Paying the full cost of power

an indicative comparative analysis of residential electricity rates across Canadian provinces

prepared for the Independent Power Producers Society of Alberta (IPPSA)

March 17, 2005

Alberta is the only province in Canada where prices to final consumers are related to the market value of the underlying commodity. This provides several benefits to ratepayers: first, ratepayers are not responsible for bad investment choices in the power sector, as they would be under a regulated system; second, there are no hidden subsidies or distortions in the provincial government's finances due to provincial ownership of power resources; and third, consumers receive appropriate price signals regarding conservation and usage. An analysis of prices to final consumers in provinces with apparently lower rates than Alberta suggests that rates in those provinces would be 25-30% higher if consumers there were charged the full value of the electricity they use, and that rates in those provinces can be expected to rise much more rapidly than those in Alberta over the next decade.

TABLE OF CONTENTS

TABLE OF FIGURES

London Economics International LLC
717 Atlantic Ave. Unit 1A
Boston, MA 02111
www.londoneconomics.com

contact:
A.J. Goulding/Gilan Sabatier
617-494-8200
ajg@londoneconomics.com

1 Scope of work

London Economics International LLC was commissioned by IPPSA to review electricity rates across Canada to small and residential consumers, and to identify ways in which the fundamentals of ratemaking vary across provinces. Differences in the industry structure across provinces mean that rates in each province differ greatly in the extent to which they fully reflect the financing, fuel, and opportunity costs of power. While these differences of necessity make direct comparisons difficult, we have developed a set of straight-forward adjustment factors which facilitate making a more fair comparison among jurisdictions.

2 How do rates to residential customers differ among provinces?

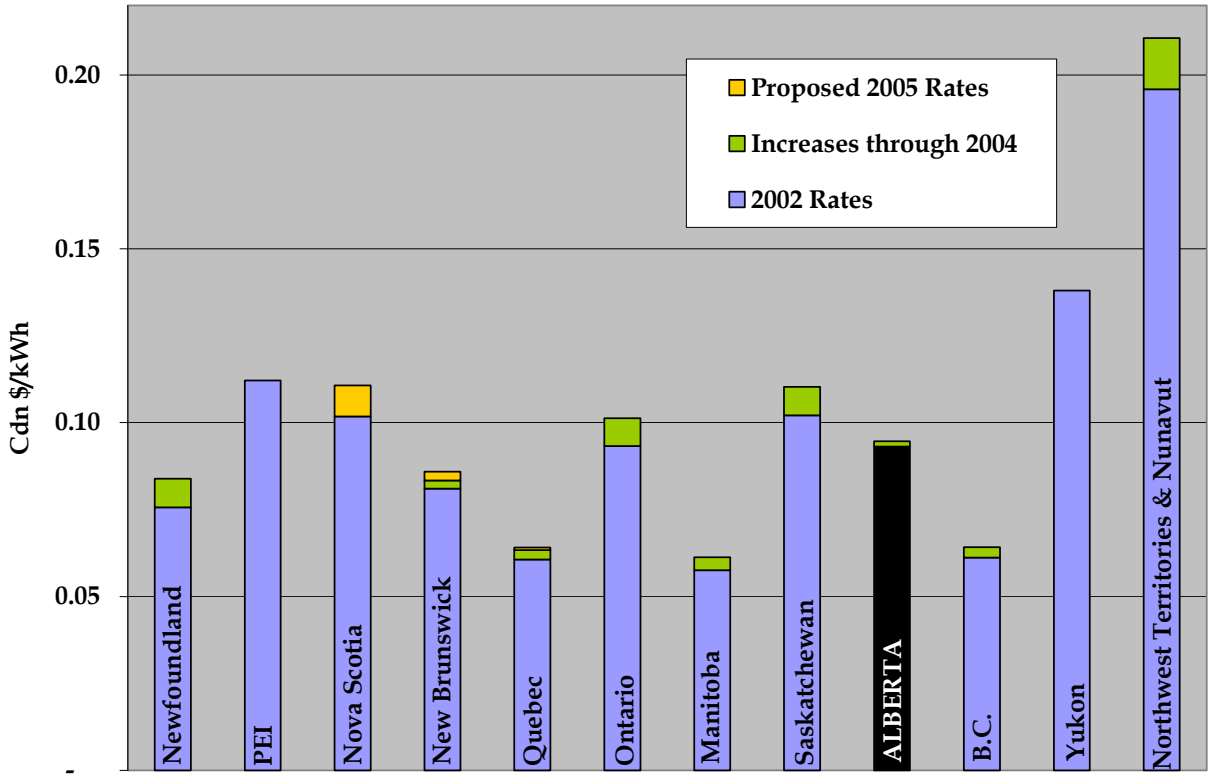
To examine rates across Canada, we first use the most recent consistent data set available, then examine rate increases announced for small consumers since the data set was assembled. Data suggests that rate differentials are narrowing over time. Note that most provinces, with the primary exceptions of Alberta and Ontario, provide bundled rates. The adjustments we propose, however, are valid regardless; as discussed later in this document, these include financing costs (which affect the entire value chain) as well as the market value of generation and the cost of responding to load growth.

2.1 2002 rates

To demonstrate the impact of distortions in prices to final consumers in neighboring provinces, we begin with an examination of recent rates. The most recent consistent data available dates to 2002. A review of rates to final consumers across all Canadian provinces using Statistics Canada data for 2002 shows that power, unsurprisingly, is most expensive in regions with dispersed load and smaller fossil generators, and cheapest in those regions with significant hydroelectric resources. For residential consumers, 2002 rates range from a low of Cdn. $0.058/kWh in Manitoba to a high of Cdn. $0.196/kWh in Northwest Territories. Rates for small consumers in Alberta in 2003 were in between this range, at Cdn. $0.093/kWh. Alberta rates for small consumers were exceeded in both Ontario and Saskatchewan, but rates for consumers in British Columbia and Quebec, as well as the aforementioned Manitoba, were lower.

Approximately two-thirds of the difference is explained by differences in the resource base. As we will see, however, some of the remaining difference is illusionary; this portion of the difference in rates in provinces such as British Columbia, Manitoba, and Quebec effectively represents a transfer from taxpayers to ratepayers in the form of indirectly subsidized financing and suppressed returns on investment.

Figure 1. Rates to final consumers in Canadian provinces, 2002



Statistics Canada, Press releases, Regulators, Utility websites

2.2 recent rate increase announcements

Rate increases have been announced in several provinces since the Statistics Canada data was published. Below, we review rate increases for residential customers since 2003, as well in each province.

- **Alberta:** Since 2002, rates (RRO) in Alberta have increased on average by 1.68% across service territories.

- **British Columbia:** Effective April 1, 2004, BC Hydro rates increased by 4.85%. Until this increase, BC Hydro rates had not changed since 1993. BC's revised rate structure includes a two-tier pricing arrangement under which large users pay a higher rate for increases in their load.

