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November 16, 2020

Sent via eFile

BCUC REVIEW OF BC HYDRO PBR REPORT
EXHIBIT A2-13

Mr. Fred James
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Re: British Columbia Utilities Commission – Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report – Project No. 1599045 – BCUC Staff Consultant Response to Zone ll RPG Information Request No. 1

Dear Mr. James:

British Columbia Utilities Commission staff submit the following for the record in this proceeding:

Pacific Economics Group Research LLC
Response to Zone ll RPG Information Request No. 1
Dated November 16, 2020

Sincerely,

Original signed by:

Marija Tresoglavic
Acting Commission Secretary

/cmv
Enclosure

1.0 Topic: Publicly-Held Utilities
Reference: Exhibit A2-7 (PEG Presentation) slide 66.

On slide 66 of its PowerPoint, Pacific Economics Group Research LLC ("PEG") states that:

> *Many publicly-held utilities have operated under MRPs* [multi-year rate plans] *(e.g., Canada and Australia).*

1.1 Have any of these publicly-held utilities been fully-integrated utilities with similar characteristics to BC Hydro (size, revenues, customers base, etc.)?

PEG Response:

Yes, there are a few. However, publicly-held utilities with fully-integrated operations are fairly rare because (1) many countries around the world have restructured their power markets to encourage competition e.g. (EU Directive 2003/54/EC) and 2) many of the remaining utilities are investor-owned. In many other countries (e.g., Australia, Mexico, and France) such restructurings produced transmission and distribution utilities but the market for generation was decontrolled. In a few countries, publicly-held utilities that were once vertically integrated have been separated into publicly-held generation, transmission, and distribution utilities. In Ontario, multiyear rate plans ("MRPs") are used to regulate Ontario Power Generation, the transmission and distribution services of Hydro One Networks, and numerous municipal power distributors. In the United States, most publicly-held generation and transmission utilities (e.g., the Bonneville Power Administration) are not subject to traditional COSR by an independent regulatory agency.

1.1.1 If yes, please provide a list of these utilities, including where they are located and their service area.

PEG Response:

Hydro-Quebec is the closest peer to BC Hydro in Canada. It has separate MRPs for its generation, transmission, and distribution operations. The following data are pertinent for comparisons of these companies.

> **BC Hydro** (as of March 31, 2020) serves about 2,000,000 customers, Revenues $6,269,000,000, Total generating capacity is 12,109.5 MW (11,931.7 is Hydroelectric) Source: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/BCHydro-Quick-Facts-20200831.pdf
>
> **Hydro-Québec** (as of 2019) has 4,356,542 customer accounts, Revenues $14,021,000,000(2019), generating capacity of 37,243 MW. Source: https://www.hydroquebec.com/data/documents-donnees/pdf/cue-card.pdf

1.1.2 In each case, please identify whether the implementation of PBR was directed by the regulator, stakeholders or the government body, and the primary rationale for doing so.

PEG Response:

In Québec, PBR for transmission and distribution services of Hydro-Québec was mandated by provincial law, and the Régie de l'énergie implemented MRPs plans for these services. With impetus from Hydro-Quebec, the Assemblée Nationale shortly thereafter 1) removed the

authority of the Régie to approve multiyear rate plans for Hydro-Québec distribution, 2) approved an alternative MRP for the company's distribution services, and 3) removed the legal mandate for the Régie to use PBR in transmission regulation. PBR for generation was mandated by provincial law.

In Ontario, PBR for power distributors was chosen by the regulator. One goal was to reduce regulatory costs for its staff as it regulated numerous power distributors.[1] The Ontario Energy Board subsequently chose PBR for Ontario Power Generation and for Hydro One Networks' transmission services.

1.1.3 Did implementation of PBR result in lower rates for ratepayers and/or increased returns to the shareholder, in any of these cases? Please provide details.

PEG Response:

PEG has not studied this matter but notes that PBR is just beginning for Hydro-Québec T&D and the transmission services of Hydro One and has not long been in effect for Ontario Power Generation. The multifactor productivity ("MFP") growth of Ontario power distributors has been a little slower than in the States but no attempt has been made to ascertain whether this was due to special business conditions.

[1] When PBR was first adopted by the Ontario Energy Board, the Board had more than 300 power distributors to regulate. Due to mergers and consolidations, this number has since been reduced to around 60.

2.0 Topic: Crown Corporations
Reference: Exhibit A2-7 (PEG Presentation) slide 69; Exhibit B-1, F2020-F2021 BC Hydro Revenue Requirements Application (RRA), page 11-5; Transcript Volume 6 (January 21, 2020), RRA, pages 735, 764.

In its RRA (page 11-5), BC Hydro states that it:

> *…does not have a mandate to maximize profits, which can dull the additional "carrot" incentive that PBR attempts to provide. This does not mean that BC Hydro will not seek out and find additional efficiencies in future years. Rather, it means that the incentive to find these efficiencies would come, as it does today, from the obligation and commitment on the part of management to deliver on its mandate within the budget set by the BCUC, and not from the opportunity to increase earnings.*

In the RRA proceedings, on January 21, 2020, Ms. Ryan (BC Hydro Chief Human Resources Officer) testified that:

> *So the holdback pay, which is what we call incentive pay at Hydro, for our directors and executives is based on the service plan, and the service plan has the measure around keeping bills affordable.*

Further, Mr. Riley (BC Hydro President and CEO) stated that:

> *Executives are eligible for up to 20 percent (holdback).*

On slide 6 of its PowerPoint, PEG states that:

> *Management can be stimulated to improve efficiency with incentivized compensation.*

2.1 Since BC Hydro does not have a mandate to maximize profits, please identify the recommended incentives that could be used in a PBR model for regulating BC Hydro?

PEG Response:

Section 60 1) (b) of the BC Utilities Commission Act states that the commission must have due regard to the setting of a rate that... encourages public utilities to increase efficiency, reduce costs, and enhance performance.

While BC Hydro may not have an express mandate to maximize profits, a regulatory system with compensation that rewards good performance and penalizes bad performance can still provide material benefits.

