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March 17, 2020

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: British Columbia Utilities Commission ("BCUC") Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report ~ Project No. 1599045

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's clarifying questions as requested by the BCUC Staff Consultant with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA ("CEC")

Written Clarifying Questions or High Level Topics for British Columbia Utilities Commission Staff Consultant

British Columbia Utilities Commission Review of British Columbia Hydro and Power Authority's Performance Based Regulation ("PBR") Report
Project No. 1599045

Mach 17, 2020

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1. Reference: Exhibit A2-5, pages 8 and 9

> In our second recent white paper for Lawrence Berkeley National Laboratory we presented the further argument that the efficacy of COSR varies with the business conditions that utilities face.[1] To the extent that key business conditions are favorable, revenue growth between rate cases roughly matches (and can even exceed) utility cost growth. Infrequent rate cases then create regulatory lag that strengthens utility performance incentives. Customers receive the benefit of base rates that are unchanged in nominal terms and falling in real terms. Regulatory cost is low.
>
> When business conditions are chronically unfavorable, on the other hand, the cost of utilities tends to grow faster than their revenue. Utilities then file rate cases more frequently, and this weakens their cost containment incentives. Frequent rate cases also raise regulatory cost. We noted in Section 2.2 that regulatory cost also depends on the number of utilities in a regulator's jurisdiction and the extent to which regulation involves complex and controversial issues.
>
> …
>
> We conclude that COSR does not work well to the extent that regulatory cost is especially high for reasons such as chronically unfavorable business conditions. Utility performance tends to deteriorate just when customer bills are rising briskly. Growth in rate base becomes the primary path to earnings growth. Regulatory cost can be high. Conscientious regulation is more costly.

1.1 Please provide the recent white paper noted in the excerpt above.

1.2 What tools are appropriate for utilities commissions or other regulators to use to influence the frequency of rate cases?

1.3 What non-PBR actions can be taken by utilities regulators to encourage or enforce cost containment?

2. Reference: Exhibit A2-5, page 18

To the extent that rate adjustments are based on a combination of external data and automatic adjustment mechanisms, the regulatory system is externalized and utilities can be more confident that efforts to improve performance will not trigger changes in regulatory policies that deprive shareholders of benefits. This process strengthens performance incentives. In addition, lessened concern about cross subsidies and risky ventures makes it possible to accord utilities greater operating flexibility.

The use of economic research is a third source of progress. Theoretical and empirical research can guide the use of external data to develop rate adjustments and benchmarks that properly reflect external business conditions. For example, research can be used to design a regulatory system that protects utilities from unavoidable input price fluctuations while ensuring customers the benefit of normal performance improvements.

The combined effect of these attributes is a regulatory process that, in spite of lower cost, can strengthen performance incentives and afford an increase in operating flexibility by making price restrictions less sensitive to company actions. The potential benefits from rate regulation are therefore increased and PBR plans can be designed so the benefits of performance improvements are shared between shareholders and customers.

Like other kinds of technological change, development of PBR has been stimulated by situations where it is particularly needed. Necessity has been the mother of invention. But PBR can nonetheless be useful in situations where COSR is less problematic. For example, numerous jurisdictional utilities may drive one regulator to embrace PBR, but its advantages might then prompt its embrace by a regulator with few jurisdictional utilities.

2.1 Please comment on the fairness for ratepayers paying the full cost for performance improvement measures while also potentially providing increased return on equity to the shareholder.

2.2 Please provide an overview of situations where PBR/MRP may not be appropriate.

2.3 Do successful PBR/MRP plans require a level of trust on the part of ratepayers? Please explain.

2.3.1 If yes, how is that best developed?

2.4 Please provide an overview of issues that can arise when a utility moves between PBR (or MRP) regulation and cost of service regulation. For example, there may be incentives to defer appropriate investment to outside the PBR/MRP term, or incentives for the utility to add costs under Cost of Service that will result in revenue inflation under PBR/MRP without commensurate cost increases, resulting in benefits to the utility during the PBR/MRP period.