- **Manitoba:** On August 1, 2004, rates for residential customers using more than 175 kWh/month increased by 6.51%.

- **New Brunswick:** Rates for residential customers increased by 2.9% in 2003 and 2004. Additionally, New Brunswick Power will increase rates by 3%, effective March 1st 2005.

- **Newfoundland:** In July of 2003, Newfoundland Power decreased its rates by an average of 0.15%. However, on July 1st 2004, Newfoundland Power's residential rates and Newfoundland Hydro's rural customers rates increased by 9.86%.

- **Northwest Territories/Nunavut:** Northwest Territories Power Corporation (NTPC) increased their rates in November of 2003 by a range of 0%-15% depending on the community served. There are 21 communities in the Northwest Territories**.**

  Having split from NTPC recently, Nunavut Power submitted in a general rate application September 2004, in which they propose a 32.7% increase in their revenue requirement. A decision is expected by April 2005.

- **Nova Scotia:** Nova Scotia Power has proposed an 8.7% rate increase for 2005.

- **Ontario:** Ontario rates for both distribution and energy are increasing after a rate freeze. Ontario has nearly 90 distribution utilities; all are in the process of adjusting rates upwards to fully incorporate a commercial rate of return. Energy rates are rising as well. In 2004, under Bill 210, the commodity portion of rates for households consuming above the lowest volume threshold increased by 17% to 5.5c/kWh. The rates are expected to be adjusted again as of April 2005. Ultimately commodity rates will reflect the cost of the regulated heritage assets (nuclear & baseload hydro plants) which are set at an average rate of 4.5c/kWh, as well as the costs of incremental supply. The OEB has until March 31st 2008 to redefine these rates.

- **Prince Edward Island:** There have been no rate increases since 2002.

- **Quebec:** Since the end of the rate freeze on December 31st 2003, Hydro-Quebec Distribution has been granted an initial 3% increase for the 2003/2004 rate year, a second increase of 1.41%, applied on April 1, 2004 for the 2004-2005 rate year and a 1.2% increase, effective April 1, 2005.

- **Saskatchewan:** On September 1st 2004, rates for residential customers in urban areas increased by 8.05%, whereas rates for those living in rural areas increased by 12.08%.

- **Yukon:** There have been no rate increases since 2002. However, under the 2005 rate filing, Yukon Energy has put forth 2007 as a tentative date for a potential rate increase.

The above increases have already begun narrowing the gap between Alberta delivered electricity prices and those in other provinces. As cheap hydro becomes less abundant, rates will increase more rapidly in provinces other than Alberta. As we will see, an appropriate accounting of the costs of producing electricity in those regions would show that Alberta electricity is priced well within Canadian norms, particularly when rates are normalized to account for differences in initial endowments.

The remainder of this memo focuses predominately on distortions in rates to final consumers in provinces with lower rates than Alberta. Note that in some provinces where rates are already higher than Alberta, rates would be still higher if costs were accounted for properly.

3 Comparing market designs

The provincial markets studied have substantial differences in market design. Before we examine the explanation for the differences in rates, it is useful to summarize the differences in market structure. Although provinces may also appear to differ in specific characteristics, such as geography, topology of the transmission system, age of system, etc., we find that such differences are in fact minor; we do not believe that major differences in rates are the result of differences in the characteristics of transmission and distribution systems.[1]

Figure 2. Key market design elements

	Provincially owned utilities?	Independent regulator?	Heritage contracts?	Small consumer right to switch?	ISO established?	Status on unbundling
Alberta	no	EUB	Balancing Pool	yes	yes	full
British Columbia	yes	BCUC	yes	no	no	transco created
Manitoba	yes	PUB	no	no	no	none
New Brunswick	yes	BCPU	no	no	no	internal
Newfoundland	yes	BCPUNL	no	no	no	in process
Northwest Territories	yes	NTPUB	no	no	no	none
Nova Scotia	no	UARB	no	no	no	internal
Nunavut	yes	URRC	no	no	no	none
Ontario	yes	OEB	yes	yes	yes	full
PEI	no	IRAC	no	no	no	none
Quebec	yes	RDE	yes	no	no	internal
Saskatchewan	yes	SRRP	no	no	no	none
Yukon	yes	YUB	no	no	no	none

Alberta: Electricity assets at all points of the value chain are under private ownership, with the exception of some municipally owned utilities. Wholesale prices are set in a competitive power exchange. An independent system operator has been set up. Consumers have the opportunity to choose their own supplier, or to remain under default supply arrangements which are periodically adjusted to reflect actual wholesale power costs.

British Columbia: Electricity is largely supplied by a vertically integrated government-owned monopoly, though one smaller integrated private utility exists. A cost-based heritage contract sets price for a large portion of wholesale volumes. New generation is expected to be from privately financed ventures, but under contract to BC Hydro. An independent transmission

[1] In fact, almost all Canadian provinces consist of a small number of urban regions clustered along the southern edge of the province, with substantial areas of minimal population concentration in other parts of the province.

company has been established, but remains under government ownership. Small consumers remain under fully regulated rates.

Manitoba: The electricity sector in Manitoba continues to be entirely vertically integrated with no competitive activity in the sector. Manitoba Hydro (MH), a Crown-owned utility, is the province's sole electrical utility and is active in electricity generation, transmission, distribution, and supply.

New Brunswick: New Brunswick Power (NB Power) is essentially the sole supplier of power in New Brunswick. The company's rates are set by the Board of Commissioners of Public Utilities (BCPU) through the cost of service method. The province has been considering deregulation of its power industry because neighboring regions like New England have moved to a competitive market.

Newfoundland: Newfoundland and Labrador Hydro (NFL Hydro) and Newfoundland Power (NF Power) are the monopoly electricity providers in the province. NF Power is an investor-owned utility and NFL Hydro is a Crown corporation. Newfoundland's utilities have not unbundled their operations, but their roles in the province are unique. NFL Hydro generates almost all of the power for the province and controls the transmission grid, but NF Power distributes the power to most of the population. NF Power purchases 90% of its supply from NFL Hydro. Moreover, the output from NFL Hydro's largest facility, the 5,000 MW Churchills Fall project, is sold to Hydro-Quebec under a long-term below market fixed-price contract which expires fully in 2041.

Northwest Territories: The electricity market is dominated by the Northwest Territories Power Corporation, a Crown owned corporation, and Northland Utilities, an ATCO company. Northland Utilities buys power from NTPC through a PPA and distributes it to retail customers in the territories for which it has a franchise agreement, such as Yellowknife.

Nova Scotia: Nova Scotia Power (NS Power) is responsible for supplying virtually all power to the province. It was privatized in 1992, and generates 97% of the electricity in Nova Scotia

Nunavut: As a result of the creation of Nunavut province in March 31, 2001, all the physical assets of Northwest Territories Power Corporation (NTPC) located in Nunavut were allocated to Nunavut Power Corporation (NPC) which is a subsidiary of the Qulliq Energy Corporation (QEC), a Crown-owned corporation.