- The government, as owner of BC Hydro, would presumably like to keep the Company's rates low and slow-growing. Efficient operation is a good way to accomplish this, since the alternative of subsidizing the Company requires the government to borrow more money, spend less on other things, and/or to raise taxes. Thus, the government would like BC Hydro to efficiently provide quality services.
- The BCUC is a government agency that has been assigned an important role in the oversight of the Company's operating efficiency. One way to exercise this responsibility is to provide BC Hydro with revenue that is compensatory only for efficient operations. This question cites a statement by the Company that management has an obligation and commitment to deliver on the Company's mandate "within the budget set by the BCUC."

- Even if the government requests a stream of earnings from BC Hydro that isn't closely tied to its rate base, it is easier to provide this stream and pay lenders, employees, and service providers to the extent that performance is good. Earnings that exceed the stream that the government requests have many uses. For example, surplus earnings can be used to fund future capex surges that the BCUC is reluctant to fully fund. Surplus earnings can also fund popular programs. For example, they can be used to bolster subsidies for low-income customers.
- The weaker profit motives of crown corporations can sometimes be advantageous. An example might be where only a small incentive for the utility to reduce externalities is politically feasible. The publicly owned utility might take this more to heart than the private one.
- The government can adjust internal incentives to match the performance metrics and external incentives that the BCUC crafts.

The potential usefulness of incentives in the Company's regulatory system is supported by the fact that there already are some incentive provisions. For example, BC Hydro is permitted to amortize its DSM expenses.

2.2 Describe the types of incentives used for public utilities that are subject to PBR.

PEG Response:

PEG has never studied this matter, but is not aware of special incentives for public utilities. For example, MRPs in Alberta and Ontario have been approved for both publicly- and privately-owned utilities in the same proceeding.

2.3 Given that BC Hydro executives already have a significant 20 percent holdback, how would you propose to motivate BC Hydro management to improve efficiency?

PEG Response:

The 20 percent hold back is material, but may warrant redesign.

3.0 Topic: Sharing Benefits under PBR
Reference: Exhibit B-1, RRA, pages 11-5, 11-21 – 11-22.

In Section 11.1.4 of the RRA which discusses Creating and Sharing Benefits Under PBR, BC Hydro states:

The goal of adopting PBR is to incent a process through which savings – that were not previously identified under cost of service regulation – are discovered. The strength of the incentives provided depends on the extent to which the amount of revenue recovered through rates is independent from BC Hydro's costs, rather than dependent on them.

In Section 11.4 of the RRA, BC Hydro discusses various mechanisms to allocate the benefits achieved under PBR between BC Hydro and its customers. This section addresses those mechanisms as well as others that may be included in a PBR plan as follows:

- PBR Term and Efficiency Carry-Over Mechanisms
- Stretch Factors and Earning Sharing Mechanisms
- Off-Ramps and

ReOpeners

Further BC Hydro states that:

> *It is important to recognize that mechanisms to allocate benefits achieved under PBR may affect the strength of the incentives provided to discover those benefits in the first place.*
>
> *The strength of the incentives provided depends on the extent to which the amount of revenue recovered through rates is de-linked from a utility's costs, over the term of the PBR plan. Incentives are weak when the utility has the ability to pass along cost changes in the form of rate changes and are strengthened as this ability becomes more limited.*

3.1 What are the pros and cons of implementing stretch factors and earning sharing mechanisms under PBR, especially for a public utility like BC Hydro?

PEG Response:

Advantages of the stretch factor approach include the following.

- Customers can share expected benefits of the stronger performance incentives that PBR provides whether or not they are achieved.
- The performance incentives of BC Hydro would not be diminished, as they would be by an earnings sharing mechanism ("ESM") .
- Stretch factors linked to benchmarking studies strengthen performance incentives and act as a crude efficiency carryover mechanism that rewards the achievement of lasting performance gains and discourages strategic cost deferrals.
- Earnings sharing invites gaming, involves some regulatory cost, and complicates marketing flexibility.

Here are some disadvantages of stretch factors.

- It is difficult to ascertain what stretch factor is appropriate.
- They do not, like ESMs, cushion earnings impacts of exogenous events.

3.2 Would you recommend stretch factors or earning sharing for BC Hydro or a hybrid of both? Please provide your reasons.

PEG Response:

PEG recommends the use of stretch factors but withholds judgment at this time on the propriety of an ESM.

3.3 Confirm or explain otherwise, that the goal of adopting PBR is to incent a process through which savings – that were not previously identified under cost of service regulation – are discovered. Please provide your reasoning.

PEG Response:

PBR can 1) strengthen utility performance incentives and 2) increase the efficiency of regulation. Both of these goals have been cited by regulators that approve PBR plans.

With respect to performance incentives, new and better ways to improve performance may be discovered under PBR since there is more incentive to consider better strategies. However, PBR also encourages utilities to adopt strategies that were known to managers under COSR but for various reasons not pursued. For example, electric utilities like BC Hydro have surely known for years of various strategies for promoting

EV loads that they have not pursued.

3.4 Confirm or explain otherwise that the strength of the incentives provided depends on the extent to which the amount of revenue recovered through rates is independent from BC Hydro's costs, rather than dependent on them. Please provide your reasoning.

PEG Response:

This statement is confirmed as it pertains to cost containment incentives.

4.0 Topic: Does MRP Make Sense for BC Hydro?
Reference: Exhibit A2-7 (PEG Presentation) slide 70; Workshop Transcript (September 8, 2020) – Volume 2; Exhibit B-1, RRA, page 11-5; Exhibit B-1, Appendix FF, Executive Summary.

On slide 70 of PEG's PowerPoint, in support of MRP, states:

- *Continued COSR [cost of service regulation] for BC Hydro means biennial rate cases entailing WEAK performance incentives and high regulatory cost*
- *BC Hydro rate cases long and complex*

From the Executive Summary of Appendix FF of the RRA,

Finally, if the PBR regime is not developed in accordance with sound economic principles, or there is not a strong commitment to the fundamental tenets of PBR on the part of either the regulator or the government, the significant resources required to design and implement a PBR regime would be difficult to justify. The adoption of PBR may simply fail the cost-benefit test under these conditions.