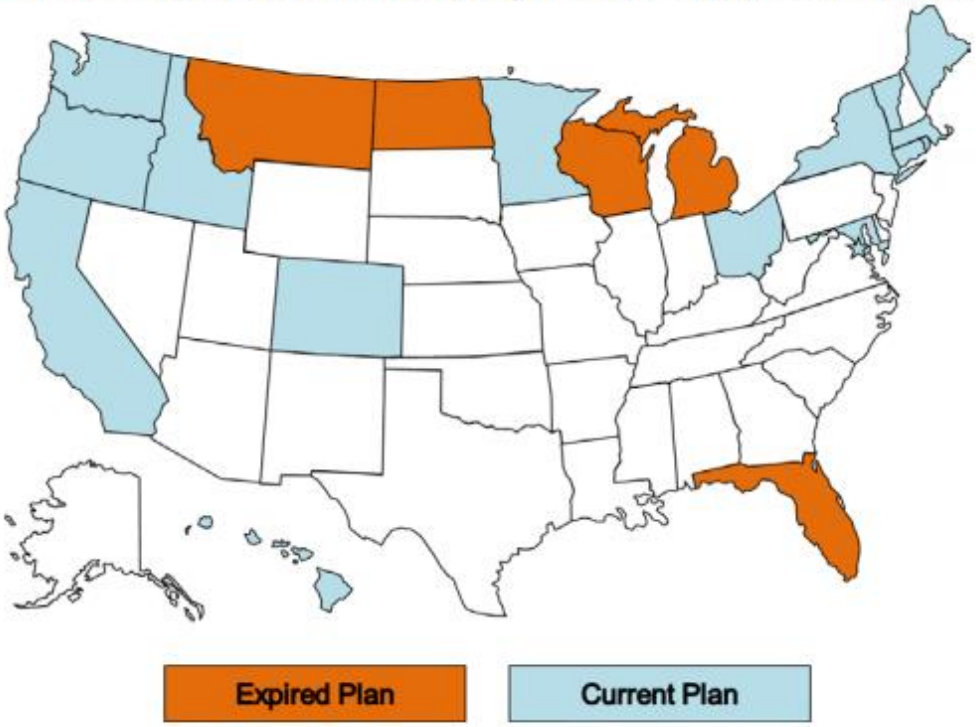
2.5 Is it appropriate for PBR plans to have a period of cost of service ratemaking afterwards? Please discuss.

2.6 Please comment on the relative merits of changing the PBR plan components in successive PBR plans vs. continuing to utilize the same metrics.

3. Reference: Exhibit A2-5, page 21

Figure 5a

Recent Electric Revenue Decoupling Precedents in American States



3.1 Please comment on any significant characteristics of US electric utilities that may differ from those in Canada; and particularly areas of difference from BC Hydro. i.e. size, ownership, etc.

3.2 The CEC notes there are 'Expired Plans.' Please provide the dates of when the plans expired.

3.2.1 Are there areas in which revenue decoupling has been tried and not repeated? Please explain and provide examples.

3.2.2 If yes, please comment on those plans and explain why they were not repeated.

4. Reference: Exhibit A2-5, page 24

Cost

Regulators in several countries use statistical cost benchmarking in rate setting. The total cost, OM&A expenses, capex, and/or total expenditure (OM&A plus capital cost expenditure) performances of utilities have all been benchmarked. Utilities may be ordered to file such studies or may file them voluntarily in hopes of securing better regulatory outcomes. Regulators have also initiated studies. These studies are often undertaken by specialized consultants.

Benchmarking has been performed with various tools that include econometric cost models, data envelopment analysis, and simpler unit cost and productivity metrics. In North America,

econometric benchmarking is facilitated by the data which the Federal Energy Regulatory Commission ("FERC") has gathered over many years on the operations of numerous U.S. electric utilities. Analogous data are gathered at the state level on the operations of natural gas utilities.

In Britain, extensive benchmarking is undertaken both at the level of total expenditures and by cost category. The use of benchmarking by regulators in Australia and Ontario is discussed in our Section 9 case studies. Benchmarking has been used to date chiefly in the context of multiyear year rate plans but also makes sense in the absence of such plans.

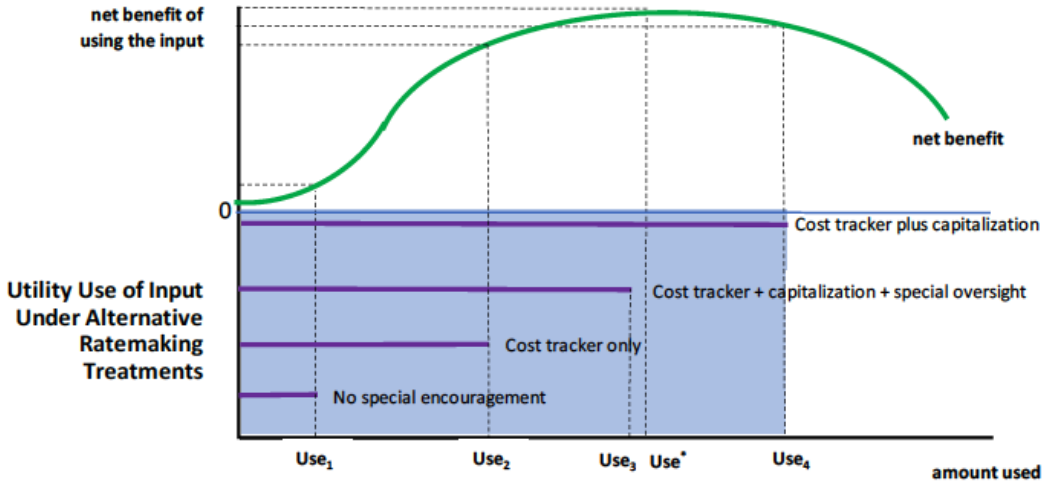
4.1 Please provide an overview of the data that has been gathered in Canada for econometric benchmarking. From where has it been gathered?

