to the terms of a Transfer Pricing Agreement[16].

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[15] This amount is indicative and not fixed as BCH may change the amount in its revenue requirement submission.

[16] Trade revenue up to C$200 million per year is offset against BC Hydro's revenue requirement.

Figure 4. Forecast BC heritage payment obligation, 2005-2014 (Cdn. $ million)

	Reference	Heritage Contract			
	2004	2005	2007	2010	2014
Heritage Contract Costs					
Cost of Energy	$ 441	$ 441	$ 434	$ 432	$ 425
Operating Costs	$ 162	$ 158	$ 166	$ 166	$ 166
Asset Related Expenses	$ 380	$ 370	$ 392	$ 430	$ 467
GRTA Expenses	$ 43	$ 43	$ 43	$ 43	$ 43
Total Heritage Contract Costs	$ 1,026	$ 1,012	$ 1,035	$ 1,071	$ 1,101
Less Other Revenues					
Skagit Valley Treaty	$ (22)	$ (23)	$ (25)	$ (25)	$ (25)
Ancillary Services and Miscellaneous Revenue	$ (4)	$ (5)	$ (6)	$ (5)	$ (5)
Total Other Revenues	$ (26)	$ (28)	$ (31)	$ (30)	$ (30)
Net Costs	$ 1,000	$ 984	$ 1,004	$ 1,041	$ 1,071
Add: Return on Equity	$ 154	$ 160	$ 192	$ 197	$ 230
Forecast Heritage Payment Obligation	**$ 1,154**	**$ 1,144**	**$ 1,196**	**$ 1,238**	**$ 1,301**

Source: BC Hydro

The payment obligation in the Heritage Contract for the supply of the heritage electricity is comprised of the cost of energy, operating costs, asset related expenses, generation-related transmission asset (GRTA) costs, and return on equity (ROE), less other revenues. Some of these costs can be predicted with reasonable accuracy, while others are subject to market conditions. BC Hydro's forecast of the payment obligation is shown in Figure 4.

BC Hydro has forecast that the cost of supplying heritage electricity over the 10-year term of the Heritage Contract will average approximately Cdn. $25.30/MWh. This price was derived using an average forecast value for the payment obligation over the ten-year period and excludes any contribution from trade income. It is important to note that this is an illustrative number as ratepayers will pay the actual cost of supply, which may not necessarily be the same. Energy costs are likely to be volatile due to varying water conditions from year to year. BC Hydro believes that energy production could vary +/- 5,000 GWh from the heritage energy amount of 49,000 GWh. BC Hydro estimates that such variation could result in a price swing of $19.00/MWh to $31.00/MWh. The revenue requirements model shields them from the financial impact of such volatility, but it means that customers are essentially taking on all volume risk.

Although ostensibly designed to protect the interests of customers, the BC heritage contracts do not provide strong incentives to BC Hydro to improve operations, drive down operating costs, or efficiently allocate storage. Some of these incentives occur indirectly, through the use of Powerex to maximize off-system sales. Customers also take on hydrology risk, though they are also granted a free call option on all additional available volumes from the heritage assets.

3.2.2 Quebec

Hydro-Quebec (HQ), the province's crown corporation, supplies virtually the entire province of Quebec. HQ has a hydro fleet of nearly 32,000 MW, plus a single nuclear plant and limited thermal capacity. In order to conform to changes in the US market, HQ functionally unbundled its production, transmission, distribution, and wholesale operations into separate entities. Generation came under the auspices of Hydro-Quebec Production while TransEnergie operates and administers HQ's transmission grid. Hydro-Quebec Distribution is responsible for distributing electricity to customers in Quebec.

For its heritage contracts, Quebec has determined a maximum quantity of energy to be delivered by HQ at a fixed price for a specified period of time. Quebec implemented this model under an Order-in-Council issued in 2001 by establishing a contract between Hydro-Quebec Distribution and Hydro-Quebec Production. This served to lock-in benefits from Quebec's heritage generation facilities for an extended period.

In 2001, Quebec's energy regulatory body, the Régie de l'Énergie, approved HQ Distribution's 2002-2011 supply plan which established a heritage electricity pool where HQ Production must supply up to 165 TWh of electricity per year to HQ Distribution at an average rate of 2.79 cents/kWh. Demand in excess of the 165 TWh would be met through a series of supply contracts acquired by HQ Distribution through an open bidding process. Deliveries will not start until 2007 (when the energy is forecast to be needed) and the duration of the long term contracts may vary between 15 and 25 years under certain conditions.

As with the BC arrangements, the Quebec heritage contract does not provide significant incentives to HQ to reduce operating costs or to maximize its overall productive capabilities, or indeed to optimize use of storage. Like BC Hydro, HQ does have the opportunity to engage in off-system sales; as such, it is again presented indirectly with some incentives to optimize storage use and generate additional volumes. HQ heritage arrangements are slightly more favorable to customers in that they do put some volume risk onto the company.

3.3 experience in Hong Kong

Hong Kong has used a contractual approach to the regulation of electrical utilities, rather than a legislative one. The government of Hong Kong has written contracts, called Scheme of Control Agreements (SCAs), with the two utilities, China Light & Power (CLP) and Hong Kong Electric Company (HEC). The SCAs are 15-year bilateral agreements negotiated between the government and the utilities (the current agreements are set to expire in 2008) that set out obligation of the utilities to provide reliable electrical service to Hong Kong, and that specify the return the utilities are entitled to earn for providing that service. Regulation under Hong Kong's SCAs is similar in principle to cost of service/rate of return regulation in the United States, with tariffs set so that the utilities earn their rate of return.

The SCAs allow each utility to earn a return of 13.5% on Average Net Fixed Assets (fixed assets valued at historical cost less depreciation), plus an additional 1.5% on assets installed after 1979.

These fixed assets include generation, transmission, and distribution facilities. The utilities are responsible for making the decision about how much to invest in assets, with the exception of generation. For generation facilities, investment is allowed subject to an Excess Capacity Mechanism – if the generation fails an Excess Capacity Threshold test,[17] (and an additional Reserve Capacity test[18] in the case of CLP), a portion of its cost is excluded from the rate base - 40% for CLP, 50% for HEC.

Tariffs are set in an annual review by the government. While operating costs, including staffing, financing, and overheads, are passed through to ratepayers, the utilities have an obligation to serve their customers at the lowest possible cost. To ensure these costs are as low as possible, the annual review includes an audit of technical and financial performance. The tariff setting process also includes a Fuel Cost Adjustment Mechanism (FCAM). Under the FCAM, the tariff is set based on a standard charge for fuel. The difference between the actual fuel costs and the standard fuel costs are passed to consumers through a rebate or a surcharge.

Finally, if profits exceed the mandated return, the excess profit is set aside into an account that can be used to top up profits in years when costs are higher than expected.

This framework has presented a number of challenges that the government of Hong Kong is seeking to address in the next renegotiation of the SCAs.

- Investment in fixed assets is almost entirely at the discretion of the utility, which, combined with the fixed rate of return on assets potentially give an incentive to over-invest.

