**** not prepared for use in regulatory proceedings or litigation****

Power prices in context: comparing Alberta delivered electricity prices to other Canadian provinces on a level playing field

LONDON ECONOMICS

Prepared for the Manning Centre for Building Democracy and the Independent Power Producer Society of Alberta ("IPPSA") by London Economics International LLC

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Alberta electricity consumers pay among the lowest amounts for electricity as a proportion of disposable income across all Canadian provinces. Fair comparison of electricity rates across provinces requires consideration of a number of factors, including differences in resource endowments, the impact of implicit provincial guarantees on leverage ratios and provincial borrowing capabilities, suppressed equity returns at provincially-owned utilities, differential tax treatment, and export revenues. When adjustments for these factors are made to electricity rates across Canada, Alberta delivered energy costs are competitive. Furthermore, Albertans benefit from the fact that risk of cost overruns and poor operating performance in generation are borne by shareholders, rather than ratepayers. These arrangements help reduce the risk of ratepayers paying for costly mistakes. Alberta is not unique in facing significant infrastructure investment requirements over the next five years; when rates are projected forward, including projected investments and rate increases in other jurisdictions, Alberta delivered electricity prices may become yet more competitive.

This paper represents the third edition of London Economics International (LEI)'s interprovincial rate comparison analysis; previous versions were published in 2004 and 2011. Where still valid, selected conclusions from the 2011 paper are reiterated here.

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1 How is Alberta different from other Canadian provinces?

Power costs in Alberta more closely approximate the full economic cost of providing electricity than do power costs in other provinces. Although delivered power prices in other provinces may appear lower, such prices mask implicit subsidies, reflect lower effective tax rates on utilities, and incorporate cross subsidies provided by export sales. By contrast, in Alberta, electricity price signals are less muted by government intervention and are highly responsive to supply-demand dynamics.[1] Furthermore, Alberta wholesale electricity market prices incorporate an explicit price on environmental externalities, unlike other Canadian provinces. Alberta was the only province to see power prices fall in response to the 2008 recession. Appropriate price signals lead to more efficient consumption and investment decisions, resulting in the lowest efficient sustainable prices in the long run.

1.1 Alberta relies on competitive market forces to set the price of wholesale generation

Prices for generation in Alberta are set according to bids from generators into a power pool. Generation is fully unbundled from transmission and distribution. The Alberta wholesale generation market has been in operation for over 18 years. Over $11.5 billion[2] has been invested in new generation in the province over the period 1998-2012 and a number of new players have entered the market since it was liberalized. All Alberta consumers have the opportunity to participate in the spot market and to hedge against changes in those prices.

The generation component is only one portion of the consumers' final bill. Transmission and distribution also impact the delivered price of electricity. Like many provinces, Alberta is planning substantial upgrades to its transmission system. While these upgrades will increase reliability, they will, over the near term, also contribute to an increase in delivered prices. However, Alberta has been at the forefront of measures to manage new transmission costs by relying on competitive bidding for new transmission projects rather than automatically allocating them to incumbents.

For distribution, Alberta has adopted an advanced regulatory structure which provides explicit incentives for efficiency, in real terms, absent significant capital expenditures;[3] this system helps to manage costs associated with the distribution portion of customer bills. Although some distribution companies plan large capital expenditures, in growing service territories the cost of new capital expenditure may be partly absorbed by the increase in customers and volumes sold.

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[1] While Alberta has generally done a better job than other provinces with respecting the independence of market and regulatory institutions, Bill 50, the Electric Statutes Amendment Act, 2009 was an exception to that rule, allowing the Government of Alberta to approve transmission investment deemed as critical transmission infrastructure projects. Subsequently, Bill 8, the Electric Utilities Amendment Act, 2012, removed that authority, subjecting all new project to complete review and approval by the Alberta Utilities Commission.

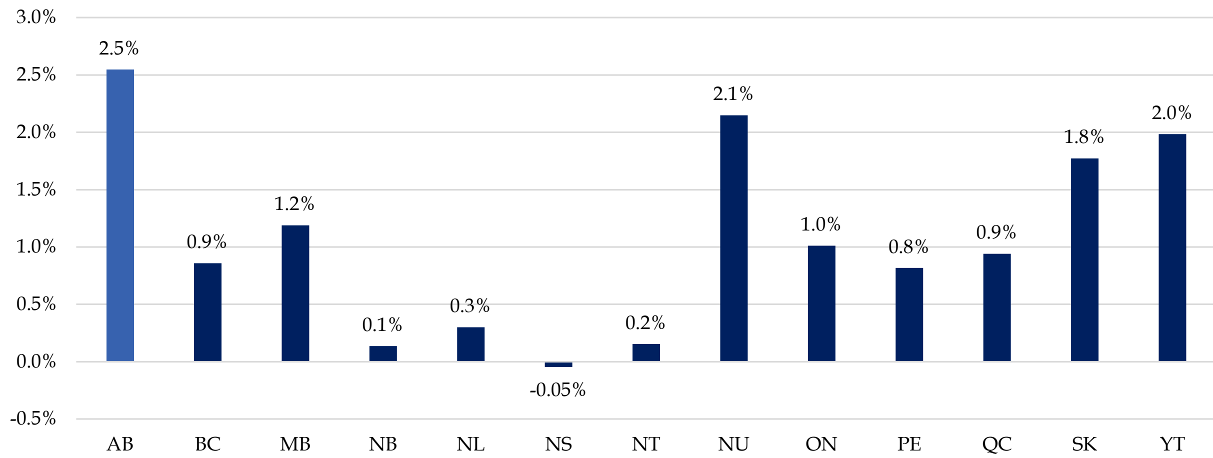
[2] Government of Alberta. "*Power for the People*". September 2012. <http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf>.

[3] Alberta Utilities Commission. "*Rate Regulation Initiative: Distribution Performance-Based Regulation*". September 12, 2012. <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

1.2 Alberta is among the fastest growing provinces in Canada

The population of Alberta grew the most of all Canadian provinces and territories with a 2.5% average annual population growth rate between 2010 and 2013, as shown in Figure 1.

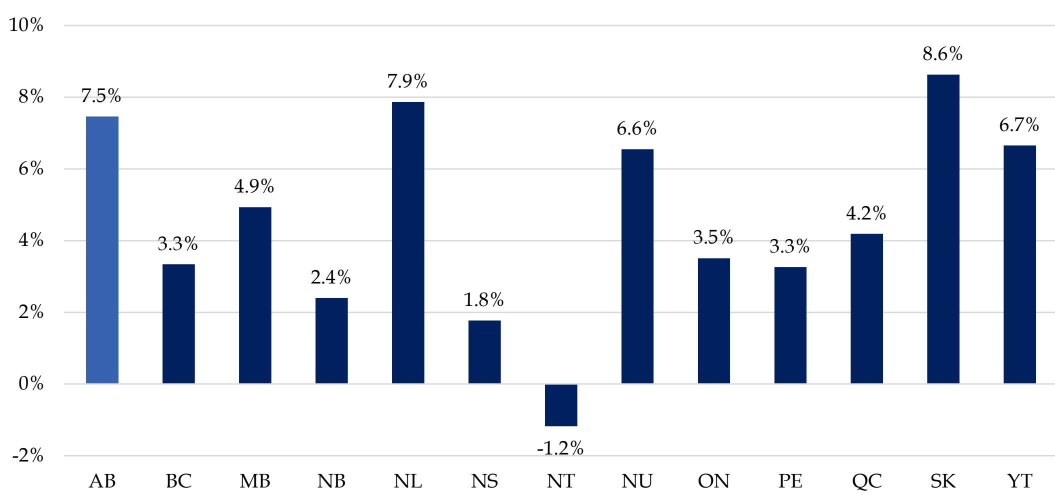
Figure 1. Annual average population growth 2010-2013



Source: Statistics Canada

Gross provincial product has also been growing rapidly for the province of Alberta since 2010. Alberta's annualized average gross provincial product growth rate between 2010 and 2012 of 7.5% is the third highest of the Canadian provinces, following Saskatchewan at 8.6% and Newfoundland and Labrador at 7.9%, as depicted in Figure 2. Each of these three provinces surpasses the annualized gross domestic product growth rate of Canada as a whole (4.6%) for the same period.

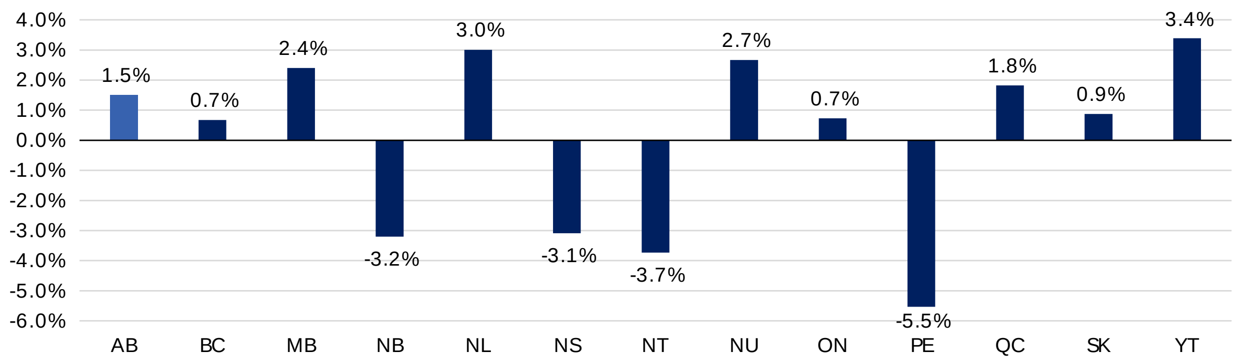
Figure 2. Annual average gross provincial product growth 2010-2012



Source: Statistics Canada

Alberta's annual average load growth between 2010 and 2013 is above the average load growth across all provinces and territories across Canada (approximately 0.1%). As presented in Figure 3, some of the provinces experienced a decline over the same period. Higher load growth means fixed costs of electricity provision can be spread across larger volumes, whereas provinces experiencing negative load growth face significant upwards rate pressure.

Figure 3. Annual average load growth by province 2010-2013



Source: Statistics Canada

1.3 Other provinces largely rely on a form of cost-of-service ratemaking

Unlike the Alberta market, which consists of multiple generators operating on short to medium term market-based contracts or spot sales, most other Canadian provinces are dominated by a single vertically-integrated provincially-owned utility. In Manitoba, Saskatchewan, and Quebec, the provincially-owned utility dominates every aspect of the value chain. In British Columbia ("BC"), the province has encouraged new supply from private generation under contract to the provincial utility. In the Atlantic provinces, privately-owned vertically-integrated utilities are the norm; in Newfoundland, Nunavut, and Yukon, in addition to BC, some small private utilities or IPPs exist alongside the provincial utility.

Figure 4. Key market design elements, 2012

	Province	Utility	Market Share of Generation	Market Share of Load	Provincially owned	Unbundled	Organized market
AB	Alberta	4 main distribution comapanies	~70 generators	NA	No	Yes	Yes
BC	British Columbia	BC Hydro	72%	71%	Yes	Yes	No
MB	Manitoba	Manitoba Hydro	94%	97%	Yes	No	No
NB	New Brunswick	NB Power	100%	100%	Yes	No	No
NL	Newfoundland and Labrador	Nalcor	96%	100%	Yes	No	No
NS	Nova Scotia	NS Power	94%	100%	No	No	No
ON	Ontario	Hydro One	56% (OPG)	20%*	Yes	Yes	Yes
PE	Prince Edward Island	Maritime Electric	74%	74%	No	No	No
QC	Quebec	Hydro Quebec	100%	94%	Yes	Yes	No
SK	Saskatchewan	SaskPower	96%	99%	Yes	No	No
YT	Yukon	Yukon Energy	94%	97%	Yes	No	No

**Electricity distributed to Hydro One customers as share of total Ontario load (Hydro One transmitted 99% of Ontario load)*

Source: Utilities annual reports, Regulators; unbundled entities may be distinct subsidiaries under common ownership

Ontario operates under a different model, with a provincially owned generation company and a provincially owned wires company, municipal and private distribution utilities, and a power authority which procures most generation under long term contracts. Although Ontario has a real time market, this market has increasingly been marginalized.

In those provinces outside of Alberta which have private sector generation, such generation is largely compensated under long term, quasi-government guaranteed contracts. Costs for generation from the incumbent utilities, and from the independent power producer ("IPP") contracts, are passed through to customers, regardless of whether that generation is needed. The ability of Crown corporations to pass costs through to customers erodes financial discipline and can lead to oversupply. Incentives to planners are asymmetric: in the event of oversupply, customers pay the costs; in the event of outages due to undersupply, political outcry ensues. This dynamic can lead planners to rely on unrealistically robust load forecasts and to approve new build which may not be needed. During an economic downturn coupled with increased attention to conservation, the consequences can be costly.

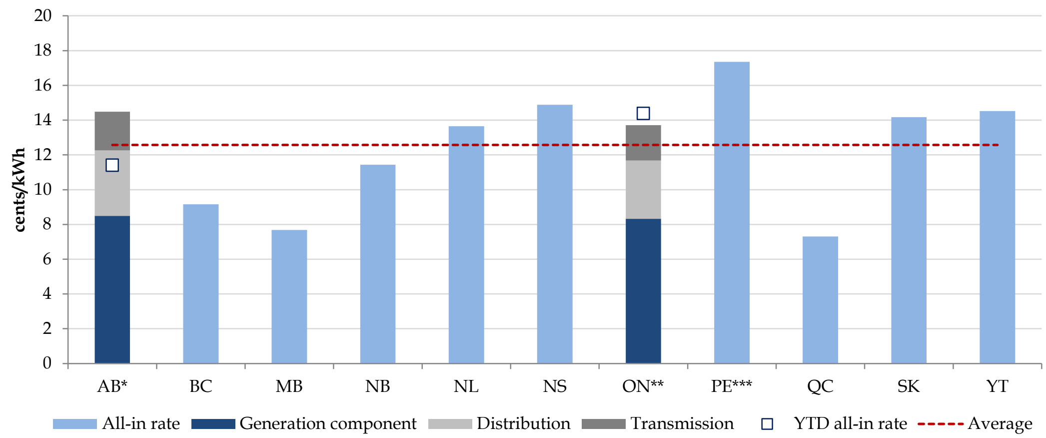
By contrast, in a system like Alberta's, if generators overbuild, it is shareholders rather than customers who bear the burden. Furthermore, existing generators which are less efficient cannot pass added costs through to consumers, but instead face lower margins. This difference in risk allocation leads to more efficient decision-making and ultimately lower costs.

2 How do delivered costs of electricity to final consumers in Alberta compare to delivered costs of electricity in other provinces?

A review of 2013 residential and industrial rates[4] across Canada reveals that Alberta has neither the highest nor the lowest rates in Canada. Furthermore, the higher relative position for Alberta rates in 2013 is strongly correlated with the conditions of the underlying wholesale market for electricity in the province. In 2013, the wholesale electricity price in Alberta reached a 5-year high of $80.19/MWh,[5] representing an increase over 2012 of nearly 25%. Since the beginning of 2014, wholesale prices have averaged $52/MWh.[6]

2.1 Residential

Figure 5. Rates to final residential customers in Canadian provinces, 2013



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average of Regulated Rate Options for ENMAX, EPCOR, FortisAlberta, and ATCO service territories plus transmission and distribution charges.*

***Ontario rate is for Hydro One.*

****PE rate is for 2012.*

Alberta weighted average residential rates were estimated at $0.145 per kWh in 2013.[7] Across Canada, residential rates in 2013, when expressed on a volumetric basis, ranged from $0.073 in

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[4] The term "rate" in this paper refers to the all-in delivered cost to consumers and can either reflect a tariff established wholly by a regulator or a combination of market prices and regulated components.

[5] All prices are in Canadian dollars unless specified otherwise.

[6] YTD average for the period January 1 through June 13, 2014.

[7] It is important to note that while we use the weighted average Regulated Rate Option ("RRO") as a residential rate, customers have the option of signing long term contracts for a market price. As of April 2012, 66% of residential customers paid the default rate, down from 93% in April 2005. Government of Alberta. "*Power for the People*". September 2012. <http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf>, Pg. 39.

Quebec to $0.149 per kWh in Nova Scotia. Most residential bills include a mix of fixed and volumetric components. To compare across provinces, we calculate the rate to final residential customers as the total dollar amount of revenues from residential customers divided by the total volume of electricity sold to residential customers. Such methodology is employed by the US Energy Information Administration when comparing the final rate to customer across US and is helpful to account for all items excluding taxes that may contribute to the final customer's bill. For provinces for which the revenues or sales data per customer type was unavailable, we used the average monthly household consumption level for those province, to calculate the $/kWh value of the fixed components of the electricity bills.[8]

Each utility provides current and historical rates on their websites and the associated maximum consumption levels per tranche. To facilitate like-to-like comparisons, fixed charges were converted to volumetric rates based on average customer demand. For Ontario, Hydro One was used as a representative. Ontario rates are the sum of energy (Regulated Price Plan rates established by Ontario Energy Board), transmission, distribution, and other charges such as debt retirement.[9] Energy charges include wholesale energy and Global Adjustment ("GA") charges.[10] For Alberta, the weighted average[11] Regulated Rate Options ("RRO") for ATCO, ENMAX, EPCOR, and FortisAlberta service territories plus distribution and transmission charges were summed to arrive at the residential rates. For detailed calculations please refer to Appendix B: Comparing Alberta and US 2012 industrial rates.

The 2013 data suggests Alberta residential rates were 15% higher than the Canadian average of $0.126 per kWh in 2013. When provinces with more than 50% hydro are excluded, Alberta was within 1% of the Canadian average of $0.143 per kWh for provinces without large hydro endowments. In 2010 the Alberta residential rates when compared to the Canadian average were 11% higher, while when compared the average excluding hydro-endowed provinces, they were 4% below average.

Since the beginning of 2014, wholesale electricity prices in Alberta have been much lower than their 2013 levels. By using the year-to-date average of $52.0/MWh (average of prices for the period January 1, 2014 through June 12, 2014), electricity rates to residential customers are estimated to be in the range of $0.114/kWh, representing a decrease of 21% from the 2013

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[8] Based on Statistics Canada estimates.

[9] The debt retirement charge, representing 0.7 cents/kWh of the final rate, will be eliminated after the end of 2015.

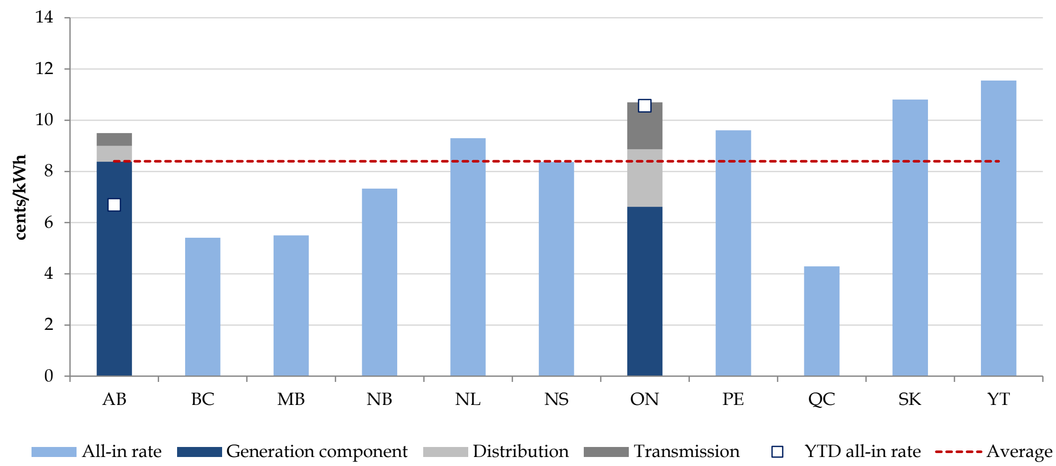
[10] There are two components of electricity commodity charges in Ontario: the Hourly Ontario Energy Price (HOEP) and the Global Adjustment (GA). The HOEP is the wholesale market price and is based on supply and demand, as balanced in real-time for each hour. The GA reflects the difference between market prices/revenues and 1) the regulated rate paid to OPG's baseload generating stations; 2) payments made to suppliers under contract with the Ontario Power Authority (OPA); and 3) contracted rates paid to non-utility and other resources. The GA is also the mechanism used to recover the cost of a number of other OPA administered programs, including demand response and conservation initiatives. Taken together, the HOEP and the GA reflect the "consumer price" of electricity in Ontario. For each contract class, the GA amount is determined by the difference between the contract/regulated price and price received in the market.