From the RRA, on page 11-5 BC Hydro states:

First, cost of service regulation should be given the opportunity to work. BC Hydro believes that unconstrained cost of service proceedings would address the issues raised the BCUC in its Decision on our Previous Application.

Second, given that BC Hydro is only now returning to enhanced regulation, it is likely to be more challenging to secure stakeholder support for the principles of PBR. BC Hydro believes that the most effective way to build the familiarity and comfort required to secure stakeholder support for the principles of PBR is through successive cost of service proceedings.

Third, cost of service regulation is more intuitive and accessible, while PBR is more esoteric and relieve heavily on specialized expertise.

4.1 Please identify the performance incentives that are considered "WEAK", as stated in PEG's slide 70.

PEG Response:

PEG's preliminary diagnosis is that incentives are weak for BC Hydro to contain its cost, manage peak loads, and to boost desirable loads.

4.2 Describe what costs are being referenced when PEG refers to "high regulatory costs" in slide 70.

PEG Response:

The principal regulatory cost of BC Hydro's regulation are the rate cases.

4.3 Confirm, or explain otherwise, that PBR also has associated regulatory costs. If so, please describe these?

PEG Response:

PBR does involve costs. These include the costs of designing PBR provisions and the costs of Z factor oversight. Some PIMs (e.g., shared DSM savings PIMs) have material operating costs.

4.4 Provide any evidence/studies that shows that the costs of COSR is less costly that PBR, especially for a public utility like BC Hydro?

PEG Response:

PEG is unaware of studies of this matter but believes that the cost of a traditional rate case greatly exceeds the incremental cost of PBR mechanism design which may occur in the same proceeding even if these mechanisms include a multiyear rate plan. A PBR mechanism typically must be litigated once for a multiyear period, with modest costs to address annual updates, while rate cases may be filed annually.

4.5 Confirm, or explain otherwise, whether BC Hydro returning to enhanced regulation and having regular rate cases could result in more stakeholder and regulatory familiarity and therefore reduce the complexity and length of rate case proceedings going forward?

PEG Response:

PEG agrees that BC Hydro's regulatory community will likely become more proficient at processing rate cases as they continue. However, first generation PBR for BC Hydro may take the form of multiple forward test years, at least for capital cost. Note also that the regulatory community would also become more efficient at processing MRPs should these become routine.

5.0 Topic: Does MRP Make Sense for BC Hydro for Crown Corporations?
Reference: Exhibit A2-7 (PEG Presentation) slide 72; Workshop Transcript (September 8, 2020) – Volume 2, page 249.

On slide 72 of PEG's PowerPoint entitled "Does MRP Make Sense for BC Hydro" it states:

No

Crown corporation arguments

From page 249 of the Transcript, Mr. Lowry says:

So let me hasten to talk about the downside of this. I think that these Crown corporation arguments do hold some water because, as I've said, there's [sic.] isn't an impressive track record of publicly held utilities doing swimmingly well under PBR.

5.1 Please identify the Crown corporations that are deemed to "hold some water", especially as it relates to implementing PBR for BC Hydro.

PEG Response:

General concerns about PBR for crown corporations are discussed on pp. 65-69 of PEG's report.

5.2 Identify and provide further information about the poor track record of publicly held utilities that are regulated under PBR, including names of the utilities and the type of PBR used in each case.

PEG Response:

Some empirical evidence on this matter was discussed on pp. 68-69 of PEG's February report. We noted there that there is no clear evidence that publicly-held utilities tend to be inferior cost performers. However, some studies have found that they respond less well to MRPs.

The poor cost performances of some publicly-held power distributors in Australia (e.g., Ausgrid) operating under MRPs in Australia are discussed in Section 9.5 PEG's February report. Publicly-held power distributors in New South Wales were subsequently partially privatized. In the Australian Energy Regulator's most recent economic benchmarking report, the four publicly-held distributors had 2nd or 3rd quartile OM&A cost performances. The partially privatized power distributors tended to be the worst performers.

In Ontario, PEG showed on pp. 67-68 of the workshop presentation that benchmarking studies have found some of the larger publicly-owned power distributors (e.g., Toronto Hydro) to be poor cost performers. However, many of the best performers in these studies are also publicly-owned. Moreover, these studies do not control well for system age and the need for replacement capex. A confidential study of power distributor cost performance in Alberta did not find the municipally-owned power distributors there to be inferior on balance. The effect of public ownership is unclear.

5.3 Explain the reasons for why PBR failed for these publicly held utilities.

PEG Response:

It is not clear that public ownership was the reason for the poor performance of these utilities. PEG has not, in any event, considered reasons for their peer performance.

5.4 Given the above, provide recommendations of how to avoid the same negative outcomes in implementing PBR for BC Hydro.

PEG Response:

Please see the response to part 5.3 of this question. PEG has not fully considered how to tailor incentives for publicly-held utilities but notes that appropriate internal incentives appears to be one key.

6.0 Topic: Baby Steps
Reference: Exhibit A2-7 (PEG Presentation) slide 74; Transcript (September 8, 2020) – Volume 2, page 157, 254.

On slide 74 of PEG's PowerPoint, PEG lists "Shared saving" PIM [Performance Incentive Mechanisms] for conservation, PIMs for local "non-wire alternatives" and systemwide peak load management

On slide 75, opportunities for pilot programs are included under Multi-year Rate

Plan. From page 157 of the Transcript:

MR. ANDREWS: Why would innovative pilot programs not be feasible under a cost of service regulatory model?