Ontario: The provincially-owned monopoly was split into separate generation and wires companies. Distribution is largely through municipal utilities. Privately-owned generators and distributors exist, as does a spot market. However, a cost-based heritage contract has been devised for provincially owned assets, and new capacity, though privately financed, will likely be under contract to a provincial power authority. An independent system operator exists. Small consumers may still switch, but most currently remain on fixed price default supply service.

Prince Edward Island: Maritime Electric is an investor-owned utility wholly-owned by Fortis, Inc. It is primarily a distribution company. The market in PEI is not deregulated. The

province's electricity demand is met through power purchased from New Brunswick Power. Domestic generation is purely for emergency purposes. The company is governed by the Maritime Electric Company Limited Regulation Act, which states that rates for electricity and ancillary services cannot be more than 110% of New Brunswick Power's rates for comparable service in New Brunswick.

Quebec: Electricity is largely supplied by a vertically integrated government owned monopoly. A cost-based heritage contract sets price for a large portion of wholesale volumes. New generation is largely from privately financed ventures, but under contract to Hydro Quebec. An independent transmission company has been established within Hydro Quebec. Small consumers remain under fully regulated rates.

Saskatchewan: The electricity sector in Saskatchewan continues to be entirely vertically integrated with no competitive activity in the sector. SaskPower (SP) is Saskatchewan's provincial electric utility and is active in generation, transmission, distribution, and supply.

Yukon: Yukon's electricity market is vertically integrated and dominated by two utilities, Yukon Energy and Yukon Electrical Company. Yukon Energy is a publicly-owned electrical utility that operates as a business, at arms length from the Yukon government. It is the main generator of electrical energy in the Yukon and owns and operates the province's transmission system, and is part of the Crown owned Yukon Development Corporation. Yukon Electrical Company is mainly a distributor in Yukon and is a privately-owned sister company of ATCO Power.

4 What are some explanations for the rate differences?

There are several key reasons why rates in provinces such as British Columbia, Manitoba, New Brunswick, Newfoundland, and Quebec appear lower than those in Alberta. These provinces have a different profile of installed capacity, with a greater amount of hydroelectric generation upon which they can rely. However, differences in natural endowments are only part of the story. Rates in these provinces are artificially suppressed in a number of ways. First, the utilities are highly leveraged, and do not provide their owners a market return on equity. Second, they maintain a bifurcated sales policy, where export sales are priced substantially higher than internal sales. Furthermore, increases in fuel prices are often absorbed by the utility, or not passed on to final consumers until after a substantial lag. Finally, prices to final consumers in BC and Quebec fail to reflect the tightening supply and demand conditions in both provinces. Over time, however, it will become increasingly hard to sustain these artificial distinctions. As such, we expect rates in these provinces to eventually begin to converge towards those seen in Alberta.

4.1 initial endowments

Alberta is one of the few Canadian provinces with little access to hydro resources. Only 7% of capacity and 3% of energy comes from hydro in Alberta, as opposed to 86% and 90% in British Columbia, and 93% and 96% in Quebec. Hydro accounts for over 90% of capacity in Manitoba and Newfoundland. Indeed, only Nunavut and Prince Edward Island have a smaller proportion of hydro capacity than does Alberta. Assuming fully depreciated plant and current

fuel prices, Alberta's lack of hydro resources adds Cdn. $0.02-0.025 per kWh to Alberta electricity prices relative to those in hydro-rich BC, Manitoba, Newfoundland, and Quebec.[2]

What is striking about these calculations is that although Alberta's resource base puts it at a disadvantage relative to almost all other Canadian provinces with the exception of PEI and New Brunswick, Alberta's rates are nonetheless lower than many provinces which would appear to have an advantage. This is particularly true for provinces like Ontario, where rates are higher than Alberta's primarily due to a mis-managed nuclear program dating back to the construction of the Darlington plant – mismanagement that would have been less likely under private ownership (or which at least would have resulted in a sharing of the consequences of bad decision-making between ratepayers and shareholders). Similarly, the calculations suggest that rates in some provinces, such as New Brunswick, would on pure resource base alone be expected to be higher than those in Alberta. For New Brunswick in 2002, this was not the case, suggesting that rates in that province may not reflect true underlying costs.

However, increasing load in many provinces, BC and Quebec in particular, is beginning to erode the available supply margin in each province. As such, each province is ultimately going to need new capacity. Here, Alberta has an advantage. Because Alberta has ready access to natural gas and coal, and the ability to expand existing coal stations, new capacity is likely to be cheaper on a marginal cost basis in Alberta. When new supply sources are examined, Alberta has a Cdn. $0.015 per kWh or more cost advantage.[3] This issue is discussed further in Section 4.4, where we discuss the potential magnitude of rate increases due to a tightening supply-demand balance in provinces outside of Alberta.