[11] GWh sales volumes to residential customers were used to arrive at the weighted average RRO.

residential rates in the province. If the 2014 annual electricity wholesale price remains at its year-to-date level, prices in Alberta could fall as far as 9.4% below the Canadian average for 2013.

2.2 Industrial

Figure 6. Rates to final industrial customers in Canadian provinces, 2013



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average unbundled rates for ENMAX, EPCOR, FortisAlberta, and ATCO*

***Ontario rate is for Hydro One*

A similar range of rates can be found across Canada for industrial consumers. In 2013, the industrial rate in Alberta was estimated to be $0.095 per kWh. The lowest rates of $0.043 per kWh were found in Quebec, while the highest rates of $0.116 per kWh were found in Yukon Territories. Industrial rates were calculated using the same process as was used for residential rates. For Ontario, all-in charges were calculated by adding transmission, distribution, the Global Adjustment, the Hourly Ontario Energy Price ("HOEP") charges, and other charges such as debt retirement.[12] The GA and HOEP were determined by the load-weighted average of the data for 2013.[13] Industrial rates for Alberta consist of wholesale energy prices,[14] as well as

[12] LEI's estimate for the average 2013 Ontario industrial rate is less than 0.01 cent different from the estimate provided by the Association of Major Power Consumers of Ontario ("AMPCO") for Class B industrial customers in Ontario. Given that the Class A customer type represents a new initiative, in which only 200 customers participate as of April 24, 2014, we believe that the average rate for Class B customers represents a better indication of the province's average industrial rate.

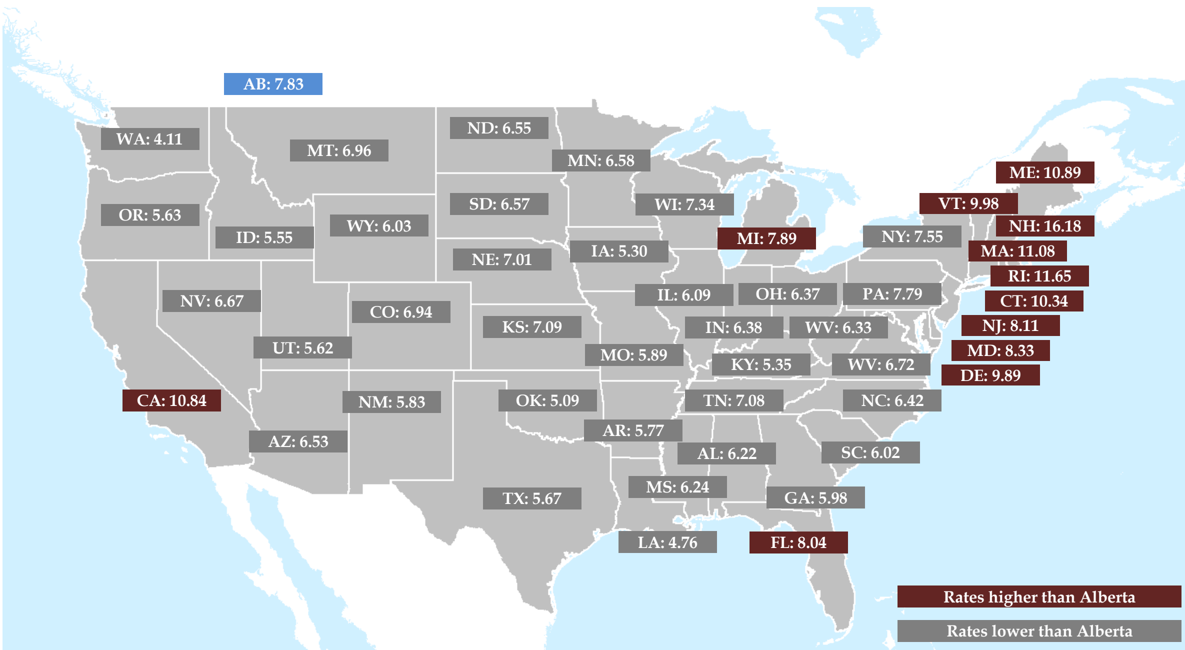
[13] IESO. "*Monthly Market Report December 2013.*" <http://www.ieso.ca/imoweb/pubs/marketReports/monthly/2013dec.pdf>.

[14] Energy prices for Alberta are load-weighted using EPCOR estimates of monthly default supply energy prices, which incorporate the impact of a typical customer class load shape. We have used the last three year (2011-2013) average load shape premium, as reported by EPCOR, for demand greater than 75 kW. . Note that as

transmission and distribution charges for each utility. Rates are based on a load-weighted average for ATCO, EPCOR, ENMAX, and FortisAlberta.

Alberta's positioning relative to other Canadian provinces with regards to industrial rates is similar to the trends found in residential rates. Industrial rates are slightly above the Canadian average for most provinces; when hydro-rich provinces are excluded, the gap between the Alberta rates and the Canadian average is further narrowed. Alberta's industrial rates are $0.095 per kWh compared to an average of $0.084 per kWh for all provinces and $0.094 per kWh for non-hydro dominated provinces.[15] A key driver behind the higher 2013 electricity rates in Alberta was the elevated, but transitory, wholesale electricity price level for the province.

Figure 7. Comparison of Alberta industrial rates with US states, 2012



Source: US Energy Information Administration (EIA), "Retail Sales of Electricity to Ultimate Customers: 2012 Utility Bundled Retail Sales", March 21, 2014.

Note: All rates listed are as of June 2012 and are displayed in Canadian cents per kWh using 1 to 1 conversion between US dollar and Canadian dollar, Bank of Canada.

When compared to industrial rates in the US, 2012 Alberta rates were competitive, averaging at 7.83 cents/kWh; using US Energy Information Administration data for 2012, Alberta industrial rates at exchange rate of 1 CAD = 1 USD[16] were found to be lower than 14 US states, including

industrial customers may represent a range of sizes, analysis here may not account for all conditions; some customers may pay substantially more.

[15] New Brunswick, Nova Scotia, Ontario, Prince Edward Island, and Saskatchewan.

[16] Bank of Canada. 2012 average conversion rate was 1 CAD = 1.0006 USD

Alaska and Hawaii.[17] Furthermore, over the last year US rates increased, with residential and industrial rates for March 2014 5.7% and 6.1% (respectively) higher than their March 2013 levels.[18] Recent policy changes regarding greenhouse gas emissions may further increase some US power prices. Applying current exchange rates would increase Alberta competitiveness relative to the US.

Despite much higher wholesale electricity prices in Alberta for 2013, rates to industrial customers in Alberta have remained competitive. In contrast to LEI 2011 findings Alberta rates for 2013 are slightly above the average for Canada. But when comparing YTD 2014 Alberta and Ontario rates with the Canadian data for 2013, Alberta rates are well below the 2013 Canadian average for both industrial and residential customers.

2.3 Impact of announced rate increases

To date, announced rate increases have served to narrow the difference between rates in other provinces and Alberta. Since 2010, primarily due to trends in the wholesale generation market in Alberta, electricity prices in the province to final residential customers have increased at a moderate pace compared to other provinces. This trend, however, has been much more pronounced for industrial customers to whom the final electricity prices have increased significantly due to larger exposure to fluctuations in the wholesale prices. Below, we summarize rate increase announcements across Canada.

Figure 8. Announced rate increases

Province		Change	Effective date	Source
BC	**British Columbia**	9.0%	April 1, 2014	BC Hydro
MB	**Manitoba**	2.8%	May 1, 2014	Manitoba Hydro
NB	**New Brunswick**	2.0%	October 1, 2013	NEB
NL	**Newfoundland and Labrador**	-3.0%	July 1, 2013	NEB
NS	**Nova Scotia**	3.0%	January 1, 2014	NEB
ON	**Ontario**	2.0%	January 1, 2014	Hydro One
PE	**Prince Edward Island**	2.2%	March 1, 2014	NEB
QC	**Quebec**	5.8%	April 1, 2014	NEB
SK	**Saskatchewan**	5.5%	January 1, 2014	SaskPower

Source: Utilities reports, National Energy Board

Note: The energy portion of the Alberta RRO rate is based cost of procuring energy through the forward market and is not set by regulator; Quebec rate increase decision is still pending.

2.4 Recent rate changes

To ensure comparability, all rates and rate changes below refer to average volumetric rates per customer class; fixed components have been converted to volumetric based on average customer consumption.

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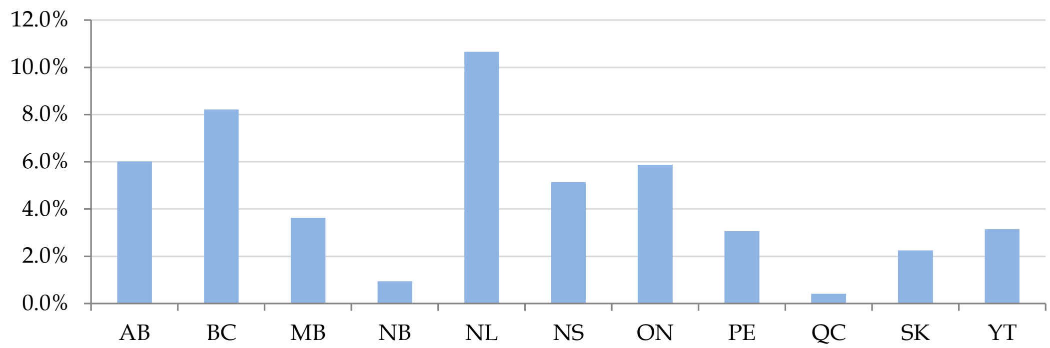
[17] For US, similar EIA data for 2013 is not yet fully available.
[18] EIA. "Electric Power Monthly: Data for March 2014." May 21, 2014

- ***Alberta:*** residential rates in Alberta have experienced an annualized growth rate of approximately 6.0% since 2010. In addition, industrial rates in Alberta increased from 6.8 cents/kWh in 2010 to 9.5 cents/kWh in 2013, an annualized increase of approximately 11.6%. The jump in industrial rates mimics the increase in wholesale electricity prices in Alberta from $50.88/MWh in 2010 to $80.19/MWh, representing an annualized increase of 16.4%. 2013 Alberta residential rates have been higher than estimated in the LEI 2011 report. Industrial rates in 2013, however, are still in-line with our previous estimates and given the expected decreases in wholesale electricity prices, LEI believes that prices to both customer classes could fall significantly in 2014.

Figure 9. Annualized change in delivered rates to residential customers (2013 vs. 2010)



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average of Regulated Rate Options for ENMAX, EPCOR, FortisAlberta, and ATCO service territories plus transmission and distribution charges.*

***Ontario rate is for Hydro One.*

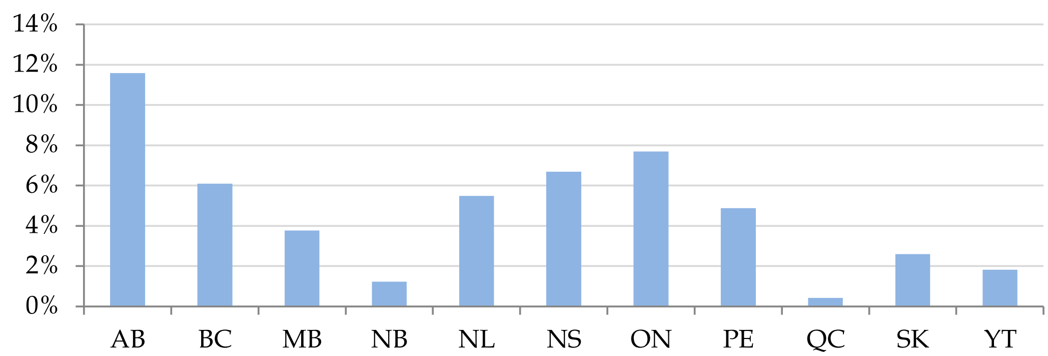
- ***British Columbia:*** compared to 2010, the 2013 average rate to within-province customers for BC Hydro increased by a total of 2.7% per annum. This general provincial rate increase, however, is composed of a combination of an increase of 26.7% to residential customers, an increase of 19.4% to large industrial customers, and a reduction of more than 68% for "other customers" type. Since 2010, the average final rate to residential customers has experienced an annualized growth of 8.2% per annum, while the average final rate to large industrial customers has increased by 6.1% per annum.

- ***Manitoba (Manitoba Hydro):*** in 2013, the final electricity rate to Manitoba Hydro within-province customers averaged 6.24 cents/kWh, representing an 11.7% increase over the 2010 rate of 5.59 cents/kWh. Between 2013 and 2010, the rates to residential and all other non-residential (general service) customers increased by 11.3% and 11.7%, respectively. Since 2010, the average domestic rate[19] for Manitoba Hydro grew by an annualized rate of 3.8%. For the same period the annualized growth rates for the residential and general service rates were 3.6% and 3.8%, respectively.

[19] Domestic rate implies rate to within-province customers (excludes exports).

- ***New Brunswick (New Brunswick Power):*** the average within-province rate for New Brunswick Power grew by 2.4% between 2013 and 2010. The average rate to residential customers also grew by 2.9% between 2013 and 2010. Over the same period, the rate to industrial customers increased by 3.8%, while the general service, which is applied to approximately 18% of New Brunswick Power total within-province electricity sales, increased by 0.9%. Since 2010, the annualized within-province growth rate in electricity prices was approximately 0.8%, while the annualized growth rates for residential, industrial, and general service electricity rates were 0.9%, 1.2%, and 0.3%, respectively.

Figure 10. Annualized change in delivered rates to industrial customers (2013 vs. 2010)



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average all-in rates for ENMAX, EPCOR, FortisAlberta, and ATCO*

***Ontario rate is for Hydro One*

- ***Newfoundland and Labrador:*** after experiencing a jump of 17.4% since 2010, industrial rates in Newfoundland and Labrador stand above the Canadian average. Since 2010, residential rates in Newfoundland and Labrador have increased by as much as 35.5% to approximately 13.7 cents/kWh. The annualized growth rates for residential and industrial customers since 2010 are 10.7% and 5.5%, respectively.

- ***Nova Scotia:*** in 2013, electricity rates for residential customers increased to 14.9 cents/kWh. This represents a total increase of 2.1 cents/kWh or 16.2% since 2010. Over the same period, industrial rates have increased by 21.4% to 8.4 cents/kWh. The annualized growth rate for residential and industrial rates since 2010 are 5.1% and 6.7%, respectively.

- ***Nunavut:*** rates in Nunavut are significantly higher than the remaining Canadian provinces and territories. Commercial rates for the financial year 2012/2013 in Nunavut were close to 61.6 cents/kWh, while the average domestic rate for Nunavut was at about 69.5 cents/kWh. Moreover, since financial year 2010/2011, territory-wide rates to final customers have increased by 29.6%.

- ***Ontario:*** as presented in the 2011 version of this report, residential rates in Ontario were well above the Canadian average for 2010. Since then, residential rates have increased by a total of 18.7%. Industrial rates in Ontario, however, have experienced a stronger increasing trend. Since 2010, industrial rates have increased by 2.1 cents/kWh representing a total increase of 24.9%. Annualized growth rates for residential and industrial electricity rates are 5.9% and 7.7%.

- ***Prince Edward Island:*** Residential rates for Prince Edward Island remain the highest among the Canadian provinces, but below the rates for Nunavut. The 2012 residential rates for the province are higher by an annualized rate of about 3.1% over their 2010 levels. Similarly to residential rates, industrial rates in Prince Edward Island have experienced a jump since 2010, increasing by about 1.3 cents/kWh (4.9% annualized growth rate) over the same period.
- ***Quebec (Hydro Quebec):*** the average within-province electricity rate for Hydro Quebec grew by 3.2% in the period 2012-2013. For the same period, the rate increase for residential customers was 1.8%; for large industrial customers, 5.3%; and for commercial and small industrial was 2.0%. The annualized average within-province electricity rate increase since 2010 was 1.06%. The annualized commercial and small industrial rate growth average was 0.4%. Residential electricity rate followed a similar annualized growth rate of approximately 0.4%, while, for the same period, the large industrial electricity rate increased also at an annualized rate of 0.4%.
- ***Saskatchewan (SaskPower):*** in 2013, the within-province electricity rate increased for all SaskPower customers groups, growing on average by 4.6% since 2012. The rate to residential customers, over the same period, increased by 3.5%; the rate to commercial customers increased to 4.6%; the rates to oilfield, power, and farm customers increased by 5.1%, 4.2%, and 3.1%, respectively. Since 2010, the within-province average rate grew by an annualized factor of 2.3%. Over the same period, the annualized factor for residential customers was 2.2%, for commercial customers 2.6%, while for oilfield, power, and farm customers, the annualized factors were 2.2%, 2.6%, and 2.2%.

Higher underlying electricity commodity prices in 2013 have changed the relative standing of Alberta residential and industrial price growth rates to those of other Canadian provinces. This change in trend, however, does not represent fundamental shifts in the distribution and transmission sectors; it is primarily driven by temporary conditions in the province's wholesale market. When those trends are excluded, estimates of the Alberta residential and industrial rates using YTD 2014 data are 21.7% and 30.3% lower than the 2013 rates.

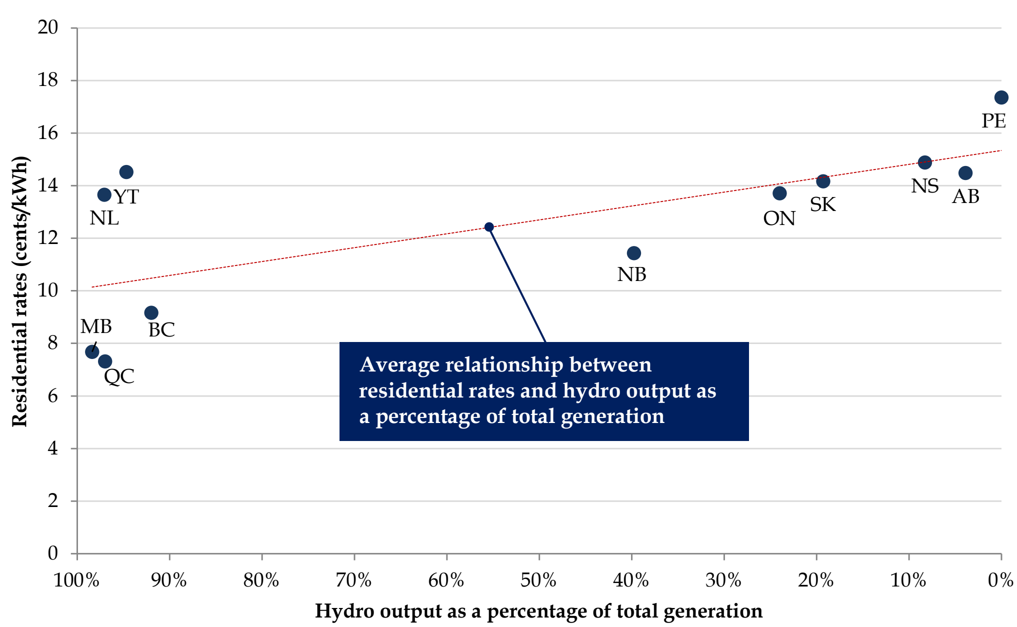
3 Delivered costs to final consumers in other provinces may not fully incorporate the full cost of power

Rates to final consumers across Canada differ for several reasons: the proportion of hydroelectric generation in capacity mix across provinces, the extent to which utilities are capitalized consistent with commercially reasonable norms, provincial owners accepting below-market equity returns, differences in taxation, and the treatment of export revenues. Below, we explore each of these issues in greater detail and calculate the combined impact on rates for each province.

3.1 Differences in initial endowments

One of the primary drivers of rate differences is the extent of hydroelectric generation in a province. As the graphic below shows, although Alberta is among the least well-endowed with cheap resources, with only 5.1%[20] of energy from hydroelectric generation, Alberta rates are nonetheless lower than some other provinces with more hydro. Furthermore, although shale gas has changed the dynamics of natural gas markets in North America, Alberta is favorably positioned with regards to the levelized cost of fossil fuel generating capacity additions relative to those provinces which are further away from natural gas fields.

