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October 28, 2020

VIA ELECTRONIC MAIL

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

Attention: Marija Tresoglavic, Acting Commission Secretary

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 first set of Information Requests 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: BC Hydro
cc: Registered Interveners

50 YEARS 1969-2019
INTERLAW MEMBER OF INTERLAW, AN INTERNATIONAL ASSOCIATION OF INDEPENDENT LAW FIRMS IN MAJOR WORLD CENTRES

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

INTERVENER INFORMATION REQUEST NO. 1

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

October 28, 2020

SECTION 1 - PBR IS NOT THE BEST OPTION GENERALLY

COST CONTAINMENT NOT THE OBJECTIVE

1. Reference: Exhibit A2-5, page 8

> Cost containment incentives are strengthened to the extent that COSR involves regulatory lag. We define this as the length of time between a change in a utility's cost and a corresponding change in its rates. A longer lag gives the utility more time to profit from efforts to cut its costs. This strengthens its cost containment incentives. This classical notion of regulatory lag is not the same as a lag in recognizing the typical impact of external business conditions on utility cost.

1.1 Please confirm that PBR typically gives the utility a financial profit incentive to cut its costs.

1.2 Please confirm that PBR formulas are typically based on aggregate actual or projected prior year cost, less flow-through items or excluded costs, multiplied by inflation factors (I factors), customer growth (G factors) and efficiency factors (X factors).

1.3 Please confirm that profit sharing of cost-reductions is not a mandatory part of regulating a utility with PBR formulas.

1.4 Please confirm that a utility operating under PBR formulas is incented to cut costs in the immediate term of the PBR because any profit share can be maximized over the term of the PBR regulation.

1.5 Please confirm that prudent management of a utility includes managing the efficiency and effectiveness of its operations.

1.6 Please confirm that such efficient and effective management of a utility is generally implemented through significant projects and programs in regard to which the utility management can generally provide accountability for the improvements.

1.7 Please confirm that prudent management of a utility would typically have efficiency and effectiveness metrics for its significant departmental operations, and that there are substantive collaborative utility efforts in the market to share comparative information regarding performance related to these metrics.

2. Reference: Exhibit A2-5, page 18

> 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 describe or otherwise explain situations where COSR can be considered as less problematic?

2.2 Are there jurisdictions in which regulators have adopted PBR regulation, then and subsequently reconsidered and dropped PBR from their regulation?

2.2.1 If yes, please provide the names of the jurisdictions with the drawbacks cited for each, if any.

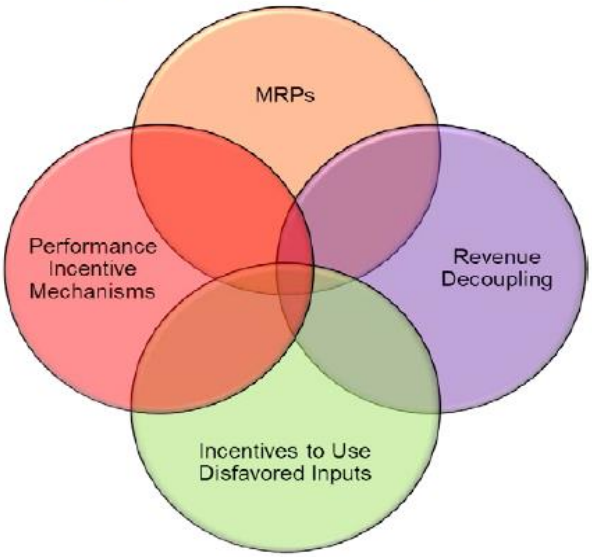
TOO COMPLICATED

3. Reference: Exhibit A2-5, pages 16- 17

> The various approaches to PBR can be and frequently are combined, as Figure 4 illustrates. One reason for these combinations is that the individual tools may not satisfactorily address all incentive problems. Another is that some tools can produce undesirable side effects that other PBR tools can

Figure 4

PBR Approaches are Frequently Combined



3.1 Please confirm that cost of service regulation be implemented over a number of years.

3.2 Can incentive programs be added to cost of service regulation to deal with perceived specific needs?

4. Reference: Exhibit A2-5 page 111 and 112

Company's Service Plans. Some of these targets are tied to efficiency.

Our analysis also sheds light on approaches to PBR that might make sense for BC Hydro. BC Hydro serves a vast area and supplies most of its power from large hydroelectric facilities. This system will occasionally require capex surges to replace aging facilities which will not automatically produce much revenue growth. This complicates reliance on an indexed ARM to escalate allowed revenue. However, we have shown that PBR options available for regulating the Company extend far beyond the MRPs with indexed ARMs which are discussed in the Company's recent PBR Report and whitepaper. For example, the revenue adjustment mechanism would not have to be indexed, or indexing could apply only to OM&A revenue (and possibly also to revenue for routine plant additions, as in the recent Fortis plans). Separate regulatory systems could apply to the Company's generation, transmission, and distributor services. Should the Commission nonetheless prefer an indexed ARM, it should be noted that better ways to provide supplemental capital revenue when an indexed ARM is used is a major focus of PBR today. Moreover, there has recently been extensive research undertaken by utilities for Colorado and Hawaii proceedings to design revenue cap indexes for vertically integrated electric utilities. This reduces the incremental cost of designing an appropriate index for BC Hydro. Were indexed ARMs to be adopted, provisions for supplemental capital revenue would be a major issue.

Refinements to the existing PBR provisions in BC Hydro's regulatory system merit consideration. We provide here some examples without making recommendations.

- Consideration could be paid to excluding some revenues from revenue decoupling or giving these revenues a partial decoupling treatment. These revenues might include those from large-volume customers and/or electrification of transportation. If revenues from electrification continue to be fully decoupled, the incentive to aggressively pursue this goal could alternatively be strengthened with a PIM.
- In the absence of an MRP, revenue decoupling could be complemented by a revenue adjustment mechanism that escalates allowed base revenue automatically between rate cases. For example, allowed revenue in the year after the second forward test year could be escalated for customer growth and/or input price inflation. This could reduce the frequency of RRAs, especially after Site C enters the rate base.
- OM&A revenue could be escalated formulaically in RRAs.[138]
- One or more PIMs could be developed which strengthen the Company's incentives to pursue systemwide and/or local peak load management. Amortization of the costs of peak load management may not provide the Company with sufficient incentive.
- Greater use of statistical benchmarking could be considered. Alternatives to simple unit cost metrics such as econometric cost modelling show promise and are used in several jurisdictions. Sophisticated cost models have been developed to appraise VIEU costs and its major components. Benchmarking is facilitated by the availability of many years of detailed data on the operations of U.S. electric utilities. Benchmarking can be used to appraise forecasted/proposed costs as well as historical costs.

4.1 Please confirm that all of the above situational issues could be accomplished under COSR if and when needed.

COSR CAN BE EFFECTIVE

5. Reference: Exhibit A2-5, page 16

Most PBR approaches used today can be characterized as incremental reforms to COSR designed to address these problems rather than entirely different regulatory systems. For example,

- Multiyear rate plans strengthen the incentive to contain the cost of base rate inputs by reducing the frequency of rate cases.
- Revenue decoupling reduces the throughput disincentive to bolster system use.
- Other PBR provisions provide targeted encouragement to use disfavored inputs.
- Performance incentive mechanisms target weak points in a utility's incentive structure.

5.1 Please explain how utilities could be regulated under COSR oversight and managed by the utility with the following:

a) Other metrics, to generate better results;

b) decoupling of revenues if needed;

c) longer regulatory timeframes for reducing the frequency of rate cases;

d) targeted incentive provisions to use disfavoured inputs if the regulator favours them; and

e) targeted incentive structures to deal with utility weak points in multiyear rate plans.

6. Reference: Exhibit A2-5, page 17 and 18

> The incentive problems that are inherent in COSR can in principle be reduced by more conscientious oversight of utility operations. However, given the uncertainties about what constitutes prudent management, uncertainties which are compounded by the information asymmetries noted earlier, this can be quite costly and ultimately ineffective. PBR can potentially provide the same or better results at lower regulatory cost. PBR can then be said to represent progress in "regulatory technology" that increases the size of the economic pie available for higher earnings and better terms of service.
>
> There are several sources of this technological progress. First, PBR makes use of automatic rate adjustment mechanisms, established in advance of their operation, which are insensitive to the utilities own cost. Such mechanisms often have mathematical formulas. Proper use of such mechanisms can reduce the frequency and scope of regulatory intervention. A second source of progress is that some PBR mechanisms rely on data on the operations of other utilities. Data on the input price and productivity trends of other utilities are illustrative.

> 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.