MR. LOWRY: There would be but there would be less need for them. I mean, a pilot program makes more sense in the context of a multiyear rate plane *where you're kind of worried about what somebody's going to say about this four years down the road, particularly if it goes badly. And so you want to take a risk but you don't want to be unduly exposed to the risks. And this runs contrary to the kind of happy talk about PBR that you sometimes hear that it's kind of created all these -- inspired all this innovation. But in reality sometimes even a sophisticated jurisdiction like the Brits have recognized that sometimes innovation needs a push, even in the context of a lengthy multiyear rate plan.*

From page 254 of the Transcript:

…sometimes there are these very complicated shared savings PIMs for conservation that a least have the benefit of doing a serious job of looking at the net benefits of conservation, and then according the company a share. That's just an idea. I don't know if the higher regulatory cost is worth it, but it's possible that the amortization of the DSM expenses today is a little bit of a crude tool. It's possible that it's pushing the company in the direction of excessive conservation.

6.1 Provide an example of how a shared saving PIM can be structured for demand- side management (DSM) programs at BC Hydro.

PEG Response:

Shared savings PIMs grant the utility a share of the estimated net benefits that result from a DSM initiative. Ex post and ex ante methods (or a mix of the two) may be used in net benefit calculations. Net benefits are the difference between benefits and costs, so this approach encourages utilities to choose more cost-effective programs and to manage them more efficiently. However, the estimation of net benefits can be a complex and controversial issue in regulatory proceedings.

One example of a shared savings PIM for DSM is the Risk-Reward Incentive Mechanism which was approved by the California regulator in 2007. Each utility had targets for three metrics (if applicable): electricity savings, gas savings and peak demand reductions. Under the original incentive design, utilities could receive a reward of up to 12 percent of the dollar value of evaluated net benefits of eligible DSM programs if they performed strongly on all three metrics. Conversely, they would be penalized if they fell below 65 percent of the target for any one of the three metrics. Critically, utility financial outcomes would be based on evaluated (*ex post*), not predicted (*ex ante*), net benefits. That meant that utility outcomes were not known until program evaluations were completed. This choice extended the process and added complexity. However, the California regulator felt it important to reward or penalize how programs actually

performed in order to properly align utility incentives and protect ratepayers from adverse outcomes.[2]

The Risk-Reward Incentive Mechanism was implemented for the first time at the end of the 2006–2008 utility program cycle. Disputes over net benefits soon developed, as the California regulator's evaluation consultants estimated program results that substantially differed from the utilities' estimates and implied very different financial outcomes, in part due to the sharp earnings cutoffs in the mechanism's reward structure.[3] Disputes stretched over several years and proved intractable enough that the California regulator modified the mechanism. It based net benefit calculations on parameters (for example, net-to-gross ratios) estimated before programs were implemented, as well as on actual program delivery outcomes.[4] It also lowered the incentive to a flat 7 percent of net benefits and eliminated the possibility of penalties. Savings used to calculate rewards were in between the utilities' and the California regulator's estimates. For programs from 2010 to 2012, the California regulator simplified these PIMs, establishing rewards conditioned primarily on utility spending (management fees) rather than evaluated program performance.

Additional examples of shared savings PIMs for DSM programs may be found in the case studies of many states including Arkansas, Minnesota, and Texas that are presented in the 2015 ACEEE report, "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency."[5] Examples of shared savings PIMs for demand response programs can be found in the case studies of Rhode Island and Texas that are presented in the 2020 ACEEE report, "Performance Incentive Mechanisms for Strategic Demand Reduction."[6]

6.2 Expand on your comment "I don't know if the high regulatory cost is worth it" in the context of shared savings PIMs for conservation. What high regulatory costs are expected in your experience?

PEG Response:

Estimation of the net benefits of DSM can be complex and controversial, as evidenced in the example presented in response to Zone II Question 6.1. The California regulator subsequently abandoned the use of shared savings PIMs for DSM.

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[2] See California Public Utilities Commission, 2007, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf.

[3] The reward/penalty function consisted of four tiers: a penalty if evaluated energy/capacity savings were less than 65 percent of a target; a dead band of no reward or penalty if savings were between 65 percent and 85 percent of a target; a 9 percent shared savings reward if savings were between 85 percent and 100 percent of a target; and a 12 percent shared savings reward if savings exceeded the target. Each transition between tiers created a sharp reward discontinuity. A small change in the evaluated savings could produce a big change in the reward. Further exacerbating these issues, a utility was paid based on the worst of the three outcomes. For example, if a utility fell below 65 percent of any of the three targets, it earned a penalty even if it performed strongly on the other two. In one case, a utility's estimated savings implied a $180 million reward; the evaluation consultants' estimates implied a $75 million penalty. See Chandrashekeran, S., Zuckerman, J., and Deason, J., 2015. "Raising the stakes for energy efficiency: A qualitative case study of California's risk/reward incentive mechanism," *Utilities Policy*, October, 79–90.

[4] This California Public Utilities Commission decision was controversial, with one commissioner objecting that the revised mechanism largely eliminated the actual performance incentives and ratepayer protections provided by the prior, *ex post*-based mechanism. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128882.pdf.

[5] Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M., and York, D., (2015), "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," American Council for an Energy-Efficient Economy Report U1504, May. The authors refer to DSM shared savings PIMs as "shared net benefits utility performance mechanisms."

[6] Gold, R., Myers, A., O'Boyle, M., Relf, G., (2020), "Performance Incentive Mechanisms for Strategic Demand Reduction," American Council for an Energy-Efficient Economy Report U2003, February.

6.3 Explain your comment that the amortization of DSM expenses is "a little bit of a crude tool" possibly pushing BC Hydro in the direction of excessive conservation. Specifically, why is it crude and do you think it is preferred over a traditional COS approach?

PEG Response:

Amortization of DSM expenses provides a positive reward for DSM but does not guard against excessively large or ineffective DSM programs. This problem can be mitigated by conscientious oversight of DSM programs. Dr. Lowry believes that, with conscientious oversight, amortization of DSM expenses is preferable to having no positive incentive. However, the amortization approach is not necessarily efficient or optimal.

6.4 Provide an example of how a PIM can be structured for non-wire alternative and systemwide peak load management at BC Hydro.