Figure 11. Percentage of hydro output against level of rates, 2013



Source: Utilities annual reports

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[20] AESO. "*2013 Annual Market Statistics*." 2013. <http://www.aeso.ca/downloads/2013_Annual_Market_Statistics.pdf>.

As a proxy for the extent to which hydro endowments contribute to lower prices to final consumers, prices in the hydro-dominated Pacific Northwest, as evidenced by the Mid-C pricing point, averaged $38.19[21] per MWh in 2013,[22] while Alberta wholesale generation prices averaged $80.19 per MWh over the same period. Canadian rate differentials suggest that as much as 4.01 cents/kWh of the difference in rates between Alberta and hydro-dominated provinces may be explained by the underlying resource mix.[23] While we observe this differential using market data, we have not applied it in our inter-provincial comparisons for the sake of conservatism. Figure 11 further supports the conclusion; there is an apparent relation between hydro endowments and residential rates.

3.2 Levels of leverage and impact on overall provincial debt burden

Along with the Maritime Provinces, Alberta is among the few provinces which do not own provincial utilities. Provincially-owned utilities may unfairly benefit from an implicit guarantee or "halo" effect around their debt because investors may assume that, regardless of the fact that the utility is at arm's length from the province, it is unlikely that the provincial parent would allow its utility to default on its debt. In the cases where a utility does pay its parent for an explicit debt guarantee, the amounts paid for the guarantee may be less than the market cost of similar guarantees, or such guarantees may simply be unavailable in the public capital markets. Regardless, a review of long term debt to total asset levels across provinces shows that provincially-owned utilities are significantly more leveraged than those which are privately owned.

Figure 12. Debt guarantees analysis of selected provincially-owned utilities

Province	Utility	Description
BC	**BC Hydro**	BC Hydro's debt is either held or guaranteed by the province. Under an agreement with the province, BC Hydro indemnifies British Columbia for any credit losses incurred related to interest rate and foreign currency contracts entered into by the province on BC Hydro's behalf.
MB	**Manitoba Hydro**	The Province of Manitoba provides flow through credit to Manitoba Hydro and guarantees the vast majority of its debt. In return, Manitoba Hydro pays a provincial debt guarantee fee to the Manitoba government in exchange for this guarantee. The assessment of the payment is determined by the province. For 2012 and 2013, the fee during the year was 1.0% of the total outstanding debt guaranteed by the province.
NB	**NB Power**	NB Power combines its borrowing requirements with those of New Brunswick, having the province make one large debenture issue and then on-lend a portion of that issue to NB Power. NB Power pays a guarantee fee of 0.65% of outstanding debt for use of the province's credit.
QC	**Hydro-Québec**	Hydro–Québec's borrowings, which consist mostly of debentures and medium-term notes, are nearly all guaranteed by the Québec government. Short-term borrowings, sinking funds, commercial paper, and standby lines of credit are also guaranteed by the Québec government.

Source: Utilities annual reports, Regulators

[21] In Canadian dollars using 2013 average US dollar to Canadian dollar exchange rate of 1.02991480, Bank of Canada.

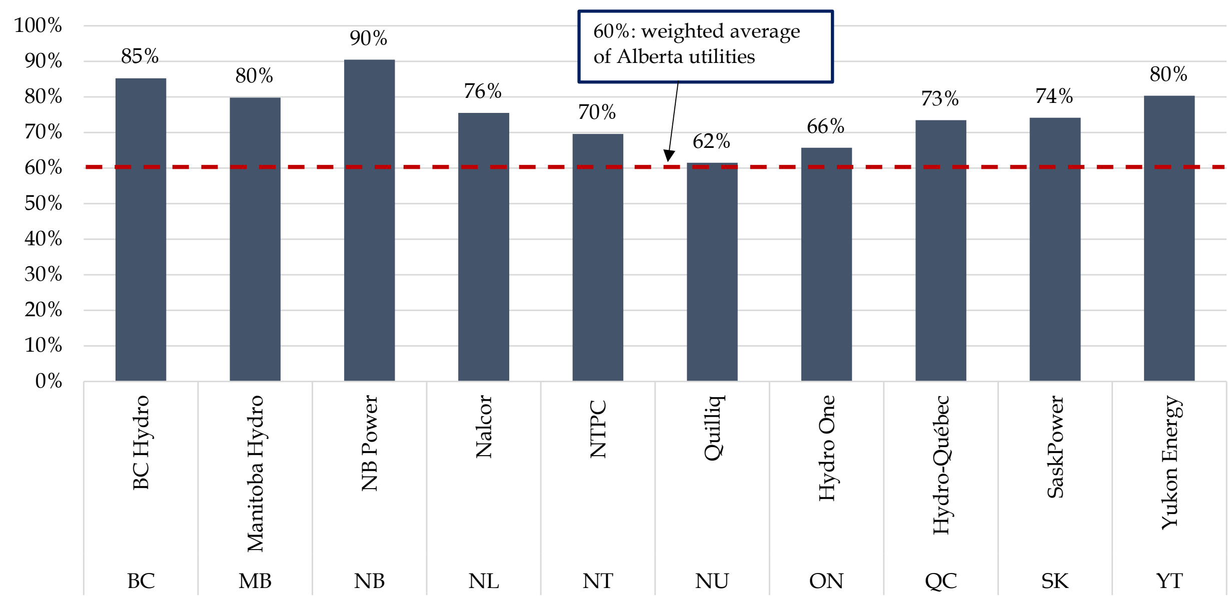
[22] EIA. "*Wholesale Electricity and Natural Gas Market Data.*" May 29, 2014. <http://www.eia.gov/electricity/wholesale/>.

[23] While regional markets may also have other differences, such as a predominance of rate-base generation, the underlying fuel mix and supply-demand balance is one of the key explanations for regional price variations.

Many provincially-owned utilities have debt guaranteed by their provincial government, in which taxpayers contribute to the subsidy of these borrowings. The borrowing requirements of Crown corporation utilities are often combined with the province as shown in Figure 12. While some are considered self-supporting by credit rating agencies, the resulting effect of provincially-owned utility borrowings is to constrain the ability of provinces to raise debt for other infrastructure needs.

As Figure 13 shows, many provincially-owned utilities have long term debt to asset ratios of over 65%. Utilities in Alberta have an average of approximately 60%.[24]

Figure 13. Debt as a portion of assets for selected utilities, 2013



Source: Annual reports

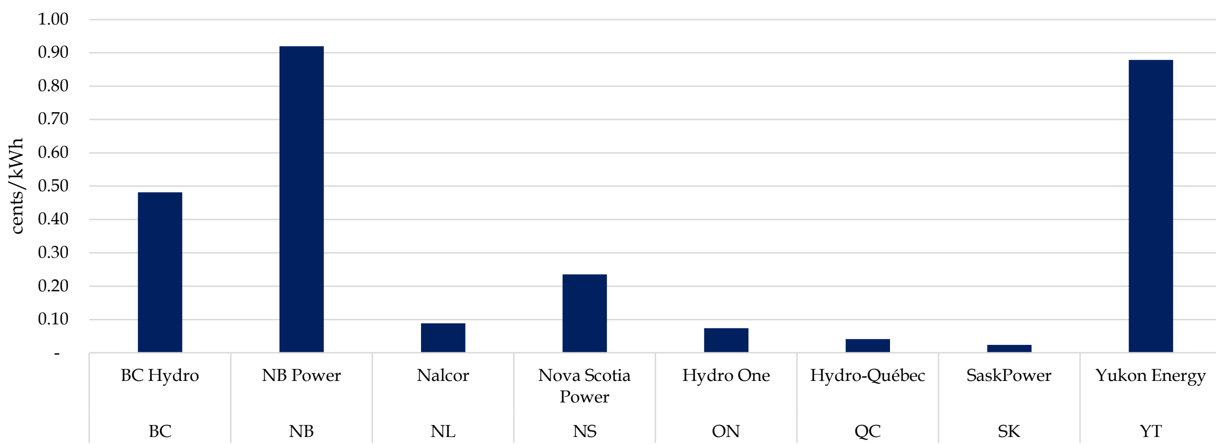
Note: Debt is calculated as total assets minus total shareholder equity. Alberta's calculations are based on each utilities' transmission and distribution segments; Hydro One only its distribution segment. Other provinces reflect the sum of all operations.

Using the approved returns on equity in each of the respective provinces, and deleveraging the balance sheet of each of the utilities, we can estimate the extent to which implicit debt guarantees suppress rates to final consumers. We calculate this by adding the amount of equity necessary to bring the utility to a 60% debt to assets capitalization ratio, multiplying this additional equity amount by the difference between debt costs and allowed equity returns, and dividing the total by domestic volumes sold in 2013. Figure 14 shows the additional increment to rates in cents per kilowatt hour. The increase for residential customers ranges from 1% to 8%

[24] ATCO, EPCOR, and FortisAlberta AUC Rule 005 filings, 2013 (ENMAX debt to assets ratio is based on their 2012 AUC Rule 005 filing).

and the increase for industrial customers ranges from 1% to 13%. While a further increase may be warranted to reflect market-based stand-alone debt costs for the provincial utilities, LEI has not made such an additional adjustment for the sake of conservatism.

Figure 14. Extent to which implicit debt guarantees suppress rates to final consumers



If provincial utility debt were consolidated onto provincial balance sheets, the impact would not be trivial. As the table below shows, the addition of utility debt to provincial debt loads increases provincial debt by a range of 16% to 65%.

Figure 15. Provincially-owned utilities' debt levels relative to overall provincial debt

Province	Provincially-owned utility	Utility debt (C$ billions)	Debt as a percentage of the utility's assets	Provincial net debt 2011-12 (C$ billions)	Provincial debt plus implicit guarantee (C$ billions)	Utility debt as a percentage of provincial & implicit guarantee debt	Combined utility and provincial debt to gross provincial product
BC	BC Hydro	20.3	85.3%	36.0	56.3	36.1%	25.6%
MB	Manitoba Hydro	11.6	79.8%	14.8	26.5	43.9%	45.4%
NB	NB Power	5.7	90.5%	10.0	15.8	36.3%	50.0%
NL	Nalcor	7.2	75.5%	7.8	15.0	48.1%	44.3%
NU	Quilliq	0.2	61.5%	0.1	0.3	53.3%	13.0%
ON	Hydro One and OPG	44.0	73.6%	235.6	279.5	15.7%	41.4%
QC	Hydro-Québec	53.7	73.5%	170.9	224.6	23.9%	62.8%
SK	SaskPower	6.4	74.2%	3.6	9.9	64.2%	12.8%

Source: Annual reports, Statistics Canada, Department of Finance Canada

This additional debt burden is not without cost for provinces. Although rating agencies have generally found that the combined debt burden is manageable for provinces, these agencies nonetheless do take the utility debt burden into account. Some examples of this fact are presented in Figure 16. In cases where the utility is performing poorly, the province's ability to raise funds for other activities may become strained. Furthermore, the capital that is locked up in a provincially-owned utility is not being invested in activities which may have a higher social return, such as health, transport, and education. In the meantime, because electricity rates are suppressed, consumption may be higher than is economically efficient. These distortions do not occur under the competitive market design in Alberta.

Figure 16. Rating agencies take the utility debt burden into account

Province		Description
BC	**British Columbia**	Among the rationale for S&P's credit rating for British Columbia, BC Hydro's debt is a factor that is taken into account. S&P notes: "in our opinion, BC's primary contingent risk relates to its local energy provider, BC Hydro, which is a wholly owned Crown corporation."
MB	**Manitoba**	Debt associated with Manitoba Hydro is accounted for in the Moody's rating of Manitoba's debt portfolio. "Manitoba Hydro, by virtue of its exports of hydroelectric power to the United States, has a natural hedge against USD-CAD currency fluctuations." Moody considers Manitoba Hydro to be self-supported, but continues to monitor the developments with Manitoba Hydro's capital plan to ensure that this status of the utility's debt remains appropriate.
NB	**New Brunswick**	The rating agencies compare NB Power to other crown utilities in terms of how the corporation manages its finances. "If the Corporation were not a viable, self-sustaining business, the rating agencies would consider the utility's debt to be supported by taxpayers and more of an imposition on the province's own credit."
ON	**Ontario**	Even though Ontario does not formally guarantee Hydro One's debt obligation, Moody's notes a "high probability of support from the Province of Ontario". Due to this belief, Moody's downgraded Hydro One's rating to A1 from Aa3 in April 2012 in conjunction with the Province of Ontario's rating downgrade to Aa2
QC	**Quebec**	Fitch Ratings corrected its outlook on Quebec's debt to negative from stable on December 2013 due to "weaker-than-planned economic and revenue performance". In response, Quebec Finance Minister Carlos Leitao believes that "government-owned companies such as electricity utility Hydro-Quebec will need to cut spending by a combined C$438 million this year and C$172 million in 2015-16."

Sources: Standard & Poor's. "Global Credit Portal." April 5, 2012. <http://www.fin.gov.bc.ca/PT/dmb/ref/ratingSP.pdf>.

Moody's Investor Service. "Credit Analysis: Manitoba, Province of Canada." August 10, 2010. <http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/Appendix_20.pdf>.

Legislative Assembly of New Brunswick. "Énergie NB Power: Credit Rating Agencies." <http://www.gnb.ca/legis/business/committees/previous/reports-e/nbpowerbp96-01/finance-e.asp>.

Moody's Investor Service. "Rating Action: Moody's downgrades Hydro One to A1, outlook stable." April 27, 2012. <https://www.moodys.com/research/Moodys-downgrades-Hydro-One-to-A1-outlook-stable--PR_244518>.

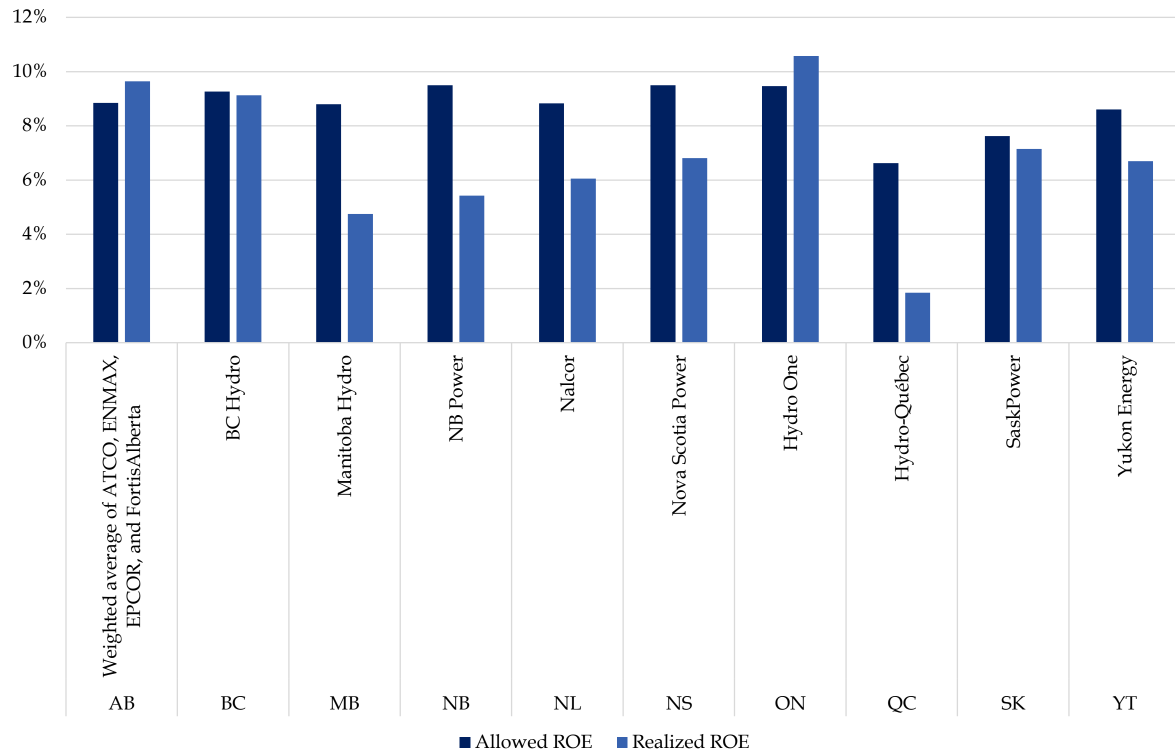
Bloomberg. "Quebec to Balance Budget Next Year After Deficit Widens." June 5, 2014. <http://www.bloomberg.com/news/2014-06-04/quebec-to-balance-budget-next-year-after-deficit-widens.html>.

In comparison to 2011, utility debt has generally increased for most Canadian utilities. The debt to asset ratio in Alberta has remained lower than the national average, resulting in continued suppressed prices for other provinces.

3.3 Suppressed equity returns

In addition to the distortion of debt costs caused by association with the provincial credit rating, provincial shareholders fail to demand an appropriate return on equity from their utilities. By not demanding an appropriate equity return, the provincial shareholder is effectively failing to collect revenues from the electricity sector which could be used to fund social investments with far higher returns, such as investments in education, health, and regional development. Even though Canadian allowed returns on equity are generally lower than in the US,[25] Canadian utilities on average over the past five years have not achieved their allowed returns.

Figure 17. Average allowed vs. realized return on equity for utilities across Canada, 2009-2013 [26]



Source: Utilities annual reports, Regulators

Note: LEI assumed that the allowed ROE for Manitoba is equal to the Canadian average.

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25 Regulated utilities in the United States have an allowed return on equity of 9.5% to 13.75%, based on a *Public Utilities Fortnightly* survey of 91 utilities between 2002 and 2012.

26 Allowed and realized return on equity rates of the Alberta utilities are specific to transmission and distribution.

Allowed and realized return on equity rates for BC Hydro is scaled to reflect post-tax returns. "BC Hydro's allowed return on its deemed equity is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the Utilities Commission Act, being FortisBC Energy." BC Hydro's realized ROE in the figure is therefore scaled by the ratio of FortisBC Energy's authorized ROE to BC Hydro's allowed pre-income tax ROE. BC Hydro. *"Revised BC Hydro Service Plan 2013/14 – 2015/16."* < http://www.bcbudget.gov.bc.ca/2013_june_update/sp/pdf/agency/bch.pdf>.

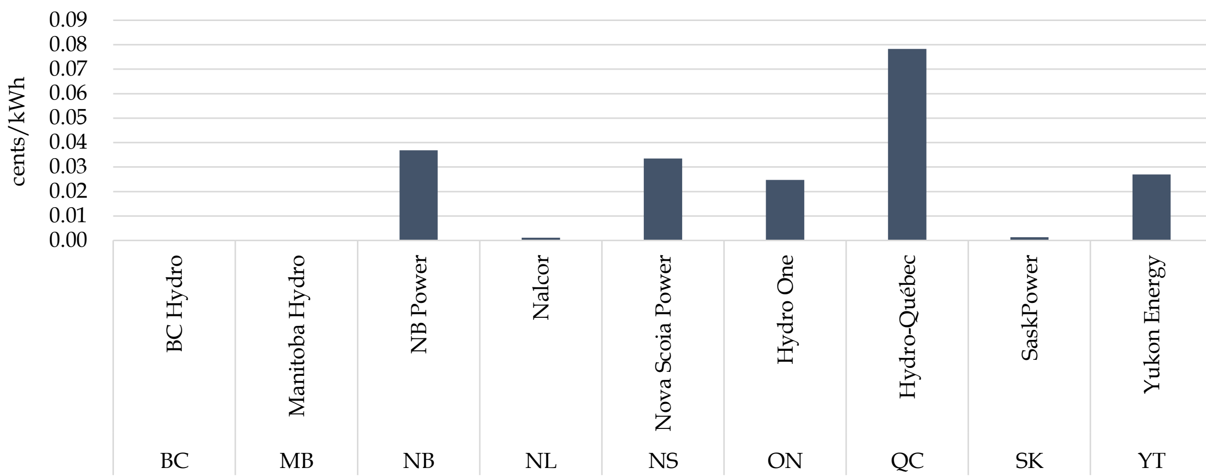
Average allowed return on equity rate is assumed for Manitoba Hydro as 5.2%.

Allowed and realized return on equity rates for Hydro One is specific to distribution. Deferred taxes are deducted from net income to calculate the rate of return on equity ("ROE") for Hydro One in accordance with the framework used by the Ontario Energy Board to calculate ROE on a deemed basis. Hydro One averages are for 2010-2013.

