OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-41

Ref: Exhibit 10, Tab D

Please confirm or correct the following list of adjustments proposed and the method of adjustment. Please note that in some cases the list in the application has been further disaggregated:

A. Adjustments to be made to base rates annually to account for changes in:

- Forecast revenue indicated by updated customer growth, demand and consumption forecasts
- Actual and forecast net new customer connection costs
- Cost of capital parameters (return on equity, short term debt rates and long term debt rate)
- Working capital allowance resulting from changes in the cost of power

Rates could also be adjusted as a result of a successful Z-factor application.

B. Rate riders added to rates once costs for the following are finalized:

- Revenue requirement impacts of contributions to Hydro One Networks Inc. Transmission
- Revenue requirement impacts of unbudgeted distribution projects required as a result of regional planning

In the meantime, the revenue requirement impacts of these costs will be tracked by OPUCN.

C. Deferral or variance accounts to be created to record changes in:

- Revenue requirement impacts of cost variances from forecast (embedded in rates) for distribution plant relocations in response to third party requests
- Revenue requirement impacts of cost variances from forecast (embedded in rates) for new customer connections

The two deferral accounts would be disposed of at the end of the plan term.

Response:

A. Confirmed.

In respect of the proposed adjustment for actual and forecast new customer connection costs, this adjustment would be made to rates for the upcoming test year. That is, there is no intent to recover, during the plan term, variances from new customer connection costs embedded in rates for the previous year. These previous year variances, for each year of the plan term, would be captured in the Net New Connection Cost Variance Account (NNCCVA) for disposition following the end of the 5 year plan term.

OPUCN's application also clarifies that OPUCN assumes applicability of the RRFE's "off ramp" mechanism, should earnings in any year of the plan term trigger that mechanism. [See Exhibit 1, Tab B, page 3, item 2.g.]

B. Confirmed.

OPUCN has proposed variance accounts for each of these uncontrollable cost categories. [See Exhibit 1, Tab c, page 38]

C. Confirmed.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-42

Ref: Exhibit 10, Tab D

For each proposed annual rate adjustment, including the rate riders and deferral accounts, please provide:

a) a reference to the Board policy or precedent that provides for the adjustment. If no Board policy or precedent exists for a proposed adjustment, please describe the particular circumstances of OPUCN that justify the need for the adjustment.

b) a best estimate of the materiality of the variance the adjustment is designed to address.

c) OPUCN's estimate of the annual time and cost (including intervenor participation) of implementing these annual updates.

Response:

a)

Adjustment	Reference/Comment
Forecast revenue indicated by updated customer growth, demand and consumption forecasts	Approved in Enbridge Gas Distribution's 2014 Custom IR Application (volume and customer additions) [EB-2012-0459]
Actual and forecast net new customer connection costs	Horizon's approved Settlement Proposal [EB-2014-0002] provides for ring-fencing of capital budget, with under spend during plan term returned to ratepayers. This variance account provides annual adjustment for variance in actual vs. forecast net capital spend for customer connections, in response to the ambitious customer growth forecast built into

	OPUCN's Capital Investment Plan based on third party (City, Region and developer) input and resulting significant capital over-recovery/timing risks to ratepayers.
Cost of capital parameters (return on equity, short term debt rates and long term debt rate)	Approved in Enbridge Gas Distribution's 2014 Custom IR Application [EB-2012-0459] Approved in Horizon's Settlement Proposal [EB-2014-0002] Applied for by Hydro One [EB-2013-0416, ExA/T4/S1]
Working capital allowance resulting from changes in the cost of power	Approved in Enbridge Gas Distribution's 2014 Custom IR Application [EB-2012-0459] through approval of annual adjustment for "gas-cost related items", which quarterly adjustments (through the QRAM process) include distribution rate adjustments for "working cash". Applied for by Hydro One [EB-2013-0416, ExA/T4/S1]
Rates could also be adjusted as a result of a successful Z-factor application	Contemplated by RRFE. Approved in Enbridge Gas Distribution's 2014 Custom IR Application [EB-2012-0459] Approved in Horizon Settlement Proposal [EB-2014-0002]
Rate rider for revenue requirement impacts of contributions to Hydro One Networks Inc. Transmission and unbudgeted distribution projects required as a result of regional planning	Enbridge Gas Distribution's 2014 Custom IR Application [EB-2012-0459] approval included variance account for mains replacement required as a result of system integrity work. Hydro One applied for annual adjustment for *"changes in other third party pass through charges"* and for new investments resulting from regional plans [EB-2013-0416, ExA/T4/S1 and S3]
Variance account for revenue requirement	Approved in Enbridge Gas Distribution's

impacts of cost variances from forecast (embedded in rates) for distribution plant relocations in response to third party requests	2014 Custom IR Application [EB-2012-0459] (relocation).
Deferral account for revenue requirement impacts of cost variances from forecast (embedded in rates) for new customer connections	Horizon's approved Custom IR plan includes adjustment for capital under spend relative to forecast (a "ring fencing") [EB-2014-0002 Settlement Proposal]

b) The following is a list of proposed annual rate adjustments with estimated materiality considerations:

- Customer connections, demand and volume forecasts - OPUCN has forecast higher than normal growth in customer connections, demand and volume based upon development plans from others including the City of Oshawa, Durham Region and local developers. Historical trend indicates annual growth of approximately 1% for customer connections with little or no growth in demand and volume. OPUCN's forecast is 3% per year in customer connections, and 2.5% and 1.3% for demand and volume respectively. Revenue requirement from the incremental growth ranges from approximately $0.5 million in 2015 to just less than $3.0 million in 2019; cumulatively, the variance could reach between $7.0 and $8.0 million over the plan period.

- Cost of capital - A 1% change in cost of capital parameters could represent between $1.0 million and $1.3 million in total revenue requirement.

- Updated cost of power – Based upon an assumption that cost of power rates increase by 5% per year, revenue requirement would increase by approximately $0.5 million over the plan period which is a material amount.

- Adjustment for Hydro One and new substation – The combined investment for these two projects exceeds $15 million which represents approximately $1.5 million in annual revenue requirement once in service. The opportunity for a material variance occurring with these two projects is significant. For example, based on discussions with Hydro One, contributions could be as high as $12 million or $6 million more than currently projected.

- Adjustment for plant relocation – The combined investment for these two projects exceeds $8 million which represents approximately $0.8 million in annual revenue requirement once in service. The timing and scope of these projects are driven by other parties and could materially change.

c) OPUCN has not prepared a rigorous estimate of the time and cost associated with the annual rate adjustment process that it has proposed. OPUCN anticipates that:

i. It would make an annual filing, which includes the information related to each of the proposed adjustments, as set out in Exhibit 10, Tab D.

ii. That filing would be subject to a written interrogatory process.

iii. A brief settlement conference would follow the interrogatory process.

iv. Any unresolved items would be brought before the Board for resolution.

As the proposed adjustments are generally numeric and mechanical in nature, and relate only to discrete, pre-defined aspects of revenue requirement, OPUCN anticipates that any unresolved issues could be addressed through a brief written hearing process as required.

While pre-defined models would not be available to OPUCN as a basis for these annual filings, it is envisioned that the process would otherwise be not unlike that used by the Board for Price Cap IRM.

OPUCN has also considered the recent Board process regarding Enbridge Gas Distribution's (EGD) 2015 Rate Adjustment [EB-2014-0276]. That process involved updating the Board's prior approval of EGD's 2015 rates for 9 adjustments. Procedural Order No. 1 was issued on January 12, 2015. Full settlement was reached less than 3 months later, as of April 9, 2015 (following some procedural issues regarding the scope of disclosure of 2014 actuals and the need for a technical conference). The Hearing Panel issued an oral decision on April 14, 2015 accepting the settlement submitted by the parties. OPUCN anticipates that its annual rate adjustment process would be no longer or more involved than EGD's recent process, and likely shorter and less involved given that there were some procedural matters raised during EGD's process, which was the first of its kind.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-43

Ref: Exhibit 10, Tab D

At page 19 of the RRFE Report, the Board indicates that distributors applying under the Custom IR option *[sic]* to demonstrate the ability to manage within the rates set, <u>given that actual costs and revenue will vary from forecast</u> [*emphasis added*]. Please indicate how OPUCN's proposed annual adjustments for variances in cost and revenue are consistent with demonstrating this ability.

a) Did OPUCN consider a set of costs and supporting forecasts that would not have required planned annual adjustments prior to filing this application? Why or why not?

b) Please describe the consequences to rates for customers and financial performance of OPUCN of selecting a five-year customer forecast, cost index and investment profile that would not require annual adjustment. In what ways would the utility be unable to balance risks and rewards for the company and its customers?

c) What additional benefits are Oshawa's customers receiving from the proposed annual adjustments that would not be provided by a custom index of rates for the five year period, based around the most likely customer forecast and most likely set of capital requirements?

d) If OPUCN's plan is reasonable, in what way are the Board's off-ramps insufficient for adjustments to the plan, should actual developments turn out substantially different from those planned?

Response:

a) The first step in OPUCN developing the Custom IR application that it has put before the Board was the preparation of the comprehensive Distribution System Plan required by the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (*RRFE*), and filed as Exhibit 2, Tab B. Based on this comprehensive 5 year distribution system plan, and the significantly large capital investment requirements dictated by that plan, OPUCN evaluated whether rates set under the Board's 4th Generation IRM methodology over the plan period would allow OPUCN to execute its plan and continue to earn a reasonable return on equity. OPUCN concluded that 4th generation IRM would not provide sufficient revenue for the tasks at hand. As discussed in OPUCN's evidence [see in particular Exhibit 1, Tab C, page 4 (bottom) through page 7], under 4th Generation IRM, even with a 2015 rebasing, OPUCN would significantly under earn from the 2016 test year and on. Forecast ROE under 4th Generation IRM would be near the off-ramp trigger of -3% relative to Board approved ROE in each of the 2016 through 2019 test years. The cumulative negative impact on earnings that would result from application of 4th generation IRM even after 2015 rebasing is forecast to be in excess of $6 million (before PILS) from 2016 through 2019.

OPUCN thus developed, and has proposed, this Custom IR plan based on its best forecasts and resulting anticipated costs. OPUCN also recognizes that over the 5 year planning horizon Oshawa's specific circumstances present considerable uncertainties. In particular, two key drivers of OPUNC's Distribution System Plan and associated Capital Investment Plan are; i) customer growth and plant relocation costs that are dependent on development in and around the City of Oshawa; and ii) associated upstream costs that are dependent on a regional planning exercise the response to which will be determined by Hydro One. Both of these key external drivers present uncontrollable and material uncertainties regarding whether OPUCN's actual costs will be more or less than forecast over the plan period.

Similarly, interests rates (underlying cost of capital) and the cost of power are very difficult to predict, and cumulative changes in these parameters over 5 years could materially impact revenue requirement and should neither benefit nor burden shareholders or ratepayers.

Given these uncertainties, and the material sensitivity of OPUCN's costs to changes in these externally determined factors, OPUCN has proposed a set of adjustments that it views as fair to both its shareholder and its ratepayers. The rate adjustments proposed by OPUCN are proposed precisely because the changes in costs that would justify such adjustments cannot be forecast, and in order to ensure that neither OPUCN's shareholder or ratepayers are benefitted or burdened by developments beyond OPUCN's ability to control.

b) OPUCN does not believe that *"selecting"* five year forecasts, cost indices or investment profiles would be an appropriate approach to distribution system planning or rate making.

OPUCN has developed the best forecasts that it can based on the information available to it, and has developed a Distribution System Plan that would allow it to continue to serve its customers reliably during the plan term if circumstances develop as forecast.

OPUCN has proposed certain adjustments to rates going forward that will protect both its shareholder and its ratepayers from material changes in costs resulting from external circumstances beyond OPUCN's ability to control. In the event that development and new customer connection does not proceed at the pace currently planned, resulting in lower required distribution system and upstream expansion costs, then rates would be adjusted downward to preclude a windfall to OPUCN's shareholder at the expense of its distribution customers. Conversely, should the cost of power in the province rise beyond the level forecast, future rate adjustment will preclude cash flow issues for OPUCN which would erode its earnings. OPUCN's cost of capital would be adjusted annually in accord with Board determined cost of capital parameters in order to maintain rates that are just and reasonable and provide OPUCN with a reasonable opportunity to recover its cost of capital.

In all other cost categories, OPUCN will be at risk for managing within its forecast and approved costs, as contemplated by the Board's *RRFE* rate making policy.

c) The annual adjustments proposed by OPUCN mitigate material and uncontrollable risks to ratepayers of paying costs in excess of those required, as a result of variances from forecast, to provide reliable electricity distribution service. The basis upon which rates for each of the test years are determined at the outset is an issue unrelated to the proposal for certain annual adjustments to mitigate risks of uncontrollable, external variables.

OPUCN has proposed rates for each of the test years on the basis of *"robust evidence of its cost and revenue forecasts over a five year horizon"* complemented by *"adjustments calculated to smooth the impact of forecasted [2015] expenditures"*, all as contemplated by the *RRFE*. OPUCN has not attempted to derive a *"custom index of rates"*.

d) OPUCN believes that its proposed annual adjustments are fair to both ratepayers and its shareholder, in that neither ratepayers nor the shareholder should benefit or be burdened by material distribution cost changes arising from the material but uncontrollable risks of the pace of development in Oshawa, changes in the cost of power, or changes in the cost of capital over the 5 year Custom IR Plan period. OPUCN believes that an annual adjustment process for certain pre-defined external factors would be more efficient, and would yield better results for both shareholders and ratepayers, than would resorting to a review of the entire ratemaking framework for OPUCN only following a 300 basis over or under earning and a resulting “off-ramp” triggering. OPUCN over recovering, or under earning, as a result of uncontrollable external circumstances over which it can exercise no control would not further the legitimate ratemaking objective of incenting cost efficiency and operational effectiveness through controllable actions, initiatives and risk management. It would merely inject uncertainty into ratemaking for OPUCN and its customers.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-44

Ref: Exhibit 10, Tab C, page 14

In its decision in EB-2013-0416, the recent Hydro One Networks Inc. rate application, the Board said in section 3.2 at pages 14 and 15:

> "The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. …It is not sufficient to embed savings in cost forecasts. …The productivity and efficiency elements allow the OEB to move away from detailed input cost assessment and focus more on utility performance. These factors provide utilities with strong incentives to continually seek efficiencies and share expected savings with ratepayers 'up front', avoiding 'after the fact' regulatory scrutiny."

a) The Hydro One decision was issued after OPUCN made its application. However, given the guidance that is now available from the Hydro One decision, please estimate the stretch factor or other productivity and efficiency index to be applied each year of OPUCN's plan term that would equate to the productivity or efficiency OPUCN has embedded in its cost forecasts.

b) If OPUCN does not agree that a stretch factor should be imposed on OPUCN for the term of the plan, please explain why a stretch factor would be ineffective or inappropriate for OPUCN's circumstances.

Response:

a) The study by PEG benchmarked the Company's total cost forecast using the same methodology that the Board adopted for setting stretch factors in IRM4. It shows that the Company's forecasted total cost is commensurate with a third tier performance in the first two years of the proposed plan and a second tier performance in the last three years. In IRM4, these results would be commensurate with a 0.3% stretch factor in the first two years and a 0.15%

stretch factor in the last three years. The average applicable stretch factor using the IRM4 methodology would be about 0.21%.

PEG's report provides forecasts of inflation and the operation and maintenance ("OM&A"), capital, and total factor productivity trends that are implicit in OPUCN's forecasts. The results show that the Company's cost forecast involves OM&A and total factor productivity growth that is markedly superior to the corresponding productivity trends of Ontario power distributors even if the higher trends of the 2003-2011 period are used. The capital productivity growth that is implicit in the Company's cost forecast is closer to the Ontario norm, as might be expected given the Company's forecasted 2015 capex surge. However, the implicit capital productivity growth in the years following the surge is well above the Ontario norm.

The table below addresses the stretch factor that is implicit in OPUCN's forecasted cost. This implicit stretch factor equals the implicit TFP trend because the base productivity trend in the X Factor for IRM4 was set equal to 0% by the Board. The implicit TFP growth is forecasted to average 0.87%. This exceeds the stretch factor expected under the default IRM methodology by 0.66%.

OPUCN Productivity Trends and Stretch Factors

	Productivity			Stretch Factor		
Year	**OM&A**	**Capital**	**Total**	**IRM4 Method**	**Implicit in Proposal**	**Difference**
2015	-2.0%	-3.4%	-2.9%	0.30%	-2.87%	-3.17%
2016	1.1%	0.4%	0.6%	0.30%	0.63%	0.33%
2017	3.2%	0.7%	1.6%	0.15%	1.60%	1.45%
2018	3.7%	0.9%	1.9%	0.15%	1.92%	1.77%
2019	4.9%	2.0%	3.0%	0.15%	3.05%	2.90%
Average 2015-2019	**2.17%**	**0.12%**	**0.87%**	**0.21%**	**0.87%**	**0.66%**

In summary, then, OPUCN's custom IR proposal uses rigorous external cost and productivity benchmarking to show that the cost forecasts offer customers good value and the prospect of continuous efficiency improvement.

b) OPUCN has proposed rates for each of the test years on the basis of *"robust evidence of its cost and revenue forecasts over a five year horizon"* complemented by *"adjustments calculated to smooth the impact of forecasted [2015] expenditures"*, all as contemplated by the *RRFE*. A "stretch factor", which is intended as a proxy for efficiency not recognized by an "inflation minus expected productivity" formulaic approach to rate making, does not fit within this ratemaking framework adopted by OPUCN.

OPUCN is currently in the second most efficient cohort for Ontario's electricity distributors. The Board's current "stretch factor" for that cohort is 0.15%, on top of an efficiency factor of 0%.

Based on the total factor productivity benchmarking analysis commissioned from PEG in support of this application, OPUCN's requested 2019 rates as compared to its forecast benchmarked costs would indicate an average "x" factor (efficiency plus stretch) of 0.87%.

That is, OPUCN's cost of service based Custom IR proposal already realizes a stretch factor that <u>exceeds</u> the Board's applicable IRM4 stretch factor by an average of 0.66%.

The Board can thus be satisfied that OPUCN's *"utility performance"* under the Custom IR Plan rates proposed will continue to reflect strong cost efficiencies and quantifiable value to OPUCN's customers.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-45

Ref: Exhibit 10/Tab C, page 15

a) Please provide the rationale for choosing the two projects to be subject to this proposed incentive.

b) Is it OPUCN's view that all other capital investment programs are not controllable?

c) What percentage of OPUCN's total capital investments do these two programs represent?

Response:

a) The two projects proposed by OPUCN to be subject to Controllable Capital Investment Efficiency Incentive Mechanism (CCIEIM) were chosen because they are sizeable and discrete, which makes them amenable to innovation, efficiency, validation, tracking and outcome verification.

b) No. Some of OPUCN's other plan term capital projects are certainly "controllable", though none of the other projects are as sizeable as the two proposed for CCIEIM treatment. The capital projects associated with new customer connections and load growth are "controllable" in the sense that expenditures can certainly be carefully managed, though the scale and scope of these projects will ultimately be driven by the pace of actual growth relative to OPUCN's best forecasts of such growth.

On the other hand, the System Renewal Capital Investment Program is not dependant on the pace of growth. While the new Distribution Station project is responsive to growth, the 4 year lead time to plan, construct and put a distribution station into service will in all likelihood preclude deferral of the project beyond the end of the Custom IR Plan term proposed.

c) The two projects proposed by OPUCN for CCIEIM treatment represent approximately 47% of OPUCN's Custom IR Plan period forecast capital expenditure of $60.8 million

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-46

Ref: Exhibit 10/Tab C, page 16

OPUCN indicates that if any projects included in the program are not completed by the end of the plan term for reasons beyond OPUCN's reasonable control, the incomplete projects will be removed from the incentive calculation.

a) Please provide more details as to what causes of delay would be considered "beyond OPUCN's reasonable control".

b) Does OPUCN agree that for any project eliminated from the calculation due to lack of completion, OPUCN would need to provide evidence that the delay was due to factors entirely outside OPUCN's control?

c) Does the rule regarding incomplete projects create a disincentive to complete a project where the capital costs are expected to exceed the Board-approved cost of the project?

d) OPUCN recognizes that the onus will be on OPUCN to demonstrate that the completed projects achieve the results of the capital program reflected in the scope and criteria for the projects as set out in OPUCN's Distribution Plan. Does OPUCN agree that some type of hearing or other review, involving interested stakeholders (intervenors) will be necessary for the incentive to be implemented for any variances that occur?

e) It appears that this proposal involves the calculation of a Rate Rider every year until the subject project assets are depreciated. What is the average life of the relevant assets? Please comment on the administrative burden involved in implementing this proposal.

Response:

a) Examples of causes considered beyond OPUCN's control that could negatively impact both project scheduling and costs include extreme weather events, client changes in project scope and schedule, utility corridor access and 3rd party dependency changes.

b) Yes.

c) On the surface and in isolation of other Board policies and practices it may appear to be a disincentive. However, the Asset Renewal Program is directed at failing assets and/or assets deemed to be at end of life. Deferral of these projects will result in poorer utility service in both reliability and customer satisfaction for which the Board collects measures at regular intervals. Further, a claim for a CCIEIM incentive at the end of the Custom IR Plan period will be subject to justification by OPUCN, including justification for any delays relied upon to exclude a project from the incentive calculation. OPUCN will file supporting evidence which it fully expects will be reviewed and tested by the Board and interested parties.

d) Yes. OPUCN anticipates that this review would form part of OPUCN's application for 2020 rates (i.e. rates following the end of the proposed Custom IR Plan period).

e) OPUCN has not determined the actual average life of the relevant assets but believes a reasonable benchmark for the incentive would be the average Plant Depreciation Rate calculated by PEG in their benchmarking studies prepared by the Board. The average Plant Depreciation Rate for utilities in Ontario as determined by PEG is 4.59%.

   Based on the current capital project management and control practices employed by OPUCN, and the proposal collection of any earned incentive by way of a rate rider (i.e. through accounting entries distinct and separate from rate components), we do not foresee an administrative burden involved in implementing this proposal.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-47

Ref: Exhibit 10/Tab C, pages 17-19

Please describe the main differences between the CCIE[I]M proposed by OPUCN and the incentive mechanism developed by Ofgem that is referred to in the evidence.

Does OPUCN agree that the proposed incentive will not achieve its purpose if OPUCN's forecast of capital costs is too high?

Response:

Like Ofgem's risk sharing model, OPUCN's proposed CCIEIM; i) recognizes the value of avoided rate base; ii) mitigates the utility's disincentive to avoid rate base by allowing the utility to earn a return on a portion of rate base avoided; and iii) incents continued efficiency by allowing the utility to recover the costs of, and earn on, only a portion of rate base in excess of that expected. However, the manner in which Ofgem implements this incentive is quite different from OPUCN's proposed mechanism, because Ofgem has adopted a very different regulatory model.

One of the most relevant differences between Ofgem's regulatory model and the model in Ontario is that Ofgem uses a "Regulated Asset Value" (RAV) concept in lieu of determining an actual cost "rate base". Under this model, RAV will depart from actual capital investment value in accord with expected capital spending as adjusted for the efficiency incentive and risk sharing described in OPUCN's evidence. This allows Ofgem to incorporate the capital efficiency incentive into rates directly through its rate base deemed for rate making purposes (the RAV).

OPUCN is proposing that its capital efficiency incentive/risk sharing be implemented through a rate rider, leaving OPUCN's rate base reflective over time of its actual capital investments.

Another essential difference between Ofgem's capital incentive model and OPUCN's CCIEIM proposal is that under Ofgem's model actual expenditure is not tracked to capital or operating expenditure. Rather total actual expenditure relative to total expected expenditure is tracked, and the difference is then “deemed” to be split between capital and operating costs in a pre-determined proportion.

OPUCN’s CCIEIM proposal is more narrowly bounded to actual versus approved capital expenditures on two specific projects.

Like Ofgem’s capital efficiency mechanism, OPUCN is proposing that a pre-determined percentage (OPUCN has proposed 50%) of any capital overspend or underspend be subject to efficiency/risk sharing treatment.

In OPUCN’s proposal, the total incentive would be effectively “capped” in accord with the 300 basis point off-ramp embedded in the *RRFE* framework, to the extent that a post-Custom IR Plan period earnings variance of more than 300 basis points, inclusive of the impact of the CCIEIM rate rider, would be subject to off-ramp review. OPUCN is not aware of whether Ofgem’s regulatory framework contains a similar “off-ramp” provision.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-48

Ref: Exhibit 10/Tab C, page 13

a) Please describe the similarities and differences between OPUCN's proposed TCECM incentive and the carry-over mechanism proposed by Enbridge Gas Distribution Inc. rejected by the Board in the Enbridge Custom IR rate application (EB-2012-0459) and referred to in OPUCN's evidence.

b) Please describe the similarities and differences between the TCECM proposed by OPUCN and the incentive mechanism approved by the Alberta Utilities Commission that is referred to in the evidence.

c) Why did OPUCN choose a 2 year period for the rate rider to apply? Were other time periods considered in the analysis of this proposal?

Response:

a) OPUCN understands Enbridge Gas Distribution's (EGD) proposed Sustainable Efficiency Incentive Mechanism (SEIM) to have had 3 elements:

 1. Calculation: The potential reward would equal one half of the difference between the average ROE achieved during the IR term and the average ROE allowed during the IR term. The potential reward would form a premium on the ROE that applies to rates for the rebasing year and the following year. The reward would be capped at 50 basis points above the allowed ROE. OPUCN's proposed TCECM is the same as EGD's proposal in all of these respects.

    EGD proposed that the ROE premium would be expressed as a dollar amount, based on the forecast of the rate base in the test year following the last year of the IR plan. OPUCN has proposed that the ROE premium would be calculated in each of the two years following the Custom IR Plan term based on the rate base in each of those years.

2. Determining whether the reward was justified: To qualify for the reward, EGD would have to show that the net present value of the long-term benefits generated by productivity initiatives undertaken during the IR term is greater than the reward, and that its Service Quality Reporting performance has been maintained at or above the pre-IR term levels for at least 3 of the 5 years of the IR term.

   OPUCN has not adopted such elements in its proposed TCECM, being of the view that while the principles make some sense the factual demonstration would be problematic and would add significant uncertainty for OPUCN in respect of whether its realized efficiencies and the work undertaken to realize them would ultimately be found to merit an incentive reward. OPUCN further noted that the Alberta Utilities Commission (AUC) adopted an incentive mechanism essentially identical to OPUCN's proposed TCECM without these additional elements of proof or future determination.

3. Implementing the reward: The reward would be administered within the rebasing case and the case for the test year following rebasing. The reward amount would be added to the revenue requirement for recovery in each of these test years. OPUCN's proposed TCECM would be implemented in the same fashion.

b) OPUCN believes that its proposed TCECM is essentially the same as the incentive mechanism approved by the AUC as referred to in the evidence.

c) OPUCN proposes a two year period for the rate rider to apply because:

   1. Two years was the period approved by the AUC, and was also the period proposed by EGD for its SEIM.

   2. Two years seems like a reasonable amount of time to provide a sustained incentive to counteract the disincentive inherent in the IRM model for efficiency investments later in the plan term, while being palatable to the Board and the parties for early adoption in Ontario as a trial mechanism.

   Longer periods were discussed, but ultimately OPUCN determined that two years struck the right balance and was supported by the precedent in Alberta and EGD's earlier application. Two years also produces an "averaging" of sorts for the strength of the efficiency investment incentive, given the 5 year total length of the proposed Custom IR Term.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-49

Ref: Exhibit 10/Tab C, page 14

Please confirm that the proposed TCECM is not symmetric, that is if the difference between average actual RoE over the plan term and Board approved RoE is positive, OPUCN will be entitled to recover 50% of that difference (up to 50bp) for the two years following the end of the plan term. However, if the difference is negative, OPUCN will not be penalized by a reduction in RoE over the two years following the plan term.

Response:

Confirmed. The TCECM is intended to mitigate the disincentive inherent in fixed term rate plans for efficiency investment later in the plan term. This disincentive arises as the time during which the utility realizes the benefits of any in-term efficiency investment decreases late in the plan term. The TCECM is not proposed as a symmetrical risk/reward program.

OPUCN’s “penalty” for under earning during the plan term is the under earning.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-50

Ref: Exhibit 10/Tab C, page 12

Following the presentation on April 2, 2015, OPUCN agreed that return on equity is affected by many factors, only one of which is efficiencies found by the utility.

a) Please list the factors other than efficiency which OPUCN believes would affect RoE over the plan term.

b) Please provide any proposal that would eliminate or reduce the effect of factors other than efficiency from the calculation of the TCECM.

c) How was the issue of the effect on RoE of factors other than efficiency addressed by the Alberta Utilities Commission in its approval of the incentive referred to in OPUCN's evidence?

Response:

a) The main external and uncontrollable factor discussed at the April 2, 2015 presentation that would affect ROE in a manner unrelated to efficiency would be weather.

Other factors that might affect ROE which are external to OPUCN's ability to control costs/obtain efficiencies would include the impact on average use of CDM activities; customer scale distributed generation; labour issues external to OPUCN (such as skilled labour markets); and regulatory changes.

b) The adjustment that would eliminate the effect of weather on the Total Cost Efficiency Carryover Mechanism calculation would be to weather normalize actual ROE for the purposes of applying the mechanism. OPUCN agrees that this would be an appropriate modification to its proposal, in order to maintain the same incentive for continued efficiency, and ensure that any efficiency reward is earned through actions by OPUCN, even in the event of warmer or colder than normal weather.

c) OPUCN has confirmed that ATCO Gas's ECM includes weather normalization of actual ROE for the purposes of calculating the incentive. OPUCN is not aware of any other ROE adjustments in this mechanism, and has to date been unable is to confirm whether there are any adjustments (including weather) for ATCO Electric's ECM.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-51

Ref: Exhibit 10/Tab C, page 14

OPUCN describes the proposed TCECM incentive as "simple to calculate and apply".

a) Does OPUCN agree that if factors that affect RoE other than efficiency are to be eliminated from the calculation, these factors would have to be considered by the Board at the time this incentive is implemented? Please confirm that the TCECM would be considered and applied at OPUCN's next rebasing application.

b) For what reasons does OPUCN believe that a stretch factor, as contemplated in the Board's RRFE policy, is an ineffective mechanism at incenting OPUCN to continue to find efficiencies in the final years of the plan term?

Response:

a) It is confirmed that the TCECM would be considered and applied at OPUCN's next rebasing. However, factors that affect ROE other than efficiency could be considered and eliminated at the conclusion of each test year, to derive the ROE for that test year to be subsequently (at the time of rebasing) input into the TCECM calculation.

For example, if ROE for TCECM calculations purposes is to be weather normalized, OPUCN could report ROE for the previous year in each rate adjustment application both on an actual and on a weather normalized basis.

b) See responses to Interrogatories 10.0-Staff-43 and 10.0-Staff-44. A "stretch factor" is a proxy for rate setting purposes for future efficiencies beyond those predictably expected from the distributor. Given that OPUCN is, in its proposed rates during the Custom IR Plan term, already committing to future efficiencies greater than those which would result from application of the Board mandated efficiency and stretch factors, no "proxy" for such further efficiencies is required. (OPUCN is already committing to delivering greater efficiencies than such "proxy" would dictate.) Further, in these circumstances, applying a "stretch factor" on top of the efficiencies to which OPUCN has already committed would be punitive, a result not intended by the *RRFE* or its underlying incentive and benchmarking policies.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-52

Ref: Exhibit 10, Tab B, pages 1-2

Please confirm that the information about the need and purpose of the projects described in this evidence was obtained from OPUCN. That is, NBM Engineering did not undertake to independently verify the need for the projects.

Response:

Confirmed.

The need for the projects was informed by the METSCO Asset Condition Assessment Report and Asset Management Plan filed as Exhibit 2, Tab B, Schedule 3.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-53

Ref: Exhibit 10, Tab B/pages 4-17 – Cost Summary Tables
Exhibit 10, Tab B/page 22/ – Contingencies
Exhibit 2, Tab A/page 12/Table 2-5 – Capital Expenditures

The cost summary tables at reference 1 do not include an expected accuracy range for the cost estimates. Also, at reference 2, NBM Engineering Inc.'s report indicates that overhead rebuilds have a 15% contingency while underground rebuilds have a 25% contingency.

a) Please confirm that with the exception of the MS-9 substation project, NBM Engineering Inc.'s report relates only to System Renewal activities.

b) Please confirm that the contingencies are included in cost estimates for underground and overhead rebuilds, and that these contingencies account for potential cost overruns?

c) Are any contingencies included in cost estimates for substation work? If not, why not.

d) What is the degree of definition or accuracy of the estimate of the design and associated cost of the new MS-9 substation?

e) Please augment Reference 1 by including the +/- percentage variation typical from cost estimates to actual costs for each project.

f) Why has the Hydro One Regional Planning Initiative which is classified under System Service been omitted from the study?

Response:

a) Yes, the report conducted by NBM Engineering was for system renewal only.

b) Yes, the contingencies are included for overhead and underground rebuilds and are intended to account for unforeseen cost overruns.

c) Yes.

d) It is an estimate and there is a 20% contingency included in the estimate.

e) The cost summary tables at reference 1 do not include an expected accuracy range for the cost estimates. Also, at reference 2, NBM Engineering Inc.'s report indicates that overhead rebuilds have a 15% contingency while underground rebuilds have a 25% contingency.

Please refer to the following table ("2014-2019 Capital Projects – NBM Estimates – May 07, 2015 – Contingencies"):

Project Number	Project Name	Total Project Estimate**	Actual Estimated Cost	Contingency	Contingency (%)
2015 CAPITAL PROJECTS - PRELIMINARY					
Planned OH 2015					
OH-2015-01	Park Rd Wenthworth To Stone including Lakefielsd/Beaupre/Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside Lakemount Evangeline/Montieth/Bala/Lakeview	**$1,675,484**	$1,456,943	$218,541	15%
OH-2015-02	Keewatin (Melrose, applegrove, Oriole, Willowdale, Springdale)	**$677,343**	$588,994	$88,349	15%
OH-2015-03	Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary	**$505,507**	$439,571	$65,936	15%
	2015 Planned OH Rebuild Total	**$ 2,858,334**			
2015 Planned UG					
UG-2015-01	Down Crescent, Delmark Ct	**$163,752**	$131,002	$32,750	25%
UG-2015-02	1333 Mary St North	**$70,457**	$56,365	$14,091	25%
UG-2015-03	Camelot Dr, Merlin Ct, Percival Ct, Lancelot Cres	**$302,230**	$241,784	$60,446	25%
UG-2015-04	Chandos Ct, Calvert Ct	**$39,105**	$31,284	$7,821	25%
UG-2015-05	1300 Oxford St	**$59,470**	$47,576	$11,894	25%
UG-2015-06	Cedar St Rebuild (Cedar St, Balsam Cr, Lakeview Ave, Bon Echo Dr, Chaleur Ave)	**$327,673**	$262,139	$65,535	25%
	2015 Planned UG Rebuild total	**$962,688**			
2016 CAPITAL PROJECTS - PRELIMINARY					
Planned OH 2016					
OH-2016-01	Rossland - Ritson to Wilson	**$486,861**	$414,702	$72,158	17%
OH-2016-02	Athabasca (Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield)	**$899,513**	$766,195	$133,318	17%
OH-2016-03	Eastlawn,Winter,Mackenzie,Labrador	**$406,448**	$346,208	$60,240	17%
OH-2016-04	Bloor St - Oliver to MS11	**$551,420**	$469,693	$81,727	17%
	2016 Planned OH Rebuild Total	**$2,344,242**			
2016 Planned UG					
UG-2016-01	NorthDale Ave,Mohawk St, Beatrice Crt,	**$163,752**	$128,534	$35,218	27%
UG-2016-02	401 Wentworth Ave	**$72,533**	$56,933	$15,600	27%
UG-2016-03	1100 Oxford St	**$180,022**	$141,305	$38,718	27%
UG-2016-04	Athabasca St, Suton Ct, MarcClaren, Cornwallis Crt	**$204,706**	$160,680	$44,026	27%
UG-2016-05	MS10 - 10F1 & 10F6 Lead Cable Replacement	**$351,962**	$276,265	$75,697	27%
UG-2016-06	Aruba Cr, Aruba Ave, Waverly St, Bermuda Ave, Antigua Cr	**$394,363**	$315,490	$78,873	25%
	2016 Planned UG Rebuild total	**$1,367,338**			

2017 CAPITAL PROJECTS - PRELIMINARY					
Planned OH 2017					
OH-2017-01	Central Park blvd N - Brentwood, Homewood to Harwood	**$609,743**	$508,967	$100,776	20%
OH-2017-02	Landsdowne - Dover, Digby, Surrey, Sussex	**$379,094**	$316,439	$62,655	20%
OH-2017-03	Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct	**$484,901**	$404,759	$80,142	20%
OH-2017-04	Rebuild Fisher St, Albert S, Avenue St & Quebec St	**$310,733**	$259,377	$51,357	20%
OH-2017-05	GrenFell South of Gibb, Marland, Montrave	**$194,225**	$162,124	$32,101	20%
	2017 Planned OH Rebuild Total	**$1,978,696**			
2017 Planned UG					
UG-2017-01	1010 Glenn St	**$225,799**	$173,692	$52,107	30%
UG-2017-02	Annandale St, Capilano Cres and Capilano Crt	**$225,725**	$173,902	$51,823	30%
UG-2017-03	CherryDown Dr & Sunnybrae Dr	**$225,214**	$173,508	$51,705	30%
UG-2017-04	Birkdale St. Muirfield St Pinehurst, Sunningdale	**$240,052**	$184,940	$55,112	30%
UG-2017-05	291 Marland Ave	**$72,993**	$56,235	$16,758	30%
UG-2017-06	321 Marland Ave	**$82,153**	$63,292	$18,861	30%
UG-2017-07	282-290 Marland Ave	**$82,153**	$63,292	$18,861	30%
UG-2017-08	310 Marland Ave	**$59,664**	$45,966	$13,698	30%
UG-2017-09	300 Grenfell	**$55,307**	$42,609	$12,697	30%
UG-2017-10	400 Grenfell	**$90,344**	$69,602	$20,742	30%
UG-2017-11	Tennyson Cr	**$53,762**	$41,419	$12,343	30%
	2017 Planned UG Rebuild total	**$ 1,413,165.00**			
2018 CAPITAL PROJECTS - PRELIMINARY					
Planned OH 2018					
OH-2018-01	Julianna & Bernhard	**$268,072**	$219,371	$48,700	22%
OH-2018-02	Mary -Rossland to Aberdeen	**$203,705**	$166,698	$37,007	22%
OH-2018-03	Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle	**$740,799**	$606,219	$134,581	22%
OH-2018-04	Riverside South - Palace and Hoskin	**$233,281**	$190,901	$42,380	22%
OH-2018-05	Riverside North - Regent, EastHaven, EastGrove, Eastdale, Eastborne, EastGlen, Florian Crt	**$728,888**	$596,471	$132,417	22%
	2018 Planned OH Rebuild Total	**$2,174,745**			

2018 Planned UG					
UG-2018-01	Gladfern, Galahad, Gentry, Gaylord	**$917,761**	$681,843	$235,918	35%
UG-2018-02	Traddles, Dickens Wickham	**$605,404**	$449,780	$155,624	35%
UG-2018-03	Oulet, Birchcliffe, Lakeview, Valley	**$344,874**	$256,221	$88,653	35%
	2018 Planned UG Rebuild total	**$1,523,164**			
2019 CAPITAL PROJECTS - PRELIMINARY					
2019 PLANNED OVERHEAD					
OH-2019-01	King St E 10F1 (Keewatin to Townline)	**$380,518**	$305,391	$75,126	25%
OH-2019-02	Vimy Ave, Lasalle Ave	**$183,262**	$147,080	$36,182	25%
OH-2019-03	Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham	**$1,312,827**	$1,053,633	$259,194	25%
OH-2019-04	Grandview, Beaufort and Newbury	**$187,324**	$150,340	$36,984	25%
	2019 Planned OH Rebuild Total	**$2,063,931**			
2019 Planned UG					
UG-2019-01	Central Park Blvd North, Exeter St and Trowbridge	**$321,795**	$239,075	$82,720	35%
UG-2019-02	Ormond Dr, EverGlades, Palmetto,Pompano Ct	**$274,089**	$203,632	$70,457	35%
UG-2019-03	Beaufort Ct	**$169,919**	$126,240	$43,679	35%
UG-2019-04	Marwood Dr	**$228,934**	$183,147	$45,787	25%
	2019 Planned UG Rebuild total	**$994,737**			

f) The Regional Plan for the GTA East is not included with OPUCN's application. However, it is factored into the OPUCN submission and is consistent with the latest findings of the participant contributors to the plan. The GTA East regional plan is expected to be finalized and released by the end of Q2, 2015. OPUCN planners have been intimately involved with the IESO and HONI planners in the analysis, development of alternative solutions and conclusions reached for the regional plan thus far.

Those costs are determined by Hydro One, and NBM was retained to review only OPUCN's capital projects and not Hydro One's. In respect of the distribution level projects associated with the Hydro One regional planning reinforcement, as of the date of the NBM study, OPUCN had no definition on whether such investments would be required or what they would need to be. OPUCN has reflected in its application and updates the latest information on costs that HONI has provided through the regional planning initiative.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-54

Ref: Exhibit 10, Tab B, page 1

a) Please provide more information regarding the "essential considerations for the estimates". Please provide a list or examples of these considerations.

b) Which of these considerations would be subject to changes outside OPUCN's control? Which would be subject to change at OPUCN's discretion?

Response:

a) Only those items noted in the NBM tables were considered in the project estimates. This includes for example the type of project - maintenance or capital, the build category - overhead, underground, station, the intended solution – new build or rebuild, and the size and location - unit volume and scale. These are required inputs for NBM to apply its knowledge and experience of the industry construction practices to establish project estimates.

b) All of the considerations listed above would be subject to change within OPUCN's discretion. There could also be external drivers, outside of OPUCN's control which could change the type of project, the build type, the solution type, and the size or location. An example is changes in customer needs that could impact any or all of the essential considerations listed above and hence project cost estimates. Another example is utility corridor conflicts in underground projects such as proximity to buildings and/or proximity to trees for overhead projects. The use of project contingencies are a pragmatic solution to account for the unknowns or the cost of imperfect information that would be experienced during the actual project construction phase.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-55

Ref: Exhibit 10, Tab B, page 2

The evidence indicates that in developing the cost estimates for the substation projects, NBM Engineering used industry standards along with an in-house resource table, and that the accuracy and practicality of the task was verified by former Hydro employees under contract.

a) Please identify the former employer of the contract employees, referred to as "Hydro".

b) With respect to the "industry standards", is this information publicly available? If yes, where can it be found? If no, is NBM Engineering willing to provide it?

c) With respect to the "in-house resource table", is this information publicly available? If yes, where can it be found? If no, is NBM Engineering willing to provide it?

d) Were the same sources of cost information used for project categories other than substations? If no, what sources of cost information were used for each of the other project categories listed?

Response:

a) NBM Engineering has several former employees of Hydro companies including but not limited to Toronto Hydro, Enersource, Milton Hydro, Burlington Hydro, to name a few.

b) No, the utility standards books are not widely available to the public at large and since NBM has prepared construction standard drawings for several utilities they would require the utility permission to disclose and reproduce.

c) No, the "in-house resource table" is not publically available and NBM respectfully declines to provide this information. This is proprietary information developed by

NBM for application to its projects, and its public release would harm NBM's competitive and commercial position in the market.

d) Yes.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-56

Ref: Exhibit 10, Tab B, page 3

Please confirm that the projects MS10 and MS11 maintenance (2015) and MS2 and MS15 maintenance (2016) are grouped under the station breaker replacement heading in the 2015 – 2019 summary chart.

Response:

Yes they are included under those headings.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-57

Ref: Exhibit 10, Tab B, pages 5-15

a) For the planned overhead and underground projects, if a project estimate is given in a particular year, does that indicate that the project is planned to be completed in that year?

b) Are there any overhead or underground projects in the charts that are listed in more than one year? If no, does this mean all projects are initiated and completed in one year? If yes, for each such project please indicate whether the cost estimates in each year are to be added to produce the total cost estimate for the project.

Response:

a) Yes.

b) No overhead and underground projects are listed in more than one year. For planning purposes all overhead and underground projects are initiated and completed in one year.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-58

Ref: Exhibit 10, Tab A, page 1

OPUCN achieved Group 2 benchmark cost performance in 2014. If the Board approves this application as filed, OPUCN drops to Group 3 in 2015.

a) Please provide the reasons for this drop.

b) At what point over the 2015 – 2019 period does OPUCN achieve Group 2 status in its benchmark cost performance?

c) What are the key factors that contribute to OPUCN's change in benchmark cost performance?

Response:

a) As noted on page 10 of PEG's report, OPUCN forecasts high capex in 2015 and brisk OM&A growth. Also, during PEG's study for OPUCN, the Company investigated a question PEG raised in regards to reported km of line. OPUCN determined that km of line reported to the Board under their RRR filing requirements were incorrect for the years 2002 through 2005. The effect of the data revision was to lower the value of the average line km variable, lowering predicted cost. OPUCN would have benchmarked at greater efficiency than it has, were the previously reported km of line used instead of the corrected data.

b) As can be seen in Table 4 of the PEG report, OPUCN reaches a cost performance level of -11.1% in 2017. Because the threshold for Group 2 is a performance of -10%, 2017 is the time at which OPUCN is forecasted to achieve Group 2 status. It would retain this status in 2018 and 2019.

c) Cost performance improves for two reasons. First, the same capex surge that is forecasted to depress cost performance in 2015 tends to slow capital cost growth in the following years as the plant added in that year starts to depreciate. Meanwhile, OPUCN is forecasting slow OM&A cost growth. The productivity results in Table 5 of PEG's Report are consistent with this explanation. It can be seen the capital, OM&A, and total factor productivity growth all rebound after 2015.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-59

Ref: Exhibit 10, Tab A, page 9

Please confirm that OPUCN's new information for the values for the "average line miles" has been filed under RRR. Are there any other differences between OPUCN's historical data used in PEG's analysis and the data in RRR? If yes, please explain the reasons for the differences.

Response:

OPUCN's revised "average line miles" have not been filed under RRR. OPUCN only recently determined the error in historical data. During the next RRR filing period, OPUCN will determine the methodology for updating the RRR database.

There are no other differences.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-60

Ref: Exhibit 10, Tab A

Please confirm that to create an econometric benchmarking model to predict OPUCN's benchmark costs to compare with OPUCN's forecasted costs, the data used was drawn from the indexes described in the evidence at Exhibit 10, Tab A.

Was any data from other utilities used to specify the model or to derive the econometric benchmark? Why? If yes, please describe the data (including utility names, data source, data elements, and time series, etc).

Response:

As explained in the first full paragraph on page 13 of PEG's report, PEG benchmarked OPUCN's forecasted cost using the econometric model it developed for the OEB. The development of benchmarking models for OPUCN and other distributors is discussed in PEG's November 2013 report prepared on behalf of the OEB. As the report details, the models were estimated using data on the operations of Ontario electricity distributors which they submitted to the Board. Price indexes used in the modelling were obtained from Statistics Canada. To benchmark forecasted costs, PEG extended these indexes using forecasts of the same or similar indexes from the Conference Board of Canada.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-61

Ref: Exhibit 10, Tab A, page 6

At this page of the Exhibit, it is stated that the model used to benchmark OPUCN is "very similar to that estimated using the full sample of data and presented in our November 2013 report".

a) Please describe any differences between these two models, and the implications, if any, of these differences on the value of the analysis to the Board in considering OPUCN's application.

b) The Board determined it would not re-estimate the econometric benchmarking model parameters when benchmarking utility costs for the purpose of assigning stretch factors, so that utilities would have more certainty as to what cost performance improvements were needed to move from one group to another. Were the model parameters re-estimated for PEG's OPUCN work? Why? If so, what implications, if any, does this have to the interpretation of OPUCN's forecasted benchmarks and their comparability with the Board's annual benchmarking results for OPUCN?

c) Which inputs, assumptions and variables (and any other parameters) in the benchmarking model contribute the most to the 11.7% benchmark differential between the model's predicted and OPUCN's forecasted costs? What are the implications, if any, of using different benchmarking model parameters for this analysis than the Board's annual benchmarking analysis?

Response:

a) & b) PEG notes on page 5 of its report that in the study for the OEB detailed in its November 2013 report:

> *"The business condition variables in the econometric cost models were chosen based on runs using data for all 73 Ontario distributors. Once chosen, however, the benchmarks for each sampled company were based*

on unique parameter estimates for the variables that were estimated using a 72-company data set that excluded the benchmarked company."

This was done to ensure that the data for each subject utility would not influence the benchmark by which its cost performance would be judged.

The exclusion of Oshawa from the sample has a small impact on the parameter estimates, as might be expected. As an illustration, the difference in the estimated parameter values for the number of customers is 0.0153 (0.4568 used for Oshawa vs. 0.4415 from the report). All else equal, this means that a 1% change in the number of customers using the 2013 report parameter estimates would have an impact on the cost benchmark that is 0.0153% less than the parameters used in the PEG analysis of OPUCN. Were the model featured in the November 2013 report to be used to benchmark OPUCN's forecasted costs, small differences in the results would be expected.

c) As explained in our response to parts a) & b) of this question, PEG's study for OPUCN used the Board's model for OPUCN. PEG has not considered how the outcome might differ with inputs, assumptions, and variables that differ from those that it employed in its study for the Board.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-62

Ref: Exhibit 10, Tab A, Table 5

Using PEG's instructions on how to derive a utility-specific TFP trend1[1] and using PEG's working papers posted on Nov 21-13 and updated Dec 20-13 and Jan 24-14[2], staff calculated OPUCN's annual growth in TFP as summarized in Table 1 (attached as an Appendix to these IRs) below. Staff found OPUCN's average growth in TFP over the 2002-2012 period to be -0.42%. Staff's results for 2010, 2011 and 2012 differ from the results shown for those years in Table 5 of the Exhibit. Please provide insight into the reasons for the different results.

a) Please calculate OPUCN's long run total factor productivity trend from 2002-2012, and from 2012 to the present.

b) Which inputs, assumptions and variables (and any other parameters) in the analysis contribute the most to the trend over the 2002-present time period? What are the implications, if any, to the Board's consideration of OPUCN's application?

c) Please confirm that the cost performance benchmark results and forecasted total factor productivity trend for OPUCN were calculated solely on the basis of forecast numbers provided by OPUCN.

d) Please confirm that the evidence compares OPUCN's forecast future TFP only to the historical Ontario distribution industry TFP. Please comment on the value of this comparison for the Board's purposes in considering OPUCN's application.

Response:

a) & b) The productivity results presented by PEG for OPUCN in its report were designed to help interpret and analyze the econometric cost benchmarking results. As such, they used the same cost specification used in the benchmarking

[1] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/401172/view/
[2] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379%20PEG%20TFP%20and%20BM%20database%20calculations.xlsx

work. The productivity work cited in the preamble to Staff's question above, which PEG prepared for the OEB, was instead used to establish a long run total factor productivity trend for the Ontario power distribution industry to inform the Board about an appropriate base productivity trend to include in the X factor. This work used a different cost specification than the benchmarking work.

The reasons for the different cost specifications are discussed in PEG's November 2013 report. The benchmarking cost specification was selected to allow for fair comparisons among distributors at a given point in time. The productivity cost specification was chosen to help identify a reasonable long run trend for the Ontario power distribution industry.