5. Reference: Exhibit A2-5, page 30

The potential impact of such incentive tools on the use of disfavored inputs is illustrated in Figure 6. This figure has two panels. The upper panel shows that the incremental net benefit from the disfavored input rises with its use up to a certain point but eventually falls. The lower panel shows how targeted incentives can influence the utility's use of the input.

Figure 6

Encouraging Utility Use of Disfavored Inputs With Trackers and Capitalization



Absent any encouragement, Figure 6 shows that the amount of the input which the utility uses is Use_1, well below the optimal level Use^*. If the cost of the input is only tracked, utility use of the input rises to Use_2, which is larger, but still suboptimally small. If the tracked cost is also capitalized with an ROE premium, usage in this example is Use_4, which is excessive. The optimal level of usage is nearly achieved when the expenditures are additionally subject to special prudence oversight.

5.1 Is the above figure theoretical, or is it founded on data?

5.1.1 If it is founded on data, please provide the data source.

6. Reference: Exhibit A2-5, page 37

7.3 Attrition Relief Mechanisms

The attrition relief mechanism is one of the most important components of an MRP. As we have noted, ARMs can substitute for rate cases and cost trackers as a means to adjust rates for trends in input prices, demand, and other external business conditions that affect utility earnings. Utilities can bolster earnings from better performance, and this strengthens performance incentives. In this section we discuss salient issues in ARM design. We first consider how ARMs are used to cap the growth in rates and revenue. Major approaches to ARM design are then discussed at a high level.

Rate Caps vs. Revenue Caps

ARMs can escalate rates or allowed revenue. Limits on rate growth are sometimes called "price caps." In a typical price cap plan, allowed rate escalation is typically applied separately to multiple service "baskets." There might, for example, be separate baskets for large-load and small-load customers. The utility can typically raise rates for services in each basket by a common percentage that is determined by the ARM, cost trackers, and any earnings sharing adjustments.

6.1 Please elaborate on the types of service "baskets" that are addressed. What are the differentiators? How many baskets are typically employed? What considerations go into selecting service baskets?

7. Reference: Exhibit A2-5, page 37

Revenue caps are often paired with a revenue decoupling mechanism that relaxes the link between revenue and system use. However, revenue caps have intuitive appeal with or without decoupling because revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must also reflect the trends in billing determinants.[26] As a consequence, revenue caps are sometimes used even in the absence of decoupling.

[26] If cost is growing by 2%, for example, and billing determinants are growing by 1% on average, rates need rise only 1%.

7.1 Please provide further details on the use of revenue caps without revenue decoupling mechanisms. Under what circumstances would this type of regulation be most or least appropriate?

8. Reference: Exhibit A2-5, page 39

Forecasting Pros and Cons

One important advantage of forecasted ARMs is their ability to be tailored to various cost trajectories. For example, a forecasted ARM can provide timely funding for the expected cost of a capex surge. Unless underspends are returned to customers, incentives to contain cost remain strong despite this flexibility. Another advantage is that capital cost forecasts can be made using familiar capital cost accounting.

On the downside, forecasted ARMs frequently do not protect utilities from unforeseen changes in inflation. Performance incentives can be weakened if capex budgets are repeatedly based on the utility's own capex. The biggest challenge with forecasted ARMs, however, is the difficulty of establishing a just and reasonable multiyear cost forecast. The efficient future cost of service is usually uncertain. Utilities are generally incentivized to overstate required cost growth while consumer advocates are incented to understate it. Given the substantial money at stake, parties are incentivized to argue their positions energetically and controversy can ensue. It is often difficult to ascertain the value to customers in a given cost forecast. Exaggeration of capex needs may reduce the company's credibility in future proceedings. However, the company can always claim that it "discovered" ways to economize.