As Figure 17 demonstrates, the realized returns on equity of most utilities are less than allowed rate of return by the regulators, which suggests utilities have not been seeking the rate increases needed to protect shareholders' (taxpayers') rights to a fair return.

This trend has remained consistent with our 2011 findings, in which realized utility returns were generally less than authorized actual returns.

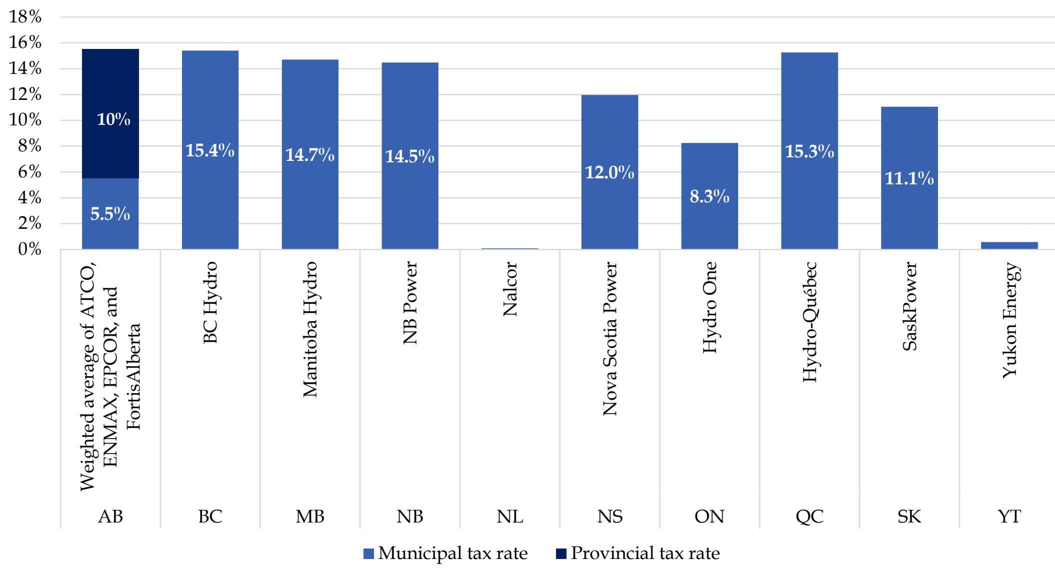
Figure 18. Extent to which suppressed returns on equity affect rates to final consumers



3.4 Differences in tax regimes

Provincially-owned utilities also face a lower effective tax burden than do privately-owned ones. As the chart below shows, over the past five years the weighted average effective tax rate for Alberta utilities was 15.5%, while the effective average tax rate over the same period for provincially-owned utilities fluctuated between 0.1% and 15.4%.

Figure 19. Tax analysis across Canadian utilities

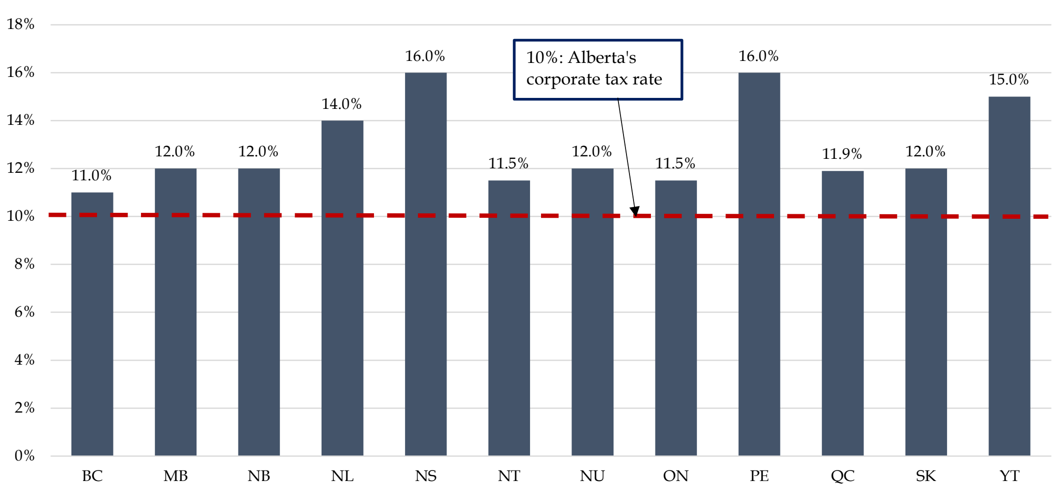


Source: Utilities annual reports

Note: Effective tax rates are calculated as the ratio of tax expense to operating income, averaged over the past five years. Hydro One effective tax rate is calculated as the average of the past four years.

Additionally, we can see from Figure 19 that provinces with provincial utilities have higher corporate tax rates. Alberta has the lowest corporate tax rate in Canada of 10%.

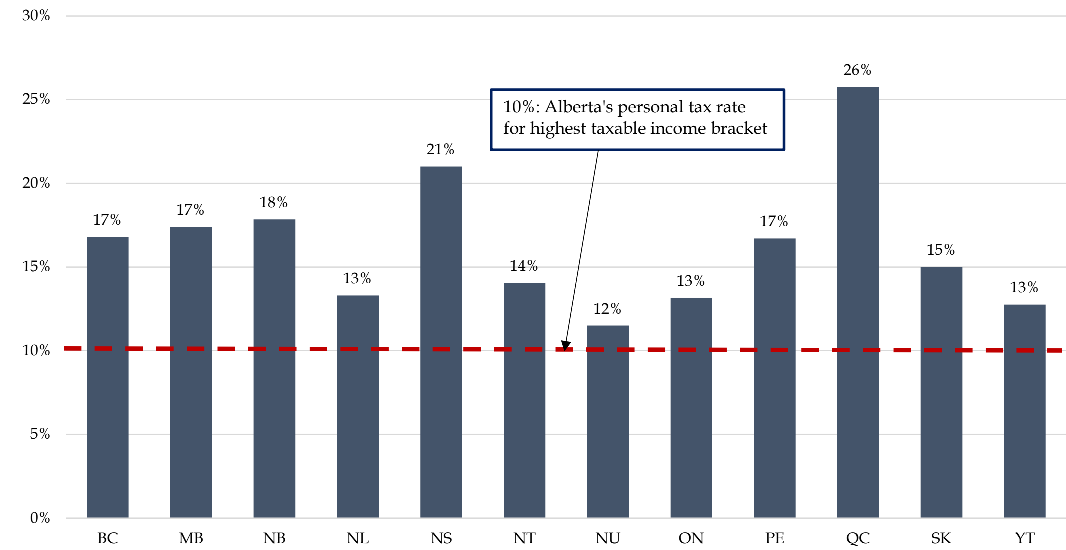
Figure 20. Provincial tax rates for corporations are lowest in Alberta



Source: Canada Revenue Agency, Government of Alberta, Revenu Québec; as of 2014

Note: Federal tax rate is 15% for corporations.

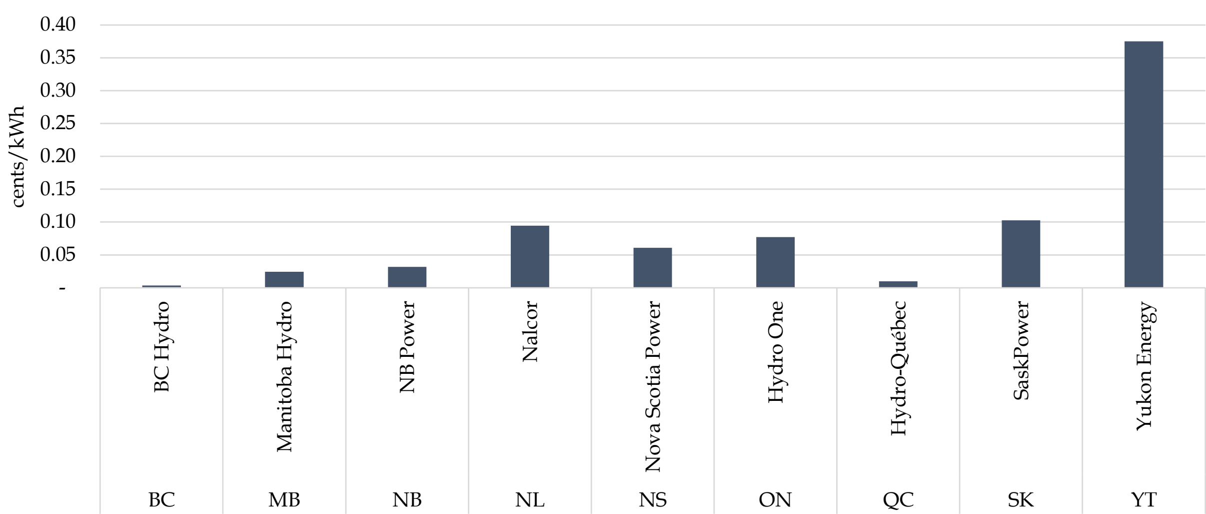
Figure 21. Personal income tax rate for highest taxable income bracket



Source: Canada Revenue Agency, Revenu Québec; as of 2014

Lower effective tax rates for provincial utilities reflect a direct subsidy from taxpayers to ratepayers. Equalizing tax rates with Alberta results in an additional adjustment to rates. To determine the impact, we calculate the amount of tax that each utility would have paid were it paying taxes at an effective tax rate of 15.5%, the Alberta prevailing rate. Were the higher statutory rate in other provinces to be used, the corresponding rate impact would be higher. The table below shows approximately how much would be added to rates in each province. The increase for residential and industrial customers ranges from 1% to 3%. While many factors contribute to Alberta's low tax levels on corporations and businesses, these low tax levels are correlated with Alberta utilities paying a full share of their tax burden; taxpayers in Alberta are not subsidizing electricity ratepayers.

Figure 22. Addition to final rates assuming effective tax rates in Alberta



Source: Utilities annual reports

Provincial corporate tax rates and personal income tax rates for the highest taxable income bracket have remained lowest relative to other provinces in Alberta, both at 10%, since 2011. However, the weighted average utility tax paid by Alberta utilities of 15.5% (compared to 28% in 2011) is still higher than the other provinces.

3.5 Impact of heritage contracts and export revenues

Rates can be distorted by other factors as well. Two such factors are heritage contracts and export revenues. In effect, heritage contracts and export revenue adjustments are other means to quantify the impact of differing resource endowments and the benefits of large scale hydro. Heritage contracts provide power to consumers at embedded cost rates; these embedded cost rates are often (though not always) below the opportunity cost of what the power could be sold for within an organized power market. The difference between the heritage contract price and the market price represents a transfer from shareholders (in this case, taxpayers) to ratepayers, and the resulting lower delivered power prices in potentially inefficient consumption patterns. Similarly, most large exporting provinces use export revenues to reduce rates within the province. Again, this reduces delivered power prices below the full value and ultimately skews consumption decisions. As with heritage contracts, this represents a transfer from taxpayer-owners to consumers, not all of whom are taxpayers. We describe these impacts in greater detail below.

3.5.1 Heritage contracts

To calculate the rate impact of heritage contracts, we examine the amount of power associated with the heritage contracts and the price. BC, Quebec, and Ontario all have some form of heritage contracts.[27] In 2013, the heritage pool in BC was 52 TWh at 2.5 cents/kWh, while the Hydro Quebec heritage pool was 162 TWh at 2.8 cents/kWh. In Ontario, the price for the "prescribed assets" of OPG serves as a heritage pool; the volume was 71 TWh and the price was 5.4 cents/kWh.[28] The next step is to determine the market price for this power based on the most appropriate nearby liquid market hub. For BC Hydro, we use the California-Oregon Border ("COB") price; for Ontario, the HOEP; and for Hydro Quebec, we use the Massachusetts Hub price. We then derive the opportunity cost by determining the difference between the heritage contract price and the relevant market price. Because the heritage contracts do not fully cover domestic demand (heritage contracts accounted for 98% of 2009 consumption in BC, 99% in Quebec, and 48% in Ontario) we multiply the opportunity cost by the heritage contract volumes, and then divide by total domestic volumes to determine the average impact of the

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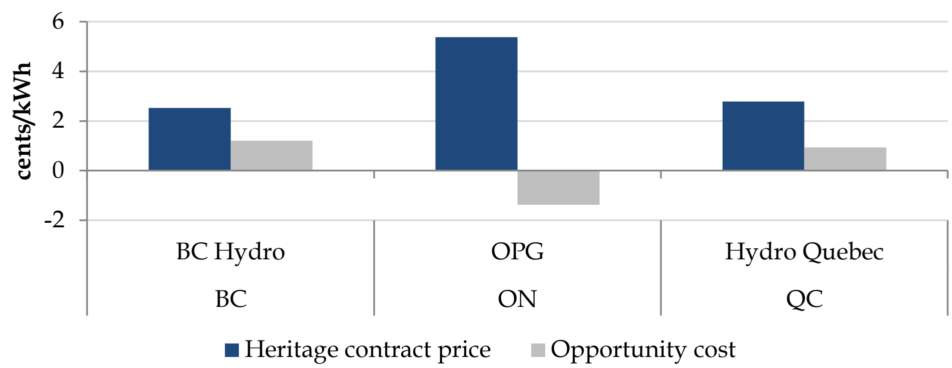
[27] In Alberta, the distribution of residual benefits from the PPA auctions through the Balancing Pool in some ways served the function of a heritage contract.

[28] In 2013, the price for output from OPG's regulated nuclear and hydroelectric assets was 5.9 cents/kWh and 4.0 cents/kWh. The amount generated during the same period were 51 TWh and 20 TWh for regulated nuclear and hydroelectric assets (respectively). The weighted average price for OPG's regulated assets comes to 5.4 cents/kWh. Sources: Ontario Energy Board. Order number EB-2010-0008; OEB, 2013 Rider, EB-2013-0002

<http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Payment_Amounts_Order_OPG_20110411.pdf>

heritage contracts on rates. The results of these calculations are summarized in Figure 23. In 2009, the opportunity cost of heritage contracts in BC and Quebec were positive, but in Ontario they were negative, indicating that the heritage contracts in Ontario imposed higher costs on consumers.

Figure 23. Impact of heritage contracts on final rates for consumers, 2013



Source: Utilities annual reports

Note: A positive opportunity cost means that the heritage costs allow customers to pay less than the current market value of the power. By contrast, a negative opportunity cost means customers are paying more than the current market value for power.

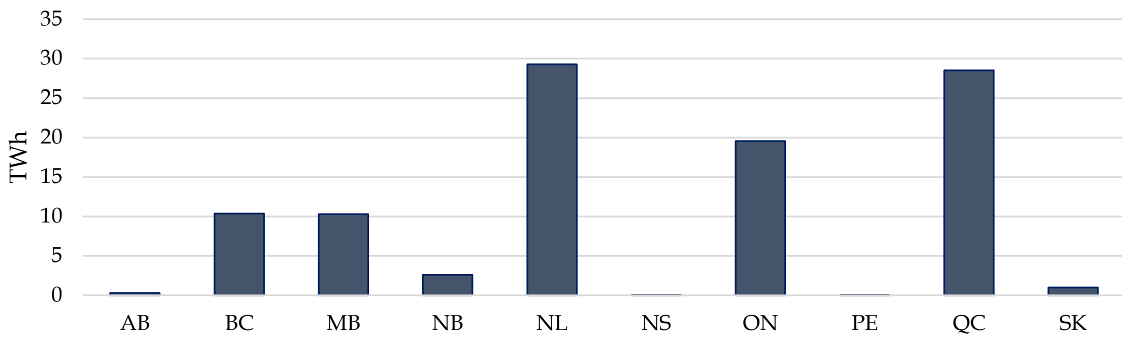
The impact of heritage contracts on 2013 rates for British Columbia, Ontario, and Quebec has followed a similar trend to the findings presented in the 2011 LEI paper. Ontario customers continue to pay relatively high prices for electricity generated by the province's nuclear and hydro power plants.

3.5.2 Treatment of export revenues

In the provinces with the largest exports, export revenues are generally used to reduce rates. This can lead to some adverse impacts: for example, as wholesale generation prices in export markets fall in response to a slow economy, Canadian utilities may be forced to increase rates to cover the shortfall in export revenues. Approved rate increases for Manitoba in 2012/13 and 2013/14 are partly based on this fact.[29]

[29] Manitoba PUC. "Manitoba, The Public Utilities Board Act, Order No. 43/13." April 26, 2013. <http://www.pub.gov.mb.ca/pdf/13hydro/43-13.pdf>

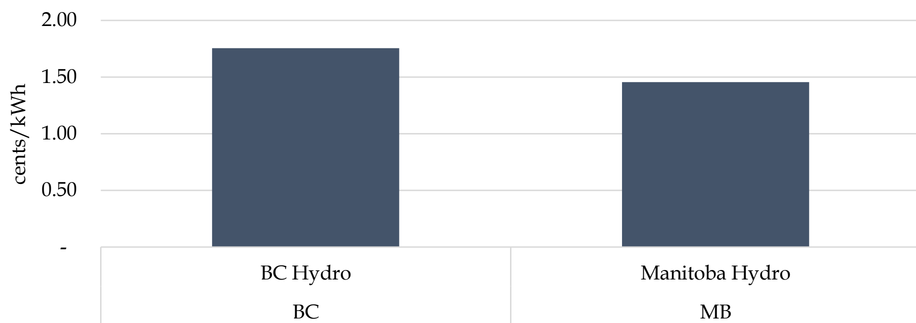
Figure 24. Average annual electricity exports by province, 2009-2013



Source: Statistics Canada

Over the past five years, on average, export revenues would have decreased rates by approximately 1.75 cents/kWh in BC, and 1.46 cents/kWh in Manitoba.

Figure 25. Average annual export revenue effect on rates to final consumers



Source: National Energy Board, Utilities annual reports

Figure 26. Treatment of export revenues by selected utilities

Province	Utility	Treatment of export revenues
MB	**Manitoba Hydro**	Manitoba Hydro keeps rates lower by leveraging the export sale opportunities associated with Manitoba's hydropower resources to create revenues that offset capital investments in new generating stations. Export sales also provide an outlet for any excess electricity and a revenue stream that directly helps to keep energy prices low in the province. Furthermore, Manitoba Hydro has significant export revenues denominated in US dollars. As part of the Corporation's foreign exchange exposure management program, in order to mitigate the foreign currency exchange risk on these revenues, Manitoba Hydro maintains a natural hedge with US dollar cash flows, including outflows from US denominated debt.
BC	**BC Hydro**	BC Hydro has been able to optimize the hydro system and uses its system's flexibility to sell periodic surpluses when prices are high and buy when prices are low. This optimization generates revenue that helps keep domestic rates low.
QC	**Hydro Quebec**	Hydro Quebec's electricity export sales increase dividend payments made to its ultimate shareholder, the Government of Quebec, which in turn helps to reduce provincial debt deficit.

Source: Utilities annual reports, Utilities publications

Note: The effect of export revenue on electricity rates is therefore disregarded for Hydro Quebec.

The expected average annual export revenue effect on rates from BC Hydro has increased from less than 1 cent/kWh in 2011 to 1.75 cents/kWh, while the calculation for Manitoba Hydro has remained consistent.

3.6 Combined effect of adjustments

When the various distortions that arise from provincial ownership are taken into account, Alberta's rates are, overall, competitive with most of its peers across Canada. To determine the full cost of power across Canadian provinces, we examine the combined impact of the distortions we describe above. This means for each province adding together the 2013 actual rates, the adjustment to correct for over-leverage, the adjustment for differing tax regimes, and the impact of heritage contracts and export sales. When the combined impact of these effects is taken into account, Alberta rates are consistent with the Canadian average.