The differences between the cost specifications are discussed on page 4 of PEG's OPUCN report. One notable difference is the exclusion of smart meter costs from the productivity data set. Another is the exclusion of customer contributions from this data set.

The following table reports productivity trends for OPUCN using both cost specifications over the 2003-2012 period. The results using TFP cost are the same as those which Staff mentions in the preamble to this question. It can be seen that the calculated TFP growth of OPUCN was considerably slower using the benchmarking data set. This is due almost entirely to a slower capital productivity trend. The OM&A productivity trends are quite similar using the two data sets.

OPUCN Productivity Trends

	Growth Rates of Productivity Indexes and Components															
	Cost				Input Prices			Input Quantities			Productivity (Using Benchmarking Cost)			Productivity (using TFP Cost)		
Year	OM&A	Capital	Total	Output Quantity	OM&A	Capital	Total	OM&A	Capital	Total	OM&A	Capital	Total	OM&A	Capital	Total
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H=A-E]	[I=B-F]	[J=C-G]	[D-H]	[D-I]	[D-J]			
2002																
2003	-9.7%	4.7%	-1.7%	1.8%	2.2%	0.5%	1.1%	-11.9%	4.3%	-2.0%	13.8%	-2.4%	3.9%	13.8%	-0.4%	6.1%
2004	-5.8%	4.8%	0.4%	0.9%	2.5%	0.2%	1.1%	-8.3%	4.6%	-0.5%	9.2%	-3.7%	1.4%	9.4%	-3.9%	1.8%
2005	1.1%	10.6%	6.9%	0.5%	3.2%	0.9%	1.8%	-2.1%	9.6%	5.1%	2.6%	-9.2%	-4.6%	2.7%	-4.1%	-1.3%
2006	-1.4%	3.6%	1.8%	1.0%	1.8%	-0.7%	0.2%	-3.2%	4.4%	1.5%	4.2%	-3.3%	-0.4%	4.2%	2.3%	3.1%
2007	7.9%	7.7%	7.7%	1.6%	3.3%	2.4%	2.8%	4.6%	5.2%	5.0%	-2.9%	-3.6%	-3.3%	-3.2%	-3.2%	-3.2%
2008	2.9%	6.0%	4.9%	0.7%	2.4%	2.4%	2.4%	0.5%	3.6%	2.4%	0.2%	-2.9%	-1.7%	0.2%	-1.3%	-0.7%
2009	-0.4%	2.8%	1.6%	0.1%	1.3%	1.2%	1.2%	-1.7%	1.6%	0.3%	1.8%	-1.5%	-0.3%	1.9%	-1.3%	0.0%
2010	-0.4%	7.2%	4.6%	0.6%	3.0%	2.0%	2.4%	-3.4%	5.2%	2.0%	4.0%	-4.6%	-1.4%	4.0%	0.4%	1.8%
2011	12.4%	3.0%	6.3%	0.2%	1.7%	0.2%	0.7%	10.7%	2.9%	5.6%	-10.5%	-2.7%	-5.4%	-9.7%	-3.0%	-5.7%
2012	12.0%	-3.2%	2.5%	0.1%	1.6%	-5.2%	-2.7%	10.4%	2.0%	5.1%	-10.3%	-1.9%	-5.0%	-10.9%	-2.5%	-6.1%
Average 2003-2012	1.84%	4.72%	3.49%	0.75%	2.29%	0.39%	1.11%	-0.45%	4.33%	2.44%	1.20%	-3.58%	-1.69%	1.23%	-1.69%	-0.42%

c) PEG obtained the required input price forecasts from the Conference Board. All other data were provided by OPUCN.

d) Confirmed.

We believe that this comparison is useful in assessing the reasonableness of OPUCN's proposal for a number of reasons:

- Forecasted cost growth should conform to an external productivity growth standard to the extent possible in a custom IR filing.

- The Board has deemed the recent historical trend in the TFP of provincial power distributors to be a reasonable base productivity trend.

- There is no reason to believe that the difference between Board's TFP and benchmarking data sets makes the productivity trend that PEG prepared for the Board irrelevant.

- OPUCN's forecasted cost growth is commensurate with this TFP trend plus a stretch factor well in excess of that deemed appropriate for comparably efficient companies under IRM4.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-63

Ref: Exhibit 10, Tab A, page 19

On this page of the Exhibit, the evidence states that "Capital productivity growth is positive from 2017 – 2019, due in part to depreciation of recent high capex." Please explain how depreciation is a source of productivity growth.

Response:

Capital quantities are typically assumed to depreciate gradually in productivity studies. A temporary surge in capex will then be followed by a period of unusually slow capital quantity growth as the capital from the surge year begins to depreciate. In PEG's recent productivity studies for the Board a geometric pattern of depreciation was used which is common in scholarly and governmental productivity studies.

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-64

Ref: Exhibit 10, Tab A

In the Board staff interrogatories on the Load Forecasts and OM&A costs, staff has questioned the customer and load forecasts provided by OPUCN. If customer counts and load growth are reduced over the course of the OPUCN plan, (for instance, annual residential customer growth of 1.5% rather than 3.0%, and total kWh growth of 1.0%, rather than 1.3%) how would his affect OPUCN's predicted benchmark cost performance and its forecasted annual growth in TFP over the course of the plan? Please provide a calculation of how these changes would affect the PEG results.

Table 1: OPUCN Total Factor Productivity Trend

			Annual Growth Rates in Outputs				Input Costs		Input Quantities		Annual Growth Rates in Inputs		Share Calculations							
PEGID	Company Name	Year	Customer Numbers	Deliveries	Capacity Proxy	Growth in Output Quantity	OM&A	Capital	OM&A	Capital	OM&A	Capital	Total Costs	OM&A Share	Capital Share	Average OM&A Share	Average Capital Share	Growth in Input Quantity	Annual Growth in TFP	Average Growth i
54	OSHAWA PUC NET INC.	2002					8,874,750	9,826,455	88,747	586,949			18,701,205	47.5%	52.5%					
54	OSHAWA PUC NET INC.	2003	1.4%	2.5%	2.7%	1.9%	8,050,337	10,099,526	78,760	600,418	-11.9%	2.3%	18,149,863	44.4%	55.6%	45.9%	54.1%	-4.3%	6.1%	
54	OSHAWA PUC NET INC.	2004	1.0%	-1.5%	2.2%	1.1%	7,593,543	10,631,704	72,463	630,884	-8.3%	4.9%	18,225,247	41.7%	58.3%	43.0%	57.0%	-0.8%	1.8%	
54	OSHAWA PUC NET INC.	2005	1.7%	-4.0%	0.0%	0.6%	7,675,842	11,243,162	70,970	661,039	-2.1%	4.7%	18,919,003	40.6%	59.4%	41.1%	58.9%	1.9%	-1.3%	
54	OSHAWA PUC NET INC.	2006	2.1%	-1.9%	0.0%	1.0%	7,571,117	11,020,964	68,739	652,809	-3.2%	-1.3%	18,592,081	40.7%	59.3%	40.6%	59.4%	-2.0%	3.1%	
54	OSHAWA PUC NET INC.	2007	0.9%	7.3%	0.0%	1.3%	8,193,467	11,811,742	71,948	682,904	4.6%	4.5%	20,005,209	41.0%	59.0%	40.8%	59.2%	4.5%	-3.2%	
54	OSHAWA PUC NET INC.	2008	1.6%	-2.2%	0.0%	0.8%	8,435,686	12,350,704	72,344	697,175	0.5%	2.1%	20,786,390	40.6%	59.4%	40.8%	59.2%	1.4%	-0.7%	
54	OSHAWA PUC NET INC.	2009	0.7%	-2.7%	0.0%	0.1%	8,399,846	12,679,017	71,117	707,118	-1.7%	1.4%	21,078,863	39.8%	60.2%	40.2%	59.8%	0.2%	0.0%	
54	OSHAWA PUC NET INC.	2010	1.0%	-0.5%	0.0%	0.6%	8,362,787	12,962,946	68,727	708,377	-3.4%	0.2%	21,325,733	39.2%	60.8%	39.5%	60.5%	-1.2%	1.8%	
54	OSHAWA PUC NET INC.	2011	0.7%	-2.8%	0.8%	0.4%	9,402,665	13,421,696	75,993	732,276	10.0%	3.3%	22,824,361	41.2%	58.8%	40.2%	59.8%	6.0%	-5.7%	
54	OSHAWA PUC NET INC.	2012	0.5%	-1.5%	0.0%	0.2%	10,665,324	13,084,837	84,859	751,862	11.0%	2.6%	23,750,161	44.9%	55.1%	43.1%	56.9%	6.3%	-6.10%	

Response:

OPUCN provided PEG with the following alternate data on output quantities for the years 2015-2019, as per the Board's request. These represent a 1.5% growth in customers instead of 3.0% and delivery volumes that show a slight decline from 2014 levels as per the adjustment to OPUCN's load forecast model. Calculations that reflect these alternative output values are shown in the following table:

Year	Alternate Customer Count	Alternate kWh	Cost Performance Using Alternate Values	TFP Growth Using Alternate Values	OM&A Productivity Using Alternate Values	Capital Productivity Using Alternate Values
2015	55,432	1,094,258,372	-5.6%	-3.94%	-3.10%	-4.44%
2016	56,263	1,097,886,864	-6.5%	-0.40%	0.05%	-0.67%
2017	57,107	1,095,158,615	-8.5%	0.55%	2.15%	-0.37%
2018	59,964	1,126,453,867	-12.9%	3.46%	5.22%	2.46%
2019	58,833	1,094,844,359	-14.4%	-0.60%	1.28%	-0.60%

It can be seen that with the alternative values OPUCN's forecasted cost still reaches a category 2 status, but in 2018 instead of 2017. The resulting TFP trend using the alternate values is -0.19% from 2015-2019. Please note that these alternate results are only relevant if one assumes that OPUCN would have no reduction in cost as a result of slower growth in output.

OSHAWA PUC NETWORKS INC.

Response to The Consumers Council of Canada (CCC) Interrogatory 10.0-CCC-37

(Ex.10/TC/p.2)

OPUCN has measured its embedded efficiencies in relation to “per customer” measures. Has OPUCN measured its embedded efficiencies in relation to unit costs of work? For example, during the test years, how do the costs compare to replace like transformers, poles and other equipment to historic years. Are there other units of measurement to demonstrate improved efficiency and productivity that OPUCN has studied? If not, why not. If yes, why were none of those other metrics proposed in this application?

Response:

OPUCN did not measure its efficiencies in relation to unit costs of work.

OPUCN has used per customer measures in addition to a number of other mechanisms and metrics including PEG’s Benchmarking Report [Exhibit 10, Tab B], distribution rate comparisons [presentation filed with the Board on April 1, 2015] and trend analyses that are included in all of OPUCN’s exhibits related to costs.

OPUCN has also addressed the Board’s requirements relating to stretch factors and other productivity and efficiency indexes in its response to 10.0-Staff-44.

OSHAWA PUC NETWORKS INC.

**Response to The Consumers Council of Canada (CCC)
Interrogatory 10.0-CCC-38**

(Ex.10/TC/p.15)

Why is OPUCN only including the System Renewal Program and the New Municipal Substation in their proposed Incentive Mechanism rather than including all capital work programs?

Response:

Please see interrogatory response 10.0-Staff-45.

OSHAWA PUC NETWORKS INC.

Response to The Consumers Council of Canada (CCC) Interrogatory 10.0-CCC-39

(Ex.10/TD/p.9)

Please explain how OPUCN adjusted its working capital allowance in previous rate applications?

Response:

In previous rebasing applications, OPUCN's working capital allowance was calculated for the test year. Under Price Cap IRM, working capital allowance is escalated along with all other cost parameters in accord with the IRM formula, for the ensuing years of the price cap term.

OSHAWA PUC NETWORKS INC.

Response to The Consumers Council of Canada (CCC)
Interrogatory 10.0-CCC-40

(Ex.10/TD/p.9)

Has OPUCN completed any benchmarking or review to see if any other LDC has used this approach to adjust its working capital allowance?

Response:

Please see response to interrogatory 10.0-Staff-42.

OSHAWA PUC NETWORKS INC.

**Response to Energy Probe Research Foundation (Energy Probe)
Interrogatory 10.0-Energy Probe-65**

Ref: Exhibit 10, Tab A, page 4

The evidence states that OPUCN's cost performance will gradually rise from a level commensurate with a Group 3 stretch factor in 2015 to a level commensurate with a Group 2 stretch factor in later years of the plan.

Please provide the Group that OPUCN was in for each of 2010 through 2015 based on the respective PEG report to the OEB.

Response:

The referenced PEG reports only exist for the assignment of 2014 and 2015 stretch factors. The 2014 stretch factor was based upon three year average cost performance from 2010-2012. The 2015 stretch factor was based upon three year average cost performance from 2011-2013. Based on the reported cost performance results, OPUCN was assigned to Group 2 for both 2014 and 2015.

OSHAWA PUC NETWORKS INC.

**Response to Energy Probe Research Foundation (Energy Probe)
Interrogatory 10.0-Energy Probe-66**

Ref: Exhibit 10, Tab A, Table 2

a) Please provide a table for each of OM&A, customer and delivery volumes in which the figures for 2010 through 2019 are compared to the figures provided elsewhere in the evidence. Please include a column that shows any difference, by year, for each of the three requested tables.

b) Please explain any difference in the tables provided above.

Response:

For the years 2014 through 2019 please see response to interrogatory 10.0-SEC-39.

For the years prior to 2014, the requested task would involve considerable work with little value. The data used by PEG was taken from OPUCN's RRR reports, which in turn was data reflecting the actual OPUCN outcomes for the relevant years. There is thus nothing significant to reconcile.

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-67

Ref: Exhibit 10, Tab A

a) What is the date of the price forecast purchased from the Conference Board of Canada noted on page 13?

b) Please update the analysis and all impacted tables based on the most recent price forecast available from the Conference Board of Canada.

Response:

a) The 2 Canadian data series purchased on 10/17/14 had last been updated 9/9/14.

- Engineering structures, Electric power generation, transmission and distribution [PIBPOWNSE (1981:Q1 - 2019:Q4)]
- Implicit Price Deflator – GDP at Market Prices [PGDP (1981:Q1 - 2019:Q4)]

The Provincial data series purchased on 10/17/14 had last been updated 7/25/14.

- Average Weekly Wages & Salaries Per Employee, Ontario [RLAWWIO (1983:Q1 - 2018:Q4)]

b) The requested task has not been performed since it would involve considerable new work and would be unlikely to produce materially different results as there has not been a big change in inflation expectations.

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-68

Ref: Exhibit 10, Tab A

In the *'Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update Report to the Ontario Energy Board'* dated July 2014, OPUCN is shown in Table 3 as having actual cost less predicted costs of -18.1% for 2010-2012 and -17.6% for 2013.

a) Please expand Table 4 in Tab A to include figures for 2010 through 2014, using actual figures for these years.

b) Please provide a version of Table 4 that reflects forecasted figures for each of 2015 through 2019 that results in a cost performance equal to that recorded in 2013 of -17.6% in each of the years shown.

c) Please confirm that the forecasted figures in Table 4 are all consistent with the evidence elsewhere in the application. If this cannot be confirmed, please provide a version of Table 4 where the forecasted figures shown for each year are consistent with the evidence filed in the current application.

Response:

a) There are no comparable figures available for the years requested. Please see response to interrogatory 10-Energy Probe-66.

b) The requested tasks would involve considerable new work and have not been performed.

c) Please see response to interrogatory 10.0-SEC-39.

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-69

Ref: Exhibit 10, Tab C

Please update Table 9 to reflect the most recent forecast and actual data from the Conference Board of Canada.

Response:

Please see response to interrogatory 10.0-Energy Probe-42, part f).

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-70

Ref: Exhibit 10, Tab C

a) Please confirm that the TCECM is solely dependent on the return on equity in the calculation of any efficiency carryover.

b) Please explain why the proposed TCECM is not symmetrical. If the TCECM was symmetrical, would this not provide an incentive to OPUCN to employ efficiency initiatives to at least meet the target ROE in order to avoid lower returns for 2 years?

c) Please confirm that because the incentive is based on ROE, there may be an incentive for OPUCN to over forecast capital expenditures, OM&A and to under forecast customer additions, distribution revenues and other revenues.

d) Please confirm that because the incentive is based on ROE there may be an incentive to delay capital expenditures and OM&A expenditures as much as possible in order to achieve returns in excess of those based on the forecast.

e) How does the TCECM avoid the delay of capital expenditures and OM&A expenses to beyond the 5 year period in order to increase the ROE in each of the 5 years, especially for expenditures in the last few years?

Response:

a) Confirmed.

b) OPUCN already has incentive to meet, and exceed, Board approved ROE in all years of its Custom IR plan, in order to benefit from increased ROE during the plan term. It is true that a symmetrical TCECM would directionally increase that incentive. However, the intention of the TCECM is to remove the disincentive for late in the rate plan term sustainable efficiency investments, and not to penalize OPUCN for lack of efficiency (beyond the penalty imposed by the assumption by OPUCN of that risk under the proposed rate plan).

c) Directionally an over forecasting of capital expenditures and OM&A would produce a greater chance of triggering the end of plan term TCECM reward. OPUCN believes that its comprehensive independent third party benchmarking reports (by NBM Engineering, Metsco and PEG) should provide the Board and the parties with comfort that OPUCN has not done this.

Similarly, directionally an under forecasting of customer additions, distribution revenues and other revenues would produce a greater chance of triggering the end of plan term TCECM reward. OPUCN believes that its forecasts of these parameters are robust, and robustly evidenced. OPUCN is more concerned that the aggressive customer growth forecasts driven by information obtained from the City of Oshawa, the Region of Durham, and local developers is overly optimistic rather than overly conservative. In any event, adjustment mechanisms have been proposed which will allow for incorporation of better customer connection and revenue forecasts as updated information becomes available during the proposed plan term.

d) Directionally, delays in capital and OM&A expenditures beyond the end of the Custom IR Plan term would produce a greater chance of triggering the end of plan term TCECM reward. OPUCN believes that the third party validation (by Metsco) and approval in this application of its comprehensive Distribution System Plan, and its commitment to report annually on execution of its approved plan, will address this concern. OPUCN will similarly continue to report annually on its reliability indices. OPUCN also assumes that its eligibility for TCECM will be determined in the rate case for the 2020 test year, and that parties will then be able to assure themselves that OPUCN's expenditures were appropriate and that any cost savings were the result of true efficiencies rather than spending deferrals.

e) The intention of an "efficiency carryover mechanism" such as the TCECM is precisely to mitigate the natural <u>dis</u>incentive during a incentive regulation plan term to defer efficiency investments, particularly in the later years of the plan term when any resulting savings accrue to the utility only for a short time.

There is nothing built into the proposed TCECM (nor to any other ECM's of which OPUCN is aware) which *"avoids the delay of capital expenditures and OM&A expenses"*, beyond the mitigation of the <u>dis</u>incentive on plan term investment. OPUCN believes that other aspects of the reporting and monitoring framework associated with Custom IR Plans should provide the Board and the parties with some comfort regarding this concern. Please see response to part d).

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-71

Ref: Exhibit 10, Tab C

With respect to the CCIEIM:

a) Please confirm that actual costs would be tracked at the program level for the two programs, and not on a project by project basis within the system renewal program.

b) Please explain fully how the costs associated with projects within the system renewal program would be tracked (on a project by project basis or on an aggregate basis) and compared to the forecasted costs taking into consideration such things as i) projects done that were not included in the forecast; ii) projects in the forecast that were not done; iii) changes in projects that change the magnitude (increase or decrease) of the project.

c) Please confirm that the CCIEIM proposal builds in a bias to over forecast the cost of these programs, given the result is that OPUCN would receive a benefit for not spending money.

d) Please provide an example of each of a $1 million over spend and under spend in the rate rider calculation for 2020 and the impact on rates beyond 2020.

e) Please confirm that there would be no rate rider calculations in 2015 through 2019 and that the mechanism only applies to the total spend over the 2015 through 2019 period.

f) Please confirm that the timing of the expenditures in 2015 through 2019 as forecast would not be relevant in the calculation of the rate rider, as the only thing that is relevant is the capital expenditure over the 5 year period.

g) Please explain how this would ensure that OPUCN does not delay spending on capital until 2019 in order to earn high returns in 2015 through 2018 and avoid an under spend in the 5 year period.

Response:

a) OPUCN intends that costs will be reported at the program level for each of the System Renewal Program and the Distribution Station program, and that the CCIEIM calculations would be done at the program level. As noted in the evidence, the costs of those projects not completed within the Custom IR term for reasons beyond the reasonable control of OPUCN would be removed for the purposes of applying the CCIEIM.

b) OPUCN's intention is that the CCIEIM incent efficiency and innovation in capital investment related to the two programs identified for inclusion in this incentive mechanism proposal. As indicated in the evidence, the onus will be on OPUCN to demonstrate that the completed projects achieve the results of the capital program as defined in OPUCN's Distribution System Plan. If OPUCN can achieve those results through modification of any of the projects or components of the program, and such modification results in reduced capital investment, then OPUCN should be rewarded for executing the approved program in a different, innovative manner and thereby reducing ratepayer costs. (If, on the other hand, OPUCN's initiatives don't work, and costs exceed those approved through approval of the Distribution System Plan, than OPUCN would be "penalized" by being allowed only a portion of the incremental costs in rate base going forward.) To maintain incentive and flexibility for innovation and creative efficiency, OPUCN has focussed its proposed CCIEIM at the <u>program</u> level, and proposes that its performance be evaluated on that basis. OPUCN anticipates having to demonstrate that the objectives of each of the system renewal projects have been addressed by its system renewal program in order to qualify for an incentive at the end of the plan period.

c) Directionally, over forecasting the cost of the CCIEIM eligible programs would produce a greater chance of triggering a CCIEIM incentive. OPUCN believes that the third party validation (by Metsco) and approval in this application of its comprehensive Distribution System Plan, it's continuing capital investment efficiency as demonstrated by the PEG econometric benchmarking study and statistical comparison of its forecast costs to the current costs of its peers, and its commitment to report annually on execution of its approved plan, address this concern. OPUCN also assumes that its eligibility for a CCIEIM award will be determined in the rate case for the 2020 test year, and that parties will then be able to assure themselves that any investment savings were the result of true efficiencies rather than spending deferrals.

d) Please see response to interrogatory 10.0-SEC-47, part f).

e) Confirmed.

f) Confirmed. OPUCN will, however, be reporting annually on its progress in executing its approved Distribution System Plan, and parties would be free to raise concerns regarding execution of that plan should they wish to do so.

g) OPUCN may not fully understand this question. The point of the CCIEIM is to incent “under spend” on capital during the plan term, consistent with prudent execution of the Distribution System Plan approved in this application as a prudent plan. The nature of a multi-year incentive regulation plan, including the Custom IR Plan proposed by OPUCN, is that the utility is left to manage its affairs within the parameters of the approved plan, including the timing of expenditures, provided that the plan outcomes approved are achieved. To the extent that the suggestion is that all capital expenditure would be deferred to the end of the plan, such an approach would be both imprudent and practically impossible given OPUCN’s resources and the amount of work involved in proper execution of the Distribution System Plan required to meet OPUCN’s obligations and the growth and consequent distribution system investment requirements in the City of Oshawa. Continuing prudent execution of the approved Distribution System Plan will be the subject of annual reporting by OPUCN, and parties will be free to raise any concerns with OPUCN’s progress during OPUCN’s annual rate adjustment proceedings.

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-72

Ref: Exhibit 10, Tab D

Through the annual rate adjustment process, OPUCN proposes adjustments for updated actual and forecast costs for required contributions to Hydro One Networks Inc. for transmission upgrades, un-budgeted distribution projects required as a result of regional planning service in OPUCN's distribution area and updated actual and forecast costs for required relocation of OPUCN distribution plant in response to 3rd party requests, as well as updated forecasts of net new customer connection costs.

a) Please confirm that at the time rates are set for each of 2016 through 2019, OPUCN would only have actual data for the year two years earlier and would not have actual data for the immediately preceding year (for example, for 2018 rates, actual data would be available for 2016, but not for 2017).

b) Does OPUCN propose to provide and updated "bridge" year forecast as part of the annual adjustment process? Fully explain the response, including providing an example.

c) How is OPUCN's proposal, noted above, different than an incremental capital module if the actual and forecasted costs noted above are significantly different from what is included in the current forecast?

d) Would each of the adjustments being proposed by OPUCN related to capital expenditures qualify for an incremental capital module if OPUCN were under the 4th generation price cap IR model? Please explain fully.

e) Please provide a table that shows for 2012 through 2019, including actual data for 2014, the total net customer connection costs, the number of customer connections and the resulting net cost per customer connection.

Response:

a) Using the annual rate adjustment proceeding to finalize 2018 rates as the example, OPUCN will have final data for 2016, and some actual and some (updated) forecast data for 2017.

b) OPUCN intends to provide the best available information that it has at the time of each annual rate adjustment application, including updated actuals and forecasts.

c) The Board has indicated that the Custom IR option is intended for distributors with significantly large multi-year investment requirements. That is the basis upon which OPUCN has brought forward this Custom IR application. In its EB-2014-0219 *Report of the Board New Policy Options for Funding of Capital Investments: The Advanced Capital Module* the Board clarified the function of the capital module approach as distinct from the rationale for Custom IR as follows [page 18, 3rd paragraph]:

> *The ACM and ICM are only available to electricity distributors opting for Price Cap IR. The ACM/ICM approach is intended to address the treatment of capital investment needs that arise <u>during</u> the rate-setting plan which are incremental to the materiality threshold defined below, while allowing the distributor to obtain necessary recovery of capital investments on a planned and prioritized basis over the whole IR period. Applicants should note that <u>custom approaches to rate setting should be addressed through selecting the Custom IR option, not by customizing an ACM or ICM proposal.</u>* [Emphasis added.]

OPUCN's proposed Custom IR Plan includes a number of adjustments to balance material risks associated with changes in certain external and uncontrollable parameters as between its shareholder and its ratepayers. The proposed adjustments are not intended to address new capital investment needs that arise during the rate setting plan term. OPUCN believes that its Custom IR approach most suitably fits its circumstances, as comprehensively described in its application materials.

d) No. Please see response to part c).

e) Please refer to the following table:

Description	Net Connections Cost	Customer Connections	Cost Per Connection
2012	153,042	324	472
2013	20,378	531	38
2014	148,346	688	216
2015	545,000	1,638	333
2016	560,000	1,688	332
2017	560,000	1,738	322
2018	575,000	1,790	321
2019	585,000	1,844	317

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-73

Ref: Exhibit 10, Tab D

With regard to the Z factor adjustment facility, OPUCN describes this as being required to address material cost increases or decreases linked to an unexpected, non-routine event not reasonably within the control of utility management or preventable by the exercise of due diligence.

a) Would the loss of a large customer qualify as a Z factor event if the loss in revenue was material?

b) Would the gain of a large customer qualify as a Z factor event if the gain in revenue was material?

c) Would a change in tax rates qualify as Z factor event, in its entirety, if the change was material? In responding to this, please include a discussion of the Board's past practice with respect to sharing of the impact of tax changes equally between shareholders and ratepayers.

d) With respect to any cost increases, would these increases be reviewed in isolation, or in conjunction with other costs, some of which may have decreased? If not, why not?

e) Would be OPUCN be required to mitigate any Z-factor event, to the best of its ability, before filing a Z-factor claim?

f) What is the level of OM&A expenses included in the forecast for each of 2015 through 2019 for a major weather event? Please also provide the actual costs associated with major weather events for each of 2011 through 2014.

Response:

a) Normally, this would be the case. However, given that OPUCN has proposed an annual mechanism for customer connections, demand and volume variances from forecast higher than normal expansion activities, the loss or gain of a large customer would be captured in such an adjustment without resort to a z-factor.

b) Please refer to part a).

c) Yes, OPUCN believes that a change in tax rates would qualify for z-factor treatment, in its entirety, if the change was material. OPUCN understands the past Board practice regarding sharing between the shareholder and ratepayers the impact of tax changes on a 50:50 basis to have been derived in the context of, and applicable to, a rate adjustment framework which includes formulaic adjustment in accord with externally identified macro-economic inflation factors. The basis for the sharing is that these macro-economic factors reflect tax changes, but on a lagged basis, and it is accordingly appropriate to recognize only a part of the impact of the tax change through an external (to the rate adjustment formula) adjustment to rates. OPUCN's Custom IR Plan proposal does not entail annual formulaic adjustment in reference to external macro-economic inflation factors, and thus no part of a prospective tax change would be reflected in the rates approved by the Board in this proceeding.

d) OPUCN has proposed a 5 year Custom IR rate plan, including a proposed set of predetermined annual adjustments, to balance risks and rewards as between its shareholder and its ratepayers. Should an unexpected, non-routine event not reasonably within OPUCN's control occur, giving rise to material cost variances from forecast that justify z-factor treatment, OPUCN would expect to seek rate changes on account of such cost variances (positive or negative). OPUCN does not expect to offset any such otherwise qualifying cost variances against other aspects of the approved rate plan. To do so would alter other aspects of the risk/reward balance approved if OPUCN's proposal is accepted by the Board.

e) Yes, as would reasonably be expected in operating an electricity distribution business.

f) OPUCN has not forecast any costs attributed to major weather events during the Test Years. The only weather event for which OPUCN tracked its costs was the December 2013 ice storm; total costs were approximately $400,000.

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 10.0-Energy Probe-74

Ref: Exhibit 10, Tab E

Given the timing of this application and the probable timing of a decision and rate order for 2015 rates, what sort of annual update process is OPUCN proposing for 2016 rates? In particular, what would be the timing of such an application, and what additional information would be used to calculate any adjustments from the forecasts included in the current application?

Response:

OPUCN would expect to file an annual update in advance of 2016, for 2016 rate adjustments, as proposed in Exhibit 10, Tab E. The timing of the annual update may be influenced by the timing of, or other direction provide in, a Decision and Rate Order for 2015.

OSHAWA PUC NETWORKS INC.

Response to Greater Oshawa Chamber of Commerce (GOCC) Interrogatory 10.0-GOCC-18

Exhibit 10, Tab B, page 2

a) What benefit rate was used for estimating costs?

b) What industry standards were used in developing the estimates?

Response:

a) The burden rate used by NBM for estimating costs was:

- Labour – Burdened at 50.23%
- Vehicle – Burdened at 34.00%
- Material – Burdened at 10.00%
- Engineering – Unburdened
- Removals – are Burdened the same way as the installations

b) The industry standards are standards that NBM has prepared using information gathered when preparing numerous construction standard drawings for several other utilities. NBM also has several former employees of Hydro companies that brought the knowledge of other utilities' standards to NBM.

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-39

[Ex.10-A]

With respect to the PEG Benchmarking the Forecasted Cost of Oshawa PUC Networks report:

a) Please provide the price forecasts from the Conference Board of Canada used in this Report. (p.4)

b) Please reconcile the OM&A, Capital Costs and Customer Level used in the study (Table 2), and the OM&A (Ex.4, p.5) and Capital Costs (Ex.2-A, p.12), and Customer Level (Ex.3, p.32) with what is set out in the rest of the application.

c) Please revise Tables 2-6 as appropriate.

Response:

Please refer to PEG's response on behalf of OPUCN:

a) Please see Attachment 1.

b) The following table reconciles amounts for the years 2014 through 2019 included in its rate application and those reported to PEG:

	OM&A		Customer Connections		Delivery MW		Capital	
	Application	PEG	Application	PEG	Application	PEG	Application	PEG
2014	10,562	10,708	54,613	54,613	1,097	1,081	13,289	13,289
2015	11,400	11,415	56,251	56,251	1,104	1,097	18,421	18,421
2016	11,850	11,881	57,939	57,939	1,114	1,117	13,082	13,082
2017	12,107	12,137	59,677	59,677	1,120	1,129	13,447	13,447
2018	12,314	12,344	61,467	61,466	1,128	1,142	13,571	13,571
2019	12,370	12,402	63,311	63,312	1,137	1,156	11,866	11,866

	2014	2015	2016	2017	2018	2019
Application [Ex4/P 5]	11,291	12,146	12,614	12,887	13,110	13,183
Bad debts	462	472	481	491	501	512
Municipal tax	155	158	162	165	168	172
Energy conservation	87	89	91	93	95	96
Donations	25	27	30	31	32	33
OM&A for Model	10,562	11,400	11,850	12,107	12,314	12,370

Notes

As per PEG's model, certain OM&A expenses are not included which are reconciled in the 2nd table.

As per PEG's model, custome connections excludes street lights, sentinel and unmetered categories.

As per PEG's model, capital expenditures are grossed up for a weighted average cost of capital component.

The capital expenditure amounts reported in Ex 2-A, Page 12 agreed with the amounts reported to PEG.

There were minor revisions in final Application results that were in most cases higher than those reported to PEG which would result in better benchmarking metrics.

c) For the years prior to 2014, the requested task would involve considerable work with little value. The data used by PEG was taken from OPUCN's RRR reports, which in turn was data reflecting the actual OPUCN outcomes for the relevant years. There is thus nothing significant to reconcile.

Description:	Engineering structures, Electric power generation, transmission and distribution (Implicit Price Series 2007=1)	Implicit Price Deflator - GDP at Market Prices (2007=1.0)	Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite)
Mnemonic:	**PIBPOWNSE**	**PGDP**	**RLAWWIO**
1981.01	0.526028932	0.447530556	
1981.02	0.542076714	0.457848746	
1981.03	0.560005894	0.468314455	
1981.04	0.577508317	0.475096736	
1982.01	0.57244937	0.488658315	
1982.02	0.580225182	0.498680612	
1982.03	0.587778621	0.507118531	
1982.04	0.579282688	0.517058655	
1983.01	0.574456462	0.521068982	330.607988
1983.02	0.574656342	0.526909708	337.651837
1983.03	0.578540612	0.537431822	342.474303
1983.04	0.579654739	0.540691205	347.918616
1984.01	0.594806014	0.544755118	353.007408
1984.02	0.600518966	0.548098956	356.435506
1984.03	0.607850053	0.552378444	360.617112
1984.04	0.616815503	0.555780904	363.677678
1985.01	0.623432511	0.559678806	368.397521
1985.02	0.622346461	0.568506797	374.629946
1985.03	0.624994867	0.571044039	378.850194
1985.04	0.623154314	0.574485624	382.370875
1986.01	0.614864711	0.578980621	386.546929
1986.02	0.616915378	0.581411206	387.811811
1986.03	0.62518347	0.587450572	394.915594
1986.04	0.635078787	0.595511344	398.952419
1987.01	0.642740018	0.60238875	403.82387
1987.02	0.645241146	0.611053282	406.713479
1987.03	0.651551172	0.617026654	411.247913
1987.04	0.671858929	0.623759553	422.28334
1988.01	0.686239647	0.630565714	425.975288
1988.02	0.684419695	0.635297825	430.136697
1988.03	0.687846898	0.645663408	434.400734
1988.04	0.693952813	0.65390937	440.560649
1989.01	0.694062442	0.658699994	446.671984
1989.02	0.695500612	0.669691833	455.787468
1989.03	0.697429048	0.676853907	461.640751
1989.04	0.698752983	0.680227049	464.527981
1990.01	0.728412148	0.684271694	466.314131
1990.02	0.732323203	0.690903709	467.974183
1990.03	0.740238713	0.698044169	477.965974
1990.04	0.74665242	0.703197145	480.717274
1991.01	0.725941828	0.710647258	487.454908
1991.02	0.725982112	0.715389105	494.019529
1991.03	0.717263464	0.717530378	498.075609
1991.04	0.715041447	0.717866754	503.118427
1992.01	0.710179869	0.721280955	505.769492

Description:	Engineering structures, Electric power generation, transmission and distribution (Implicit Price Series 2007=1)	Implicit Price Deflator - GDP at Market Prices (2007=1.0)	Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite)
Mnemonic:	**PIBPOWNSE**	**PGDP**	**RLAWWIO**
1992.02	0.704539731	0.725057326	509.926457
1992.03	0.695690001	0.728132368	514.591721
1992.04	0.698842747	0.729595291	517.74069
1993.01	0.710875642	0.732199577	520.724337
1993.02	0.702925648	0.736567786	521.787047
1993.03	0.708856948	0.73416805	523.649739
1993.04	0.713836115	0.739528368	527.25266
1994.01	0.725409864	0.74210863	533.854754
1994.02	0.734659235	0.741858318	540.463167
1994.03	0.743070736	0.748569537	543.76237
1994.04	0.740027265	0.752352982	544.890219
1995.01	0.740394151	0.757504457	548.890283
1995.02	0.737191257	0.76175675	544.941467
1995.03	0.736991759	0.764466954	550.868991
1995.04	0.738145663	0.76817161	555.669287
1996.01	0.74609536	0.771622901	560.111982
1996.02	0.764314468	0.773661784	565.719285
1996.03	0.774915332	0.77728559	572.403813
1996.04	0.776739296	0.782792687	578.789308
1997.01	0.776932156	0.785316865	583.917177
1997.02	0.796207731	0.783172156	587.117171
1997.03	0.789655265	0.784898201	592.505434
1997.04	0.800418291	0.787537673	597.822441
1998.01	0.812747925	0.785482495	597.834356
1998.02	0.811078024	0.785537259	599.603067
1998.03	0.812878888	0.780883269	599.754934
1998.04	0.820641971	0.782608409	602.825504
1999.01	0.829052298	0.786116344	611.104665
1999.02	0.831626068	0.794687366	618.818777
1999.03	0.827634631	0.803659538	626.691041
1999.04	0.827718554	0.807853362	631.872828
2000.01	0.83719015	0.817347636	633.247511
2000.02	0.840431382	0.829590465	643.658889
2000.03	0.848394482	0.837636856	655.907544
2000.04	0.854310588	0.844215919	655.968682
2001.01	0.849675707	0.853021332	662.282993
2001.02	0.851298342	0.852412226	669.090891
2001.03	0.841052616	0.842273919	671.056784
2001.04	0.849108608	0.835604328	674.551335
2002.01	0.849734381	0.839976287	677.66993
2002.02	0.8506229	0.854164937	672.483596
2002.03	0.856197553	0.859503631	673.168289
2002.04	0.859001222	0.870766218	678.449954
2003.01	0.864896302	0.882896376	677.875354
2003.02	0.853404001	0.876013518	682.158278

Description:	Engineering structures, Electric power generation, transmission and distribution (Implicit Price Series 2007=1)	Implicit Price Deflator - GDP at Market Prices (2007=1.0)	Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite)
Mnemonic:	**PIBPOWNSE**	**PGDP**	**RLAWWIO**
2003.03	0.863288229	0.889799252	688.186509
2003.04	0.867898665	0.890187572	694.497937
2004.01	0.889810735	0.901041645	705.365067
2004.02	0.902089762	0.912613839	706.78768
2004.03	0.912324624	0.91816886	696.467401
2004.04	0.924067114	0.922846395	701.217514
2005.01	0.923553875	0.928137676	716.122028
2005.02	0.927660289	0.935007519	717.160744
2005.03	0.937048526	0.948439027	728.388119
2005.04	0.949607189	0.960187264	731.039613
2006.01	0.950214514	0.961716705	736.916292
2006.02	0.957031964	0.965610695	744.950414
2006.03	0.967412246	0.97192322	749.240901
2006.04	0.969361348	0.975224089	748.26545
2007.01	0.974264892	0.989815891	740.971026
2007.02	0.990742776	1.00007101	749.954867
2007.03	1.01384203	0.998508505	774.770218
2007.04	1.01999714	1.01142325	778.720053
2008.01	1.01503497	1.03013342	779.514056
2008.02	1.04098218	1.05144427	786.073371
2008.03	1.06072851	1.05420932	787.276737
2008.04	1.07755472	1.01968238	794.448858
2009.01	1.0859539	1.00423862	800.926989
2009.02	1.08030322	1.01058605	798.687295
2009.03	1.06520907	1.0182236	799.394125
2009.04	1.0716239	1.033347	801.339543
2010.01	1.10235209	1.04128526	809.119097
2010.02	1.12060575	1.03963358	801.343525
2010.03	1.13063985	1.04113133	813.296055
2010.04	1.12884799	1.05203988	821.783442
2011.01	1.12552417	1.06502009	829.922965
2011.02	1.14208973	1.07647499	833.620592
2011.03	1.16089599	1.0781234	828.707243
2011.04	1.17697758	1.08956777	832.254077
2012.01	1.18716534	1.09306633	841.221692
2012.02	1.1717573	1.09067982	847.86136
2012.03	1.19404057	1.09643203	853.576948
2012.04	1.19771558	1.10113482	849.911358
2013.01	1.19973039	1.10902603	856.7721
2013.02	1.20172319	1.10519528	855.1171
2013.03	1.21702359	1.11158023	855.1288
2013.04	1.23463716	1.11313496	861.8868
2014.01	1.25516915	1.12881371	871.4469
2014.02	1.26686279	1.13136463	866.1449
2014.03	1.268256	1.133913	870.3889

Description:	Engineering structures, Electric power generation, transmission and distribution (Implicit Price Series 2007=1)	Implicit Price Deflator - GDP at Market Prices (2007=1.0)	Average Weekly Wages & Salaries Per Employee, Ontario ($, Industrial Composite)
Mnemonic:	**PIBPOWNSE**	**PGDP**	**RLAWWIO**
2014.04	1.270539	1.137969	875.7602
2015.01	1.283045	1.142541	880.9796
2015.02	1.290965	1.148031	886.5565
2015.03	1.299279	1.153957	891.5034
2015.04	1.307986	1.160665	897.7642
2016.01	1.317991	1.165851	903.8242
2016.02	1.327122	1.171319	910.0122
2016.03	1.336282	1.177491	916.1769
2016.04	1.345474	1.183805	922.185
2017.01	1.355105	1.189748	928.6808
2017.02	1.364194	1.196225	935.0942
2017.03	1.37315	1.203262	941.4676
2017.04	1.381974	1.210266	947.9854
2018.01	1.390173	1.216664	954.5539
2018.02	1.398927	1.222673	961.1933
2018.03	1.407746	1.229012	967.7753
2018.04	1.416628	1.235727	974.3597
2019.01	1.425255	1.242091	
2019.02	1.434393	1.248512	
2019.03	1.443724	1.254854	
2019.04	1.453246	1.2612	

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-40

[Ex.10-B]

With respect to the NBM Capital Project Cost Estimates 2015-2019:

a) Please provide the "criteria for high budgetary costing" that was provided by the Applicant to NBM.

b) Please provide the basis for a 25% contingency for underground rebuilds.

c) For each material capital project, please provide a breakdown of the project estimate.

Response:

a) No budgetary cost estimates were provided by OPUCN to NBM as confirmed by NBM. OPUCN did only provide a project scope which consists of project name, project #, location, capital project # and description to NBM part of which is included in the NBM report and shown below as a sample from the evidence filed. NBM provided the corresponding project estimate shown as well below.

2015 Overhead Project Summary:

Planned OH Projects - 2015	
Project Name:	OH-2015-01
Project #:	Park Rd - Wenthworth - Rebuild
Location:	Stone/Lakesfield/Beaupre/Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside
Capital Budget #:	OH-2015-01
Description:	185 Pole, 1 Ph, 35 Transformers, 7,400 m
Project Estimate:	$1,675,484.32

b) From a qualitative perspective, underground rebuilds have more unpredictable cost exposure than overhead projects due to the inability to accurately identify physical field conflicts with designs. The typical underground obstructions relate to maintaining clearances with other utility infrastructure (gas, communications, water) as well as natural elements such as landscaping and tree roots. Atypical underground obstructions can be encountered due to abandoned underground plant or nonstandard clearances to buildings and rights of way, etc. In all cases the contingency is additive and includes site corrective and restorative work. From a quantitative perspective, the 25% contingency is based on NBM's extensive utility experience.

c) Please refer the summary table below:

			Labour$	Material$	Other$ *	Total $ **
2015 CAPITAL PROJECTS - PRELIMINARY	**SCOPE/ COMMENTS**					
Planned OH 2015						
Park Rd Wenthworth To Stone including Lakefielsd/Beaupre/Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside Lakemount Evangeline/Montieth/Bala/Lakeview	180 poles and 7400m 8 kVsingle phase primary lines, 35 Tx	**$1,675,484**	$850,396	$522,845	$302,243	$1,675,484
Keewatin (Melrose, applegrove, Oriole, Willowdale, Springdale)	2000 m 45 poles 3 phase 13.8kV ,8 kV single phase, 24 Tx	**$677,343**	$335,416	$232,374	$109,553	$677,343
Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary	OH Rebuild - Two Laneways Total 1650 meters, 35 poles, 12 Tx	**$505,507**	$258,810	$130,205	$116,492	$505,507
	2015 Planned OH Rebuild Total	**$2,858,334**				
2015 Planned UG						
Down Crescent, Delmark Ct	UG primary cable replacement, 900 m single phase, dip poles (11 Tx connections)	**$163,752**	$24,797	$45,165	$93,790	$163,752
1333 Mary St North	UG primary cable replacement, Townhomes, 400 m single phase, dip poles (4Tx connections)	**$70,457**	$11,346	$22,619	$36,491	$70,456
Camelot Dr, Merlin Ct, Percival Ct, Lancelot Cres	UG primary cable replacement, 1850 m single phase, dip poles (14 Tx connection)	**$302,230**	$41,365	$106,309	$154,556	$302,230
Chandos Ct, Calvert Ct	UG primary cable replacement, 300 m single phase, dip poles (3Tx connections)	**$39,105**	$5,491	$9,025	$24,589	$39,105
1300 Oxford St	UG primary cable replacement, 400 m single phase, 3 TX connections dip poles	**$59,470**	$11,137	$14,933	$33,401	$59,470
	2015 Planned UG Rebuild total	**$635,014**				

2016 CAPITAL PROJECTS - PRELIMINARY	SCOPE/ COMMENTS					
Planned OH 2016						
Rossland - Ritson to Wilson	OH Rebuild - 900 m, 3 phase 44kV and 13.8kV, 24 poles 3 Tx and associated equipment	**$486,861**	$244,679	$169,920	$72,262	$486,861
Athabasca (Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield)	650m 13.8 kV 14 poles and 2000m 8 kV 40 poles, 25 Tx (#6 cu)	**$899,513**	$469,405	$283,196	$146,912	$899,513
Eastlawn,Winter,Mackenzie,Labrador	OH rebuild - 1250 m 8kV, #6cu, 35 poles, 6 Tx, and associated plant	**$406,448**	$210,357	$130,159	$65,932	$406,448
Bloor St - Oliver to MS11	20 poles, 600m 44kV and 2 circuits of 13.8kV, 3 UG dips at Station,	**$551,420**	$271,552	$193,508	$86,359	$551,420
	2016 Planned OH Rebuild Total	**$2,344,242**				
2016 Planned UG						
NorthDale Ave,Mohawk St, Beatrice Crt,	UG primary cable replacement, 1200 m single phase, dip poles (6 Txs connections)	**$163,752**	$15,422	$40,931	$107,399	$163,752
401 Wentworth Ave	UG primary cable replacement, Townhomes, 400 m single phase, dip poles (3Txs connections)	**$72,533**	$11,826	$23,162	$37,546	$72,533
1100 Oxford St	UG primary cable replacement, 900 m single phase, dip poles (7 Txs connections)	**$180,022**	$20,923	$53,776	$105,324	$180,022
Athabasca St, Suton Ct, MarcClaren, Cornwallis Crt	UG primary cable replacement, 1000 m single phase, dip poles (10 Txs connections)	**$204,706**	$26,884	$70,175	$107,647	$204,706
MS10 - 10F1 & 10F6 Lead Cable Replacement	UG Primary Cable Replacement, 235m 3-Phase, dip poles	**$351,962**	$14,129	$94,318	$243,515	$351,962
Aruba Cr, Aruba Ave, Waverly St, Bermuda Ave, Antigua Cr	Underground Cable Replacement, 2705m single phase, dip poles (15 txs connections)	**$394,363**	$32,549	$121,183	$240,631	$394,363
	2016 Planned UG Rebuild total	**$1,367,338**				

2017 CAPITAL PROJECTS - PRELIMINARY	SCOPE/ COMMENTS					
Planned OH 2017						
Central Park blvd N - Brentwood, Homewood to Harwood	OH rebuild - 2000 m 13.8 kV, 16 Tx, and associated plant	**$609,743**	$283,368	$230,550	$95,825	$609,743
Landsdowne - Dover, Digby, Surrey, Sussex	OH Rebuild - 1300 m 8kV, #6 cu, 28 poles, 8 TX, and associated equipment	**$379,094**	$181,907	$135,376	$61,811	$379,094
Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct	OH Rebuild - 1600 m 8kV,#6 cu 45 poles, 12 Tx, and associated equipment	**$484,901**	$235,597	$161,447	$87,857	$484,901
Rebuild Fisher St, Albert S, Avenue St & Quebec St	Aging OH Plant over 30 yrs 700m, 15 wood poles, 5 Tx 8kV #6 primary	**$310,733**	$132,562	$131,057	$47,115	$310,733
GrenFell South of Gibb, Marland, Montrave	OH Rebuild - 550 m 13.8kV & 8kV, #6cu, 22 poles, 4 Tx, and associated equipment	**$194,225**	$99,557	$64,098	$30,570	$194,225
	2017 Planned OH Rebuild Total	**$1,978,696**				
2017 Planned UG						
1010 Glenn St	UG primary cable replacement, 1000 m single phase, Townhomes, dip poles (9 Tx connections)	**$225,799**	$33,611	$74,513	$117,675	$225,799
Annandale St, Capilano Cres and Capilano Crt	UG primary cable replacement, 1100 m single phase, dip poles (9 Tx connections)	**$225,725**	$33,709	$76,684	$115,332	$225,725
CherryDown Dr & Sunnybrae Dr	UG primary cable replacement, 1000 m single phase, dip poles (14Tx connections)	**$225,214**	$38,013	$75,340	$111,860	$225,214
Birkdale St. Muirfield St Pinehurst, Sunningdale	UG primary cable replacement, 1500 m single phase, dip poles (8Tx connections)	**$240,052**	$24,233	$62,874	$152,945	$240,052
291 Marland Ave	Replace 3 x 50 kVA Vault TX, 80m 3 phase #2 primary	**$72,993**	$12,422	$16,789	$43,782	$72,993
321 Marland Ave	Replace 3 x 50 kVA Vault TX, 80m 3 phase #2 primary	**$82,153**	$12,471	$20,046	$49,636	$82,153
282-290 Marland Ave	Replace 3x50kVA Vault Tx, 80m 3 Phase	**$82,153**	$12,471	$20,046	$49,636	$82,153
310 Marland Ave	Replace 1x75kVA Vault Tx, 80m 1 Phase	**$59,664**	$6,427	$16,953	$36,284	$59,664
300 Grenfell	Replace 3 x 50 kVA Vault TX, 120m 3 phase #2 primary	**$55,307**	$12,422	$16,789	$26,095	$55,307
400 Grenfell	Replace 3 x 250 kVA Vault TX, 120m 3 phase #2 primary	**$90,344**	$12,422	$51,827	$26,096	$90,345
Tennyson Cr	UG primary cable replacement, 300m single phase, dip poles(2 Tx Connections)	**$53,762**	$6,524	$10,148	$37,090	$53,762
	2017 Planned UG Rebuild total	**$ 1,413,165**				

2018 CAPITAL PROJECTS - PRELIMINARY	SCOPE/ COMMENTS					
Planned OH 2018						
Julianna & Bernhard	OH Rebuild - 855 m 8kV, #6 cu, 24poles, 6 Tx and associated equipment	**$268,072**	$137,819	$85,014	$45,239	$268,072
Mary -Rossland to Aberdeen	OH Rebuild - 1000 m, 1 phase 8kV, #6 cu, 26 poles, 5 Tx and associated equipment	**$203,705**	$144,437	$90,328	$48,940	$283,705
Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle	OH rebuild - 2200 m 1 phase 8kV, 55 poles, 17 Tx and associated eqyipment	**$740,799**	$342,665	$285,323	$112,811	$740,799
Riverside South - Palace and Hoskin	OH rebuild - 1000 m 1 phase 8kV, 26 poles, 4 TX and associated equipment	**$233,281**	$106,205	$86,651	$40,425	$233,281
Riverside North - Regent, EastHaven, EastGrove, Eastdale, Eastborne, EastGlen, Florian Crt	OH rebuild - 2350 m 1 phase 8kV, 58 poles, 15 Tx and associated equipment	**$728,888**	$331,916	$284,360	$112,612	$728,888
	2018 Planned OH Rebuild Total	**$2,174,745**				
2018 Planned UG						
Gladfern, Galahad, Gentry, Gaylord	UG primary cable replacement 2800m single/three phase (30 Tx)	**$917,761**	$116,145	$27,738	$773,879	$917,761
Traddles, Dickens Wickham	UG primary cable replacement 2200m single phase (22 Tx)	**$605,404**	$89,585	$236,525	$279,294	$605,404
Oulet, Birchcliffe, Lakeview, Valley	UG primary cable replacement 1500m single phase (17 Tx)	**$344,874**	$54,305	$137,102	$153,467	$344,874
	2018 Planned UG Rebuild total	**$1,523,164**				

2019 CAPITAL PROJECTS - PRELIMINARY	SCOPE/ COMMENTS					
Planned OH 2019						
King St E 10F1 (Keewatin to Townline)	1000 m, 21 poles 3phase, 8 Tx and associated equipment	**$380,518**	$175,806	$147,804	$56,908	$380,518
Vimy Ave, Lasalle Ave	OH Rebuild - 500 m 8kV, #6 cu, 12 poles, 4 Tx and associated equipment	**$183,262**	$89,361	$65,143	$28,758	$183,262
Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham	OH Rebuild - 4550m, 13. & 8kV, #6 cu, 120 poles, 35 Tx and associated equipment	**$1,312,827**	$609,732	$490,479	$212,616	$1,312,827
Grandview, Beaufort and Newbury	OH Rebuild - 600 m 8kV, #6 cu, 15 poles, 3 Tx and associated equipment	**$187,324**	$98,590	$56,274	$32,459	$187,324
	2019 Planned OH Rebuild Total	**$2,063,931**				
2019 Planned UG						
Central Park Blvd North, Exeter St and Trowbridge	UG primary cable replacement, Townhomes, 2000 m single phase, dip poles includes Townhomes Complex 1055 Central Park Blvd N 12 Tx connections	**$321,795**	$34,718	$97,707	$189,370	$321,795
Ormond Dr, EverGlades, Palmetto,Pompano Ct	UG primary cable replacement, 1800 m single phase, dip poles (8 Tx connections)	**$274,089**	$23,298	$69,840	$180,952	$274,089
Beaufort Ct	UG primary cable replacement, 950 m single phase, dip poles (5 Tx connections)	**$169,919**	$17,864	$48,633	$103,422	$169,919
Marwood Dr	UG Primary Cable replacement, 850m 3-phase, dip poles (5 Tx Connections)	**$228,934**	$39,960	$69,424	$119,550	$228,934
	2019 Planned UG Rebuild total	**$994,737**				

*** Note 1: "Other$" includes vehicles, contractors and non-standard materials**

**** Note 2: Contingencies are included in costs**

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-41

[Ex.10-C, p.2]

Please provide details of specific efficiencies and productivity initiatives and measures the Applicant plans to undertake during the test period.