8.1 Please confirm that it is equally problematic if the forecasted ARM does not protect ratepayers from unforeseen changes in inflation.

8.2 Please summarize the key ways in which ratepayers are best protected under PBR/MRP plans.

8.3 Please elaborate on how 'Performance incentives are weakened if capex budgets are repeatedly based on the utility's own capex.

9. Reference: Exhibit A2-5, page 40

In energy distribution, the number of customers served has been found to be a sensible stand-alone measure of growth in operating scale. This provides the foundation for the following revenue cap index,

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Customers} + Y + Z. \qquad [3]$$

When the scale of the utility business is multidimensional, growth in its scale can be measured by a scale *index*. For example, an index for a VIEU could track trends in generation capacity and transmission line length as well as the number of customers served.

In United States MRPs, the inflation measure in an indexed ARM is often a macroeconomic price index such as the gross domestic product price index. This complicates the choice of an X factor since the propensity of the GDPPI to track industry input prices becomes an issue. This is a particular concern in the U.S. because GDPPI growth is materially slowed by the MFP growth of the economy. Canadian MRPs are more likely to feature the average of the trends in a macroeconomic inflation measure (e.g., $CPI^{Alberta}$) and a provincial labor price index. The ability of such inflation measures to track industry input price growth is rarely considered.

9.1 Please comment on the use of growth factors for O&M vs growth capital. How should they differ, if at all?

9.2 How should growth factors be established if there is not a 1:1 relationship between, for example, cost/customer and customer growth? Over what period of time should data be reviewed to establish an expected relationship.

9.3 Does the MFP growth of the economy also slow the GDPPI growth in Canada, or is it just not considered? Please explain.

9.3.1 If it is not considered, please explain why not.

9.4 Are there significant differences in the impact of the MFP growth of the economy in Canada and the US?

9.5 What would be the best way for industry input price growth to be addressed in Canada? Please explain.

10. Reference: Exhibit A2-5, page 52-53

Z Factors

As noted in Section 7.1, a Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings and are not effectively addressed by other ARM provisions. Many MRPs have explicit eligibility requirements for Z-factor events. Here is a typical list of requirements.

Causation: The expense must be clearly outside of the base upon which rates were derived.

Materiality: The event must have a significant impact on the finances of the utility. Materiality can be measured based on individual events or the cumulative impact of multiple events. Some plans have materiality thresholds of both kinds.

Outside of Management Control: The cost must be attributable to some event outside of management's ability to control.

…

Z-factors can reduce utility operating risk and encourage more cautious behavior by government agencies, without weakening performance incentives for the majority of costs. Z-factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most of the benefits of MRPs. Disadvantages of Z factors include the fact that they can materially raise regulatory cost, and the possibility that they may weaken utility incentives to mitigate the impacts of triggering events. It may be easier for the utility to obtain higher revenue from the process than it is for customers to obtain lower revenue. Z factors also raise overcompensation concerns in plans with indexed ARMs.

10.1 Please provide a range for standard 'materiality' thresholds.

10.2 Given the asymmetric access to information, how are customers expected to become aware of Z-factor incidents that might reduce costs?

11. Reference: Exhibit A2-5, page 59-60

7.9 Plan Termination Provisions

Plan termination provisions are one of the more important issues in MRP design. Rates are often reset in a general rate case, and this typically occurs in the last year of the plan. This option passes all benefits of any long run cost savings achieved during the plan to customers. A true up to cost is also welcomed if poor plan design had caused marked earnings surpluses or deficits.

The downsides of scheduling rate cases in advance are several and include the following.

- This option involves relatively high regulatory cost.
- Performance incentives are weakened. The incentive to realize longer-term gains is known to attenuate in the later years of an MRP. This occurs because utilities would in those years incur the upfront costs of performance-improving initiatives but receive few (or none) of the benefits that result.
- Marketing flexibility is complicated.
- Scheduled rate cases can provide perverse incentives to utilities. Utilities may be incented to defer certain costs so that they are high in the test year for new rates and/or ask for supplemental revenue in the out years of the new plan.

Several alternatives to scheduled rate cases have been devised that can mitigate these problems. The plan may contain no requirement that a rate case be held to set new rates. Parties may retain the option to negotiate a plan extension. New rates that are otherwise based on a traditional rate case may be subject to adjustment under the terms of an efficiency carryover mechanism ("ECM").

11.1 Why is marketing flexibility complicated?

11.2 Please elaborate on the 'true up to cost'. Should this be undertaken over a single year, or is a longer period of Cost of Service appropriate to develop a well-founded base year?