Figure 27. Rates for residential customers adjusting for various distortions, 2013

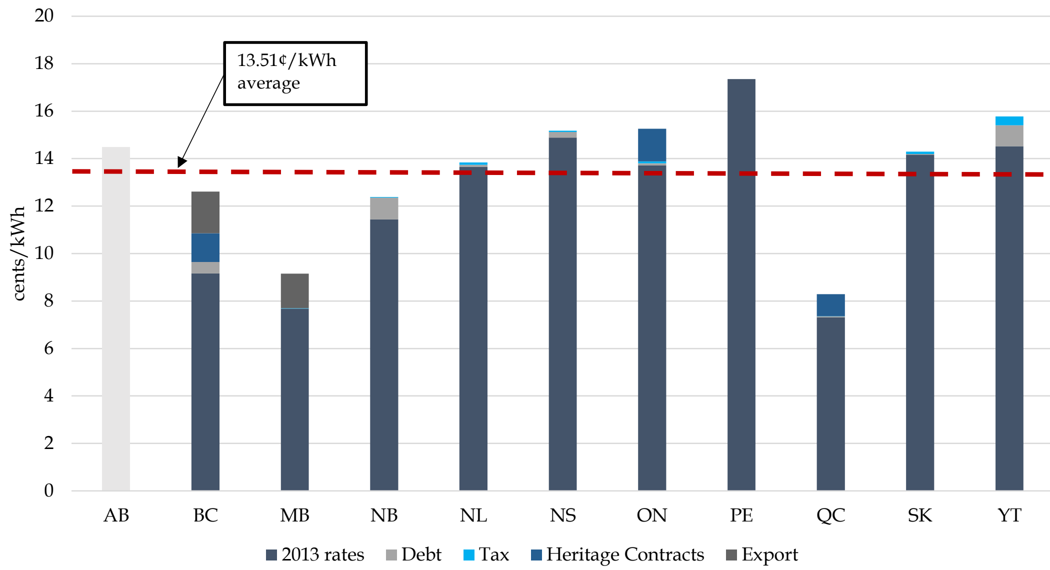
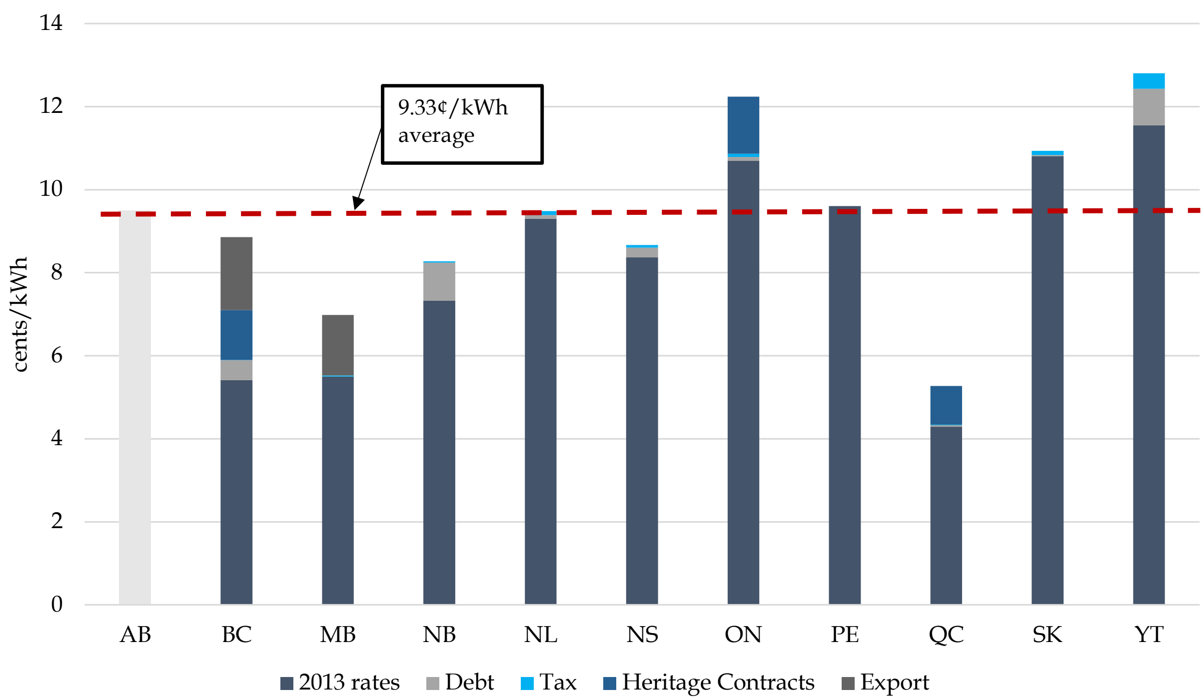


Figure 28. Rates for industrial customers adjusting for various distortions, 2013



Source: National Energy Board, Utilities annual reports

4 Rate outlook for next five years

Rates to final consumers consist of a number of elements, primarily grouped first around the cost of generation and second around the cost of delivery (transmission and distribution). While analysis suggests that wholesale generation costs in Alberta over the next five years will remain moderate, rates to final consumers may rise due to the extent of projected capital expenditures.

This section provides an overview of the methodology and assumptions used in developing an outlook for the residential and industrial rates in Alberta for the next five years. This involves three key steps: first, developing an outlook for wholesale market prices in Alberta using our proprietary model; second, developing an outlook for the increase in distribution and transmission tariffs from new capital expenditure in Alberta; third, the sum of these components produces the expected delivered price. To determine the generation component, we develop an outlook for wholesale prices, based on assumptions regarding market topology, fuel price projections, emission costs, demand, supply, and new entry.

To calculate the evolving cost of energy delivery in Alberta:

- We created composite residential and industrial Alberta delivery charges based on the current load-weighted average rate to residential and industrial customers for major utilities. The utilities meet approximately 87% of total load in Alberta.

- We then determined the level of future capital expenditures in transmission and distribution across Alberta, estimated the current regulated asset base ("RAB") and total revenue requirement across Alberta, and identified changes to the RAB and total revenue requirement as a result of the new capital expenditure projects.

- We next appropriately divided changes in the total revenue requirement amongst residential, industrial and other customers to estimate the change in the distribution and transmission component of rates.

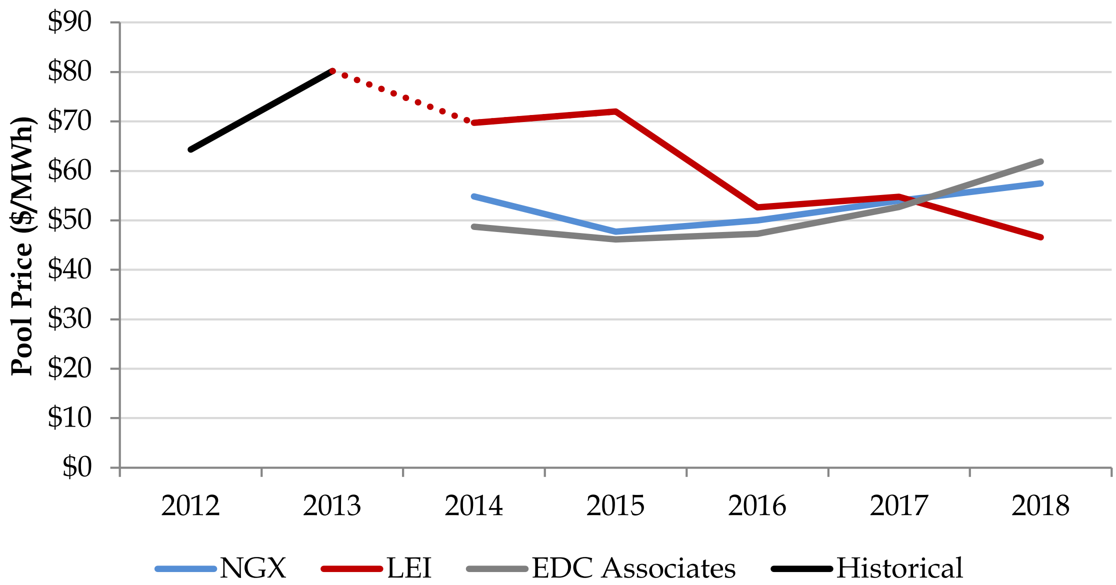
It is important to emphasize that ***the analysis presented here is simplified and indicative.*** Projected rates shown here are generic; utility specific rates will vary. Future rates are dependent both on the timing of new capital expenditures and the treatment of such capital expenditures in rates. Wholesale generation prices are affected by levels of projected demand, fossil fuel costs, and new entry. Detailed comprehensive scenario analysis of all of these elements was beyond the scope of this engagement. Nonetheless, while other outcomes are possible, we believe the underlying conclusions are sound: the key drivers of rate increases in Alberta over the next few years after 2014 will be the timing and magnitude of investments in transmission and distribution, rather than wholesale generation prices.

4.1 Developing an outlook for wholesale generation prices

LEI's outlook for wholesale generation prices ranges from $69.7/MWh in 2014 to $46.6/MWh in 2018. This compares with an average price of $50.8 per MWh in 2010. In 2013, prices were temporarily elevated due to the combined Sundance 1 and 2 outages, which took offline 560

MW of base load capacity. Over the next few years, however, prices are expected to return to their pre-2011 levels due to the return of Sundance 1 and 2 online, the energizing of the Montana-Alberta tie-line making available to the Alberta market of up to 300 MW of wind generating capacity, and significant capacity additions including ENMAX's Shepard (800 MW) generation plant. As the chart below demonstrates, LEI projections of 2015 Alberta pool prices, as of January 2014, are above the price of forwards currently traded on NGX (June 2014). Therefore, by using its own pool price forecast, LEI has estimated a more conservative scenario for the expected decrease of industrial and residential rates over the next two years.

Figure 29. LEI outlook for prices are consistent with forwards, 2014-18



Source: EDC forecast: AESO "2014 ISO Tariff – Appendix J – Transmission Rate Impact Projection", Natural Gas Exchange ("NGX"). Accessed on June 9, 2014

Figure 30. Assumptions for 5 year wholesale price outlook for Alberta, 2014-18

Supply

- LEI assumes retirements in Alberta will be primarily driven by the Federal coal-fired power plant retirement regulation
- New entry is synchronized with demand in the long term and tested to be "economic" given modeled conditions
- Entrants are assumed to be gas-fired and wind power plants. Gas fired plants are assumed when economical, while wind power plants are added in fixed increments of 75 MW annually starting in 2018
- By 2040, 6.4 GW of generic gas-fired and 1.7 GW of generic wind generation are assumed to enter the market

Demand

- LEI has applied a modified alternative to AESO's 2012 demand growth forecast with an average annual growth rate for the period 2015-2040 of approximately 1.8% for both total energy and peak demand

Fuel Prices

- LEI forecasts AECO natural gas prices through a combination of Henry Hub forwards ("HH"), EIA's long-term forecast for HH prices, and the historical basis spread between AECO and HH prices. As a result, AECO gas prices are estimated to increase from $3.7/MMBtu in 2015 to $11.2/MMBtu by 2040

Import/Export

- Beyond the inclusion of MATL, LEI assumes that changes in Alberta imports and export capabilities are assumed to remain modest increasing from 865 MW in 2015 to 1,050 MW in 2017 and remaining stable thereafter

Emissions

- Emissions, including offsets, are taken into consideration. The carbon tax is assumed to increase from the current $15/tonne (12% reduction requirement) to $20/tonne (20% emission reduction requirement) at the beginning of the modeling horizon in 2015

Transmissions

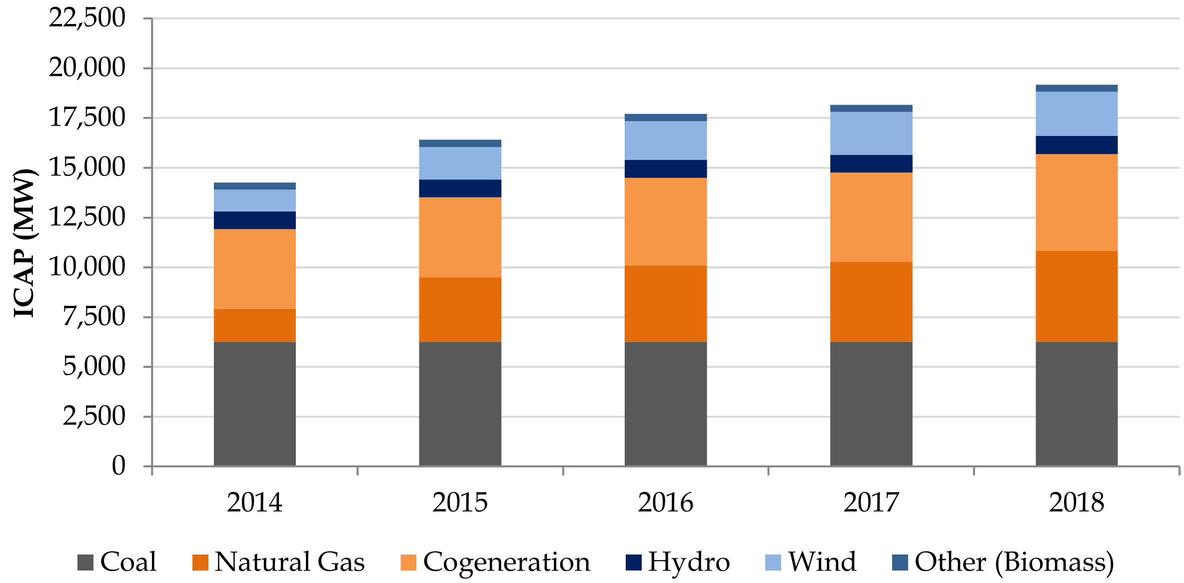
- The Alberta market is assumed to be a single zone for purposes of SMP and Pool Prices, with no long-term intra-provincial transmission constraints assumed

Alberta's market is modeled as one zone with current interties to British Columbia and Saskatchewan. Alberta is assumed to be a net importer from its neighbors. Demand (MW) grows at 1.8% per annum in accordance with the historical rate of growth until 2040. Generic plants are assumed to enter the market when price levels signal that it is economic for them to do so. Natural gas price assumptions are based on NYMEX Henry Hub futures, adjusted for the historical differential between NGX AECO forwards[30] and Henry Hub prices over the last three years since 2011.[31]

[30] NGX-AECO stands for the National Gas Exchange Inc.'s Alberta Energy Company's Nova Industry Transfer (NIT) storage and exchange point for natural gas in Alberta. For more information, see <http://www.ngx.com>.

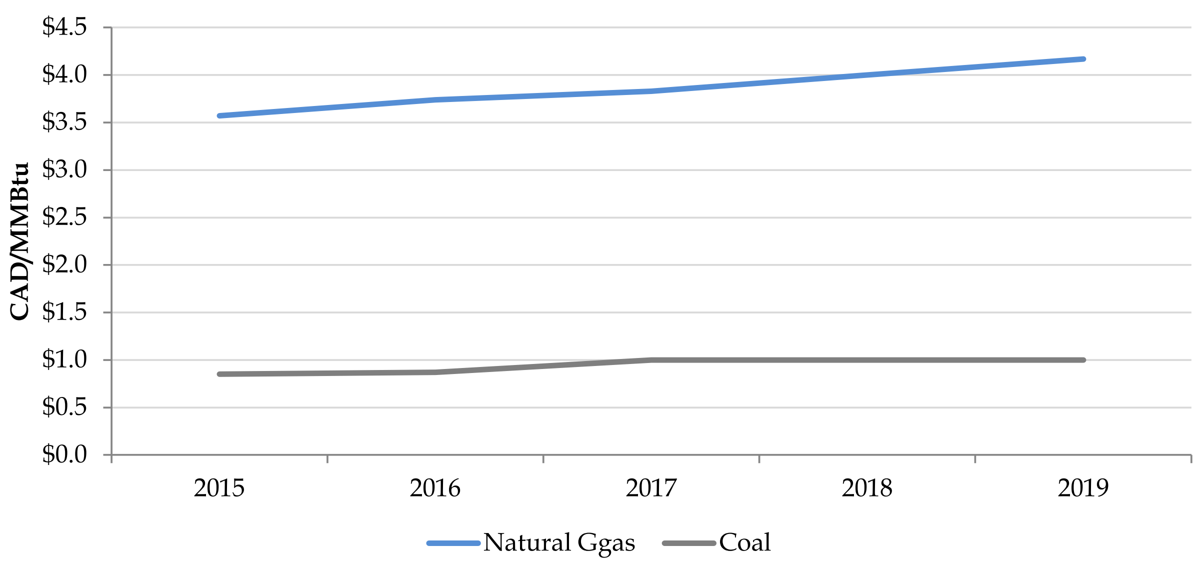
[31] For more information, see <http://www.eia.doe.gov/oiaf/aeo>.

Figure 31. Demand and supply outlook, 2014-18



LEI assumption.

Figure 32. Fuel price assumptions, 2014-18



LEI assumption.

4.2 Determining delivery charges

Figure 33. Steps for calculating five year price outlook for wires components

1. Estimate the current regulated asset base (RAB)
2. Estimate the total revenue requirement based on existing asset base
3. Determine the level of future capital expenditures in transmission and distribution
4. Estimate changes to operating and depreciation expenses as the result of the new capital expenditure
5. Estimate changes to the RAB and total revenue requirement as a result of the new capital expenditure minus the depreciation on existing assets
6. Allocate the changes in the total revenue requirement between customer classes
7. Estimate the change in the distribution and transmission component of rates

To estimate future wires charges, we create a simplified model of transmission and distribution rates. The process starts with calculating the current transmission and distribution regulated asset base ("RAB") for four major utilities in Alberta.[32] This data was obtained from the latest rate filings with Alberta Utilities Commission ("AUC").

The next step is to calculate the current revenue requirement. The annual revenue requirement includes the summation of the allowed return on invested capital (weighted average cost of capital multiplied by the rate base) and operating expenditures. Expenses are the ongoing costs of operating and maintaining the service provider's equipment, which include salaries and

[32] The four major utilities are ATCO, ENMAX, EPCOR, and FortisAlberta.

related labor costs, general and administrative expenditures, materials and supplies, and electricity generation and fuel costs. Depreciation is also included as an expense to arrive at the total revenue requirement.

Figure 34. List of expected transmission projects in Alberta, 2014-18

Name of project*	Estimated cost (CAD millions)	Year in service**
Alberta Industrial Heartland Bulk Transmission Development	$ 659.46	2014
Algar Area System Reinforcement	$ 48.62	2015
Central East Area Transmission Development	$ 144.13	2014
Central East Area Transmission Development	$ 53.17	2017
Christina Lake Area Development	$ 134.39	2014
Christina Lake Area Development	$ 297.31	2015
Edmonton Region 240kV Line Upgrades	$ 58.51	2015
ENMAX South 69kV Conversion	$ 19.94	2014
FATD - East Calgary Development	$ 158.40	2014
FATD - East Calgary Development	$ 254.61	2015
Hanna Region Transmission Development	$ 37.12	2014
New Fidler Substation Connection	$ 86.91	2017
North Central Region Transmission Development	$ 64.71	2014
North South Transmission Reinforcement	$ 2,696.25	2014
North South Transmission Reinforcement	$ 556.28	2015
NW Ft McMurray Transmission Development	$ 366.29	2016
Red Deer Transmission Development	$ 325.70	2015
South and West of Edmonton Transmission Development	$ 172.17	2016
Southern Alberta Transmission Reinforcement	$ 310.99	2014
Southern Alberta Transmission Reinforcement	$ 526.65	2015
Southern Alberta Transmission Reinforcement	$ 2,021.48	2017
Total	**$8,993.08**	

**Only projects with estimation of cost have been included*
***In service year of last project stage*
Source: Alberta Electric System Operator[33]

Notes: Only projects that are approved and expected to be completed between 2014 and 2018 are included. The Etzikom Coulee-to-Whitla 240-kV line has been taken out of the Southern Alberta Transmission Reinforcement project cost estimate for 2017.[34]

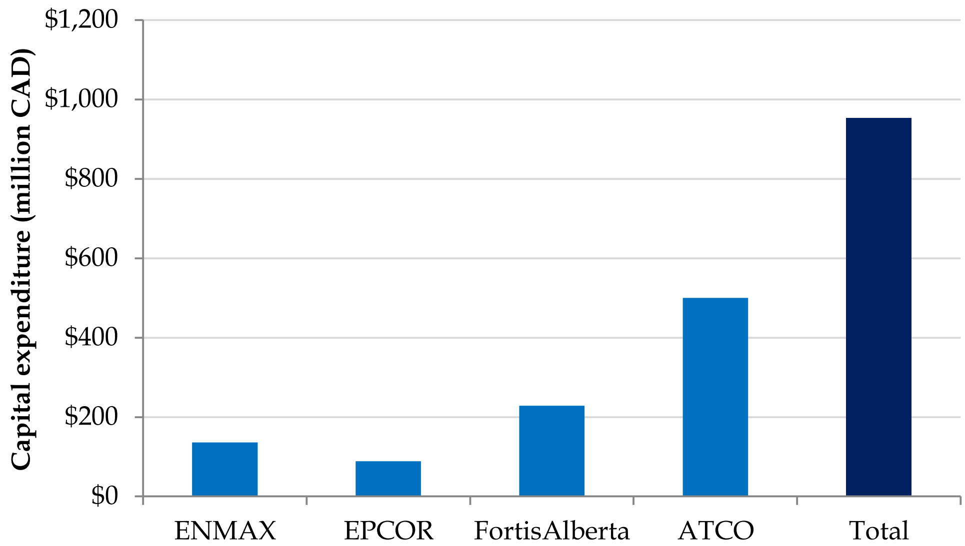
New capital expenditures to be incurred in each subsequent year also form a key part of the RAB. The rate base will increase by the amount of new investment placed in service over the previous year, and decrease by the amount of depreciation. In Alberta, over the next five years, we assume approximately $14 billion to be allocated for transmission and distribution

33 AESO. <http://www.aeso.ca/downloads/Q1_2014-Transmission_System_Projects_Quarterly_Report.pdf>.

34 AESO <http://www.aeso.ca/downloads/AESO_SATR_Newsletter_WEB.PDF>

projects.[35] Figure 34 shows the list of transmission projects included in the model. Figure 35 shows projected distribution capital expenditure by utility.[36]

Figure 35. Distribution capital expenditure, 2013-14



Note: Impact of distribution capital expenditure differs depending on utility and associated rate design. Distribution operating expenses and depreciation are added separately to revenue requirement.