Response:

Please see responses to interrogatories 10.0-Staff-44, 4.0-CCC-30 and 4.0-CCC-31.

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-42

[Ex.10-C, Table 5]

Please explain the variances in the cost estimates between the Applicant and NBM.

Response:

NBM was retained to complete an independent forecast of costs associated with the work listed in the referenced table. NBM was not provided with OPUCN's cost forecasts for this work. The basis for NBM's forecasts are explained in NBM's report. Other than the explanation regarding the timing for Distribution System (MS9) costs in the note at the bottom of the referenced table, and confirmation that OPUCN's total costs forecast for the subject projects are less than the total costs forecast by NBM, OPUCN has not consulted with NBM to undertake a detailed comparison of these individual components of the cost estimates.

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC)
Interrogatory 10.0-SEC-44

[Ex. 10-C, p.8]

Is the inflation built into the Applicant's OM&A cost forecasts based on the Conference Board of Canada CPI for Oshawa? Please explain why CPI is appropriate considering the Board uses GDP-IPI for inflation.

Response:

OPUCN subscribed to the Conference Board of Canada's online data service to assist with metrics used in producing results for the rate application. OPUCN believes the Conference Board of Canada is a reasonable source of economic data, their online service is easily accessible and provides metropolitan level information for Oshawa specifically.

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-45

[Ex.10-C, p.12-19]

Please provide copies of the documents referenced at:

a) Alberta Utility Commission, Rate Regulation Initiative, Distribution Performance Based Regulation, September 12, 2012 (Footnote 8)

b) Ofgem, Revenue Using Incentives to Deliver Innovation and Outputs Model (RIIO Model).(p.17)

c) ET1 Price Control Finance Handbook (footnote 13,15)

Response:

a) Please see Attachment 1.

b) The reference is to a model. The associated document is the Price Control Finance Handbook requested in part c).

c) Please see Attachment 2.

Decision **2012-237**

AUC
Alberta Utilities Commission

Rate Regulation Initiative

Distribution Performance-Based Regulation

September 12, 2012

The Alberta Utilities Commission
Decision 2012-237: Rate Regulation Initiative
Distribution Performance-Based Regulation
Application No. 1606029
Proceeding ID No. 566

September 12, 2012

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Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

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1 Introduction and background

1. On February 26, 2010, the Alberta Utilities Commission (AUC or Commission) began a rate regulation initiative to reform utility rate regulation in Alberta. The first stage of the rate regulation initiative is to implement a form of performance-based regulation (PBR) for electric and natural gas distribution companies in place of the existing cost of service regulatory system, usually referred to as rate base rate-of-return regulation. The second stage of the rate regulation initiative will consist of generic reviews of legal and economic issues related to utility regulation for the purpose of making the regulatory system more consistent among companies, more predictable over time and more efficient.

2. In its February 26, 2010 letter,[1] the Commission indicated that the first stage of the rate regulation initiative would apply only to the electricity and natural gas services of Alberta distribution companies under the Commission's jurisdiction. It would not apply to the electricity and natural gas services of transmission companies or to retail electricity or natural gas sales. However, if a company provided both distribution and transmission services, the company was given the option to apply to include its transmission services in its PBR proposal.

3. The procedural steps for this stage of the rate regulation initiative are set out in Appendix 3 to this decision. The division of the Commission presiding over this proceeding was Mr. Willie Grieve (chair), Mr. Mark Kolesar and Dr. Moin Yahya.

4. This decision sets out the Commission's determinations about the form of performance-based regulation that will be employed beginning in 2013 for Alberta electric and natural gas distribution companies.

1.1 The current regulatory framework

5. The utility companies to which this decision applies (the companies) are three electric distribution companies, ATCO Electric Ltd. (ATCO Electric or AE), FortisAlberta Inc. (Fortis or FAI) and EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) and two gas distribution companies, ATCO Gas and Pipelines Ltd. (ATCO Gas or AG) and AltaGas Utilities Inc. (AltaGas or AUI). The distribution and transmission service rates charged by these companies are currently regulated under a rate base rate-of-return form of cost of service regulation.

6. The Commission also regulates the distribution and transmission rates of ENMAX Power Corporation (ENMAX or EPC). In 2009, the Commission approved a formula-based ratemaking

[1] Exhibit 1.01, AUC letter of February 26, 2010.

or FBR plan (also known as a PBR plan) for ENMAX's distribution and transmission services.[2] Prior to that, ENMAX was also regulated under a rate base rate-of-return framework.

7. Under the current rate base rate-of-return regulatory framework, rates are established through a two-phase process. In the first phase, the total amount of money required by the company to provide its regulated services in a year is determined. This is referred to as the revenue requirement, and it is made up of the total annual operating, maintenance and administrative expenses of the company plus the company's capital-related costs (depreciation, debt, and return on equity). The company's debt and equity are used to finance the company's assets (wires, pipes, etc.), which are referred to as its rate base. The cost of debt is the interest that the company pays on its bonds. The cost of equity is determined by the regulator and is referred to as the approved rate of return on equity (ROE). The return on equity actually earned is sometimes referred to as the utility company's profit since all other expenses and costs (operating, maintenance, administration and debt costs) are recovered without any profit margin built into them.

8. In the second phase of a rate application, monthly, hourly or other rates to be paid by individual customers for use of the distribution system are established by determining how much of the revenue requirement should be recovered from each customer class (residential, commercial, etc.) and on what billing unit basis (monthly charge, per kilowatt hour or gigajoule, etc.). Rates are established by dividing the revenue requirement for each customer class by the billing units.

9. In Alberta, all of these determinations are made on a forecast basis, generally for two years. So, for example, a company could file a rate application for the two years 2011 and 2012. A forecast revenue requirement would be provided by the company for each of the two years, called test years. The Commission is required to test the application for reasonableness and allow only reasonable forecast expenses, including capital-related costs, to be included in the revenue requirement and rates for the two test years. These forecasts are based on the companies' plans and expectations over the two test years. When new rates are implemented for the two years, the company begins to collect them and may or may not carry out the plans it put before the Commission in its forecasts. At the end of the two years, the company may apply for rates for the next two test years.

10. If the company is able to provide service for less than it had forecast during the previous two years, or if billing units (the number of customers, electricity or natural gas use, etc.) are greater than were forecasted, the company is permitted to keep the extra revenue as extra profit in those years. However, the forecast revenue requirement and rates for the next two years are to take into account the actual results from the previous two years. In this way, customers receive the benefit of the company's improved productivity (lower costs and higher billing units) from the previous period in the rates determined for the next two years. If the company then improves its productivity in these next two years, those benefits will again be passed on to customers in the next period, etc. Of course, the actual results for the immediate prior year are not available to assist in assessing the forecasts for the two test years of a new test period. This means that any efficiency gains in the prior year may not be fully incorporated into those forecasts.

[2] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID No. 12, March 25, 2009.

11. While this regulatory model is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized.[3] Generally, under cost of service regulation, since the company earns a profit on the equity in its rate base, there is an incentive to choose spending money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned. In addition, there is no incentive to minimize the costs of capital assets. The more that is spent and included in the company's rate base, the more return that can be earned. This means that the regulator must make some sort of after-the-fact assessment of whether the company spent too much money on capital assets and, if so, must disallow recovery of the amount by which actual costs exceeded a prudent amount. In addition, there is little incentive for the company to invest in long term cost reduction initiatives because any cost reductions achieved would be passed on to customers automatically in subsequent rate proceedings. The use of forecasted test years in Alberta was adopted partly in response to these incentives. However, while there are incentives to reduce expenses in the test years so as to beat the forecast and thereby increase profits, this only works for investments in efficiency that can be recovered in a year or two. In addition, this framework also creates an incentive for the companies to provide cost forecasts (both operating and maintenance (O&M), and capital) that are higher than what the company expects to be able to achieve or to provide conservative forecasts of the number customers and other billing units that are lower than what the company expects, thus increasing profits above the approved return.

12. In addition to the issues raised by the basic regulatory model, the framework has been made more complicated by the restructuring of the industries. In both the electricity and natural gas industries, companies that were once vertically integrated monopolies engaged in electricity generation, distribution, transmission and retailing, or in natural gas production, distribution, transportation and retailing, are now structurally separated. The production of electricity and natural gas and the retailing of electricity and natural gas are now open to competition. The costs for the distribution and transmission services must be separated from the costs of production and retailing and separate rate bases established. Issues of cost allocations among different regulated entities or among regulated and unregulated affiliates in the same corporate structure emerge and must be monitored. These issues include allocations of rate base, charges from one division to another, prices charged by affiliates providing services in competitive markets that also provide those services to the regulated affiliate, among others. In the current regulatory framework, each of these issues must be monitored and assessed in every regulatory application, and a number of new regulatory tools have been developed to deal with these costs and allocations both within and outside of the normal rate review process. As a consequence, the industry restructuring has added to the need for rate riders (items on the bill to recover costs that change from time to

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[3] See Brown, Carpenter and Pfeifenberger regarding capital expenditure gaming (Exhibit 34.01, slide 3); Dr. Carpenter regarding incentive to bias its rate base allowance upward, (Transcript Volume 7, pages 1194 and 1195); Dr. Cronin that regulated firms are overcapitalized (Exhibit 299.02, page 124); Dr. K. Gordon, ATCO Gas witness in an earlier proceeding regarding over-forecasting, (Exhibit 357.06 citing Application No. 1400690, 2005-2007 Rate Application, Transcript Volume 5, pages 838-846); Ms. Frayer and Dr. Weisman, regarding cost-of-service's significant regulatory burden (Fortis application, Exhibit 100.02, Appendix 2, page 5, lines 20-23 and Exhibit 103.03, Dr. Weisman evidence, page 9, paragraph 20); Dr. Weisman's evidence that cost-of-service regulation "is essentially a cost-plus contract" (Exhibit 103.03 page 23 paragraph 57); Calgary evidence that a "regulated firm may use its information advantage strategically in the regulatory process to increase its profits … to the disadvantage of ratepayers." Exhibit 298.02, page 15, paragraph 34; The United States Department of Justice that "cost-of-service regulation may do little to promote, and may actually inhibit the achievement of, technical, allocative, or dynamic efficiency" as quoted by the UCA in Exhibit 299.02, page 119.

time[4]), flow-through mechanisms and deferral accounts. At last count the Commission was administering approximately 100 deferral accounts, riders and pass-through mechanisms for the distribution and transmission companies under cost of service regulation.

13. One result of the basic regulatory model and the industry restructuring that has been imposed on top of it has been both a tremendous increase in the detailed information filed by the regulated companies and an increase in the number of ongoing proceedings for deferral accounts and related matters. For example, in a recent revenue requirement application filed by EPCOR amounted to approximately 4,200 pages including all schedules and appendices.[5] The process that followed produced another 8,000 pages of information requests and responses as well as additional evidence and written questions and responses. In addition, from that proceeding, one of the issues was spun-off to be considered in a separate proceeding. As another example, there is a 10-year ongoing series of proceedings to benchmark and, through that, to establish a method to review and approve charges to the ATCO utilities by their affiliate ATCO I-Tek Inc.[6] As a further complication, a number of issues have been litigated differently by different companies and decided differently by different board[7] or Commission panels.

1.2 Performance-based regulation

14. In its February 26, 2010 letter, the Commission stated that the rate regulation initiative:

> ... proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources. In addition, rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings. These changes in the structure of the industry, occasioned by the introduction of competition in the retail and generation/production segments of the electricity and natural gas industries, have resulted in additional negative economic incentives for companies regulated under rate-base rate of return regulation. These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing. Traditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers. The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected.[8]

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4 Examples of rate riders include but are not limited to: ENMAX's Quarterly Transmission Access Charge, FortisAlberta's Quarterly Transmission Access Rider, ATCO Electric's Rider S Quarterly System Access Services Adjustment and EPCOR'S Rider K Transmission Charge Deferral Account True-up Rider.

5 EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID No. 437.

6 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010; Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011; ATCO Utilities, 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009, Application No. 1605338, Proceeding ID No. 240.

7 The Alberta Energy and Utilities Board (board or EUB), is a predecessor to the Alberta Utilities Commission.

8 Exhibit 1.01, AUC letter of February 26, 2010, pages 1-2.

15. In stating its intention to move to a performance-based regulation framework for the distribution companies, the Commission also stated the following objectives for PBR:

> The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.[9]

16. A basic PBR plan begins with rates established through a cost of service proceeding such as a rate base rate-of-return proceeding. Those rates are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than in cost of service proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.

17. Establishing prices in this way during the term of a PBR plan creates stronger incentives for the companies to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under cost of service regulation, especially with rates under cost of service regulation that are re-set every two years. At the same time, under a PBR regulatory framework, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of the companies. In addition, the X factor in a PBR plan is often increased by a stretch factor so as to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost of service to PBR.

18. But an I-X mechanism alone is not sufficient. In competitive markets, other factors that affect only the industry in question, such as an increase in taxes, would be passed through to customers by that industry in its competitive prices. PBR plans typically include a Z factor to deal with such significant events outside the companies' control that are specific to the industry and would not be reflected through the inflation factor (I). The Z factor can also be used to increase or decrease the companies' prices to reflect cost changes caused by unique company-specific events (such as floods or ice storms) outside the company's control and that are not reflected in the inflation factor.

19. In some cases, these types of costs may be predictable, although the amounts of these costs may not be. In those cases, other mechanisms may be established to allow for automatic adjustments to rates to pass those costs through to customers. For example, in the ENMAX FBR plan established in Decision 2009-035, the Commission made provision for the flow-through of transmission system charges imposed on the distribution company by the Alberta Electric System Operator (AESO).[10] Other similar types of charges beyond the control of the companies

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[9] Exhibit 1.01, AUC letter of February 26, 2010, page 1.
[10] Decision 2009-035, pages 52-53. For further discussion on the AESO's role see Section 7.4.2.1.1.

may also be included in a PBR plan as a Y factor to be passed through to customers. The companies' proposals in this proceeding included a number of these types of factors.

20. In the ENMAX FBR plan,[11] the Commission also established a G factor to deal with capital additions to ENMAX's transmission system. In this proceeding, each of the companies proposed specific provisions for some types of capital investments to be handled outside the I-X mechanism. In this decision those types of capital adjustments are referred to as K factors.

21. All of these types of cost-based adjustments (whether Z, Y or K) are carefully defined and limited in their scope because they are inconsistent with the objectives of PBR in that they have the effect of lessening the efficiency incentives that are central to a PBR plan.

22. PBR plans are typically established for a defined term such as five years. At the end of the term, rates are often re-established in a cost of service proceeding, and another PBR term begins based on those rates. Other approaches may also be used at the end of the PBR term, such as simply continuing the plan or making some changes to the parameters and continuing based on existing rates. However, it is likely that a cost of service review will occur eventually.[12] In either case, the values of I and X, for example, and the other parameters of the plan are reviewed and may be changed. The fact that eventually rates will be re-established based on cost of service lessens the efficiency incentives under PBR as the time for the cost of service review approaches. Generally, the longer the PBR term, the greater are the incentives for the company to look for and invest in new productivity-enhancing business practices.

23. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality, regardless of the form of regulation. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures.

24. It is the Commission's expectation that the adoption of a PBR plan will make the regulatory system more efficient over time as the Commission, interveners and companies become more familiar with it. At the same time the Commission expects that, under PBR, customers will experience lower rates than they would have had if the current rate base rate-of-return framework had continued unchanged.

25. During the first PBR term, the Commission will also conduct generic proceedings to deal with a number of utility regulatory issues so that the regulatory framework will be more efficient in the future.[13]

[11] Decision 2009-035, pages 41-48.
[12] Transcript, Volume 1, page 197, lines 11 to 22, Dr. Makholm.
[13] The generic cost of service proceedings is discussed in Section 16.

1.3 Performance-based regulation preparations

26. In its February 26, 2010 letter, the Commission invited interested parties to assist the Commission in determining the scheduling and the scope of issues for PBR implementation. The Commission held a roundtable with 18 interested parties on March 25, 2010 to discuss steps for the implementation of PBR.[14] The companies objected to the Commission's stated preference that PBR begin on July 1, 2011. The companies asked for more time to prepare for PBR and to file rate cases to establish their going-in rates for PBR, a process that would take some time. In addition, during the roundtable, participants agreed that the Commission should conduct a workshop so that the participants could become more familiar with the theory of and experience with PBR. Participants also agreed that the Commission should initiate a short proceeding to establish common principles to guide and assess PBR proposals to be subsequently filed by Alberta distribution companies within the Commission's jurisdiction.

27. In its April 9, 2010 letter[15] the Commission announced that in response to requests by participants, it had engaged the Van Horne Institute to conduct an independent PBR workshop on May 26 to 27, 2010 in order to educate participants about the issues, terminology and concepts raised by PBR. Participants were informed that the information provided and views expressed at the workshop did not necessarily represent the views of the Commission. Ninety-two people representing all of the utility companies and intervener groups attended the workshop.

28. Also, in its letter of April 9, 2010, the Commission initiated a proceeding to solicit comments on the principles that should guide the development of PBR in Alberta. The proceeding commenced on June 10, 2010 with submissions from the various parties and closed on June 24, 2010 with the submission of reply comments.[16] The Commission reviewed these submissions, and in Bulletin 2010-20,[17] dated July 15, 2010, the Commission found that there was general agreement on the following five principles:[18]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

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14 See Attachment 1 of Exhibit 6.01 for a list of participants, page 2.
The following parties suggested clear objectives before instituting PBR: AltaLink, page 1; ATCO, page 1; Calgary, Principle 1, page 3; UCA, page 1; IPCAA, Principle 1, page 1.

15 Exhibit 6.01, AUC letter of April 9, 2010.

16 Appendix 1 of Bulletin 2010-20 lists the parties who made submission and the associated exhibit numbers.

17 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

18 Exhibit 64.01, Appendix 2 of Bulletin 2010-20 lists references of parties with similar principles in their submissions.

29. The gas and electric distribution companies present at the March 25, 2010 roundtable (other than ENMAX) agreed that they could each file a PBR proposal by the end of the first quarter of 2011. Therefore, in Bulletin 2010-20, the Commission directed these gas and electric distribution companies to file their PBR proposals by March 31, 2011. The distribution companies that are also transmission facility owners could choose whether or not to include their transmission operations in their proposed PBR plans. Parties were required to explain how their PBR proposals were consistent with the Commission's five principles for PBR and how their proposals would satisfy the Commission's objectives for PBR.

30. On September 8, 2010, the Commission notified the parties that it had retained National Economic Research Associates (NERA) to prepare a total factor productivity (TFP) study that could be used as the basis for determining an X factor in a PBR plan for the electricity and natural gas distribution industries.[19] The NERA TFP study was to be filed by December 31, 2010.[20] The filing date for the companies' PBR proposals was later changed to July 26, 2011, in order to allow the companies sufficient time to consider the evidence to be filed by NERA, with the objective being to implement PBR effective January 1, 2013.[21]

1.4 Overview of PBR proposals and the Commission's approach

31. In Bulletin 2010-20[22] that established the PBR principles, the Commission also provided the following guidance to the companies and interveners:

> In the Commission's opinion, a PBR plan consisting only of an I - X formula would, to the greatest extent possible, mimic the efficiency incentives of competitive markets provided that the X factor requires the company to achieve annual productivity improvements at least equivalent to those of the relevant industry. Therefore, the Commission expects each proposal to include I - X as part of the PBR plan. Some parties proposed principles that dealt with certain aspects of various PBR plans such as exogenous adjustments, earnings sharing, the term of the plan, capital adjustments, reporting requirements and rate structure changes, among others. In the Commission's opinion, these are more properly considered as potential elements of a PBR plan and are not principles. In making their proposals, companies may choose to include these or other elements in order to address circumstances resulting from Alberta's market structure, the industries in which the companies operate, unique company-specific circumstances or other circumstances that may be relevant. Companies are expected to fully explain the circumstances that give rise to the need for each element, how each element addresses that need and how each element is justified by the principles and objectives of PBR.[23]

32. The companies filed their PBR proposals on July 26, 2011. Interveners filed their PBR evidence on December 16, 2011.

33. The Commission received a wide range of proposals from the companies and the interveners. Parties agreed with the Commission's objectives and principles and, for the most part, fashioned their PBR proposals to be consistent with them. The Office of the Utilities

19 Exhibit 71.01, AUC letter – Retention of Consultant to Develop a Basic X Factor.
20 Exhibit 80.02, NERA first report.
21 Please see Appendix 3 for details of the procedural steps.
22 Exhibit 64.01, AUC Bulletin 2010-20.
23 Exhibit 64.01, Bulletin 2010-20, page 3.

Consumer Advocate (UCA) expressed concerns about moving to PBR at this time.[24] The UCA's position was that the companies are performing well under the current cost of service framework and that more company-specific information is needed to implement the type of PBR plan that the UCA envisions. The Industrial Power Consumers Association of Alberta (IPCAA) recommended a limited adoption of PBR until two types of performance metrics (quality of service and asset condition metrics) are available and the necessary quality and reliability safeguards are implemented.[25] EPCOR proposed a PBR plan that excludes all capital-related costs from the application of an I-X mechanism.[26] The other parties (ATCO Electric,[27] ATCO Gas,[28] Fortis,[29] AltaGas,[30] the Consumers' Coalition of Alberta (CCA)[31] and The City of Calgary (Calgary)[32]) proposed or accepted plans that applied an I-X mechanism to all categories of costs. Each of these parties also argued for or accepted some type of provision to deal with some capital costs outside of the I-X mechanism and proposed or accepted the need for certain new or existing deferral accounts and rate riders.

34. In seeking to develop a PBR mechanism that can best achieve the Commission's objectives while being consistent with all of its principles to the maximum extent possible, the Commission has carefully considered all of the submissions of the companies and interveners. The Commission is employing an I-X mechanism and a five-year term as part of its PBR plan in order to create the same efficiency incentives as those that are present in competitive markets to the greatest extent possible for the electric and gas distribution companies. The inclusion of an efficiency carry-over mechanism will further enhance these incentives. In doing so, the Commission is also making provision for the exclusion of some capital costs from application of the I-X mechanism where necessary in order to accommodate the unique circumstances of each regulated company. The Commission is employing a revenue-per-customer cap for natural gas distribution companies and a price cap for electric distribution companies in order to recognize the differences between those two industries. The Commission is also making provision for the treatment of necessary deferral accounts and flow-through mechanisms for each company as part of its PBR plan.

35. In making its determinations, the Commission has considered the effect of the combination of the I-X mechanism with the treatment of some capital-related costs outside of the I-X mechanism, the Z factor adjustments and the provision for deferral accounts and flow-throughs to protect the companies from significant unforeseen events that are outside their control. In addition, the Commission has considered the statements of a number of witnesses regarding the incentives to over-forecast capital expenditures, the observation of Dr. Lowry that the companies have considerable flexibility in the timing of capital replacements[33] and the views of Dr. Weisman that with the incentives created by the plan, the companies will discover new ways to conduct their businesses.[34] Having considered the statements of the parties and

24 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 12-13.
25 Exhibit 306.01, IPCAA Vidya Knowledge Systems evidence.
26 Exhibit 103.02, EPCOR application.
27 Exhibit 98.02, ATCO Electric application.
28 Exhibit 99.01, ATCO Gas application.
29 Exhibit 100.01, Fortis application.
30 Exhibit 110.01, AltaGas application.
31 Exhibit 307.01, CCA evidence.
32 Exhibit 298.02, Calgary evidence.
33 Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 59; Exhibit 636.01, CCA argument, Section 8.1, paragraph 118.
34 Exhibit 103.03, EPCOR application, Appendix A, page 20, paragraph 49.

witnesses, and the full record of the proceeding, the Commission is satisfied that the PBR plans approved in this decision will provide each of the companies with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return over the five-year term of the plan. With regard to earning a fair rate of return, there was general agreement[35] among the experts and the parties that the opportunity to earn a fair rate of return should be considered over the term of the PBR plan and not on a year-by-year basis.

36. Customers will share the benefits from the improved efficiency incentives under PBR through the inclusion of an X factor and a stretch factor in the plan. Customers will be protected against earnings significantly above the approved ROE, and the companies will be protected against earnings significantly below the approved ROE, by the incorporation of a re-opener in the plan. If the ROE of a company meets the conditions for a plan re-opener to take effect, this will afford an opportunity for the Commission to re-examine the parameters of the plan and, if required, to adjust them.

37. The Commission is also making provision for enhanced quality of service rules and measures to address the incentive that companies might have to reduce their costs in such a way that service quality declines in the short and long term.

38. The Commission has sought to make the PBR plans as easy to understand, implement and administer as possible given the structure of the electric and natural gas industries in Alberta, the need to accommodate the unique circumstances of each company and the recognition that this is the first time PBR has been adopted for all of the distribution companies. The Commission is confident that as the parties become more familiar with PBR and as the companies discover new ways to adapt their businesses to the opportunities PBR offers, it will be possible to further streamline the regulatory framework to achieve the Commission's objectives.

39. Finally, the Commission is satisfied that the PBR plans meet the objectives for PBR described in its February 26, 2010 letter. Furthermore, the Commission has taken particular note of the five PBR principles articulated in Bulletin 2010-20. The Commission is satisfied that the PBR plans overall, and each of the elements of the plans, are consistent, to the maximum extent possible, with all five principles.

40. The Commission intends to review PBR as it comes to the end of the first term and to consider extending the plans or incorporating other approaches if those can be demonstrated to better balance regulatory efficiency and regulatory effectiveness in a way that achieves the Commission's objectives and satisfies the Commission's principles.

2 Approaches to rate regulation

41. The UCA (Office of the Utilities Consumer Advocate), IPCAA (Industrial Power Consumers Association of Alberta), and EPCOR each proposed alternatives to the Commission's preferred approach to PBR (performance-based regulation) stated in its letter of February 26, 2010 and Bulletin 2010-20. These proposals affected either the time at which PBR could be implemented in Alberta for the electric and gas distribution companies, the nature of PBR, or the

[35] Transcript, Dr. Carpenter, Volume 3, pages 565-566; Transcript, Mr. Camfield, Volume 8, page 1373; Transcript, Mr. Gerke and Dr. Weisman, Volume 10, pages 1828-1829; Transcript, Ms. Frayer, Volume 11, page 2190.

costs to which PBR would apply. In this section, the Commission addresses each of these alternative proposals. The Commission also addresses specific elements of these proposals throughout this decision.

2.1 The UCA's proposal

42. The UCA proposed a delay in the implementation of PBR. The UCA developed its own objectives for PBR and then used those objectives, in combination with its view of what a PBR plan should be like, to justify the delay.

43. The UCA's objectives were expressed as follows:

- Better economic incentives in order to achieve productivity improvements, which will result in lower customer rates than under cost of service regulation,
- Clearly defined performance standards with penalties for failure to achieve specified performance targets, and
- A reduction in the overall regulatory burden by improving the efficiency of the regulatory framework.[36]

44. The UCA stated that if PBR would not meet its three over-arching objectives, then the move to PBR at this time must be reassessed. The UCA also submitted that based on the available information, there is no compelling reason to switch to PBR. Three principal reasons were given for this position:

1) The evidence of Dr. Cronin [expert witness for the UCA] that regulatory burden does not go down under PBR;
2) The large capital forecasts upon which the applicants' PBR plans are based, and, in the case of EDTI the complete exclusion of capital from its PBR plan; and
3) The lack of information presently available about the applicants: (i) comparative performance; (ii) present efficiency levels, and (iii) potential for efficiency improvements.[37]

Commission findings

45. The Commission has considered the UCA's objectives for PBR and its reasons for reassessing the move to PBR at this time. The Commission agrees with the objectives that PBR should provide better economic incentives and result in lower rates than under cost of service regulation. The Commission also agrees that PBR should reduce the regulatory burden by improving the efficiency of the regulatory framework. The Commission considers that clearly defined performance standards and the imposition of penalties to achieve performance targets is a good approach to addressing service quality issues, and, therefore, the Commission has included maintaining service quality as an integral part of its first PBR principle. Service quality issues and the Commission's approach to maintaining service quality are addressed in Section 14 of this decision.

46. The Commission acknowledges the UCA's concerns about the capital forecasts filed by the companies in this proceeding and has addressed these concerns in this decision.

[36] Exhibit 634.01, UCA argument, paragraph 20, page 4.
[37] Exhibit 634.01, UCA argument, paragraph 28, page 5.

47. The Commission considers the UCA's first and third reasons for reconsidering and delaying implementation of PBR at this time to be closely related. Dr. Cronin argued that the regulatory burden does not go down under PBR and cites the Ontario PBR plans as an example. In the Commission's view, the type of PBR plan envisioned by Dr. Cronin would not decrease the overall regulatory burden because significant effort would still be required, although on different matters than under cost of service regulation. Dr. Cronin expressed his view that PBR plans require collecting significant amounts of information in order to carry out comparisons of the productivity and efficiency performance of various individual companies in Alberta with each other and with other North American companies. Dr. Cronin requires this information in order to determine how close those companies are to the "efficiency frontier"[38] and, therefore, their potential for efficiency improvements.[39] In addition, Dr. Cronin argued for the use of company-specific total factor productivity studies (which is also a data-intensive undertaking) to establish company-specific X factors. Dr. Cronin further suggested that comparisons of companies could be made at even more disaggregated levels, such as individual cost types or cost centres.[40]

48. In the Commission's view, adopting this type of an approach to PBR might very well increase the regulatory burden. Indeed, Dr. Cronin, in describing the approach used in Great Britain (one that appears to require the same type of information as that proposed by Dr. Cronin), stated that the regulator there "busies hundreds of analysts"[41] to give effect to its regulatory approach.

49. It is not the Commission's intention to build a PBR regulatory framework that requires or invites the Commission to manage the companies through analysis of and distinct incentive schemes for lower level cost data provided in company-specific TFP studies. Nor is it the Commission's intention to benchmark companies against each other or against an estimated efficiency frontier. In the ENMAX proceeding, Dr. Cronin expressed similar views to those expressed in this proceeding, and the Commission rejected them in Decision 2009-035, dealing with the ENMAX FBR proposal.[42] The Commission's objective is to provide incentives for improved efficiencies, both in the short run and the long run, as well as opportunities for the companies, without Commission direction and control, to discover and implement those efficiencies over longer time periods than they would have under the current regulatory framework. In the Commission's view, the PBR approach envisioned by the UCA would not achieve the objective of improving the efficiency of the regulatory process, nor would it satisfy the principle that**,** to the greatest extent possible, a PBR plan should create the same efficiency incentives as those experienced by companies in a competitive market. It would also not satisfy the principle that a PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

50. The Commission has also considered the UCA's view that PBR need not be implemented at this time because "based on the limited information available, it appears very likely the applicant utilities have superior performance, their rates are below or equal to other jurisdictions; their reliability is higher; and ROE is much higher than other jurisdictions."[43] The UCA's

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[38] For further discussion on the efficiency frontier approach please refer to Section 6.2.
[39] Exhibit 634.01, UCA argument, paragraph 40, page 7.
[40] Transcript Volume 18, page 3420, line 8 to page 3422, line 7.
[41] Transcript, Volume 17, pages 3227, lines 15-16; Transcript, Volume 18, pages 3430-3431.
[42] Decision 2009-035, paragraph 175.
[43] Exhibit 634.01, UCA argument, paragraph 48, page 9.

conclusion is based on a benchmarking of the Alberta companies to a number of U.S. local distribution companies selected by Dr. Cronin.[44] These comparisons show that ENMAX's and EPCOR's local distribution rates are at the lower end of the range of rates of the selected companies and that Fortis is in the range of two local distribution companies in the northern states.[45] Information provided in response to an undertaking showed that ATCO Electric's local distribution rates are much higher than the other companies in the UCA's comparison group.[46]

51. The Commission is not satisfied that these comparisons can justify a decision to delay PBR until more information can be provided and analysed. ENMAX's rates are already regulated under a PBR plan. EPCOR has explained that a great deal of its local distribution network is in need of replacement. As a result, its rates can be expected to be lower because its capital-related costs included in rates will be lower than if the local network had already been substantially replaced. Indeed, as discussed in Section 7.3, the Commission's observation in this proceeding is that differences among the companies' capital proposals under PBR can be explained to some degree by where those companies are in the long term cycle of capital investment and replacement. Furthermore, this observation makes suspect the results of benchmarking across different regulated companies, whether Canadian companies or, as in the UCA analysis, U.S. companies. There may also be significant differences among the companies that cannot be accounted for in benchmarking studies.

52. Accordingly for all of the reasons stated above, the Commission is not persuaded by the UCA to reconsider or delay implementation of PBR for Alberta distribution companies.

53. The UCA has proposed that if the Commission proceeds at this time with PBR, it should engage in benchmarking and, if not benchmarking, then it should use a menu approach to PBR. If the menu approach is not employed by the Commission, the UCA recommended that the Commission adopt the ENMAX FBR model. The UCA's proposal for benchmarking and its menu approach to PBR are both addressed Section 6.2.

2.2 IPCAA's proposal

54. IPCAA objected to the full implementation of PBR at this time. IPCAA proposed the use of an I-X mechanism only for general and administrative (G&A) costs and the retention of cost of service regulation for the remaining costs (O&M (operating and maintenance) as well as capital-related costs). IPCAA's concern is that PBR creates incentives to reduce costs and that the Commission's current quality of service rules are not sufficient to protect service quality and asset condition. IPCAA, therefore, recommended a limited adoption of PBR until specific quality of service and asset condition performance metrics are implemented.[47]

Commission findings

55. The Commission understands IPCAA's concerns about the potential effects of the incentives created by PBR on service quality and the condition of the companies' capital assets. The Commission also recognizes that its own current quality of service rules may not be sufficient to properly address IPCAA's concerns or, indeed, the Commission's concerns under PBR. However, the Commission does not agree that these concerns must be addressed before a

44 Exhibit 299.02, Cronin and Motluk UCA evidence, page 27.
45 Exhibit 299.02, Cronin and Motluk UCA evidence, page 27; Exhibit 614.01, UCA undertaking.
46 Exhibit 614.01, undertaking response given by Dr. Cronin.
47 Exhibit 304.01, IPCAA policy evidence.

PBR plan can begin. The Commission is confident that its plans to address service quality and asset condition issues early in the PBR term will be sufficient to allow PBR to proceed. The Commission has taken into account IPCAA's concerns in its quality of service determinations and plans described in Section 14.

56. Furthermore, the Commission notes that IPCAA's proposal to include only G&A expenses in PBR would result in a negative effect on incentives because of the exclusion of a significant portion of the operations of a company from the I-X mechanism. Such an effect is well documented in this proceeding.[48] Therefore, based on all of the above, the Commission does not accept IPCAA's suggestion to limit the PBR plans to G&A expenses only.

2.3 EPCOR's proposal to exclude capital

57. EPCOR has proposed to exclude all capital-related costs from the application of the I-X mechanism.[49] The reason given by EPCOR is that it must embark on a major capital replacement program to address its aging local distribution system. EPCOR argued that, in its case, including all current capital-related expenses under the I-X mechanism and making provision for its significant capital additions outside of the I-X mechanism would be too complex to implement and could prevent EPCOR from making efficient capital decisions because of the way in which a capital mechanism outside of the I-X mechanism might be structured.

Commission findings

58. The Commission understands EPCOR's concerns but is itself concerned that excluding all capital from the I-X mechanism will not create new incentives to more optimally make efficient trade-offs between capital and maintenance and may serve to exacerbate the already significant incentives under a rate base rate-of-return framework to prefer capital investment over O&M expenses. In addition, the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only. Therefore, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from application of the I-X mechanism. However, the Commission does address EPCOR's concerns about how its capital program can be treated outside of the I-X mechanism in Section 7.3.2.4 of this decision.

2.4 EPCOR's transmission proposal

59. In its February 26, 2010 letter, the Commission indicated that reform of rate regulation for electricity and natural gas transmission services would not be undertaken at that time because:

> The electricity transmission system is entering a period of significant change with substantial planned expansions while natural gas transportation rates are one subject of more extensive negotiations between the province's two largest regulated natural gas transportation service providers.[50]

48 Transcript, Volume 1, page 143, Dr. Makholm.
49 Exhibit 103.02, EPCOR application, pages 10-18.
50 Exhibit 1.01, AUC letter dated February 26, 2010, Rate regulation initiative round table.

60. Nonetheless, on July 15, 2010, the Commission released Bulletin 2010-20, which stated that "those distribution companies that are also transmission facility owners may choose to include their transmission components in the PBR plan if that is their preference."[51]

61. Of the Alberta distribution companies affected by the bulletin that also had an integrated transmission function, EPCOR was the only company that proposed to include its transmission component in its PBR plan. EPCOR explained that the highly integrated nature of its distribution and transmission functions allowed for economies of scale and scope and that a single, joint rate application for the two business operations reduced regulatory burden.[52]

62. As further outlined in the subsequent sections of this decision, EPCOR proposed that in its PBR plan, the I-X mechanism would apply only to the company's O&M and other non-capital costs, with capital expenditures treated as a flow-through item. EPCOR proposed this type of PBR plan for both its distribution and transmission functions.[53] In these circumstances, as discussed in Section 6.4.3, Dr. Cicchetti noted that an X factor for EPCOR should reflect the changes in O&M productivity only. Furthermore, because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, Dr. Cicchetti offered that his recommended X factor was relevant to both functions:

> The two functions are highly integrated and interdependent, with shared management and staff, who utilize the same offices and other assets. There are common union settlements and the primary O&M input for both functions is labour. Accordingly, my recommendations apply to both functions.[54]

63. In its proposed PBR plan, EPCOR included four service quality performance measures and proposed targets for each of these measures along with a penalty adjustment in its formula for non-compliance with the performance targets. The four service quality performance measures were: Total Recordable Injury Frequency Rate (TRIF), System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Service Connection Time (SCT).[55] For three of these measures, TRIF, SAIDI and SAIFI, EPCOR proposed to report combined distribution and transmission results.[56] During the hearing, EPCOR witnesses testified that there are no service quality issues that are unique to transmission.[57] As such, EPCOR concluded that its proposed service quality measures that combine distribution and transmission are "reasonable and workable."[58]

64. No party to this proceeding opposed the inclusion of EPCOR's transmission function in the company's PBR plan. However, the CCA and IPCAA expressed their concerns with the lack of relevant reliability metrics for transmission in Alberta to be used as service quality performance measures in PBR plans for electric transmission operations.

65. In argument and reply, IPCAA pointed to the absence of standard province-wide service quality measures for electric transmission services in Alberta. In IPCAA's view, a PBR

51 Exhibit 64.01, AUC Bulletin 2010-20, page 3.
52 Exhibit 103.02, EPCOR application, paragraph 14.
53 Exhibit 103.02, EPCOR application, paragraph 3.
54 Exhibit 103.05, Cicchetti evidence, pages 20-21.
55 Exhibit 630.02, EPCOR argument, paragraph 292.
56 Exhibit 630.02, EPCOR argument, paragraph 309.
57 Transcript, Volume 10, page 1813, lines 17-21.
58 Exhibit 646.02, EPCOR reply argument, paragraph 283.

mechanism for transmission facilities would be "far more complex and have much greater impact than at the distribution level," since the consequences of service quality degradation for transmission are much more severe than for distribution:

> Reductions in customer service quality at a POD [point-of-delivery where the distribution system connects to the transmission system] level will have an order of magnitude larger impact as transmission level outages affect either thousands of smaller customers at a [distribution company] point of delivery or large industrial facilities such as gas plants, refineries and oil sands facilities.[59]

66. Accordingly, IPCAA asserted that transmission service quality measures should be considered in a province-wide process. In IPCAA's view:

> Applying PBR to EDTI's transmission function could result in a piecemeal approach to transmission regulation, which is managed and delivered on a province-wide basis, and typically consists of large, capital intensive projects, the costs of which are flowed through to customers.[60]

67. The CCA expressed concern over the lack of data that EPCOR proposed to report in relation to transmission reliability and proposed that the Commission direct EPCOR to also report additional reliability measures such as energy not supplied, average interruption time and overhead line maintenance cost index for its transmission reliability. The CCA indicated that these measures are being used by other transmission companies.[61]

Commission findings

68. The Commission has two concerns with EPCOR's proposed inclusion of its transmission function under its PBR plan.

69. First, EPCOR's proposed X factor, which would be applicable to both its distribution and transmission functions under its PBR plan, is only for non-capital costs. Dr. Cicchetti stated that because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, his recommended X factor (calculated using the O&M data for the distribution component of NERA's sample) was relevant to both functions.[62] In the Commission's view, it is uncertain whether the same conclusion can be reached when the X factor is calculated based on the entirety of the costs (both O&M and capital) of the company.

70. In its productivity study, NERA measured the TFP of the distribution component of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[63]

71. As explained above, the Commission has not accepted EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs in its PBR plan. No evidence was filed in this proceeding on what the relevant X factor for the electric transmission function should be if the I-X mechanism is applied to both O&M and capital costs.

59 Exhibit 635.01, IPCAA argument, paragraph 75.
60 Exhibit 642.01, IPCAA reply argument, paragraph 38.
61 Exhibit 636.01, CCA argument, paragraphs 363-365.
62 Exhibit 103.04, Cicchetti evidence, pages 20-21.
63 Exhibit 80.02, NERA report, page 6.

Accordingly, the Commission cannot set an X factor for EPCOR if the transmission function is included in the plan.

72. Second, EPCOR's proposed measures, targets and penalties to ensure service quality were proposed in the context of a PBR plan that excludes capital-related costs from the rates subject to the I-X mechanism. It is unclear whether these measures, targets and penalties would be adequate to ensure transmission service quality for a PBR plan that is not restricted in this manner. EPCOR's proposals for service quality measures are further discussed in Section 14.

73. The creation of reliability standards and performance targets for transmission is still under development. Unlike transmission, the Commission has been monitoring service quality performance through AUC Rule 002[64] for electric utilities and gas distributors. While further measures and performance targets will be developed as part of AUC Rule 002, as discussed in Section 14, there has been a history of measuring and reporting performance for the distribution function with which companies and industry stakeholders are familiar. There is no similar starting point for transmission.

74. In light of the above considerations, the Commission finds that transmission services should not be a part of EPCOR's PBR plan. EPCOR's transmission services will continue to be regulated under cost of service regulation.

3 Going-in rates

3.1 Purpose and background

75. Going-in rates are the starting rates for the implementation of a PBR (performance-based regulation) plan. The going-in rates are sometimes referred to as "year zero rates." They are the rates to which the approved PBR formula is applied to determine the rates to be charged to customers during the first year of the PBR term. Thereafter, the current year's rates are adjusted by the PBR formula to determine the upcoming year's rates until the end of the PBR term.

76. In Decision 2009-035,[65] the Commission determined that ENMAX's going-in rates were to be based on the company's revenue requirement as determined in a forecast cost of service rate setting proceeding.[66] The Commission directed that the going-in rates for ENMAX would be its approved 2006 rates, adjusted to include previously disallowed short term incentive plan costs. With respect to adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs, the Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."[67] The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[68] The Commission accepted a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was approved on

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[64] AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective July 1, 2010 (Rule 002).

[65] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009.

[66] Decision 2009-035, paragraph 72.

[67] Decision 2009-035, paragraph 73.

[68] Decision 2009-035, paragraph 74.

the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent "operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan."[69]

77. In a December 16, 2010 letter granting deadline extensions for the filing of the companies' PBR proposals in this proceeding, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used by the Commission to establish the going-in rates for the companies.

3.2 Proposals for going-in rates

78. All of the companies proposed that their 2012 approved rates be used as the basis for their going-in rates. In addition, all of the companies, with the exception of EPCOR, proposed adjustments to their 2012 approved rates in setting going-in rates for the PBR term. The companies collectively proposed a total of nine individual adjustments to their going-in rates. Like ATCO Electric and ATCO Gas, AltaGas stated that its adjustments were necessary to earn a fair rate of return during the PBR plan.[70]

79. EPCOR pointed to Decision 2009-035 in proposing that its 2012 approved distribution and transmission tariffs be used as the going-in rates for the company's PBR plan[71] without adjustment. In UCA-EDTI-10(b) EPCOR stated:

> The approved distribution rates and transmission revenue requirement will form EDTI's going-in rates and revenue requirement and, for many of the same reasons stated by the Commission in Decision 2009-35 [sic.], no adjustments to those rates for PBR purposes will be necessary or warranted. If the rates and revenue requirement are just and reasonable for 2012, they will also be just and reasonable as EDTI's going-in rates and revenue requirement. As the Commission indicated in Decision 2009-035, costs and financial results will fluctuate from year to year over the PBR Term. In some years, costs will be higher than expected and in other years lower, EDTI will be incented to improve its efficiency and productivity and under EDTI's PBR Plan, some of these gains will be shared with customers and some will be retained by EDTI.[72]

80. AltaGas requested that its going-in rates be based on its 2012 distribution rates approved in response to its 2010 to 2012 GRA (general rate application) subject to certain adjustments. ATCO Electric and ATCO Gas proposed to use their 2012 final distribution rates as the basis for the going-in rates for the PBR term subject to certain adjustments.[73] Fortis also proposed to use its 2012 approved rates as the basis for its going-in rates but requested that the rates be adjusted to reflect its 2013 opening rate base balance, which would recognize 2012 actual capital expenditures.[74]

69 Decision 2009-035, paragraph 79.
70 Exhibit 628.01, AltaGas argument, page 81; Exhibit 628.01, AltaGas argument, page 80; Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.
71 Exhibit 103.02, EPCOR application, page 2.
72 Exhibit 238.01, EPCOR information responses, pages 25 and 26.
73 Exhibit 98.02, ATCO Electric application, paragraph 208 and Exhibit 99.01, ATCO Gas application, paragraph 10.
74 Exhibit 100.02, Fortis application, page 11.

81. There were no objections by interveners to the companies' proposals that the 2012 approved rates be used as the starting point for going-in rates in the PBR term. The CCA stated that, for the purposes of going-in rates, the approved revenue requirements have been set by rigorous cost of service regulatory oversight. However, the CCA stated that it was uncertain of the finality of these revenue requirements because of placeholders or the potential impact of other adjustments for outstanding appeals or applications.[75]

82. The UCA recommended that the "going-in rates must include recognition of efficiency gains achieved in the last cost of service test period."[76] IPCAA and the CCA did not provide argument on going-in rates but agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[77]

Commission findings

83. Prior to initiating the current proceeding, the Commission considered two alternatives for establishing the going-in rates at the commencement of the PBR term. The first alternative was to use the actual results for the immediately preceding year, in this case 2012, and adjust the 2012 approved rates to reflect the actual 2012 results to form the basis for the going-in rates for PBR. This approach would account for any expenses that were not forecast in the 2012 revenue requirement and any unaccounted for efficiency gains realized in 2012, all subject to a prudency review. However, the Commission recognized that the actual results for 2012 would not be available until well into 2013 and that a prudency review of these results would require a significant regulatory process. The Commission did not adopt this approach because it is inconsistent with the Commission's objective to implement PBR effective January 1, 2013 as set out in the Commission's letter of December 16, 2010.[78]

84. The other alternative was to adopt the approach approved in Decision 2009-035 which uses rates approved in the most recent revenue requirement proceeding as the basis for establishing the going-in rates.

85. In an effort to promote regulatory efficiency, and so as not to delay the commencement of PBR, the Commission in its December 16, 2010 letter, adopted the approach approved in Decision 2009-035 and directed that the companies' approved rates for 2012 would be used as the basis for establishing going-in rates. Accordingly, rates that will form the basis for the going-in rates for PBR will have been established in the context of a full rate case, or in the case of Fortis, on the basis of a negotiated settlement approved by the Commission.

86. With respect to proposed adjustments to going-in rates, the Commission again has two alternatives. The first alternative is to consider making adjustments to include certain costs that were either not forecast or otherwise approved for inclusion in the 2012 revenue requirement, as proposed by certain of the companies. In this context, the Commission could also consider an adjustment to going-in rates to reflect efficiency gains that may have occurred in 2012 that were not already reflected in 2012 approved rates, as proposed by interveners.