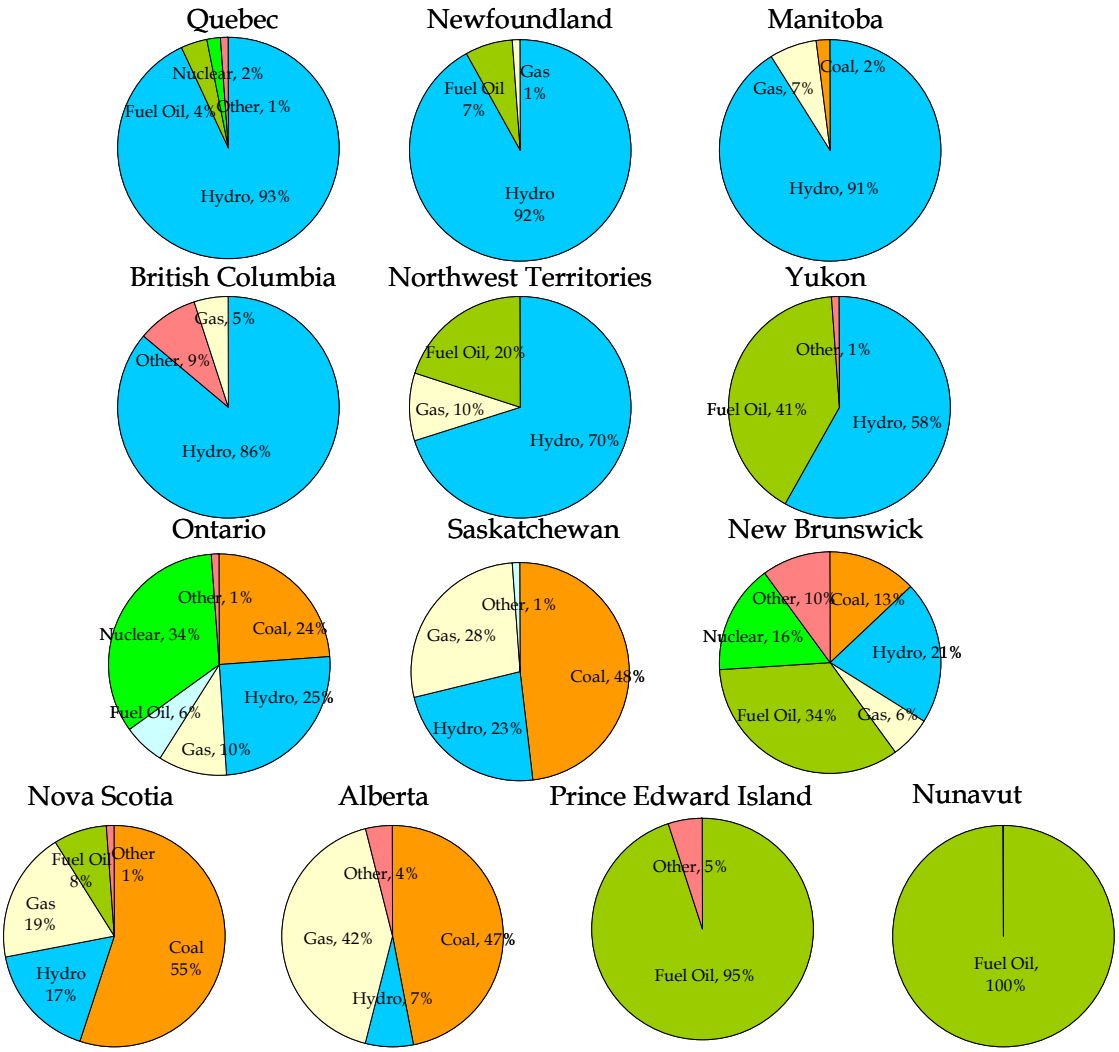
---

[2] These numbers were developed by examining the marginal cost of the existing resource base in each Canadian province. In each case, we looked at current installed capacity, efficiencies, and delivered fuel costs. Clearly, a province which derives a large proportion of its resources from hydro, and pays a water usage tax of $3-$5/MWh, faces substantially lower marginal costs than one in which there is a much higher proportion of gas-fired plants. In the latter system, even using a relatively efficient 7,000 heat rate unit and gas prices of $5/MMBtu, costs would approach $35/MWh. In this simplified example, the cost advantage of the legacy hydro system vs. an all gas system at the specified level of efficiency would be $0.03/kWh. Obviously, gas prices have been substantially higher recently. Our calculations take into account all fuel sources in each province, and adjust for fuel transportation costs. The assumption of fully depreciated plant is aggressive; however, given the lengthy depreciation schedules for hydro plants, the results do not change substantially if we relax this assumption.

[3] This calculation is based on marginal costs only. It assumes that 50% of new supplies in Alberta come from expansions at existing coal stations or proposed new facilities, and 50% come from gas. In BC and Quebec, all new supplies are assumed to come from gas. In addition, in these provinces, delivered gas prices are assumed to be 10-25% higher than in Alberta. Note that the magnitude of the advantage for Alberta depends on the fact that expansion of existing coal stations has lower capital costs than building a greenfield coal station, and that some of the stations have coal reserves in extremely close proximity. Again, a simplistic example can help to demonstrate the nature of the advantage. Assume two systems, one expanding using minemouth coal stations, the other gas plants distant from producing areas. If we assume coal at $2/MMBtu, and an 11,000 heat rate, the marginal cost will be about $22/MWh. The distant gas system, with a gas cost of $6/MMBtu and again using reasonably efficient gas technology with a 7,000 heat rate, would be obtaining power at a marginal cost of $42/MWh. The advantage for the coal fired region converts to $0.02/kWh.

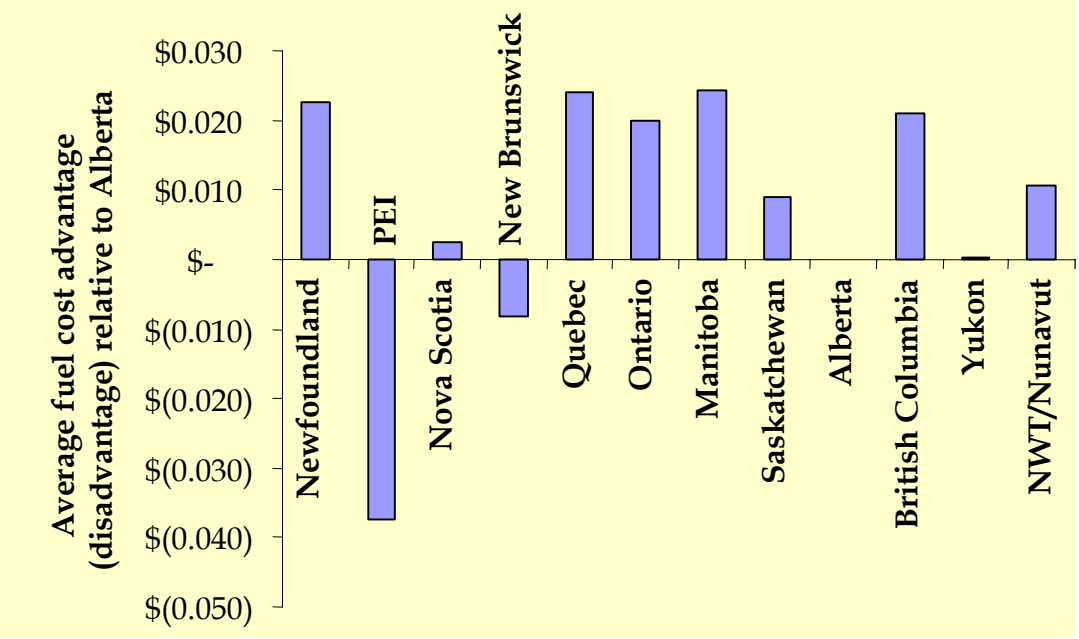
The issue of differences in embedded resource endowments extends to the ability to cost-effectively procure reserves and certain kinds of ancillary services. Other provinces benefit from their ability to rely on a more interconnected system than that in Alberta. Alberta's relative isolation from the North American grid increases costs because it means there is a smaller pool of resources on which to draw for such products.