6.1 Please confirm COSR can accommodate the following:

a) uncertainties about prudent management and those compounded by information asymmetries;

b) automatic rate adjustment mechanisms;

c) avoid triggering changes that would deprive the shareholder of benefits;

d) employing the use of empirical data to develop rate adjustments and benchmarks; and

e) providing operating flexibility.

SECTION 2 - BC HYDRO IS NOT HE CORRECT UTILITY FOR PBR

GOVERNMENT IS THE SHAREHOLDER

7. Reference: Exhibit A2-5, page 5

2.6 Alternative Approaches to Power Industry Regulation

Various tools are available to policymakers today to regulate the electric power industry. These can be usefully grouped into three broad categories:

- Structural
- Command and Control
- PBR (aka incentive) approaches

Some tools are typically wielded by regulators while others are often wielded by other branches of government such as legislatures. The diversity of tools available to policymakers is illustrated in Figure 2.

Structural Approaches

Policymakers influence power industry performance by their decisions concerning the structure of markets that utilities might serve. They long ago decided to permit utilities to monopolize some markets provided that the terms of service that they offer can be regulated by public agencies. However, competition may be permitted in some markets that utilities serve and utility participation in some markets may be discouraged. Utilities may be required to outsource some of their functions and/or to use competitive bidding to determine the sourcing of some inputs.

Basic Approaches to Power Industry Regulation

Public Service Commission	Other Branches of Government
Structural	
Competitive bidding requirements	Independent energy efficiency provider
Participation in some markets prohibited	Retail and bulk power supply competition
Command and Control	
Revenue requirements	Renewable portfolio standard
System planning & large capex projects	Energy efficiency portfolio standard
Rate designs	Appliance efficiency standards and building codes
Compensation for distributed generation	
Performance-Based Regulation	
Multiyear rate plans	
Revenue decoupling	
Performance metric systems	
Targeted encouragement to use strategic inputs	

Command and Control Approaches

Policymakers have many opportunities to decide what utilities do. They can, for example, after consultation with utilities and other stakeholders periodically determine the utility's revenue requirement, its allocation between services, and the design of rates. They can also oversee utility business plans and rule in advance on the propriety and funding of major capex projects. New kinds of command and control regulation have developed over the years. For example, utilities may be asked to file integrated system plans that consider demand-side management and outsourcing options and address transmission and distribution as well as generation. A renewable portfolio standard ("RPS") and/or an energy efficiency portfolio standard ("EEPS") may be imposed.

7.1 Please confirm that 'structural', 'command and control', and 'incentive' approaches are all part of the COSR regime, or can be, with the government as shareholder, legislator, and responsible for the regulator.

7.2 Please confirm that the PBR incentive for the utility shareholder may not be relevant for BC Hydro or the BC government.

8. Reference: Exhibit A2-5 page 9

Utility operations may also produce positive externalities. For example, low carbon electrification of transportation can benefit the environment. The local community may benefit from the retention of a large industrial load or from forms of generation that rely more on labor and other local inputs. The failure of utilities to capture extra benefits of their actions may cause them to do too little to create these benefits.

8.1 Please confirm that in BC, under COSR with the government, regulator, and utility focused on the 'public interest', the positive externalities can be and are being addressed in significant ways.

8.2 Please confirm that specific directives and policy related to positive externalities are often already established for BC Hydro by the BC governments and regulators as well as by the utility.

9. Reference: Exhibit A2-5, page 111

- The crown corporation status of BC Hydro means that it is financially vulnerable to government intervention in its affairs. This greatly complicates BCUC regulation and must be considered when choosing PBR options. However, the Y factor and Z factor provisions of MRPs can afford the Company some financial protection from these interventions.

9.1 Please compare and contrast how PBR and COSR can accommodate government initiatives and interventions.

9.2 Please confirm that government and regulator interventions, at the time, may be considered to be 'in the public interest' and that the utility is often directed to follow the 'public interest' at the time.

9.3 Please confirm that the concept of the 'public interest' can and does vary from time to time, and that the regulatory regimes, be they COSR or PBR, will of necessity make the appropriate accommodations.

10. Reference: Exhibit A2, pages 5-6

Performance-Based Approaches

The term PBR encompasses approaches to regulation designed to strengthen utility incentives to perform well. There are four well-established PBR approaches.

- Relaxation of the link between revenue and system use
- Targeted performance incentive mechanisms

- Special incentives to use disfavored inputs
- Multiyear rate plans

PBR is explained further in the sections that follow.

10.1 Please confirm that the utility could provide incentives internally to individuals to achieve desired results versus providing the incentive to the utility shareholder.

10.2 Please explain why the utility and the utility regulator cannot provide adequate incentives for desired performance outcomes and why only PBR can provide sufficient strength to the incentive motivations of the utility.

11. Reference: Exhibit A2-5, pages 15-16

3.6 The PBR Alternative

PBR was noted in Section 2.6 to encompass various approaches to regulation that strengthen utility incentives to perform well. The development of PBR has been driven in part by incentive problems encountered under COSR. Our discussion in Section 3.2 revealed that the following incentive problems are especially notable in COSR for energy utilities.

a) Frequent rate cases reduce a utility's incentive to contain cost.

b) Cost trackers generally produce particularly weak incentives to contain tracked costs. For energy utilities, the costs of fuels and purchased power that they handle are a particular problem since these costs are large and commonly tracked.

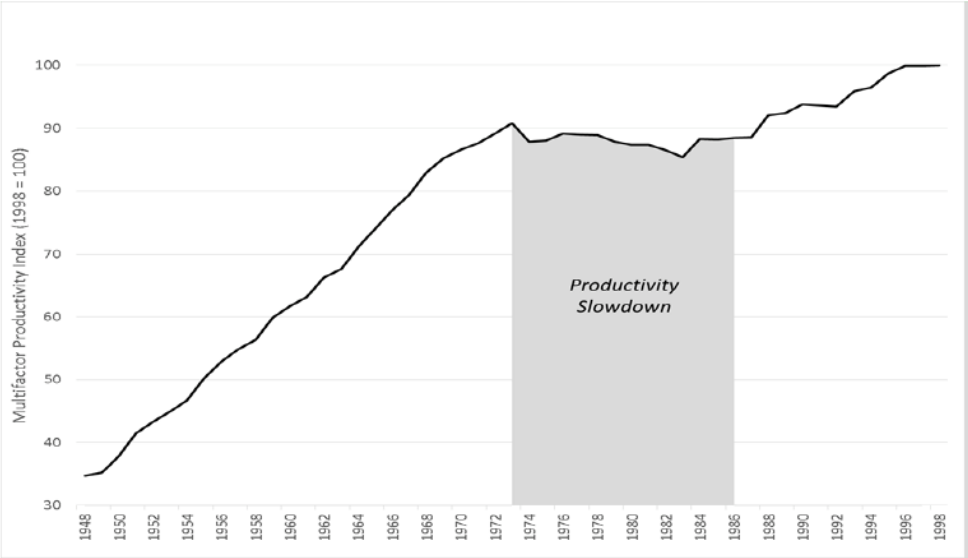
---

[9] Computation of this index ended in 1998. For a discussion of this research, see Glaser, John L., "Multifactor Productivity in the Utility Services Industries," *Monthly Labor Review*, May 1993: 34–49.

[10] A basis point is one-hundredth of 1 percent.

Figure 3

Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948–1998)



c) Utilities have weak incentives to contain external costs, and these can also be large for energy utilities.

d) Problems a), b), and c) combine with legacy rate designs to greatly weaken utility incentives to contain uneconomic load growth.

To the extent that these problems are severe, utilities have weak incentives to contain cost. Rate base growth is the main path to earnings growth. Utilities tend to underutilize inputs that can help them reduce their capital costs and tracked costs. These inputs notably include those for DSM.

11.1 Please confirm that:

a) Frequency of rate cases can be established by the Commission;

b) Tracked costs can be regulated under the oversight of the BCUC, which is an experienced regulator;

c) there is no incentive for BC Hydro to add costs at a corporate level for shareholder profitability's sake, which it does not, and that BC Hydro is not regulated to produce a profit based on rate base growth;

d) Incentives for BC Hydro management and personnel can be managed with internal management metrics; and

e) external costs can be monitored and tracked by the utility with BCUC oversight providing transparency and accountability.

12. Reference: Exhibit A2-5 page 111

- The efficacy of MRPs would be increased if management compensation is tied to cost performance goals. It is our understanding that BC Hydro's executives already receive performance-based pay that is tied in part to the achievement of performance targets in the Company's Service Plans. Some of these targets are tied to efficiency.