75 Exhibit 636.01, CCA argument, paragraph 11.
76 Exhibit 634.01, UCA argument, page 72.
77 Exhibit 642.01, IPCAA reply argument, paragraph 62.
78 Exhibit 79.01, AUC letter dated December 16, 2010, Request for deadline extensions.
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87. The second alternative is to again adopt the approach followed in Decision 2009-035. In that decision the Commission rejected the adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs. The Commission stated that it would “not accept adjustments to the going-in rates to account for 2006 actual results.”[79] The Commission further stated that: “[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period.”[80] The Commission did accept however, a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was accepted on the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent “operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan.”[81] The Commission found that an adjustment of this kind “is qualitatively different from rate adjustments made after the fact to reflect actual results.”[82]

88. The Commission considers the second alternative is in keeping with the decision to use 2012 approved rates rather than 2012 actual costs as the basis for going-in rates. The 2012 rates have been tested and approved by the Commission as just and reasonable for 2012. Accordingly, the 2012 approved rates are the correct starting point on which to base going-in rates. The Commission confirms the findings in Decision 2009-035 that adjustments to going-in rates should not be made to reflect actual results. Further, adjustments should not be made selectively but, rather, should only be made in the context of a full rate case. Adjustments may be made in exceptional situations, however, like the case of the short term incentive plan adjustment approved in the ENMAX decision.

89. Accordingly, the Commission will consider adjustments that are in the nature of a correction to the going-in rates, and which are not rate adjustments made after-the-fact to reflect actual results. This approach is consistent with the Commission’s finding in Section 7.4.4 that differences between placeholder amounts and final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

90. The Commission will consider each of the proposals of the companies and interveners to include adjustments to going-in rates.

91. Given the above findings, the Commission directs the companies to use their respective approved 2012 distribution rates as the going-in rates for the PBR term, subject to the specific adjustments allowed below.

3.3 Requests for adjustments to going-in rates

3.3.1 UCA requested adjustment for efficiency gains

92. The UCA recommended that efficiencies achieved by the companies prior to the commencement of the PBR term should be reflected in going-in rates. The UCA stated that prior to the implementation of PBR, the utilities had undertaken projects that will create new

[79] Decision 2009-035, paragraph 73.
[80] Decision 2009-035, paragraph 74.
[81] Decision 2009-035, paragraph 79.
[82] Decision 2009-035, paragraph 81.

efficiencies. However, none of the applications included any "mechanism or adjustment to allow customers to benefit from these efficiencies in going-in rates."[83]

93. The UCA identified two specific adjustments for ATCO Gas to account for efficiency gains: one to remove the costs of old facilities from going-in rates and one to remove certain costs for meter reading to account for the adoption of automated meter reading in 2012.[84]

94. IPCAA and the CCA agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[85]

95. EPCOR disagreed with the UCA's proposed adjustments to going-in rates for efficiencies achieved under cost of service regulation and pointed to its actual return on equity being close to or below the target ROE.[86] The ATCO companies argued that the 2011 to 2012 distribution rates proceedings included a forecast of anticipated productivity improvements. The ATCO companies argued, "there is a danger that any adjustment could be giving customers the benefit of those productivity improvements twice, because they have already been incorporated into the 2012 going-in revenue for PBR."[87]

Commission findings

96. As stated in Section 3.2 above, it is the Commission's view that adjustments to going-in rates should not be made to reflect actual costs incurred in the test year which form the basis for the going-in rates. Adjustments should only be made in the context of a full rate case. Accordingly, the Commission denies adjustments to reflect possible efficiency gains in a prior period that are not captured in the going-in rates. This finding is consistent with the Commission's determination in Decision 2009-035 which denied the UCA's request to reduce going-in rates by an amount to reflect actual costs incurred in the test year just as it disallowed ENMAX's request for increases to the going-in rates to reflect higher actual costs.[88]

3.3.2 Company proposals

3.3.2.1 Proposals to move from mid-year to end-of-year for rate base purposes

97. ATCO Electric requested an adjustment to its 2012 distribution rates to move from a mid-year calculation of rate base to an end-of-year calculation of rate base to reflect the full impact of its 2012 capital investment.[89] ATCO Electric submitted that the Commission has approved the full amount of the costs relating to its 2012 capital investment, totalling $367 million, in the company's revenue requirement in its 2011 to 2012 General Tariff Application.[90] ATCO Electric's mid-year rate base was $1.392 billion compared to its end-of-year rate base of $1.508 billion. The capital related costs include financing costs, income tax, and depreciation.[91] Based on the evidence of Dr. Carpenter, ATCO Electric submitted that NERA's TFP study to be used for calculating X does not compensate ATCO Electric for the full year impact of

83 Exhibit 634.01, UCA argument, page 72.
84 Exhibit 300.02, UCA evidence of Russ Bell, pages 87 to 89.
85 Exhibit 642.01, IPCAA reply argument, paragraph 62 and Exhibit 636.01, CCA argument, paragraph 375.
86 Exhibit 646.02, EPCOR reply argument, paragraph 302.
87 Exhibit 647.01, ATCO Electric reply argument, paragraph 246 and Exhibit 648.02, ATCO Gas reply argument, paragraph 518.
88 Decision 2009-035, paragraph 83.
89 Exhibit 98.02, ATCO Electric application, paragraphs 215 to 220.
90 Exhibit 98.02, ATCO Electric application, paragraphs 215 and 216 and Decision 2011-134.
91 Exhibit 98.02, ATCO Electric application, paragraphs 217 and 218.

2012 additions that were not incorporated in the 2012 rates. Dr. Carpenter's evidence purported to show that NERA's study is based on a rate base growth of peer group utilities of 4.5 per cent and the company had an approximate rate base growth of 17 per cent in 2012.[92]

98. ATCO Gas also proposed to use end-of-year values rather than applying the mid-year convention for its rate base calculations in order to reflect the full impact of its 2012 capital investments.[93] ATCO Gas submitted that the mid-year convention is used in order to recognize that not all investments occur on the first day of January. In employing the mid-year convention, the revenue requirement is adjusted to reflect the full year costs including depreciation, income tax, and carrying costs for the prior year's investment[94] but an adjustment for capital investments is required to fully recognize the investments in going-in rates.

99. Interveners disagreed with the proposal to use end-of-year investment values to determine rate base. Calgary stated that the effect of moving from the mid-year convention to the end-of-year is to increase the baseline revenue requirement. Calgary argued that, "AG's approach has the effect of increasing the baseline revenue requirement – the starting point for the revenue trajectory – over and above the point at which the Commission has already deemed reasonable from the approved revenue requirement."[95] It would also be inconsistent with its proposed use of average number of customers in ATCO Gas's PBR formula.[96]

100. The CCA supported Calgary's position and argued that ATCO Gas' request should not be approved.[97]

Commission findings

101. The mid-year rate base convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.

102. Had a cost of service rate application been filed for 2013, it would have accounted for 2012 capital expenditures in opening plant balances for rate base and an entire year's operating expenses for the use of those assets. However, 2013 capital expenditures would still be subject to the mid-year convention. In its December 16, 2010 letter, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used to establish the going-in rates for the companies. Therefore, PBR will take these going-in rates and will in effect apply the I-X mechanism to the mid-year rate base. Carrying forward the mid-year forecast balance of rate base in the 2012 rates into the going-in rates continues to reflect the fact that new capital assets are put into service throughout the year. The Commission finds that the introduction of PBR does not require a departure from the use of the mid-year convention. No evidence was provided that other regulators employ this practice in adopting a PBR plan.

92 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 76.
93 Exhibit 99.01, ATCO Gas application, page 45-46.
94 Exhibit 99.01, ATCO Gas application, paragraph 132.
95 Exhibit 298.02, Calgary evidence, page 49, paragraph 176.
96 Exhibit 629.01, Calgary argument, page 69.
97 Exhibit 636.01, CCA argument, paragraphs 230 and 231.

103. The Commission finds no compelling reason to depart from the use of the mid-year convention. Accordingly, the Commission denies ATCO Electric's and ATCO Gas' proposal to use 2012 end-of-year forecast values rather than applying the mid-year convention for the rate base calculations included in going-in rates.

3.4 Individual adjustments to going-in rates requested by the companies

3.4.1 Fortis

104. Fortis proposed to update its 2013 opening values to reflect 2012 actual capital expenditures and related effects.[98] Fortis also proposed two adjustments to account for the full cost of a distribution control centre and one for depreciation rates.

105. At the hearing, Fortis requested a one-time adjustment to going-in rates to reflect the full cost of a distribution control center.[99] This adjustment was required because the timing of the distribution control centre implementation changed and now falls between 2012 and 2013.

106. With respect to the depreciation rates, Fortis proposed an adjustment to the depreciation rates established in its negotiated settlement. The negotiated settlement was signed on November 7, 2011 and approved by the Commission on April 18, 2012 in Decision 2012-108.[100] Fortis argued that "going-in rates for depreciation costs alone are fine on a going in basis" but due to Fortis' PBR assumptions the going-in rates should recognize "$60 million more of rate base compared to the plan assumptions when we set our PBR proposal."[101]

3.4.2 ATCO Electric

107. ATCO Electric requested two adjustments: one to include the final 2012 costs for three buildings and an adjustment for capitalized pension costs.

108. ATCO Electric proposed adjustments to its 2012 distribution rates to recognize full forecast costs and property taxes for three buildings with in-service dates falling in the second half of 2012.[102] The three buildings are located in Grande Prairie, Lloydminster, and Stettler.

109. ATCO Electric also proposed an adjustment to remove the cash basis current year recovery of its capitalized pension costs from going-in rates.[103] ATCO Gas removed the cash basis current year recovery of capitalized pension costs in its 2011 to 2012 general rate application[104] and ATCO Electric sought a similar change to ensure distribution pension costs were treated in the same manner by both ATCO companies. ATCO Electric therefore is no longer seeking cash basis current year recovery of capitalized pension costs.[105] Consequently, an

[98] Exhibit 100.02, Fortis application, paragraph 42.
[99] Exhibit 633, Fortis argument, page 122.
[100] Decision 2012-108: FortisAlberta Inc, Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
[101] Testimony of Mr. Lorimer, Transcript, Volume 11, pages 2184-2188 as quoted in Fortis argument, Exhibit 633.01, pages 121-122.
[102] Exhibit 98.02, ATCO Electric application, paragraphs 210-214.
[103] Exhibit 98.02, ATCO Electric application. paragraphs 221 and 222.
[104] Decision 2011-450 ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) 2011-2012 General Rate Application Phase I, Application No, 1606822, Proceeding ID. No, December 5, 2011, paragraph 5, Table 2 shows capital pension – removal of immediate collection: costs of $13,257,000 were removed for 2012.
[105] Exhibit 98.02, ATCO Electric application, paragraphs 221 and 222.

adjustment to going-in rates is required to reflect the change in recovery of these costs. In Application No. 1608750 (Proceeding ID No. 2078, the ATCO Utilities Compliance with Decision 2012-166[106]) filed on August 15, 2012, the Commission has been requested to determine the adjustment required to reflect the removal of the cash basis current year recovery of capitalized pension costs from the 2012 revenue requirement for ATCO Electric. ATCO Electric stated that the adjustment of capitalized pension costs was not commented on by interveners and it should be approved.[107]

3.4.3 ATCO Gas

110. ATCO Gas proposed an adjustment to going-in rates to account for the actual 2011 to 2012 urban mains replacement (UMR) capital expenditures in excess of the forecasts approved in Decision 2011-450.[108] ATCO Gas requested the opportunity to file a future application for an adjustment to its 2012 going-in revenue requirement for its actual 2011 to 2012 UMR expenditures. ATCO Gas submitted this approach is consistent with the mid-year convention and the effect on 2012 capital investment is consistent with what would occur under a cost of service rates application had one been filed to set rates for 2013.[109] ATCO Gas stated:

> The findings of the Commission on this matter are similar to the findings of the AEUB in Decision 2003-072, where the Board held ATCO Gas' UMR expenditures at approximately $7 million per year for the years 2003 and 2004.1 In the 2005 –2007 GRA, ATCO Gas was able to support the prudence of the actual UMR projects undertaken in 2003 and 2004, at a total cost of approximately $22 million, rather than the $14 million that had been approved.[110]

111. ATCO Gas stated that "[i]t is not reasonable to expect ATCO Gas to carry the cost of these prudent investments over the full term of its PBR Plan."[111] It further stated with respect to the ability to recover these UMR costs: "[t]o not provide ATCO Gas with this ability increases the risk to the utility, and it prevents ATCO Gas from having a reasonable opportunity to recover its prudently incurred costs, including a fair return."[112]

3.4.4 AltaGas

112. AltaGas proposed four adjustments to going-in rates: annualization of costs associated with monthly meter reading, income tax timing differences between 2012 and 2013, including losses carried forward, impacts of changes in pension expense from 2012 to 2013, and recovery of 2013 Natural Gas System Settlement Code (NGSSC) capital forecasts and annualization of capital and O&M expenses related to NGSSC costs.[113] AltaGas stated that its proposed annualized adjustments for metering and NGSSC costs are required in order for it to earn a fair return.[114]

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106 Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.
107 Exhibit 631.01, ATCO Electric argument, paragraph 318.
108 Exhibit 389.01, ATCO Gas update, page 5 and 6.
109 Exhibit 389.01, ATCO Gas application update, paragraph 8.
110 Exhibit 389.01, ATCO Gas update, page 2, paragraph 4.
111 Exhibit 389.01, ATCO Gas update, page 3, paragraph 5.
112 Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.
113 Exhibit 628.01, AltaGas argument, pages 80 and 81.
114 Exhibit 628.01, AltaGas argument, paragraph 273.

113. AltaGas proposed its 2012 distribution rates be adjusted to reflect changes in income taxes and depreciation.[115] The adjustment for income taxes is intended to recognize changes in income tax timing differences between 2012 and 2013, including losses carried forward.[116] AltaGas has requested an adjustment to account for a forecast change from 2012 to 2013 related to income taxes. This adjustment would be for book to tax timing differences.[117] In the hearing, AltaGas was asked about its proposal to adjust taxes to reflect a reduced level of capital cost allowance. The AltaGas witness responded:

> Well, our proposal is that the going-in rates be adjusted to allow for the increase in the income taxes, the cash income tax, expense the company will be incurring as a result of the -- of its ability to claim an equivalent CCA amount as it had in 2012. In other words, in 2012 because AUI was able to claim maximum CCA at the direction of the Commission, it effectively reduces its cash taxes to zero. So there is in fact zero dollars for income taxes sitting in the revenue requirement, which would drive the going-in rates. So we're simply asking that the company be allowed to have a component for income taxes in its going-in rates, which would be the equivalent of what it would require under normal circumstances.[118]

114. AltaGas also proposed an adjustment for the impact of changes in pension expenses from 2012 to 2013.[119] On April 18, 2012, AltaGas provided corrections and updates to its application.[120] AltaGas stated, with respect to meter reading that, due to the timing of Decision 2012-091, AltaGas "will not be able to commence the additional readings until July 1, 2012. As AltaGas' intention is to adjust its 2012 revenue requirement in its compliance filing to reflect only a half year of the additional costs, it will be necessary to make an adjustment to going-in rates to reflect the full year of costs."[121] AltaGas also asked to reserve the right to apply for a going-in adjustment for the NGSSC capital cost forecast for adjustments not included in its 2012 compliance filing.[122]

Commission findings

115. The Commission considers that each of the individual adjustments to going-in rates except for the those items specifically referred to below are requests to adjust approved 2012 revenue requirements for after-the-fact events or circumstances and are therefore denied. The Commission has confirmed the position taken in Decision 2009-035 that it will not accept adjustments to the going-in rates to account for 2012 actual results. As noted in that decision: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[123]

116. However, the Commission will allow the ATCO Electric requested adjustment to going-in rates to remove its cash basis current year recovery of capitalized pension costs. In

[115] Exhibit 110.01, AltaGas application, page 12, paragraph 44.
[116] Exhibit 628.02, AltaGas argument, page 80.
[117] Exhibit 110.01, AltaGas application, paragraph 44.
[118] Transcript, Volume 9, page 1610, lines 10 to 23, AltaGas witness Mr. Mantei in response to cross-examination by CCA counsel.
[119] Exhibit 628.01, AltaGas argument, pages 80-81.
[120] Exhibit 529, AltaGas corrections and amendments to AltaGas' application.
[121] Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
[122] Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
[123] Decision 2009-035, paragraph 74.

Decision 2012-166[124] the Commission approved the request of the ATCO Utilities to no longer collect the capital component of pension costs in the current year on a cash basis and to fund it as part of each utility's invested capital.[125] Given this decision and ATCO Gas' removal of similar costs in its general rate application, the Commission considers that this adjustment provides for consistent treatment between the ATCO distribution companies for the purpose of setting going-in rates for PBR. The requested adjustment is similar in nature to the adjustment to going-in rates permitted in Decision 2009-035 for the inclusion of ENMAX short term incentive plan costs. It is also similar to the replacement of a placeholder, and is not a rate adjustment made after-the-fact to reflect actual results. The Commission grants ATCO Electric's removal of its cash basis current year recovery of capitalized pension costs for the purposes of establishing going-in rates. The necessary adjustment to 2012 revenue requirement will be determined by the Commission in Proceeding ID. 2078. With respect to AltaGas' NGSSC costs for 2012, the Commission determined in Decision 2012-091, that the evaluation of AltaGas' 2012 forecast costs for NGSSC will be determined in AltaGas' compliance filing to its general rate application.[126] The Commission's decision on AltaGas' compliance filing to its general rate application will establish the final rates for 2012. These rates will form the basis for the going-in rates for PBR and, as a result, recovery of NGSSC costs in 2013 are already accounted for, adjusted by I-X. Accordingly, there is no need for an adjustment for NGSSC costs in AltaGas' going-in rates. With respect to AltaGas' request for a going-in rates adjustment for tax timing differences, the Commission has addressed this issue in Section 7.4.2.3.5 by indicating that book-to-tax timing differences should be the subject of a Y factor application.

3.5 Other adjustments to going-in rates

117. Certain parties to this proceeding requested removal of all deferral accounts and other Y factor adjustments from their 2012 revenue requirements. For instance, ATCO Gas requested removing the amounts included 2012 approved revenue requirement corresponding to deferral accounts treated as Y factor adjustments under PBR.[127]

Commission findings

118. The removal from going-in rates of amounts corresponding to approved Y factor items from going-in rates is discussed in Section 7.4.4 of this decision.

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[124] Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

[125] Decision 2012-166, paragraph 70.

[126] AltaGas Utilities Inc. Compliance Filing Proceeding ID No. 1921 and Decision 2012-091, AltaGas Utilities Inc, 2010 to 2012 General Rate Application – Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012.

[127] Exhibit 99.01, ATCO Gas application paragraph 135 and Exhibit 632.01, ATCO Gas argument, paragraph 330.

4 Price cap or revenue cap

119. The electric distribution companies (ATCO Electric, EPCOR and Fortis) proposed that their PBR (performance-based regulation) plans take the form of a price cap. Under a price cap plan, a company is allowed to change its customer rates according to an indexing formula that is typically comprised of an inflation measure, known as the I factor, and a productivity offset, commonly referred to as the X factor. An illustrative generic formula describing a typical price cap plan can be written as follows:

For each customer class:

$$\mathbf{Rates_t = Rates_{t-1} * (1 + I - X) \pm Other\ Adjustments}$$

120. As the formula above illustrates, the current year's customer rates for each class are derived by adjusting the previous year's rates by a percentage equal to the difference between the relevant I and X factors (as well as any other allowed or mandated adjustments discussed in other sections of this decision).

121. A price cap plan establishes annual customer rates regardless of the amount of energy transported through a company's system. Accordingly, under price cap plans the company ordinarily bears the risk of a change in energy volumes transported through its system. An increase in the amount of energy transported would lead to an increase in the company's revenues, and a decrease in the amount of energy transported would lead to a decrease in the company's revenues. As a result, parties to this proceeding pointed out that the use of price caps can be problematic when there is expected to be a continuing decline in sales per customer.

122. ATCO Gas and AltaGas both presented evidence that average gas deliveries per customer had been declining for most customer classes in Alberta and for several years and were expected to continue to decline. The average decline rate for ATCO Gas and AltaGas was approximately 1.5 per cent per year.[128] No party took issue with this evidence. Dr. Lowry, on behalf of the CCA, also confirmed that declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand side management (DSM) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards.[129] None of the electric distribution companies indicated a similar trend in declining use per customer.[130]

123. Because the rates charged by ATCO Gas and AltaGas are composed of fixed and variable components, a significant portion of revenue for both companies is determined by actual deliveries. The gas distribution companies submitted that a price cap plan would result in chronic revenue shortfalls in an environment of declining deliveries per customer.[131] To address this issue, both gas distributors, ATCO Gas and AltaGas, proposed that their PBR plans take form of a revenue-per-customer cap.

124. A revenue-per-customer cap is similar to the price cap plans discussed above. However, instead of limiting the change in customer rates from one year to the next, it limits the change in

[128] Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).
[129] Exhibit 307.01, PEG evidence, page 17.
[130] Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
[131] Exhibit 632, ATCO Gas argument, paragraph 141 and Exhibit 628, AltaGas argument, page 35.

a company's revenue per customer on a class by class basis, as illustrated by the following general formula:

For each customer class:

$$\textbf{Revenue per customer}_t = \textbf{Revenue per customer}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

125. Under a revenue-per-customer cap plan, the approved revenue per customer from the previous year is adjusted by the I-X index on a class by class basis to arrive at the upcoming year's revenue-per-customer cap. However, to calculate actual customer rates, the indexed revenue must be divided by the forecast consumption per customer on a class by class basis. Consequently, unlike in a price cap plan, forecast billing determinants represent an integral part of the revenue cap mechanism, regardless of any other adjustments outside of the I-X indexing mechanism.

126. Both gas distribution companies indicated that a revenue cap plan is common for natural gas distribution companies in Canada because it allows the company to update its billing determinants and adjust its rates to account for the effect of the declining use per customer that is common to the natural gas industry.[132] ATCO Gas highlighted the fact that PBR plans in the form of revenue cap plans were previously approved by the regulators for other Canadian gas distribution companies, including Enbridge Gas, Gaz Métro and Terasen Gas.[133]

127. As AltaGas explained in its evidence, PBR plans designed in the form of price caps are not consistent with the underlying cost structure of gas distribution companies. AltaGas pointed out that the total cost of gas distribution largely depends on the capacity required to provide for maximum daily throughput (peak loads) and transport distances (or the length of distribution line), and is largely unrelated to total energy use. However, these predominately fixed costs are mostly recovered through variable charges, for example dollars per gigajoule delivered. As a result, while changes in use per customer have virtually no impact on cost, they have a direct impact on the company's total revenues.[134]

128. This effect is further amplified by the economies of density[135] in the gas distribution industry, with the result that the price charged for an additional unit of gas delivered to customers is typically above the marginal cost of delivery. In such circumstances, increases in use per customer will increase revenue more rapidly than costs and, conversely, decreases in use per customer will decrease revenue more rapidly than costs. Consequently, unexpected changes in use per customer may lead to "windfall profits or extraordinary losses."[136] More importantly in the context of Alberta gas distribution companies, when use per customer is expected to decline on a continuing basis, the revenue decline will be fairly certain. By focusing on revenue per customer as opposed to the price per unit of gas delivered, the revenue cap approach to PBR is designed to account for the revenue decline associated with declining use per customer.

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132 Exhibit 99.01, ATCO Gas application, paragraph 19 and Transcript, Volume 8, page 1364, lines 18-20.
133 Transcript, Volume 3, page 551, line 2 to page 552, line 2.
134 Exhibit 477.01, AltaGas rebuttal evidence, paragraph 18.
135 As AltaGas explained in its evidence, economies of density exist when an increase in usage to a customer on the network leads to a less than proportional increase in total costs. In gas distribution, costs are primarily related to connecting a customer to the network and are not related to the customer's use, leading to economies of density. (Exhibit 110.01, footnote 1 on page 2).
136 Exhibit 110.01, Christensen Associates evidence, paragraph 7.

129. The CCA stated that revenue caps sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation in the circumstances where average use by small-volume customers has a markedly downward trend.[137] This view was shared by Calgary.[138]

130. With respect to the incentive properties of the proposed PBR plans, parties to this proceeding agreed that both price cap and revenue cap formulas create similar incentives to minimize costs.[139] In fact, both gas companies pointed out that they would be indifferent as between a price cap plan and a revenue cap plan if there were a deferral account or some other revenue adjustment mechanism to account for changes in use per customer under the price cap plan. However, neither company favoured the use of a price cap plan with the adjustment mechanism due to the increased complexity and administrative burden of such approach as compared to the proposed revenue-per-customer cap plans.[140]

131. At the same time, NERA pointed out that price caps and revenue caps differ with regard to their potential impact on sales (either in total or on a per-customer basis) and in the incentive to maintain quality. NERA explained that a firm under a price cap plan has an incentive to increase sales if its additional revenues from new sales exceed its incremental costs. Firms under a revenue cap plan do not have such an incentive. Additionally, NERA noted that service quality can be more of a concern under revenue caps than price caps because, under a revenue cap, if poor service quality leads to fewer sales, the lost revenue can be made up through the price increases for remaining customers that arise from application of the formula.[141]

132. Parties also observed that a revenue-per-customer cap plan would diminish the disincentive a company has to promote the DSM measures. AltaGas noted that, because the price it charges for the delivery of gas is typically greater than the marginal cost for the service, any reduction in gas consumption will have a greater impact on revenues than costs. Thus, under a price cap plan, it is in the financial interest of the company to limit the reduction in customer use and, instead, encourage increased consumption, if possible.[142] The CCA experts reached a similar conclusion and pointed out that revenue cap plans mitigate the disincentive to promote DSM plans by weakening the link between changes in system use (e.g., energy deliveries and peak demand) and changes in earnings.[143] However, Ms. Frayer on behalf of Fortis pointed out that revenue caps may create distorted incentives for companies to act like monopolists, raising prices while reducing output in order to maximize profit margins, giving rise to the so-called "Crew-Kleindorfer effect."[144]

133. AltaGas submitted that, unlike a revenue cap formula that applies to a firm's overall revenue, the proposed revenue-per-customer cap approach provides an incentive to continue connecting new customers because customer growth drives revenue growth. In contrast, a straight revenue cap formula would not provide such an incentive because under a revenue cap

137 Exhibit 307.01, PEG evidence, page 16.
138 Transcript, Volume 15, page 2926, lines 23-35 and page 2927, lines 1-11.
139 Exhibit 195.01, AUC-NERA-13; Exhibit 628, AltaGas argument, page 35; Exhibit 629, Calgary argument, page 37.
140 Exhibit 632.01, ATCO Gas argument, page 44 and Exhibit 628.01, AltaGas argument, page 35.
141 Exhibit 195.01, AUC-NERA-13.
142 Exhibit 110.01, Christensen Associates evidence, paragraph 8.
143 Exhibit 307.01, PEG evidence, page 16.
144 Exhibit 100.02, Frayer evidence, page 23.

approach the company can raise prices to meet the revenue cap without having to connect new customers.[145]

134. Finally, ATCO Gas and AltaGas pointed out that their respective revenue-per-customer cap plans do not contemplate an adjustment if the forecast PBR revenue or consumption per customer deviates from the actual values. However, the two PBR plans differ with regard to their treatment of forecast customer growth. ATCO Gas proposed that the forecast of the average number of customers be reconciled with the actual number of customers when it becomes available, while AltaGas' plan does not provide for such a true-up.[146]

Commission findings

135. A price cap plan sets customer rates in accordance with the established I-X index, regardless of the company's actual costs and the amount of energy transported. A revenue cap also employs an I-X index. However, under the latter approach, it is the revenue of the company and not its rates that is adjusted by the I-X index. Consequently, customer rates may fluctuate so long as revenue does not exceed the revenue cap.

136. The PBR plans proposed by ATCO Gas and AltaGas demonstrate that under a revenue-per-customer cap plan, customer rates are calculated on a class by class basis by dividing the revenue-per-customer cap derived from the formula by the forecast use per customer for the upcoming year. For example, if the actual billing determinants from the previous year were used for calculating customer rates in the upcoming year, the declining use per customer would lead to a systematic under-recovery of revenues by the companies. Under the proposed revenue-per-customer cap plans, customer rates will go down if the company forecasts an increase in energy consumption per customer in the upcoming year. Likewise, customer rates will go up if a decrease in energy consumption per customer is projected for the coming year. In either case, a company's revenue per customer will not exceed the value established by the PBR formula.

137. Under a price cap plan, the company ordinarily bears the risk of changes in energy volumes delivered, while under a revenue cap plan the company is largely protected from volumetric risk. Parties to this proceeding pointed out that the volumetric risk may become too great to bear when there is an expected continuing decline in use per customer.[147] In this circumstance, the use of a price cap may be problematic as it may expose the company to significant reductions in revenues resulting from declines in use per customer.

138. Both ATCO Gas and AltaGas indicated that, despite the overall sales growth, they are experiencing a continuing decline in use per customer, averaging approximately 1.5 per cent per year.[148] This rate of decline in average customer use is forecast to continue into the future. Furthermore, the companies noted that overall customer growth and increased consumption by some existing customers does not completely offset overall declines in the average use per customer.[149] The Commission accepts the average usage per customer decline rates forecasted by ATCO Gas and AltaGas and accepts the position that a price cap plan would result in significant

145 Exhibit 243.01, AUI-CCA-2(g) and (h).

146 Exhibit 99.01, ATCO Gas application, paragraphs 43-44; Transcript, Volume 8, page 1370, line 25 to page 1371, line 6 (AltaGas).

147 Exhibit 632, ATCO Gas argument, paragraphs 141-143 and Exhibit 628, AltaGas argument, page 35.

148 Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).

149 Transcript, Volume 3, page 554, lines 12-15 and Volume 8, page 1356, lines 2-9.

revenue reductions under existing rate structures due to declining gas usage if such declines in revenue were not otherwise adjusted for.

139. The Commission also agrees with AltaGas' argument that the revenue-per-customer cap approach to PBR is consistent with the underlying cost structure of gas distribution utilities. A large proportion of gas distributors' costs are fixed, while a significant amount of these costs is recovered through variable charges. As a result, unexpected changes in use per customer may lead to significant variations in the revenues of gas distribution companies that are not offset by cost changes. By focusing on revenue per customer as opposed to price per unit of gas delivered, the revenue-per-customer cap PBR plans proposed by ATCO Gas and AltaGas account for the impact of changes in use per customer on the companies' revenues.

140. Given the above, the Commission considers that forecasting use per customer for the upcoming year is warranted in this case since it accounts for the declining use per customer.

141. The Commission agrees with the parties to this proceeding that the incentive properties of both price cap and revenue-per-customer cap plans are largely the same. Both types of plans rely on an I-X indexing mechanism that decouples revenues from the costs of service, thus creating efficiency incentives. Additionally, both price cap and revenue-per-customer cap formulas use customer growth as a driver for revenue growth, thus providing incentives to continue connecting new customers. The Commission also acknowledges that, by making companies indifferent to volume changes, revenue-per-customer caps provide incentives to promote DSM plans.[150]

142. The Commission also accepts NERA's proposition that diminished service quality can be more of a concern under revenue caps than price caps. However, the Commission considers that concerns with respect to the maintenance of service quality can be addressed through service quality monitoring and reporting measures under both price cap and revenue cap PBR plans. Service quality is discussed in Section 14 of this decision.

143. Overall, the Commission agrees with ATCO Gas and AltaGas that the revenue-per-customer cap approach to PBR adequately addresses the issues associated with declining usage per customer without decreasing the intended efficiency incentives of performance-based regulation. The Commission observes that Calgary and the CCA supported the use of revenue-per-customer cap plans for ATCO Gas and AltaGas.[151]

144. Regarding the issue of a true-up to the actual number of customers, as proposed by ATCO Gas, the Commission notes that the focus of the PBR plans proposed by the gas distribution companies in this proceeding is on indexing the revenue per customer for each customer class, not the overall revenue of a company. Accordingly, the correct measure to true up, if any, is the forecast use per customer.

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150 The commission has denied certain types of demand side management programs proposed by the gas distribution companies as being inconsistent with the legislative framework. For example see, Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011, paragraph 683 and Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012, paragraph 625.

151 Exhibit 329, Calgary argument, page 37; Exhibit 636, CCA argument, page 2 and Transcript, Volume 13, page 2534, lines 13-17 (Lowry).

145. In the interest of regulatory efficiency, the Commission considers that no true up for the actual weather normalized use per customer is required. The Commission directs the gas companies to use the actual average change in weather normalized use per customer (per class) for the preceding three years as their forecast percentage change in weather normalized use per customer for the upcoming year. This percentage change is to be applied to weather normalized use per customer (actual and projected per class) for the current year to determine the forecast for the upcoming year. The Commission is satisfied that the rate of change in weather normalized use per customer over the preceding three year period will result in a reasonable forecast of weather normalized use per customer for the upcoming year.

146. With respect to the PBR plans of ATCO Electric, EPCOR and Fortis, these companies indicated that a declining use per customer or other types of volumetric risk are not an issue for them.[152] As well, Dr. Lowry pointed out that North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.[153] Consequently, the Commission has no concerns with the use of a price cap approach in the PBR plans for the electric distribution companies.

5 I factor

5.1 Characteristics of an I factor

147. The inflation factor, also referred to as an I factor or an input price index, is the component of a price cap or revenue cap PBR (performance-based regulation) plan that reflects the expected changes in the prices of inputs that the companies use. As the companies' experts explained, a PBR formula should be designed to produce rates that reflect inflationary pressures on input prices that a company is expected to experience from year to year during the term of the plan.[154] The purpose of the inflation factor is to pass on to customers the increases in the costs of goods and services purchased by the company (for example, cost of the materials and supplies, salaries of the company's staff, etc.*)* that are driven by macro-economic forces and are beyond the control of the company's management.[155]

148. The UCA noted that, by setting an automatic adjustment for the company's cost changes, an input price index obviates the need to hold frequent cost of service proceedings. The UCA pointed out that, in effect, the I factor mirrors the process of reviewing a company's costs and adjusting rates on a prudency basis, in effect using the selected inflation measure as a prudency test.[156]

149. In their respective PBR submissions, parties outlined a number of considerations for choosing the relevant I factor. Specifically, parties proposed the following selection criteria for establishing an inflation index:[157]

[152] Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
[153] Exhibit 307.01, PEG evidence, page 17.
[154] Exhibit 110.01, Christensen Associates evidence, paragraph 29; Exhibit 98.02, Carpenter evidence, page 15.
[155] Exhibit 100.02, prepared testimony of Julia Frayer, page 33.
[156] Exhibit 299.02, Cronin and Motluk UCA evidence, page 182, A87.
[157] Exhibit 631.01, ATCO Electric argument, paragraph 38; Exhibit 632.01, ATCO Gas argument, paragraph 34; Exhibit 628.01, AltaGas argument, pages 11-12; Exhibit 633.01, Fortis argument, paragraph 63; Exhibit 636.01, CCA argument, paragraph 48.

- The I factor must be indicative of the change in input prices that the company expects to experience over the term of the PBR plan.
- The inflation index must be published by a reputable, independent agency and made readily available on at least an annual basis.
- The I factor should be transparent, simple to calculate and easy to understand.
- The selected I factor should not be overly volatile.
- The I factor should reflect a broad measure of inflation rather than the experience of the specific company to which the PBR plan is to apply, so that the company cannot significantly affect the index.

150. In addition to these criteria, Dr. Ryan on behalf of EPCOR indicated that, in conducting his analysis and recommending an inflation index, he considered the Commission's findings in Decision 2009-035. In particular, EPCOR's expert recommended using an input-based index, thus avoiding the need for making adjustments to the productivity factor, which would be the case if an output-based price index were used.[158] This recommendation was also supported by the UCA.[159]

151. Additionally, in setting out his proposed criteria, Dr. Ryan recommended that if the inflation factor was composed of different component indexes, the weighting of these should be fixed rather than vary year to year, so that the company's incentives are not influenced by relative rates of inflation in the component indexes.[160]

152. The CCA pointed out that the I factor selection criteria are often in conflict and that there is "considerable art in developing an index that sensibly balances simplicity and accuracy."[161]

Commission findings

153. The I factor provides a mechanism to adjust the companies' prices[162] (in the case of a price cap plan) or revenues (in the case of a revenue-per-customer cap plan) year over year to reflect changes in the prices of inputs that the companies use.

154. As the ATCO companies pointed out in their arguments, a PBR plan should provide incentives for the company to undertake efficiency improvements to manage and minimize the costs that are within its control. However, changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors.[163] In competitive markets, when faced with a universal, economy-wide increase in input prices (such as an increase in salaries and wages, higher fuel prices, etc.), companies are often left with no choice but to pass on these higher costs to consumers. Similarly, when the prices of inputs go down, competition in the market forces the companies to lower their prices. The I factor in the PBR plans is intended to mimic this characteristic of competitive markets.

158 Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
159 Exhibit 634.02, UCA argument, paragraph 76.
160 Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
161 Exhibit 636, CCA argument, paragraph 49.
162 Utility output prices are most commonly referred to as rates. In the context of a price cap plan they are referred to as prices.
163 Exhibit 631, ATCO Electric argument, paragraph 37.

155. All parties agreed that the selected I factor should be indicative of the change in input prices that the companies are expected to experience, be transparent, simple to calculate and easy to understand. In addition, parties recommended that the inflation factor should not be overly volatile, must be published on a regular basis by a reputable independent agency and should not be overly influenced by the company itself. The Commission agrees.

156. The choice between input and output inflation indexes, the use of a single index or a composite I factor consisting of multiple indexes and the weights to be assigned to the elements of a composite I factor are discussed in the subsequent sections of this decision.

5.2 Selecting an I factor

5.2.1 The rationale behind a composite I factor

157. In Decision 2009-035, dealing with ENMAX's 2007-2016 FBR (formula-based ratemaking) application, the Commission approved a composite I factor that includes the distribution construction price index as measured by the Canadian Electric Utility Construction Price Index (EUCPI) and the Alberta Average Hourly Earnings (AHE) index with a 50:50 fixed weighting throughout the PBR term.[164]

158. The companies argued that, in general, no single measure of inflation can explain all the cost trends facing a utility, and they maintained that greater accuracy can be achieved by constructing a composite index composed of published indexes, weighted according to the average relationship among the company's various inputs.

159. Specifically, AltaGas' experts explained that a utility primarily purchases two types of inputs, employee time and goods and services from other firms. The prices that a company in Alberta must pay for these inputs will be affected primarily by economic conditions within the province of Alberta.[165] This position was supported by the other companies with each proposing that their respective I factors consist of two inflation indexes, one reflecting labour cost and the other reflecting the cost of non-labour items. Such a blended I factor would generally be calculated each year using the following weighted-average formula:

$$\textit{I factor} = w_l \ * \ \textit{Labour Price Index} + w_n \ * \ \textit{Other Costs Price Index}$$

160. For labour costs, the companies preferred to use either Average Hourly Earnings (AHE) or Average Weekly Earnings (AWE) for Alberta. For non-labour costs, the companies preferred to use either the EUCPI adjusted for Alberta inflation or the Alberta Consumer Price Index (CPI). These sub-indexes would be weighted based on the companies' historical proportions of labour (w_l) and non-labour (w_n) costs. The following table summarizes the proposed I factors as outlined in the electric distribution companies' respective PBR applications:

164 Decision 2009-035, paragraphs 144 and 149.
165 Exhibit 110.01, Christensen Associates evidence, paragraph 30.

Table 5-1 Summary of electric distribution companies' I factor proposals

	ENMAX[166] (distribution)	ATCO Electric (distribution)	Fortis	EPCOR (distribution)
Labour costs	Alberta AHE	Alberta AWE	Alberta AHE	Alberta AHE
Non-labour costs	EUCPI (no adjustment)	EUCPI (adjusted for Alberta)	EUCPI (adjusted for Alberta)	Alberta CPI
Weights (labour/non-labour)	50:50	65:35	61:39	80:20

161. Table 5-2 below presents the I factors proposed by the gas distribution companies in their respective PBR plans:

Table 5-2 Summary of gas distribution companies' I factor proposals

	ATCO Gas	AltaGas
Labour Costs	Alberta AWE	Alberta AWE
Other Costs	Alberta CPI	Alberta CPI
Weights (labour/non-labour)	57:43	57:43

162. The UCA supported the use of a composite I factor and indicated that the Commission should use the input price index approved for ENMAX in Decision 2009-035 for all the companies in this proceeding.[167]

163. The CCA also acknowledged the need for an inflation measure that reflects the "special inflationary conditions that sometimes occur in Alberta." The CCA pointed out that inflation can be much more rapid in Alberta than in Canada as a whole in some periods (for example, 2006 to 2008) and appreciably lower in other periods (2009 to 2010), since the province's economy can experience "booms and busts" because it is largely influenced by the production of price-volatile commodities.[168]

164. The CCA recommended that the I factor consist of either a single macroeconomic measure of Alberta price inflation or an appropriately designed custom index of Alberta utility input price inflation. With respect to macroeconomic inflation measures, the CCA recommended using either the Alberta gross domestic product implicit price index for final domestic demand (GDP-IPI-FDD) or the Alberta CPI.

165. PEG on behalf of the CCA, developed an index that tracks the prices of three categories of input costs: labour, materials and services, and capital. Specifically, PEG recommended using either CPI or GDP-IPI-FDD for Alberta as the proxy for the materials and supplies input price index and the Alberta AHE or AWE for the labour price index. For the capital cost category, PEG constructed this element as the product of a rate of return on capital (set initially at the weighted average cost of capital established for the subject utility in its most recent rate case)

[166] As approved in Decision 2009-035. ENMAX was included in this table for comparison purposes.
[167] Exhibit 634.02, UCA argument, paragraph 73.
[168] Exhibit 636, CCA argument, paragraph 44.

and a triangularized weighted average of past values of the EUCPI, with an adjustment to reflect Alberta construction market conditions.[169]

166. Calgary also recommended using the Alberta GDP-IPI-FDD index and indicated that it did not support the adoption of a composite I factor consisting of several weighted indexes because such an inflation measure would not be consistent with the simplicity principle.[170]

Commission findings

167. A number of parties pointed out that, because the Alberta economy is influenced by the production of price-volatile commodities such as oil and natural gas, it can experience wider swings in economic activity than the rest of the Canadian economy. As a result, inflation in the province can be quite different from inflation in the Canadian economy as a whole.

168. The companies also highlighted the fact that the presence of large scale capital-intensive oil and gas activity in Alberta leads to strong competition for labour resources, especially those involved in technical and engineering services, as well as capital-intensive projects. Accordingly, the companies were particularly concerned that the I factor be able to capture the effect of the tight labour market in Alberta.[171] As Dr. Cicchetti on behalf of EPCOR explained:

> But high oil prices and high gas prices, although those are now falling, but high oil prices at least have the effect of making the demand in the job market tighter, and the demand for people who are engineers of whatever kind who can be employed by electric distribution companies is tighter.[172]

169. The Commission agrees with these observations. Because of the relatively tight labour market in Alberta, salaries and wages have been rising faster than the national average during petroleum industry booms and have declined more rapidly or risen less quickly during economic slowdowns, as compared to the rest of Canada. Therefore, the Commission will include an Alberta-specific labour inflation component in the I factor of the companies' PBR plans to reflect labour inflation in the province.

170. The Commission agrees with the companies that all-encompassing macroeconomic inflation measures, such as Alberta GDP-IPI-FDD or Alberta CPI proposed by the CCA and Calgary, when used as the only measure of inflation, do not reflect the input price inflation faced by the companies. As ATCO Gas pointed out, using a single macroeconomic index for the I factor may result in a significant revenue shortfall due to the under-recovery of its labour-related costs.[173] Furthermore, the CCA agreed that both CPI and GDP-IPI-FDD in this context are output price indexes, thus requiring adjustments to the productivity measure (in this case a TFP (total factor productivity) study) in determining an X factor as explained in Section 6.4.1 below.[174] In the Commission's view, the need for such an adjustment more than offsets any simplicity and transparency benefits of using a single macroeconomic inflation measure.

[169] Exhibit 307.01, PEG evidence, pages 52-54 and Exhibit 376.18, ATCO-CCA-63 attachment.
[170] Exhibit 629.01, Calgary argument, page 22.
[171] Transcript, Volume 7, page 1291, lines 13-16, Volume 11, page 2137, line 24 to page 2138, line 1.
[172] Transcript, Volume 11, page 2061, lines 19-24.
[173] Exhibit 632, ATCO Gas argument, paragraph 49.
[174] Exhibit 636, CCA argument, paragraph 51.

171. Accordingly, for the reasons above the Commission finds that the use of a composite I factor in the PBR plans of Alberta utilities is warranted.

172. The Commission considers that the composite I factors proposed by the companies generally conform to the input price index selection criteria outlined in Section 5.1. The proposed sub-indexes for labour and non-labour costs are published by Statistics Canada on a regular basis and, as explained in further sections of this decision, do not require any subjective modifications. The Commission considers that these indexes are sufficiently broad-based to avoid potential concerns about the activities of the companies significantly influencing these measures.

173. In addition, as explained in Section 6.4.1 below, since all the components of the I factors proposed by the companies can be considered input price indexes for the Alberta electric and gas distribution companies, using such a composite I factor does not require an adjustment to TFP in determining an X factor in order to account for an input price differential and a productivity differential.

174. With respect to the customized index for labour, capital and materials proposed by the CCA, the Commission notes that a similar index was proposed by the UCA in the ENMAX FBR proceeding, as outlined in Decision 2009-035. In that decision, it was noted that this type of I factor was more data intensive and more complex than the Commission considered desirable for the purposes of a PBR plan.[175] Indeed, in this proceeding, the CCA pointed out that the selection of an inflation measure for a PBR plan is difficult because greater accuracy comes at the cost of greater complexity.[176] ATCO Gas pointed out that the CCA's index needed a 15 page spreadsheet with a number of significant, complex calculations.[177] During the hearing, Dr. Lowry concurred that the calculation of the proposed customized index would likely require a Ph.D.'s expertise.[178] As such, the Commission considers that the customized index proposed by the CCA suffers from the same data intensity and complexity drawbacks as did the UCA's proposal for ENMAX. Furthermore, similar to the proposed I factors of ATCO Gas and Fortis, the CCA's customized inflation factor involves a modification to EUCPI to attempt to better reflect Alberta inflation. The Commission discusses the shortcomings of such adjustments in Section 5.2.3 below.

175. Finally, the CCA contended that the added complexity of a customized inflation index was warranted because it better tracked input price inflation. However, when the CCA compared its proposed customized I factor to a GDP-IPI-FDD index, the results were within 0.01 percentage points of each other over the 2001 to 2010 period.[179]

176. In light of the above considerations, the Commission is not persuaded that the customized index proposed by the CCA is superior to the types of I factors proposed by the companies.

177. Similar to the findings in Decision 2009-035, the Commission recognizes that the blended I factors proposed by the companies do not specifically account for changes in the cost

175 Decision 2009-035, paragraph 139.
176 Exhibit 636, CCA argument, paragraph 49.
177 Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 164.
178 Transcript, Volume 13, page 2587, lines 1-6.
179 Exhibit 372.01, AUC-CCA-20(c).

of capital.[180] Although there was some debate at the proceeding as to whether financing rates in the economy as a whole may be reflected sufficiently in the rate of inflation, it is the Commission's view that financing rates are a function of interest rates in the economy as a whole, which themselves are ultimately reflected in the rate of inflation. As Dr. Lowry stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[181]

178. On the issue of whether changes in the cost of capital are reflected in the selected I factor, AltaGas stated in its rebuttal evidence:

> The inflation factor, like the X-factor, is designed to mirror the way prices change in a competitive economy. In a competitive economy, the price of capital inputs is determined by the real rate of return on assets, their rate of economic depreciation and the price of acquiring and installing capital. In much of productivity research, including previous productivity research conducted by us [Christensen Associates Energy Consulting] and PEG, the real rate of return has been computed using the current year's nominal rate of return and the rate of inflation in recent years. This produced significant year-over-year volatility in the real rate of return, which, in turn, led to significant year-over-year volatility in the price of capital services. With this volatility, researchers were unable to determine the trend rates of price inflation with any degree of accuracy. In recent years, researchers have noted the real rate of return fluctuates around a constant value and have taken the approach of using a fixed, real rate of return when computing capital price inflation. Fixing the real rate of return at a constant value implies the price of capital services moves in proportion to the price of acquiring and installing that capital. Thus, the relatively straight forward way of computing the inflation factor proposed by AUI is also theoretically sound.[182]

179. The theory supported by the AltaGas experts implies that changes in the cost of capital (both debt and equity) are sufficiently reflected in the company's selected inflation measure. AltaGas' proposed I factor is similar to what the Commission has adopted.

180. Accordingly, the Commission considers that a composite I factor consisting of two broad-based indexes for labour and non-labour costs captures changes in the cost of capital (both debt and equity). In addition, including a separate adjustment for the company's actual cost of capital in the I factor would require accounting for other cost items such as rate base and depreciation to determine the weighting of the capital cost component of such an I factor. In Decision 2009-035, the Commission expressed its concerns with an I factor that appeared to be an effort to move closer to an inflation index that tracked the experience of a specific company to which the PBR plan would apply rather than a broader industry inflation measure.[183] The more the selected inflation measure tracks the actual performance of an individual company, the more it resembles cost of service regulation and the more the incentive properties of PBR are

[180] Decision 2009-035, paragraphs 139-140.
[181] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[182] Exhibit 477, Christensen Associates rebuttal evidence filed on behalf of AltaGas, paragraph 56.
[183] Decision 2009-035, paragraph 141.

diminished. For all these reasons, the Commission finds that no adjustments for company-specific capital costs should be incorporated in the I factor.

181. Overall, the Commission is satisfied that a composite I factor consisting of two indexes (one for labour and the other for non-labour costs), represents a reasonable balance between the need for transparency and the need for accuracy in establishing an input price inflation measure for the Alberta electric and gas distribution companies.

182. The individual components of a composite I factor are discussed below.

5.2.2 Labour input price indexes (AHE vs. AWE)

183. Some of the companies proposed using the Alberta AHE as the labour price index component of their I factors, while others preferred using the Alberta AWE instead. Both of these indexes are published by Statistics Canada. However, since the agency produces many variations of the AWE and AHE indexes, careful attention must be paid to the definition of a particular inflation measure when evaluating it.