- Because Hong Kong's utilities are vertically integrated, costs are bundled. This makes it difficult to separate the costs of generation from the costs of transmission and distribution. Expenses such as salaries and other overheads are difficult to assign to one portion of assets.

- Rates of return are fixed, rather than being subject to periodic adjustment. This creates challenges in two directions. In the low interest environment of the mid 2000s, the returns to assets for the companies are high relative to similar firms, suggesting that tariffs are also too high. However, under a high interest rate environment, the fixed rates of return could easily become too low relative to other firms with similar risk profiles. In

17 Excess Capacity Threshold (ETC) test: A unit passes the ECT test if the Loss of Load Probability (roughly the expected amount of time that the utility would not be able to meet load obligations, according to a set formula) in the year it is added is greater than or equal to a set limit, currently set at less than one day per year.

18 Reserve Capacity (RC) test: If reserve capacity before commissioning of the new unit is greater than the combined capacities of utility's two of the largest units, plus the spinning reserve requirement, the unit fails the RC test.

that case, the utilities would find it difficult to finance investments, possibly leading to underinvestment.

- The fuel cost adjustment mechanism provides no incentives to manage the risks of fuel price changes or to reduce fuel costs.

4 Experience from other industries

It is not necessary to limit ourselves to the electricity generation industry when seeking regulatory models. A range of industries combine network and commodity elements, each with some degree of regulation. The examples we present here are from Australia, and are provided courtesy of LEI Global Alliance Partner Meyrick and Associates.[19] At first glance, these examples may appear to be somewhat removed from the power sector. However, each exists in an environment where a regulated asset existed in parallel with competitive assets; the issues of providing incentives for efficiency, maintaining investment, and imposing performance standards are consistent with best regulatory practice for generating assets.

The first two sections focus on regulatory regimes in Australia's coal and rail sectors that have a high level of regulatory interaction – mimicking to a certain extent a traditional cost of service regime albeit with certain limited efficiency incentive mechanisms. The third section provides examples of more light-handed regulation, where the regulator has the right to intervene but lets market participants set their own prices, as illustrated through case studies of Australia's port and grain sectors. Thus, while from different sectors, these case studies provide examples for price-setting approaches that could easily be adopted in Ontario's electricity sector, as we discuss in the last section.

4.1 Australian coal terminals – Dalrymple Bay

4.1.1 context

The Dalrymple Bay Coal Terminal (DBCT) is located at the Port of Hay Point, 40 kilometers south of Mackay in the state of Queensland, Australia. The DBCT commenced operations in 1983 as a publicly owned, common user coal export facility, and is one of the largest coal-exporting terminals in the world (handling 56 million tones per annum). Coal is shipped through the terminal from 13 mines in the Bowen Basin, with all coal transported from mine to terminal by rail.

The terminal is an integral part of the local coal supply chain, providing unloading, stockpiling, coal blending, cargo assembly and out-loading services to mines. In addition, it also has a coordination role, helping to ensure the matching of the delivery of coal by rail to the scheduled ship arrivals.

The DBCT was sold by the Queensland Government to a private group known as Prime Infrastructure (now Babcock and Brown) in 2001. A wholly-owned subsidiary of Babcock and Brown, DBCT Management Pty Ltd, operates and manages the facility.

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[19] LEI works closely with Dr. Denis Lawrence at Meyrick; Dr. Lawrence has been part of the LEI team for several OEB engagements.

Over recent years, the DBCT has been the subject of an extensive regulatory review, covering among other things, third-party access, capacity expansions, and service price settings. For this reason, we believe the DBCT case provides some useful insights into the nature and rationale of the building block-based approach to access and price regulation, which is applied to DBCT as well as to most rail track systems in Australia.

DBCT is regulated by a State regulator under the Queensland Competition Authority Act (1997). This Act established the Queensland Competition Authority (QCA) as the chief State regulatory agency, which is responsible for critically assessing and dealing with the appropriateness of the pricing practices of monopoly businesses, as well as deciding upon access to the services provided by the essential infrastructure of these businesses.

As DBCT is regarded as possessing monopoly-like characteristics that allow it to exercise considerable market power as an export coal terminal in the Bowen Basin area, its financial settings and operational activities are regulated by the QCA. DBCT is the only coal export terminal in Australia that is regulated in this way. The other terminals, which either remain under public sector control or are operated by cooperatives of mining companies, are not subject to formal economic regulation.

In late 2001, the Queensland Government declared the coal handling services of the DBCT for third party access under Part V of the QCA Act. The economic rationale behind declaration is that granting access (or increased access) would promote competition in an upstream or downstream market. It is important to recognize that this process is a negotiate/arbitrate model — that is, it is primarily the responsibility of the access provider and the access seeker to negotiate on price and non-price terms and conditions. The QCA only becomes involved when negotiations repeatedly fail and either party has lodged a dispute notice with the QCA.

In June 2003, Prime Infrastructure lodged a draft access undertaking with the QCA for the coal handling services at DBCT. The QCA undertook an investigation to evaluate the appropriateness of the undertaking, inviting written submissions from all interested/concerned parties. However, in April 2004, the access seekers, dissatisfied with the terms and conditions offered by Prime, lodged a dispute resolution notice with the QCA. This meant that along with running its own investigation process, the QCA was also required to launch a process of arbitrating the dispute between Prime and the access seekers. Taken together, these two processes culminated in the QCA making explicit decisions on the prices to be charged at the DBCT.

4.1.2 price regulation approach

The QCA thus proceeded to establish a comprehensive price regulation structure for DBCT – establishing a regulatory ratebase, setting DBCT's allowed return, and putting in place appropriate incentive mechanisms and performance standards. This approach, though applied to a coal export terminal, is similar to how one might approach regulating the electricity generation sector. As such, we provide some detail as to the detailed implementation of QCA's price regulation of DBCT below.

Setting the ratebase was QCA's starting point. The value of the regulated asset base is a key determinant of the annual revenue requirement and, as a consequence, the proposed reference tariff to be paid by terminal users. The QCA valued the DBCT on the basis of a Depreciated Optimized Replacement Cost (DORC) methodology, an approach widely used in Australia.

Next, the QCA set DBCT's allowed return. The QCA adopted a Weighted Average Cost of Capital (WACC) approach to establishing an appropriate rate of return for the DBCT. This partly reflected the fact that Prime Infrastructure (the owner of DBCT) had not been listed long enough to allow reliable estimates to be made of its required return on equity from share-market data. In addition, there were no similar, listed coal export terminals in Australia or overseas that would allow the return on equity to be accurately benchmarked. As such, a first principles analysis of the terminal's underlying risks was undertaken. Based on an assumed risk free rate of 5.8%, an assumed market risk premium of 6%, and an assumed equity beta of 1 and an assumed asset beta of 0.5[20], the QCA determined that DBCT's return on equity should be 11.84% in nominal, pre-tax terms.