Figure 3. Differences in installed capacity across provinces



Excerpted from Canadian Market Briefings, available at www.londoneconomicspress.com

Figure 4. Indicative Alberta cost disadvantage based on resource endowments (Cdn. c/kWh)



4.2 treatment of debt and equity returns

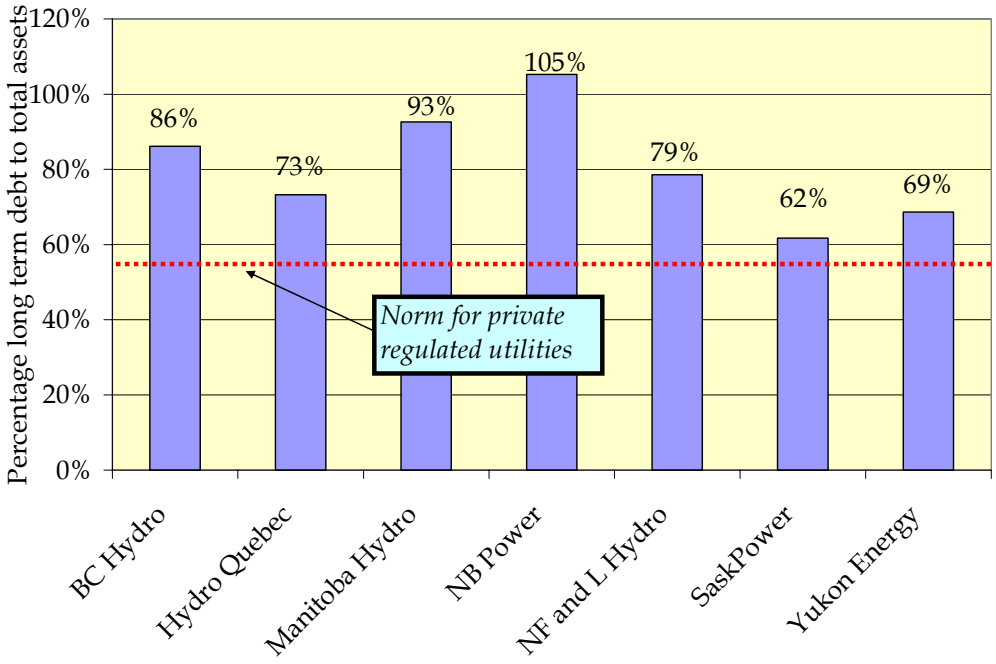
The provincially-owned power-related corporations across Canada benefit from either an implied or explicit provincial debt guarantee. This "halo effect" allows the provincially owned utilities to raise more debt than they otherwise would be able to, and at lower interest rates.[4] Although this results in lower power costs, it increases the cost of borrowing for the provincial government as a whole, and lowers the amount that the province as a whole can borrow, because rating agencies and investors regard the guarantees to the utilities as contingent liabilities to the provinces. Effectively, taxpayers are paying a little bit more on provincial debt in interest than they otherwise would, so that ratepayers receive lower electricity bills. It is important to understand, however, that although their association with the provincial government allows the utilities in BC and Quebec to raise funds more cheaply, the debt is nonetheless on the utilities' books and is recovered through rates – it is just that their ability to rely on implicit government backing raises financing costs for the rest of the provincial government's activities.

In addition to the distortion of debt costs caused by the halo effect, provincial shareholders fail to demand an appropriate return on equity from their utilities. Failure to demand an appropriate equity return effectively means that the shareholder is failing to collect revenues from the electricity sector which could be used to fund social investments with far higher

[4] The extent to which the guarantee is explicit depends on the offering and the province. For example, debt in Ontario for Ontario Power Generation and Hydro One is no longer provincially guaranteed. However, it is highly unlikely that the province would allow either to default. In some cases, the crown corporations pay a debt guarantee fee in return for their use of the province's credit rating.

returns, such as investments in education, health, and regional development. A typical private integrated utility would normally be earning upwards of 12% as a return on equity, and would have a much higher proportion of equity in its capital structure.[5] Provincially owned utilities have upwards of 80% debt (versus 55%-60% for a private integrated utility), and in some years settle for returns on equity as low as 3%.

Figure 5. Debt as a proportion of assets for selected provincially-owned utilities[6]



We have examined the impact of appropriately capitalizing several provincial utilities, including BC, Manitoba, Newfoundland, and Quebec. To do so, we have assumed that each was capitalized at 55% debt and 45% equity, the norm for North American utilities. We have assumed that each maintains an A credit rating, has an average debt life of 15 years, and is granted an 11.5% return on equity.[7] We have used these parameters to develop a total annual

[5] The average private regulated North American utility has approximately 56% debt, and is allowed an equity return in rates of 8.5% to 15%, based on a London Economics International LLC survey of 77 private electric utilities. Coincidentally, the debt to equity ratio used for deriving the Ontario Power Generation (OPG) heritage contracts was quite similar, at 55% debt/45% equity.

[6] Calculated using most recent annual reports available, generally for 2003-2004; debt calculated as assets minus shareholder equity.

[7] While Canadian regulators have often limited returns to lower amounts, such values were often for the less risky regulated wires business, as in the 9.88% ROE allowed to Ontario distributors. Rates for a large integrated business incorporating generation risk would need to be higher. In addition, the 11.5% number is consistent with the overall North American overall average.

financing revenue requirement, which we have compared to current financing revenue requirements. We have then divided the difference by the total volumes sold within the province to determine the impact on rates. Based on this methodology, we determined that, were consumers in BC charged the full financing costs of power, rates in BC would rise by over 13% or Cdn. $0.008 per kWh; a similar calculation for Quebec shows an increase of over 16% or Cdn. $0.01 per kWh. In Manitoba, the impact was even more profound; rates would need to rise over 20% (Cdn. $0.014 per kWh) to reflect an appropriate capitalization structure. The impact was more muted in Newfoundland and Saskatchewan, where rates would rise by less than 5% if appropriate capitalization metrics were applied. In New Brunswick, rates are distorted by the extremely high level of debt carried by the utility, and would rise by nearly 10% if the utility were appropriately capitalized.

This effect would likely be amplified if we were to take into account the taxation status of the various utilities. Tax status of crown corporations, and of provincially-owned private corporations, differs from province to province. Some make substantial "payments in lieu of taxes" (PILs). Crown corporations, however, generally do not make Federal tax payments. However, it is important not to overemphasize the issue of taxation in rates, as some of this effect is already captured through the use of the pretax return on equity described in the calculations above.

4.3 charging full value

The previous analysis looks at distortions in neighboring provinces from a cost perspective. However, it is also important to examine the question from a value perspective. Several of the provinces with rates lower than Alberta have utilities with substantial sales outside of their home province. Most striking are BC, Quebec, and Manitoba.[8] These sales are at market rates, that is, the price is set not by a regulator but by the market, just like prices in Alberta. By selling power to provincial residents at less than its full value, BC, Quebec, and Manitoba lose out twice: as shareholders, they again are accepting lower revenue and profits than could otherwise be achieved – profits which could be used to reduce taxes or invest in social infrastructure; as policymakers, underpriced electricity is encouraging overconsumption and causing corresponding detrimental environmental impacts.