These assets will begin to depreciate as soon as they come into service. The depreciation rates for transmission assets are determined based on AUC-accepted depreciation rates from current tariff filings for utilities in Alberta.[37] Depreciation rates for distribution assets are also based on AUC-accepted rates from current tariff filings for utilities in Alberta.[38] Furthermore, we calculate the addition to the operating expenses as the result of the new capital expenditures using the current ratios of operating expenses to total RAB for all four major utilities.

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[35] Approximately $9 billion is allocated to transmission (see Figure 34) and approximately $5 billion is allocated to distribution (this is based on a simplified assumption of approx. $1 billion allocated to distribution in 2013-2014 (see Figure 35) to recur for the next 5 years).

[36] While our simplified rates model assumes common treatment for capital expenditure amongst all distribution companies, in fact treatment of capital expenditure in rates currently varies. Future treatment of capital expenditure will depend on the outcome of ongoing rate design proceedings before the Alberta Utility Commission.

[37] These rates vary from 34 to 37 years according to AUC filings for AltaLink and ENMAX. Source: ENMAX. *Formula Based Ratemaking, 2007-2016*. Page 75.

[38] These rates vary from 27 to 31 years according to AUC filings for ATCO Electric and ENMAX. ATCO Electric *General Tariff Application, 2011-2012*, Schedule 16-3. Source: ENMAX. *Formula Based Ratemaking, 2007-2016*. Page 75

Distribution capital expenditures are obtained from recent rate filings of the major utilities with AUC as shown in Figure 35. Major components of these expenditures include capital maintenance and upgrades. Distribution capex is normally provided for the following two years. The historical growth rate of distribution capex for each utility is used to extend the outlook until 2018.

The treatment of plant, property and equipment that is in the process of being constructed and has not yet been entered into service can affect cash flows to the utility. The key issue in the regulatory treatment of this cost component is timing, specifically when the work in process is properly entered into the RAB. In our modeling, we use the allowance for funds used during construction ("AFUDC") method. Under AFDUC, no returns are provided on these assets until construction is completed. Instead, they are recorded in an accounting sense, with the value of the underlying investment increasing annually to reflect the accumulated returns. When the plant is placed into service, its cost (properly adjusted to reflect the value of all deferred returns) is then placed into the RAB.

When considering the investment schedule for the proposed capital expenditures, LEI assumed that all transmission and distribution investments are brought into service according to their announced schedule.

Given the current consumption (kWh) by each customer class as a weight, we calculate the increase in residential and industrial rates over the next five years.[39] We add the outlook for wholesale energy prices and the current level of transmission and distribution charges to arrive at the final rates.

4.3 Impact on rates

4.3.1 Residential rate outlook

Residential rates are projected to increase from 14.5 cents/kWh in 2013 to 14.7 cents/kWh in 2018, as shown in Figure 36. This is mainly accounted for the expected increases in residential rates due to transmission investments offsetting the projected decrease in wholesale electricity prices.[40] The effect of transmission and distribution investments for residential customers is approximately 3.8 cents/kWh between 2013 and 2018, with a significant portion due to additional transmission projects entering the rate base in the period 2016-2018.[41]

[39] Note that this treatment assumes rates adjust in the year RAB adjusts; in fact, rate adjustments may lag due to filing schedules. While we recognize that some utilities use construction work in progress ("CWIP") rather than AFUDC, our modeling uses AFDUC throughout. CWIP would cause the rate increase to occur somewhat earlier.

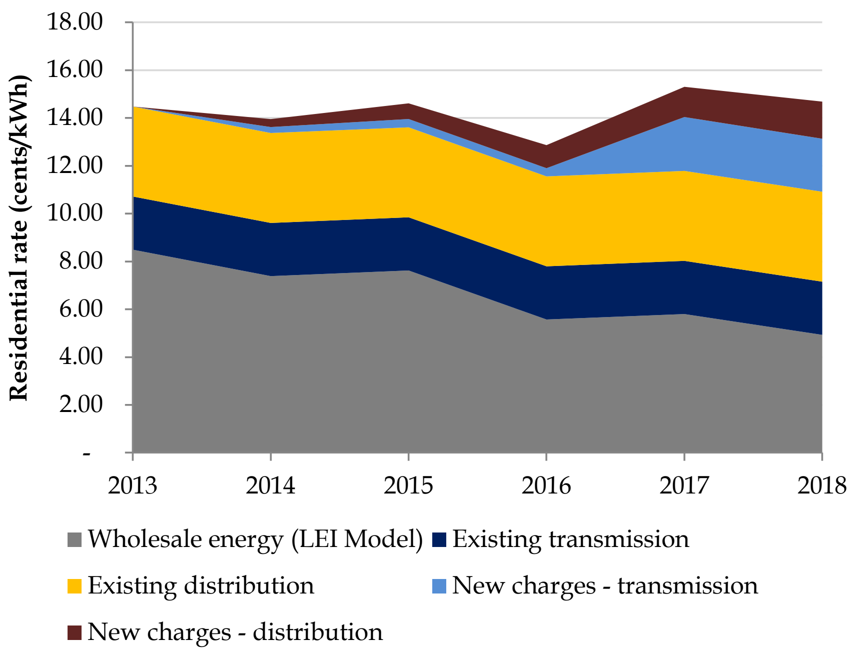
[40] When estimating the energy portion of the Alberta residential rates, we have applied the 2013 average premium added by the province's RRO providers to the wholesale price in their RRO energy charges.

[41] The 3.8 cents/kWh estimate is in line with the AESO "Transmission Rate Impact Projection Workbook" (May 2014), where AESO estimates an increase of 3.75 cents/kWh over the same period for residential customers.

4.3.2 Industrial rate outlook

Industrial rates are projected to decrease from 9.7 cents/kWh in 2013 to 6.7 cents/kWh in 2018, as shown in Figure 37. As with the residential rates, the change in rates will be driven by a combination of decreases in wholesale prices and increases in distribution and transmission costs.[42] However, unlike the case with residential rates, industrial rates are more exposed to fluctuations in the electricity commodity prices. As a result, the expected increases in the transmission and distribution charges are not large enough to offset the expected decrease in wholesale electricity prices over the next few years. The effect of transmission and distribution investments for industrial customers is approximately 0.7 cents/kWh between 2013 and 2018.[43] The wholesale energy charges are projected using LEI's internal model, as explained in Section 4.1. Wholesale prices are expected to dip by 2018, then stabilize, with the coal-fired capacity retirements projected to commence by the end of the decade.

Figure 36. Residential customers price outlook, 2013-18

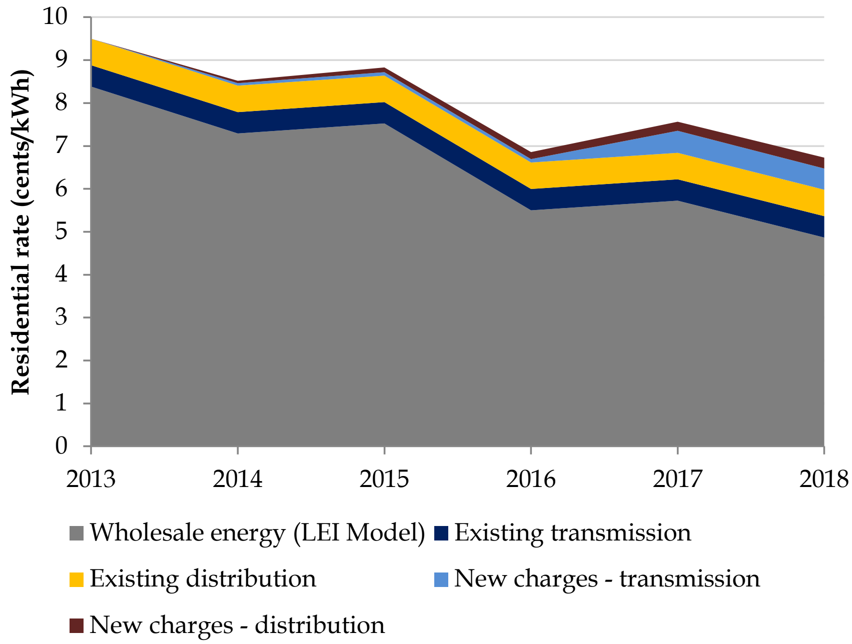


[42] To estimate industrial rates, the average annual AESO price is adjusted to reflect the load shape of a typical industrial customer. For details, please see Appendix C.

[43] In the AESO "Transmission Rate Impact Projection (TRIP) Workbook" (May 2014), the AESO estimates an increase of 1.1 cents/kWh associated with transmission over the same period for industrial customers. LEI all-in estimates of future industrial rates are in line with the TRIP model when differences in wholesale price forecasts are accounted for.

Note: *Transmission and distribution charges for current projects are assumed to remain constant for the forecast horizon. This assumption is based on expectation of amortized maintenance costs on existing assets equaling depreciation.*

Figure 37. Industrial customers price outlook, 2013-18



Note: *Transmission and distribution charges for current projects are assumed to remain constant for the forecast horizon. This assumption is based on expectation of amortized maintenance costs on existing assets equaling depreciation.*

4.3.3 Collective impact

When we examine the scenarios broadly, we find that, when holding energy costs constant under the current investment plan, expected transmission capital expenditure contributes 63% of the increase in rates, while distribution contributes the remainder. Considering the increase to the residential and industrial rates over the next five years and looking back at the rates adjusted for various distortions in Section 3.6, Alberta rates will likely to become more competitive relative to other provinces.

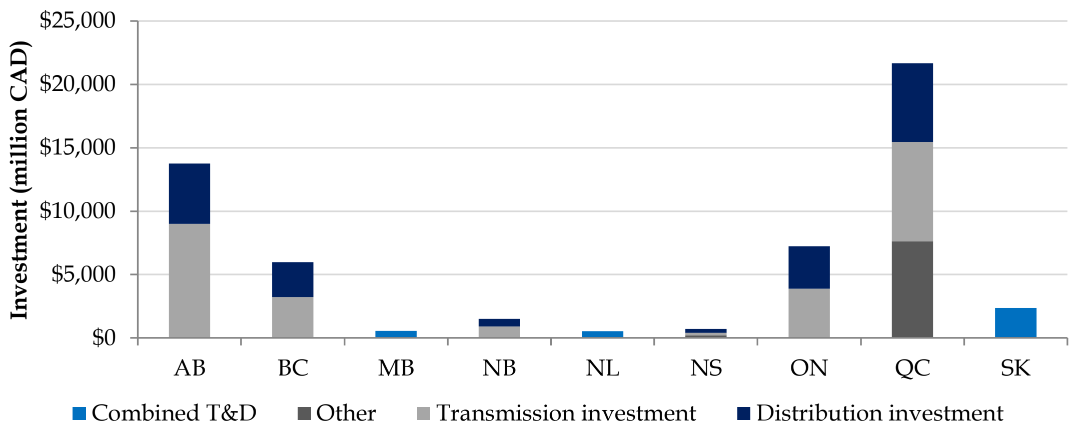
In the period between 2013 and 2018, Alberta residential rates are estimated to increase by a total of 0.2 cents/kWh (or on average, 0.3% per annum). However, the growth rate for residential rates in Alberta is likely to be slower than that of the other Canadian provinces, bringing Alberta to a level 17% higher than the Canadian average (excluding all territories and Prince Edward Island) in 2018 (relative to 23% above the Canadian average in 2013).

Industrial rates, however, are estimated to decrease significantly, falling by nearly 2.8 cents/kWh for the period 2013 through 2018 (on average 6.7% decline each year).[44] As a result, industrial rates are forecast to fall from their 2013 level of 20% above the Canadian average (excluding all territories and Prince Edward Island) to more than 18% below the Canadian average in 2018.

4.4 Prospects for other provinces

Other provinces also have aggressive wires infrastructure development programs. We created preliminary estimates for transmission and distribution capital expenditure and their impact on rates for other provinces in Canada. We use similar methodology to that adopted in Section 4 for Alberta. Planned transmission and distribution projects for the 2014 to 2018 period (as shown in Figure 39) are all included. We add these to the existing regulated asset base and apply the weighted average cost of capital that was previously used in the Alberta model. We use similar depreciation lives to what was used in the Alberta model to arrive at the additions to the revenue requirement. Then, using the current consumption level for each province as a divisor to the resulting revenue requirements, increasing at projected load growth rates, we calculate the increase in rates over the next five years. The main effect on rates is shown in Figure 40.

Figure 38. Transmission and distribution capital expenditure for other provinces, 2014-18



Source: Utilities annual reports

[44] This decline is mainly driven by a decline in wholesale energy prices between 2013 and 2018 (estimated to decline on average by 11.3% per year). The effect of wholesale prices is less significant on the residential price forecast because transmission and distribution costs form a higher proportion of the residential rates (approximately 48% in 2013) relative to industrial rates (approximately 13% in 2013).

Note: Only projects that are approved and expected to be completed between 2014 and 2018 are included. LEI assumptions of average annual transmission investments of $1.6 billion for Hydro Quebec are in line with Hydro Quebec's estimated Transmission Budget for 2014 of $1.8 billion.[45]

Figure 39. Expected nominal rate increase from new capital expenditures

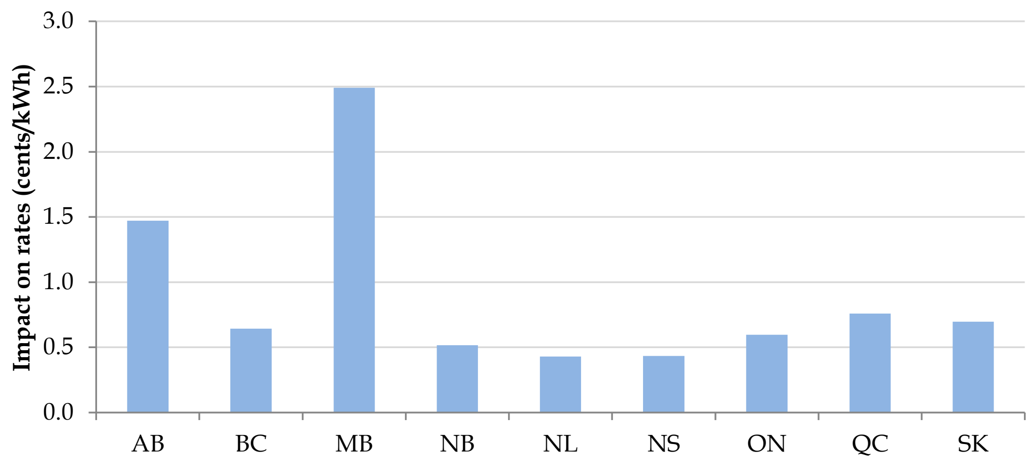
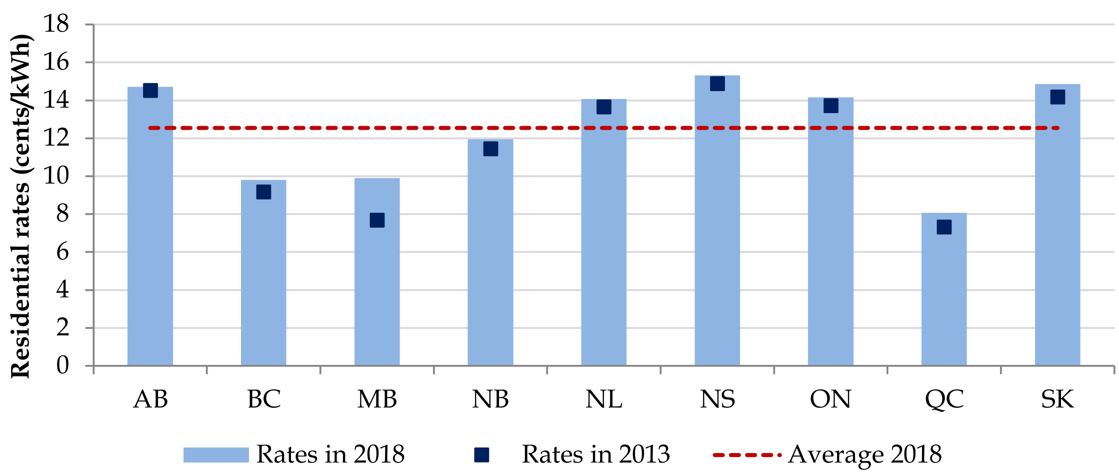


Figure 40. Expected nominal residential rates in 2018



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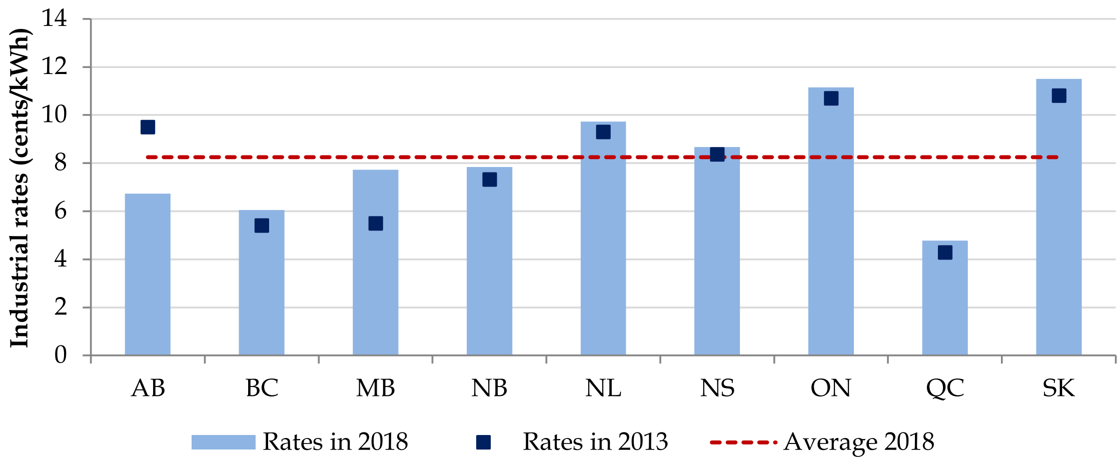
[45] Hydro Quebec. "*Investment plan for transmission projects below $25 million – year 2014*". August 2013. < http://publicsde.regie-energie.qc.ca/projets/223/DocPrj/R-3855-2013-B-0004-Demande-Piece-2013_08_02.pdf>.