The QCA put forward a revenue cap as the most efficient means of providing the asset owner with revenue certainty (over all possible volume outcomes) and an incentive to obtain productivity improvements, with the latter targeted by an "overs" mechanism. This mechanism provides scope for the owner to earn 2% above the revenue cap if it can prove that it has contributed to higher productivity and thereby led to effective cost savings across the terminal. The reason for incorporating this incentive mechanism is to offset for the fact that the efficient pass-through of operating costs to users of the terminal does not in itself provide any incentive for the owner to strive for productivity improvements.

In addition, the QCA emphasized the importance of performance because it serves to assure stakeholders that a regulated entity is complying with its access obligations (of quality of service provided). To this end, DBCT management has proposed an extensive list of key performance indicators (KPIs) focusing on critical aspects of the coal supply chain, such as tonnes/hour of train handling; percentage of trains arriving within an hour of scheduled arrival time; average ship delay in port; and, stockyard utilization ratio.

At the same time, the QCA adopted a framework that encourages and facilitates capital spending and expansion of the terminal. This framework involves the Authority automatically approving management's intended capital expenditure if: the expansion path is consistent with the approved DBCT Master Plan; 60% of the proposed expansion is subject to firm contractual commitments from access seekers; and, 60% of existing users (as determined by contracted tonnages), other than those users who have formally committed to the expansion tonnes, do not oppose the expansion. If future capital expenditure is approved, both the revenue cap and reference tariffs are revised and recalculated based on the submitted capital expenditure and additional tonnage forecasts. The expansion costs are then rolled into the asset base.

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[20] The latter reflects the low correlation between DBCT returns and the Australian economy.

Finally, while direct competition is limited by both infrastructure and institutional conditions, indirect competition does play an important role in disciplining terminal behavior. The mines served by the different terminals are competing in the same commodity markets and have very similar costs of production. This means that logistics costs can be a critical determinant of competitive success. Consequently, poor service performance and/or high prices at DBCT could see the mines that currently use the terminal lose contracts to mines feeding other terminals. Alternatively, global commodity producers that operate mines on several continents may reduce or cease their operations at mines that use the DBCT.

4.2 Rail access in Victoria

4.2.1 context

Over recent years, considerable effort has gone into developing and implementing rail infrastructure access regimes in Australia. Constitutionally, rail transportation falls to the province of State governments rather than the national government. Each State has taken a different path in corporatizing or privatizing their rail operations, and also in fashioning regulatory arrangements intended to secure third party access to the rail track. In addition, several states have agreed to hand over control of the major rail links between state capitals to the Australian Rail Track Corporation (ARTC), which is wholly owned by the national government and regulated by the federal competition regulator, the Australian Competition and Consumer Commission (ACCC). The result has been a patchwork of different regulatory regimes across the country, all of which have common features but each of which also has its own distinctive characteristics. One regime worthy of examination is the Victorian Rail Access Regime (VRAR). The Victorian rail track is leased, on a long term basis, to Pacific National, which is Australia's largest rail operator. Pacific National also dominates the provision of above-rail services in Victoria.

In October 2005, the Victorian Government established the Rail Network Pricing Order 2005, which came into effect on 1 January 2006. Clause 4.1 of the Pricing Order sets out a number of principles that govern the setting of rail access prices. The two main principles are that prices should be set to levels which ensure that forecast revenue from declared rail transport services is consistent with efficient cost of supply, and the overall framework for setting prices should seek to provide incentives to the access provider to incur an efficient level of costs.

The Essential Services Commission (ESC) is the responsible statutory body for regulating Victoria's rail freight infrastructure and its services. One of the key terms and conditions that the ESC has jurisdiction over is the appropriate level of access charges. Under Section 5(a) of the 2005 Order, the ESC has the power to select the appropriate methodology for calculating rail access prices for declared rail services and, ultimately, to determine and enforce the level of access prices that an access provider obtains from an access seeker for use of declared rail infrastructure services.

4.2.2 price regulation approach

The ESC thus designs and implements rail pricing, including setting the regulated asset base, establishing an allowed rate of return, and putting in place appropriate efficiency and performance incentives. As with the example of the coal export terminal in the previous section, regulation of rail pricing has many similarities to electricity pricing and thus may serve as a useful example to the OEB.

Under the 2005 Order, the value of the asset base (RAB) for regulatory access purposes is based on the accumulated capital expenditure since 30 April 1999.[21] As such, only efficient capital expenditure incurred on relevant rail infrastructure on or since 30 April 1999 may be recovered as part of a revenue cap. This means that the asset owner (the Government) of pre 30 April 1999 assets decided to forego a return on those assets, which effectively delivered an ongoing subsidy to all users. The Government's intention was to encourage additional use of rail infrastructure services. The decision to exclude pre 30 April 1999 capital expenditure in formulating the asset base has implications for the type of asset valuation method used, with the ESC adopting the Depreciated Actual Cost (DAC) approach rather than the Depreciated Optimized Replacement Cost (DORC) approach used elsewhere in Australia.

The ESC employs a weighted average cost of capital (WACC) approach to establishing the appropriate rate of return on capital for operators in the Victorian intrastate rail system. This is in line with other Australian rail regulators that are engaged in setting access conditions, prices, and returns. A real, after-tax, forward-looking WACC is used to generate return estimates.

The Victorian Rail Access Regime also stipulates market-based incentives for access providers and service operators to:

- **Improve operating efficiency --** Section 4.2 of the Pricing Order allows an access provider to retain all or part of the lower costs due to efficiency increases in the subsequent access period. Similarly, an access provider would incur all or part of the higher costs of declines in efficiency. Additionally, the Victorian regime provides for an 'efficiency carry-over' mechanism that creates an incentive for the rail operator to generate operating cost efficiencies toward the end of the regulated access period. The benefit of these efficiencies is crystallized in the next access period.

- **Increase the utilization of rail services --** The ESC has modified the standard revenue cap so that higher-than-forecast revenues obtained from increased volumes within the access period can be retained by the access provider. This provides a financial incentive for the access provider to increase network usage (the modal share of rail).

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[21] 30 April 1999 is when private sector rail infrastructure operators were granted leases (by the Victorian state government) to the network.

- **Maintaining performance service and quality standards --** The Commission does have the discretion to 'clawback' revenue in the next access period if it determines that an access provider has underperformed against the service standards outlined in an access arrangement. This provides an incentive for providers to maintain standards of quality and reliability.

Finally, the ESC expects a rail access provider/operator to undertake a level of capital spending that is required to attain a 'fit for purpose' service standard. This standard is based on a combination of good industry practice and achieving the lowest sustainable cost of the delivering rail services. Given the need for long term planning in the rail sector, the ESC requires that forecast capital expenditure estimates be set for a timeframe covering the current and subsequent access periods. In addition, capital expenditure must be framed with reference to the access provider's asset management planning and related capacity to deliver effective on-the-ground systems maintenance and monitoring. After the Commission has approved the capital expenditure forecasts, they are used to re-calculate the regulated value of the asset base during the access period, which in turn feeds into a revised revenue requirement.