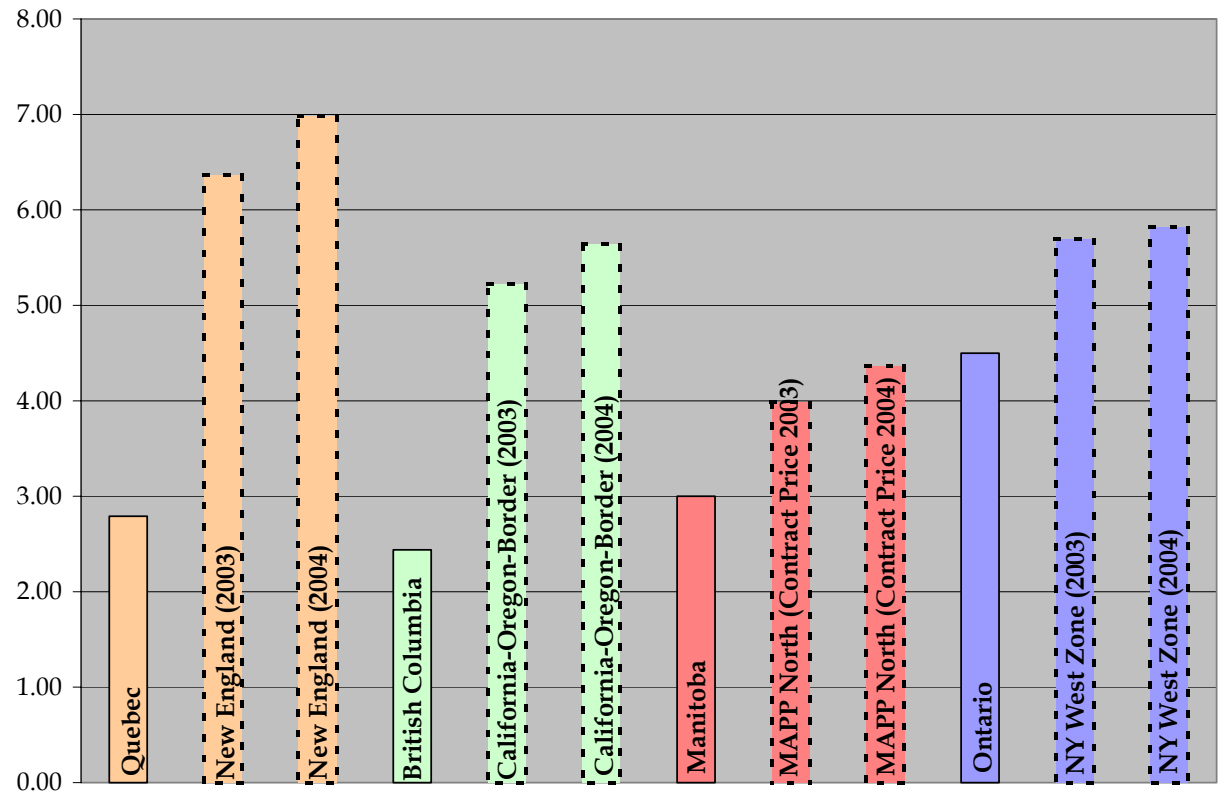
The effect of this underpricing on rates can be quantified by examining the heritage contracts in each province. As discussed earlier, both BC Hydro and Hydro Quebec have set up contracts between their generation subsidiaries and their distribution subsidiaries. These contracts are

[8] The case of Newfoundland is unique, in that its exports are also priced below market due to historical arrangements related to Churchill Falls. As such, we do not discuss it here. Ontario also has substantial trade with neighboring regions. However, its rates are already higher than Alberta's and are expected to increase still further. Furthermore, those customers in Ontario purchasing at spot prices receive prices similar to those in neighboring regions. Even under the forthcoming Ontario heritage contracts, prices there will be closer to the market value of the power in neighboring regions. Under the new regulated rate for OPG, average prices for OPG output should be approximately Cdn. $45/MWh; this is 10-20% lower than nearby Eastern New York average prices. Ontario consumers, however, will need to buy a blend of heritage-priced and market-priced power, meaning there is less distortion in Ontario rates since the price cap has been relaxed.

generally set based on average historical production from the hydro facilities, and the associated volumes are sold to the distribution subsidiary based on historical embedded cost. This information can be used to determine what prices to final consumers would have been had rates reflected the full value of the power sold.

To calculate the rate impact, we first examine the amount of power associated with the heritage contracts and the price. We then determine the market price for this power based on the most appropriate nearby liquid market hub. For BC Hydro, we used the California-Oregon Border (COB) price; for Hydro Quebec, we have used the Massachusetts Hub price. For Manitoba Hydro, the pricing point we used was North MAPP. We have used the 2003 average market prices as a proxy; given the nature of the hydro resources involved (both utilities have substantial opportunities for storage), realized prices would likely have been higher. We then examine the difference between the heritage contract price and the relevant market price, accounting for transmission costs and the impact of the hypothetical change in the regional supply balance. We multiply the difference in price by the affected volumes, and adjust for total regional consumption.

Figure 6. Comparison of heritage contracts and relevant market prices (cents/kWh)



These calculations show that, were BC consumers charged the full value of the power that they consume, rates in the province would be at least Cdn. $0.021/kWh higher; in Quebec, rates would be at least Cdn. $0.026/kWh higher. The calculations for Manitoba are more difficult,

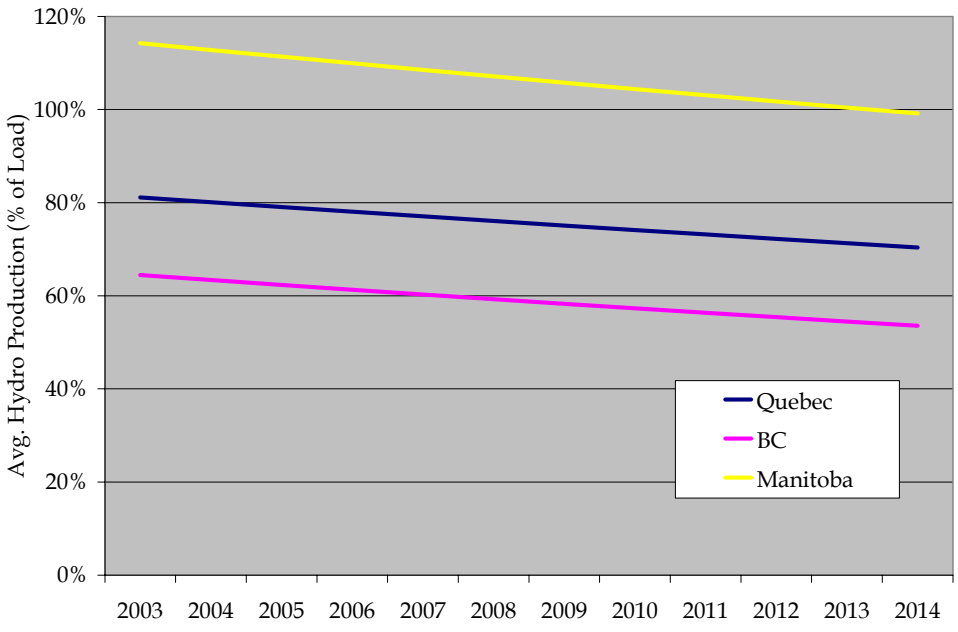
given that no heritage contract is currently in place. To address this issue, we calculated a proxy heritage contract for Manitoba which takes into account the remaining undepreciated capital costs which must be recovered, appropriate fuel costs, water rental costs, and operating expenses. We estimate that a heritage contract in Manitoba would likely be in the range of Cdn. $0.026 - $0.03/kWh. By contrast, the potential export revenues would likely average Cdn. $0.035 - $0.04/kWh net of transmission costs. Based on these calculations, valuing generation in Manitoba at market rates would add Cdn. $0.005 - $0.01/kWh to customer bills.