12.1 Please discuss the appropriateness of the BC Hydro management incentives and whether or not they can be improved with respect to their link to effective and efficient operational performance of the utility.

12.2 Please confirm that there is a substantial base of information with respect to management incentives and organizational performance.

THERE IS A PRE-SET RETURN

13. Reference: Exhibit A2-5, pages 3 and 4

2.3 Importance of Fairness

An important and widely-accepted fairness principle is that utility revenue should roughly equal the efficient cost of service. Application of this principle ensures that customers receive most benefits from electricity but also ensures that an efficient utility has a reasonable chance to pay its suppliers and earn its target rate of return (which should be commensurate with its operating risk.) This principle affects the cost of service as well as fairness since utility businesses are capital-intensive and doubt about fair compensation can raise their operating risk and their cost of raising funds in capital markets. Another common fairness principle is that electric services should be affordable to low income customers.

2.5 Competitive Market Analogy

Good utility regulation is sometimes characterized as simulating outcomes of well-functioning competitive markets. Prices of products in such markets reflect the costs of typical firms, not those of individual suppliers. Prices are sensitive to product quality. To be fully well-functioning, suppliers should pay for most collateral costs of their operations so that there are few negative externalities.

Suppliers in competitive markets are incentivized to contain their costs and provide goods and services in the bundles and price/quality combinations that customers want. They do not generally favor capital cost over operation, maintenance, and administrative ("OM&A") expenses. Replacement of poorly performing plant is motivated chiefly by a desire to preserve service quality and avoid rising OM&A expenses. Major tasks in the supply chain may be outsourced, including many that are capital-intensive.

Competition between suppliers passes most benefits of industry performance gains to customers in the long run. However, superior returns may be earned by superior performers.

13.1 Please confirm that the BCUC does regulate the BC Hydro revenue requirement enabling its profitability, that the shareholder has established the return it requires from the utility, and the BCUC and the utility must regulate the return within this context.

13.2 Please confirm that as a matter of fairness, the Commission may determine a fair return for BC Hydro investments based on comparisons to market returns and/or on any such information the Commission may consider relevant.

14. Reference: Exhibit A2-5, page 8

> Tracker treatment of the principal variable costs of energy utilities weakens their incentive to discourage uneconomic load growth. High usage charges further weaken this incentive since when there is excess capacity, load growth bolsters margins between rate cases. In the longer run, load growth also creates opportunities for load-related capex. The strong incentive that energy utilities therefore have under COSR to boost load growth and resist DSM is sometimes called the "throughput" incentive.

14.1 Please confirm that for BC Hydro the profitability return provided by the Commission is not necessarily related to any 'throughput incentives' that BC Hydro might face.

14.2 Please discuss the implications of the 'throughput incentive' with respect to BC Hydro's established targeted net income as compared to a utility incented to increase its ROE.

FREQUENCY OF RATE CASES CAN BE MANAGED

15. Reference: Exhibit A2-5 page 8-9

> 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.

In the face of unusually high regulatory cost, the scope and thoroughness of prudence reviews may be further contained. This weakens incentives that are already weak when rate cases are frequent. A larger share of volatile and/or rapidly rising costs may be tracked. This can reduce the frequency of general rate cases and thereby reduce regulatory cost and help to preserve utility incentives to contain costs that are not tracked. However, incentives to contain tracked costs are weakened unless trackers are incentivized and/or the prudence of these costs is carefully reviewed. In the extreme, the regulator may opt for formula rates that are essentially comprehensive cost trackers.[2] Regulators faced with high regulatory cost may also be more inclined to limit utility operating flexibility when the prudence of actions utilities might take with more flexibility is difficult to assess.

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.

15.1 Please provide the author's understanding of the BC Hydro regulatory costs as a percentage of its revenue requirements, and provide any comparative information on regulatory costs that the author may have.

FOSSIL FUEL ISSUES ARE NOT RELEVANT FOR BC HYDRO

16. Reference: Exhibit A2-5 page 9 and page 111

It is also noteworthy that most power in North America is generated using fossil fuels, the production and consumption of which harms the environment. Utilities in most North American states and provinces pay no taxes for power from fossil-fueled generation that they produce or purchase. Even if they did, these taxes might well flow through to customers via energy cost trackers. Traditional COSR thus typically produces weak utility incentives to reduce harmful generation emissions.

Utility operations may also produce positive externalities. For example, low carbon electrification of transportation can benefit the environment. The local community may benefit from the retention of a large industrial load or from forms of generation that rely more on labor and other local inputs. The failure of utilities to capture extra benefits of their actions may cause them to do too little to create these benefits.

- The abundance of hydroelectric resources in BC and frequently cloudy weather reduce concerns about DSM and DGS which have recently sparked interest in PBR in some jurisdictions. However, DSM can still cost-effectively reduce some of the Company's load-related costs and increase the amount of hydroelectric power available to displace use of fossil fuels in the United States.

16.1 Please confirm that fuel costs, and particularly fossil fuel costs, are not substantially relevant because BC Hydro has limited fossil fuel use.

SECTION 3 - REVENUE DECOUPLING MAY NOT BE RELEVANT FOR BC HYDRO

17. Reference: Exhibit A2-5, page 19

4. Relaxing the Revenue/Usage Link

Regulators are increasingly interested in relaxing the link between a utility's revenue and the kWh and kW of system use by customers. This is a form of PBR because it reduces incentives that utilities have to boost the utilization of their systems (aka "throughput"). We noted in Section 3.2 that utilities generally profit from increased capacity utilization under legacy rate designs with their high usage charges. Even when demand growth taxes capacity there may be profitable investment opportunities, and utilities are largely indifferent to the growth in tracked costs and externalities that demand growth entails. Higher system use is undesirable to the extent that alternatives to higher use such as DERs are less costly. A diminished throughput incentive reduces the disincentive utilities otherwise have to facilitate use of DERs. Relaxation of the revenue/usage link can also address any problem of declining average use that the utility is experiencing. The frequency of rate cases can to that extent be reduced, thereby strengthening cost containment incentives and reducing regulatory cost.

Two methods are widely used in North America for relaxing the revenue usage link: revenue decoupling and lost revenue adjustment mechanisms ("LRAMs"). These options are discussed in turn.

17.1 Please provide any specific revenue/usage links which BC Hydro has that could be relaxed or delinked, and provide the associated potential benefits.

18. Reference: Exhibit A2-5, page 19

4.1 Revenue Decoupling

Revenue decoupling adjusts a utility's rates mechanistically to help its *actual* revenue track its *allowed* revenue more closely. Most decoupling systems have two basic components: a **revenue decoupling mechanism** ("**RDM**") and a revenue adjustment mechanism. The RDM tracks variances between actual and allowed revenue and adjusts rates periodically to reduce them. A rate rider is commonly used to draw down these variances by raising or lowering rates.

The revenue adjustment mechanism escalates allowed base rate revenue to provide relief for cost pressures. The great majority of decoupling systems have some kind of revenue adjustment mechanism since, if allowed revenue is static, the utility will experience financial attrition as its costs rise. Costs of utility base rate inputs typically rise since input prices typically rise and the demand for utility services typically grows. When utilities do not have multiyear rate plans, revenue adjustment mechanisms approved in the United States typically escalate allowed revenue only for customer growth.[11]

The potential benefits of revenue decoupling are numerous. It eliminates the lost-margin disincentive for a wide array of utility initiatives to encourage DSM and DGS, without relying on complicated load impact calculations or rate designs with high fixed charges that could discourage customers from adopting DSM.[12] For example, it reduces the risk from offering customers time-sensitive usage charges that shift loads away from peak demand periods. Decoupling can also compensate utilities for reduced usage-charge revenue due to DER promotion by third parties, such as

---

18.1 Please identify the rate designs that BC Hydro has in place under its COSR, including BC Hydro's proposed optional rates currently being developed which have elements of revenue decoupling included.