In addition to regulated pricing structures, there is some competition between rail systems within Victoria. Competitive pressure from road transport is the most pervasive. The Victorian rail network only carries a small proportion of the mining exports, which have characteristically underpinned the viability of rail systems in Australia. The major rail traffics are grain and general cargo, and both are subject to considerable competition from road. Moreover, Victoria is a comparatively compact state, and haulage distances are correspondingly short. Competition from road transport acts as a very real constraint on the rates that rail operators can charge to end users, which acts to effectively constrain the ability of Pacific National to extract monopoly rents from its control of the rail track. The pressure from road operators does not, however, prevent Pacific National from leveraging its control of the rail track to strengthen its competitive position in the provision of above-rail services.

4.3 use of light-handed regulation in other Australian infrastructure sectors

In contrast to the previous examples, over recent years, some Australian regulatory bodies have adopted a so-called 'light-handed' approach to regulating access to, and the prices charged for, essential infrastructure services. This approach encourages access seekers and infrastructure operators to reach their own commercial agreements on access, with the regulator taking on a facilitator role. In addition, access price regulation involves undertaking price monitoring and notification rather than imposing more onerous price and/or revenue cap arrangements.

The purpose here is to outline briefly the key features of the light-handed access regimes that are currently in place in two areas, namely port services in South Australia and grain terminal handling in Victoria. (Light-handed regimes are also in place for the ports of Victoria and for major national airports).

4.3.1 South Australian ports

The Essential Services Commission of South Australia (ESCOSA) is the responsible statutory body for regulating declared port infrastructure and its services. This primarily involves facilitating access processes and conducting price monitoring.

Regulated services are subject to the Ports Access Regime, which falls under Part 3 of the Maritime Services (Access) Act 2000. The following port services have been declared as regulatory services:

- providing berth access for vessels at the common-user terminals at Port Adelaide, Port Giles, Port Pirie, Port Lincoln, Wallaroo, Thevenard and Ardrossan. All these ports are privately operated by Flinders Ports Pty Ltd, with the exception of Ardrossan (managed by Ausbulk Ltd). Therefore, these two companies are the regulated operators.

- pilotage services facilitating access to the port; and

- facilities for loading or unloading vessels.

The Ports Access Regime states that access to the above services should occur on fair commercial terms. The ESCOSA has a strong preference for the access provider (Flinders Ports) reaching a commercial agreement with a prospective customer on access.

Section 3 of the Essential Services Act 2002 sets out the key features of the price monitoring system covering declared port services in South Australia. The operator is allowed to set its own prices for essential maritime services (mentioned above) for a three-year period, from October 2004 to October 2007. The operator must post a comprehensive (in coverage, not necessarily in size) price list for the declared services on their website. The operator must inform the ESCOSA of having done so and of the changes made to these prices from time to time. The operator and access seekers (customers) are free, and are encouraged by the ESCOSA, to enter into commercial arrangements covering price and service quality levels. Importantly, price levels can differ from posted prices if both parties agree to this. This may be appropriate in the case where an access seeker is prepared to pay a higher price to utilize a port service that necessitates the operator making an additional investment in capacity (and therefore incurring new costs). Finally, the ESCOSA has the authority to monitor and publish reports on essential maritime service prices and related performance indicators. This includes benchmarking against other Australian ports.

The ESCOSA will undertake a review of the effectiveness of the current price monitoring arrangement to decide whether price regulation is warranted after October 2007. The ESCOSA argues that the threat of re-regulation (that is, of the introduction of tighter, more intrusive regulation) acts as an ongoing incentive against an operator misusing its market power.

4.3.2 Victorian grain terminals

Under the Victorian Grain Handling and Storage Act 1995 (GHSA), the Essential Services Commission is responsible for the regulation of certain services provided by the export grain terminals at the ports of Portland and Geelong. The objectives of the Commission include: promoting competition in the storage and handling of grain; protecting the interests of users of the grain handling and storage facilities in terms of price by ensuring that charges across users and classes of services are fair and reasonable; and, ensuring users and classes of users have fair and reasonable access for grain to the port facilities.

The Act also establishes the access regime applying to declared export grain terminals. It was enacted in 1995, at the time of the privatization of the Grain Elevators Board (GEB). The access regime was introduced to ensure that consumers were not disadvantaged by the privatization of "bottleneck monopoly" facilities.

In 2003, the ESC review of the access regulations resulted in amendments to the GHSA, which reduced the scope of the regulatory regime. The requirement to set prices according to defined principles was removed, and the Commission no longer plays a role in price-setting per se. The Commission's role has, since October 2003, been confined to resolving access disputes between access seekers and the service provider.

The terminal operator is entitled to vary the terms and conditions of access according to the actual and opportunity costs of providing the regulated services, and may take into account, amongst other things, the volume and timing of the grain shipments for which access is sought. The operator is, however, prohibited from offering terms and conditions of access which vary according to the identity of the person seeking access, or which require the access seeker to obtain other services in order to have access to regulated services.

The GHSA gives a person seeking access to regulated services the right to seek a determination from the Commission on the terms and conditions on which access is to be provided. There are three circumstances in which access disputes may be brought before the Commission for a determination. These are: where the terminal operator has failed to make a formal response to a request from an access seeker within a reasonable period; where the terminal operator and an access seeker cannot agree on the terms and conditions of access; or, where a user of prescribed services' reasonable right of access is hindered.

The Commission is obliged to determine the dispute "as quickly as proper consideration of the dispute allows, having regard to the need to carefully investigate all matters affecting the merits and fair settlement of the dispute." To facilitate this process, the Commission has published the Grain Handling and Storage Access Regime: Guidelines (the Guidelines) which sets out how it will conduct its regulatory role of resolving access disputes.

To assist the Commission in performing its regulatory role, the GHSA requires that grain handlers keep separate records of the costs of providing regulated services, and to provide certain other information to the Commission on an annual basis. This requirement is intended to ensure that the Commission has access to necessary data when it is assessing whether access terms are likely to represent a significant exercise of market power, and to assist it in determining an access price.

In the three years since the changes were made to the GHSA, the Commission has not been called upon to arbitrate a dispute, and a further review is currently underway to determine whether continued regulation is necessary.

4.4 Implications for Ontario

While these examples come from very different industries than electricity, the monopolistic position of some of the companies described above and the approach that regulators have taken in regulating and supervising these companies' pricing holds several lessons for Ontario's electricity sector. The examples from Queensland's coal industry and Victoria's rail industry reflect a more traditional cost-of service regulation approach that is often used in the electricity sector. While both used a regulated asset base and allowed rate of return as part of the pricing mechanism, they also used different types of incentive mechanisms that may be useful to consider within the Ontario context. Queensland's "overs" mechanism provides a premium to the owner to earn an amount above the revenue cap if it can prove it has contributed to higher productivity, while the Victoria system allows the owner to retain all or part of the lower costs due to efficiency increases in a given regulatory period. Both of these approaches encourage companies to increase efficiency and might be easily implemented in the electricity generation sector should the OEB decide that a cost of service regime pricing approach is most appropriate.