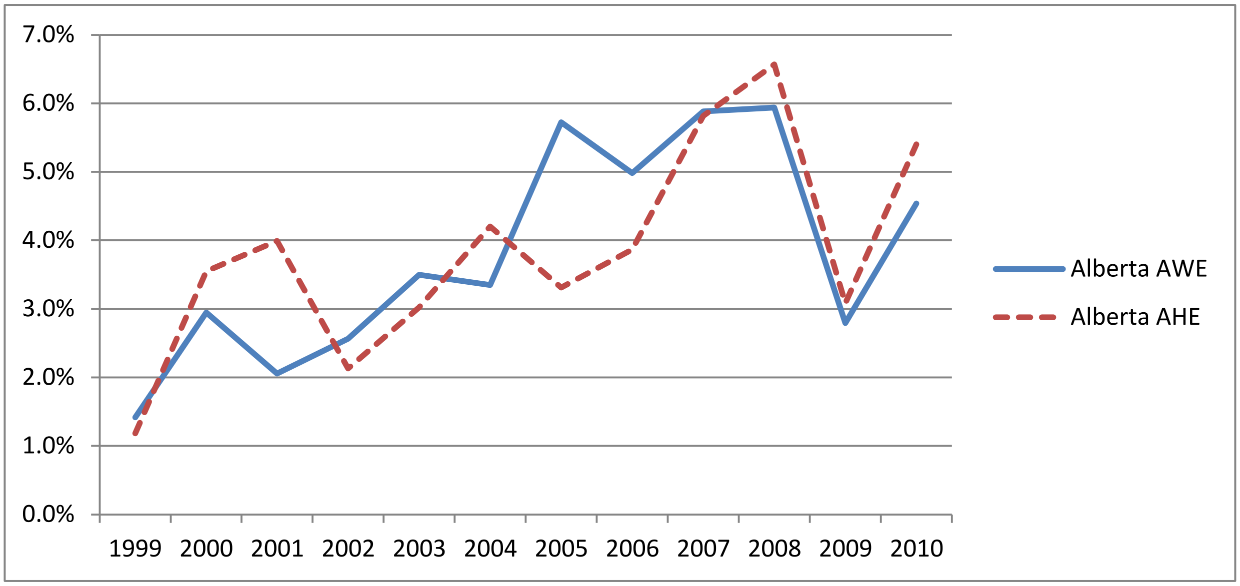
184. In their respective PBR applications, Fortis and EPCOR proposed using the AHE index, defined as average hourly earnings for salaried employees (paid a fixed salary), including overtime and unadjusted for seasonal variation, which is published for selected industries classified using the North American Industry Classification System (NAICS).[184] ATCO Electric, ATCO Gas and AltaGas proposed to use the AWE, defined as average weekly earnings, including overtime and seasonally adjusted for all employees in selected industries classified using the NAICS.[185]

185. The broadest measure for both AHE and AWE indexes is the aggregate index or industrial aggregate, which includes all NAICS industries (including utilities), except for those industries that are unclassified. As Dr. Ryan explained in his evidence, it is preferable to use either AHE or AWE for the industrial aggregate, since the weights of the individual industries in these two labour inflation indexes are not known. Further, an Alberta AHE or AWE for the utilities sector would be influenced by the companies.[186] Consequently, all the companies proposed using the AHE or AWE labour input price indexes at the industrial aggregate level.

186. In response to the Commission’s information request (IR) as to whether there would be material differences in the inflation rates used for the PBR formulas if AHE or AWE were employed to calculate an I factor, the companies agreed that even though the two inflation measures may differ from each other substantially in a single year, over an extended period, both measures of labour costs increase at a similar rate. For example, Fortis pointed out that, over the period from 1999 to 2009, Alberta AHE grew by an average of 3.7 per cent annually, while Alberta AWE grew by an average of 3.8 per cent annually.[187] A similar conclusion was reached by Dr. Ryan.[188] Based on the inflation data filed by the parties, the Commission has produced the following table which compares the Alberta AHE and AWE growth rates over the period of 1999 to 2010:

184 Statistics Canada Table 281-0036, data vector V1808689.
185 Statistics Canada Table 281-0028, data vector V1597350.
186 Exhibit 103.04, Dr. Ryan evidence, paragraph 13.
187 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
188 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

Table 5-3 Alberta AHE and Alberta AWE, 1999-2010 (in per cent)[189]



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average 1999-2010
Alberta AWE	1.4	2.9	2.1	2.6	3.5	3.4	5.7	5.0	5.9	5.9	2.8	4.5	**3.8%**
Alberta AHE	1.2	3.6	4.0	2.1	3.0	4.2	3.3	3.9	5.8	6.6	3.1	5.4	**3.8%**

187. However, the companies restated their preferences for the labour index set out in their PBR applications. ATCO Electric and ATCO Gas argued that the AWE index more accurately represents their labour input costs as compared to the AHE index and therefore better meets AUC PBR Principle 4.[190] Fortis proposed to use the Alberta AHE for the labour component of the I factor, arguing that approximately 75 per cent of its employee compensation is based on an hourly rate of pay.[191] AltaGas argued that, because many of its employees and its contractors' employees are wage employees, it preferred to use the AWE index, which takes both hourly and salary compensation into account.[192] EPCOR concluded that, for the purpose of calculating an I factor to use in the PBR formulas, it is immaterial which measure is used.[193]

Commission findings

188. As EPCOR explained, both the AWE and AHE indexes are obtained from the same Statistics Canada survey[194] and therefore are based on the same underlying data. Table 5-3 above demonstrates that, over the period from 1999 to 2010, the two series yielded essentially the same overall average inflation rate.

189 For AWE, see Exhibit 540.02. For AHE, see Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
190 Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.
191 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
192 Exhibit 248.02, AUC-ALLUTILITIES-AUI-4.
193 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
194 Survey of Employment, Payrolls and Hours (SEPH).

189. The Commission observes that there is no significant difference between the Alberta AWE and Alberta AHE over an extended period of time at the industrial aggregate level and accordingly, for the purposes of establishing an I factor, either measure can be adopted.

190. Parties to this proceeding pointed out that, based on the Statistics Canada definitions of the two indexes, the main difference is that the AWE index includes both salaried employees and those paid an hourly wage while the AHE index referenced in this proceeding includes salaried employees only. In that regard, the Commission agrees with Fortis' explanation that year-to-year differences between the two measures can be explained by the fact that the adjustment of labour utilization in response to variations in economic activity are made through the number of hours worked in the short term, while salaries are slower to adjust to economic booms and slowdowns.[195]

191. In the Commission's view, using the AWE index which includes both salaried employees and those paid an hourly wage would capture the inflationary trends in labour costs more quickly than an index which includes salaried employees only. Further, given that the AWE reflects variations in economic activity sooner than the AHE, using the AWE in the composite I factor would mitigate somewhat the effect of the inflation lag resulting from using the actual inflation from the preceding 12-month period for the upcoming year's I factor, as further discussed in Section 5.3 below. In addition, the Commission observes that unlike the AWE index (from Statistics Canada Table 281-0028) that is published monthly, the AHE index (from Statistics Canada Table 281-0036) proposed by Fortis and EPCOR is published on an annual basis. As such, using the Alberta AHE index for January 1st rate changes will effectively result in a 24-month lag between the I factor used in the PBR plan and the actual labour inflation experienced by the provincial economy in any given year.

192. The other difference between the two indexes is that the proposed AWE index is seasonally adjusted, while the AHE is not. Taking into account the fact that the purpose of the seasonal adjustment is to adjust for patterns that occur within a year, the Commission agrees with the ATCO companies' view[196] that the adjustment for seasonal variation is not relevant in this case, since the companies will be using the inflation indexes over a 12-month period. Accordingly, seasonal adjustment is not a reason to choose one index over the other.

193. Finally, the Commission is satisfied that the Alberta AWE index, at the industrial aggregate level which includes all industries in the Alberta economy, is sufficiently broad-based to avoid potential concerns about the companies' actual experience significantly influencing these measures.

194. For all these reasons, the Commission considers that using the Alberta AWE index from Statistics Canada Table 281-0028, data vector V1597350 as a labour cost component of the I factor for the Alberta companies provides a reasonable overall reflection of labour price changes.

5.2.3 Non-labour input price indexes

195. In Decision 2009-035, the Commission approved the use of EUCPI as a component of ENMAX's composite I Factor. Having analyzed its recent experience under the PBR plan,

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195 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.

196 Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.

ENMAX noted that, because the EUCPI portion of its I factor is a Canada-wide index, it may not be sufficiently aligned with actual cost increases faced by an electric distribution company in Alberta.[197] The CCA also objected to the use of the unadjusted national EUCPI index in the PBR plans of the Alberta electric distribution companies.[198]

196. EPCOR, ATCO Gas and AltaGas proposed to use the all items Alberta CPI for the non-labour component of their I factors.[199] The CPI for all items is the broadest measure of the consumer price inflation, and reflects the prices of a wide variety goods and services in the economy. EPCOR, ATCO Gas and AltaGas argued that the Alberta CPI is perhaps the best index to reflect changes in their non-labour input prices. Furthermore, these companies indicated that they have traditionally used, and the Commission has adopted, the Alberta CPI in the past to forecast general supply-related costs in their cost of service rate applications. In addition, AltaGas noted that the use of the Alberta CPI reflected the fact that most of its non-labour inputs are sourced within the province.[200]

197. The proponents of the Alberta CPI generally agreed that this index may be regarded as an output rather than an input-based price index and, as such, could be influenced by the economy-wide productivity. However, as AltaGas observed, economy-wide outputs also serve as inputs in the form of goods and services purchased by companies. Additionally, Dr. Ryan, Dr. Carpenter and Dr. Schoech explained that, in the context of a composite I factor, the Alberta CPI will be used only to track changes in the prices of their non-labour inputs. Accordingly, the companies generally agreed that the Alberta CPI could be regarded as a proxy for an input price index for the purposes of their composite I factors, obviating the need for an adjustment to the TFP to calculate the X factor.[201]

198. In turn, ATCO Electric and Fortis proposed using the EUCPI for distribution systems as a price index for their non-labour input costs.[202] In her evidence, Ms. Frayer pointed out that, since the EUCPI is a national indicator, an adjustment factor was necessary to capture the differences in inflationary trends between Alberta and the Canadian average. To develop such an adjustment factor, Ms. Frayer proposed using the ratio of the Alberta to Canada GDP implicit price index (GDP-IPI) as a proxy for the inflation differential between the province and the rest of Canada.

199. After comparing the 10-year average of Alberta and Canada GDP-IPI trends for the period of 2000 to 2009, Fortis' expert recommended an adjustment factor of 29 per cent (or 1.29) per year to the national EUCPI to reflect Alberta inflation.[203] Using similar logic, and by taking a mid-point of the 10-year (2000 to 2009) and 15-year (1995 to 2009) ratios of Alberta to Canada GDP-IPI, ATCO Electric recommended an adjustment to the national EUCPI of 23 per cent (or 1.23) per year.[204]

200. The CCA supported an adjustment to EUCPI to account for the difference between Alberta and Canada inflation; however, it did not agree with ATCO Electric's and Fortis'

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197 Exhibit 297.01, ENMAX evidence, page 15.
198 Exhibit 636, CCA argument, paragraph 46.
199 Monthly Alberta CPI is reported in Statistics Canada Table 326-0020, data vector V41692327.
200 Exhibit 628, AltaGas argument, page 16.
201 Transcript, Volume 4, page 612, line 25 to page 614, line 10; Volume 8, page 1415, line 12 to page 1416, line 3. See also Exhibit 103.04, Ryan evidence, paragraph 32.
202 Statistics Canada Table 327-0011, data vector V735224.
203 Exhibit 100.02, prepared testimony of Julia Frayer, pages 41-43.
204 Exhibit 98.01, ATCO Electric application, Schedule 3-3.

proposal for an adjustment. Specifically, the CCA expressed its opinion that GDP-IPI is an improper basis for comparing inflation in Alberta and Canada as a whole because price inflation in Alberta is especially sensitive to the prices of oil and gas exports, which are volatile. In PEG's view, the GDP-IPI-FDD index was more suitable for this purpose because it is less volatile that GDP-IPI index.[205] In addition, the CCA argued that, by using the most recent period of 10 to 15 years to compare price trends and adjust the Alberta EUCPI, the companies would lock in the favourable inflation differential observed in that period.[206]

201. The UCA stated that the EUCPI is more likely to represent the input capital costs of the Alberta companies because the CPI is an output measure for consumers and is wholly inappropriate for determining the I factor for the companies.[207] The UCA also contended that the EUCPI is a relevant index for gas distribution companies as well because many materials and services used in capital construction for gas distribution companies are similar to those used by electric distribution companies.[208]

202. Calgary also objected to the use of the Alberta CPI and observed that the cost components included in this index have little relevance to the cost of gas and electric distribution activities. Further, in Calgary's view, using Alberta CPI in conjunction with AWE could lead to double counting of labour costs.[209]

Commission findings

203. The Commission recognizes that using the EUCPI presents a number of problems. First, the EUCPI is a national indicator. Statistics Canada does not produce an Alberta-specific version of this index. Therefore, an adjustment to the EUCPI to account for Alberta-specific inflation must be considered. However, making such an adjustment introduces issues associated with comparing inflation in Alberta to Canada. These include whether to use levels or growth rates as the best indicator of the difference in inflation rates, whether to keep an adjustment constant or permit it to change during the PBR term and selecting an appropriate time period for such a comparison, among others.[210]

204. The ATCO companies, when commenting on an adjustment to the EUCPI proposed by PEG, submitted that such a complicated customization of the EUCPI would add complexity and confusion to a PBR plan.[211] In the Commission's view, adjusting the EUCPI introduces a high degree of subjectivity and makes the resulting I factor less transparent and more difficult to understand.

205. Additionally, as ATCO Gas and AltaGas pointed out, no construction price index similar to the EUCPI is available for gas distribution companies. The UCA contended that the EUCPI is relevant for gas companies. However, as the gas companies submitted in their arguments, it is not clear why an index covering electric distribution capital relating to substations, wires, conductors and transformers is applicable to gas distribution companies with capital costs

205 Exhibit 372.01, AUC-CCA-19(c).
206 Exhibit 372.01, AUC-CCA-19(c).
207 Exhibit 634.02, UCA argument, paragraph 81.
208 Exhibit 361.02, AUC-UCA-10.
209 Exhibit 629, Calgary argument, pages 21-22.
210 For more discussion on this issue, see Exhibit 226.01, AUC-FAI-4 and Exhibit 372.01, AUC-CCA-19.
211 Exhibit 631, ATCO Electric argument, paragraph 50 and Exhibit 632, ATCO Gas argument, paragraph 53.

relating to pipe, distribution compressors, regulators and meter stations.[212] The Commission agrees that the EUCPI should not be used as part of an I factor in a PBR plan for the gas distribution companies.

206. In the previous section of this decision the Commission agreed that the substantial influence of the oil and gas sectors on inflationary pressures in Alberta can lead to substantially different inflationary pressures than in the Canadian economy as a whole with respect to labour costs. The Commission considers that the same is true for non-labour costs. Accordingly, the Commission finds that it would be more accurate to use an Alberta measure of non-labour input price inflation.

207. If EUCPI without adjustment to reflect the Alberta environment is undesirable given the differences in inflationary pressure between Alberta and Canada as a whole, and if adjusting EUCPI to Alberta is problematic, then the Commission must consider other available indexes to adjust non-labour costs for inflation.

208. Dr. Lowry recommended using the Alberta GDP-IPI-FDD as the inflation measure for materials and services, since this index is less volatile than the Alberta CPI. However, Dr. Lowry discussed the benefits of using the GDP-IPI-FDD in the context of a customized I factor which also includes separate capital and labour components.[213] The Commission dismissed in Section 5.2.1 PEG's customized approach to setting the I factor. It is unclear whether the same benefits would be realized when this index is used for a two part I factor consisting only of labour and non-labour components.

209. Unlike the Alberta GDP-IPI-FDD, the CPI for Alberta is readily available from Statistics Canada on a regular basis and does not require any subjective adjustments or modifications. As a result, this index is easily understood by customers. While it may be argued that the Alberta CPI is less relevant to the electric and gas companies' business when used as the only inflation measure in a PBR plan, the Commission agrees with the proponents of Alberta CPI that it adequately reflects the price changes for the non-labour expenditures of Alberta companies to which it will apply. The Commission notes that the Alberta distribution companies (both gas and electric) have used the Alberta CPI as an escalator index for the non-labour items in their cost of service general tariff applications.[214]

210. The Commission agrees with the companies' experts that, because the CPI is a proxy for changes in the companies' non-labour input prices, it may be considered an input price index for the purposes of calculating a composite I factor, obviating the need for any further adjustments to TFP in deriving an X factor, as discussed in Section 6.4.1 of this decision.

211. Finally, during the hearing, the Commission inquired whether there would be a material difference to the I factors if the Alberta CPI were used instead of the adjusted EUCPI proposed by ATCO Electric and Fortis. The provided undertakings demonstrate that over the recent 10-year period, the Alberta CPI tracks very closely to the proposed adjusted EUCPI.[215]

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212 Exhibit 632, ATCO Gas argument, page 12 and Exhibit 628, AltaGas argument, page 16.
213 Exhibit 307.01, PEG evidence, page 52.
214 Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 173; Transcript, Volume 4, page 614, lines 17-19 (ATCO Electric); Transcript, Volume 11, page 2137, lines 11-18 (Fortis).
215 Exhibit 540 and Exhibit 592.

212. In light of the above considerations, the Commission is not persuaded that either the Alberta GDP-IPI-FDD or the adjusted EUCPI, with its increased complexity and subjectivity, represent a better alternative to the Alberta CPI. Accordingly, the Commission finds that the all-items Alberta CPI (from Statistics Canada Table 326-0020, data vector V41692327) should be used as a non-labour input price index in the composite I factor in the PBR plans of each of the Alberta gas and electric distribution companies.

5.2.4 Weighting of the I factor components

213. In Decision 2009-035, the Commission approved a 50:50 ratio for the components of the ENMAX's I factor by examining the company's historical cost ratios for capital and operating expenses. For the purpose of the ENMAX's I factor, the EUCPI was used to track changes in capital related costs while the AHE index was used to track changes in all O&M (operating and maintenance) expenses.[216]

214. In this proceeding, the companies have not split their costs into capital-related and O&M components for the purposes of calculating an I factor, but rather they have split them into costs driven by labour inflation and costs driven by non-labour inflation. The companies proposed that the labour and non-labour components of their I factors be weighted based on their historical proportion of labour expenditures in total combined operating and capital expenditures for the (three to five-year) period immediately preceding the PBR term.

215. The companies contended that this proposed weighting better reflects the changes in input prices that they expect to experience over the term of the PBR plan. As the ATCO companies explained:

> All labour, regardless of whether it is for capital or for O&M activities, has [the] same inflationary pressures. All workers employed by ATCO Electric or retained by ATCO Electric through a contractor exist in the same labour market here in Alberta. Labour inflation does not discriminate by whether or not the worker's pay is charged to capital or O&M. Indeed, many of ATCO Electric's staff will work on a capital project one day and an O&M project the next.[217]

216. Likewise, the companies noted that inflationary pressures on non-labour costs were likely to be the same regardless of whether they relate to O&M or capital.[218] As a result, the companies grouped their expenditures into labour costs (primarily consisting of salaries, wages and contract labour), and non labour costs (primarily consisting of materials and services) to arrive at the proportional shares for the components of their respective I factor proposals set out in Table 5-1 and Table 5-2 above.

217. The UCA supported the 50:50 weighting approved for ENMAX in Decision 2009-035 because, in Dr. Cronin and Mr. Motluk's view, this weighting reflects the capital shares in Ontario and other jurisdictions internationally.[219]

218. The CCA submitted that three weighting issues are salient in this proceeding: the denominator in the cost share calculations, the weight assigned to labour, and whether company-

216 Decision 2009-035, paragraph 148.
217 Exhibit 631, ATCO Electric argument, paragraph 47.
218 Exhibit 628, AltaGas argument, page 13 and Exhibit 631, ATCO Electric argument, paragraph 48.
219 Exhibit 634.02, UCA argument, paragraph 87.

specific costs should be used to establish weightings.[220] With respect to the first issue, the CCA did not agree with the companies using the sum of O&M and capital expenditures as the denominator in the calculation of the I factor weights. The CCA indicated that the correct denominator to be used in the composite I factor is the sum of O&M and administration expenses and capital costs, which include depreciation, return on rate base, as well as income and property taxes. The inclusion of these additional non-labour items in the total amount of costs would reduce the weight of the labour component.

219. Regarding the second issue, the CCA submitted that the weight assigned to the labour component should reflect only the share of direct labour O&M expenses in total company costs. Specifically, the CCA did not agree with the approach of including contractor expenses and capitalized labour in the labour component. The CCA pointed out that contractor expenses do not consist entirely of labour expenses. In addition, since the EUCPI and the Alberta CPI already reflect labour cost trends, the CCA argued that using these indexes for the non-labour component would result in a double counting of labour inflation. Furthermore, the CCA submitted that capitalized labour does not have the same effect on a utility's earnings as O&M expenses.[221] Dr. Lowry provided the following explanation on this subject:

> [T]he way that construction labour prices affect a utility's accounting is different from the way that the direct labour price does. The direct labour price -- let's say there's a big run-up in the price because they discovered another big oilfield or something in northern Alberta. Then by the way the O&M expenses go up. But as for the capitalized piece, that's going to be recovered over 40 years, so it does not give -- and of course the reverse is true too. If there was suddenly the price of oil collapsed […] and all of a sudden there was lower labour prices in Alberta, it immediately lowers your O&M expenses, but it does not have that much of an affect on your capital cost.[222]

220. Finally, the CCA noted that using company-specific costs to establish the weights for the I factor in the subsequent PBR plans could weaken cost containment incentives, stating that the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. The CCA submitted that it has no objection to using company specific costs to establish the weights for the I factor in this proceeding only, provided it is clearly understood that in any future plan the cost shares will not be company-specific.[223]

Commission findings

221. The Commission explained in Section 5.2.1 of this decision that a relatively tight labour market in Alberta warrants the inclusion of a separate I factor component to reflect the unique labour inflation experience in the province. The Commission agrees with the companies that all workers employed by the companies or retained through a contractor are generally in the same Alberta labour market and subject to the same compensation inflation trends regardless of whether their work is accounted for as O&M or capital related labour.

222. Accordingly, the Commission considers that an I factor with a labour and a non-labour cost component represents an improvement over an I factor with an O&M and a capital

[220] Exhibit 636, CCA argument, paragraph 52.
[221] Exhibit 636, CCA argument, paragraph 54.
[222] Transcript, Volume 13, page 2593, line 15 to page 2594, line 4.
[223] Exhibit 636, CCA argument, paragraph 55 and Exhibit 372.01, AUC-CCA-18(a).

component, as previously approved in the ENMAX FBR plan, because it provides for a better tracking of inflation in prices of inputs that the companies use.

223. Dr. Lowry and Calgary pointed out that because both the EUCPI and the Alberta CPI include some labour, using these indexes along with the AWE or AHE indexes can result in a potential double-counting of labour inflation if all capitalized labour is removed from the non-labour category.[224] The Commission agrees. However, because no evidence was provided on the share of labour in either CPI or EUCPI,[225] correcting for any possible double-counting is problematic. One possible approach would be to adjust the weightings proposed by the companies by removing all capitalized labour as well as contractor expenses from the labour component. However, because capitalized labour and contractor expenses would comprise between 30 and 50 per cent of this component (based on the data for ATCO Electric, AltaGas and Fortis),[226] making this adjustment is tantamount to assuming that the share of labour in the Alberta CPI is between 30 and 50 per cent as well. In the absence of any information on the size of the labour component in the Alberta CPI, the Commission is not prepared to adopt this approach.

224. The CCA observed that contractor expenses do not consist entirely of labour expenses. However, as the ATCO companies pointed out, the contractors do not supply materials, and as such, their costs relate mostly to labour.[227] Similarly, Fortis also indicated that its contractor costs are "primarily labour, almost all labour."[228] AltaGas explained that because contractor costs consist of labour and services related to the use of contractor machinery, these costs tend to be driven by labour cost escalation, rather than general inflation.[229] The Commission agrees with this explanation.

225. With regard to the other concerns expressed by the CCA, such as the effect of capitalized labour on a company's earnings and whether it is necessary to include depreciation and return on rate base in the calculation of the I factor weights, the Commission observes that these proposals rely on the same rationale as the proposal to include a separate I factor component for the cost of capital. As explained in Section 5.2.1 of this decision, the Commission considers that no specific adjustments for the cost of capital need to be incorporated into the inflation index. Accordingly, the Commission accepts the companies' approach of using the sum of O&M and capital expenditures when calculating the weights for their respective I factors.

226. Finally, the Commission agrees with the CCA that, ideally, the weightings for the components comprising the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. However, in this proceeding, the Commission was presented with no data to assess an alternative to examining the companies' own historical cost ratios relative to labour and non-labour components. For this reason, the Commission will rely on the weights calculated on the basis of the companies' historical costs, as provided in their PBR applications.

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224 Transcript, Volume 13, page 2593, lines 11-14 and Exhibit 636, CCA argument, paragraph 54.
225 For example, Dr. Ryan pointed out that Statistics Canada does not report the share of labour in the EUCPI (Exhibit 103.04, paragraph 21).
226 Estimates calculated by the Commission's staff based on the cost information provided in Exhibit 224.01; Exhibit 110.01, Appendix III, Composite I factor calculation; Exhibit 539 and referenced Rule 005 filings.
227 Exhibit 647, ATCO Electric reply argument, paragraph 76 and Exhibit 648.02, ATCO Gas reply argument, paragraph 117.
228 Transcript, Volume 11, page 2146, lines 15-18.
229 Exhibit 650, AltaGas reply argument, paragraphs 23 and 42.

227. In light of the above considerations, the Commission accepts the companies' method of calculating the weights for the I factor components. The Commission has examined the companies' historical ratios of labour to non-labour expenditures in recent years, as provided in the PBR applications and presented in tables 5-1 and 5-2 above. ATCO Electric's estimates resulted in a 65 per cent weighting of the labour component, although this ratio reflects the fact that ATCO Electric was the only company to apply a 50 per cent multiplier to its contractor costs.[230] The Commission does not agree with this adjustment. The Commission observes that the historical cost ratios are approximately 60 per cent labour and 40 per cent non-labour for the other companies (not including EPCOR). Accordingly, the Commission finds that a 60:40 weighting of the labour and non-labour components is a reasonable estimate of the balance of labour and non-labour costs for all companies, including ATCO Electric.

228. Nevertheless, the Commission has decided in the previous section of this decision to use Alberta CPI for non-labour costs. The Commission observed earlier in this section that the CPI includes some embedded labour. Therefore, using this index for the non-labour component together with the AWE index for the labour component may lead to a double-counting of labour costs. In this case, the 60:40 weighting would overstate the companies' input price inflation in years when growth in the Alberta AWE exceeds the growth in the Alberta CPI. Conversely, the companies' input price inflation would be understated in years when growth in the AWE is lower than the growth in the Alberta CPI. Accordingly, to temper the possibility that inflation in the companies' input prices will be overstated or understated, the Commission considers that a 55:45 ratio of labour to non-labour expenditures should be used for calculating the I factors in the companies' PBR plans.

229. Consistent with the findings in Decision 2009-035, in order to ensure that the companies' incentives will not be influenced by the relative rates of inflation between the components in the I factor, the Commission also finds that the 55:45 ratio of labour to non-labour expenditures should be held constant throughout the PBR term.[231]

230. EPCOR's proposed 80:20 labour to non-labour weighting reflects the company's proposal that the I-X mechanism be applied only to its non-capital related costs. As discussed in Section 2.3 of this decision, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from the I-X mechanism. As such, the Commission directs EPCOR to use the 55:45 weighting in the calculation of its I factor.

5.3 Implementing the I factor

231. As the ATCO companies' expert Dr. Carpenter pointed out in his evidence, one of the difficulties in using the current year's inflation in the PBR formula is that the actual inflation indexes become available for each calendar year only in the first half of the following year, and there may not be any independent forecasts for the selected input price measures. To address this problem, Dr. Carpenter indicated that several methods could be used in practice. One method would be to accept a lag, either with or without a subsequent true up for the difference between the inflation actually experienced in a given year and the lagged inflation factor used to

[230] Exhibit 98.02, ATCO Electric application, Schedule 3-1.
[231] Decision 2009-035, paragraphs 147-148.

determine rates for that year. Alternatively, a forecast of expected inflation could be used with or without a subsequent true up to the actual inflation rate.[232]

232. ENMAX's FBR plan approved in Decision 2009-035 uses actual inflation from the previous year to set rates in a current year.[233] Specifically, ENMAX uses its selected input price indexes for the 12-month period ending December 31st of the previous year to set the I factor in the PBR formula and arrive at rates to be implemented on July 1st of the current year and to remain in effect until June 30th of the next year.[234]

233. Furthermore, in Decision 2010-146, the Commission recognized that the I factor indexes used by ENMAX may be periodically revised by Statistics Canada and ordered that these revisions be handled as a flow-through adjustment not subject to the materiality limit.[235]

234. The companies proposed two different approaches to implementing the I factor. AltaGas and EPCOR proposed to use an I factor mechanism similar to the one used by ENMAX. To accommodate the planned January 1st rate changes, AltaGas proposed that the inflation factor be calculated by computing annual price indexes for the 12-month period ending in June of the previous year. For example, in calculating rates for January 1, 2013, the AWE component of the I factor would be based on the change in the actual average AWE for the 12 months ending June 2012, as compared with the actual average AWE for the 12 months ending July 2011.[236] The UCA and Calgary agreed with this concept.[237]

235. An alternative method was put forward by ATCO Electric, ATCO Gas and Fortis and supported by the CCA. These companies proposed adopting a forecast inflation rate for the upcoming year with a subsequent revenue adjustment to true up to the actual inflation for that year. In supporting the I factor true-up approach, ATCO Gas argued that the 18-month lag between the inflation index used in the PBR formula and the actual inflation experienced by the companies could have a significant impact on its revenues, further amplified by the compounding effect of indexing. ATCO gas argued that, as a result, the inflation lag can cause windfall gains or losses, possibly triggering earnings sharing or a PBR re-opener.[238]

236. The ATCO companies also pointed out that the proposed I factor true-up does not amount to a true-up to actual companies' costs. Rather, it improves the accuracy of the inflation component of the indexing mechanism by truing up the I factor to the actual inflation index results.[239] Dr. Lowry on behalf of the CCA agreed that the use of a true-up for the actual inflation index results will produce a more accurate inflation adjustment and is warranted, particularly in light of the volatility of price inflation in Alberta.[240]

237. In contrast, AltaGas submitted that the lagged approach will be reasonably reflective of the company's input cost changes in the upcoming year and will provide a fair balance between accuracy and regulatory efficiency. As such, AltaGas argued that no I factor true-up was

232 Exhibit 98.02, written evidence of Paul R. Carpenter, page 15.
233 In other words, in year *t* the I factor will be based on the actual inflation indexes from year *t-1*.
234 Proceeding ID No. 12, Exhibit 15, EPC amended application, page 52.
235 Decision 2010-146, paragraphs 167-168.
236 Exhibit 110.01, Appendix I - Christensen Associates report, paragraphs 32-33.
237 Exhibit 634.02, UCA argument, paragraph 88; Exhibit 629, Calgary argument, page 22.
238 Exhibit 632, ATCO Gas argument, paragraphs 60-61.
239 Exhibit 631, ATCO Electric argument, paragraph 55 and Exhibit 632, ATCO Gas argument, paragraphs 58-59.
240 Exhibit 372.01, AUC-CCA-21(a).

necessary as it introduces an unnecessary level of complexity to the PBR plan and results in additional adjustments to future rates and additional regulatory filing requirements.[241]

238. EPCOR's expert, Dr. Ryan, also commented on the redundancy of the inflation correction procedure currently employed by ENMAX which requires recalculating the previous year's inflation factor if revised data are released.[242] Dr. Ryan noted that, since Statistics Canada series revisions can extend several years into the past, this could involve substantial recalculation and subsequent adjustments of prices in previous years without any obvious overall effect, except for allocating some part of price changes to a previous or subsequent year.

239. In Dr. Ryan's opinion, the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor, provided that the unrevised value is used as the basis for subsequent calculations. Dr. Ryan illustrated this concept with the following example:

> For example, if a series was 100 in Year 1 and 105 in Year 2, the inflation component for this series from Year1 to Year2 (to be used as part of the I factor in Year 3) would be 0.05 (or 5%). Now, if Statistics Canada was to revise the Year 2 series value to 104, and release the Year 3 series value of 107, then the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would simply be calculated as (107- 105)/105, and no adjustment because of the change from 105 to 104 would be needed, since this effect (from 104 to 105) has already been included in the previous year's inflation component. Similarly, if the Year 2 series value was revised to 106 (rather than 105), the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would still be calculated as (107-105)/105 and no adjustment because of the change from 105 to 106 in Year 2 would be needed, as this effect (from 105 to 106) would be automatically included in the subsequent year's inflation component.[243]

240. At the same time, Dr. Ryan cautioned that more substantial revisions to a component data series would need to be examined on a case-by-case basis to determine whether other adjustments would be needed. Dr. Ryan proposed that, if a termination, substantial revision or modification to a Statistics Canada data series impacted the company's inflation factor, EPCOR would be able to apply for an appropriate amendment to its inflation factor in its first annual rate adjustment filing following the termination, substantial revision or modification.[244]

Commission findings

241. EPCOR and AltaGas proposed to use the actual inflation results for the most recent 12-month period to calculate the I factor for the upcoming year with no subsequent true-up, while the ATCO companies and Fortis proposed to forecast the I factor for the upcoming year, followed by a true-up to reflect the actual inflation in that year.

242. In the Commission's view, both approaches would eventually achieve the same purpose of reflecting the inflationary pressures on the companies' input prices. Under a forecast and true-up method, the forecast I factor is reconciled to the actual inflation indexes and rates are adjusted through a regulatory proceeding. Under the alternative approach, the true-up occurs automatically by virtue of using the actual inflation indexes from the preceding year; however,

241 Exhibit 628, AltaGas argument, page 15.
242 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
243 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
244 Exhibit 103.02, EPCOR application, paragraphs 74-75.

the true up is implemented after a longer period of regulatory lag. Both approaches represent a true-up to the inflation indexes and do not imply a true-up to the actual costs of the company, thus preserving the incentive properties of the PBR regime.

243. The main difference between the two methods is that the approach preferred by the ATCO companies and Fortis ensures that the impact of actual inflation in any given year is reconciled soon after the year's end, while the alternative approach of using the actual inflation from the previous year involves a certain lag for such a true-up to occur. In this proceeding, parties' concerns with the lagged approach seemed to be centered on the fact that the lag between the inflation index used in the PBR formula and the actual inflation experienced in the economy would expose the companies to windfall gains or losses, although these would be transitory.[245]

244. The Commission considers that if inflation is higher in some years and lower in other years, as appears to be the general case in the economy,[246] then using the most recent historical inflation rate will average out the effect of any regulatory lag over the PBR period. Indeed, as ATCO Gas observed in its argument, in the absence of a true-up, the I factor in 2009 would be higher than actual inflation. The opposite would have occurred in 2010, where the I factor without the true-up would be lower than actual inflation.[247] As such, inflation will tend to balance out over the PBR term, obviating the need to true-up the I factor through a separate regulatory proceeding.

245. When discussing the benefits of the two approaches, it is important to distinguish between the fact that inflation is generally positive (in other words, prices are increasing most of the time) and the fact that the actual inflation rate will increase year-over-year in some cases and will decline in others, although prices are still increasing. For example, as Table 5-3 above demonstrates, although the level of labour prices has been increasing consistently year over year from 1999 to 2010, the rate of change in salaries and wages (i.e., labour price inflation) went up and down during this period.

246. In order for the companies to be concerned with the lagged approach and the compounding effect to take place, the rate of inflation in each year would have to be consistently higher (or lower) than in the previous year. If it is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent past inflation rate will average out the effect of the lags over the PBR period.

247. With respect to the concern that gains or losses resulting from the inflation lag may trigger earnings sharing or a re-opener, the Commission explained in Section 10 of this decision that in order to maximize the incentive properties of the PBR plans, ESM (earnings sharing mechanism) should not be part of the companies' PBR plans. As well, as set out in Section 8 below, the Commission will examine the need for re-openers on a case by case basis. Where relevant, the consequences of the inflation lag would be considered as part of any such review.

248. In light of these considerations, the Commission finds that the lagged approach currently used by ENMAX and proposed by AltaGas and EPCOR in this proceeding represents a better alternative as compared to the forecast and true-up method proposed by the ATCO companies and Fortis. For the purposes of clarity, based on the availability of Statistics Canada indexes, the

[245] Transcript, Volume 4, pages 629-630.
[246] See, for example, the inflation indexes chart in Exhibit 512.02, AUC-Fortis-7 attachment.
[247] Exhibit 632.01, ATCO Gas argument, paragraph 61.

Commission directs the companies in their annual PBR rate adjustment filings to use the inflation indexes for the most recent 12-month period for which data is available, as specified in the formula below. The Commission considers that this approach will provide a fair balance between accuracy and regulatory efficiency and will make the companies' PBR plans more transparent and simple to understand thereby furthering the objectives of the third Commission PBR principle.

249. On the issue of the periodic revision of historical inflation indexes by Statistics Canada, the Commission agrees that Dr. Ryan's proposed method of accounting for revisions to the indexes by means of using the unrevised values in the subsequent I factor calculations represents an improvement over the rate adjustment method currently employed by ENMAX. Accordingly, the Commission finds that the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor and directs the companies to use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's inflation factor calculations.

250. The Commission also agrees with Dr. Ryan's recommendation that if a termination, substantial revision or substantial modification to the Statistics Canada data series used in the companies' I factors occurs, such changes should be brought forward to the Commission as part of the annual PBR rate adjustment filings. Any changes to the I factors arising from such data series modifications will be dealt with on a on a case-by-case basis.

5.4 Commission directions on the I factor

251. The Commission directs that the I factor to be used in the PBR plans of the Alberta utilities shall be calculated as follows:

$$I_t = 55\% \text{ x } AWE_{t\text{-}1} + 45\% \text{ x } CPI_{t-1},$$

where:

I_t	Inflation factor for the following year.
AWE_{t-1}	Alberta average weekly earnings index for the previous July through June period.[248]
CPI_{t-1}	Alberta consumer price index for the previous July through June period.[249]

6 X factor

6.1 Purpose of the X factor

252. The X factor is one of the key elements of PBR plans employing an I-X indexing mechanism to adjust a regulated company's prices or revenues each year during the PBR term. In general terms, the X factor can be viewed as the expected annual productivity growth during the

[248] The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September.

[249] The Commission recognizes that Alberta CPI information for July may be available when the September annual PBR rate adjustment filing is made but the Commission is directing the July through June period in order to ensure the companies have enough time to prepare their filings.

PBR term. Through the I-X mechanism, a PBR plan is designed so that the changes in the prices of the company's distribution services reflect changes in input prices as reflected by the I factor and the rate of expected productivity growth.

253. The X factor, combined with the I factor, is designed to mirror the pressures of competitive market forces. In competitive markets, firms are not able to earn additional profits from productivity improvements that their competitors also adopt because competition acts to drive down prices.[250] However, to the extent that the firm is more productive than its competitors, it earns an extra return, which serves as a reward for its better than average productivity. Conversely, firms that are less productive than average earn lower returns.[251] The X factor in a PBR plan imitates these pressures by requiring the regulated companies to adjust their prices to reflect the expected productivity growth.

254. NERA and other experts in this proceeding drew attention to the fact that the magnitude of the X factor has no influence on the incentives for the company to reduce costs.[252] As Dr. Carpenter explained in his evidence:

> Under PBR, a utility which successfully saves a dollar of operating expenditure keeps that dollar (or a portion of the dollar under an earnings sharing mechanism). The opportunity to save the dollar (or portion thereof) of expenditure is unrelated to the level of rates, and therefore the magnitude of the productivity factor does not influence the incentive to find the savings.[253]

255. AltaGas explained that while the size of the X factor does have an impact on the company's return, it is the decoupling of the revenues and prices from the company-specific costs that provide the incentives, rather than the magnitude of the X factor itself.[254] Similarly, EPCOR and the CCA noted that it is the length of the term of the PBR plan (i.e., regulatory lag) that is the primary source of the incentives.[255]

Commission findings

256. During the term of the PBR, a company's prices or revenues will change with inflation, represented by the I factor, adjusted by the expected productivity growth represented by the X factor. Customers of a regulated company under PBR directly benefit from annual rates that are adjusted to reflect this expected productivity growth.

257. The Commission agrees with the experts of the companies, NERA and the CCA, that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. As the companies' and the CCA's experts pointed out, the PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time of the PBR term, and not from the magnitude of the X factor itself.

[250] Exhibit 98.02, Carpenter evidence, page 18.
[251] Exhibit 616.02, page 13, William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities FORTNIGHTLY*, (22 Jul. 1982).
[252] Transcript, Volume 1, page 117, lines 10-15; Exhibit 633, Fortis argument, paragraphs 140-141.
[253] Exhibit 98.02, Carpenter evidence, page 17.
[254] Exhibit 628, AltaGas argument, page 32.
[255] Exhibit 630.02, EPCOR argument, paragraph 80; Exhibit 636, CCA argument, paragraph 105.

6.2 Approaches to determining the X factor

258. As the record of this proceeding demonstrates, there are different approaches to setting the productivity target included in the X factor of a PBR plan. In Decision 2009-035, the Commission expressed its preference for an approach to determining the X factor that is based on the average rate of productivity growth in the industry as a whole.[256] As NERA explained, under this concept, the purpose of the X factor is to reflect the long-term underlying industry productivity trend.[257] NERA favoured this approach to the determination of the X factor as evidenced by the two reports[258] prepared by NERA on total factor productivity for the regulated electric utility industry. While differing from NERA on how to determine the underlying industry productivity trend, EPCOR, AltaGas and the ATCO companies used this approach to setting the X factor.[259]

259. The CCA generally agreed with NERA's opinion that the X factor should reflect the productivity growth of the industry in which the company operates. In addition to using the index approach employed by NERA for estimating the industry productivity trend, the CCA's experts relied on an econometric model for this purpose as well. In PEG's view, the econometric approach produces a more customized productivity estimate reflecting Alberta business conditions.[260] The econometric approach to measuring TFP is further discussed in Section 6.3.4 below.

260. In Fortis' view, the analysis of the historical industry productivity trend needs to be complemented with an assessment of a company's going-forward costs and especially capital expenditure costs.[261] NERA pointed out that this type of X factor derivation resembles the building blocks concept currently employed by regulators in the United Kingdom and Australia. Under this approach, the X factor does not come from a TFP growth study, rather it is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[262] Fortis' expert, Ms. Frayer, explained that in these circumstances, the X factor represents not a productivity factor itself, but rather a smoothing factor for rates, while the productivity target is embedded in the forecast of future operating and capital costs that are then used to forecast a revenue requirement and rate schedule.[263]

261. The UCA's preferred approach to determining the X factor centered upon efficiency benchmarking and consideration of a level of inefficiency for each particular company.[264] Under this method, the regulator must perform a benchmarking assessment of historical efficiency for a comparator group of companies, based upon a comprehensive analysis of their costs including capital, labour, materials and power losses. Following this analysis, the companies are assigned different productivity targets that are set higher, the more inefficient any particular company was

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256 Decision 2009-035, paragraph 176.
257 Exhibit 391.02, NERA second report, paragraph 36.
258 Exhibit 80.02, NERA report and Exhibit 391.02, NERA second report.
259 Exhibit 630.02, EPCOR argument, paragraph 67; Exhibit 628, AltaGas argument, page 29; Exhibit 631, ATCO Electric argument, paragraph 84; Exhibit 632, ATCO Gas argument, paragraph 94.
260 Transcript, Volume 13, pages 2529-2530.
261 Transcript, Volume 11, page 2104, lines 23-24 and Exhibit 474.01, Fortis rebuttal evidence, paragraph 19.
262 Exhibit 391.02, NERA second report, pages 27-28.
263 Exhibit 474.02, Frayer rebuttal, page 38.
264 Transcript, Volume 17, page 3167, line 1 and Exhibit 299.02, Cronin and Motluk UCA evidence, pages 117-125.

found to be as compared to its peers (or, in other words, the further away a company was found to be from the efficiency frontier).[265]

262. In the absence of a complete set of the detailed historical cost information for Alberta gas and electric distribution companies upon which to base the benchmarking assessment, the UCA experts recommended constructing a menu which pairs data on a range of probable productivity performances with the associated ROE (return on equity) that would be permitted with each productivity choice. In the UCA's view, the menu approach to the X factor would mitigate the risks from information asymmetry and incent the companies to reveal their performance potential.[266]

263. For practical purposes, Dr. Cronin and Mr. Motluk recommended the use of the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[267] This menu was based on the analysis of the performance of 48 distribution utilities in Ontario operating under the cost of service (1988 to 1993) and PBR (1993 to 1997) regimes.[268] The UCA's X factor menu recommendation is as follows:

Table 6-1 The X factor menu proposed by the UCA's experts[269]

Selection	X factor (in per cent)	ROE ceiling (in per cent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

264. Dr. Cronin and Mr. Motluk explained that under this arrangement, the companies can choose a combination of productivity growth and ROE: a higher productivity target would permit higher returns.[270] The UCA experts explained that the menu above has an earnings sharing mechanism embedded in it. In particular, the menu selections were designed in such as way that moving among menu choices (for example, from option A to option B) results in a 57:43 earnings sharing between a company and the ratepayers. At the same time, if a company's actual ROE exceeds the earnings ceiling associated with a particular menu option, 100 per cent of earnings above the ROE cap is given to ratepayers.[271]

Commission findings

265. NERA explained that because in competitive markets prices move according to the productivity of the industry in question rather than the particular costs of one company, it has

265 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 131-136.
266 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 140-141.
267 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.
268 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
269 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
270 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 153 and 154.
271 Transcript, Volume 17, page 3205, lines 11-20.

become customary for regulators in the design of objective PBR formulas to set the X factor based on the underlying trend in industry productivity growth.[272]

266. Similarly to the discussion in the proceeding dealing with ENMAX's FBR plan, in this proceeding the parties offered several principal approaches to determining the X factor. With respect to Fortis' approach, which involved setting the X factor based on the forecast revenue requirement over the PBR term, the Commission agrees with NERA's characterization that this method essentially resembles a five-year test period under traditional cost of service rate making.[273]

267. The Fortis approach first determines the forecast revenue requirement over the PBR term and then develops a formula to be applied to rates which will yield the forecasted revenue requirement each year. As NERA observed, while Fortis' approach resembles the practices of regulators in the United Kingdom and Australia, it is inconsistent with the institutional foundation for performance-based-rate regulation generally adopted in Canada and the United States.[274] Accordingly, the Commission restates its opinion expressed in Decision 2009-035 that this method effectively involves a multi-year cost of service rate setting exercise and changes the theoretical basis for utilizing the X factor, which is to emulate the incentives of a competitive marketplace for the benefit of ratepayers and shareholders alike.[275]

268. The efficiency frontier and benchmarking method advocated by the UCA's experts represents yet another approach to determining the value of the X factor. In contrast to productivity studies that deal with the rate of industry productivity growth over time, the efficiency frontier analysis focuses on a company's productivity level (i.e., efficiency[276]) at a particular time in relation to comparable companies. In other words, instead of looking at how the industry's productivity changes over time, this method examines whether one particular company is less or more efficient at the time of measurement as compared to its peers.

269. In the Commission's view, the efficiency benchmarking analysis is prone to two major criticisms. First, as NERA and Dr. Carpenter explained, the efficiency levels are hard to estimate as this type of analysis requires a multitude of historical company-specific data, which exhibit a great deal of year to year volatility and are prone to errors.[277] Indeed, as the UCA witnesses observed, this method of developing the X factor would busy "hundreds of analysts" both of the companies and the regulator.[278]

270. More importantly, Dr. Makholm and Dr. Carpenter pointed out that in practice it is virtually impossible to determine whether a firm is or is not efficient by looking at benchmark data alone, since relative efficiency depends on a boundless number of variables, both observable

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272 Exhibit 80.02, NERA report, pages 1 and 3.
273 Exhibit 195.01, AUC-NERA-9(a).
274 Exhibit 391.02, NERA second report, page 9.
275 Decision 2009-035, paragraph 174.
276 The difference between terms "productivity" and "efficiency" is a definitional one. Dr. Makholm agreed when people refer to productivity, they usually refer to productivity growth, and they just leave out the word "growth" because productivity growth is measured in a percentage and some people confuse productivity growth with the actual efficiency at a point in time or the efficiency of one company. (Transcript, Volume 3, page 528, lines 5-25.)
277 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
278 Transcript, Volume 17, page 3227 and pages 3430-3431.

and unobservable.[279] Factors such as age of plant, soil type, weather and geography, customer density, etc., are to be taken into account when considering efficiency levels. In these circumstances, inadvertently leaving out an important productivity driver may invalidate the results of the study.[280] Overall, the Commission agrees with the following criticism by NERA of the UCA's approach:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie in the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[281]

271. In contrast, because TFP (total factor productivity) studies (such as the one prepared by NERA in this proceeding) focus on rates of change in productivity within an industry, not levels, the unique cost features of any particular company cancel out in the process. In other words, these productivity studies do not examine whether one firm has a greater level of output for the same inputs levels as another firm. Rather, the focus is to study how the ratio of outputs to inputs changes over time for the industry as a whole.

272. Under the UCA's efficiency benchmarking approach to developing the X factor, a company is incented to catch up to the level of efficiency experienced by peer companies deemed to be more efficient by the regulator, rather than to meet or beat the industry rate of productivity growth. Because of the practical and theoretical problems associated with measuring efficiency levels described above, the Commission does not accept this approach for the purposes of PBR in Alberta.

273. With respect to the menu approach to setting the X factor proposed as an alternative by the UCA's experts, for the reasons outlined below, the Commission is not prepared to adopt this approach.

274. First, similar to a discussion in sections 6.3.3 and 6.3.7 of this decision, the Commission is not persuaded that the UCA's X factors, based on ten-year data for Ontario distribution companies, represent a better indicator of the underlying long-term industry productivity trend than NERA's TFP based on a broad sample of companies over the period of 1972 to 2009. Second, as ATCO Electric pointed out, it is not clear why the X factor/ROE tradeoffs presented in the menu were reasonable for the Alberta companies.[282] In particular, the ROE ceilings in the menu do not correspond to the Commission's determinations in the most recent Generic Cost of Capital decision.[283] In addition, EPCOR pointed out that the UCA's menu approach presupposes the inclusion of an ESM (earnings sharing mechanism) in the PBR design.[284] The Commission determines in Section 10 of this decision that in order to maximize the incentive properties of PBR, an ESM should not be part of the companies' plans.

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279 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
280 Transcript, Volume 18, pages 3482-3483.
281 Transcript, Volume 3, page 491, line 20 to page 492, line 6.
282 Exhibit 647, ATCO Electric argument, paragraph 123.
283 Transcript, Volume 17, pages 3204-3205.
284 Exhibit 646.02, EPCOR reply argument, paragraph 74.

275. In addition, the Commission observes that the Ontario Energy Board did not accept the menu approach, partly because of the concerns regarding "the unnecessary complexity encompassed in the proposed menu."[285] A similar concern was expressed by EPCOR's expert, Dr. Weisman, who supported his view with the following quotation from an academic article:[286]

> Allowing for a choice among incentive plans can complicate the regulatory task, thereby sacrificing simplicity. The costs of reduced simplicity must be weighed against the expected gains from creating "win-win" situations.[287]

276. The Commission shares these concerns. In the Commission's view, the UCA's menu approach does not conform to AUC Principle 3, which requires, among other things, that a PBR plan should be easy to understand, implement and administer. Based on the above considerations, the Commission does not accept the menu approach proposed by the UCA.

277. The Commission restates the preference expressed in Decision 2009-035 for an approach to setting the X factor that is based on the long-term rate of productivity growth in the industry. During the hearing, NERA explained the rationale behind this approach as follows:

> The theory that we're drawing from doesn't require such precision. It says that there is an industry out there that's doing something. If it's a competitive industry -- it's an industry for making [hockey sticks], I don't know. [...] And of all the makers of hockey sticks, there's a productivity trend for hockey stick makers, and if you can't keep up, your business will fail. We don't need to be vastly more sophisticated than to measure the productivity of the hockey stick industry and use that as our way of allowing regulatory lag to eke out a few more years to avoid a couple of rate cases and to allow a little more productivity pressure to be visited on utility managements to try to make the businesses run better.[288]

278. As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[289]

279. Given the approach approved above, the starting point for determining the X factor is to estimate the underlying industry TFP growth for the services included in the companies' PBR plans. Then, it is necessary to consider any adjustments to the industry TFP that may be required to arrive at an X factor for Alberta gas and electric distribution companies. And finally, the Commission will consider whether a stretch factor is justified and if so, the size of a stretch factor. Sections 6.3 to 6.5 below deal with each of these steps.