The issue of opportunity cost pricing can be extended to losses. Alberta and Ontario are the only provinces in which the market value of losses is considered. Were this practice to be adopted in other regions, rates in those areas would further increase.

4.4 tightening supply-demand balance

As we have established, the primary driver of lower electricity costs in British Columbia and Quebec is the availability of low cost hydro resources. However, increasing load growth is eroding the hydro surplus. Over time, the heritage contracts will make up a smaller proportion of overall internal demand. Over the next 10 years, heritage contracts will account for 70% of load in Quebec, down from approximately 81%, and less than 55% in British Columbia, down from approximately 64% of load today as show in Figure 7.

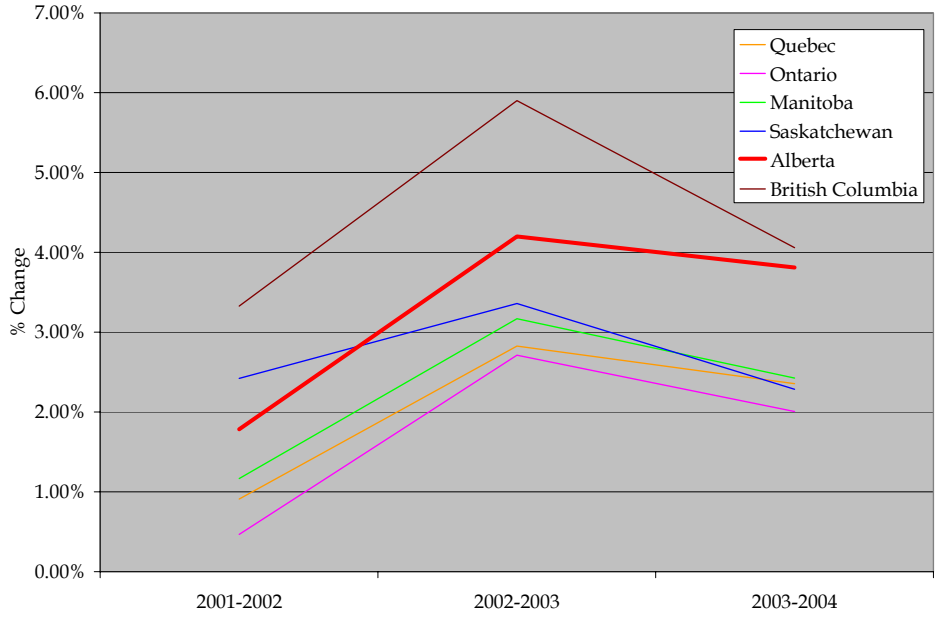
Figure 7. Average historical hydro production as a percentage of expected future load for selected provinces



Assuming the shortfall is made up entirely of gas-fired generation from efficient new combined cycle gas turbines, we can expect electricity prices in Quebec to increase by Cdn. $0.018/kWh, and in British Columbia by Cdn. $0.014/kWh. The impact of an increase in peak load can

already be seen in Manitoba, given that a combination of poor hydrology and load growth contributed to Manitoba being a net importer for the first time this decade in 2004. Simply covering Manitoba Hydro's reported loss in 2004 would require an increase of over Cdn. $0.02/kWh.[9] Because Alberta's power already is derived from a mix of coal and gas resources, new coal capacity may become available in Alberta, and Alberta generation is close to the source of its fuel, prices in Alberta are expected to rise by much less.

Figure 8. Load Growth in Major Canadian Provinces, 2001-2004[10]



National Energy Board

5 What adjustments should be made to make a fair comparison?

Based on the foregoing analysis, we can draw the following conclusions:

- Much of the difference in rates between Alberta and those provinces with lower rates is due to resource endowments; without access to hydro, electricity prices in these provinces would potentially be higher than those in Alberta.

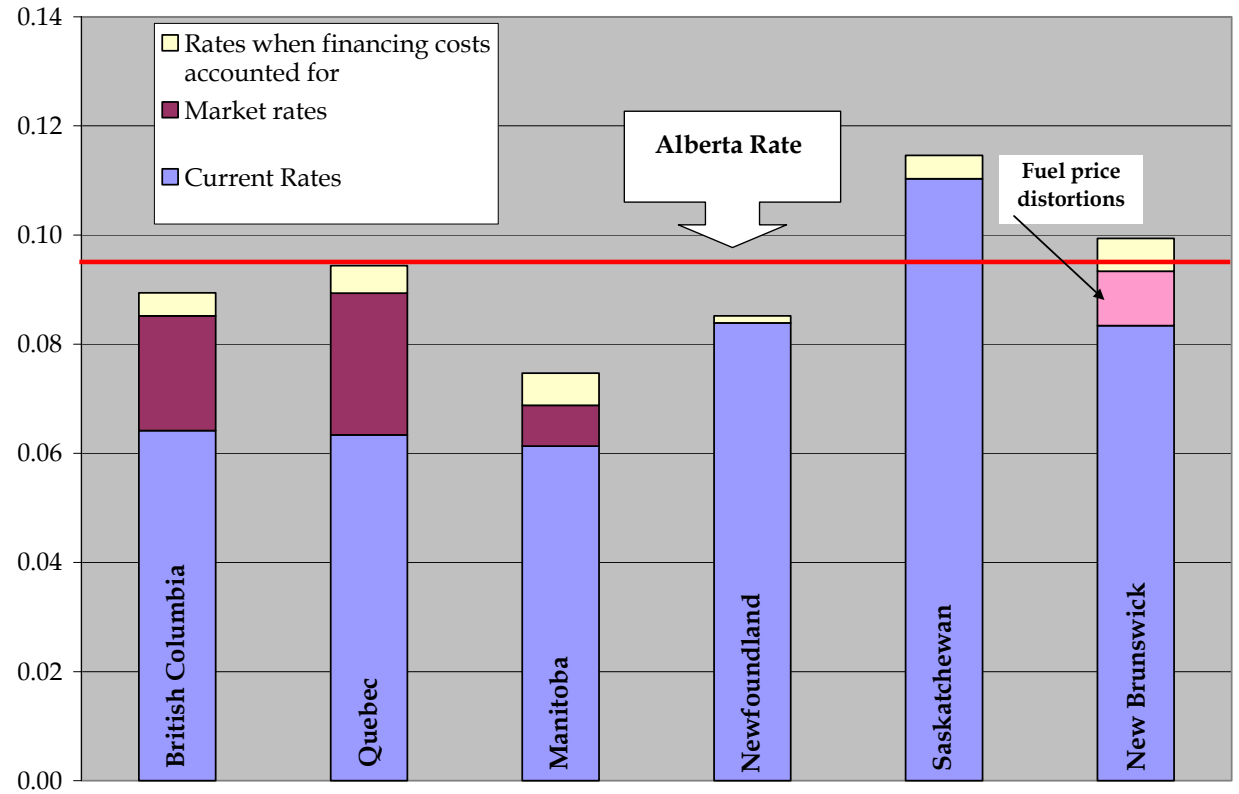
[9] 2004 conditions were anomalous for Manitoba Hydro; its internal generation was approximately one-third lower than its recent average production. Under normal conditions, it would be approximately 10 years before Manitoba's system would begin to be persistently short on energy, though it would become short on peak sooner given that peak demand has been growing much more rapidly than overall load.