PEG Response:

This is an area of considerable experimentation in contemporary PBR. In North America, non-wires alternatives ("NWA") PIMs are probably most developed in the state of New York, where they are used by most power distributors. Consolidated Edison ("Con Ed") has two such PIMs: one for the Brooklyn/Queens Demand Management ("BQDM") program and one for all NWA programs implemented subsequent to the approval of the BQDM. We discuss each PIM in turn.

The BQDM program was one of the first instances where incentives targeted DSM and other DERs in a specific part of a utility's service territory.[7] Approved by the New York Public Service Commission in December 2014, this program relies on DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs. Successful implementation of the BQDM program defers or avoids traditional infrastructure investments, which would otherwise have been added to Con Ed's rate base. This creates a potential disincentive for the utility to implement the program. To avoid this, the commission adopted the following reward provisions:[8]

1. BQDM program costs were initially recovered via a surcharge. Following Con Ed's 2016 rate case, however, recovery via the surcharge ceased and remaining costs will be recovered through base rates but variances between amounts included in base rates and actuals will be deferred for review in Con Ed's next rate filing. All BQDM project investments will be amortized over a 10-year period.
2. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred BQDM program costs. The commission felt that this measure should put BQDM projects on an equal footing with traditional capital projects from the utility's perspective.
3. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on BQDM program costs, conditional on Con Ed's performance on metrics tied to three outcomes.
    a. **Peak demand reductions from customer-side DER**. The MW reduction in peak-day load in the targeted area that is due to customer-side DER is calculated. Reductions equal to or

[7] NY Public Service Commission (2014). Order Establishing Brooklyn/Queens Demand Management Program, New York Public Service Commission, Case 14-E-0302.

[8] Con Ed had also proposed a third shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50% share of the annual net savings realized by customers. The commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.

less than 20 MW does not earn a reward. Beginning at a peak demand reduction of 21 MWs, the utility earns 1 basis point for each MW (up to a maximum of 45 basis points).

b. **Diversity of customer-side DER providers.** A diversity index is calculated, based on the portfolios of customer-side DERs selected to achieve the needed peak load reductions in 2016, 2017, and 2018. Based on this index, the company is eligible to earn up to 25 additional basis points.

c. **Reduction in $/MW costs.** The percentage reduction in the $/MW unit cost that the utility can achieve (relative to the avoided traditional infrastructure investments) is calculated. For every full 1% reduction, the utility earns 1 basis point (up to a maximum of 30 basis points).

Con Ed's subsequent NWA projects have had a different incentive mechanism. While the cost of an NWA project continues to be amortized over a 10-year period at the company's allowed rate of return with the costs tracked for recovery through a rider between rate cases, the ROE adders are not available. Instead, a PIM provides the company a share of the estimated net benefits of each NWA project that the company pursues. This reward is amortized over the effective life of the NWA project (e.g., the period of time in which an NWA project will result in the deferral or avoidance of the capex project) including carrying charges at Con Ed's approved weighted average cost of capital.

The method by which the financial reward is derived varies slightly based on the size of the project. If the project defers an infrastructure investment that would be rated at 69 kV or higher, the project is deemed to be large. These projects tend to defer investments at the area station level or higher, require longer lead times for execution (e.g., 3 years or longer), and defer more costs from traditional infrastructure investments. Projects that would defer infrastructure investments at less than 69 kV are deemed to be small, deferring fewer costs on a project by project basis, requiring less lead time, and have a simplified process for reward calculations.

The net benefits calculation requires the filing of a benefit cost analysis prior to project commencement. This includes a comparison of the present value of the costs and benefits of undertaking a traditional utility investment and the costs and benefits of DER alternatives that would be necessary to defer or avoid a traditional solution. The difference between these calculations is the net benefits of the NWA projects compared to the traditional investment. The composition of the benefit cost analysis and the calculation of net benefits varies between small and large projects, with small projects including fewer benefits for NWA projects. For large projects, the benefit cost analysis includes numerous avoided costs at the wholesale and distribution levels; reliability benefits; avoided impacts from emissions, land use, and water use; DER costs; program administration costs; lost utility revenues; and shareholder rewards. Small projects rely on a simplified benefit cost analysis which excludes non-energy benefits other than carbon (e.g., economic growth, health impacts of non-wires alternative projects) and any benefits associated with the deferral of the traditional project.

These net benefit calculations conducted prior to the deployment of the NWA are often referred to as "Initial Net Benefits", and Con Ed receives 30% of initial net benefits as a reward for undertaking these projects. For large projects Con Ed collects the reward once 70% of the NWA deployment is operational and has been verified. For small projects the Initial Net Benefits are divided by the MW of avoided load required, which Con Ed collects as each MW of the NWA becomes operational and has been verified. If a small project involves less than 1 MW of avoided load, Con Ed must wait for the entire project to become operational and be verified. Recoveries of rewards will be halted without the need for refunds if the NWA is determined to be operationally or technically infeasible.

After the NWA is deployed, the Initial Net Benefits calculation is adjusted to reflect the actual non-wires alternative cost. This adjustment can be an increase in the share of Initial Net Benefits if the company is able to deliver the targeted savings at a lower cost than forecast or a decrease if costs were higher than expected. In some instances, a second adjustment to reflect changes in the MW of avoided load that is

needed to defer the traditional investment may be needed. If the MW of avoided load required is reduced, the Initial Net Benefits and actual costs would be calculated on a per MW basis and reduced accordingly. If the MW of avoided load required is increased, the additional NWA procurement will not be eligible for any rewards beyond the 10-year amortization period at Con Ed's approved rate of return. Additional NWA procurement would also not be factored into the comparison of actual and forecast costs.

In no event will Con Ed's share of Initial Net Benefits be lower than the floor of $0 or higher than the cap of 50% of Initial Net Benefits. This reward is amortized over a 10-year period, accruing interest at the Con Ed's approved weighted average cost of capital.

6.5 Provide an example of how pilot programs are included under MRP and how BC Hydro would be incented to implement pilot programs.