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285 Exhibit 299.02, Cronin and Motluk UCA evidence, page 174.
286 Sappington, David E. M., *Designing Incentive Regulation*. Review of Industrial Organization, Volume 9, 1994, page 260.
287 Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., page 16.
288 Transcript, Volume 3, page 476, line 17 to page 477, line 5.
289 Exhibit 391.02, NERA second report, paragraph 2.

6.3 Total factor productivity

6.3.1 The purpose of total factor productivity studies

280. As set out in the previous section of this decision, the Commission opted for an approach to set the X factor based on the average rate of productivity growth in the industry. Under this approach, the first step in determining the X factor is to examine the TFP (total factor productivity) of the electric and gas distribution industries.

281. For this purpose, the Commission engaged NERA to conduct a TFP study applicable to Alberta gas and electric companies.[290] NERA filed its report entitled "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" dated December 30, 2010 as Exhibit 80.02. The study was based on a population of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP of the distribution component of the electric companies. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[291]

282. In addition to NERA's study, PEG on behalf of the CCA performed a TFP also referred to as a multifactor productivity (MFP)[292] study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companied as providers of gas transmission, storage, distribution, metering and general administration services.[293]

283. In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Accordingly, the task of productivity measurement involves comparing a firm's outputs and inputs over time. Total factor productivity measures all of a firm's inputs and outputs, combining the various inputs and outputs into single input and output indexes suitable for comparison to one another for purposes of measuring the rate of productivity growth over time.[294]

284. NERA pointed out that the main purpose of the TFP growth study is to measure the underlying long-term trend in industry productivity growth.[295] The UCA agreed with NERA that TFP should reflect long-term productivity growth.[296] Similarly, ATCO Electric and ATCO Gas expressed their understanding that a TFP study produces an estimate of the long-term TFP growth of the industry. At the same time, the ATCO companies cautioned that in using the TFP result as a starting point for determining the X factor in a PBR plan, it is necessary to

[290] Exhibit 71.01, AUC letter – Retention of Consultant to Develop Basic X Factor, September 8, 2012.
[291] Exhibit 80.02, NERA report, page 6.
[292] Dr. Lowry explained that, strictly speaking, MFP is a more accurate term than TFP, since the latter implies that all of the company's inputs are taken into account in its computation, which is often not possible or practical to do. However, Dr. Lowry agreed that generally these terms can be used interchangeably. MFP is the term used by Statistics Canada (Transcript, Volume 13, page 2451).
[293] Exhibit 307.01, PEG evidence, page 2.
[294] Exhibit 80.02, NERA report, page 5.
[295] Exhibit 391.02, NERA second report, paragraph 38.
[296] Exhibit 634.02, UCA argument, page 21, paragraph 117.

consider whether the historical long-term productivity trend of the industry is a reasonable estimate of the expected productivity growth of the utility during the PBR plan term.[297]

285. EPCOR concurred that the purpose of the TFP is to assist in determining what productivity growth is expected to be over the course of the PBR term.[298] In contrast, IPCAA contended that TFP analyses have no apparent relevance to electric distribution system economics, save as broad long-term overall indicators.[299] However, IPCAA's concerns in this regard appeared to center on the fact that TFP studies rely on energy throughput as an output measure, as further discussed in Section 6.3.6 of this decision.

286. In Fortis' view, since statutory requirements must take precedence over other ratemaking principles, the TFP study should not be the core foundation for the Commission's determination of the X factor. Specifically, Fortis submitted that because the Alberta statutory framework under the *Electric Utilities Act*, SA 2003, c. E-5.1, mandates that the rates being set must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service, and because rates are being set for the initial PBR term, expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the long-term industry productivity growth.[300]

Commission findings

287. As set out in Section 6.2 above, the objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company. Under this approach, the first step in determining the X factor is to examine the underlying industry productivity growth over time, commonly measured by total factor productivity.

288. Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question.[301]

289. The Commission does not share Fortis' view that expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the industry TFP when determining the X factor. In the Commission's view, Fortis' submission is reflective of the company's overall approach to determining the X factor as a mechanism to recover the forecast cost of service revenue requirement over the PBR term. As set out in Section 6.2 above, the Commission does not agree with this approach.

290. Fortis emphasized that the *Electric Utilities Act* stipulates that the companies' rates must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service. In the Commission's view forecasting the projected revenue requirement over a PBR term is not the only way to satisfy this statutory mandate. In that regard, the Commission agrees with NERA's explanation that the rationale behind the X factor (to which the TFP study contributes) is to emulate the incentives of competitive markets as they relate to productivity. In

297 Exhibit 631, ATCO Electric argument, paragraph 81 and Exhibit 632, ATCO Gas argument, paragraph 90.
298 Exhibit 630.02, EPCOR argument, paragraph 62.
299 Exhibit 306.01, Vidya Knowledge Systems evidence, page 5.
300 Exhibit 633, Fortis argument, paragraphs 100-103.
301 Exhibit 391.02, NERA second report, paragraph 38.

competitive markets, if a company achieves greater productivity growth than the industry, it is rewarded by larger earnings in the short run. If a company's productivity growth is lower than the industry productivity, its earning suffer in the short run.[302] Accordingly, in the Commission's view, the approach to determining the X factor based on the average productivity growth in the industry together with the selection of the I factor and the other features of the approved PBR plans provide regulated companies with a reasonable opportunity to recover their prudent costs of providing the regulated services.

6.3.2 Relevant time period for determining the TFP

291. The appropriate time period over which to calculate TFP for purposes of the companies' PBR plans garnered much attention in this proceeding. NERA recommended the use of its full set of data from 1972 to 2009, being the longest time period available from the Federal Energy Regulatory Commission (FERC) Form 1 dataset that NERA relied on.[303] The majority of other parties recommended a substantially shorter period.

292. NERA pointed out that the TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycles or other idiosyncratic swings associated with annual changes in the use of inputs and outputs, for example, major capital replacements. Consequently, NERA argued that the more years of data that are added to the study, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.[304] As a result, NERA's TFP calculation was based on the 38 years of available data.

293. In its second report NERA provided additional reasons in support of its position to use the longest time period available. NERA pointed out that in a competitive market, from which the incentives inherent in PBR plans are drawn, equilibrium prices are affected only by changes in long-run average cost. Short-run changes in productivity, even industry-wide changes in productivity, do not cause firms to enter or leave an industry.

294. Furthermore, on the issue of whether a more recent period is more reflective of the expected productivity growth in the coming years as advocated by most other parties, NERA argued that unless there is reliable proof to the contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic manner in the short term, or in a longer-term cyclical manner, it will eventually revert back to its long-term underlying trend.[305]

295. NERA noted that if one suspects that any of the TFP growth series are not stable in the long term (thereby justifying a departure from the use of long-term industry data), the appropriate response to such suspicion is to implement a statistical testing procedure in accordance with accepted research in the area of "structural breaks." In that regard, NERA experts explained that such analysis involves a two-step process: first, it is necessary to postulate a theory about why a structural break could have occurred, and, second, it is necessary to perform a number of statistical tests to see if the postulated hypothesis is supported by the data.[306] Dr. Makholm emphasized that performing an ex post statistical analysis of visual data without

302 Exhibit 195.01, AUC-NERA-8(a).
303 Transcript, Volume 1, pages 44-47.
304 Exhibit 80.02, NERA report, page 6.
305 Exhibit 391.02, NERA second report, page 14.
306 Transcript, Volume 1, pages 81-85.

having a supportable hypothesis for a structural break harms the process and biases the researcher.[307]

296. Dr. Makholm observed that he was not aware of any academic studies that would suggest that a structural break occurred at any time within the 1972 to 2009 time period for which data were available with respect to the electric distribution industry in North America.[308] As a result, NERA supported the use of the full time period as the most objective basis for the TFP calculation. Calgary supported this position.[309]

297. The companies' experts contended that NERA's sample period, especially the early part of it, was not relevant for estimating the industry's current TFP trends or the trends that might be expected to prevail during the PBR term. Specifically, ATCO and EPCOR experts in their respective evidence pointed out that in the 1970s and 1980s, the utilities sector was vertically integrated, owning and operating generation facilities with little wholesale and no retail competition. Dr. Carpenter and Dr. Cicchetti concluded that productivity improvements pertaining to the vertically integrated utilities observed in the early part of NERA's study period were unlikely to be realized by today's unbundled distribution companies and as a result, a more recent period should be used for estimating the industry TFP.[310]

298. Furthermore, to test NERA's conclusion that a structural break had not occurred in the electric distribution industry, Dr. Cicchetti performed a number of statistical tests on NERA's productivity data and found that the TFP growth in the 1999 to 2009 period was statistically different than in prior years. Dr. Cicchetti concluded that a structural break occurred in 1999 and, therefore, a more recent period should be used for the purpose of the TFP and X factor determinations.[311]

299. Ms. Frayer on behalf of Fortis also noted that there have been structural changes in the electric utility sector involving changes in investment trends, technology deployment, operating practices, customer consumption patterns, and regulatory incentives. In addition, Fortis' expert indicated that as industries and firms get more and more efficient, it is unreasonable to assume that they should sustain the same level of productivity growth over time. Accordingly, Ms. Frayer's analysis was mostly based on the data from the years 2000 to 2009.[312]

300. In the same vein, based on their observation of the cumulative rate of TFP growth, AltaGas experts argued that a significant break in the productivity trend occurred around the year 2000. Specifically, Dr. Schoech observed that prior to 2000, the TFP for the U.S. electricity distributors in the NERA study grew at a substantial 1.6 per cent, while since 2000, the TFP has been declining at the approximate rate of -1.4 per cent. Similar to the other companies' experts, Dr. Schoech offered restructuring of the industry and changing consumption patterns as possible explanations for changes in the productivity.[313]

301. In developing their recommendations as to the relevant time period for the TFP calculations, the companies' experts also considered regulatory precedents. Dr. Cicchetti noted

307 Transcript, Volume 1, page 88, lines 7-15 and page 95, lines 11-19.
308 Transcript, Volume 1, page 91, line 23 to page 92, line 2.
309 Exhibit 629, Calgary argument, page 23.
310 Exhibit 103.05 Cicchetti evidence, page 10 and Exhibit 98.02, Carpenter evidence, page 21.
311 Exhibit 473.07, Cicchetti rebuttal evidence, page 14.
312 Exhibit 474.02, Frayer rebuttal evidence, pages 18-20 and Exhibit 100.02, Frayer evidence, page 79.
313 Exhibit 110.01, Christensen associates evidence, pages 11-12.

that based on his experience with PBR plans for energy utilities, the typical range for estimating the industry TFP growth is about 10 to 11 years.[314] Dr. Carpenter indicated that other TFP studies that he had seen generally use time frames no longer than 10 to 15 years.[315] Ms. Frayer pointed to a number of TFP studies used by other regulators with sample periods from four to 13 years.[316]

302. PEG agreed that there is some value in a shorter period because even long term drivers of TFP growth such as technological change can vary over a period of several decades. Dr. Lowry noted that in the past he often advocated a period of at least 10 years, but recent empirical results and NERA's testimony persuaded him that a minimum of 15 years is typically more desirable.[317]

303. In reviewing NERA's TFP estimate, PEG submitted that the relevant time period should essentially focus on the concept of a business cycle. As Dr. Lowry explained, because NERA's study used delivery volumes as an output measure, the resulting TFP is highly sensitive to changes in economic conditions. Therefore, Dr. Lowry advocated that when choosing the relevant time period, it is necessary to choose a start and end date that are at a similar point with respect to the business cycle, so that the key demand drivers are at the same levels.[318]

304. In that regard, Dr. Lowry observed that the last two years in NERA's sample, 2008 to 2009, were characterized by a deep recession and he recommended excluding these years to avoid distorting the long-run TFP trend. As a result, the CCA expert recommended a sample period for NERA's TFP study that ends in 2007 (avoiding the two recession years) and begins in 1988, a year with similar values for two key volume driver variables, cooling degree days and the unemployment rate.[319] For the purpose of its MFP study of U.S. gas distribution companies, PEG used the sample period of 14 years from 1996 to 2009 based on Dr. Lowry' judgment and experience.[320] PEG noted that this was the longest period available for the dataset on which PEG relied.[321] The CCA's expert explained that a 2009 sample end date was acceptable in this case, since his study did not use a volumetric output index and therefore would not be subject to volume related impacts of the 2008 to 2009 recession.

305. With respect to the 10 to 15-year timeframes advocated by the companies' experts relying on the NERA study, PEG contended that the suggested sample periods do not have an objective basis. In particular, Dr. Lowry noted that the companies have provided no credible explanation of why the sample period should begin just as the period of slower productivity growth begins. Moreover, Dr. Lowry reiterated his opinion that if a substantially shorter sample period (e.g., 10 to 15 years) such as those advocated by company witnesses is to be entertained, the exclusion of the 2008 to 2009 recession years becomes imperative for recognition of a long-term trend given the volumetric output index utilized in the NERA study.[322]

314 Exhibit 103.05 Cicchetti evidence, paragraph 18.
315 Exhibit 98.02, Carpenter evidence, page 25.
316 Exhibit 474.02, Frayer rebuttal evidence, page 21.
317 Transcript, Volume 13, pages 2490-2491.
318 Transcript, Volume 13, pages 2490-2491 and pages 2502-2503.
319 Exhibit 569.01, PEG evidence errata, page 9.
320 Transcript, Volume 13, pages 2490-2491.
321 Exhibit 372.01, AUC-CCA-5(a).
322 Exhibit 569.01, PEG evidence errata, pages 7-9.

Commission findings

306. The length of a sample period can be a critical issue when indexes are used to estimate long run productivity trends, as demonstrated by the fact that just removing the last two years from NERA's sample period raises the TFP growth trend from 0.96 to 1.13 per cent.[323] The CCA submitted that when selecting the relevant sample period for a TFP study, the following two objectives must be considered:

- smooth out the effect of cost and output volatility
- capture the TFP growth trend that is most likely to be pertinent during the PBR plan period[324]

307. Most experts in this proceeding agreed that the time period for the TFP measurement should be long enough to smooth out the inevitable year-to-year variation in results that obscures the long term productivity trend of the industry.[325] As Ms. Frayer observed, specific annual circumstances with respect to weather and consumption, capital spending, labour, etc., contribute to the volatility of year-to-year TFP numbers.[326] There appeared to be an agreement among the parties that a sample period of at least 10 years is desirable for the purpose of determining the long-term industry TFP.[327]

308. However, much of the debate in this proceeding was centered on the issue of what historical time period to use to predict the productivity growth likely to be experienced by the industry during the PBR term. NERA's experts contended that unless the TFP growth series is not stable in the long term, as demonstrated by a structural break, the best economic assumption is that the industry productivity growth will eventually revert back to its long-term underlying trend.[328] Therefore, the use of the longest time period for which data is available is warranted absent evidence of a structural break in the productivity of the industry.

309. While accepting that a long-term productivity measure is required, the companies' experts contended that the period recommended by NERA was too long. These experts pointed to a number of changes in the electric distribution industry over time, of which the unbundling of distribution and generation facilities and the introduction of retail competition in the mid 1990s were the most significant, and suggested that the underlying industry TFP trend had changed.[329] In other words, using NERA's terminology, the companies hypothesized that a structural break in the industry productivity trend had occurred.

310. A discussion arose during the hearing as to whether restructuring and various other changes to the electric distribution industry can be characterized as a structural break that alters the long-term industry productivity trend.[330] NERA was of the opinion that the determination on

323 Exhibit 307.01, PEG evidence, page 36.
324 Exhibit 636, CCA argument, paragraph 63.
325 See, for example, Exhibit 80.02, NERA report, page 6; Exhibit 307.01, PEG evidence, page 19; Exhibit 98.02, Carpenter evidence, page 25.
326 Exhibit 100.02, Frayer evidence, page 63.
327 Exhibit 307.01, PEG evidence, page 28, and Transcript, Volume 13, page 2494, line 6; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
328 Exhibit 391.02, NERA second report, page 14.
329 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
330 See for example, Transcript, Volume 3, pages 477-481; Volume 4, pages 570-571; Volume 8, pages 1400-1403; Volume 11, pages 1995-1997; Volume 11, pages 2109-2113.

the subject of structural breaks lies outside the scope of regulatory proceedings and belongs to a realm of academic study. Dr. Makholm stated in testimony:

> [W]e want to stress the importance of making sure that something that would have such a severe affect on a TFP growth trend as bifurcating the study period would not come about lightly, and not come about in a contested proceeding among interested parties where the minutiae of econometrics or empirical work often go way beyond the heads of even the experts in the room. And in that respect, it was our search or objectivity and a support among people who have no interest in the outcome of the question that led us to say, in our second report, that you would want, if something so important as a structural break entered this kind of analysis, to have that support come from outside the proceeding from disinterested sources.[331]

311. With respect to the statistical tests performed by Dr. Cicchetti, NERA commented that without the underlying economic theory, these statistical tests have a very limited explanatory power. When viewed in isolation, the statistical tests simply confirm that the TFP growth in a particular period was distinctly (i.e., “statistically significant”) different from the TFP growth in other periods. The test does not, by itself, explain the reasons for such a difference and cannot prognosticate whether the TFP growth in any particular period is indicative of the changes in productivity likely to occur during the prospective PBR term.

312. The Commission agrees with NERA’s view that a deviation from reliance on the longest period of available data requires support that a structural break in the industry has occurred. The Commission also agrees that the determination of whether a structural break has occurred demands the scrutiny of academic experts, peer review and testing by parties independent of the current proceeding.

313. NERA indicated that to the best of its knowledge, the only structural breaks discussed by scholars were the World Wars, the Great Crash in 1929 and the 1970s oil price shock.[332] The companies did not point to any external studies on this issue. In the absence of any independent academic studies examining the issue of structural breaks in the electric and gas distribution industries, the Commission is not prepared to accept the proposition that the long term underlying TFP trend of the industry had changed around the mid- or late1990s as implied by the companies’ experts.[333]

314. With respect to the electric industry restructuring, the Commission observes that NERA used data only on the distribution portion of the sampled companies’ businesses.[334] In the Commission’s view, this approach sufficiently mitigates the concerns about the impact of industry restructuring on the TFP estimate. The Commission accepts NERA’s view that electric industry restructuring did not necessarily lead to a change in the rate of growth of productivity for the distribution portion of the industry.[335]

315. Furthermore, the Commission is not persuaded by the companies’ arguments that a more recent period provides a better indication of likely industry TFP during the PBR term. As further

331 Transcript, Volume 2, page 300, lines 8-22.
332 Exhibit 391.02, NERA second report, pages 15-16.
333 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
334 Exhibit 80.02, NERA report, page 6.
335 For example, Transcript, Volume 1, pages 109-111 (Dr. Makholm).

explained in Section 6.3.6 of this decision, because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns. In these circumstances, as PEG observed in its evidence, a company's productivity growth in one five or 10-year period may be very different from its productivity growth in the following five years, depending on what part of the business cycle the economy is in.[336] Dr. Lowry explained that the productivity of a company going into a recession (i.e., from peak to trough of a business cycle) may be very different from the productivity of the same company coming out of the recession when energy throughput is used as an output measure.[337]

316. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.[338] The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

317. In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle. Notably, the CCA seemed to reach a similar conclusion and indicated that if the years 2008 and 2009 were to be included in the study, the length of a sample period would have to be considerably longer than 10 to15 years and NERA's use of the full set of 1972 to 2009 data becomes reasonable, subject to certain other reservations about NERA's analysis.[341]

318. With respect to the argument that some other jurisdictions relied on a shorter time period for estimating TFP growth, the Commission notes that in many of those cases the period for a TFP study is driven by data limitations rather than a deliberate choice of the most relevant period for productivity calculations or is the result of settlement negotiations. This is especially true in the case of PBR plans based on efficiency frontiers and benchmarking studies which require a large amount of company-specific data for the selected group of peer companies. Dr. Cicchetti and Ms. Frayer noted that their observation of the other regulators' use of a 10-year period was more in the nature of a "rule of thumb."[342] The circumstances leading to the acceptance by other regulators of a sufficient TFP time period are varied and in the Commission's view do not suggest an accepted regulatory practice. This conclusion is reinforced by the differing views on the correct time period over which to conduct a TFP study reflected in the evidence of the various experts in this proceeding.

336 Exhibit 307.01, PEG evidence, page 23 and Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
337 Transcript, Volume 13, page 2503, line 9 to page 2504 line 1.
338 Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
339 Exhibit 632, ATCO Gas argument, paragraph 77 and Exhibit 628, AltaGas argument, page 21.
340 Exhibit 650, AltaGas reply argument, page 18.
341 Exhibit 645, CCA reply argument, paragraph 38.
342 Transcript, Volume 11, page 2056, lines 10-15 and Volume 11, page 2115, lines 1-14.

319. In light of the above considerations, the Commission agrees with NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the Commission's view, in the absence of any external scholarly studies pointing to a structural break in the TFP trend of the electric distribution industry, NERA's analysis based on a full 1972 to 2009 sample is the best indicator of the expected industry productivity growth during the PBR term. Moreover, such an approach eliminates the inevitable subjectivity involved in choosing a truncated time period for determining the industry TFP and mitigates the incentive to "cherry-pick" the start and end points to arrive at a desired TFP value.

320. In this respect, the Commission observes that PEG's preference for a 15-year sample period appeared to be primarily based on Dr. Lowry's personal judgement:

> Q. But what I'm trying to understand, though, Sir, the principles that you're applying in coming up with your period so that the subjectivity of picking the dates is reduced?
> A. Yes. Just based on my experience, you know, I used to think that you needed 10 years to smooth things out, and now I'm thinking more like 15. I don't know what more to say.[343]

321. The Commission recognizes that because PEG did not use a volumetric output measure, the resulting TFP may be less sensitive to the choice of start and end dates. As well, Dr. Lowry noted that the quality of data on the gas industry prior to 1996 was not good.[344] As such, the Commission acknowledges that it is uncertain whether having a longer time period for PEG's data would result in a different TFP measure. Nevertheless, in the Commission's view, PEG's approach to selecting the time period is more subjective than NERA's. Dr. Lowry acknowledged that if the Commission were to adopt his approach, the start and end dates of a sample period have to be reconsidered at the time of any PBR rebasing.[345]

6.3.3 The use of U.S. data and the sample of comparative companies in the TFP study

322. NERA's TFP study used a population of 72 U.S. electric and combination electric/gas companies. NERA noted that this population includes companies of different sizes and located in differed parts of the United States reflecting a wide diversity of geography, development and age.[346] PEG's study was based on a national sample of 34 U.S. gas distributors,[347] also with different operating characteristics.[348] In both studies, the sample size reflected the availability of reliable data for the U.S. companies in question.[349]

323. When questioned by the CCA on whether it is preferable to use a region-specific sample rather than a national sample, NERA's experts indicated that it is acceptable to base a TFP study on either all companies in an industry for which good data are available or to select a sub-sample

343 Transcript, Volume 13, page 2499, lines 5-10.
344 Transcript, Volume 13, page 2495, lines 14-16.
345 Transcript, Volume 13, page 2506, lines 7-9.
346 Exhibit 80.02, NERA report, page 4.
347 In its evidence, PEG also reported results of a subgroup of 7 Western U.S. companies (Exhibit 307.01, tables 1 and 2). However, as Dr. Lowry indicated, PEG did not base its recommendations on the Western subgroup analysis and it was included just as "another number for the Commission to use if they see fit" (Transcript, Volume 13, pages 2525-2527). Accordingly, the Commission did not discuss this part of PEG's evidence.
348 Exhibit 307.01, PEG evidence, pages 26-27.
349 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.

if the sub-sample is large enough to provide a reliable measure of productivity growth.[350] In that regard, Dr. Makholm pointed out that NERA's previous TFP study for Alberta from 2000[351] was based on a group of companies from the Western region. However, because the number of companies remaining in the Western region had declined since that time, NERA concluded that a TFP estimate based on this smaller group would give a less reliable, consistent and robust measure of productivity growth. As a result, NERA examined a national population of companies for its TFP analysis in this proceeding.[352]

324. The UCA indicated that NERA's sample of U.S. utilities is not comparable to Alberta gas and electric utilities in many respects. For example, the UCA noted that the NERA study sample contained companies that are unlike any Alberta distribution utility in terms of geography and climatic conditions. In addition, the UCA indicated that the U.S. utilities are subject to multiple different regulatory regimes with some operating under PBR and others under cost of service regimes. Further, the UCA pointed to differences in a number of other operational characteristics such as retail sales or number of employees between the companies in NERA's sample and Alberta utilities.[353]

325. In the UCA's opinion, it is critically important that the multiple differing regulatory, operational, organization and geographical circumstances of the companies included in the NERA sample be fully understood. Accordingly, the UCA argued that the companies included in the comparative group for Alberta utilities should be (i) unbundled, (ii) have some degree of comparability, and (iii) if possible, some should have been under PBR for quite some time.[354] Given the availability of historical data (1988 to 1997) for the distribution utilities in Ontario, the UCA argued that there is simply no need to use the U.S. data.[355]

326. In response to these criticisms, NERA explained that the purpose of the TFP study is not to explain productivity levels but instead productivity growth rates. In other words, NERA's study did not examine whether one company has a greater level of output for the same level of inputs than another. Rather, NERA looked at how the ratio of outputs to inputs changes over time. As such, the unique cost features of any particular company cancel out in the process.

327. Furthermore, NERA observed that the theoretical purpose of the X factor (to which the TFP study contributes) is not to find proxies for the companies to be regulated but rather to find the long-term, underlying industry productivity growth trend that firms would face in competitive markets. As such, a focus on finding companies just like those in Alberta would not accomplish this objective. Given the generally-perceived similarity of both the legal construct for utility regulation in Canada and the United States as well as the organization of the utility industries in the two countries, NERA maintained that using the U.S. data is warranted in this case.[356] Calgary and Fortis agreed with this approach.[357]

350 Transcript, Volume 3, page 394, line19 to page 396, line 20.
351 Evidence of Jeff D. Makholm on behalf of UtiliCorp Networks Canada on its proposed PBR plan dated September 1, 2000 (Exhibit 195.01, AUC-NERA-5(a)).
352 Exhibit 391.02, NERA second report, paragraphs 45-46.
353 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 219-227.
354 Exhibit 634.02, UCA argument, paragraph 99.
355 Transcript, Volume 17, page 3219, lines 3-7 and page 3222, lines 1-16.
356 Exhibit 391.02, NERA second report, paragraphs 36-38.
357 Exhibit 629, Calgary argument, pages 23-24.

328. The other parties to this proceeding generally agreed with NERA's position on these issues. With respect to the study sample, EPCOR pointed out that the standard approach in North American PBR regulatory jurisdictions is to compare each company to the industry performance and not to specific peer groups.[358] Fortis also agreed with this approach, although Ms. Frayer expressed some concerns as to the applicability of the NERA study to Alberta companies.[359] The ATCO companies agreed with Dr. Makholm's opinion that a sample with fewer than 12 companies is too small to be representative of the industry TFP trends and supported NERA's approach of using the national population.[360]

329. Regarding the use of U.S. data, the CCA and the ATCO companies indicated that there are no suitable Canadian data available to make a reliable TFP estimate for the gas or electric distribution industries in Canada. Furthermore, even if suitable data were available, it is uncertain whether there are enough utilities in Canada to make a TFP estimate reliable given the small sample size it would be based upon.[361] Overall, the ATCO companies did not object to the use of the U.S. data, albeit subject to an adjustment for a productivity gap between the United States and Canadian economies, as further discussed in Section 6.4.2 of this decision.[362]

330. Similarly, Dr. Cicchetti on behalf of EPCOR noted that because of the differences between the United States and Alberta economies, the industry TFP trends that NERA estimated do not reflect economic conditions in Alberta. Nonetheless, Dr. Cicchetti concluded that NERA's U.S. data were a good starting point to use for the purposes of determining an X factor for EPCOR.[363] Ms. Frayer's preference was to consider relevant Canadian or Alberta utility data when available. However, in developing her recommendations for Fortis' X factor, Ms. Frayer used U.S. data and data from other jurisdictions, including the U.K., New Zealand and Australia.[364]

331. In the view of Dr. Schoech, it would be most desirable to look at the TFP growth for natural gas distribution companies that are most comparable to AltaGas in terms of their market context, in particular, the number of customers served and population density.[365] However, recognizing that there may not be historical data for utilities closely similar to AltaGas, the company's experts used broader sources of data to determine an appropriate historical estimate of TFP and to develop their proposal for the X factor. Specifically, in AltaGas' analysis, the results of the NERA's study were complemented with Statistics Canada's estimate of MFP trends in the gas distribution sector which also include water and other system utilities.[366]

332. AltaGas also took issue with PEG's study sample. First, AltaGas noted that PEG's productivity analysis was drawn from data representing less than half of the U.S. gas distribution industry. Second, in AltaGas' view, the selection of companies was biased, favouring larger service providers. And finally, AltaGas contended that it was unlikely that PEG's productivity study included any gas distributors with service territories and business contexts comparable to

[358] Exhibit 630.02, EPCOR argument, paragraph 55.
[359] Exhibit 633, Fortis argument, paragraph 91 and Exhibit 474.02, Frayer rebuttal evidence, pages 14-15.
[360] Exhibit 631, ATCO Electric argument, paragraph 71; Exhibit 632, ATCO Gas argument, paragraph 78.
[361] Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89.
[362] Transcript, Volume 3, page 591, line 23 to page 592, line 3.
[363] Exhibit 630.02, EPCOR argument, paragraph 59.
[364] Exhibit 633, Fortis argument, paragraph 96.
[365] Transcript, Volume 8, page 1417, line 12 to page 1418, line 9.
[366] Exhibit 628, AltaGas argument, pages 22-23.

those of the company.[367] The latter concern was also raised by Dr. Carpenter, who noted that ATCO Gas has a customer density well below the average of PEG's sample.[368]

Commission findings

333. As explained earlier in Section 6.2 of this decision, the UCA's approach to determining the X factor was based on an examination of the companies' efficiency or, in other words, whether one company has a greater level of output for the same level of inputs compared to other companies. The Commission explained that under this approach it is important to control for all the factors contributing to a firm's level of efficiency, since inadvertently leaving out an important productivity driver may invalidate the results of the study. In these circumstances, the search for companies with similar characteristics (location, size, geography, weather, consumption patterns, etc.) for the purposes of inclusion in the comparative group on which to base the productivity study becomes of paramount importance for the PBR plans based on efficiency benchmarking.

334. As set out in Section 6.2 above, the Commission does not accept the efficiency benchmarking approach for the purposes of PBR in Alberta because of the practical and theoretical problems associated with measuring efficiency levels.

335. Under the approach adopted by the Commission, the focus of the TFP study is on the industry productivity growth rate, not levels. As NERA explained, in this case the manifest differences between the companies in terms of their geographic areas and climatic conditions, operational characteristics, regulatory regime, size or any other consideration do not matter as much to the study as it only deals with the average of year to year changes in productivity growth. As such, the unique cost features of any particular company cancel out in the process.[369]

336. Indeed, the experience of Dr. Cronin and Mr. Motluk corroborates this conclusion. The UCA witnesses observed that the Ontario companies exhibited a similar productivity growth rate during the PBR term despite the inherent differences in age, past performance and investment needs.

> But what was remarkable about that performance was the near uniformity that the [local distribution companies] exhibited in engendering TFP of 1.2 percent per year. It didn't matter if they were large, medium, or small. It didn't matter if they had more aged infrastructure. It didn't matter if they were high growth or low growth. It didn't matter if they were high capital additions or low capital additions. What they did was they found a way to operate under the PBR for that period of time. This was again confirmed under the second variable [productivity factor] PBR in the first half of this decade.[370]

337. The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.[371]

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367 Exhibit 628, AltaGas argument, pages 23-24.
368 Exhibit 472.02, Carpenter rebuttal evidence, page 80.
369 Exhibit 391.02, NERA second report, paragraph 37.
370 Transcript, Volume 17, page 3183, line16 to page 3185, line 4; and see also at Transcript, Volume 17, page 3192, lines 16-20.
371 Exhibit 391.02, NERA second report, paragraph 38.

338. In these circumstances, it is the Commission's view that when it comes to the sample size and the use of U.S. data in TFP studies, the relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities, but: (i) whether the sample in the TFP study is reflective of the productivity trend in the U.S. power distribution industry, and (ii) whether the U.S. industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies.

339. Regarding the first question, the Commission agrees with NERA, ATCO Electric and the CCA that a TFP study can be based on either all companies in the industry for which good data are available or on a sample of companies as long as this sample can provide a reliable, consistent and robust measure of industry productivity growth. The Commission observes that both NERA and PEG used data availability and data consistency as the primary criteria for including a particular company in their study sample.[372] Accordingly, the Commission does not consider that NERA's and PEG's sample selection is biased in any respect.

340. Furthermore, NERA pointed out that a study sample has to be large enough to provide robust estimates and did not recommend using a sample with fewer than 12 companies.[373] As noted earlier in this section, NERA's sample consisted of 72 companies of different sizes, reflecting a wide diversity of geography, development and age.[374] As well, PEG's study was based on a sample of 34 U.S. gas distributors.[375] The Commission considers these samples to be large enough and diversified enough to produce a TFP estimate that is reflective of the overall industry productivity growth.

341. With regard to the second question, the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports.[376] Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.[377]

342. Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.[378] This issue is further discussed in Section 6.4.2 of this decision dealing with the proposal for a productivity gap adjustment.

343. In light of the above considerations, the Commission finds NERA's and PEG's TFP study samples of 72 and 34 U.S. companies, respectively, to be acceptable, subject to the

372 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.
373 Transcript, Volume 3, page 395, lines 12-24.
374 Exhibit 80.02, NERA report, page 4.
375 Exhibit 307.01, PEG evidence, page 26.
376 Transcript, Volume 2, page 290, lines 22-24; Exhibit 307.01, PEG evidence, page 25.
377 Exhibit 195.01, AUC-NERA-7 and Exhibit 634.02, UCA argument, paragraphs 110-111.
378 Exhibit 391.02, NERA second report, paragraph 36; Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89; Exhibit 630.02, EPCOR argument, paragraph 59.

issues discussed below, as the starting point for a TFP analysis applicable to Alberta distribution utilities.

6.3.4 Importance of publicly available data and transparent methodology

344. In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.[379]

345. NERA agreed with these requirements and pointed out that the extent to which PBR regulation transmits incentives to company management is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between rate cases. In NERA's view, creating an index number for relative industry TFP with those attributes requires a high-quality transparent and uniform source of data that is readily available to the parties of regulatory proceedings. For this purpose, NERA used the data collected by the Federal Energy Regulatory Commission (FERC) for electric and combination electric/gas utilities on its Form 1 and other publicly available sources.[380] In NERA's view, the FERC Form 1 data are the only data that satisfy the criteria of transparency and objectivity for a large number of industry participants.[381]

346. NERA also expressed its opinion that transparency is the essential component of any analysis for the purpose of PBR plans. To this end, for each step of its analysis NERA documented the methodology and the data used to measure TFP. In addition, NERA's calculations and working papers, including any adjustments to the electronic dataset (such as for missing observations or rare but evident data anomalies) were made available for inspection and assessment by other parties.

347. All parties confirmed the importance of relying on publicly available data and transparent methodologies for the purpose of the TFP studies used in regulatory proceedings in order to make such studies objective and neutral.[382] In this respect, while no party questioned the transparency of NERA's methodology and the availability of FERC Form 1 data, parties to this proceeding took issue with PEG's productivity study over issues of objectivity and transparency.

348. With respect to transparency, ATCO Gas and AltaGas pointed out that PEG's study relied on a proprietary data which could not be fully tested in a public forum. Furthermore, these companies noted that even after examining PEG's working papers (made available under a confidential process), it was still unclear where individual data came from, as limited details were provided on the methods and sources used in the study.[383] Because of this lack of transparency in PEG's data and calculations, Dr. Carpenter indicated that he was not able to fully evaluate and replicate the results of PEG's TFP study.[384]

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[379] Exhibit 71.
[380] Exhibit 80.02, NERA report, pages 3-4 and Transcript, Volume 1, pages 55-57.
[381] Transcript, Volume 1, page 56, lines 6-14.
[382] Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 631, ATCO Electric argument, paragraph 73; Exhibit 632, ATCO Gas argument, paragraph 80; Exhibit 628, AltaGas argument, pages 24-25; Exhibit 645, CCA reply argument, paragraph 45.
[383] Exhibit 476.01, Carpenter rebuttal evidence, pages 74-77 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 36.
[384] Exhibit 476.01, Carpenter rebuttal evidence, page 77 and Transcript, Volume 6, page 1007, lines 7-15.

349. On the same subject, NERA observed that since there is no federal collection of universal and consistent data on the U.S. gas distributors similar to the FERC data set for the electric industry, statistical data from individual states must be used. Because of the varying data reporting requirements in different states, NERA cautioned that compilation of data from varying sources may not be consistent.[385]

350. The gas companies' concern regarding the lack of objectivity in PEG's study primarily related to the econometric model that Dr. Lowry and his colleagues used in addition to the index approach for estimating TFP. In particular, PEG regressed the TFP index for the 32 gas companies in its sample against the number of gas distribution customers, the number of electricity customers (for companies that provide both gas and electric service), the line miles and a time trend variable. Applying the obtained coefficients to the projected variables for Alberta gas companies, PEG came up with a TFP estimate customized for business conditions in Alberta.[386]

351. With regard to this method of TFP calculation, ATCO Gas' and AltaGas' experts pointed to a number of issues in the set-up of PEG's econometric model relating to the choice of explanatory variables, model specification, the interpretation of results, the presence of heteroskedasticity, etc.[387] NERA observed that an econometric estimation of TFP growth is unavoidably based on many judgments that are difficult for non-specialists to understand. In NERA's view, such econometric analyses are more suitable for the purpose of peer-reviewed scholarly research and not for setting the level of consumer prices in a PBR plan.[388]

352. To allay concerns about the use of proprietary data, PEG recalculated the TFP growth of the sample of gas distributors employing data that are entirely in the public domain. This resulted in a modest decrease in PEG's TFP number, from 1.32 per cent to 1.19 per cent. At the same time, PEG noted that although most of its data can be independently gathered from the public sources, it chose to purchase them from respected commercial vendors because of the higher quality and value added services that they provide.[389] In that regard, Dr. Lowry proposed that the value added by the commercial vendors in gathering and processing the data is well worth the restriction of a confidentiality agreement to permit their use in a regulatory proceeding.[390]

Commission findings

353. Because the parameters of the PBR formula will be used to determine customer rates in a contested regulatory process and those rates will be in place for a number of years, the significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated.[391] In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that

385 Transcript, Volume 1, page 52, lines 16-22.
386 Exhibit 307.01, PEG evidence, page 33.
387 Exhibit 476.01, Carpenter rebuttal evidence, pages 83-84 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
388 Exhibit 391.02, NERA second report, paragraph 99.
389 Exhibit 478.01, PEG rebuttal, pages 20-21.
390 Transcript, Volume 13, pages 2456-2459.
391 Exhibit 391.02, NERA second report, paragraphs 95-96 and Exhibit 476.01, Carpenter rebuttal evidence, page 29.

NERA's TFP analysis complies with these criteria.[392] The Commission agrees. As Dr. Cicchetti commented on this issue:

> So my conclusion is NERA was objective and neutral as required to be by this Commission. It's also transparent in that you can see where the information came from. You can actually go back to the raw information to see if NERA made any mistakes in building the data set together and the like. And in that fashion I think they did exactly what the Commission asked and therefore I would use it as I did in my starting point.[393]

354. With respect to PEG's study, the Commission shares the gas companies' concerns that the TFP analysis of Dr. Lowry and his colleagues was not fully transparent and conducive to the detailed scrutiny by other experts or by the Commission.

355. While there is nothing inherently wrong with using proprietary data in regulatory proceedings, procedural fairness requires that parties must be provided with the opportunity of a fair hearing in which each party is given the opportunity to respond to the evidence against its position. This requirement clearly requires parties and the Commission to be able to fully understand, test and respond to the evidence filed in a proceeding. Further, the Commission has the obligation to provide reasons for its decisions. It can only do so if it is able to fully understand, test and analyze the evidence filed before it. Accordingly, fully transparent information is always preferable to information that requires the filing of motions for protection of confidential information and the execution of confidentiality agreements. It is also problematic if, in order to fully comprehend the confidential information, further explanations must be provided on the procedures used, assumptions made, judgment exercised and data adjustments made that produced the confidential evidence. In addition, as NERA observed, the problem with data that are not publicly available is that the research cannot be replicated. As well, there is a concern that such data will not be available at all or that only the original provider using the same assumptions, methodology and adjustments could be engaged to provide a consistent analysis when the parameters of the PBR regime are to be reset.[394]

356. The Commission agrees that it is highly desirable that any TFP analysis can be replicated by all willing parties to the proceeding. As Dr. Carpenter explained, until one has managed to replicate a piece of analysis, it is not possible to look for errors, adjust assumptions, and test for sensitivities.[395] In addition, as NERA pointed out, if Dr. Lowry and his colleagues at PEG are the only persons who are able to repeat the TFP analysis, the success of any future PBR plans will depend on PEG's participation.[396] For all of the above reasons, the Commission confirms its preference for a TFP study that relies on publicly available data.

357. The Commission's main concern with PEG's study relates to the overall lack of transparency with respect to data processing. The Commission accepts that because there is no central repository for data on the gas distribution industry, any researcher of this subject would be compelled to combine information from different sources, thus facing a problem of data consistency and uniformity.[397] However, to the extent that PEG compiled its dataset from a

392 Exhibit 632, ATCO Gas argument, paragraph 83; Exhibit 631, ATCO Electric argument, paragraph 76; Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 628, AltaGas argument, page 24.
393 Transcript, Volume 11, page 2017, lines 10-17.
394 Exhibit 391.02, NERA second report, paragraph 98.
395 Exhibit 476.01, Carpenter rebuttal evidence, page 82.
396 Transcript, Volume 1, page 56, lines 15-23.
397 Transcript, Volume 1, page 56, lines 6-14 and Volume 13, page 2467, lines 2-7.

number of sources (publicly available or not), it is of vital importance that all the steps and any adjustments to the data be clearly documented and explained. This would allow other experts to verify the accuracy of the data. As well, computation of the TFP estimate must be clearly explained. In this way, other parties to the proceeding can test and verify the calculations and, if necessary, replicate them in future proceedings. PEG's study did not satisfy these requirements.

358. For example, Dr. Lowry explained that PEG examined the dataset obtained from a commercial vendor and when necessary, made adjustments to the data to correct for any obvious anomalies:

> [...] not only does my staff do an initial screening and look for oddities to correct, to look for corrections, go make sure that that's what the form really said; but then it comes to me, and that's the final step is that I will go through very carefully and meticulously all the data and see if it squares with my expectations. And there will usually be 10 or 15 observations that need to be changed based on my second screening of the data.[398]

359. The Commission accepts that sometimes it may be necessary to adjust the raw data and in fact, NERA had to adjust its data as well. However, as Dr. Carpenter explained in his evidence, PEG did not clearly outline the adjustments it made.[399] In contrast, NERA made available for inspection and assessment by other parties any adjustments to the electronic dataset that it made as an integral part of its report.[400]

360. The importance of publicly available data and transparent methodology is demonstrated by the extent to which parties to this proceeding relied on NERA's working papers for developing their recommendations. For example, Dr. Cicchetti was able to estimate partial factor productivity (PFP) for EPCOR relying entirely on NERA's data.[401] As well, Dr. Cicchetti performed a number of statistical tests on productivity using company-level panel data.[402] Dr. Lowry, after scrutinizing NERA's working papers, suggested a number of corrections to NERA's study and was able to immediately quantify the impact of his recommendations on NERA's TFP estimate.[403]

361. If the parties had been using PEG's data, they would not have been able to engage in this type of detailed analysis without first executing a confidentiality agreement and working with PEG to understand all adjustments that were made to the vendor's data. For example, Dr. Carpenter pointed out that the output file that PEG provided included only summary results and did not provide the data for individual companies. As well, Dr. Carpenter pointed to the fact that PEG's computer code was written for a software package that was not commercially available.[404]

362. With respect to PEG's econometric model for TFP, the Commission agrees with NERA's explanation that the outcome of any regression model is highly dependent on the choice of explanatory variables, which represents the subjective judgment of the person conducting the analysis. As NERA explained:

398 Transcript, Volume 13, page 2460, lines 4-12.
399 Exhibit 472.02, Carpenter rebuttal evidence, page 28.
400 Exhibit 80.02, NERA report, Appendix II.
401 Exhibit 103.05, Cicchetti evidence, pages 22-23.
402 Exhibit 473.07, Cicchetti rebuttal evidence, page 9.
403 Exhibit 478, PEG rebuttal evidence, Table 3 on page 12.
404 Exhibit 476.01, Carpenter rebuttal evidence, pages 74 and 77.

> DR. MAKHOLM: I was the first one to do that. I did the first decomposition of electric utility TFP numbers anywhere, and it's my thesis. I've done that. And if you go to the back of that, you'll see page after page after page of coefficients that depend on the specification that I chose, the number of things I decided to measure, the kind of dummy variables that I would use.
>
> And the results of those decompositions, as I call them, were dependent on my particular specification and what I judged to be useful at the time. I put it that -- to this group and to this Commission that those decisions of mine, which were useful for doing my thesis work, could have been done differently, and they could have changed the result of how we would predict the TFP growth should be for any region or size of company or any arbitrary company out there, and it could have been a lot different.[405]

363. Dr. Lowry also agreed that the exclusion of relevant variables biases the estimators and noted that PEG's analysis included "as many variables that matter as we can."[406] For example, PEG offered that a company's productivity growth is a function of the number of customers (gas and electric, if applicable), line miles and time.[407] However, in AltaGas' opinion, the model should also have included the volume of gas delivered, as variation in usage per customer also affects productivity.[408] Therefore, the Commission agrees with NERA's conclusion that econometric models are prone to the criticism of being less objective and too complex for the purposes of PBR plans.

364. In light of the above considerations, the Commission agrees with NERA, ATCO Gas and AltaGas that the lack of publicly available data and transparent methodology represent major drawbacks to the use of PEG's productivity analysis. In contrast, as noted earlier in this section, the Commission agrees with the companies that NERA's TFP study was transparent and objective.

6.3.5 Applicability of NERA's TFP study to Alberta gas distribution companies

365. The data used in NERA's study are for the distribution portion of the electric companies, whether standalone or combination electric/gas companies according to FERC Form 1. NERA indicated that its study did not include data for standalone gas companies, since it was not aware of a readily available data source that would permit a comparably transparent TFP study for standalone gas companies.[409]

366. In NERA's view, the productivity of gas and electricity companies is similar. For example, NERA observed that both electricity and natural gas distribution are highly capital intensive. Additionally, in some instances the electricity and gas distribution facilities share the same support structure.[410] During the hearing, Dr. Makholm noted that based on his personal knowledge of operations of gas and electric distribution industries, the institutional framework and regulatory and business requirements for the two sectors are quite similar. Accordingly,

405 Transcript, Volume 3, pages 475-476.
406 Transcript, Volume 13, page 2548, lines 14-22.
407 Exhibit 307.01, PEG evidence, page 33.
408 Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
409 Exhibit 80.02, NERA report, pages 6-7.
410 Exhibit 80.02, NERA report, pages 6-7.

Dr. Makholm expressed his opinion that it is not necessary to differentiate the productivity growth for gas and electric distribution industries.[411]

367. Furthermore, NERA observed that according to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 per cent while for natural gas distribution, water and other systems TFP growth was 0.21 per cent, using gross output as the output measure. Using value added as the measure of output, the numbers are 0.37 per cent for electric power generation, transmission and distribution companies and 0.34 per cent for natural gas distribution, water and other systems.[412] At the same time, Dr. Makholm cautioned that NERA's observation of the Statistics Canada indexes was merely a "relatively casual view" of a data source that NERA did not use in its study.[413] PEG, AltaGas and the ATCO companies also indicated that Statistics Canada's MFP indexes were subject to a number of reporting difficulties, as further discussed in Section 6.3.7 below.[414]

368. In light of the above considerations, NERA expressed its opinion that a specialized TFP study for gas distribution companies would not be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad sample of gas companies that such a study would require to be a part of a transparent and objective PBR plan. Based on its familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective, NERA concluded that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both the electricity and gas companies in Alberta.[415]

369. ATCO Gas and AltaGas noted that it would be preferable to base the X factor for gas companies on a study that measured TFP growth for the gas industry, if a study of sufficient transparency and quality were available. However, because the two gas companies rejected PEG's productivity study, they noted that no such study was available in this proceeding.[416]

370. In these circumstances, ATCO Gas expert Dr. Carpenter observed that in the absence of any compelling reason to distinguish between electric and gas companies, and having regard for the Statistics Canada figures that NERA cited in its report, it is reasonable to assume that the same TFP is appropriate for gas and electric utilities in Alberta.[417] Similarly, AltaGas noted that NERA's report, along with the examination of Statistics Canada MFP indexes, provides some evidence useful for estimating the TFP growth rate of Canadian gas distribution companies.[418]

371. In a similar vein, the CCA noted that since the gas and electric power distribution businesses have similarities (such as a gradual growth in rate base and the importance of customers as a cost driver), TFP research from one industry could be used to set a productivity estimate for firms in the other industry if data for both industries were unavailable. However, the CCA maintained that this was not the case in the present proceeding. In the CCA's view, PEG's analysis on U.S. gas distribution companies is suitable for the purpose of setting establishing a

411 Transcript, Volume 1, pages 49-51.
412 Exhibit 80.02, NERA report, page 7.
413 Transcript, Volume 1, page 47, lines 4-6.
414 Exhibit 307.01, PEG evidence, pages 41-43; Exhibit 99.01, Carpenter evidence, page 26; Exhibit 110.01, Christensen Associates evidence, paragraphs 43-44.
415 Exhibit 80.02, NERA report, pages 4-5.
416 Exhibit 632, ATCO Gas argument, pages 27-28 and Exhibit 628, AltaGas argument, page 25.
417 Exhibit 99.01, Carpenter evidence, page 31.
418 Exhibit 628, AltaGas argument, page 25.

TFP for Alberta gas utilities. In addition, the CCA noted that other studies of the TFP trends of Canadian gas distributors, prepared for disinterested parties such as the Ontario Energy Board and the Gaz Métro Task Force, could also be useful for the purpose of setting a gas distribution company TFP.[419] Calgary agreed that with the inclusion of PEG's TFP analysis, there are data on the record for both electric and gas companies and that the Commission's determination on TFP should reflect a range which includes both analyses.[420]

372. The UCA submitted that the range of its proposed X factor menu accommodates the TFP results of both NERA and PEG. Accordingly, the UCA argued that its X factor menu provides appropriate X factor choices for both electric and gas companies.[421]

Commission findings

373. Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available.

374. However, parties could not agree on whether the TFP estimates from PEG's study and various other studies on the productivity trends of Canadian and the U.S. gas distributors used by other regulators, as well as Statistics Canada's MFP indexes, represent a superior indicator of TFP for gas distribution companies as compared to the TFP estimate from NERA's study of the electric distribution industry.

375. As set out in Section 6.3.7 of this decision, because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. With respect to the TFP studies of Canadian gas distributors prepared for other regulators (such as the Ontario Energy Board and the Gaz Métro Task Force) that PEG discussed, the Commission considers that while this productivity research can provide a useful reference for determining the general reasonableness and direction of a productivity estimate for the gas distribution companies, these studies cannot be viewed as substitutes for NERA's TFP study.