Our other examples focused on more light-handed regulation approaches. These two case studies, from the South Australian ports and the Victorian grain terminal sectors, provide a clear example of how regulators can allow competitive pricing yet maintain a clear right to intervene should market participants abuse this right. Should the OEB be comfortable allowing OPG to establish bilateral contracts for the sale of generation from its nuclear and hydroelectric facilities, this approach could easily be used as a way to ensure that OPG does not engage in monopolistic pricing. It does not, however, encourage improved efficiency at OPG's facilities, which may be better addressed through a different regulatory approach.

5 Private sector "regulation by contract"

Private contracts "regulate" the behavior of the contracting parties for their mutual benefit. Some contracts contain provisions which might be adapted to a regulated environment. Traditional tolling agreements, for example, specify a range of conditions which generators must meet in order to be paid, including availability, maintenance outages, and expected heat rates. While such agreements would need to be modified in the context of nuclear and hydro assets, there are nonetheless insights which can be gained from private practice.

5.1 standard contract provisions

Traditional cost of service utility regulation placed most risk, including but not limited to construction cost overruns, availability risk, fuel price risk, and outage costs, on the shoulders of ratepayers. Ratepayers were charged the cost of replacement power to cover plant outages; utilities were not subject to explicit standards for the amount or length of maintenance outages or when they were scheduled. Generally speaking, utilities were not heavily scrutinized by regulators with respect to the ongoing heat rates of their fleets or their overall plant availability, except within very broad parameters. This approach is very different from what occurs when private sector parties freely agree to contract with one another; in private sector contracts, the sharing of risks, and the financial consequences, are often carefully spelled out.

Traditional power purchase agreements (PPAs) specify quantities to be delivered, the price to be paid for those quantities, and the consequences of non-performance. PPAs can be "one part" (a simple energy tariff, denominated in $/MWh, but possibly with differentiation by time of day or season, or with ascending or descending blocks), or "two part", with a capacity and an energy payment. Capacity payments could be specified in terms of a fixed monthly, quarterly, or annual payment, or in terms of $/MW/month; they could also contain overall availability requirements.

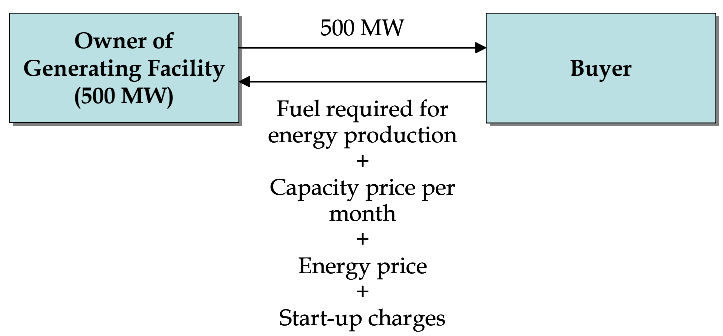
These traditional PPAs put the fuel supply price risk on the seller, and the risk of being unable to use or profitably sell the output on the buyer. Tolling contracts change the allocation of risk; the buyer takes on fuel supply risk, but reduces its take or pay exposure. The plant operator retains operational risks; contracts are structured so as to enforce availability standards and to minimize scheduled maintenance, particularly during peak periods.

It is possible to imagine adopting several aspects of private sector contracts in a regulated generation environment. Private sector contracts are designed to allocate risk and provide incentives; there is no readily apparent reason why a similar approach cannot be devised for regulated generation. The elements of a regulated contract with generators on behalf of ratepayers would include plant-by-plant availability targets, fuel efficiency standards, efficient fuel procurement incentives, incentives to schedule maintenance effectively, incentives to increase output economically, liquidated damages for non-performance, and specified force majeure provisions. While such provisions are more straight-forward to design in the context of fossil-fueled plants, they are by no means impossible to devise for nuclear and hydro electric facilities.

5.2 tolling agreements

Tolling is a type of transaction in which a fuel supplier enters into a long-term contract with a power generator to purchase the plant's output in exchange for supplying fuel. Typically, the fuel supplier is a marketer who takes on the risk of selling power on the spot market, although the fuel supplier could also be a utility, a load serving entity like a retail supplier, a major commercial or industrial customer, or some other entity. The output of the generating facility is owned by the marketer, and the generator receives a guaranteed stream of income in the form of a "tolling" fee. Thus, the owner of the facility is responsible only for converting a specific amount of fuel to power and delivering it to a mutually agreed delivery point. In exchange for the revenues from selling the power, the toller assumes the risks of obtaining the fuel and marketing the power. Figure 5 illustrates an arrangement under a typical tolling transaction for a 500 MW facility.

Figure 5. Typical arrangement under a tolling agreement



Tolling is increasingly favored by plant developers as a way to lower the risk of financing new gas-fired power plant projects. The tolling fee compensates for the capital cost of construction, the fixed costs associated with maintaining availability, and the variable costs associated with energy conversion, while allowing the generator to earn a fixed return. Although this return may be lower than what could be earned via merchant sales, the profits are more stable.

In one recent tolling arrangement, Calpine Energy Services Canada Partnership (CESCP), a wholly-owned partnership of Calpine, entered into a tolling agreement with Calgary Energy Centre LP for the provision of tolling services to the 300 MW Calgary Energy Facility. In accordance with the terms of the agreement, CESCP is obligated to deliver all fuel required to operate the facility and to pay for (e.g., purchase) all electricity generated or deemed to have been made available by the Calgary Energy Facility for a tolling fee of approximately Cdn.$1.6 million per month. Upon entering into this arrangement in August of 2002, CESCP also made an upfront payment of Cdn.$27.7 million to Calgary Energy Centre LP. Additionally, as a pre-payment for the provision of future tolling services of the Calgary Energy Facility, CESCP was required to pay to the Calgary Energy Centre LP a monthly amount equivalent to the fixed charge component of the monthly tolling fee until the completion date of the Calgary Energy Facility. The Calgary Energy tolling agreement is a 20-year contract with a possibility of two five-year extensions.[22]

Gas tolling has emerged in the last decade, but the practice of tolling itself is not new. Tolling agreements are used extensively in virtually every industry in which the production process is relatively simple, involving for instance the transformation of a single input into a single output, which makes it easy for the user to monitor toller performance. Agro-processing is one sector in which such simple transformative activities are common, and not surprisingly, is the sector in which tolling was originally developed. There is ample evidence, going back to the Middle Ages, of cereal grains being milled in exchange for an in-kind toll. These arrangements are common in the oil industry, where refiners are paid for the use of their idle capacity to convert barrels of crude oil into petroproducts. Coal suppliers have also entered into a number of tolling arrangements and with electric generators.