PEG Response:

PEG discussed California, British, and Australian pilot program frameworks on pages 31-32 of their February report. Utilities in all three jurisdictions have their revenue requirements escalated according to the terms of MRPs.

6.6 Confirm, or explain otherwise, that utilities, on average, are less innovative under a cost of service regulation regime. Provide any examples to support your reasoning.

PEG Response:

Marketing is one example. The rate and service offerings of utilities are generally much more limited than those that are typical of competitive markets. COSR's high regulatory cost and weak marketing incentives under current business conditions help to explain this.

6.7 Explain your comment that "sometimes innovation needs a push". How could this be achieved under MRP? Provide any examples to support your reason.

PEG Response:

Electrification of transportation is a good example. Under BC Hydro's current regulatory system, frequent rate cases, effective revenue decoupling, and limited marketing flexibility have discouraged aggressive EOT marketing. EOT can be encouraged by various means that include exclusion of EOT revenue from tracking, an EOT PIM, marketing flexibility, and a pilot program.

7.0 Topic: Does PBR Make Sense in a Recession
Reference: Exhibit A2-7 (PEG Presentation) slide 78; Workshop Transcript (September 8, 2020) – Volume 2, page 263.

On slide 78 of PEG's PowerPoint, PEG states that a

- *Recession will hopefully be winding down by the time that a PBR regime would be implemented.*
- *Revenue decoupling and tracking of bulk power sales margins would protect BC Hydro from unexpectedly we[a]k sales volumes*
- *Issues of whether to raise rates at all during recession is legit but arises under COSR as well as PBR*

Further on page 263 of the transcript, Mr. Lowry states:

I was thinking more in the case about the MRP, that if you decided to do – the Commission decided we're going to do an MRP and we're going to do it next year, well than maybe you would use some work of a simple index to escalate allowed revenue for 2022. Then you're working on something that would kick in starting in the early part of 2023, right? And hopefully by then the inflation (audio drops) would be – you know, kind of the whole North American economy, so there would be less of an issue about this.

…..

Well, a stair step or hybrid could well be somewhat less risky for the company than an index. I mean, the whole use of an actual comprehensive indexing for a vertically integrated utility is it's not widely done. I had mentioned the Hawaiian Commission is wanting to go in that direction. But, you know, this isn't generally done – hasn't been done since back in the 1990s, really. So I wasn't really advocating that for BC Hydro, although it is feasible.

7.1 Please explain the timing of the implementation of a PBR regime as it relates to whether the BC economy is in a recession.

PEG Response:

It is Dr. Lowry's understanding that a PBR regime developed in 2021 would likely not be implemented until April 2022. The recession will hopefully be finished or drawing to a close by that date.

The question of how to deal with recessions is not unique to PBR. BC's regulatory community spent much of 2020 --- a recession year --- in a rate case intended to consider how much the Company's rates should be raised in the 2020 and 2021 fiscal years. Another rate case will soon begin to address rates in fiscal year 2022.

7.2 Confirm or explain otherwise if it would be prudent for BC Hydro to delay implementing PBR if the BC economy is in the midst of a recession.

PEG Response:

The question of whether to implement scheduled rate increases arises under COSR and MRPs alike. In each case, rate increases can be delayed. The propriety of some PBR provisions (e.g., a possible electric vehicle PIM) have little to do with recessions.

7.3 Explain what contingencies or mechanisms for escalating allowed revenue can be put in place should a recession be in place under a PBR regime.

PEG Response:

In the unlikely event that BC was still experiencing severe recessionary conditions in fiscal year 2022, the indicated rate increase could in principle be postponed until 2023. PBR might, in any event, not involve a multiyear rate plan.

8.0 Topic: Shareholder Benefits
Reference: Workshop Transcript (September 8, 2020) – Volume 2, page 153.

From page 153 of the Transcript:

MR. QUAIL: But to what extent is the fact that the return on equity is set by order in council, the government, make that largely irrelevant? There's no impact on what is retained for the benefit of the shareholder at least, regardless of decoupling.

MR. LOWRY: Well, I mean, I guess I'm not familiar with how literally that is true. I mean, I didn't think that the company's cost -- you know, I didn't think there was a true-up mechanism that by dint of some law or order in council insured that the company's ROE was always the same. I didn't think that that existed in British Columbia.

MR. QUAIL: Well, in practice, the government's cut is quantified precisely by order in council and at least the practice, I think it's fair to say, has been that Hydro hasn't sought to somehow stash away any spare I mean their situation has been the opposite and their burden, as people have said, with a large surplus of electricity. I don't see how a lot of these considerations really engage the real life circumstances of this utility as it's right now.

MR. LOWRY: Okay. Well, one thing that I will really admit, that I don't know everything about BC Hydro's regulation because as I say I wasn't aware that at the end of the day the company always earns only it's target rate of return.

MR. QUAIL: Yeah, there's a stipulated amount by order in council which is set by the government and is immutable.

8.1 Since the return on equity is a stipulated amount by order in council that is always the same, what impact would this have on any PBR regime that is implemented for BC Hydro? How would this affect BC Hydro's incentives and benefits to implement PBR? Would this result in lower rates for ratepayers? Please provide your reasoning.

PEG Response:

Dr. Lowry's response to this line of questioning during the workshop was influenced by a misunderstanding. Dr. Lowry understood the questioner to be referring to the *rate* of return on equity. The Company's return on equity is fixed but its rate of return on equity is not.

PEG has not had the time or budget to fully consider this complicated issue but notes the following.

- The calculation of BC Hydro's revenue requirement does involve the calculation of gross and net plant value, a rate base, and amortization expenses.
- While the Company's proforma return on rate base is unconventional, it appears to be in the ballpark of a conventional return even though it is not closely linked to the rate base. Moreover, its importance is reduced by the Company's high reliance on debt financing.
- The Company's revenue requirement and rates are still very sensitive to its capex. Furthermore, even if capital cost as conventionally defined was partly absorbed by the government it would result in some combination of higher taxes, more government borrowing, and reductions in government services. Containment of BC Hydro's capex should therefore be an important goal of regulators.