Figure 41. Expected industrial rates in 2018



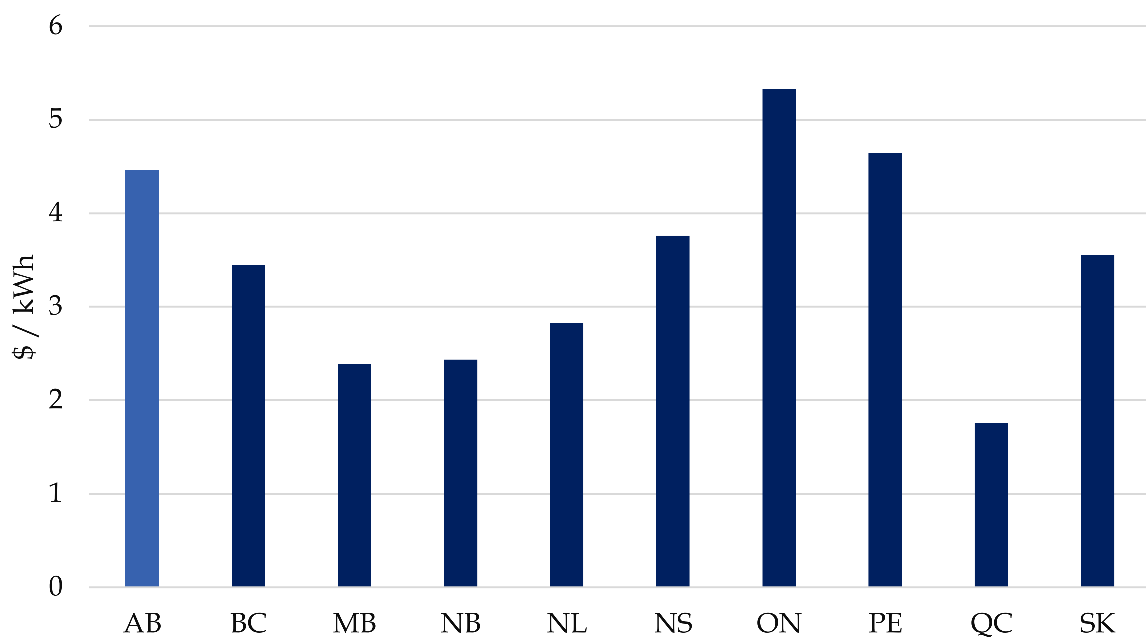
5 Productivity and affordability

Alberta is among the most productive provinces in its use of electricity. Furthermore, a portion of rate increases over recent years can be attributed to the fact that Alberta inflationary pressures are higher than in other provinces. Nonetheless, Alberta is tied for the most affordable when bills as a proportion of monthly income are considered.

5.1 High electricity productivity

Electricity productivity depicts how effectively a province uses electricity and is measured in dollars of gross provincial product divided by the volume of electricity consumed. The gross provincial product to consumption comparison across the provinces in 2012 ranges from $1.75/kWh to $5.33/kWh as presented in Figure 42. In relation to the other provinces, Alberta's ratio of $4.46/kWh is third to the Ontario's leading $5.33/kWh and Prince Edward Island's $4.64/kWh, which indicates the high electricity productivity generated by these three provinces.

Figure 42. Electricity productivity across all Canadian provinces, 2012



Source: Statistics Canada

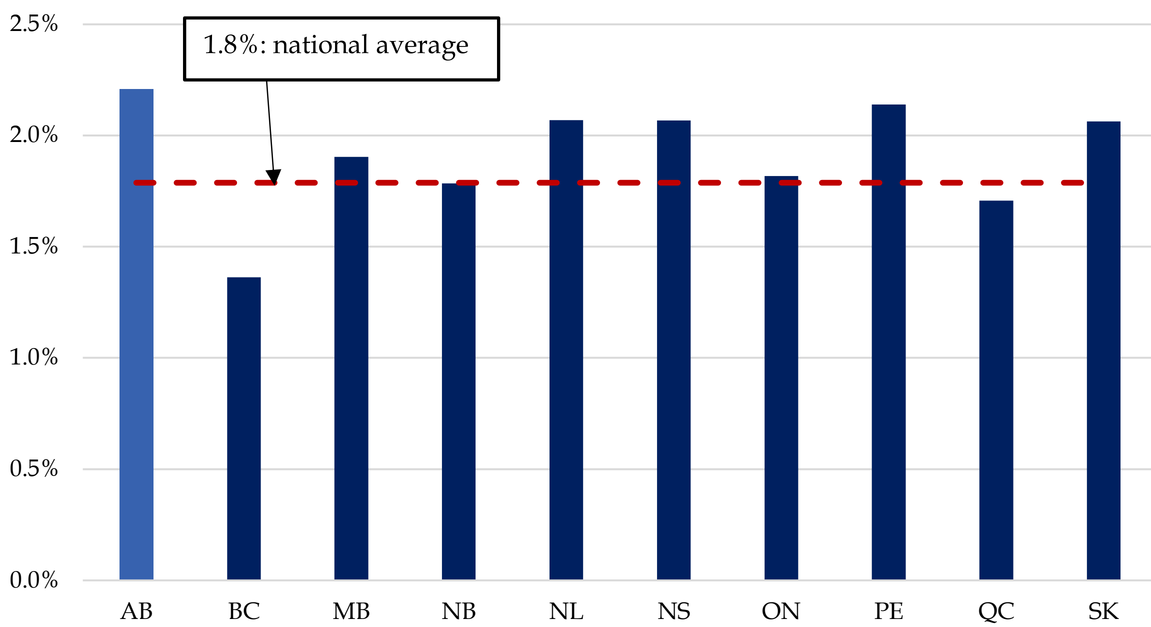
The relatively high gross provincial product of Ontario skews the Canada-wide average electricity productivity.[46] However, the finance and insurance sector of Ontario accounts for a large portion of its gross provincial product (at 9% in 2012, in comparison to Alberta's 4% and the 5% average across all Canadian provinces for the same year), which increases Ontario's electricity productivity by over 25%.[47]

5.2 Higher consumer price index growth

The provincial consumer price index is reflective of the inflation pressures faced by each province. The affordability of Alberta's electricity rates is despite the rapid growth of its consumer price index in relation to the rest of Canada.

Alberta's annualized growth of the consumer price index from 2004 to 2013 is the highest amongst the Canadian provinces as presented in Figure 43. As such, the higher prices paid by Alberta consumers today can in part be explained by the overall increased inflation specific to the province's economy. Likewise, current prices in other provinces may appear lower due to their slower inflation increases.

Figure 43. Annualized growth of the consumer price index, 2004-2013



Source: Statistics Canada

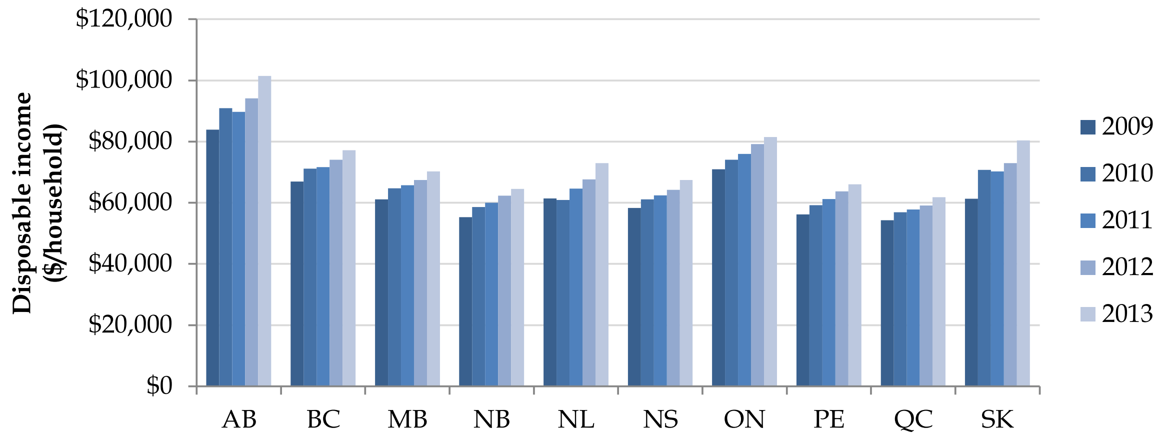
[46] The average electricity productivity across the Canadian provinces is $3.67/kWh in 2012, in comparison to the 2012 US national electricity productivity of $4.37/kWh. Source: Statistics Canada, EIA, World Bank.

[47] Statistics Canada. "*Gross domestic product (GDP) at basic prices, by North American Industry Classification System (NAICS), provinces and territories, annual.*" June 17, 2014. <http://www5.statcan.gc.ca/cansim/a37>.

5.3 Electricity rates and disposable income

To ensure comparability between final electricity rates across Canadian provinces, LEI took the standpoint of the average household for each province and estimated the ratio between the average household annual electricity bill and the average household annual disposable income. We believe that such analysis would better take into account the differences between cost of living and average income across the Canadian provinces.

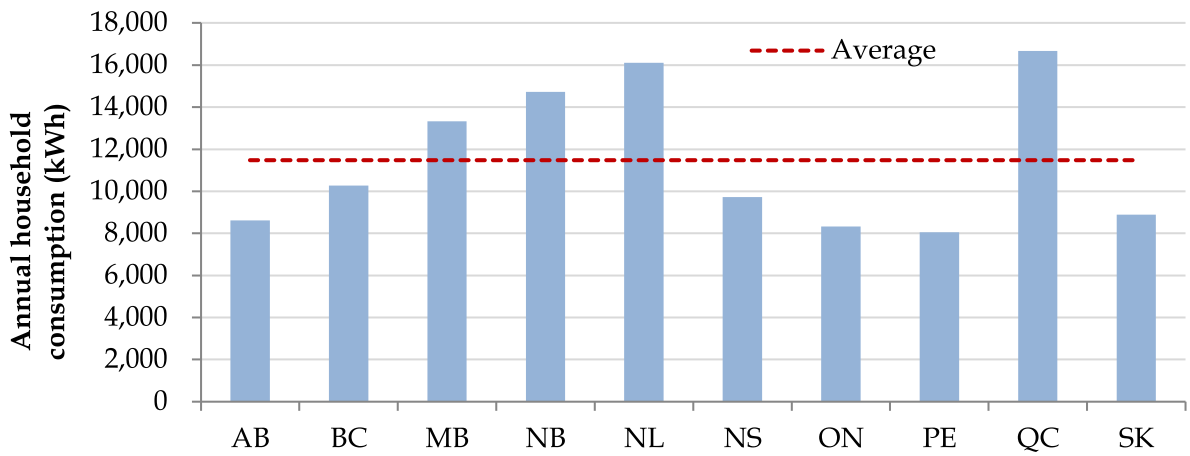
Figure 44. Average nominal household disposable income (2009-2013)



Source: Statistics Canada

As presented in Figure 44, the average per household disposable income in Alberta is nearly 37% higher than the average of the Canadian provinces and 25% higher than that of Ontario, the province with second highest disposable income per capital in Canada. Moreover, Alberta has consistently had the highest national disposable income per household even if we look as far back as 2009.

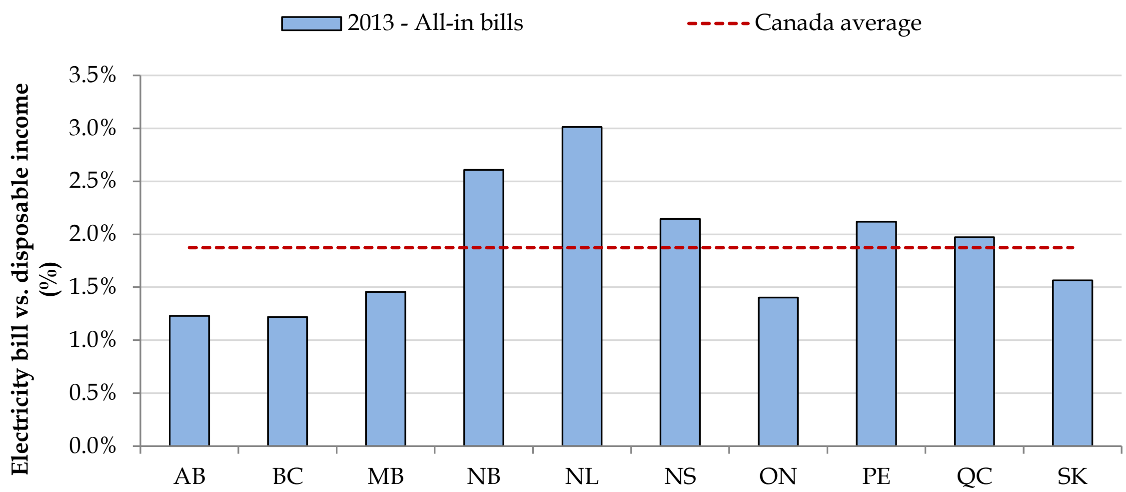
Figure 45. Average annual household electricity consumption (2011)



Source: Statistics Canada

Despite its much higher disposable income, however, the Alberta average household's total electricity consumption for 2011[48] was well below the Canadian average. As presented in Figure 45, Alberta's annual household electricity consumption is only marginally higher than that of Ontario and Prince Edward Island and nearly 25% lower than the average of the Canadian provinces.

Figure 46. Electricity bill share of nominal disposable income - 2013



Alberta's combination of close-to-average nominal electricity rates, the highest disposable income per household across the provinces, low tax rates, and one of the lowest household electricity consumption rates in Canada, results in it being tied for the lowest electricity bill to disposable income ratio, equal to that of British Columbia.

48 LEI used 2011 data from Statistics Canada on average consumption per household;more recent data were unavailable.

6 Implications for Alberta

When carefully examined, electricity rates in Alberta are within range of rates in other provinces in Canada. As provinces across Canada follow Alberta in making necessary upgrades to their electricity infrastructure, the gap between Alberta and other provinces may narrow. However, in addition to being cost competitive when rates are examined on a full cost basis, the Alberta market has a number of other advantages. These include appropriate risk allocation, substantial transparency, a clear separation between policymakers and power sector companies, and the ability of customers to hedge a large portion of their bill, unlike other jurisdictions where no stable, long-term pricing options exist. These attributes provide greater economic efficiency than arrangements in other provinces.

6.1 Risk allocation

The Alberta market design seeks to allocate risk to the parties best able to manage it. If generators build too many plants relative to actual demand, it is the generators who suffer, not the ratepayers. In the current lower wholesale price environment, unhedged generators face lower profits, or in some cases, losses. Were the Alberta generation sector a regulated environment, customers could perversely see increases in their bills as a result of declining demand, since utilities would seek to recover their lost profits in rates. In the Alberta market design, unhedged generators face volume risk; they also are at risk if their projects exceed budget. Such a market design helps to prevent phenomena like the Sir Adam Beck hydroelectric generating facility's new 10-kilometer tunnel under the city of Niagara Falls. The new tunnel cost approximately $1.5 billion, a 50% increase over the initial budget of $1 billion approved by the government of Ontario in 2004, and was delayed nearly 3 years beyond the initial target in-service year of 2010.[49] The cost of that project will be recovered from ratepayers. This experience follows that of the Darlington nuclear station; Ontario ratepayers continue to pay for Darlington cost overruns 24 years after the plant was completed.[50]

Through their provincial utilities, ratepayers outside of Alberta are also significantly exposed to developments in US markets. By pursuing oversized large scale projects using inappropriate costs of capital to serve export markets, Canadians may be inadvertently providing subsidized power to US consumers. Canadian ratepayers remain responsible for the costs of these facilities if US export sales fail to materialize, or are less lucrative than anticipated. Were these large scale projects built by private developers, shareholders would take on the risk of exposure to US markets. Even if construction of such large projects by provincially-owned utilities made sense in the 1960s, it may not today, given the greater diversity of generating technologies available and the more granular sizes in which they can be constructed.

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[49] OPG. "*Niagara Tunnel Project*." <http://www.opg.com/generating-power/hydro/projects/niagara-tunnel-project/Pages/niagara-tunnel-project.aspx>

[50] The original cost estimate for Darlington generating station was $3.9 billion; it ultimately cost $14.4 billion. It currently accounts for a sizable component of the Global Adjustment. Eileen O'Grady, "OPG Ontario Darlington 4 reactor back – report," Reuters, August 23, 2010.

6.2 Transparency

Because of the risk allocation described above, only shareholders suffer when generation planning goes awry, and if they do, they have the ability to change management. Shareholder scrutiny may help prevent poor decisions, just as regulatory oversight may in a traditional regulated environment. It is more difficult in Alberta than in other provinces for ministries to rule by directive because the Alberta government has no provincially-owned companies to issue directives to. Utility planning is open, and subject to AUC oversight except where specified by law. Generators and IPPs answer to their shareholders, and the constant consideration of fiduciary duty may be more potent than the fear of a potentially distant election. While many provinces have worked to improve independent oversight of provincially-owned utilities, governments have often proved less capable of regulating themselves than they are of regulating private entities.

6.3 Avoidance of use of power sector for political ends

Canadian provincial governments have found it difficult to resist the temptation to use provincially owned utilities to further various policy aims. The power sector has been seen as a means to create jobs or for rural development, sometimes without exploration of whether a provincially owned utility is indeed the most cost effective means of achieving these ends. Provincial ownership makes layoff and siting decisions more politicized than they would be at a private company. Currently, Albertans pay only for power through their electricity rates. By contrast, to cite but one example, Ontario ratepayers will pay not only for power, but for the politically motivated decision to interfere with the siting and construction of new power plants, currently estimated at $950 million.[51]

6.4 Ability of customers to hedge

Of all provinces, Alberta provides its customers with the greatest opportunities to hedge. By contrast, consumers in Ontario cannot hedge against the Global Adjustment; if the Ontario Power Authority chooses to sign additional contracts, regardless of the supply situation, all customers will pay. Customers are exposed to similar impacts in other provinces: if BC Hydro builds Site C in hopes of an export market which doesn't materialize, or if Manitoba Hydro or SaskPower overbuild, there is no practical way for customers to avoid costs or hedge against them other than through pleading to the government.

[51] Auditor General of Ontario estimates Oakville power plant and Mississauga power plant cancellation costs to be $675 million and $275 million respectively. Sources: Auditor General. "Oakville Power Plant Cancelation Costs." (October 2013) <http://www.auditor.on.ca/en/reports_en/oakville_en.pdf>; Auditor General. "Mississauga Power Plant Cancellation Costs." (April 2013) <http://www.auditor.on.ca/en/reports_en/mississaugapower_en.pdf>

Figure 47. Options available to Alberta residential and industrial customers

Product	Product Description
Regulated Rate Option	Option available to customers who have not chosen a retailer. Available providers depend on location of customer
5 year fixed electricity	Fixed price electricity contract
4 year fixed electricity	Fixed price electricity contract
3 year fixed electricity	Fixed price electricity contract
Dual fuel fixed contract	Due to synergies between natural gas and electrcitiy marketing, several retailers offer dual fuel products. Fixed dual fuel products available for 3 and 5 years.
Variable price products	Floating price plans, flow-through prices for electricity rate (or natural gas if dual fuel product) are based on hourly Alberta Pool Prices (daily wholesale market prices in Alberta for natural gas) with additional charges
Conservation Programs	Introduction of methods redicing energy consumption by improving consumption efficiency
Green Energy Products	Products that promote renewable energy consumption

Source: UCA and retailer websites.

Alberta customers have choices that most consumers in other Canadian provinces do not have. The ability to hedge, as well as the additional options available through retailers, provides additional value over and above the relative level of prices.

6.5 Concluding remarks

Our conclusions from previous editions of this paper remain unchanged. Were it not for the extent and timing of planned transmission investments, it is possible that Alberta delivered power costs would become yet more competitive when compared to other Canadian provinces. Given that other provinces are also considering significant investments in electricity infrastructure, Alberta may maintain its position even if the proposed transmission investment proceeds as planned. There are a host of benefits to allowing the market to determine the price of power. These include transferring risk to investors and away from consumers, relieving taxpayers of the cost and risk of utility debt, encouraging efficient consumption decisions and enabling provinces to focus scarce resources on activities which the private sector cannot perform, such as social programs. In addition to these structural benefits, Alberta's reliance on market principles has produced genuine price advantages for its residential and industrial customers. Should the policy environment in Alberta change, additional upward pressure on delivered electricity rates may result.

7 Appendix A: Works consulted

7.1 Rates filings and tariff sheets

Alberta Government. *"2013 Rates."* Accessed June 2, 2014. <http://www.ucahelps.alberta.ca/historic-rates-2013.aspx>.

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8 Appendix B: comparing Alberta and US 2012 industrial rates

State	Industrial rates (CAD cents/kWh)
HI	30.82
AK	16.82
NH	16.18
RI	11.65
MA	11.08
ME	10.89
CA	10.84
CT	10.34
VT	9.98
DE	9.89
MD	8.33
NJ	8.11
FL	8.04
MI	7.89
AB	**7.83**
PA	7.79
NY	7.55
WI	7.34
KS	7.09
TN	7.08
NE	7.01
MT	6.96
CO	6.94
VA	6.72
NV	6.67
MN	6.58
SD	6.57
ND	6.55
AZ	6.53
NC	6.42
IN	6.38
OH	6.37
WV	6.33
MS	6.24
AL	6.22
IL	6.09
WY	6.03

Note: US 2012 industrial rates are based on Form EIA-861, "Electric Power Annual: Electric Sales, Revenue, and Price", as of March 21, 2014.