18.2 Please explain how RDMs and RAMs would achieve benefits that are not achieved under the current regime.

19. Reference: Exhibit A2-5, page 21

Figure 5a

Recent Electric Revenue Decoupling Precedents in American States

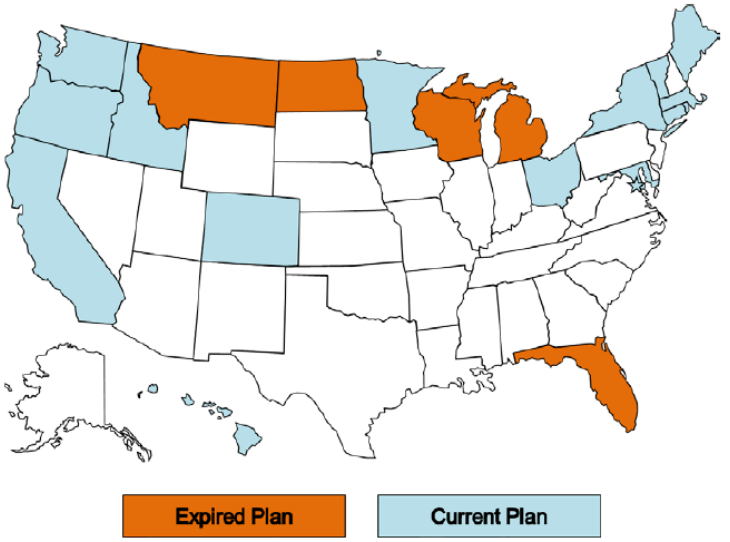
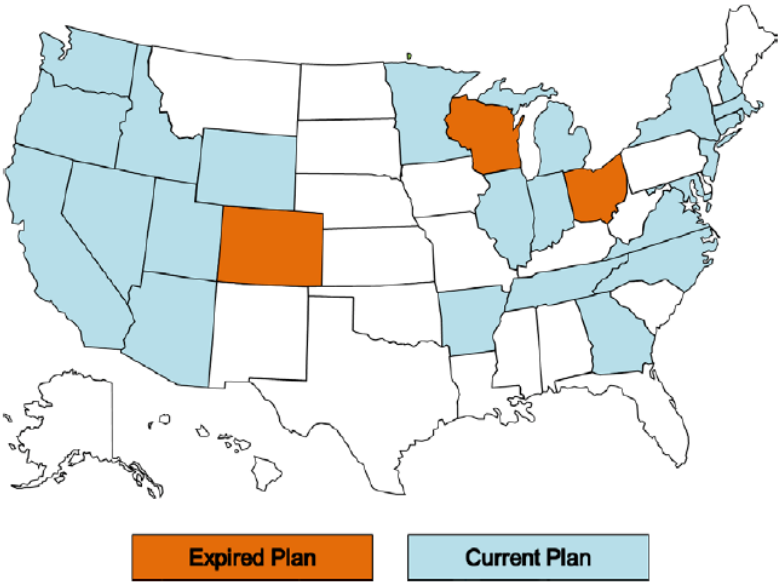


Figure 5b

Recent Gas Revenue Decoupling Precedents in American States



19.1 Please explain the difference in revenue decoupling between electricity and gas, if any, and explain why this might occur.

19.2 Please provide the same maps, with an overlay with an overlay of where PBR is and is not applicable.

20. Reference: Exhibit A2-5, page 109

Revenue Decoupling

The Non-Heritage Deferral Account adjusts revenue for margin fluctuations between rate cases which result from variances between actual and forecasted sales volumes. Decoupling currently encompasses all tariffed services. However, the approach to decoupling that the Company uses does not provide any automatic escalation to allowed revenue.

20.1 Please confirm that automatic escalations for revenue could be incorporated into COSR if the Commission found it to be appropriate.

21. Reference: Exhibit A2-5, pages 110-111

10.4 Commentary

Our review of BC Hydro's business and BCUC regulation prompts the following comments on the suitability of PBR for BC Hydro.

- Under the Company's current regulatory system, which features revenue decoupling but no automatic revenue escalation, the foreseeable future will likely involve biennial rate cases that involve weak cost containment incentives and high regulatory cost. It is not at all clear

[136] The incentive for British Columbia Transmission was a potential change to the return on equity that was dependent on the final cost of the Vancouver Island Transmission Reinforcement Project.

[137] There are concerns that this facility will be completed at a cost that is well above the budget estimate.

why frequent rate cases, which have not worked well in other jurisdictions (or for BC Hydro in this jurisdiction), should be "given a chance to work."

21.1 Please confirm that there is nothing preventing BC Hydro or the Commission from conducting regulation of BC Hydro with longer than biennial rate cases under the COSR.

21.1.1 Please confirm that doing so could involve automatic rate adjustments and stronger effectiveness and efficiency by the Commission.

22. Reference: Exhibit A2-5 pages 107, 111 and 113

PBR Approaches

The BCUC has more experience with PBR than most North American regulators. Section 60 (b.1) of the Utilities Commission Act allows the BCUC to "use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period." This gives the BCUC the legal authority to approve multiyear rate plans that use various attrition relief mechanisms.

- The BC regulatory community has experience with various kinds of PBR including multiyear rate plans, revenue decoupling, amortization of DSM costs, and incentivized capital cost trackers. Its lengthy experience with RRAs with multiple forward test years is also helpful background for considering an MRP for BC Hydro. The Commission has more legislative authorization to pursue PBR than many in North America.
- Canada has emerged as a PBR leader.

22.1 Please confirm that the BCUC PBR experience is primarily with private corporations, such as FortisBC and FortisBC Energy Inc., which are driven by shareholder profit interests.

23. Reference: Exhibit A2-5 page 111

- As a vertically integrated utility serving many large-load customers, the marketing flexibility that MRPs can facilitate can help BC Hydro retain and attract large-load customers. AMI has already been installed and can facilitate better rate designs. However, increased marketing flexibility might require an MRP that doesn't have earnings sharing.

23.1 Please describe the increased marketing flexibility that is proposed as being needed, and describe why BC Hydro is constrained from achieving it.

23.2 Please explain what MRP might have that BC Hydro cannot achieve, and why BC Hydro is prevented from achieving the flexibility it requires.

24. Reference: Exhibit A2-5, page 111

- MRPs streamline regulation, but the regulatory burden of the BCUC is not remarkably large. Only a few jurisdictional utilities provide retail gas and electric services, and some of these already operate under MRPs. If BC Hydro nonetheless operated under an MRP, a notable benefit would be that proceedings to update its plan could be scheduled to occur in different years from those of the Fortis utilities. Another would be more time for the regulatory community to consider important generic issues.

24.1 Please provide any evidence that the Commission is not able to schedule utility rate proceedings to times that are efficient and effective for the Commission with respect to the utilities that it regulates.

SIZE OF CAPITAL

25. Reference: Exhibit A2-5 page 48 and page 49

Capital Cost Trackers

Many MRPs provide supplemental revenue for some capital costs. Trackers are often used for this purpose. Provisions for supplemental capital revenue have joined ARMs as critically important issues in many MRP design proceedings.

Capital cost trackers typically compensate utilities for the annual costs (e.g., depreciation, return on undepreciated asset value, and taxes) which eligible capex gives rise to. Such trackers are sometimes used in MRPs to address capex surges that are difficult to address with the ARM. The capital cost of utilities is typically less volatile than OM&A expenses, but we noted in Section 7.3 that capex surges are sometimes needed by VIEUs and UDCs alike. Moreover, capital cost tends to stay high for many years after capex surges whereas OM&A expenses may be unusually high one year and unusually low the next. Thus, if the ARM does not fund a capex surge, the utility can materially underearn for several years.

Forecasted ARMs can address expected capex surges better than index-based ARMs. Thus, there is less need to add capital cost trackers to forecasted ARMs. However, MRPs with forecasted ARMs sometimes do permit utilities to request supplemental revenue for unforeseen capex, or for capex with uncertain completion dates.

Appraising the Need for Trackers

A key question in the approval of a capital cost tracker is the need for tracking. This question involves two issues, the need for high capex and the need for tracking the capex. We address each issue in turn.

Ascertaining the Need for High Capex

It can be challenging to ascertain the need for high capex in a proceeding considering capital cost trackers, as it is in a forward test year rate case. Capital cost trackers for energy distributors often address the cost of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges that are commonly tracked, such as those for new generation capacity or emissions control facilities. Distribution modernization plans involve a measure of discretion. The utility might, for example, claim that it is desirable to replace some assets a little before they absolutely must be in order to avoid having too many assets to replace at the same time. The regulatory community does not always have much expertise in evaluating such claims.

Generation plant additions can also involve discretion, but regulators of vertically integrated electric utilities have years of experience considering both the need for new capacity and the right generation technology. Integrated resource planning and/or a certificate of public convenience and necessity ("CPCN") are often required before the construction or purchase of generation capacity can proceed. There are often competitive alternatives to a utility's proposal to increase generation capacity. Proponents of these alternatives are often aggressive in pressing their cases in these hearings.

Other Evidentiary Guidelines Here are some other useful guidelines concerning evidence of need for capital cost trackers.