376. In particular, PEG referenced the 1.07 per cent TFP estimate for Enbridge Gas Distribution and the 1.65 per cent TFP estimate for Union Gas over the period 2006 to 2010. PEG also referred to the 1.66 per cent average annual TFP growth of Gaz Métro over the period 2000 to 2009.[422] However, the Commission observes that these TFP estimates are company-specific (i.e., these studies measure each company's own historical productivity growth and not the TFP growth of the industry).[423] Relying on these TFP estimates is not consistent with the Commission's preferred approach to determining the X factor that is based on the average long term productivity growth of the industry, as set out in Section 6.2 above. As NERA explained, the theory behind this approach dictates that the purpose of a TFP study is to estimate the long-

[419] Exhibit 636, CCA argument, paragraph 73.
[420] Exhibit 629, Calgary argument, page 24.
[421] Exhibit 634.02, UCA argument, paragraph 106.
[422] Exhibit 307.01, PEG evidence, pages 40-41.
[423] These reports were filed as Exhibit 376.03 (Gaz Métro) and Exhibit 376.04 (Union Gas Ltd. and Enbridge Gas Distribution Inc.).

term productivity growth of the industry, not the productivity growth of any particular company.[424]

377. PEG also referenced two TFP estimates with respect to the U.S. gas distribution industry. The first study found a TFP estimate of 1.18 per cent for the U.S. gas distribution industry over the period of 1999 to 2008, and the second study reported a TFP of 1.61 per cent over the period of 1994 to 2004.[425] In the Commission's view, differences in employed sample periods, input and output measures, as well as methodologies (e.g., indexing vs. econometric estimates), do not allow for a direct comparison of these numbers with NERA's TFP estimate.

378. Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies.

6.3.6 Output measure in the TFP study

379. As set out in Section 6.3.1 above, productivity growth is specified as the difference between the growth rates of a firm's physical outputs and physical inputs.[426] Accordingly, the choice of an output measure directly affects the estimated TFP growth.

380. NERA indicated that its practice, both in this proceeding and in previous TFP growth analyses that it has undertaken, has been to use the sales volume, measured in kilowatt hours (kWh) as the measure of output. NERA recognized that it is possible to specify two or more outputs (such as kWh or numbers of customers) into a single output for measuring TFP. However, NERA stated its preference for kWh sales output measure, as the most representative of the nature of a company, the size of its system, and its revenues.[427]

381. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

382. According to the CCA's experts, the correct output specification in a TFP study depends on the nature of the PBR plan. Specifically, PEG contended that volumetric output measures, such as the kWh sales used by NERA in its TFP study, are not correct in the context of revenue-per-customer cap plans. To arrive at this conclusion, Dr. Lowry of PEG showed that, if one accepts the belief that the costs of gas distributors are chiefly driven by the growth in the number of customers served, the mathematical logic of Divisia indexes dictates that the number of

424 Exhibit 391.02, NERA second report, paragraph 38.
425 Exhibit 307.01, PEG report, page 40 and Exhibit 366.04.
426 Exhibit 80.02, NERA report, page 5.
427 Exhibit 391.02, NERA second report, paragraph 47.
428 Exhibit 391.02, NERA second report, paragraph 47.

customers represents a relevant output measure to use in determining TFP as part of a PBR plan based on a revenue-per-customer cap.[429]

383. During the hearing, Dr. Lowry also explained that since under a revenue-per-customer cap plan, a company's revenues are driven by customer growth and are largely insensitive to the amount of energy sold, the number of customers is the relevant output measure to use for TFP studies used in a revenue-per-customer cap PBR plan. In contrast, under a price cap plan, a change in the amount of energy sold has an immediate effect on a company's revenues, and thus the use of a volumetric output measure is justified.[430] Accordingly, the CCA argued that output measures that place a heavy weight on volumetric and other usage should be used to determine the output index for TFP studies used in the context of a price cap PBR plan, while the number of customers should be used to determine the output index for TFP studies used in the context of a revenue-per-customer cap PBR plan.[431] NERA agreed with this logic.[432]

384. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

385. In a similar vein, Mr. Johnson on behalf of Calgary noted that in the case of a gas company with declining use per customer, it is likely that under a price cap approach the I-X component would have to be higher than if it was applied to a revenue cap.[434] That is, if one assumes that the I factor remains unchanged, Mr. Johnson appeared to suggest that for a company experiencing the declining use per customer, the X factor will be lower under a price cap plan as compared to a revenue cap plan in order to generate the same revenue stream.

386. AltaGas' expert, Dr. Schoech, generally agreed with Dr. Lowry that in the presence of declining use per customer for gas distribution companies, the use of a volumetric output measure would result in a lower TFP growth rate than is reflective of actual productivity growth and some adjustment would be necessary to account for this fact if the TFP study were to be used for the gas distribution companies.[435] Since Dr. Schoech expressed his preference that the output measure should include both volumes and customers, he indicated that any adjustment to an X factor for a price cap to determine an X factor for a revenue-per-customer cap must apply only to the portion of the revenue requirement generated through the volumetric charges.[436]

429 Exhibit 307.01, PEG evidence, pages 16-17; Exhibit 610.03, Attachment to CCA undertaking; Exhibit 645, CCA reply argument, paragraphs 89-91.
430 Transcript, Volume 14, page 2871, line 25 to page 2872, line 11.
431 Exhibit 636, CCA argument, paragraph 113.
432 Exhibit 273.03, CCA-NERA-2(e).
433 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
434 Transcript, Volume 15, page 2926, line 23 to page 2927, line 8.
435 Transcript, Volume 8, page 1528, lines 12-17 and page 153, line 23 to page 1534, line 7.
436 Transcript, Volume 9, pages 1714-1715.

387. At the same time, Dr. Schoech pointed out that because both the NERA study and the Statistics Canada MFP measures base their output only on volumes, and not on both volumes and customers, the baseline for making this type of adjustment was not available.[437] Consequently, since the number of customers variable was not available for neither NERA's nor Statistics Canada's studies, AltaGas submitted that there is no basis for making an adjustment to the X factor to account for declining usage per customer.[438]

388. Similarly, Dr. Carpenter on behalf of the ATCO companies generally acknowledged that in the presence of declining use per customer, a volumetric output index employed in a gas utility TFP study produces a lower gas TFP growth rate compared to an output measure based on the number of customers.[439] However, Dr. Carpenter did not accept PEG's premise that the number of customers is a primary driver of the gas companies' costs.[440] With regard to the relevant output measure for a gas TFP study, Dr. Carpenter concluded that it is unclear whether the output index should be based on the number of customers, energy delivered, or a combination of the two.[441] Nevertheless, based on his examination of the record of this proceeding, Dr. Carpenter concluded that "the NERA output index is the best we have."[442]

389. ATCO Gas did not agree with Dr. Lowry's logic and submitted that the way in which TFP is measured should not depend on the use of the resulting estimate. As such, ATCO Gas argued that the determination of whether the TFP estimate should be made using the number of customers as the output measure or energy delivered as the output measure should not depend on what use is to be made of the resulting estimate.[443]

390. The experts of the other electric companies expressed some concerns with NERA's use of kWh as the measure of output. Dr. Cicchetti noted that any TFP study for electricity distribution should reflect the fact that activities associated with customer numbers are critical to the services that distributors provide, for example extending distribution networks to serve new customers, meter reading, service calls, etc. Accordingly, in Dr. Cicchetti's view, an output measure in a TFP study should include the number (and perhaps location) of customers that the companies serve.[444] A similar argument was put forward by IPCAA's and the UCA's experts who noted that using kWh as the only output measure does not accurately reflect the outputs the distribution company is providing.[445] In this case, Dr. Cicchetti explained that because in the electric distribution industry the usage per customer is growing, not declining, the rate of growth of customers will be smaller than the rate of growth of energy throughput.[446] Accordingly, Dr. Cicchetti's, IPCAA's and the UCA' recommendations on output measure would result in a lower TFP and a lower X for electric companies.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In

437 Transcript, Volume 8, page 1534, lines 9-17.
438 Exhibit 628, AltaGas argument, page 36.
439 Transcript, Volume 6, page 979, lines 20-24.
440 Transcript, Volume 6, page 983, lines 3-11.
441 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
442 Transcript, Volume 6, page 981, lines 1-2.
443 Exhibit 632.01, ATCO Gas argument, pages 21-27.
444 Exhibit 103.05, Cicchetti evidence, pages 13-14.
445 Exhibit 306.01, Vidya Knowledge Systems evidence, pages 4-5; Exhibit 299.02, Cronin and Motluk UCA evidence, page 235.
446 Exhibit 103.05, Cicchetti evidence, page 14.

Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

Commission findings

392. The Commission agrees with the experts in this proceeding that each possible output measure (for example, energy sales, number of customers, line miles, peak usage, etc.) or combination thereof has its own merits and disadvantages.[448] However, the Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan.[449]

393. As discussed in Section 4 of this decision, the Commission recognizes that the rate designs of the gas distribution companies do not entirely reflect their cost drivers. While a large proportion of gas distributors' costs are fixed, a significant portion of these costs is recovered through variable charges. Also, as discussed in Section 4, both AltaGas and ATCO Gas are experiencing a declining use per customer. In these circumstances, a decline in use per customer would lead to a decrease in the companies' revenues that would not be offset by a decrease in costs. As a result of these considerations, the Commission is approving PBR plans in the form of a revenue-per-customer cap for ATCO Gas and AltaGas.

394. The experts in this proceeding explained that by focusing on revenue per customer as opposed to prices per unit of gas delivered, the revenue-per-customer cap plan effectively shields the revenue of gas companies from variations in energy use per customer.[450] In these circumstances, Dr. Schoech[451] on behalf of AltaGas and Dr. Cicchetti[452] on behalf of EPCOR acknowledged that the number of customers, not the volumes sold, becomes the driver of a company's revenues.[453] The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study.

395. Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.[454] Therefore, the Commission considers that kWh sold output measure used by NERA in its TFP study remains an acceptable output measure to use for the purpose of the price cap PBR plans approved for ATCO Electric, Fortis and EPCOR.

396. The Commission acknowledges the concerns of Fortis, EPCOR, IPCAA and the UCA that a single output measure such as kWh may not capture all of the outputs that an electric distribution company provides. However, as the Commission observed earlier in this section, a consensus on the best measures to use has not been reached, with different experts offering different measures. For example, Dr. Cronin noted that the most relevant output measure is the

447 Exhibit 474.02, Frayer rebuttal evidence, page 16.
448 Exhibit 391.02, NERA second report, paragraph 47.
449 Exhibit 307.01, PEG evidence, page 12; Exhibit 273.03, CCA-NERA-2(e).
450 Exhibit 100.02, Frayer evidence, page 23; Transcript, Volume 6, page 986, lines 9-13; Transcript, Volume 14, pages 2871-2872.
451 Transcript, Volume 9, pages 1714-1715.
452 Transcript, Volume 11, page 2070, lines 3-6.
453 Transcript, Volume 9, page 1714, lines 8-18.
454 Transcript, Volume 14, 2872 lines 4-7.

number of customers.[455] In Dr. Cicchetti's[456] and Ms. Frayer's[457] view, both megawatt hours and the number of customers have to be considered. Dr. Carpenter concluded that it is unclear whether the output measure should be based on the number of customers, energy delivered, or a combination of the two.[458] Dr. Lowry preferred energy delivered.[459] In light of this uncertainty, the Commission is not persuaded that NERA's output measure of kWh sold is an inferior output measure compared to the variety of alternatives proposed.

397. With respect to Ms. Frayer's concern that the use of a single output measure based on energy volumes will make the resulting TFP estimate more volatile, the Commission agrees with NERA that using kWh with the longest time series available will mitigate such volatility.[460] Overall, the Commission agrees with Dr. Carpenter's view that NERA's output index measuring kWh sold is an acceptable measure to use for the purpose of calculating TFP growth for electric distribution companies.

6.3.7 Other productivity indexes

398. In addition to the two TFP studies performed by NERA and PEG, ATCO's, Fortis' and AltaGas' experts relied on the various MFP indexes published by Statistics Canada and academic publications examining productivity in different sectors of the U.S. and Canadian economies. In developing their productivity target recommendations, the experts of Fortis and AltaGas examined the Statistics Canada MFP indexes for the utilities industry. However, Ms. Frayer and Dr. Schoech acknowledged that the use of these indexes may be problematic for establishing the TFP for electric and gas distribution companies because, for the purposes of the Statistics Canada MFP index, electric distribution is combined with power generation and transmission. Natural gas distribution is combined with water, sewage and other systems.[461]

399. Because of the presence of these items not pertaining to electric distribution, Ms. Frayer's preference was to rely on the Statistics Canada MFP for the utilities sector in general, not the more specific index for electric utilities.[462] Similarly, Dr. Schoech and his colleagues observed that the Statistics Canada MFP for the natural gas and water subsector showed some "significant structural anomalies" and also considered data for the utilities sector in general.[463]

400. The CCA's experts pointed out that the Statistics Canada MFP indexes have several problems that limit their usefulness in this proceeding. First of all, PEG noted that the inclusion of power generation and transmission in the electric sector and the inclusion of water systems in the gas sector substantially reduces the relevance of Statistics Canada's MFP indexes for the electric and gas distribution companies. Second, PEG highlighted the fact that the output of the industry is measured volumetrically and thus may not be an accurate reflection of gas sector productivity growth, as discussed earlier in Section 6.3.6 of this decision. In addition, PEG also expressed a number of other concerns with Statistics Canada's MFP indexes, including the influence of large conservation programs in several Canadian provinces not experienced in

455 Transcript, Volume 17, page 3236, lines 6-8.
456 Transcript, Volume 11, page 2070, lines 1-2.
457 Transcript, Volume 11, pages 2108-2109.
458 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
459 Exhibit 307.01, PEG evidence, page 36.
460 Exhibit 391.02, NERA second report, paragraph 47.
461 Exhibit 110.01, Christensen Associates evidence, paragraph 43; Exhibit 100.02, Frayer evidence, pages 58-66.
462 Exhibit 100.02, Frayer evidence, pages 65-66.
463 Exhibit 110.01, Christensen Associates evidence, paragraphs 44 and 47.

Alberta, the effect of the recent economic recession and the use of value added indexes which ignores the productivity of intermediate inputs.[464]

401. Ms. Frayer[465] and Dr. Carpenter[466] also examined the study of productivity trends at the provincial level prepared by the Center for the Study of Living Standards (CSLS).[467] As Ms. Frayer explained, the CSLS report "provides an analysis of the economic conditions and productivity of ten Canadian provinces over a ten-year period from 1998 to 2007."[468] Ms. Frayer observed that this report used the same methodology and underlying data that Statistics Canada employed in the calculation of its MFP indexes. As a result, Ms. Frayer noted that the CSLS productivity indexes do not differ substantially from the MFP indexes published by Statistics Canada.[469]

402. Because of the similarities between the Statistics Canada and the CSLS analyses, the CCA indicated that its concerns with respect to the Statistics Canada MFP indexes equally apply to the CSLS estimates. Additionally, PEG indicated that in correspondence with the authors of the CSLS study, the authors "conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination."[470]

403. Finally, for this proceeding Ms. Frayer also updated her TFP study performed for the Ontario Energy Board in 2007. Ms. Frayer's updated study covered 78 local distribution companies in Ontario for the period 2002 to 2009 and found negative TFP growth in the range of -0.4 per cent to -1.5 per cent.[471]

404. PEG expressed its concerns with this study primarily relating to methodology and the short sample period. With respect to methodology, PEG took issue with Ms. Frayer's use of line miles as a proxy for the capital quantity trend. The UCA echoed this concern.[472] In addition, PEG noted that Ms. Frayer's sample period was "far too short" to smooth out the effects of annual variations in productivity growth arising from the use of volatile output measures such as energy volumes and peak demand.[473]

Commission findings

405. The Commission agrees with the CCA's experts that because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. The Commission does not share Ms. Frayer's view that looking at a more aggregated MFP index for the utilities sector in general would help to address this problem. As the CCA

464 Exhibit 307.01, PEG evidence, pages 41-43.
465 Exhibit 100.02, Frayer evidence, page 58.
466 Exhibit 98.02, Carpenter evidence, page 33, A74.
467 The Center for the Study of Living Standards, *New Estimates of Labour, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the three-digit NAICS Level, 1997-2007*, issued on June 8, 2010.
468 Exhibit 100.02, Frayer evidence, page 66.
469 Exhibit 100.02, Frayer evidence, pages 66-68.
470 Exhibit 307.01, PEG evidence, pages 43-44 and Exhibit 376.01, ATCO-CCA-57(b).
471 Exhibit 100.02, Frayer evidence, pages 72-76.
472 Exhibit 299.02, Cronin and Motluk UCA evidence, page 81.
473 Exhibit 645, CCA reply argument, pages 32-33.

explained, such an aggregate index still includes such items as generation, transmission and water systems, which further dilutes the productivity trend of the distribution component.[474]

406. In addition, PEG observed that Statistics Canada uses volumetric output measures for calculating its MFP indexes.[475] As mentioned in Section 6.3.6 above, Dr. Lowry explained that in the presence of a declining use per customer experienced by the gas distribution industry, a gas TFP study based on a volumetric output index will understate the productivity of the gas industry.[476]

407. As Ms. Frayer observed, the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes. Accordingly, the Commission considers that this study is prone to the same criticisms as the Statistics Canada indexes. Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

408. With respect to Ms. Frayer's updated study on Ontario distribution companies, the Commission shares the CCA's concern that the short period covered by the study (2002 to 2009) does not allow measuring the long-term industry productivity trend. As the Commission observed in Section 6.3.2 of this decision, most experts in this proceeding agreed that a period of less than 10 years will not achieve this purpose.[477] Furthermore, the Commission is not persuaded that a TFP study based exclusively on Ontario distribution companies represents a better indicator of the underlying industry productivity trend for the electric or gas distribution industries compared to NERA's study covering a broad sample of companies from across the United States.

6.3.8 Commission determinations on TFP

409. There are two productivity studies on the record in this proceeding. The first, conducted by NERA, calculated a TFP of 0.96 per cent.[478] This TFP value was based on an analysis of the distribution portion of 72 U.S. electric and combination electric/gas companies over the period of 1972 to 2009.[479] The second study was conducted by PEG on behalf of the CCA for the gas distribution industry and found a TFP in the range of 1.32 to 1.69 per cent. PEG's study examined 34 U.S. gas distribution companies over the period of 1996 to 2009.[480]

410. The ATCO companies, Fortis and AltaGas relied on the various MFP indexes published by Statistics Canada as well as the CSLS study examining productivity in different sectors of the U.S. and Canadian economies for a variety of purposes.[481] As explained in Section 6.3.7 above,

474 Exhibit 645, CCA reply argument, paragraph 113.
475 Exhibit 307.01, PEG evidence, page 42.
476 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
477 Exhibit 307.01, PEG evidence, page 28; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
478 In its first report NERA estimated a TFP of 0.85 per cent. However, in its second report it accepted one of the adjustments proposed by PEG (related to labour quantity estimation for the period 2002 to 2009). This adjustment resulted in a recalculated TFP estimate of 0.96 per cent.
479 Exhibit 391.02, NERA second report, Table 3.
480 Exhibit 307.01, PEG evidence, page 2.
481 Exhibit 98.02, Carpenter evidence, paragraph 43; Exhibit 100.02, Frayer evidence, page 58; Exhibit 110.01, Christensen Associates evidence, paragraph 43.

the Commission determined that the MFP indexes published by Statistics Canada as well as the CSLS study are unsuitable for determining TFP for either the electric or gas distribution industries.

411. The Commission has evaluated the NERA and PEG TFP studies with respect to a number of issues and criteria discussed by the parties, such as the relevant time period and sample size, the relevance of the U.S. data to Alberta companies, the use of publicly available data and transparent methodology, and the applicability of the obtained TFP number to both gas and electric companies as set out in sections 6.3.2 to 6.3.6 of this decision. Based on this evaluation, the Commission finds that NERA's study is preferable to use in this proceeding given the objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution companies from the United States.

412. In the Commission's view, NERA's study was more objective and transparent compared to PEG's analysis. First, as the Commission observed in Section 6.3.2 above, the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria. Moreover, as set out in Section 6.3.4, PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. As such, while the Commission recognizes the value of a separate productivity study focusing on gas distributors, the drawbacks of PEG's TFP research do not allow the Commission to rely on it.

413. The Commission notes that in addition to the issues discussed in sections 6.3.2 to 6.3.7 above, PEG expressed a number of other concerns with NERA's study relating to the correct index form and the capital quantity index to use, among others.[482] Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer. For instance, PEG advocated the use of a chain-weighted form of a Tornqvist-Theil index, while NERA preferred the use of a multilateral Tornqvist-Theil index.[483] Similarly, PEG indicated that the correct capital quantity measure to use should be the inflation-adjusted value of gross plant, while NERA insisted on using the net plant value.[484] Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study.

414. The Commission also observes that all of the companies' experts used NERA's study as a starting point for their X factor recommendations despite expressing some reservations about particular aspects of the study and offering various adjustments primarily relating to the sample period.[485]

415. In light of the above considerations, the Commission accepts NERA's methodology and finds that NERA's TFP estimate of 0.96 per cent represents a reasonable starting point for setting an X factor for the Alberta companies. Accordingly, based on NERA's study, the Commission

482 Exhibit 569.01, PEG rebuttal evidence, redlined pages; Exhibit 478, PEG rebuttal evidence, pages 11-17; Exhibit 609.02, CCA undertaking response: PEG adjustments to NERA.

483 Transcript, Volume 1, pages 76-77.

484 Transcript, Volume 1, pages 74-75 and Exhibit 461.02, AUC-NERA-16.

485 Exhibit 103.05, Cicchetti evidence, page 16; Exhibit 98.02, Carpenter evidence, page 32; Exhibit 100.02, Frayer evidence, page 79; Exhibit 110.01, Christensen Associates evidence, page 15.

finds that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric distribution companies.

416. With respect to the gas companies, as discussed in Section 6.3.6 above, the Commission agrees with Dr. Lowry's argument that it is necessary to match the output measure to the type of PBR plan (price cap or revenue-per-customer cap).[486] However, in the absence of a reliable and transparent TFP study on the gas distribution industry and information on how changes in the relevant output measures and input measures for electric and gas distribution industries compare to each other over the 1972 to 2009 study period, the Commission is not prepared to make any adjustment to NERA's TFP estimate in order to obtain a TFP estimate for the gas distribution companies.

417. The Commission observes that NERA, ATCO Gas and AltaGas agreed that NERA's study represents a reasonable starting point for determining the TFP trend for gas distributors.[487] The Commission agrees. Accordingly, the Commission finds that NERA's TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the gas distribution companies.

6.4 Adjustments to arrive at the X factor

418. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment if an output-based measure is used for the I factor.[488] Additionally, Dr. Carpenter on behalf of the ATCO companies,[489] Dr. Cicchetti on behalf of EPCOR,[490] and Dr. Schoech on behalf of AltaGas[491] expressed their views that NERA's TFP analysis based on the U.S. data needed to be adjusted for the differences in the economy-wide productivity growth between the United States, Canada and Alberta.

419. In addition to the above adjustments, parties discussed whether the companies' proposals to exclude all of or part of capital from the I-X mechanism should have any effect on the X factor. Each of these possible adjustments is addressed in the following sections of this decision.

6.4.1 Input price and productivity differential if an output-based measure is chosen for the I factor

420. Similar to the discussion in Decision 2009-035 dealing with ENMAX's FBR plan,[492] parties to this proceeding pointed out that the choice of an I factor can influence the X factor depending on the productivity that may be embedded in a particular inflation measure.

421. As Dr. Carpenter and Ms Frayer explained, there are two types of inflation measures that can be used for the I factor: input-based and output-based. Input-based measures reflect the change in the prices of goods and services purchased as inputs into the companies' production

486 Exhibit 307.01, PEG evidence, page 12.
487 Exhibit 80.02, NERA report, pages 4 and 5; Exhibit 99.01, Carpenter evidence, page 31; Exhibit 628, AltaGas argument, page 25
488 Exhibit 461.02, AUC-NERA-17(a) and (b).
489 Exhibit 98.02, Carpenter evidence, pages 26-34.
490 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
491 Transcript, Volume 8, page 1414, lines 9-25.
492 Decision 2009-035, paragraphs 126-128.

process. A labour cost index such as AWE or AHE represents an example of an input price index since they track the changes in the wages and salaries of company's employees and contracted labour services. In contrast, output-based measures reflect the change in the prices of the basket of goods and services that are outputs of the economy and are typically purchased by final consumers rather than by companies as inputs. The CPI (consumer price index) would usually be an example of this type of measure.[493]

422. Given that the purpose of the I factor in a PBR plan is to track the prices of the inputs used by the electric or gas distribution industries (and therefore, the companies), the use of an input-based price index is preferred. However, on many occasions, the desired input price index may not be readily available or may not exist at all.[494] As a result, PBR plans may need to use output-based measures that are readily available, widely known and easy to explain to consumers, stakeholders and regulators.[495] NERA pointed out that the CPI is the most common inflation measure in PBR plans in Canada, while the GDP price index (also an output-based measure) is dominant in the United States.[496]

423. Nevertheless, using an output-based inflation index in a PBR plan may be problematic. Because the measure of output inflation already incorporates the effects of economy-wide productivity gains, such an index would not necessarily be indicative of the input price inflation likely to be experienced by the industry and, accordingly, the companies during the plan term. As a result, it may be necessary to adjust the TFP estimate when determining the X factor to correct for the difference between the output inflation included in the inflation factor and the industry input inflation.[497]

424. NERA and Dr. Carpenter explained that for practical purposes this adjustment consists of two adjustments to TFP to arrive at the X factor: a productivity differential and an input price differential.[498] In its evidence, PEG explained the logic behind those two adjustments as follows:

> The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing the [I-X index] growth, to the extent that the MFP growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.[499]

425. As Fortis' expert pointed out, in this case an X factor based on TFP with these two adjustments may be interpreted as the difference between the productivity growth rate of the industry and the productivity growth rate included in the output inflation measure used. On the other hand, if an input price index is used for the I factor, no adjustment to TFP is required. In this case, the resulting X factor would reflect the productivity growth of the industry.[500]

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493 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 33.
494 Exhibit 476.01, Carpenter rebuttal evidence, page 67.
495 Exhibit 100.02, Frayer evidence, pages 33-34.
496 Exhibit 391.02, NERA second report, paragraph 65.
497 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 54; Exhibit 628, AltaGas argument, pages 12-13.
498 Exhibit 461.02, AUC-NERA-17(b) and Exhibit 476.01, Carpenter rebuttal evidence, page 67.
499 Exhibit 307.01, PEG evidence, pages 20-21.
500 Exhibit 100.02, Frayer evidence, page 52.

Commission findings

426. The interaction between the I factor and the X factor described above is based on a well-established theoretical foundation, as demonstrated by the agreement of parties on the need to adjust TFP in determining an X factor if an output-based inflation measure is chosen for the purpose of the PBR plan.[501] Consequently, the parties advised that, when possible, it is preferable to use input-based price indexes for the I factor of the PBR plan, since using such indexes avoids the need for an input price differential and a productivity differential adjustment to TFP.

427. As set out in Section 5 of this decision, the Commission approved a composite I factor consisting of AWE and CPI indexes for Alberta. While the AWE index represents an example of an input-based measure, the CPI is generally regarded as an output rather an in input price index. However, as the Commission explained in Section 5.2.3 above, in the context of this proceeding, the Alberta CPI will be used only to monitor price trends for the companies' non-labour inputs. EPCOR, AltaGas and ATCO Gas submitted that because the Alberta CPI is a good proxy for the price changes for that particular group of expenditures, it may be considered an input price index for the purpose of their composite I factors.[502] The Commission agrees.

428. Accordingly, since both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.

6.4.2 Productivity gap adjustment

429. As discussed in Section 6.3.1 above, NERA's study used a population of 72 U.S. electric and combination electric/gas companies. In these circumstances, Dr. Carpenter indicated that to the extent that utilities in Canada have different productivity expectations than utilities in the U.S., an adjustment to the NERA's TFP number would be required in a Canadian PBR context.[503]

430. Dr. Carpenter observed that there is a well-documented productivity gap between the Canadian and the U.S. economies, with Canadian productivity growth rates consistently lower than productivity growth in the U.S. For example, Dr. Carpenter pointed to a Statistics Canada study that found that average annual MFP growth was 0.9 percentage points lower in Canada than in the United States from 1961 to 2008.[504] In addition, Dr. Carpenter observed that in its TFP analysis, NERA showed that on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[505]

431. At the same time, the ATCO companies' expert acknowledged that while the existence of the economy-wide productivity gap has been documented by government statistics and academic studies, the specific causes of the gap are not well understood and it is not clear whether a similar

501 Transcript, Volume 1, pages 141-142; Transcript, Volume 4, pages 611-612; Transcript, Volume 8, page 1415; Transcript, Volume 11, pages 2133-2134; Transcript, Volume 13, page 2589.

502 Exhibit 630.02, EPCOR argument, paragraph 31; Exhibit 628, AltaGas argument, pages 12-13; Exhibit 648.02, ATCO Gas reply argument, paragraph 94.

503 Exhibit 98.02, Carpenter evidence, pages 25-26.

504 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009.

505 Exhibit 98.02, Carpenter evidence, page 29.

productivity gap exists in the electric and gas utility sector. For example, Dr. Carpenter noted that studies relying on the Statistics Canada data typically define the utility sector more broadly, including power generation and transmission in the electric sector and water and sewage utilities in the gas sector.[506] Thus, these studies may not provide an accurate estimate of productivity growth for electric or gas distribution companies. As a result, Dr. Carpenter conceded that there is no evidence to permit a direct comparison of Canadian and U.S. productivity growth rates for electric or gas distribution companies.[507]

432. Despite the lack of direct empirical evidence, Dr. Carpenter concluded that it is likely that the economy-wide productivity gap between Canada and the U.S. persists at the utility sector level. Dr. Carpenter arrived at this conclusion as a result of following considerations.[508]

- First, Dr. Carpenter indicated that he was not aware of any evidence that differences in the composition of the two economies drive the different rates of productivity growth. For example, Dr. Carpenter noted that the proportion of total GDP generated by the various sectors of the Canadian and the U.S. economies is not very different.
- Second, Dr. Carpenter noted that he was not aware of any compelling evidence that there is one sector or a group of sectors in the Canadian and the US economies that drives the productivity gap. According to Dr. Carpenter, there is evidence that the productivity gap occurs in a wide range of sectors, which is likely to include the utility sector.
- Third, Dr. Carpenter observed that while there is some disagreement among researchers as to the possible explanations for the U.S.-Canada gap, he had seen no reason to believe that the productivity gap is unlikely to affect the utility sector.

433. As a result of these considerations, Dr. Carpenter indicated that NERA’s TFP estimate for the U.S. companies needed to be adjusted for the observed U.S.-Canada productivity gap. Using the economy-wide productivity estimates from Statistics Canada and the U.S. Bureau of Labour Statistics presented in NERA’s report, Dr. Carpenter proposed an adjustment of approximately -1.5 percentage points to NERA’s TFP.[509]

434. Furthermore, Dr. Carpenter expressed his view that the recommended productivity gap adjustment was conservative for Alberta. The ATCO companies’ expert noted that the CSLS report[510] and another productivity study[511] show a Canada-Alberta productivity gap, with Alberta having slower productivity growth in the utility sector and in the business sector in general. However, because ATCO Electric and ATCO Gas make up a significant part of the utility sector in Alberta, Dr. Carpenter indicated that adjustment for a Canada-Alberta productivity gap may not be appropriate since the resulting X factor would be “ATCO-specific” rather than reflective of the industry productivity trends.[512]

435. AltaGas agreed with Dr. Carpenter that in the case that the TFP analysis “did not focus on the Canadian gas distribution industry, an adjustment for the U.S.-Canada productivity gap

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506 Transcript, Volume 6, page 1004, lines 4-25.
507 Exhibit 98.02, Carpenter evidence, pages 26-27.
508 Exhibit 98.02, Carpenter evidence, pages 27-29.
509 Exhibit 98.02, Carpenter evidence, page 30, Tables 2 and 3.
510 The CSLS report was discussed in Section 6.3.7 of this decision.
511 Rao, Someshwar, Andrew Sharpe and Jeremy Smith, *An Analysis of the Labour Productivity Growth Slowdown in Canada since 2000*, International Productivity Monitor, Spring 2005.
512 Exhibit 98.02, Carpenter evidence, pages 33-34.

would generally be appropriate.[513] With respect to the Canada-Alberta productivity gap, AltaGas observed that the CSLS report (from which the existence of such a gap was inferred) was conducted on an experimental basis. As such, AltaGas did not propose to make an adjustment for differences in productivity growth between Alberta and Canada.[514]

436. EPCOR submitted that neither the company itself nor its expert Dr. Cicchetti have proposed an adjustment for the productivity differences between the U.S. and Canada or between Canada and Alberta. During the hearing, Dr. Cicchetti explained that the data for Canadian companies do not exist in a fashion that would allow anyone to have an authoritative opinion on the difference in productivity between Canadian and U.S. electric distribution utilities.[515] At the same time, when establishing the components of EPCOR's PBR plan, Dr. Cicchetti urged the Commission to recognize that the actual trend in input prices for labour in Alberta are likely to be above the past trends in the U.S. reflected in NERA's data.[516] As a result, EPCOR submitted that the Commission should not increase the X factor "to something more than -1.0 per cent" that Dr. Cicchetti recommended for the company, given the difference in U.S. and Alberta labour economics.[517]

437. Fortis noted that the company did not ground its X factor approach or recommendation on the basis of a productivity gap. Furthermore, Fortis submitted that the relevant Canada to Alberta considerations in the company's proposal were with respect to the I factor, where the appropriate "Albertasizing" of input price measures was undertaken.[518]

438. The CCA did not believe that any adjustment to the X factor to account for the U.S.-Canada productivity gap was necessary. Having examined the analysis of MFP conducted in several papers by Statistics Canada, PEG found that productivity growth differences between the United States and Canada "vary so widely by industry as to render economy-wide differences in productivity growth useless in quantifying differences in productivity growth between specific industries in the two countries."[519] In addition, PEG observed that the productivity gap between the U.S. and Canada was largely due to differences in sectors that do not include utilities, such as mining and oil extraction and manufacturing.[520]

439. In a similar vein, NERA indicated that it was not aware of any evidence to point to a productivity gap between U.S. and Canadian utilities:

> NERA has seen no evidence to point to a productivity gap between US and Canadian utilities. The existence of a macroeconomic productivity gap between the US and Canada does not necessitate the existence of a productivity gap between US and Canadian utilities – or even suggest such a gap for companies, which operate as regulated utilities in markets subject to highly similar sets of accounting, administrative and legal institutional arrangements in the US and Canada.[521]

513 Exhibit 628, AltaGas argument, page 30.
514 Exhibit 628, AltaGas argument, page 31.
515 Transcript, Volume 11, page 2009, lines 16-24.
516 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
517 Exhibit 630.02, EPCOR argument, paragraphs 74-75.
518 Exhibit 633, Fortis argument, paragraphs 130-131.
519 Exhibit 376.01, ATCO-CCA-42(c).
520 Exhibit 376.01, ATCO-CCA-42(c).
521 Exhibit 291.02, Calgary-NERA I-9(c), Exhibit 195.01, AUC-NERA-7.

440. Calgary stated that there is fundamentally little if any difference between the productivity of the U.S. and Canadian distribution utilities.[522] Similarly, the UCA expressed its concerns with establishing the existence of a productivity gap between U.S. and Canadian distribution companies based on the difference in productivity in the overall Canadian economy compared to the overall U.S. economy. In their evidence, Dr. Cronin and Mr. Motluk presented the results of various studies of Canadian electric and gas distribution utilities showing that the TFP growth rates of Canadian distribution companies were "notably higher" than for the U.S. distribution companies as measured by NERA's TFP growth rate.[523] As such, the UCA's experts argued that there was a reverse productivity gap between U.S. and Canadian distribution companies.[524]

Commission findings

441. Parties did not dispute the fact that there presently exists a well-recognized difference between the rate at which the U.S. and the Canadian economies have been able to improve productivity (referred to as a "productivity gap"). Using macroeconomic productivity data from Statistics Canada and the U.S. Bureau of Labour Statistics, NERA showed that, on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[525]

442. At the same time, parties could not agree on whether the same productivity gap exists between the U.S. and Canadian electric and gas distribution industries. Little direct evidence on whether a gap exists is available. Dr. Carpenter and Dr. Cicchetti pointed to the fact that it is not possible to directly review the productivity gap in the electric and gas utility sectors, as no data on productivity growth for Canadian electric and gas companies exist.[526] The UCA experts proposed examining TFP growth estimates of Canadian utilities obtained from various regulatory proceedings for this purpose. However, in the Commission's view, because the TFP estimates introduced by Dr. Cronin and Mr. Motluk represent a variety of sources, methods, samples and time periods, it is uncertain whether these estimates can be directly compared to NERA's TFP calculation to make a judgment on the existence of a productivity gap for the electric and gas distribution industries between the two countries.[527] As such, the Commission will proceed with evaluating the indirect evidence of a productivity gap between U.S. and Canadian utilities.

443. On a conceptual level, the Commission agrees with NERA's and the interveners' proposition that the existence of a macroeconomic productivity gap between the U.S. and Canada does not mean that there is a productivity gap between U.S. and Canadian utilities. As Dr. Lowry explained:

> And also the thrust of my evidence is that if you look under the hood of the Canadian economy and go sector by sector, it's nothing, you know, remotely true that all the sectors are behind their American counterparts. The numbers are just all over the place. So there's very bad predictive value by saying that for a given industry just because the Canadian economy's productivity trend is slower that therefore a given sector should be slower.[528]

522 Exhibit 629, Calgary argument, page 28.
523 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 76-79 and 86-87.
524 Exhibit 634.02, UCA argument, paragraphs 134-135.
525 Exhibit 80.02, NERA report, page 20, Table 4.
526 Exhibit 476.01, Carpenter rebuttal evidence, page 41; Transcript, Volume 11, page 2009, lines 16-24 (Cicchetti).
527 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 78-79.
528 Transcript, Volume 13, page 2562, lines 11-19.

444. To examine which particular sectors of the Canadian economy contribute to a productivity gap, parties relied on a number of government and academic studies. For example, Dr. Carpenter observed that one Statistics Canada study[529] found evidence of the labour productivity gap in six of the nine industries examined, including utilities and transportation, manufacturing, retail trade, information and cultural industries; and finance, insurance, and real estate. Another study[530] that Dr. Carpenter relied on identified a U.S.-Canada productivity gap in 20 of 33 categories, including electric utilities, gas utilities, mining, food, textiles, printing, and electrical machinery.[531]

445. However, the Statistics Canada study[532] referenced by the CCA's experts, PEG, did not support this conclusion and showed that "the MFP trend of the engineering sector of the economy which includes energy utilities actually exceeded that of the U.S. over a recent sample period."[533] Another study by Statistics Canada[534] quoted by PEG showed that in the 2000 to 2008 period, the decline in the business sector MFP growth rate was due chiefly to declining productivity in two industrial classifications: mining and oil and gas extraction, and manufacturing.[535] The UCA also presented the results of an academic study[536] showing that for the period from 1961 to1995, Canada was "significantly more productive than the United States in coal mining, construction, tobacco, petroleum refining, electric utilities, and gas utilities."[537]

446. Without engaging in a debate on the methodology, time period and relevance of the academic studies discussed in this proceeding,[538] the Commission observes that there is no consensus in the literature on whether a productivity gap exists for the utility sector in general or for the electric and gas distribution sectors in particular. On a related issue, Dr. Carpenter pointed out that there remains a disagreement among the researchers as to the possible explanations for the U.S.-Canada productivity gap.[539]

447. Furthermore, as Dr. Carpenter indicated, some of the academic studies on productivity referenced by the parties in this proceeding refer to the Canadian utility sector in general, which includes power generation and transmission in the electric utilities sector and water and sewage systems in the natural gas utilities sector.[540] As such, it is uncertain whether the productivity of the utilities sector reported in the studies is an accurate reflection of the electric and gas distribution companies' TFP growth.

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529 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009 (No. 25), Statistics Canada.

530 Gu, Wulong and Mun Ho, *A Comparison of Industrial Productivity Growth in Canada and the United States*, Published in Industry-level Productivity and International Competitiveness between Canada and the United States, 2001.

531 Exhibit 98.02, Carpenter evidence, page 28.

532 Baldwin, Gu and Yan, *Relative Multifactor Productivity Levels in Canada and the United States: A Sectoral Analysis*, The Canadian Productivity Review, June 2008 (No. 19), Statistics Canada.

533 Exhibit 636, CCA argument, paragraph 102.

534 Baldwin and Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends,* The Canadian Productivity Review, August 2009 (No. 25), Statistics Canada.

535 Exhibit 636, CCA argument, paragraph 102.

536 Lee, Frank C., and Jianmin Tang. 2000. *Productivity Levels and International Competitiveness between Canadian and U.S. Industries.* American Economic Review, 90(2): 176-179.

537 Exhibit 634.02, UCA argument, paragraphs 136-138.

538 Exhibit 476.01, Carpenter rebuttal evidence, pages 42-46; Exhibit 650, AltaGas reply argument, paragraph 87.

539 Exhibit 98.02, Carpenter evidence, page 29.

540 Exhibit 98.02, Carpenter evidence, page 26; Exhibit 476.01, Carpenter rebuttal evidence, page 45.

448. In light of the conflicting evidence from the government and academic research, and the uncertainty of whether the results of such research can be used for establishing the existence of a productivity gap between U.S. and Canadian distribution utilities, the Commission considers that no definitive conclusion can be reached on the existence of such a gap. Further, the Commission finds it to be significant that parties observed the business, operational and regulatory similarities between utilities in both jurisdictions. For example, NERA commented on the similarity of the institutional frameworks in which the Canadian and U.S. utilities operate. As NERA explained:

> [F]rom the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the United States have virtually indistinguishable regulatory environments – so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[541]

449. Dr. Cicchetti also pointed to similarities in the business environment between the utilities in the two countries by observing that electric and gas distribution companies in both the United States and Canada "are certainly the last remaining holdout in the U.S. context of unionized employees."[542]

450. In light of these considerations, the Commission finds that no adjustment to NERA's TFP is necessary to account for the observed economy-wide productivity gap between the U.S. and Canada. The Commission observes that Dr. Carpenter was not aware of any jurisdiction in Canada that has adjusted a TFP estimate in setting the X factor in recognition of the productivity gap between the two countries.[543]

451. With respect to a Canada-Alberta productivity gap, the Commission notes that Dr. Carpenter's conclusions as to the existence of such a gap were largely derived from the examination of the CSLS study.[544] However, as the Commission explained earlier in this section and in Section 6.3.7, because the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes, it is not clear to what degree the results of this study are reflective of the productivity trends in the electric and gas distribution industries.

452. More importantly, the Commission explained in Section 6.2 of this decision that the X factor should reflect the average rate of productivity growth in the industry. Accordingly, the Commission agrees with Dr. Carpenter's observation about the size of the ATCO companies and concludes that because the companies in this proceeding make up a large part of the utility sector in Alberta, an adjustment for a Canada-Alberta productivity gap (in the utility sector) would result in an X factor that would reflect the companies' own experience rather than industry productivity trends.[545]

453. Dr. Cicchetti proposed that when setting the X factor for Alberta companies, some recognition be given to the fact that the actual trend of input prices for labour in Alberta is likely to be above the past trends in the U.S. that are reflected in NERA's TFP estimates.[546] In

541 Exhibit 391.02, NERA second report, page 20.
542 Transcript, Volume 11, page 2071, lines 3-6.
543 Transcript, Volume 4, page 635, lines 7-11.
544 Exhibit 98.02, Carpenter evidence, page 33.
545 Exhibit 98.02, Carpenter evidence, pages 33-34.
546 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

EPCOR's view, the consequence of this would be that NERA's TFP growth rate would be higher than the actual TFP growth rate for Alberta.[547]

454. The Commission has a number of concerns with the EPCOR proposition. First of all, Dr. Cicchetti did not provide any information on the relative labour inflation in Alberta and the United States for NERA's study period to support his conclusion that labour inflation in Alberta has been consistently higher than labour inflation in the U.S. over this entire period.

455. Furthermore, the actual impact of labour inflation on the TFP estimate is not so direct as to warrant an immediate upward adjustment to NERA's estimates. NERA explained that its overall input index (in the form of a Tornqvist-Theil volume index) primarily captures changes in input volume.[548] Because NERA used the number of employees as a labour quantity measure,[549] the resulting TFP estimate is largely, but not completely, insulated from the effect of labour inflation. NERA explained that its overall input index "is affected by input prices to the extent that the input expenses are the shares by which the input volumes are weighted."[550] Since NERA used nominal dollars to construct the input price shares,[551] adjusting for higher labour inflation (assuming that the labour inflation in Alberta was consistently higher than in the United States) would result in a higher share of labour in NERA's input index. However, a higher share of labour in the overall input index does not necessarily lead to a reduction to TFP. For example, if the rate of growth in the labour index (i.e., labour quantity) were lower than the rate of growth of the capital and materials indexes (quantities of capital and materials), assigning more weight to the labour index would actually result in a lower overall input index. Holding the output index constant, this would result in a higher TFP growth.

456. In the absence of any analysis on how historical Alberta labour inflation would affect NERA's TFP estimate, the Commission cannot accept EPCOR's proposition that an adjustment to the TFP factor is necessary to account for the difference in U.S. and Alberta labour economics.

6.4.3 Effect on the X factor of excluding capital from the application of the I-X mechanism

457. Because EPCOR's proposed PBR plan indexes only operating costs and excludes capital costs, Dr. Cicchetti noted that a PFP (partial productivity factor) measuring only changes in O&M productivity was a relevant measure to use instead of TFP as a basis for EPCOR's X factor.[552] The ATCO companies agreed with this logic and submitted that if all capital expenditures were to be excluded from indexing under the PBR plan, a different X factor would likely be required based on the PFP associated with O&M.[553]

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547 Exhibit 630.02, EPCOR argument, paragraphs 74-75.
548 Exhibit 195.01, AUC-NERA-3(a) and (d).
549 As NERA explained in its second report, before 2002, NERA used number of employees for labour quantity. Because FERC Form 1 no longer contains employee data after 2002, NERA estimated the number of employees using the inflation-adjusted distribution payroll growth for the years 2002 to 2009. (Exhibit 391.02, NERA second report, page 10). In either period, labour quantity is measured by a number of employees, and is not reflective of labour inflation.
550 Exhibit 195.01, AUC-NERA-3(d).
551 Exhibit 195.01, AUC-NERA-3(b).
552 Exhibit 103.05, Cicchetti evidence, page 20.
553 Exhibit 631, ATCO Electric argument, paragraph 102 and Exhibit 632, ATCO Gas argument, paragraph 112.

458. The UCA argued that the same reasoning applies to the exclusion from indexing of a portion of capital expenditures. Because NERA's TFP estimate was based on the entirety of the distribution companies' inputs (i.e., capital, labour and materials), the UCA argued that the exclusion of some or all capital from the I-X mechanism would require an adjustment to NERA's TFP and the resulting X factor.[554] At the same time, the UCA observed that the issue of what the relevant X factor should be in this case was not addressed in this proceeding, and a separate process was required:

> However, if the Commission determines that there is need for a capital adjustment outside of the I-X mechanism, then a separate proceeding is definitely required. The proceeding would have to examine the appropriate X factor having regard to the exclusion of a material portion of capital from the I-X mechanism. This alternative creates additional regulatory burden. It would create uncertainty for the Applicants and the ratepayers. The UCA does not recommend this alternative.[555]

459. PEG observed that to the extent that the capital expenditures excluded from indexing are sizable and involve the "normal kinds of [capital expenditures] undertaken by the sampled utilities," it may be necessary to raise the TFP estimate.[556] To support its view, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP growth to increase from 1.32 per cent to 1.53 per cent.[557]

460. In response, the ATCO companies submitted that based on the structure of their PBR plans, there is no need to adjust the TFP (and the resulting X factor). Specifically, the ATCO companies noted that while some capital expenditures were included as flow-through factors under the companies' respective plans, the vast majority (approximately 85 per cent for ATCO Electric and 95 per cent for ATCO Gas) of their revenues were covered under the I-X portion of the plan. As such, the ATCO companies argued that their PBR plans were comprehensive, and thus no adjustment to the X factor was required.[558]

461. Similarly, AltaGas indicated that under the revenue-per-customer cap proposed by the company, the impact of capital expenditures removed from the I-X mechanism and included in the proposed flow-through factor represented only around five per cent of the company's total revenue requirement. AltaGas argued that given the relative size, scope and the effective isolation of the projects included in the flow-through factor from other elements of the company's plan, there was no reason to adjust the X factor for the exclusion of some part of capital.[559]

Commission findings

462. The Commission agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism. However, for the reasons explained below, the Commission has not made any adjustment to

554 Exhibit 634.02, UCA argument, paragraph 204.
555 Exhibit 634.02, UCA argument, paragraph 205.
556 Exhibit 307.01, PEG evidence, page 60.
557 Exhibit 307.01, PEG evidence, page 29.
558 Exhibit 631, ATCO Electric argument, paragraph 103 and Exhibit 632, ATCO Gas argument, paragraph 113.
559 Exhibit 628, AltaGas argument, pages 31-32.

NERA's TFP estimate to account for capital that is excluded from the application of the I-X mechanism.

463. With respect to excluding all capital from the application of the I-X mechanism, the Commission explained in Section 2.3 that it did not accept EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs. As such, no consideration of the partial productivity factors of the type proposed by Dr. Cicchetti is required in determining the X factor for EPCOR's proposed PBR plan.

464. With respect to the exclusion of some capital, as further discussed in Section 7.3.2.4 of this decision, the Commission's preferred method of dealing with companies' concerns regarding unusual capital expenditures is through the use of capital trackers. The Commission acknowledges that, in theory, because the capital expenses subject to these trackers will be not be subject to the I-X mechanism, NERA's TFP number may need to be adjusted.

465. However, the Commission observes that the direction of any TFP adjustment to account for the exclusion of some of the capital is not clear, as demonstrated by the parties' conflicting evidence on this subject. Dr. Cicchetti's analysis showed that excluding capital from NERA's TFP estimate results in a more negative PFP trend, and therefore the X factor when capital is excluded from the application of the I-X mechanism should be lower than if capital were included.[560] In contrast, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP to rise. Accordingly, to the extent that the capital expenditures excluded from indexing are sizable, the CCA experts advocated a higher X factor.[561]

466. Additionally, the Commission indicated in Section 7.3.4 below that it is not approving any of the capital factors proposed by the companies as part of this decision. In Section 7.3.4, the Commission has invited the companies to file their capital proposals in their first capital tracker filing on or before November 2, 2012. In its submissions, the UCA was referring to the exclusion of a "material portion of capital" from the application of the I-X mechanism.[562] AltaGas and the ATCO companies argued that their proposed capital flow-through factors (which, in AltaGas' view were of a nature similar to NERA's definition of a capital tracker) would not have a large effect on the overall revenue requirement.[563]

467. In light of this conflicting evidence and the resulting uncertainty as to the materiality and the direction of any adjustment to account for the exclusion of some capital from the I-X mechanism, the Commission will not be making any adjustments to TFP during the PBR term to account for the fact that some capital may be excluded from the application of the I-X mechanism.