8.2 Confirm, or explain otherwise, that this stipulated return on equity would provide no benefits for BC Hydro's shareholder in implementing PBR. Please provide your reasoning.

PEG Response:

Please see the response to the preceding question and to question 2.1 for a discussion of the incentive issue.

8.3 In order to have an effective PBR regime for BC Hydro, would this order in council need to be revised, in your opinion? Please provide your reasoning.

PEG Response:

Dr. Lowry has not considered this complicated issue.

8.4 How would you recommend that the order in council be revised to implement a success PBR regime for BC Hydro? Please provide your reasoning.

PEG Response:

Dr. Lowry has not considered this complicated issue.

9.0 Topic: PBR Implementation
Reference: Exhibit A2-7 (PEG Presentation) slide 73 - 74; Exhibit B-1, RRA, page 11-24, 11-25.

On slides 73 - 74 of PEG's PowerPoint, PEG lists "Baby Steps" for PBR Ideas for BC Hydro. It also states that "Baby Steps" include: "3 forward test years".

On page 11-24 of the RRA, BC Hydro states:

….*we conclude that the PBR term should be at least five years as a longer term would provide stronger incentives.*

Further on page 11-25 of the RRA, BC Hydro describes two important considerations that should inform the length of the PBR term:

- First, as the length of the PBR term increases, the incentives for the utility to achieve efficiencies also increases…..
- Second, the PBR term must be long enough to allow the utility to undertake the changes and investments necessary to discover and achieve additional efficiencies…..

9.1 In your opinion, which of these "Baby Steps" on slides 73 – 74, would you recommend that BC Hydro to implement first, and provide your reasons?

PEG Response:

Dr. Lowry has not considered what package of PBR reforms makes the most sense for BC Hydro. All of the steps mentioned in slides 73-74 could be implemented in first-generation PBR. However, the need for and desirability of the alternative DSM incentives is unclear. Further, alternative attrition relief mechanisms

merit consideration.

9.2 Of these "Baby Steps" which of these would provide the most benefits to BC Hydro, its ratepayers and shareholder in your opinion, and provide your reasons?

PEG Response:

Dr. Lowry has not considered this complicated issue.

9.3 In addition to these "Baby Steps" identified in these slides, are there any other recommendations? Please list these.

PEG Response:

It is unclear at this time what package of PBR reforms makes the most sense for BC Hydro. However, here are some additional ideas that merit consideration.

- Statistical benchmarking results could be used mechanistically in rate setting whether or not an indexed ARM was approved.
- Benchmarking could extend to proposed forward test year costs as well as historical costs.

9.4 Provide your reasons for suggesting a PBR "Baby Step" of 3 forward test years.

PEG Response:

Dr. Lowry mentioned 3 forward test years as an example of a step towards a more incentivized, efficient regulatory system that merits consideration. It is not necessarily the optimal approach. The benefits of the approach include the following.

- It is well within the capabilities of BC's regulatory communities.
- It is one way to finesse the addition of Site C costs to the rate base.
- Parties would have a chance to further improve their knowledge of BC Hydro and to further sharpen their rate case skills.
- Bunching three rate case years should boost regulatory efficiency and encourage parties to develop sensible streamlining provisions such as the indexation of OM&A revenue.
- If intervenors can reduce the Company's revenue requirement by 3% in each test year of current rate cases, they can hopefully reduce it by 3% over three forward test years.

9.5 Confirm, or explain otherwise, if you agree with BC Hydro's two considerations that informed its proposed length of the PBR term. Provide your reasons.

PEG Response:

Dr. Lowry agrees that these are valid considerations in the choice of an optimal term for a multiyear rate plan. Terms longer than 3 years create more opportunities for long-run cost containment. A recent decision in Massachusetts approved an MRP proposal of a gas distributor on the condition that they extend the plan period from the five years that the company proposed to ten years.[9]

9.6 Confirm, or explain otherwise, if you agree that a PBR term should be at last five years and provide your reasons.

PEG Response:

[9] Massachusetts Department of Public Utilities Docket 19-120, NSTAR Gas Co., Order, October 30, 2020.

Notwithstanding the benefits of a longer plan term, a term of three to four years is preferable to the status quo, which involves only one or two years.

10.0 Topic: Productivity Factors
Reference: Exhibit B-1, RRA, page 11-13; **Workshop Transcript (September 8, 2020) – Volume 2, page 249.**

On pages 11-3 and 11-4 of the RRA, BC Hydro states that:

..while the utility's past performance may inform the productivity factor at the start of a PBR plan, it cannot be used repeatedly. Rather, ongoing adjustments to the productivity factor should be based on a representative peer group of utilities in the same industry.
The selection of peer group is fundamental to the fairness of the PBR plan, since benchmarking against utilities that are not facing the same operating circumstances could result in a formula that is too aggressive or too lenient.

From page 249 of the Transcript:

So let me hasten to talk about the downside of this. I think that these Crown corporation arguments do hold some water because, as I've said, there's isn't an impressive track record of publicly held utilities doing swimmingly well under PBR.

10.1 Please identify the appropriate peer group that could be used for benchmarking BC Hydro, in your opinion.

PEG Response:

Econometric benchmarking studies do not require the choice of a peer group. A sample is needed for the estimation of model parameters, and variation in the business conditions faced by the utility can sharpen parameter estimates. The resultant benchmark uses the exact business conditions that the company faced historically (or is expected to face in a forecasted test year).

Whether a peer group or econometric method is chosen, a threshold issue in the selection of data for the study is whether the study will address costs of generation (G), transmission (T), and distribution (D) jointly or separately. If they are considered jointly, the econometric sample and any peer group would use data on the GTD costs of vertically integrated electric utilities. If G, T, and D are considered separately, the generation study would likely use data from hydroelectric power generators. The T&D studies would use data from T and D operations, respectively. It is an empirical issue but not obvious a priori that custom peer groups are needed for T or D.