The relevance of tolling to the designated assets is limited to the notion that private contractual arrangements contain explicit expectations regarding availability and efficiency of operations. Although the designated assets have limited fuel costs (in the case of hydro) or relatively small potential to improve the efficiency of fuel usage (for nuclear assets), the overall concept of tolling is another tool which regulators can use when examining how to appropriately apportion risks between generators and ratepayers. It is increasingly being incorporated into Single Buyer models in jurisdictions which have yet to deregulate, and in which there is limited opportunity for generators to either optimize fuel pricing (due to fuel pricing being set by the state monopoly supplier) or to engage in alternative power sales. Tolling minimizes take-or-pay risk, both to the generator, which no longer has to purchase fuel which may or may not be used, and the purchaser, which will not be stuck paying the generator for the variable costs of power the purchaser is unable to use.

[22] The recent Calpine bankruptcy has caused this tolling agreement to be unwound.

6 Implications for Ontario

6.1 issues unique to hydro and nuclear assets

In a normal private sector tolling agreement, the power purchaser provides capacity payments to cover the fixed costs of the plant, fuel at a specified heat rate, and payments, when the plant runs, to cover variable operating and maintenance (O&M) costs. The plant operator may be offered a rate for excess power generated due to improved efficiencies at the plant, or the opportunity to sell excess power generated to third parties. Because capacity payments are linked to availability, the plant operator has an incentive to improve availability, and if the payments are sculpted hourly or seasonally, plant operators have a particular incentive to ensure that the plant is available at the times when the power is most valuable. Because fuel supply is provided based on a target heat rate, plant operators have an incentive to improve plant heat rates and either sell the excess fuel or use it to generate additional power. Of course, deterioration in heat rates increases costs to generators because they must make up any shortfall.

These types of arrangements have favorable incentive properties for fossil fuelled plants, but may be more difficult to apply to nuclear and hydro assets. The issues that complicate tolling arrangements for these facilities are specific to each asset class. In the case of nuclear assets, revenue sufficiency to maintain safety is a primary concern. If capacity payments are sufficient to cover required future safety needs, then strong performance incentives can be embedded into them. The generator may be required to pay for replacement power when the plant is out of service for an unplanned outage, in addition to foregoing capacity payments for that period. Likewise, if the plant is available for a greater period of time than expected in the formulation of the capacity payments, the generator can earn additional revenues. However, the contract must clearly delineate how risks are to be shared between customers and the generator. In some cases, the generator may have immediate unexpected safety needs that require investment – this may require an ability to apply for a temporary increase in capacity payments or some other financial transfers to assure that funds are available in such situations.

On the fuel supply side, we can imagine a form of "uranium tolling", in which an annual allowance is provided for fuel costs based on a relevant index of uranium costs, and an expected conversion rate. This would in fact be little different from a traditional tolling arrangement, however, the dynamics of nuclear plant operations differ from fossil stations. The cost of nuclear plant outages likely far exceeds any potential gains from more efficient fuel utilization, if indeed plant operators have much ability to influence the efficiency of fuel conversion. This suggests that regulators should focus on incentives for safe operation and increased capacity factors, which can be accomplished through a series of availability linked capacity payments coupled with the potential loss of equity returns in the event of continued safety violations.

Private sector contracts normally contain carefully drawn force majeure provisions. The idea that many of the factors driving costs or revenues for nuclear and hydro operators are beyond the control of the operators is simply not true, or is irrelevant to the question of whether the generator should assume that risk. Private sector hydro owners take on hydrology risk. Brookfield Power does not receive top up payments in low hydro years for its Mississagi hydro assets. Nuclear operators are often forced to pay for the cost of replacement power when their units are offline for extensive periods. American Electric Power was forced to do so after the extended outage of its Cook station, ultimately resulting in lower earnings for its shareholders. Merchant nuclear operators may face even greater costs under their contracts.

While safety is also a concern for hydro assets, particularly dam integrity, the main challenge in developing incentive-based contracts for hydro stations is two fold: how to provide incentives to both increase output under particular hydrological conditions, and how to assure that storage is efficiently allocated.

Price signals are among the most effective ways to encourage hydro operators to efficiently allocate stored water to the highest value periods. An arrangement which simply pays a flat capacity payment and a minimal fixed variable payment provides little incentive for the hydro operator to properly utilize storage or to maximize output. Payments based on average hydrology, rather than actual hydrology, will over- or under-compensate the generator for output in any given year unless that year is an "average" hydrology year. Again, such payments may not result in incentives for maximizing output or managing storage.

Overall, we tend to believe that for hydro stations, providing payments which are shaped as much as possible to reflect the overall shape of HOEP are beneficial. When hydro plants are not operating, they should not be paid. When they are operating, payments need to reflect the opportunity cost of the water being stored. While it is true that this is of far greater concern for storage hydro, and particularly for pump storage, it is also necessary for run of river facilities. In some run of river applications, small adjustments to operations are possible to maximize output at peak periods. In addition, the arrangements for the designated assets should probably be structured in such a way that if OPG so desired, it could at its own risk make investments that would allow it to increase output at the facilities. The increased output would receive the same economic treatment as existing production. Thus, providing peaking prices to run-of-river hydro may incentivize OPG to seek ways to increase output at those plants.

While we believe that arrangements should be consistent across designated assets of similar technologies (i.e., all hydro assets should be treated similarly), hourly and seasonal price signals are critical to the operation of pump storage facilities. Given OPG's current market power, making the pump storage completely market-based may not be feasible over the near term. However, application of a profit-sharing and rebate scheme for such facilities could allow market prices to be used for signaling purposes, even if the full effect of market prices does not flow through to OPG's bottom line.

6.2 potential models to consider

Based on the models for generation regulation observed worldwide, we have developed three alternative approaches which could be applied in Ontario. These are designated as Scenarios 1 to 3. Scenario 1 is traditional cost of service ratemaking. Scenario 2 is a form of efficiency target regulation. Scenario 3 is "regulation by contract" deploying a contract-for-differences (CfD) structure. Each approach is described briefly below.

6.2.1 Scenario 1: cost-of-service ratemaking

Under a cost-of-service approach, in 2007 OPG would file with the OEB regulatory accounts showing a proposed regulated asset base (RAB) for the designated assets. Separate filings would be made for each type of generation asset – thus, there would be one filing for nuclear and one filing for hydro assets. This RAB would likely be the current book value of the assets. OPG would also propose an allowed return on RAB, which could be a commercial return, a return incorporating the current 5% return on equity, or some other level.[23] The filing would also specify depreciation on the assets for 2008. OPG would also provide a forecast of operating costs associated with the designated assets for 2008, and levelized long-term capital expenditures. The summation of the return on ratebase, 2008 depreciation, 2008 operating costs, and budgeted capital expenditures would provide OPG's revenue requirement for 2008.

In addition, OPG would be required to provide a forecast of volumes to be produced from the assets. The revenue requirement divided by forecasted volumes produces the prices that OPG would receive for output from the designated assets. OEB would review OPG's filings using a process of its choice. If the information provided is supported by the review, then the Board would approve the filing and associated rates. In 2008, OPG would repeat the process for 2009. However, the filing in 2009 would be slightly different. By 2009, actual data from 2008 would be available, including actual expenditures by OPG and actual volumes produced. Thus, rates for 2010 would incorporate a true-up based on 2008 actual results – if OPG in 2008 recovered more than its revenue requirement, the excess would be returned (with interest) to ratepayers in 2010; if OPG had a revenue shortfall, it would be entitled to recover the difference (with interest) in rates in 2010. From 2009 onward, the process would be similar in each subsequent year.