- Competitive bidding is a common feature of hearings to consider CPCNs for generation plant additions. This kind of evidence can also be pertinent in proceedings to review distribution system capex. By providing evidence of bidding, a utility's case for prudence is encouraged.
- Metrics for quantifying the benefits of capex projects are useful. In the case of system modernization projects, benefits can include SAIDI and SAIFI improvement (or non-degradation), OM&A cost savings, reduction in employee injuries or injuries to others, reduction in the length of time to respond to customer calls, reduction in the number of estimated or incorrect customer bills, etc.

Ascertaining the Need to Track High Capex

Evaluating of the need to track the cost of high capex is somewhat simplified in the absence of an MRP. If a utility has been filing rate cases fairly frequently, and sometimes underearns, high capex is likely to impose additional attrition, making rate cases even more frequent, and possibly annual. Under these conditions, a tracker for the cost of a capex surge is quite likely to reduce rate case frequency without much concern about overearning. Determining the need for a capital cost tracker can be more complicated for a utility operating under an MRP with an ARM that provides some compensation for cost growth. Under an indexed ARM, for example, the question may arise of how much capex the index funds.

25.1 Please confirm that the metrics for quantifying the benefits of capital investments can be generated and used by BC Hydro independently of the regulatory regime.

25.2 Please confirm that Commission oversight of such metrics can also be achieved independent of the regulatory regime. (i.e. MRPs are not the exclusive preserve of prudent management and the cost effective and efficient management of a utility).

SECTION 4 - SPECIFICS OF REGULATION

BENCHMARKING IN RATE SETTING

26. 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.

26.1 Please confirm that when utilities are benchmarking, each utility may be significantly different from others and have different circumstances such that the benchmarks may provide helpful learning, but likely cannot be definitive with respect to rate setting

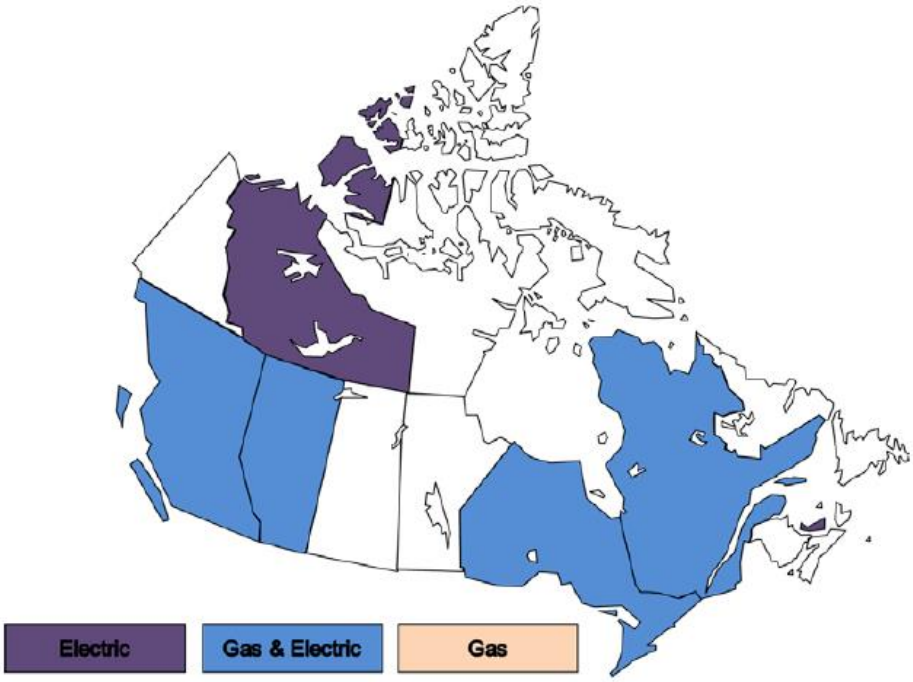
26.2 Please confirm that benchmarking can be achieved by a utility without the need for PBR.

MULTIYEAR RATE PLAN

27. Reference: Exhibit A2-5, page 36

Figure 7b

Recent MRPs for Energy Utilities in Canadian Provinces



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27.1 Please confirm that the electric MRP for FortisBC covers only a small portion of BC and is tiny in comparison to that which is not.

28. Reference: Exhibit A2-5 page 62 -63

7.11 MRP Pros and Cons

Advantages

MRPs have several general advantages over COSR under modern operating conditions. The ARM can provide timely rate escalation for increasing cost pressures. The frequency of rate cases can thus be reduced without tying rate adjustments to the utility's own costs. Regulatory lag can be

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Pacific Economics Group Research, LLC

increased despite timely rate adjustments. This means that there are increased opportunities for utilities to bolster earnings from various efforts to contain growth in the rate base and other costs that are addressed by the ARM (i.e., costs that are not tracked). There is more incentive to buy services rather than build plant when this is the low-cost strategy. The ARM thus addresses attrition at the same time that it strengthens performance incentives. Avoiding a full true up of revenue to the company's cost when the plan expires by such means as an ECM can magnify the incentive "power" of the plan considerably.

Provisions can be added to MRPs which further strengthen a utility's incentive to embrace DSM and DGS. These include revenue decoupling and the tracking of utility DSM expenses. In addition MRPs can, by strengthening general incentives to contain cost, provide their own incentive for utilities to use DSM and DGS to contain load-related costs of base rate inputs such as load-related capital expenditures. A utility might, for example, be more incentivized to use DSM and well-sited customer DGS to reduce the need for a costly distribution system upgrade. Time of use pricing has more appeal since this can help contain growth-related costs.[46] Note also that MRPs strengthen incentives to embrace DSM and DGS without requiring complicated load or cost savings calculations. The combination of an MRP, revenue decoupling, demand-side management PIMs, and the tracking of DSM-related costs can thus provide four "legs" for the DSM "stool."[47]

The PIMs included in the plans can address "holes" in the incentive framework. For example, we have noted that MRPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall materially if the quality of its offerings falls below industry norms. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality.

MRPs can also encourage good utility performance by increasing operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency and reliance on ARMs for revenue escalation means that the prudence of utility actions must be considered less frequently. Utilities are more at risk from bad choices (e.g., needlessly high capex) and can gain more from good choices. Knowledge of stronger incentives informs commission reviews of a utility's operating prudence.

To the extent that products and services aren't subject to revenue decoupling, an MRP can also strengthen incentives to market them effectively. This is a useful attribute in an era when changing technologies and customer needs create opportunities for new rates and services. Services to price-sensitive large-volume customers are sometimes exempted from decoupling provisions.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. The strengthened performance incentives can encourage a more performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, the occasional rate cases, an efficiency carryover mechanism, and/or careful RAM design.[48]

MRPs can also improve the efficiency of regulation. Rate cases are less frequent and can be better planned and executed. The terms of MRPs of utilities in the same jurisdiction can be staggered so that rate cases overlap less. Streamlining the rate escalation chore can free up resources in the regulatory community to more effectively address other important issues. Senior utility executives have more time to attend to their basic business of providing quality service cost-effectively.

Disadvantages

MRPs also have notable disadvantages.[49] They are complex regulatory systems that require skills that the regulatory communities in some jurisdictions do not possess. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers.

Controversies can arise over plan design. The main sources of controversy in a typical MRP proceeding are the appropriate ARM and mechanisms for supplementing capital revenue. There are opportunities for strategic behavior that erode potential plan benefits for customers. Forecasts may be biased and more years of costs may require forecasts. Costs may be opportunistically bolstered or deferred to produce extra revenue. Protections against such strategies such as multiyear capex plans erode the cost savings from frequent rate cases.

These and other concerns have prompted many consumer advocates to oppose MRPs. Best practices in the MRP approach to regulation have evolved to address many of these problems. However, efficacy of many of these remedies is not yet assured.

28.1 Please explain why MRPs require so many different adjustments to accommodate the reality of the utility industry and specific utilities, and why most of these adjustments cannot be accomplished by utilities under COSR.

ATTRITION RELIEF MECHANISMS

29. 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.

The utility is often permitted to raise rates for services by less than the allowed overall rate growth. In some plans, slower growth in rates for some services in a basket can, within limits, permit more rapid rate growth for other services in the same basket. However, customers in each basket are insulated from the discounts and other market developments going on with services in other baskets, except as these developments influence shared earnings.

Price caps have been widely used to regulate industries, such as telecommunications, where it is desirable for utilities to market their services aggressively and promote system use. This will generally be so to the extent that utilities have excess capacity and use of their systems does not involve negative externalities. When rates have high usage charges, price caps make utility earnings more sensitive to the kWh and kW of system use and thereby strengthen utility incentives to encourage greater use.

Under *revenue* caps, the escalator permits growth in allowed revenue (aka the revenue requirement). The allowed revenue yielded by a revenue adjustment mechanism must be converted into rates, and this conversion requires assumptions regarding billing determinants. Rate growth typically does not equal allowed revenue growth since the growth rates of allowed revenue and billing determinants differ.