Most of the data for a benchmarking study would likely come from the United States, where standardized data have been available on G, T, and D operations for many years. Data from Alberta, Ontario and Quebec also merit consideration for inclusion but the incremental cost can be sizable.

10.2 Discuss any challenges of choosing a representative peer group of utilities in the same industry given your comments that there is not an impressive track record of publicly held utilities doing swimmingly well under PBR.

PEG Response:

The peer group should not be limited to publicly-owned utilities and it should be noted that data from such utilities are more difficult to gather and process since they tend to be from diverse distributors with different accounting norms.

11.0 Topic: Revenue Caps
Reference: Exhibit B-1, RRA, page 11-20 - 11-21; **Exhibit A2-7 (PEG Presentation) slide 81.**

BC Hydro states on page 11-21 of its RRA, that the PBR Formula should be a Revenue Cap. Further:

A revenue cap would recognize the continued uncertainty around the load forecast. A revenue cap is also consistent with the approach that the BCUC has previously approved for FortisBC's natural gas and electricity utilities.

On slide 81 of PEG's PowerPoint:

Progress has recently been made in developing rate and revenue cap indexes for VIEUs, transmitters, and hydroelectric generator

11.1 Confirm, or explain otherwise, if you agree with BC Hydro that the PBR Formula should be a Revenue Cap. Please provide your reasons.

PEG Response:

PEG believes that the case for a revenue cap is not clear cut. The benefits of a revenue cap are reduced for BC Hydro by its heavy reliance on power supplies from low-cost renewable generation, its excess capacity, its sizable industrial load, and its EOT mandate.

11.2 Discuss what progress has been made in developing revenue cap indexes for VIEUs, similar to BC Hydro's operations.

PEG Response:

A *price* cap index based on statistical cost research was first approved for Central Maine Power in 1994, when it was still vertically integrated. Since then, most MRPs for VIEUs have not used indexed ARMs. However, Hawaiian Electric has effectively operated under a revenue cap index ("RCI") applicable to G, T, and D for several years.[10] Moreover, Hawaii's commission recently opted for an RCI for next-generation PBR and is currently considering the appropriate X factor and stretch factor.[11] In Ontario, RCIs are currently used in the MRPs for the transmission services of Hydro One Networks. A price cap index has been approved for hydroelectric services of Ontario Power Generation. In Québec, price cap indexes apply to the generation and distribution services of Hydro-Québec, while the O&M expenses of Hydro-Québec's transmission service are escalated by a revenue cap index.

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12.0 Topic: Carve Outs
Reference: Exhibit B-1, RRA, page 11-19, Table 11-2 (page 11-40).

On page 11-19 of the RRA, BC Hydro states that:

Overall, we believe that a hybrid approach, which includes some "carve outs" from the PBR formula, would be appropriate for BC Hydro given our capital investment requirements and various uncontrollable costs.

[10] Hawaii Public Utilities Commission, Docket 2013-0141, Order #32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule, March 31, 2015.

[11] Hawaii Public Utilities Commission, Docket 2018-0088, Decision and Order #36326, May 23, 2019.

Table 11-2, taken from page 11-40 of the RRA shows which components would likely be "carved out" from the PBR formula entirely as well as those component "adders" in a PBR formula.

Table 11-2 Management of Various Cost Components under a PBR Plan

Likely subject to PBR formula with some "adders" or "carve outs"	Various options – approach best determined through PBR application process	Likely "carved out" from the PBR formula entirely
Operating Costs	Capital Expenditures	Cost of Energy
		Taxes
		Finance Charges
		Demand Side Management
		Revenues and Subsidiary Net Income

12.1 Confirm, or explain otherwise, if you agree that "adders" or "carve outs" may be necessary under a PBR Plan for BC Hydro. Please provide your reasons.

PEG Response:

PEG agrees that some adders and carveouts might be necessary in an MRP for BC Hydro.

12.2 Confirm, or explain otherwise, if you agree with the "adders" and "carve out" that BC Hydro has identified in Table 11-2. Please provide your reasons.

PEG Response:

The carve outs would likely include many of the costs that are currently subject to variance account treatment. These would likely include costs of energy and DSM expenses. The need for capital cost adders and carve outs would be a key issue if an indexed ARM nominally applies to capital as well as OM&A revenue.

12.3 Are there additional "adders" and "carve outs" that you would recommend to be incorporated in Table 11-2? Please list and provide your reasons.

PEG Response:

PEG does not have additional recommendations at this time but notes that pension and benefit expenses are often tracked in MRPs.

13.0 Topic: Design of a PBR Approach
Reference: Exhibit B-1, RRA, page 11-19 – 11-20

Dr. Weisman provides some principles to guide the design of a PBR approach that appropriately reflects the unique circumstances of a utility:

- *It should be more broad-based than targeted so that a utility does not develop excessive attention to those items covered by the PBR formula at the expense of items that are "carved out" of the formula and so that the utility is not incented to make inefficient decisions to push additional costs outside of the PBR formula;*

- *Items over which the utility has little or no control should be "carved out" of*

the PBR formula;

- *With regards to capital projects, the productivity improvements assumed by the "X" factor must recognize that increased investment is required in the electricity industry.*

13.1 Confirm, or explain otherwise, if you agree with Dr Weisman's comments. Please provide your reasons.

PEG Response:

Dr. Lowry fully agrees with the first point. The need to carve out costs over which utilities have little or no control depends on their importance and the degree to which the ARM is likely to provide inappropriate revenue adjustments. The need for increased investment varies considerably across the electric utility industry.

13.2 Are there other principles that you would add to these principles? If so, please list these and provide your reasons.

PEG Response:

Yes. Here are some additional PBR design principles that merit mention.

- Individual utilities typically face a mix of favorable and unfavorable business conditions. They are want to emphasize the unfavorable conditions and to downplay the favorable ones.
- A capex surge causes cost growth to accelerate but subsequently causes cost growth to slow.
- Regulators should provide balanced attention to the goals of stronger performance incentives, streamlined regulation, and a fair allocation of PBR benefits between the utility and its customers.