The primary advantage of cost-of-service ratemaking is that it provides for a high degree of revenue certainty for OPG. Although the annual filing process does require some resources on the part of both the regulator and OPG, once implemented, it is largely mechanical. The major drawback of this type of price setting process is that it provides virtually no incentives to OPG to improve plant and operational efficiencies and to reduce costs. Because OPG recovers its costs and return, no more and no less, it has no incentive to reduce costs or to maximize output. In addition, it receives no signals about how to use hydro storage effectively, or about when to schedule maintenance outages so as to minimize the impact on the overall system. Furthermore, because OPG would continue to receive market prices for output from some of its units, the

[23] Return on ratebase is equivalent to a weighted average cost of capital (WACC). Assuming a 50/50 debt/equity ratio, 6% cost of long term debt, and 12% return on equity (ROE) for contracted baseload assets, a typical commercial pretax WACC might be approximately 9%. Using the current 5% ROE applied to OPG designated assets, and holding all other assumptions constant, the resulting WACC would be 5.5%.

possibility for strategic behavior exists with regards to maintenance scheduling of the designated assets. To the extent that a well-timed outage pushes up market prices, OPG may be able to earn additional profits in a fashion unintended by the regulator.

6.2.2 Scenario 2: efficiency target ratemaking

The starting point for efficiency target ratemaking would be similar to the cost-of-service scenario outlined above. Rates in 2008 would be set based on a filing from OPG outlining its revenue requirement. However, instead of dividing the revenue requirement by projected volumes, the revenue requirement would be divided by five year average output from the designated assets (with projected averages used for the restarted Pickering units), plus a working capital adjustment factor.[24] An alternative approach would be to use existing prices as a base price, given that existing prices were established in a fashion intended to provide OPG with revenue sufficiency. If it is accepted that existing prices incorporate an accurate representation of appropriate costs (and given that these prices have embedded within them a lower than commercially reasonable allowed return on equity), then a full examination to justify them may not be necessary.[25]

The result would be a price cap on OPG output. This price cap would be in place for five years.[26] Annually for each year after 2008, the price cap would be increased by inflation per an appropriate index specified by OEB, and decreased by an X factor, also specified by OEB. The X factor would be designed to represent expected efficiency improvements specific to operation of the nuclear and hydroelectric plants which constitute the designated assets.

One approach to developing such an X factor would be to perform a productivity study for each asset class (one for nuclear and one for hydro), using data for a representative sample of similar North American plants. This productivity study would examine the most recent five year period for which data was available, and would include plant operating under a range of ownership and market conditions.

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[24] The working capital adjustment factor is designed to account for the fact that under the efficiency target scheme we describe here, OPG may face greater volatility in its revenue streams from the designated assets, primarily due to hydrology. Because in any year it may earn less or more than its "expected" revenue requirement as output from the hydro stations changes, it may need to maintain a reserve to cover low hydrology years. However, given that calculations incorporate five year average hydrology, and the price cap is set to run for five years, over the course of the arrangements OPG should be revenue neutral.

[25] Gaining adequate oversight over OPG's new capital investment programs would probably provide greater ratepayer benefits than reviewing costs associated with the designated assets. Even using existing prices as a baseline, we can effectively embed within rates the incentive properties that we seek.

[26] We have chosen five years for illustrative purposes; the length of the regulatory period depends on the desired balance between the stability of the regulatory arrangements, which gives the company time to respond to the associated incentives, and the desire to avoid over- or under-rewarding the company by having a too low or too high X factor in place for too long a period of time.

Note that performing such a study is not a trivial exercise. At least three questions need to be answered: first, what form of productivity analysis should be used? A number of statistical and econometric techniques can be deployed, ranging from Data Envelopment Analysis (DEA) to Total Factor Productivity (TFP). The choice of method affects the magnitude of the results; this does not mean that each method is flawed, but rather that each approach looks at the question from a different perspective. The OEB would need to determine which perspective was most compelling given the intended purpose.[27] Second, is the data from the sample size relevant for the specific situation found in Ontario? Ontario operating conditions for hydro are not terribly unique from those faced across North America, so the argument of uniqueness may be less relevant. The issue becomes more debatable when we switch to the nuclear side of the business, given that the CANDU technology does have some elements that make it distinctive. Any productivity study based on North American nuclear operations would need to address whether technological differences should have any impact on the results. Third, any productivity analysis needs to explore whether the future looks like the past – to what extent will future productivity gains keep pace with, or exceed, those observed in the past? None of these three questions raises insurmountable obstacles to the determination of an appropriate X factor for the designated assets. Rather, each issue needs to be addressed to assure that the calculations are robust.

The interaction between the OEB and OPG would proceed differently than under Scenario 1. In Scenario 2, OPG would submit its revenue requirement as in Scenario 1; it would also submit its average volumes calculations. OEB would then provide its preliminary guidance on the appropriate X factor to be applied over the next five years. OPG and intervenors could then respond, following which OEB would make a final determination on the X factor to be applied. Once the X factor was determined, the scheme would run until the next regulatory review. Thus, there would be no annual true-up or recalculation of rates, though OPG would be required to make informational filings.

Scenario 2 has some advantages over Scenario 1. It reduces the overall regulatory burden by eliminating the need for an annual evaluation of actual costs. Furthermore, and more importantly, it provides strong incentives to OPG both to maximize volumes (more volumes mean more revenues) and to achieve operating cost efficiencies (failure to meet the X factor would result in lower profits; efficiency improvements in excess of those embedded in the X factor would result in additional profits).

Scenario 2 shares some of the drawbacks of Scenario 1, however. Scenario 2 provides no particular signal to OPG regarding how to efficiently schedule maintenance outages or to utilize storage. In addition, the process of setting the X factor presents the regulator with a challenging task, though this challenge may be compensated for by the fact that the regulator no longer needs to go through an annual cost review process. An additional distinction between the two scenarios is that Scenario 1 provides greater flexibility to change regulatory regimes, because it

[27] Although choosing the method is beyond the scope of this engagement, we would likely favor TFP analysis, due to the fact that TFP examines usage of both capital and labor and how this usage has changed over time.

is essentially an annual arrangement. Scenario 2 runs for a longer term, thus it requires the regulator to have confidence that the proposed arrangements are appropriate for a longer period of time.