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.

29.1 Please confirm that the Commission could provide for any formula-based automatic rate adjustments under COSR that it deems fair, just and reasonable.

29.2 Please confirm that in some significant measure the Commission has already done this for a number of rates and/or costs for BC Hydro.

30. Reference: Exhibit A2-5, page 42-43

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends on growth in billing determinants and tracked costs. In the energy utility

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industry, such freezes usually apply only to base rates but have in a few cases also applied to rates for energy procurement.[31]

Unchanged rates are compensatory for utilities when the growth in the costs addressed by these rates matches the growth in their billing determinants. Such favorable operating conditions have occurred over the years under special circumstances.

- Rate freezes have often been featured in telecom MRPs where utilities were experiencing slow input price inflation and rapid technological change and demand growth.
- We noted in Section 3 that electric utilities in the first three decades after 1940 generally experienced brisk demand growth and, except during wars, slow inflation. Some utilities were able to operate for many years without rate cases.
- Following the addition of large solid-fuel power plants to their rate base in the late 1980s and early 1990s, some VIEUs experienced unusually slow cost growth due to excess generating capacity and flat or declining generation rate bases. Inflation was moderate and growth in average use, though slower than in the 1940-1970 period, was still materially positive. Several VIEUs operated without general rate cases for more than a decade under these conditions.
- Mergers and acquisitions have facilitated rate freeze agreements by creating temporary but sometimes sizable cost containment opportunities as the parties realized economies of scale (and sometimes scope).

Favorable circumstances like these are less common today. While inflation is currently slow, we have noted that some utilities need high capex today and there is typically no growth in average use available to finance cost growth. A revenue per customer freeze combined with revenue decoupling might be more feasible.

30.1 Please confirm that BC Hydro has had regulated and legislated rate freezes and/or rate cap formulas at different times in its past, and did not require MRP/PBR regulation.

CAPITAL COST TRACKERS

31. Reference: Exhibit A2-5, page 49

Ratemaking Treatments of Tracked Costs

Once a capex budget is established, the treatment of variances from the budget becomes an issue. Some capital cost trackers return all capex underspends to ratepayers. As for overspends, some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made between rate cases if cost exceeds the budget. In between these extremes are mechanisms in which deviations from budgeted amounts that are in prescribed ranges are

31.1 Please confirm that BC Hydro's capital is not recorded on its books and amortized into rates at budget amount, and while rates are set on planned capital additions, subsequent rates are based on actual costs capitalized.

PERFORMANCE METRIC SYSTEMS

32. Reference: Exhibit A2-5, pages 22 and 23

5. Performance Metric Systems

5.1 The Basic Idea

Performance metrics (called "outputs" in Britain) quantify aspects of utility operations which matter to customers and the public. The use of metrics in regulation can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce the cost of oversight on balance. A **performance metric system** is a system for routinely monitoring select metrics and using them in performance appraisals. "Scorecards" summarizing results for key metrics are often tabulated and may be posted on a publicly-available website or included in customer mailings.

Metrics that are closely linked to the welfare of customers and the public include those that address the cost of service and service quality. A familiar example of such metrics is the system average interruption frequency index ("SAIFI"), which measures an aspect of service reliability. There is also an interest in "intermediate" metrics that are closely associated with variables of ultimate interest. An example is the number of customers taking service with time-sensitive rates.

In a performance metric system, target (aka "benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. This is typically done by taking the differences or ratios between the actual and target values. Performance appraisals can focus on the *level* of a metric or on its *trend*.

5.2 Popular PIMs

Service Quality

Service quality is the one of the most common areas of utility operations where metrics are employed in utility regulation. Service quality PIMs can strengthen incentives to maintain or improve quality and simulate the connection between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have traditionally fallen into two general categories: reliability and customer service.[15]

Reliability

Performance metric systems commonly feature metrics for systemwide outage frequency and duration and may also feature regional or local reliability metrics. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics used in PIMs are SAIFI and the system average interruption duration index ("SAIDI"). Other reliability metrics used in PIMs have included the customer average interruption duration index ("CAIDI") and the momentary average interruption duration index ("MAIFI").

Customer Service

Customer service PIMs have used a wide array of metrics, including results of customer satisfaction surveys, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on these metrics is often assessed through a comparison of a company's current year performance to its recent historical performance. Because of a lack of standardization in customer service data and the effort required to process available data, benchmarking a company's performance on service quality PIMs is very difficult.

32.1 Please confirm that performance metrics can be implemented by a utility and can have regulatory oversight review under COSR and without MRP or PBR.

33. Reference: Exhibit A2-5, pages 109- 110

Performance Metric System

BC Hydro has a performance metric system with the BCUC which is limited to the reporting of several metrics. These include metrics for service quality (e.g., SAIDI and SAIFI) and DSM. The Company's reliability reporting includes its performance relative to Canadian Electricity Association averages. The BCUC expressed some concerns about the relative paucity of these metrics, particularly when it comes to benchmarking and productivity, in its most recent revenue requirements application decision. The Company commissioned the Brattle Group to undertake a statistical benchmarking study of its non-fuel OM&A expenses for its current RRA. This study used simple unit cost metrics and U.S. operating data.

BC Hydro also develops performance targets as part of "Service Plans" that it presents to the BC provincial government. These targets encompass a wide array of performance areas including reliability, safety, energy efficiency, rates, and the accuracy of capex project forecasts. The Company files annual reports on its performance with the government.

33.1 Please confirm that PBR incentives are not required for a utility to operate with a more robust set of performance metrics than BC Hydro uses in its Service Plans.

34. Reference: Exhibit A2-5 page 23 and page 110

Conservation PIMs tie the revenue of a utility to indications of success in their DSM programs. Sensible performance metrics for such PIMs include the peak MW or total MWh of load. In either case, the focus is typically on the *change* in the metric attributable to DSM.

The success of a utility conservation program depends partly on kWh of load savings achieved and partly on program cost per kWh saved. Some conservation PIMs have a "shared savings" format that can guard against excessive program cost. Net benefits of programs are calculated, and these are shared mechanistically between utilities and their customers.

PIMs can strengthen incentives for utilities to embrace DSM. Revenue decoupling and LRAMs can remove the throughput disincentive to resist DSM whereas DSM PIMs can provide a *positive* incentive.

However, DSM PIMs also have some disadvantages. As with LRAMs, the calculation of load savings from DSM and their cost impact is generally costly and can be controversial. Independent verification of savings has sometimes been required. PIMs for DSM therefore typically exclude many kinds of DSM programs (e.g., customer information programs). In this situation, utilities are incentivized to focus on programs addressed by the PIMs and may neglect programs that aren't addressed.

Targeted Incentives to Use Disfavored Inputs

The Company's DSM expenses are tracked and amortized over 15 years, which is the average life of DSM initiatives.

34.1 Please confirm that BC Hydro's Power Smart DSM has numerous performance measurement metrics which it uses to manage the entire program and that it does not neglect the usefulness of consumer information programs or the importance of customer behaviours.

34.2 Please confirm that additional performance metrics required to improve Power Smart metrics could be implemented without the need for PBR.

Z FACTORS

35. Reference: Exhibit A2-5 pages 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.

Prudence: The cost must have been prudently incurred.

Eligible events may, in principle, raise or lower earnings. For example, a cut in corporate income taxes could lower earnings.

One of the primary rationales for Z-factor adjustments is the need to adjust revenue for the effect of changes in tax rates, highway relocations, mass transit construction, system undergrounding requirements, and other government initiatives on utility cost. Absent such adjustments, policymakers can adopt new policies that increase the cost of a utility, confident in the knowledge that its earnings, rather than customer bills, will be affected between rate cases.

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.

35.1 Please confirm that a Z-factor for PBR enables adjustments to rates set with formulas that do not anticipate particular events affecting costs or revenues.

35.2 Please confirm that in BC under COSR the utility has the ability to apply to the Commission for rates and/or deferral accounts for unanticipated costs or revenue impacts.

36. Reference: Exhibit A2-5, page 53

7.5 Targeted Incentives to Use Disfavored Inputs

MRPs often include targeted incentives to use disfavored inputs. Utility DSM expenditures are commonly tracked in North American MRPs. We noted in Section 6.3 above that the British approach to ARM design is based on totex rather than a traditional revenue requirement. MRPs in Australia, Britain, and the U.S. have had provisions for pilot programs. MRPs are sometimes touted for encouraging innovation but, in practice, utilities often worry that innovative practices might be adversely treated by regulators in the next rate case.