All rates listed are for 2012 and are displayed in Canadian cents per kWh using average US dollar to Canadian dollar exchange rate for 2012 of approximately 1 to 1 between USD and CAD. Source: Bank of Canada

9 Appendix C: Residential and industrial rate calculations

Residential electricity rates in Alberta consist of a wholesale energy cost component, a distribution component, a transmission component, as well as regulatory charges. LEI has estimated the residential electricity rate for customers receiving service from each of the four largest utilities. LEI has also calculated a weighted average for the province based on the relative number of customers served by each of the four utilities. Rate calculations exclude transitional rate riders. The rates are estimated through the following steps:

1 The wholesale energy cost component is equal to the annual average Regulated Rate Option (RRO) tariff for 2013, in "dollars per kWh", for each utility.[52] This value is converted to "cents per kWh" by multiplying by 100.

2 Distribution charges, which consist of both fixed monthly (dollars per day) and variable (cents per kWh) charges, are based on each utility's 2013 Alberta Utilities Commission (AUC) rate application.

   a Fixed monthly charges, which are reflected as a "dollar per day" charge, are converted to "cents per kWh" based on the assumption that the average household consumes 592 kWh of electricity per month.[53] First, the "dollar per day" value is multiplied by 30.42 days (the average number of days per month per non-leap year) to get to a "dollar per month" value. The "dollar per month" value is then divided by 592 kWh per month (the assumed average residential consumption) to get a "dollars per kWh" value. Lastly, the "dollars per kWh" value is multiplied by 100 to get to a "cents per kWh" value.

3 Transmission charges, which for residential customers are purely volumetric (cents per kWh), are based on each utility's 2013 AUC rate application.

4 The average Balancing Pool Adjustment Credit for 2013 is estimated to be 0.55 cents per kWh. This is based on AESO's filing with AUC.[54] When, utility-specific Balancing Pool Adjustment Credit was available, it was used instead of the AESO default rate. The Balancing Pool Adjustment Credit appears as a rebate on consumers bills.

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[52] FortisAlberta's cost calculator <http://www.fortisalberta.com/Default.aspx?cid=359&lang=1> assumes an all-in cost (generation, distribution, transmission, and regulatory charges) of 15 cents/kWh for residential customers. It is important to note that the residential rates fluctuate every month as the underlying RRO generation component changes.

[53] Average consumption for residential customers is calculated as the provincial average over the period January 2012 through February 2014 of the monthly total consumptions for residential customers divided by the number of residential customers as reported by MSA in "Retail Statistics 2014 April 29" <http://www.albertamsa.ca/>

[54] Alberta Utility Commission. "*Alberta Electric System Operator 2013 Balancing Pool Consumer Allocation Rider F.*" November 14, 2012.

5 As mentioned previously, the weighted average cost for Alberta is estimated by averaging the individual cost for each of the four utilities and weighting by the number of customers.

Industrial electricity rates in Alberta consist of similar charges to residential electricity rates. They are composed of a generation component, distribution and transmission charges, and a regulatory component.

Transmission and distribution charges are from the 2013 rates filings of each utility with AUC. AESO files additional revenue requirements with AUC to manage the transmission system in Alberta, a portion of which are passed on to industrial customers. These charges include both volumetric and fixed components such as demand charges and system access service charges. The rates are estimated through the following steps:

1 The generation component of industrial electricity rates is equivalent to the actual wholesale price of electricity on the Alberta Electricity System Operator (AESO) market, adjusted for the typical load shape of industrial customers. The arithmetic average annual electricity prices on the AESO administered market in 2013 were $80.19 per MWh. To calculate the average price paid by an industrial consumer, the average annual AESO price is adjusted to reflect the load shape of a typical industrial customer. In this case, the annual average AESO prices are multiplied by 1.1159. The 11.59% adjustment factor represents the typical premium that an indicative industrial customer can expect to pay relative to the average spot market price due to a higher degree of peak consumption. [55]

2 Distribution charges, which consist of both demand (cents per day, cents per kVA per day, or cents per kW per day) and variable (cents per kWh) charges, are based on each utility's 2013 AUC rate application

a Demand charges, which are reflected as either "cents per day", "cents per kVA per day", or "cents per kW per day", are converted to "cents per kWh" based on the assumption that the average industrial customer consumes 146,353 kWh of electricity per month and a power factor of 0.8.[56]

i "Cents per kW per day" and "cents per kVA per day" charges are converted to "cents per kWh" in the following manner. First, the assumed 146,353 kWh monthly consumption is converted into an estimated peak daily demand by

[55] EPCOR estimates monthly default supply energy prices, which incorporate the impact of a typical customer class load shape. We have used the three year (2011-2013) average load shape premium, as reported by EPCOR, for demand greater than 75 kW. <http://www.epcor.com/power-natural-gas/regulated-rate-option/commercial-customers/Pages/commercial-rates.aspx>

[56] Average consumption for industrial customers is calculated as the provincial average over the period January 2012 through February 2014 of the monthly total consumptions for large industrial divided by the number of sites for large industrial as reported by MSA in "Retail Statistics 2014 April 29" <http://www.albertamsa.ca/>

dividing by average days in a month. Then, and if necessary, "cents per kVA per day" charges are converted into "cents per kW per day" by dividing by the 0.8 power factor assumption. The "cents per kW per day" charges are then multiplied by the assumed daily peak demand and the average number of days per month to arrive at a "cents per month" charge. This "cents per month" charge is then divided by the assumed monthly consumption of 146,353 kWh to obtain the final "cents per kWh" estimate.

ii "Cents per day" charges are converted to "cents per kWh" by multiplying by the average number of days per month (30.42) and then divided by the assumed monthly consumption (146,353 kWh) to obtain "cents per kWh".

3 The default Balancing Pool Adjustment Credit for 2013 is estimated to be 0.55 cents per kWh. This is based on AESO's filing with AUC.[57] When a utility-specific Balancing Pool Adjustment Credit was available, it was used instead of the AESO default rate. The Balancing Pool Adjustment Credit appears as a rebate on consumers bills.

4 As mentioned previously, the weighted average cost for Alberta is estimated by averaging the individual cost for each of the four utilities and weighting by the number of customers.

[57] Alberta Utility Commission. "*Alberta Electric System Operator 2013 Balancing Pool Consumer Allocation Rider F.*" November 14, 2012.

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Figure 48. Utility A rates, 2013

Residential		Transmission	Distribution
For all kWh delivered($/kWh)		0.021	0.007
Sub-Total (cent/kWh)		2.135	0.687
Chrages ($ per day)			0.494
Sub-Total (cent/kWh)		0.000	2.536
Total (cents/kWh)		2.135	3.223
Balancing Pool (cent/kWh)	-0.550		
RRO (2013 cent/kWh)	8.615		
Final Rate (cent/kWh)	13.423		

Load factor	**100%**	
Residential consumption	**592**	kWh/Month
Industrial consumption	**146,353**	kWh/Month
kVa to kW	**0.8**	Assumption

Industrial		Transmission+ Distribution
Total (cents/kWh)		3.117
Balancing Pool (cent/kWh)	-0.550	
Wholesale charges (cents/kWh)	8.948	
Final Rate (cent/kWh)	11.515	

Adjustment to wholesale prices to account for load shape	**11.59%**

Figure 49. Utility B rates, 2013

Residential		Transmission	Distribution
For all kWh delivered($/kWh)		0.022	0.018
Sub-Total (cent/kWh)		2.238	1.822
Chrages ($ per day)			0.647
Sub-Total (cent/kWh)		0.000	3.324
Total (cents/kWh)		2.238	5.146
Balancing Pool (cent/kWh)	-0.561		
RRO (2013 cent/kWh)	8.522		
Final Rate (cent/kWh)	15.345		

Load factor	**100%**	
Residential consumption	**592**	kWh/Month
Industrial consumption	**146,353**	kWh/Month
kVa to kW	**0.8**	Assumption

Industrial		Transmission	Distribution
For all kWh delivered($/kWh)		0.005	0.000
Sub-Total (cent/kWh)		0.527	0.000
Charges for kW of capacity ($ per kW-month)		4.997	0.594
Sub-Total (cent/kWh)		0.041	0.005
Total (cents/kWh)		0.568	0.005
Balancing Pool (cent/kWh)	-0.562		
Wholesale charges (cents/kWh)	8.948		
Final Rate (cent/kWh)	8.959		

Adjustment to wholesale prices to account for load shape	**11.59%**

Figure 50. Utility C rates, 2013

Residential		Transmission	Distribution
For all kWh delivered($/kWh)		0.019	0.007
Sub-Total (cent/kWh)		1.946	0.697
Chrages ($ per day)			0.343
Sub-Total (cent/kWh)		0.000	1.765
Total (cents/kWh)		1.946	2.461
Balancing Pool (cent/kWh)	-0.566		
RRO (2013 cent/kWh)	9.499		
Final Rate (cent/kWh)	13.341		

Load factor	100%	
Residential consumption	592	kWh/Month
Industrial consumption	146,353	kWh/Month
kVa to kW	0.8	Assumption

Industrial		Transmission	Distribution
For all kWh delivered($/kWh)		0.004	0.004
Sub-Total (cent/kWh)		0.418	0.409
Charges for kW of capacity ($ per kW-month)		0.422	5.273
Sub-Total (cent/kWh)		0.003	0.043
Total (cents/kWh)		0.422	0.452
Balancing Pool (cent/kWh)	-0.566		
Wholesale charges (cents/kWh)	8.948		
Final Rate (cent/kWh)	9.257		

Adjustment to wholesale prices to account for load shape	11.59%

Figure 51. Utility D rates, 2013

Residential		Transmission	Distribution
For all kWh delivered($/kWh)		0.028	0.062
Sub-Total (cent/kWh)		2.780	6.150
Chrages ($ per day)			0.011
Sub-Total (cent/kWh)		0.000	0.057
Total (cents/kWh)		2.780	6.207
Balancing Pool (cent/kWh)	-0.579		
RRO (2013 cent/kWh)	7.802		
Final Rate (cent/kWh)	16.210		

Load factor	100%	
Residential consumption	592	kWh/Month
Industrial consumption	146,353	kWh/Month
kVa to kW	0.8	Assumption

Industrial		Transmission	Distribution
For all kWh delivered($/kWh)		0.008	0.000
Sub-Total (cent/kWh)		0.810	0.000
Charges for kW of capacity ($ per kW-month)		6.887	18.812
Sub-Total (cent/kWh)		0.056	0.154
Total (cents/kWh)		0.866	0.154
Balancing Pool (cent/kWh)	-0.577		
Wholesale charges (cents/kWh)	8.948		
Final Rate (cent/kWh)	9.392		

Adjustment to wholesale prices to account for load shape	11.59%

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Figure 52. Utility A rates, 2010

Residential		Transmission	Distribution
For all kWh delivered (cent/kWh)		1.720	1.405
Sub-Total (cent/kWh)		1.720	1.405
Charges ($ per day)		-	0.534
Sub-Total (cent/kWh)		-	2.707
Total (cent/kWh)		**1.720**	**4.112**
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.589		
Final Rate (cent/kWh)	**12.120**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial		Transmission	Distribution
For all kWh delivered (cent/kWh)		0.582	-
Sub-Total (cent/kWh)		0.582	-
For each kW of Capacity ($ per kW per month)		3.243	5.379
Sub-Total (cent/kWh)		0.300	0.430
Total (cent/kWh)		**0.882**	**0.430**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**6.447**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 53. Utility B rates, 2010

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.750	5.310
Sub-Total (cent/kWh)		1.750	5.310
Customer charges (cent/day)		-	90.380
Sub-Total (cent/kWh)		-	4.582
Total (cent/kWh)		**1.750**	**9.892**
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.877		
Final Rate (cent/kWh)	**18.219**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.420	-
Sub-Total (cent/kWh)		0.420	-
First 500 kW demand (cent/kW/day)		13.61	20.73
Customer charges (cent/day)		-	214.46
Services ($/day)		2.207	
Sub-Total (cent/kWh)		0.782	1.018
Total (cent/kWh)		**1.202**	**1.018**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**7.354**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 54. Utility C rates, 2010

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.337	0.761
Sub-Total (cent/kWh)		1.337	0.761
Service charges (cent/day)		-	31.629
Sub-Total (cent/kWh)		-	1.603
Total (cent/kWh)		**1.337**	**2.364**
Administration charges (cent/day)	1.203		
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.872		
Final Rate (cent/kWh)	**11.477**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial	Energy	Transmission	Distribution
Energy charges (cent/kWh)		0.439	0.514
Sub-Total (cent/kWh)		0.516	0.514
Demand charges (cent/kVA/day)		8.075	1.367
Customer charges ($/day)			12.528
Sub-Total (cent/kWh)		0.415	0.828
Total (cent/kWh)		**0.932**	**1.342**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**7.408**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 55. Utility D rates, 2010

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.259	0.492
Sub-Total (cent/kWh)		1.259	0.492
Customer charges (cent/day)		-	40.758
Sub-Total (cent/kWh)		-	2.066
Total (cent/kWh)		**1.259**	**2.558**
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.594		
Final Rate (cent/kWh)	**10.111**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.534	0.243
Sub-Total (cent/kWh)		0.534	0.243
Demand charges(cent/kVA/day)		6.235	8.399
Customer charges (cent/day)		-	34.542
Sub-Total (cent/kWh)		0.199	0.416
Total (cent/kWh)		**0.733**	**0.659**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**6.526**		

Adjustor for wholesale charges to account for load shape	6.80%

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10 Appendix D: Background on LEI

10.1 LEI activities

London Economics International LLC (LEI) is a global economic, financial and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensive results. LEI is involved in strategic consultancy, with a key differentiating factor from its competitors in combining strategic analysis with an in depth focus and understanding of the dynamics of the energy sector. The firm has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulated markets worldwide.

The firm has worked with a number of infrastructure companies, financial institutions, multilateral institutions, multilateral organizations, utilities, and government institutions in evaluating energy and water sector transactions, financing mechanisms, and providing advice on both strategic direction and operations. Infrastructure market design, regulatory economics, privatization and unbundling, and advice on mergers and asset acquisitions are among LEI's core competencies. LEI has worked in Alberta on a variety of engagements since deregulation of the market in the mid-1990s, has deep expertise in renewable energy policies and markets across North America and the rest of the world, and has a developed practice area in price forecasting, asset valuation and strategic advisory services for generation facilities

10.2 LEI experience in Alberta

LEI has extensive experience in the Alberta market having worked on market design, asset valuations, contract evaluation, price forecasting, market power, and ratemaking design for a variety of entities (including the independent system operator, generators, transmission companies and distribution companies) since the mid-1990s. This experience includes (but is not limited to):

- ***AESO Cost Causation Study – Q1 2013:*** LEI developed a transmission cost causation study for the Alberta Electric System Operator ("AESO"). The study will be used for the determination of the AESO's Demand Transmission Service Rate DTS, and is expected to be filed with AESO's 2014 tariff application to the Alberta Utilities Commission ("AUC"). The study is intended to cover four main topics: (i) Functionalization of Capital Costs; (ii) Functionalization of Operating & Maintenance ("O&M") costs; (iii) Classification of Bulk and Regional System Costs; and (iv) Implementation Considerations.

- ***Formula-based ratemaking expert testimony*:** Prepared filings on behalf of Alberta wires utilities proposing a formula-based tariff-setting scheme. Developed a formula for periodic adjustments to an average tariff metric based on an inflation factor, efficiency factor, the impact of capital investments, operational performance relative to defined metrics; and defined mechanisms for additional adjustments based on force majeure and financial performance outside a defined range. Provided strategic advice to the CEO and other senior managers on presenting the firm's proposal to the regulator and other stakeholders; and provided expert testimony in support of the firm's filing to its regulator.

- ***Contract valuation:*** LEI prepared an expert report regarding a dispute over contract valuation in Alberta. LEI analyzed the contract and the broader economic environment and market fundamentals to determine the value of the contract as of that date. The analysis involved economic modeling to provide energy market price, volume and revenue forecasts. We also valued the contract using cost, market and income valuation approaches.

- ***Evaluation of wind power projects:*** LEI provided analysis of the current regulatory framework and potential revenue sources for a portfolio of wind power projects in Alberta, including detailed a forecast of electricity prices and a discussion of the market dynamics, which provided the basis for determining the value of wind projects. The engagement also included a discussion of the sale of RECs to the US.

- ***Comprehensive studies of the Alberta electricity market:*** For a variety of clients, LEI has produced a complete study of the Alberta electricity market. We have reported on the current regulatory status and expected regulatory changes, evaluated the market participants, discussed impending developments and analyzed the current and future direction of the market. Using our proprietary forecasting tool, LEI has developed long term price projections and analyzed the sensitivity of prices to changes in underlying market conditions.

- ***Alberta Electricity Industry Structure Review:*** LEI performed the Electricity Industry Structure Review, which involved analysis of the roles of the Power Pool, the Transmission Administrator, the Market Surveillance Administrator, the Balancing Pool, and the System Controller. LEI performed extensive stakeholder consultation, as well as preparing analysis of how these roles are performed in ten competitive wholesale markets worldwide. We then created a series of models for the evolution of all the entities studied, as well as for the organization of the industry as a whole. These models, after further stakeholder interaction and discussion with the government were distilled into final recommendations regarding how the institutions should be structured in the future.

- ***Real options-based valuation:*** LEI was retained by the Balancing Pool of Alberta to conduct a real options-based valuation of one specific SCGT generation unit to provide a realistic, market-based foundation to determine the reservation price of the unit contracts for that plant.

- ***White paper analysis for stakeholders in response to Alberta Department of Energy's regulations on market power:*** in response to government proposed policies on what defined market analysis on the proposed market power tests to be added to regulation, LEI wrote a paper specifically demonstrating the adverse effects of the 20% hard cap market share limit proposed by the Department of Energy. The white paper was filed as testimony with the Department of Energy in their consultation on Section 6 of the Electric Utilities Act.

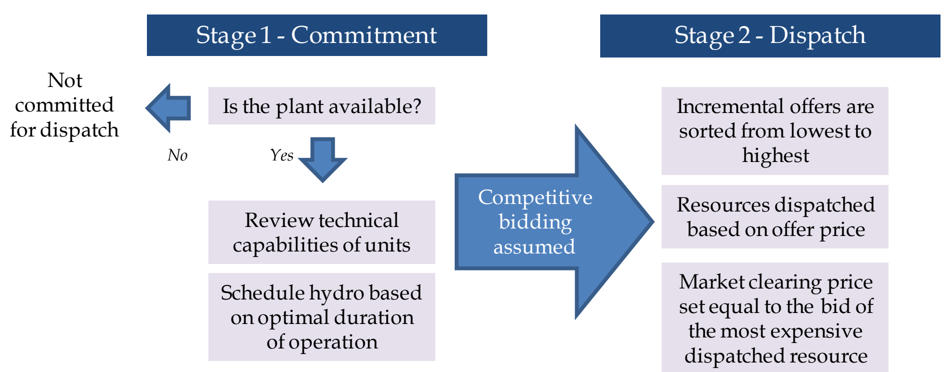
In addition to the above mentioned project experience, LEI publishes semi-annual regional market updates and 10-year energy price forecasts for major markets in North America (including Alberta) and around the world through London Economics Press (LEP).[58] Along with providing price projections, the reports highlight major developments in each of the regions as well as the underlying structural dynamics. LEI also provides more detailed regional market price forecasts tailored to a client's individual needs, including longer time horizons and forecasting of plant-specific revenues or the impact of structural or market design changes.

10.3 LEI modeling tools

LEI employs a proprietary simulation model, POOLMod, to forecast wholesale energy prices in Alberta and other organized electricity markets. POOLMod simulates the dispatch of generating resources in the market, subject to least cost dispatch principles, to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a "near optimal" maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. It then allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 56. POOLMod's Two-stage Process



POOLMod then commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to

[58] London Economics Press. <http://londoneconomicspress.com/>.

the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing). POOLMod is a zonal transportation based model, giving it the ability to take into account thermal limits across pre-defined zones on the transmission network.