[10] Since 1999, peak demand in Alberta has increased by 14.84% total based on the AESO's "10 year Transmission Plan".

- When financing costs are appropriately accounted for, prices in British Columbia and Quebec would be approaching Cdn. $0.075/kWh; in Manitoba, they would be approaching Cdn. $0.07/kWh. When recent rate hike proposals are factored in, prices would be just under Cdn. $0.08/kWh.

- If an alternative approach is used, by valuing output in these provinces at market rates, prices in both BC and Quebec would be approaching Cdn. $0.09/kWh; for Manitoba, they would be around Cdn. $0.07/kWh.

Figure 9. Adjusted Rate Comparison (cents/kWh)



- A true apples-to-apples comparison would, for those provinces where a market rate comparison is possible, use market rates for generation and the effect of appropriate capitalization to adjust only transmission and distribution rates. The impact of these calculations is shown in Figure 9, assuming a 50/50 split in the asset base between generation and wires assets. This graphic suggests that rates in many provinces would be close to those in Alberta even before the issue of tightening supply is addressed.

- Even if market rates and appropriate capitalization techniques are not used, by 2013 prices in British Columbia and Quebec are likely to be near Cdn. $0.085/kWh before accounting for inflation; assuming current gas prices and technology (and that natural gas is the preferred new build choice), we can expect that prices will be within 10% of

Alberta levels by that time. Prices in Manitoba will be somewhat lower, but will still need to rise to pay for new, more expensive generation.[11]

- Other provinces with less profound hydro endowments will see rates increase much more rapidly. In particular, rates in Ontario can be expected to rise still further as the government attempts to shut down existing coal-fired capacity. Likewise, those provinces with large fossil fueled capacity, particularly oil or gas fired, can expect to see continued increases at rates higher than those expected in Alberta.

6 Concluding remarks – why Alberta's market design is superior for the long term

There are several reasons why Alberta's market design is likely to produce more cost-effective outcomes for consumers and taxpayers over the long run:

Private investors bear the costs of any bad decisions regarding new generation investments – when poor investments are made, shareholders lose money and rates are unaffected, whereas in provincially owned systems, bad investments are ultimately recovered from ratepayers.

Taxpayers do not bear the burden of indirectly subsidizing financing costs – direct and indirect debt guarantees raise the cost of financing other government activities; implicit guarantee of power sector debt increases perceived indebtedness in BC and Quebec by one-third, increasing overall interest costs on non-power sector related activities.

Consumers receive more appropriate price signals - artificially low prices in neighboring provinces lead to over-consumption of electricity and less conservation, with corresponding negative environmental and economic effects.

Government resources are more effectively deployed – BC and Quebec together have nearly Cdn. $80 billion locked up in their investments in the electricity sector, money which if the assets were sold could be reinvested in areas in which governments are uniquely able to produce high social returns, such as in health, education, and infrastructure. By relying on market forces and private investment, Alberta is able to deploy its resources in a more dynamic fashion.

Alberta has added more new capacity over the past five years than any Canadian province – Whereas other Canadian provinces are just beginning to consider how to meet potential shortfalls, the Alberta market has already provided for over 3,300 MW of new build. This will help moderate prices over the long term, just as other provinces begin to need to raise rates to cover costs of new construction.

---

[11] Note that our assumption is that proposals for a joint Manitoba-Ontario initiative to build large new hydro stations will not go ahead. Even if it did, the station would need to be paid for through rates in one of the two provinces. We are more confident of new hydro generation coming on line in Newfoundland than in Manitoba.

When the full cost of electricity are considered in neighboring provinces, prices to consumers rise 25-30%, producing prices close to those observed in Alberta. Furthermore, prices in Alberta will face less upward pressure than those in other provinces over the next several years, as such provinces exhaust their available hydro resources. Over the long run, we can expect the Alberta electricity market arrangements to produce sustainable competitive outcomes for consumers.

7 Appendix A – a note on public debt

It is important to note that some explanations for differences in electricity rates are not consistent with the actual rate structure in various provinces. It is often emphasized that Alberta has no public debt associated with electricity assets. This statement, though factually correct, is misleading. Technically speaking, the other provinces have no public debt associated with the electricity sector either; the debt appears on the books of BC Hydro, Hydro One, Hydro-Quebec, Manitoba Hydro, NB Power, Ontario Power Generation (OPG), SaskPower, etc. Each of these utilities repays its debt using revenues received from ratepayers. Likewise, in Alberta, there is debt associated with the power sector – it sits on the books of ATCO, Fortis Alberta, TransAlta, AltaLink, and the municipal utilities, as well as various independent generators such as CalPine, TransCanada, and others.

Nonetheless, there are two important distinctions. First, in Alberta, if any of these entities take on more debt than they can afford, it is ultimately shareholders and bondholders who are at risk, rather than ratepayers. (Note that ratepayers in Alberta, just like ratepayers in other provinces, are paying the debt on the monopoly wires business through rates; unlike ratepayers in the other provinces, however, rates do not guarantee recovery of generation-related debt.) Second, although the debt in British Columbia, Ontario, and Quebec is one step removed from the province – it bears an explicit or implicit guarantee, for which the utilities (ratepayers) are in some cases charged a fee – when the overall obligations of the province are looked at as a whole, credit markets will take into account the fact that if BC Hydro, OPG or Hydro One, or Hydro Quebec were ever to default, the province is ultimately responsible for repayment. This likely raises financing costs for the entire province by a modest amount, which may or may not be greater than the guarantee fee received from the utility.

The subsidy element in other provinces arises not because debt is raised on the provincial books instead of the utility's (it isn't), but because the provincial utilities do not pay market rates for the debt guarantees provided by their government owners, are allowed to achieve higher proportions of debt to equity than private firms, and do not provide their provincial owners with the maximum return on equity available. By earning less than they otherwise could from their utilities, the provincial governments are essentially subsidizing ratepayers at the expense of taxpayers; higher dividends could be used to increase spending on health and education, as could proceeds from an outright sale of the Crown corporations.