36.1 Please confirm that in BC conservation and efficiency measures are required under legislation, and that the Commission regularly approves Pilot Programs for DSM and rates which are beneficial to the utility and to customers, and this does not require an MRP.

MARKETING FLEXIBILITY

37. Reference: Exhibit A2-5, page 54

7.7 Marketing Flexibility

Multiyear rate plans can afford utilities greater flexibility in the products and terms of services that they offer. In this section we first consider the need for flexibility and then consider forms of flexibility and some precedents.

Need for Flexibility

Generally speaking, the need for marketing flexibility is greater to the extent that demand for utility services is complex, changing, and elastic with respect to the terms of service offered. Demand elasticity is greater when customers use large amounts of electricity and have alternative ways to meet their needs that are competitive with respect to cost and quality. Elasticity is also typically greater for products that are "discretionary" in the sense that they do not address a customer's most basic needs. "Core" customers are those with fewer options and lower elasticities of demand for basic services.

These customers often have relatively elastic demands for service because they have power-intensive technologies, options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Margins from customers like these loom larger in the finances of vertically integrated utilities than they do in the finances of UDCs, since many of these customers take delivery of power from the transmission grid.

Advanced metering infrastructure, distributed storage, and other new technologies open the door to new value-added services, including premium quality services. Many customers (including large-load customers) have an interest in purchasing special green power packages. Plug-in electric vehicles are a new and power-intensive consumer technology that can reduce the use of petroleum fuels.

AMI makes it more cost-effective to offer tariffs for services to small-volume customers which feature time-sensitive volumetric charges or demand charges. Customers can be encouraged by such tariffs to reduce system use in hours when service is especially costly and to increase use when it is especially cheap.

Improved marketing can bolster utility earnings by increasing revenue, building customer loyalty, and encouraging customers to use utility services in less costly ways. Incremental earnings from better marketing can be shared with customers. Customers also benefit from rate and service offerings that are more tailored to their needs.

What Kinds of Flexibility are Feasible?

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to "light-handed" regulation and outright decontrol. Light-handed regulation typically takes the form of expedited or interim approval of certain rate and service offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

37.1 Please identify any instances where BC Hydro does not have marketing flexibility sufficient to achieve its objectives.

37.2 Please confirm that where BC Hydro requires marketing flexibility, such as in gaining access to longer term markets in the US, it can apply to the Commission for such flexibility and has done so under its current regulatory regime.

EARNINGS SHARING

38. Reference: Exhibit A2-5 page 56 and pages 57-58

7.8 Earnings Sharing Mechanisms and Off-Ramps

Some MRPs include explicit controls on the earnings utilities can achieve. Two approaches to earnings control are common: earnings sharing mechanisms and off-ramp mechanisms. These approaches can be used separately or in combination.

Pros and Cons of ESMs

Whether to add an ESM to an MRP is one of the more difficult decisions in plan design since there are several noteworthy pros and cons. On the plus side, an ESM can reduce the risk that revenue will deviate substantially from cost. Unusually high or low earnings may reflect unusual utility performance, but may also reflect windfall gains or losses or a poor plan design. The reduction in risk can help parties agree to a plan and make it possible to extend the period between rate cases. Consider also that the stretch factor approach to sharing plan benefits is difficult to incorporate into forecasted and hybrid ARMs. An ESM then provides a way to share benefits of improved performance during the plan. Note finally that it is difficult to build into ARMs the possibility that certain expenditures can be postponed to years following the expiration of a plan. An ESM is one means of sharing the benefits of cost deferrals.

On the downside, an ESM weakens utility performance incentives. ESM design also raises regulatory cost, and the ESM filings themselves can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that earnings are shared. Offering marketing flexibility can be complicated in the presence of an ESM, because favorable terms offered to some customers can affect the earnings variances distributed to all customers.[39] MRPs for telecommunications utilities have often had marketing flexibility and, partly for this reason, have rarely had ESMs. There is less need for an ESM if the plan features other risk mitigation measures, such as inflation indexing, cost trackers for capex surges, Z factors, or revenue decoupling.

38.1 Please confirm that earnings sharing with respect to management of any activity in BC Hydro would deplete the ratepayer benefit of such earning achieved by BC Hydro.

OFF RAMPS

39. Reference: Exhibit A2-5, page 58-59

Off-ramps

The Basic Idea

Off-ramp mechanisms allow MRPs to be reconsidered before their expiration if certain events occur during the plan. The qualifying events typically involve extreme ROEs, but may instead involve other considerations such as unusual inflation or reliability events. The rules for what happens following a qualifying off-ramp event vary. A formal proceeding to reconsider plan terms may be mandatory or at the commission's discretion. Reconsideration may be limited to a revision of plan terms but may also include the possibility of a new rate case.

Off-Ramp Pros and Cons

Similar to ESMs, off-ramps reduce operating risk by providing a "fail safe" in case of markedly undesirable outcomes. This can help parties support the MRP. The reduction in risk that off-ramps provide can make it easier to choose other plan provisions that involve more risk but have offsetting

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benefits, such as stronger performance incentives. For example, the plan can have a longer term and/or not have an ESM.

On the other hand, off ramps reduce opportunities to gain from improved performance and reduces the downside from an exceptionally bad performance. A utility could encourage a triggering event to escape an undesirable MRP. There is less need for an off-ramp if the plan features an ESM, a cost tracker for capex surges, revenue decoupling, Z factor provisions, or other measures that reduce risk.

Because off-ramps have a material downside, they should be designed carefully if used. For example, the ROE should deviate quite significantly from the commission-approved target before an off ramp is triggered. It is desirable for the ROE variance to be extreme on average over two or more years.

39.1 Please provide any evidence that the author has available with regard to how many utilities have resorted to using off-ramps while under MRPs or PBR, and how often this has occurred.

EFFICIENCY CARRY OVER MECHANISMS

40. Reference: Exhibit A2-5, page 60

Efficiency Carryover Mechanisms

ECMs were noted in Section 7.1 to limit the true up of a utility's revenue to its cost at the conclusion of a multiyear rate plan. Several approaches are possible to the design of ECMs. Two questions are salient. First, how are the efficiency gains (or losses) to be carried over determined? Second, how are carryovers effected following the plan?

Calculation of Efficiency Gains

A threshold issue in the calculation of efficiency carryovers is the areas of performance that are considered for carryover. For example, utility performance has a marketing as well as a cost containment dimension. ECMs could, in theory, permit utilities to keep some of the incremental margins from marketing efforts in areas, such as EVs and value-added services, where these efforts are deemed desirable. Where regulators have little interest in encouraging better marketing, however, only *cost* efficiencies may be considered for carryover.[41] Another threshold issue to consider is whether efficiency *losses* should be considered for carryover as well as efficiency *gains*.

Once the area of performance eligible for carryover has been resolved, a method for measuring performance must be chosen. One consideration is the years for which performance is appraised. Some ECMs measure performance during the prior plan. This can make sense to the extent that past performance is indicative of lasting performance gains. All plan years can be considered, or the focus can be on the last years of the plan, since cost in these years has a larger impact on revenue in the test year. An alternative approach is to measure the value implicit in the revenue requirement in the test year.

Another consideration is how to measure performance in the years of interest. The allowed revenue permitted by the MRP is one possible benchmark, and is described as such in some efficiency carryover mechanisms.[42] The revenue requirement in a forward test year can be appraised by calculating the hypothetical revenue that would result from escalating allowed revenue in the last year of the expiring plan using the ARM in that plan for one additional year.

40.1 Please confirm that efficiency carry over mechanism would not be required for BC Hydro because BC Hydro has a fixed net income requirement from the shareholder, and BC Hydro performance improvements are all captured for ratepayers' benefits.