6.2.3 Scenario 2b: availability linked increase in allowed return on equity

One interesting approach OEB could take would be to continue with rates under the current structure, which incorporate the aforementioned below commercial rate of return. (OPG is one of the few companies in the world which has a lower cost of equity than of debt.) However, these rates would be augmented by a bonus account. The bonus account, if fully earned, would be sufficient to bring OPG up to a full commercial return (likely a minimum 10% return on equity). The bonus amount would be set for the entire year, but divided by five year average production by the designated assets to develop a volumetric rate. This volumetric rate would be further sculpted seasonally and hourly to provide appropriate price signals. OPG would only receive the payment for volumes produced; there would be no force majeure provisions of any kind, because force majeure would already by covered by the existing pricing arrangements.

This bonus incentive return approach could have several advantages. It is simple to administer. Because it gives OPG something that it wants (higher returns), OPG may support it. OEB can be stringent regarding the availability requirements, because OPG cannot argue that it is not already achieving some degree of revenue sufficiency. The arrangements also provide clear signals to OPG to improve availability, and if the payments are sculpted properly, to improve availability particularly during the times when output is most needed. The drawback of this approach is that it does not put significant pressure on OPG to reduce costs – only to improve availability. It is worth noting that while this approach would appear (if OPG did meet availability targets) to increase rates, the impact on bills is less certain. If OPG improved availability significantly, this could drive down wholesale market prices, ultimately lowering overall consumer bills.

6.2.4 Scenario 3: regulation by contract[28]

Scenario 3 builds on elements of Scenarios 1 and 2, but is structured differently. As with Scenario 1, OPG would make an initial filing stating its revenue requirement. It would, however, distinguish between the revenue requirement for its nuclear assets and for its hydroelectric assets. In addition, it would bifurcate the revenue requirement for each set of assets so as to isolate the return component. For each set of assets, it would then provide its average past five year volumes (with Pickering restarted units treated as in Scenario 2); these

[28] The term regulation by contract is used somewhat loosely here. The contract could be a formal contract run through the OPA, or it could be simply a series of regulatory accounts kept in accordance with OEB guidelines and under OEB oversight. If structured as a formal contract through OPA, the contract could later be auctioned off to load serving entities, apportioned among distribution companies, or derivatives otherwise created to facilitate future market development.

volume estimates (V) would enable calculation of a rate for nuclear assets and a rate for hydroelectric assets, where each rate in turn segmented the return component (R_n for nuclear, R_h for hydro) from operating expenditure (O), capital expenditure (C), and depreciation (D; $(O+C+D)/V=OCD_n$, OCD_h). OPG's filing would also calculate R_n and R_h as a percentage of HOEP since market opening in Ontario (S). [29]

Based on this filing, long term arrangements with OPG would be structured. For the sake of illustration, let us assume that these arrangements would last for 10 years, provided the HOEP continued to be calculated in substantively the same fashion. OPG revenues would be based on a contract for differences formula with OCD as the strike price. The CfD would work as follows: OPG would sell power into the Ontario spot market as it saw fit.[30] However, it would be required to rebate on a monthly basis an amount equal to HOEP-OCD-S*HOEP. Because neither OCD_n nor OCD_h would under normal circumstances be lower than HOEP, it is unlikely that there would be an occasion in which ratepayers would end up compensating OPG.

The strike price of the CfD assures that OPG recovers its costs; this strike price could be escalated, or indeed subjected to the I-X formula as in Scenario 2. The S*HOEP component serves a different purpose – to provide the return on assets. Because this component would fluctuate hourly (and by extension, seasonally), it would provide signals to OPG regarding maintenance scheduling and use of storage. The overall structure of the CfD also provides for the opportunity for OPG to earn additional revenues by maximizing output.

Monthly clearing services could be provided by the Independent Electricity System Operator (IESO). OPG would be required to file annual statements with OEB showing its overall return on equity under these arrangements. OEB could institute a profit sharing mechanism in which if OPG's ROE exceeded a certain threshold – for example, following a period of high prices, or due to the impact of revenues from ancillary services – excess earnings would be shared with ratepayers. Although we have suggested that the CfD contract with ratepayers run for 10 years, these arrangements could be put in place for any length of time, up to and including the remaining accounting life of the individual plants.

In terms of incentives, Scenario 3 is superior to either Scenarios 1 and 2 in that it relies on market signals to drive operating decisions. However, a drawback is that it is more complicated to implement. Although it does not require frequent decisions or reviews by OEB, as does Scenario 1, or (unless added to the OCD strike price calculation) the potentially risky determination of an X factor, it does require initiating a settlements process. The arrangements

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[29] S is designed to relate returns to the average level of HOEP. Thus S=the "share" of HOEP which accounts for returns. Essentially, the formula is designed such that the more output OPG provides from the designated assets during high price periods, the more it can make.

[30] Although OPG in theory could sell the CfD to third parties, such a sale would likely result in a lump sum payment to OPG and an arrangement to pass through the OCD component. OEB would then need to determine the disposition of the lump sum between OPG's shareholder and ratepayers.

are not easily understood by ratepayers (they do not fit well into a soundbite), and may be confused with the former Market Power Mitigation Agreement (MPMA) calculations.

It is important, however, not to exaggerate the difficulties inherent in implementing Scenario 3. In fact, the proposed CfD arrangements are similar in structure to those incorporated into contracts with independent power producers (IPPs) in recent rounds of OPA contracting.[31] These OPA contracts also require a complex settlements process, and indeed OPA's revenue requirement will (once these plants come online) need to reflect this.

6.3 concluding remarks

As economists, our clear preference is for Scenario 3, though perhaps a form that incorporated only the shared savings approach rather than having the strike prices change using an X factor mechanism. There is no question that Scenario 3 would be more challenging to implement than the other two approaches. However, it provides the right incentives to OPG, and indeed forces it to act in a fashion consistent with a commercial company.[32] In addition, if OEB so desired, the arrangements could be put in place to run through the life of the assets, with reviews every five years simply to assure that the arrangements were running smoothly and remain consistent with overall market design objectives.

Those who view Scenario 3 as complex should examine the current procedures; current practice with regards to the designated assets cannot be viewed as being either simple or transparent. In fact, Scenario 3 is simpler than the former Market Power Mitigation Agreement. Furthermore, any complexity occurs during the initial set-up period. Once the structure is established, the calculations are relatively mechanistic.

Scenario 3 is not without precedent in Ontario; as already discussed, it mimics arrangements for some forthcoming IPPs. If the OPA can manage CfDs with IPPs, the OEB can manage similar contract structures with OPG. It is also not without precedent worldwide; for example, the liberalization of the England and Wales market featured vesting contracts structured as contracts for differences. While Ontario's hybrid market approach is unique globally, the principles of regulation that can be applied are not. Scenario 3 provides a degree of balance between the desire to maintain market structures while at the same time allowing consumers to benefit from legacy assets that they can claim to have already paid for.

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[31] These contracts are structured as CfDs in which the strike price as proposed by the developer covers the developer's "revenue requirement," i.e. its projected operating and capital costs and its return on and of capital. When the HOEP is above the strike price, the developer may retain 5% of the difference; when below, the developer is paid all of the shortfall.

[32] This includes forcing OPG to hedge against hydro volatility internally, rather than incorporating the hedge into any sort of "heritage contract" arrangements with a balancing mechanism.