SECTION 5 - THIS IS NOT THE CORRECT TIME FOR PBR

41. Exhibit A2-5, pages 11, 12-13

Table 1

Indicators of Energy Utility Financial Attrition in the United States (1927-2015)

Multiyear Averages	Average Annual Electricity Use			Average Annual Natural Gas Use			GDPPI Inflation[4]	Summary Attrition Indicators	
	Residential[1]	Commercial[1]	Average [A]	Residential[2]	Commercial[3]	Average [B]	[C]	Electric [C]-[A]	Natural Gas [C]-[B]
1927-1930	7.06%	6.67%	6.86%	NA	NA	NA	NA	NA	NA
1931-1940	5.45%	2.00%	3.73%	NA	NA	NA	-1.59%	-5.31%	NA
1941-1950	6.48%	5.08%	5.78%	NA	NA	NA	5.26%	-0.52%	NA
1951-1960	7.53%	6.29%	6.91%	NA	NA	NA	2.42%	-4.49%	NA
1961-1967	5.37%	10.48%	7.93%	NA	NA	NA	1.77%	-6.15%	NA
1968-1972	6.38%	6.43%	6.41%	1.78% [7]	3.97% [7]	2.88%	4.66%	-1.75%	1.78%
1973-1982[6]	1.34%	1.61%	1.47%	-2.15%	-1.10%	-1.63%	7.24%	5.77%	8.86%
1983-1986[6]	0.90%	2.26%	1.58%	-3.07%	-4.26%	-3.66%	3.13%	1.55%	6.79%
1987-1990	1.39%	2.29%	1.84%	-1.25%	1.33%	0.04%	3.33%	1.49%	3.29%
1991-2000	1.15%	1.68%	1.41%	-0.37%	0.30%	-0.04%	2.03%	0.62%	2.07%
2001-2007	0.73%	0.64%	0.68%	-2.12%	-1.55%	-1.83%	2.47%	1.79%	4.30%
2008-2015	-0.47%	-0.20%	-0.34%	-0.85%	0.47%	-0.19%	1.53%	1.87%	1.72%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, *Historical Natural Gas Annual 1930 Through 1999* (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014). U.S. Bureau of Mines, *Minerals Yearbook,* various issues prior to 1968.

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2015), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2015), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2015).

[4] Bureau of Economic Analysis, Table 1.4.4. "Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers", Revised April 28, 2017.

[5] Growth rates are for 1932-1940. Data are not available before 1931.

[6] Shaded years had unusually unfavorable business conditions.

[7] Consistent data are not available before 1967.

Table 2

U.S. Electric Utility Rate Cases: 1948–1977[6]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

3.4 COSR Under Modern Business Conditions

Table 1 shows that key business conditions that affect the frequency of rate cases have in more recent years been considerably less favorable on balance for the typical U.S. electric utility than they were in the decades before 1970 when COSR became a tradition. In the earlier period, brisk demand growth boosted utilization of capacity and the realization of scale economies. Growth in residential and commercial average use grew briskly and, under legacy rate designs, helped utilities self-finance cost growth. Inflation was generally slow. We call this period the "golden age" of COSR because this regulatory system worked well under these conditions.

Table 1 shows that growth in residential and commercial average use of U.S. electric utilities is typically negative today. Some utilities nonetheless need high levels of capex which don't automatically produce self-funding revenue growth. Reasons for high capex include a growing need to replace old facilities, improve system resiliency, and to increase access to, generate, and handle power from renewable resources.

We noted above that COSR provides weaker incentives for cost management when business conditions are chronically adverse. This idiosyncrasy of COSR raises concerns about the ability of electric utilities to cope with modern operating conditions. If utility performance incentives are weak, performance can deteriorate despite mounting competition. Utilities may, for example, choose such a time to accelerate replacement capex. Utilities may also be slow to address mounting environmental concerns.

The end result can be higher rates that further discourage use of grid services. This is a source of potential instability in the electric utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut costs.

41.1 Please confirm that under modern business conditions, utilities face many more 'public interest' issues to deal with, and must absorb such costs that are not associated with revenue increases and must pass them along to ratepayers.

41.1.1 Please acknowledge that BC Hydro and other ratepayers face significant costs for such issues.

41.2 Does the author have any evidence with respect to cost pressures from public interest issues versus cost pressures from reduced use of energy or distributed sourcing of alternative energy?

41.2.1 If so, please provide.

42. Exhibit A2-5, page 110 -111

10.3 Business Outlook

Our analysis in Section 3.2 suggests that a choice between COSR and PBR for BC Hydro depends in part on the Company's business outlook. Inflation is expected to be slow in the next few years. However, the Company's most recent load forecast suggests slow growth in its load. All residential load growth is expected to result from additional customer growth, as the Company forecasts no increase in residential use per customer. Under COSR, slow volume growth will prevent the Company's *revenue* growth from keeping pace with cost growth between rate cases. One bright spot in the demand outlook is the BC government's encouragement for low carbon electrification.

On the cost side, inflation is expected to be slow. Site C assets are expected to enter rate base around 2024.[137] Their depreciation will then slow the Company's cost growth. However, several generating stations were built before 1970, while many transmission assets were placed in service during the 1960s and 1970s. As a result, many grid assets are approaching replacement age. The decline in bond yields that has for many years moderated utility input price inflation may have ended.

42.1 Please confirm that, in part, the choice between COSR and PBR for BC Hydro, depends upon the ability for the regulatory regime to produce benefits for ratepayers that cannot be provided by the alternative regime while providing a fair return to the utility.

43. Exhibit A2-5, pages 13-14

Some electric utilities today need sustained high distribution capex to replace aging facilities, handle large DG power surpluses, and/or to improve system reliability and resiliency. Technological change has created opportunities for advanced metering infrastructure ("AMI") and other "smart grid" capex that improves utility performance (e.g., accommodation of intermittent renewables).[8] Few of these investments produce much automatic revenue growth. The frequent rate cases and new cost

trackers that grid modernization programs can give rise to weaken incentives for utilities to manage these programs cost effectively.

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a utility distribution company ("UDC"). Furthermore, slow demand growth and requirements by state regulators for VIEUs to buy rather than build new generation capacity that *is* needed can reduce VIEU generation capacity additions. On the other hand, VIEUs sometimes need to modernize old power plants. Projects to replace old generators can be quite expensive. VIEUs may also be permitted to buy or build new generation capacity that is needed to meet load growth or replace power plants that are rendered obsolete by high cost and/or emissions problems.

Regulatory resources that are currently devoted to electric rate cases have many alternative uses in this era of rapid change. For example, many regulators lack experience with grid modernization proposals. They want to make sure that capex planning takes proper account of non-wire alternatives ("NWAs") to capex such as DSM and behind-the-meter DGS. Regulators are also concerned about how to regulate new products and services that a smarter grid makes possible. DSM programs and new services can be offered by third parties as well as utilities. Other issues raised by modern operating conditions include rate designs, compensation to DGS customers for their power surpluses, "smart grid" investments, and the cost-effective glide path to increased renewables reliance.

Modern conditions also provide new reasons to afford utilities more marketing flexibility. There is growing interest in green power packages and in miscellaneous new services that may be enabled by smart grid technologies. Greater reliance on intermittent renewable resources for power supplies has increased the need for many utilities to use peak load management. Customers should be encouraged to shift their loads from hours when renewable resources are scarce to hours when they are plentiful. Rate designs can be changed to encourage this shift.

43.1 Please explain what a VIEU is.

43.2 Pleaser provide any quantitative evidence that the author may have with regard to which utility responses to these issues result in optimal ratepayer outcomes.

OPPORTUNITY FOR COST OF SERVICE TO WORK AFTER LIMITATIONS ON BCUC JURISDICTION

44. Exhibit A2-5 page 94

Economic benchmarking has not been used extensively to support the AER's IRM decisions for power transmitters but has played a larger role in setting revenue requirements for power distributors.[115] In its revenue requirement decisions, the AER used economic benchmarking to help determine the efficiency of distributors' OM&A expenses in the base year, the historical year upon which the distributors' revenue requirements were based. OM&A revenue requirements were then escalated for the years of the MRP using a "base, step, trend" methodology.

44.1 Please confirm that setting a baseline for revenue requirements can be accomplished under COSR as well as PBR.

GIVEN THE AUTONOMY TO MANAGE ITS EXPENDITURES FOLLOWING THE COMPREHENSIVE REVIEW

45. Exhibit A2-5, page 96

The Régie initiated proceedings to develop PBR plans for Hydro-Québec's transmission and distributor services in 2014. In these proceedings, the company proposed limited steps away from COSR. In 2018 and 2019, the Régie approved new regulatory systems for the Company's transmission and distributor services.

The new regulatory system for transmission services features different ratemaking treatments for OM&A and capital costs over the four-year term of the plan. Funding for OM&A expenses will grow at the rate of inflation minus an X factor plus a growth term. The X factor was established through a process of *jugement* that amounted to a review of studies and precedents from other jurisdictions. However, the Régie asked that productivity and statistical benchmarking studies be filed by the company and intervenors during the term of the plan. Capital revenue escalation is provided through annual rate filings, though a "parametric formula" was chosen to help appraise the reasonableness of Hydro-Québec's transmission capital cost. An ESM will asymmetrically share some overearnings with customers. Hydro-Québec's ability to keep its share is tied to its service quality performance.

45.1 Please confirm that parametric formula for rate-setting do not need to result in over or under earning for the utility, and all such over- or under-earning can be returned to ratepayers if the Commission so determines.