560 Exhibit 103.05, Cicchetti evidence, pages 22-24.
561 Exhibit 307.01, PEG evidence, pages 29 and 60.
562 Exhibit 634.02, UCA argument, paragraph 205.
563 Exhibit 628, AltaGas argument, page 32; Exhibit 631, ATCO Electric argument, paragraph 103; Exhibit 632, ATCO Gas argument, paragraph 113.

6.5 Stretch factor

6.5.1 Purpose of the stretch factor

468. Generally speaking, a stretch factor is an additional percentage applied to the X factor, thereby increasing the overall value for X and thus slowing the price or revenue cap growth determined by the I-X indexing mechanism.[564]

469. Parties to this proceeding differed in their interpretation as to the purpose of the stretch factor and based their recommendations accordingly. Nevertheless, most parties to this proceeding agreed that the rationale behind the stretch factor is to share with customers the benefits of the expected acceleration in productivity growth as the company transitions from a cost of service ratemaking system to performance-based regulation. Dr. Cicchetti explained the logic behind this reasoning as follows:

> In North America, an industry productivity trend that is estimated using historical data will overwhelmingly reflect the productivity experience of an industry that has been regulated using cost of service methods. [...] A principal rationale for PBR is to create stronger performance incentives compared with cost of service regulation. This, in turn, implies that when utilities become subject to PBR, it is expected that they will achieve incremental productivity gains compared to what has been observed under traditional cost of service regulation. The productivity "stretch factor" reflects the expectation that productivity growth will increase, at least temporarily, under incentive regulation and adding this "stretch" goal to an estimate of the historical productivity trend embodies an estimate of these expected, incremental productivity gains in the approved X-factor.[565]

470. Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:

> DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> Q. So it's good for that period of time when you move from cost of service into incentive-based regulation? Is that fair?
> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so-called low-hanging fruit argument, that the -- in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on.[566]

471. AltaGas,[567] NERA,[568] the UCA[569] and Calgary,[570] supported this rationale behind the stretch factor. Accordingly, these parties supported the inclusion of a stretch factor in the

564 Exhibit 98.02, Carpenter evidence, page 34; Exhibit 307.01, PEG evidence, page 16.
565 Exhibit 103.05, Cicchetti evidence, pages 27-28.
566 Transcript, Volume 9, page 1766, lines 4-22.
567 Exhibit 110.01, AltaGas application, paragraph 45 and Transcript, Volume 9, page 1689, lines 19-24.
568 Exhibit 195.01, AUC-NERA-12(a) and Transcript, Volume 1, page 116, lines 21-24.
569 Transcript, Volume 17, page 3287, lines 14-25.

companies' PBR plans. The parties' specific recommendations as to the size of the stretch factor are discussed in the following section of this decision.

472. In Ms. Frayer's view, which Fortis adopted, a stretch factor is a mechanism to adjust the company's revenue or rates each year to reflect firm-specific expected productivity gains vis-à-vis the gains expected for the industry as a whole. In other words, according to Ms. Frayer, a stretch factor "creates an incremental incentive for productivity, in order to "catch-up" with the rest of industry, in the case of a company that is underperforming."[571] In that regard, Fortis argued that because of its strong productivity performance in recent years (as demonstrated by the continued reduction in controllable operating costs per customer since 2004), there was no "low-hanging fruit" for the company to pick under PBR.[572]

473. The CCA and its expert, Dr. Lowry, indicated that both the operating efficiency of the company and the difference between the incentive power of the current regulation and the PBR plan should form part of the consideration as to whether to add a stretch factor.[573] Similarly, Dr. Carpenter expressed his view that both of these considerations are relevant in determining whether a stretch factor is required:

> If there is evidence to suggest that a particular utility is less efficient than the industry as a whole, and if the incentives for improving efficiency are likely to be much stronger in the future than they have been in the past, then it might be reasonable to expect that utility to be able to achieve more rapid productivity growth than the historical trend rate measured in a TFP study. A stretch factor may then be appropriate.[574]

474. However, the Dr. Lowry and Dr. Carpenter did not agree on whether a stretch factor should be assigned to Alberta companies. In Dr. Carpenter's view, it is not clear whether the PBR regime will create much stronger incentives for efficiency than the existing cost of service regime since the current regulation in Alberta contains "significant efficiency incentives because of the time between rate cases and the forward-looking test periods."[575] As such, the ATCO companies argued that a stretch factor should not be applied to their PBR plans.[576]

475. In contrast, Dr. Lowry and his colleagues at PEG argued that the current regulatory system in Alberta, under which the companies file rate cases every two years, has "weak performance incentives."[577] Accordingly, Dr. Lowry noted it is reasonable to expect that there will be some productivity acceleration in Alberta with the adoption of a PBR regime and, as a result, a stretch factor should be included in the companies' PBR plans.[578]

476. Finally, in discussing whether a stretch factor should be a part of the companies' PBR plans, parties to this proceeding pointed to an inter-relationship between a stretch factor and an ESM (earnings sharing mechanism). Specifically, all the companies contended that a stretch factor and an ESM were mutually exclusive and preferred to keep only the one alternative of

570 Exhibit 298.02, Calgary evidence, paragraph 133 and Transcript, Volume 15, page 2935, lines 18-25.
571 Exhibit 100.02, Frayer evidence, page 79.
572 Exhibit 633, Fortis argument, paragraphs 144-146.
573 Exhibit 636, CCA argument, paragraph 108 and Transcript, Volume 13, pages 2564-2565.
574 Exhibit 476.01, Carpenter rebuttal evidence, page 62.
575 Exhibit 476.01, Carpenter rebuttal evidence, page 58.
576 Exhibit 631, ATCO Electric argument, paragraph 108; Exhibit 632, ATCO Gas argument, paragraph 118.
577 Transcript, Volume 13, page 2564, lines 6-10 and Exhibit 307.01, PEG evidence, page 46.
578 Transcript, Volume 13, page 2564, lines 3-10 and Exhibit 636, CCA argument, paragraph 118.

their choice.[579] Accordingly, EPCOR and AltaGas argued that an ESM should not be a part of their plans, given that their PBR proposals contained a stretch factor.[580] Conversely, in the view of the ATCO companies and Fortis, the inclusion of an ESM in their PBR plans provided an additional justification for not imposing a stretch factor.[581]

477. On this issue, NERA commented that, although there may be some aspects of a trade off between an ESM and a stretch factor, it does not view an ESM and a stretch factor as mutually exclusive.[582] The CCA and the UCA experts shared this view as demonstrated by the fact that PEG's incentive power model and the X factor menu advocated by Dr. Cronin and Mr. Motluk included both an ESM and a stretch factor.[583]

478. Calgary also offered that there is no mutual exclusivity between an ESM and a stretch factor. In Calgary's view, a stretch factor is intended to deal with the attempt to capture the additional efficiencies resulting from the transition from the cost of service regime to PBR. In contrast, the ESM is intended to address the proper sharing of any efficiencies derived from operating under the I-X mechanism that are achieved during the PBR term.[584] Calgary noted that a number of PBR plans in North America have both of these elements, as shown in NERA's second report.[585]

Commission findings

479. The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

480. The ATCO companies and the CCA agreed that this reasoning forms part of the consideration when adding a stretch factor. As such, the Commission observes that this definition of stretch factor has been accepted by all parties to this proceeding, except Fortis.

481. In Fortis' view, a stretch factor should be added if a particular company were found to be less efficient than the industry as a whole. The ATCO companies and the CCA also noted that this rationale should be considered when determining the need for a stretch factor. However, as set out in Section 6.2 of this decision, the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies. Therefore, the Commission did not include the consideration of the companies' comparative levels of efficiency in its determination on the need for a stretch factor.

482. The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the

579 Exhibit 98.02, ATCO Electric application, paragraph 45; Exhibit 99.01, ATCO Electric application, paragraph 41; Exhibit 529, AltaGas corrections and amendments to application, page 4; Exhibit 100.02, Fortis application, paragraphs 83-84; Exhibit 103.02, EPCOR application, paragraphs 84-85.
580 Exhibit 103.02, EPCOR application, paragraphs 84-85; Exhibit 529, AltaGas corrections and amendments to application, page 4.
581 Exhibit 98.02, Carpenter evidence, page 35; Exhibit 100.02, Fortis application, paragraph 85.
582 Exhibit 195.01, AUC-NERA-12(d).
583 Transcript, Volume 13, page 2579, lines 17-21; Transcript, Volume 17, page 3188, lines 13-19.
584 Exhibit 629, Calgary argument, page 60.
585 Exhibit 391.02, NERA second report, Table 3, page 30.

"low hanging fruit") due to increased incentives.[586] In the Commission's view, two issues are salient when considering the need for a stretch factor. The first issue is whether NERA's TFP estimate, on which the X factors for the Alberta companies are based, provides a good estimate for the productivity growth under PBR. As Dr. Cicchetti explained, in the case that an industry TFP trend is estimated using historical data that predominantly reflect the productivity experience under cost of service regulation, such a TFP target may need to be "stretched" to account for higher incentives under PBR.[587] However, it is not clear the extent to which NERA's data include both cost of service and PBR forms of regulation,[588] and there was no evidence on the record of this proceeding upon which to make such an adjustment.

483. The second issue to consider is whether there is a potential for the Alberta companies to collect the "low-hanging fruit" when transitioning from the current cost of service regulation to a PBR framework. In that regard, the Commission does not share Dr. Carpenter's view that the efficiency incentives under the current cost of service price setting framework in Alberta and PBR are going to be largely the same.

484. On the same topic, Fortis and the ATCO companies also argued that there will be no "low-hanging fruit" to pick under PBR because of the companies' strong productivity performance in recent years.[589] However, as the CCA pointed out, it is possible that the companies are unable to appraise the productivity gains that are achievable under PBR.[590] Dr. Weisman addressed this matter in an academic article that he co-authored as follows:

> With very limited potential rewards but significant disallowance risks, the traditional regulatory model strongly encourages the prudent use of tried-and-true operating practices and technologies. It thus provides very limited incentives, if not explicit disincentives, to look beyond the status quo to discover and employ new, innovative operating practices and technologies. This is why the provision of enhanced incentives can stimulate a discovery process that enables regulated firms to become more efficient than they previously knew how to be.[591]

485. The Commission observes that having analysed its recent experience under PBR, ENMAX also pointed to a number of efficiency improvements and cost-minimising measures that were realized since the transition to a regulatory regime with stronger efficiency incentives. Notably, ENMAX indicated that the company would not have undertaken these productivity initiatives under a traditional cost of service regulatory framework.[592]

486. Finally, the Commission notes that the companies characterized the inclusion of a stretch factor (or a lack thereof) as an alternative to an ESM. In this regard, the Commission agrees with NERA and the interveners that although there is some trade-off between an ESM and a stretch

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586 Transcript, Volume 9, page 1766, lines 4-22.
587 Exhibit 103.05, Cicchetti evidence, pages 27-28.
588 Exhibit 299.02, Cronin and Motluk UCA evidence, page 79, footnote "c".
589 Exhibit 633, Fortis argument, paragraphs 144-146; Exhibit 631, ATCO Electric argument, paragraph 271; Exhibit 632, ATCO Gas argument, paragraph 296.
590 Exhibit 645, CCA reply argument, paragraph 47.
591 Exhibit 500.02, Weisman, Dennis L., and Pfeifenberger, Johannes P., *Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates*, The Electricity Journal, January-February 2003, page 60.
592 Exhibit 297.01, ENMAX evidence, pages 16-18.

factor, they are not mutually exclusive.[593] This is demonstrated by the fact that a number of PBR plans in North America have both of these components.[594] Nevertheless, as set out in Section 10 of this decision, the Commission determined that an ESM should not be part of the companies' PBR plans. Accordingly, the inclusion of an ESM in the PBR plans of the companies cannot provide an additional justification for not imposing a stretch factor.

487. In light of the above considerations, the Commission agrees with EPCOR, AltaGas and the interveners that a stretch factor should be a part of the PBR plans for the Alberta companies.

6.5.2 Size of the stretch factor

488. Parties acknowledged that unlike TFP estimates, stretch factors are commonly set based upon regulatory judgment and evidence from other jurisdictions rather than on a theoretical basis.[595] However, in the parties' view, this judgement has to be informed by the empirical evidence to accord with best regulatory practices.[596]

489. In this respect, Dr. Cicchetti found informative the average level of the stretch factor assigned to electric distributors in Ontario. The Ontario Energy Board, in its third generation incentive regulation plan, set the stretch factors at 0.2 per cent, 0.4 per cent and 0.6 per cent for the most efficient, the average efficient and the least efficient distributors, respectively. The average of the stretch factors imposed by the Ontario Energy Board is 0.4 per cent. Dr. Cicchetti noted that this was also the stretch factor approved by the Commission for ENMAX in Decision 2009-035.[597] Given Dr. Cicchetti's view that his recommended O&M PFP was of a "conservative nature," and in conjunction with not having an ESM, EPCOR's expert recommended that the company's PBR plan include a stretch factor of 0.2 per cent that lies at the mid-point between a stretch factor of zero (Dr. Cicchetti's preferred value), and the 0.4 per cent assigned to ENMAX.[598]

490. The UCA also relied on the Ontario Energy Board's determination on the stretch factor. The UCA indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[599]

491. AltaGas indicated that it is prepared to dispense with the ESM with the addition of a "modest stretch factor of between 0.1-0.2 per cent."[600] Dr. Schoech explained that this recommendation reflected his evaluation of how the X factor should change if an ESM is removed from the plan.[601]

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593 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 13, page 2579, lines 17-21 (Dr. Lowry); Transcript, Volume 17, page 3188, lines 13-19 (Dr. Cronin); Exhibit 629, Calgary argument, page 60.
594 Exhibit 391.02, NERA second report, Table 3, page 30.
595 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
596 Exhibit 103.05, Cicchetti evidence, page 28; Exhibit 634.02, UCA argument, paragraph 152; Transcript, Volume 13, page 2567, lines 1-10 (Dr. Lowry).
597 Decision 2009-035, paragraph 185.
598 Exhibit 103.05, Cicchetti evidence, pages 30-31.
599 Exhibit 634.02, UCA argument, paragraph 146.
600 Exhibit 529, AltaGas corrections and amendments to application, page 4.
601 Transcript, Volume 9, page 1689, lines 9-16.

492. PEG indicated that its research suggests that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent. In developing its stretch factor recommendations, PEG examined regulatory precedent and noted that the average explicit stretch factor approved for PBR plans of energy companies with rate escalation mechanisms informed by productivity research is about 0.50 per cent.[602] In addition, PEG developed an incentive power model that estimates the typical cost performance improvements that will be achieved by companies under stylized regulatory systems. Calibrating this model for the circumstances of Alberta companies produced a stretch factor value of 0.19 per cent.[603] Based on the results of PEG's research, the CCA recommended that all companies be assigned the 0.19 per cent stretch factor that resulted from PEG's incentive power model.[604]

493. Based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[605]

494. Similar to the discussion about the size of the X factor, parties commented on whether the presence and the magnitude of a stretch factor have any effect on the incentives of PBR plans. EPCOR, AltaGas and the ATCO companies submitted that the strength of the incentives under a PBR plan is not tied to the magnitude of the X factor (including the stretch).[606] NERA and the CCA supported this view.[607]

495. In contrast, Calgary argued that inasmuch as the companies are going to be incented to find capital and operating efficiencies under PBR relative to the cost of service regulation, a stretch factor "will play a key role as an additional driver to achieve those efficiencies."[608] In a similar vein, the UCA submitted that a stretch factor should incent a company to "obtain maximum efficiency improvements."[609]

496. Fortis' evidence on this matter was contradictory. On one hand, Fortis argued that "the level of X, regardless of whether that level includes some notion of stretch, does not determine if the incentive properties of PBR grow or diminish. Whatever X is, or more accurately the result of I-X is, the incentive to attain and better that result exists."[610] On the other hand, Fortis submitted that "the imposition of a stretch factor [...] by its nature and effect could only increase the perceived incentive to cut costs in any available manner."[611]

602 Exhibit 307.01, PEG evidence, page 45.
603 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
604 Exhibit 636, CCA argument, paragraph 106.
605 Exhibit 629, Calgary argument, page 33.
606 Exhibit 630.02, EPCOR argument, paragraph 86; Exhibit 628, AltaGas argument, page 34; Exhibit 631, ATCO Electric argument, paragraph 112; Exhibit 632, ATCO Gas argument, paragraph 122.
607 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.
608 Exhibit 641, Calgary reply argument, paragraph 132.
609 Exhibit 634.02, UCA argument, paragraph 157.
610 Exhibit 644, Fortis reply argument, paragraph 86.
611 Exhibit 633, Fortis argument, paragraph 157.

Commission findings

497. As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents.[612]

498. The UCA's experts recommended that the Commission assign stretch factors of between 0.2 and 0.6 per cent, similar to the Ontario Energy Board's determination in its third generation incentive regulation plans.[613] Dr. Cicchetti also found informative the average level of the stretch factor assigned to electric distributors in Ontario, and recommended a stretch factor of 0.2 per cent.[614] PEG proposed that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent.[615] A similar range of 0.13 to 0.5 per cent was advocated by Calgary.[616] AltaGas recommended a stretch factor of 0.1 to 0.2 per cent.[617]

499. Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. Accordingly, the Commission considers that a stretch factor for Alberta companies should be on the lower end of the 0.2 to 0.6 per cent ranges recommended by PEG and the UCA's experts. The Commission observes that the CCA expressed its preference for a stretch amount on the lower side of the 0.19-0.5 per cent range recommended by its experts, PEG.[618] The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable. This stretch factor should apply to the companies' plans for the duration of the PBR term.

500. Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs.[619] Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[620]

6.6 X factor proposals and the Commission determinations on the X factor

501. As discussed previously in this section, the X factor proposals in this proceeding reflected the parties' views as to the purpose of and approaches to determining the X factor, the relevant productivity estimates to use and the need for any adjustments, as well as considerations on the need for a stretch factor. Table 6-2 below shows that the parties' recommendations for an X factor are based on a variety of time periods and TFP indexes that the parties considered relevant.

612 Transcript, Volume 1, page 115, lines 6-19 (NERA). On this subject, see also Exhibit 103.05, Cicchetti evidence, page 28; Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
613 Exhibit 634.02, UCA argument, paragraph 146.
614 Exhibit 103.05, Cicchetti evidence, pages 30-32.
615 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
616 Exhibit 629, Calgary argument, page 33.
617 Exhibit 628, AltaGas argument, page 33.
618 Exhibit 636, CCA argument, paragraph 106.
619 Exhibit 628, AltaGas argument, page 34;
620 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.

Table 6-2 Summary of the X factor proposals

	ATCO Electric/ ATCO Gas[621]	EPCOR[622]	Fortis[623]	AltaGas[624]	CCA[625]
Starting point	-0.28 to -1.09	-1.0	-1.0	-1.0 to -1.7	1.32 for gas companies 1.08 to 1.23 for electric companies
Productivity research relied upon	NERA's TFP	PFP based on NERA's data	Statistics Canada MFP index and NERA TFP	Statistics Canada MFP index and NERA TFP	PEG's TFP for gas companies NERA's TFP for electric companies
Time period	1994-2009 and 1999-2009	1999-2009	2000-2009	2000-2009	1996-2009 (PEG data) 1989-2007 (NERA data)
Adjustment for the U.S.-Canada productivity gap	-1.31 to -1.73	--	--	--	--
Stretch factor[626]	No	0.2	No	0.1 to 0.2	0.19
Proposed X factor (in per cent)	**-2.0**	**-1.0**	**-1.0**	**-1.3**	**1.08 to 1.32**

Note: Numbers do not add up due to a number of assumptions and qualifications that parties incorporated in their X factor proposals (for example, choice of a mid-point value for a range of X, application of a stretch factor only if an ESM was excluded from the plan, etc.).

502. Calgary recommended an X factor in the range of 1.0 to 1.7 per cent based on the results of NERA's and PEG's productivity studies.[627] As well, based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[628]

503. IPCAA did not make a specific recommendation on the X factor except to mention that a negative X factor unduly increases the risk of the companies over-earning.[629]

504. The UCA's experts, Dr. Cronin and Mr. Motluk, recommended using the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[630] As set out in Section 6.2, the Commission did not accept the UCA's menu approach. The UCA also indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the

621 Exhibit 98.02, Carpenter evidence, page 32, Table 3.
622 Exhibit 103.05 Cicchetti evidence, page 16.
623 Exhibit 100.02, Frayer evidence, pages 78-79.
624 Exhibit 110.01, Christensen Associates evidence, pages 13-15.
625 Exhibit 636, CCA argument, paragraphs 60-62.
626 Exhibit 631, ATCO Electric argument, paragraph 106; Exhibit 632, ATCO Gas argument, paragraph 116; Exhibit 630.02, EPCOR argument, paragraph 81; Exhibit 633, Fortis argument, paragraph 142; Exhibit 628, AltaGas argument, page 33; Exhibit 636, CCA argument, paragraph 106.
627 Exhibit 629, Calgary argument, page 24.
628 Exhibit 629, Calgary argument, page 33.
629 Exhibit 635, IPCAA argument, pages 2-3 and Exhibit 642, IPCAA reply argument, paragraphs 5-6.
630 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.

companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[631]

Commission findings

505. As noted earlier in this section, the parties' X factor proposals were based on a variety of productivity indexes, approaches, and sample periods that they considered to be the most relevant in determining the X factor.

506. There was some discussion about whether the X factor to be used in a PBR plan necessarily has to be positive. The companies contended that there is nothing inherently wrong with a negative X factor. All companies proposed negative X factors in their respective PBR applications. Calgary did not agree with this conclusion and argued that a negative X factor does not provide the proper incentives to reduce costs.[632] IPCAA observed that a lower X factor would lead to a higher risk of company over-earning.[633]

507. On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive. As NERA's and EPCOR's experts explained during the hearing, a negative TFP (and the resulting X factor) just means that a particular industry grows more slowly in its productivity than the economy as a whole or that input costs are growing faster in the industry than in the economy.[634] Because the economy-wide productivity represents the average productivity of different industries comprising the national economy, some of the industries must be below average and some above. For instance, Dr. Makholm and Dr. Schoech pointed to the construction industry as an example of a sector with slower productivity growth.[635]

508. In Section 6.2 of this decision, the Commission reiterated its preference for an approach to setting the X factor based on the long-term rate of productivity growth in the industry. The Commission dismissed the alternative approaches to determining the X factor, such as the building blocks approach proposed by Fortis and the efficiency benchmarking and menu approaches proposed by the UCA.

509. In Section 6.3 of this decision, the Commission examined multiple aspects of the parties' TFP recommendations and determined that the results of NERA's TFP study represent a reasonable starting point for establishing a productivity estimate for Alberta electric and gas distribution companies. Based on the results of NERA's study, the Commission determined that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric and gas distribution companies. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor, some of which would have resulted in a negative X factor.

510. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment to TFP if an output-based measure is used for the I factor.[636] However, the Commission explained in Section 6.4.1 above that because

631 Exhibit 634.02, UCA argument, paragraph 146.
632 Exhibit 629, Calgary argument, page 30.
633 Exhibit 304.01, IPCAA evidence, page 2.
634 Transcript, Volume 3, page 487, lines 20-22 and Volume 11, page 1987, line 17 to page 1988, line 11.
635 Transcript, Volume 3, page 488, lines 24-25, Volume 9, page 1678, lines 17-25.
636 Exhibit 461.02, AUC-NERA-17(a) and (b).

both components of the approved I factors can be considered input-based price indexes, no adjustment to TFP is required.

511. Additionally, Dr. Carpenter on behalf of the ATCO companies indicated that NERA's TFP analysis based on U.S. data needed to be adjusted for a productivity gap between the U.S. and Canadian economies.[637] Dr. Schoech on behalf of AltaGas also noted that this productivity gap warrants consideration.[638] As well, Dr. Carpenter and Dr. Cicchetti urged the Commission to consider the possible adjustment for the productivity performance of the Alberta economy when setting the X factor for the companies.[639] The Commission has reviewed the issue of productivity gap in Section 6.4.2 of this decision and determined that no adjustment to NERA's TFP is necessary to account for the differences in the economy-wide productivity growth between the U.S. and Canada, or Canada and Alberta.

512. The Commission has considered IPCAA's suggestion that a stretch factor be used to adjust for 2012 rates for historical over-earning. Give the approach the Commission has taken to the requested adjustments to going-in rates requested by the companies (see Section 3.4), the Commission will not make an adjustment to the stretch factor for that purpose. In Section 3.4, the Commission rejected adjustments to going-in rates to reflect selected actual results on 2012 because those adjustments could not be made without concurrently reviewing all actual results for 2012. The Commission will not assume what the results of such a review might be and seek to capture assumed 2012 productivity gains through an increased stretch factor.

513. Parties also discussed the effect on X of excluding all or part of capital from the I-X mechanism, as set out in Section 6.4.3. In that regard, because the Commission did not accept EPCOR's proposal to exclude capital from its PBR plan, no consideration of the partial productivity factors, of the type proposed by Dr. Cicchetti, is required in determining the X factor for the companies. With respect to the exclusion of only some capital, the Commission determined that no adjustments to TFP will be made during the PBR term to account for the possible exclusion of some capital from the I-X mechanism.

514. Based on the above, the Commission finds that no adjustments to the industry TFP growth rate are required when establishing the X factors for the companies. Accordingly, the Commission finds that the X factor to be used in the PBR plans of the electric and gas distribution companies prior to consideration of a stretch factor is 0.96 per cent.

515. Furthermore, as set out in Section 6.5 of this decision, the Commission determined that a stretch factor of 0.2 per cent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the Commission finds that the total X factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 per cent.

637 Transcript, Volume 4, pages 595-596.
638 Transcript, Volume 8, page 1414, lines 9-25.
639 Exhibit 98.02, Carpenter evidence, pages 33-34; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

7 Adjustment to rates outside of the I-X mechanism

7.1 Introduction

516. The Commission recognizes the need to make provision for recovery of a limited number of costs outside of the I-X mechanism. It is common for PBR plans to make special provision to reflect the cost impact of significant unforeseen events that are outside the ability of the regulated entity to control. Approved costs of this nature are recovered through a Z factor rate adjustment. In addition, the companies have proposed a capital factor for the recovery of certain specific capital project costs as well as Y factor rate adjustments to permit the flow through to customers of third party charges that are beyond the control of the companies, Commission directed costs, deferral accounts and certain other costs. This section will review each of the proposals to deal with costs outside of the I-X mechanism.

7.2 Z factors

517. A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

518. The Commission considered the criteria for when the impact of an exogenous event would qualify for a Z factor adjustment to rates in Decision 2009-035 and accepted the following proposal put forward by Dr. Cronin:[640]

> With respect to exogenous events, the Commission considered the evaluation criteria proposed by Dr. Cronin, and has determined that the following criteria for an exogenous adjustment should be adopted.
>
> 1) The impact must be attributable to some event outside management's control;
> 2) The impact of the event must be material. It must have a significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
> 3) The impact of the event should not have a significant influence on the inflation factor in the FBR formulas; and
> 4) All costs claimed as an exogenous adjustment must be prudently incurred.

519. Applying these criteria, if an exogenous event has an economy-wide impact, the cost of that impact will be reflected in and recovered through the I factor. Providing the company with additional revenues through a Z factor adjustment in circumstances where the event has economy-wide impacts would result in a double-counting of the impact of the exogenous event. The criteria adopted by the Commission in Decision 2009-035 also speak to the recovery of costs after they have been incurred and subsequently found by the Commission to have been prudently incurred.

520. All of the companies' proposed plans include Z factors and generally agreed with the continued use of the criteria established in Decision 2009-035.[641]

[640] Decision 2009-035, Section 9.3, paragraph 247, page 54.

521. NERA stated that generally PBR plans have Z factors to permit "[u]tilities to recover the costs of unforeseeable events with material impacts."[642] However, NERA also suggested that Z factors should be limited to exogenous factors that impact the entire industry "like a tax change, or a change in investment tax credit, or something else that would lift or lower the price that the industry would have to compete against if we were talking about a competitive business."[643] A Z factor should not be used to address the impact of an exogenous event which affected the company alone.[644]

522. All interveners accepted that Z factors are a necessary component of a PBR plan.[645] The primary concern of interveners was to limit the use of Z factors by having clearly defined criteria and appropriate materiality thresholds. The UCA suggested the continued use of the criteria from Decision 2009-035 because those criteria were working well in the ENMAX plan, and there is no evidence to the contrary.[646] Calgary proposed an alternative set of criteria that were substantially similar to the four criteria adopted in Decision 2009-035, and added a criterion requiring the company to promptly report the event when first discovered.[647]

Commission findings

523. The Commission considers it necessary to include a Z factor in the PBR plan to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan. The Commission continues to support the criteria established in Decision 2009-035 to determine if the impacts of an exogenous event qualify for Z factor treatment, with one clarification. The Commission considers that for the negative impact of an exogenous event to qualify for cost recovery, the extent of the impact must, by necessary implication, be unforeseen prior to the occurrence of the event. This criterion is necessary to distinguish the cost impacts of exogenous events that are not foreseeable from the cost impacts of other events that are beyond the company's control but are foreseeable and therefore may qualify for Y factor treatment as discussed in Section 7.4 below. In Decision 2009-035 the Commission also made a distinction between exogenous adjustments and flow-through items by stating:[648]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them.

[641] Exhibit 628.01, AltaGas argument, Section 9.1, page 47; Exhibit 630.02, EPCOR argument, Section 9.1, paragraph 159, page 59; Exhibit 631.02, ATCO Electric argument, Section 9.2, paragraph 205, page 54; Exhibit 632.01, ATCO Gas argument, Section 9.2, paragraph 214, page 70; Exhibit 100.02, Fortis application, Section 7, paragraph 118, page 34.

[642] Exhibit 391.02, NERA second report, Section IV-C-3, paragraph 71, page 35.

[643] Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.

[644] Transcript, Dr. Makholm, Volume 1, pages 179-180.

[645] Exhibit 634.02, UCA argument, Section 9.1, paragraph 209, page 38; Exhibit 636.02, CCA argument, Section 9.1, paragraph 145, page 59; Exhibit 942.01, IPCAA reply argument, Section 9.0, paragraph 12, page 2; Exhibit 629.01, Calgary argument, Section 9.1, page 42.

[646] Exhibit 634.02, UCA argument, Section 9.2, paragraph 214, page 38.

[647] Exhibit 629.01, Calgary argument, Section 9.2, page 43.

[648] Decision 2009-035, Section 9.3, paragraph 251, page 55.

524. Accordingly, the Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

(1) The impact must be attributable to some event outside management's control.
(2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.
(3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
(4) All costs claimed as an exogenous adjustment must be prudently incurred.
(5) The impact of the event was unforeseen.

525. The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment.

526. Inclusion of a Z factor based on clearly defined criteria is consistent with the Commission's PBR principles. The Commission observes that when an exogenous event occurs within a competitive industry that is not generally felt within the economy as a whole, the companies within the industry will generally adjust their prices in response to the event. A Z factor will permit the regulated distribution companies in Alberta to do the same. The Commission notes that Dr. Makholm agreed with this characterization.[649]

527. With respect to the opinion of Dr. Makholm that a Z factor should not be available to deal with the impacts of a company specific exogenous factor because it would not parallel competitive markets, the Commission notes that no such restriction was imposed in Decision 2009-035. Further, the Commission considers that allowing a company specific exogenous factor to potentially qualify for Z factor treatment is in keeping with the fourth Commission PBR principle which states that the design of PBR plans should recognize the unique circumstances of each regulated company. Also, allowing recovery of the costs of a company specific exogenous event is consistent with providing the company with a reasonable opportunity to recover its prudently incurred costs. Accordingly, the impact of company specific exogenous events will not be excluded from consideration for Z factor treatment.

528. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the company needs to recover and also reductions to costs that need to be refunded to customers. The Commission agrees with the CCA and considers it necessary to allow the Commission and interveners to apply for Z factor adjustments to rates where circumstances warrant.

7.2.1 Z factor materiality

529. Materiality may be considered on an event-by-event basis or cumulatively. Under the ENMAX FBR plan, materiality is evaluated on an event-by-event basis.[650] Most of the companies in this proceeding proposed that materiality be evaluated on a cumulative basis. That is, if the sum of the effects of a number of exogenous events in a year would have a material impact on the company, they should be considered as though they were one event for Z factor purposes.

[649] Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.
[650] Decision 2009-035, Section 9.3, paragraph 231, page 51.

530. The following table sets out the materiality thresholds of the Z factor as approved for ENMAX in Decision 2009-035 and as proposed by each of the companies in this proceeding:

Table 7-1 Summary of companies Z factor materiality proposals

	ENMAX[651]	AltaGas[652]	ATCO Electric[653]	ATCO Gas[654]	EPCOR[655]	Fortis[656]
Threshold	$1.0 million	Variable (approx. $0.2 million)[657]	$0.5 million	$0.5 million	$1.0 million distribution $0.5 million transmission	$0.5 million
Basis for determining the threshold	Size of revenue requirements	Annual impact on ROE ≥ +/- 25 basis points	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria[658]
Cumulative	No	Yes	Yes	Yes	Yes	No

531. Concerns were raised by interveners over having materiality thresholds set too low, particularly when materiality is measured on a cumulative basis, because it allows companies to qualify for Z factor adjustments on too frequent a basis. It was suggested by Calgary's witness, Mr. Matwichuk that AUC Rule 005[659] is not the appropriate source for finding the criteria to determine the materiality thresholds for Z factor adjustments, and if comparisons to PBR plans in other jurisdictions are made, a higher threshold would be used.[660] The UCA suggested that the materiality thresholds should be established by taking 0.25 per cent of net assets, which would result in significantly higher threshold levels.[661]

532. The CCA stated that it is appropriate to address the materiality of Z factors on an individual event basis in order to achieve consistency with the process established in Decision 2009-035.[662] Dr. Lowry submitted that having low materiality thresholds that could result in frequent Z factor applications is contrary to the spirit of PBR. Dr. Lowry stated the following at the oral hearing:

> I can tell you too that, you know, in some jurisdictions, including the Ontario Energy Board, they're not very encouraging to the utilities to come in even for Z factor proposals as violating the spirit of the PBR.[663]

Commission findings

533. Setting a Z factor threshold too low invites parties to submit applications on too frequent a basis, and undermines the regulatory efficiency that PBR seeks to achieve. Setting a Z factor

651 Decision 2009-035, Section 9.3, paragraph 248, page 54.
652 Exhibit 110.01, AltaGas application, Section 7.2, paragraph 84, page 26.
653 Exhibit 98.02, ATCO Electric application, Section 7, paragraph 206, page 7-1.
654 Exhibit 99.01, ATCO Gas application, Section 2.6, paragraph 112, page 40.
655 Exhibit 103.02, EPCOR application, Section 2.3.4.1, paragraphs 134-140.
656 Exhibit 219.02, AUC-ALLUTILITIES-FAI-19.
657 Transcript, Mr. Mantei, Volume 8, page 1487.
658 Transcript, Mr. Lorimer, Volume 12, page 2238.
659 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
660 Transcript, Mr. Matwichuk, Volume 15, page 2953.
661 Exhibit 634.02, UCA argument, Section 9.2, paragraph 217, page 39.
662 Exhibit 636.01, CCA argument, Section 9.3.1, paragraph 152, page 61.
663 Transcript, Dr. Lowry, Volume 14, page 2673.

threshold too high may limit a company's reasonable opportunity to recover prudently incurred costs, or conversely may prevent customers from realizing the benefit of a reduction in costs.

534. Exogenous events may occur during the PBR term but by definition they are exceptional occurrences which may either add costs to, or remove costs from, the provision of utility service. Additionally, not all events beyond the control of the company will qualify under other Z factor criteria, thereby further reducing the number of already rare events that could result in a rate adjustment outside of the I-X mechanism. Given the exceptional nature of a qualifying exogenous event and the equally exceptional measure of authorizing a recovery outside of the I-X mechanism, the Commission considers that the PBR principles require a relatively high threshold and that this threshold should apply to each event unless otherwise permitted in exceptional circumstances.

535. The Commission considers that the approach to establishing a materiality threshold based on the impact to ROE as proposed by AltaGas is reasonable. However, the Commission finds that the materiality threshold should be higher. In order to establish the threshold the Commission has calculated the impact on ROE that the dollar threshold established for ENMAX represented in 2006 (going-in rates). Accordingly, the Commission establishes the threshold as the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established (2012). This dollar amount threshold is to be escalated by I-X annually. The companies are directed to calculate and file the 2012 threshold amount along with supporting calculations in the compliance filing to this proceeding.

7.2.2 Process for considering a Z factor application

536. Having separate Z factor applications from the PBR annual filings may result in a need for more applications, and therefore may increase the administrative burden. However, if separate Z factor applications can be completed prior to the PBR annual filings, the annual filing process will not be complicated with potentially contentious Z factor items.

537. The companies generally agreed that addressing Z factors as part of the annual PBR rate adjustment filing process, rather than through a separate regulatory process, would be in the best interests of regulatory efficiency.[664] Fortis raised concerns that a Z factor application may require a protracted review, and as such, including Z factors as part of the annual PBR rate adjustment filing process may not be optimal.[665]

538. The UCA stated that "[t]o maximize regulatory efficiency, Z factor applications should be made at the same time as deferral and other PBR filings."[666] Calgary addressed the issue of how to process Z factor applications when it included a new criterion for Z factors that "the utility will be required to report promptly at the first discovery of an event and then apply for disposition of the accumulated savings or costs at the time of annual reporting."[667] In addition,

[664] Exhibit 632.01, ATCO Gas argument, Section 9.3, paragraph 219, page 71; Exhibit 631.01, ATCO Electric argument, Section 9.3, paragraph 210, page 55; Exhibit 630.02, EPCOR argument, Section 9.3, paragraph 168, page 63; Exhibit 628.01, AltaGas argument, Section 9.3, page 48.

[665] Exhibit 633.01, Fortis argument, Section 9.3, paragraph 180, page 83.

[666] Exhibit 634.02, UCA argument, Section 9.3, paragraph 220, page 40.

[667] Exhibit 629.01, Calgary argument, Section 9.2, page 43.

the CCA stated that "the utilities and stakeholders should both be eligible to file Z factor proposals."[668]

539. The Commission outlined the process for Z factor applications in Decision 2009-035.

> In order to ensure fairness to all stakeholders, EPC or other parties are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. The Commission also directs that the impact of any proposed exogenous adjustment be initially captured in a separate account pending a ruling from the Commission. The impact of any proposed adjustment is to be measured from the time the event occurred. The disposition of the account would follow the Commission's ruling on the proposed adjustment.[669]

Commission findings

540. The Commission finds that the process established in Decision 2009-035 is satisfactory. Accordingly, companies are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. Further, Z factor applications should be submitted as soon as possible after the costs associated with the exogenous event have been incurred or the savings have been realized.

541. A party may file a Z factor application at any time. However, in order to minimize the number of rate adjustments during the year, unless otherwise permitted, the Commission directs that Z factor rate adjustment applications be filed as part of the annual PBR rate adjustment filing. Please see Section 15.1.2 for a more detailed explanation of how the inclusion of Z factor amounts will be included in the annual PBR rate adjustment filing process.

542. In Decision 2009-035 the Commission recognized that some Z factors may result from changes in circumstances that carry forward into future periods.

> The Commission recognizes that, in some cases, a "Z" adjustment for an extraordinary event will be transitory and will not be subject to the I minus X adjustment. In other cases, the extraordinary event may require a "Z" adjustment that is subject to the I minus X adjustment going forward. The Commission will make this determination on a case by case basis.[670]

543. The Commission recognizes that some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

7.3 Capital factors

7.3.1 Need for a capital factor

544. All of the companies argued that they are experiencing some cost pressures on capital expenditures that will require special treatment under PBR. There was some agreement among NERA and the experts representing the companies and interveners that certain types of unusual

[668] Exhibit 636.01, CCA argument, Section 9.1, paragraph 145, page 59.
[669] Decision 2009-035, Section 9.3, paragraph 250, page 55.
[670] Decision 2009-035, Section 9.3, paragraph 249, page 54.

capital expenditures may require capital factors as part of a PBR plan to provide for sources of revenue in addition to the revenue generated by the I-X mechanism.

545. The companies offered several reasons why capital factors are required, including the costs being outside of the control of the company, the costs to build capital being significantly higher than historic norms, the need to build specific large projects, and high growth rates of the system. Another reason that was cited by several of the companies was a surge in replacement activities requiring an unusually high level of capital expenditures during the PBR term.[671] Because of the long term nature of utility assets, the cycles in which the companies purchase capital assets are much longer than the length of the PBR term. The evidence and testimony indicated that installation of large amounts of facilities during high growth periods in the past creates an echo effect when those facilities come to the end of their useful lives and must be replaced in current dollars with large replacement projects. Consequently, the companies submitted that if a utility is at a stage where it must invest more than the historical rate of capital asset growth or capital asset replacement assumed in the X factor, a special capital factor may be required.[672]

546. Experts representing the interveners acknowledged that under some circumstances special treatment of capital may be required, although most of the interveners took issue with the extent to which special capital treatment had been proposed.[673] There was concern expressed that double-counting may occur in circumstances where the companies should be able to recover the capital expenditures through the I-X mechanism, but are also provided with relief through a capital factor.[674] The double-counting may occur because the I-X mechanism already provides funding for capital projects and the addition of a capital factor outside of the formula would provide that funding again. The CCA also argued that companies have some flexibility in the timing of replacement expenditures without affecting safety or reliability, so utilities may have the ability to defer some replacement capital expenditures instead of seeking a capital factor adjustment.[675]

547. One of the concerns with approving capital factors is that the efficiency incentives created by a PBR plan may be reduced because the incentives to find efficiencies by substitution among various types of inputs (expenses and capital) may be lessened. In an exchange with Commission counsel, Dr. Makholm addressed how significant of a concern this is.

> Q. If the Commission was to accept company proposals that excluded significant capital components, does that mean that the X factor, if it was the same as your TFP estimate, would be wrong?
>
> A. DR. MAKHOLM: It wouldn't mean that the TFP growth number that we've calculated, that's then used for the X factor, would be wrong. It would call into question

671 Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 97, page 36; Exhibit 631.01, ATCO Electric argument, Section 8.3, paragraph 146, page 40; Exhibit 628.01, AltaGas argument, Section 5.4, page 32.

672 Exhibit 98.02, ATCO Electric application, Section 5, paragraph 46, page 5-1; Exhibit 99.01, ATCO Gas application, Section 2.4, paragraph 45, page 20; Exhibit 628.01, AltaGas argument, Section 8.2, pages 38 to 39; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 96, page 35

673 Exhibit 629.01, Calgary argument, Section 8.3, page 40, Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 49, Exhibit 634.02, UCA argument, Section 8.3, paragraph 182, page 33.

674 Transcript, Dr. Makholm, Volume 1, page 162.

675 Exhibit 636.01, CCA argument, Section 8.1, paragraph 118, page 46.

> the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.
>
> The theory upon which this kind of PBR formula is based doesn't apply to a kind of regime that would only target, for instance, O&M costs. So in that respect, the formula is wrong. The application of PBR in this context, drawing upon a competitive paradigm, is wrong; not the calculation of the TFP growth itself.[676]

548. The UCA agreed with NERA's opinion with respect to the impact on PBR incentives that results from the use of capital factors.

> The creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market. For the examples listed, the factors affecting the forecast are not beyond the utility's control, in fact the decision to proceed is entirely a utility management decision. Management must weigh the costs and benefits of all options, including the status quo, and decide on a course of action.[213] If there is flow-through treatment, the incentive to examine alternatives will be eliminated.[677]
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> [213] Exhibit 0300.02, Evidence of Russ Bell at A26.

Commission findings

549. The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan. The capital proposals of the companies were all quite different. Some companies asked for considerably more capital to be treated outside of the I-X mechanism than others.

550. The Commission shares the concerns raised by NERA and interveners that a capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting. At issue are the types and levels of capital expenditures that can reasonably be expected to be recovered through the I-X mechanism. The Commission finds that a mechanism that permits the recovery of specific types of capital outside of the I-X mechanism should be included in a PBR plan. In the sections of this decision that follow, the Commission addresses these issues by adopting a capital factor that, to the greatest extent possible, seeks to maintain the incentive properties of PBR and avoids double-counting.

7.3.2 Methodologies for addressing capital

551. A number of alternatives for a capital factor were explored during the proceeding. These included determining the average rate of capital growth in the TFP study and providing for

[676] Transcript, Volume 1, page 143.
[677] Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, pages 35-36.

capital in addition to that amount as required, modifying the X factor in consideration of a need for higher capital spending, excluding all capital from going-in rates and the I-X mechanism, and providing compensation for capital needs outside of the normal course of the company's operations by way of a capital tracker.

7.3.2.1 The average rate of capital growth in the TFP study

552. Dr. Carpenter approached the issue of identifying the amount of capital expenditures that the I-X mechanism can support by proposing that the capital factor be calibrated by comparing the capital requirements of the company to a benchmark level established by the median level of growth in plant observed in the utilities in the NERA TFP study.[678] Dr. Carpenter examined capital investment information about the companies in NERA's TFP study to estimate that the median level of annual growth in plant was 4.5 per cent over the relevant time period of the NERA TFP study that he used to determine the X factor he proposed.[679]

553. There were several issues identified with respect to the approach suggested by Dr. Carpenter.

554. Dr. Makholm commented on Dr. Carpenter's analysis as follows:

> Simple trends from past data series not having to do with our type of TFP growth study is what he is proposing as a way of creating -- I can't remember whether it was his Y or K factor, I'm not sure, one of those two. I think in our evidence and in responses to data request responses -- data requests, we drew a line between those types of things and the specific ring fenced engineering-based justified capital expenditures that consumed our 15 or 20 minutes before the break. For our purposes, at least for my purposes, using that kind of trend to project capital input over the course of a PBR plan is not very reliable. I wouldn't do it.[680]

555. NERA also stated:

> Under this logic additional adjustments would need to be made to account for the fact that the regulated firm's labor input and material input may be growing at different trend rates than the 72 utilities in the NERA sample. If, however, adjustments are made to each input to account for the differences between the trend rates of the regulated firm and the 72 utilities the result would be that regulated prices would be tied to actual productivity changes of the regulated firm rather than the industry's productivity. This means that the PBR incentive properties would be similar to the incentive properties under cost of service regulation. An important linchpin of performance based regulation and price cap regulation is that the X factor represents the productivity of the industry and not the productivity of the regulated company.[681]

556. NERA also calculated a different capital growth rate of 1.32 per cent for 1972 to 2009 based on the capital index used in its TFP study.[682] NERA stated "[w]e deal with capital quantity inputs measured in a very idiosyncratic way with one hoss shay techniques, and I think what you'll find in response to AUC NERA 15 that we're trying to dissuade anybody from taking the

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[678] Transcript, Dr. Carpenter, Volume 4, page 643.
[679] Transcript, Dr. Carpenter, Volume 4, page 643.
[680] Transcript, Dr. Makholm, Volume 1, page 155.
[681] Exhibit 195.01, AUC-NERA-8(a).
[682] Exhibit 195.01, AUC-NERA-8(b).

trends in capital quantity input we use to arrive at TFP growth analysis from being used to project new investments in whatever over the course of PBR planning."[683] Dr. Ros went on to explain:

> Can I just add productivity growth is the change in outputs and change in the three different inputs. So what Dr. Carpenter has observed is investment, net investment, which is not an input in the TFP study. And your question doesn't follow in the sense you're not mentioning anything about what's going on with output or other input at the same time. But in addition to that, it seems to be implying that in order for a TFP [PBR] plan to be effective you have to track exactly the type of changes that the utilities are likely to experience over the next five years, which does away with the incentive properties of performance-based ratemaking.[684]

557. Dr. Lowry also explained the impact that customer growth has on capital, and that customer growth for the Alberta utilities is more rapid than it is for the typical utility.[685] In theory, a company could be experiencing significantly higher capital growth than 4.5 per cent, but if the capital expenditures are required to add new customers and additional load to the system, there would be offsetting impacts to outputs in the calculation of TFP, and productivity growth would not necessarily be significantly impacted.[686]

558. ATCO Electric employed Dr. Carpenter's analysis to develop the ATCO K factor proposal. That proposal was based on a three plank approach. The first plank was intended to include the level of capital expenditures the I-X mechanism can support, which ATCO Electric determined to be 4.9 per cent annual growth.[687] The second plank was comprised of the remaining amount of capital growth in its current four year capital forecast, which was to be funded by the ATCO K factor. ATCO K factor programs were selected on the basis that they were stable and predictable and could be forecast for a four year period. The third plank was comprised of capital projects that do not occur on a routine basis and, therefore, could not be accurately forecasted. The end result of the three plank approach was that ATCO Electric prepared an overall capital forecast, and proposed a method by which that forecast could be recovered in the PBR plan. Mr. Freedman explained the ATCO Electric approach as follows:

> When we did our forecast of the rate base growth on its own, that showed us that we were closer to 10 percent. So when we were designing the planks, we were just looking at that. We tested the results and the outcomes of all of that afterwards, after we designed the planks to see it was in. What the results were going to give us with these planks was still in the area of reasonableness, and we showed those results in section 16 of the application.[688]

559. Mr. Freedman further explained in a discussion with Commission counsel how the determination of the 4.9 per cent that could be funded from application of the I-X mechanism was determined:

683 Transcript, Dr. Makholm, Volume 1, page 154.
684 Transcript, Dr. Ros, Volume 1, page 157.
685 Transcript, Dr. Lowry, Volume 13, page 2605.
686 Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 61.
687 Dr. Carpenter had calculated a 4.5 per cent median annual investment growth rate for the companies in the NERA TFP study. ATCO Electric chose 4.9 per cent for its first plank because of the types of capital projects it could identify.
688 Transcript, Mr. Freedman, Volume 7, page 1263.

> So when we looked at the capital maintenance programs and the programs that fell within that definition, we looked at the dollar impact of that. We looked at the results that were arising from that through -- and we would see that through -- in Section 16 of our application. And given that the 4.5 percent was part of a range and that was considered. We could have gone more aggressive but we didn't want to -- we didn't want to gray it up with putting some programs in that may be not quite as stable and predictable and readily factorable. So it could have been more aggressive to get it down to the 4 1/2 percent, but looking at the results that were being generated with the overall plan, ATCO Electric believed that it could put forward the programs as we've selected.
> Q. The 4.9 fell out of that analysis; is that right?
> A. MR. FREEDMAN: Correct.[689]

560. Under its approach ATCO Electric forecasted a total amount of revenue requirement first, and then developed rates (in this case using a PBR formula) to ensure that it is collecting the amount of revenue requirement needed to fund the forecasted amounts over the PBR term.

561. With particular reference to the ATCO Electric K factor, the UCA pointed out that the requirement for business cases for capital spending would have been subject to extensive review under cost of service regulation, and that the same level of testing would be required under PBR if the ATCO Electric K factor approach were used.[690]

Commission findings

562. The Commission finds that the evidence of capital investment growth of the companies included in NERA's total factor productivity study can not be used to determine the average amount of capital expenditures that could be recovered through the I-X mechanism because the Commission agrees with Dr. Makholm's, Dr. Ros' and Dr. Lowry's criticisms that such an approach does not account for the variability of capital investments and other inputs in relation to outputs from year to year. In addition, the Commission agrees with Dr. Makholm's observation that a simple trend analysis of average capital investment is an unreliable predictor of the amount of capital that can be funded through the I-X mechanism. Accordingly, the Commission rejects Dr. Carpenter's approach to determining the amount of capital growth that should be recovered through the I-X mechanism.

563. Because the ATCO Electric approach forecasts the total amount of capital revenue requirement over the PBR term to ensure that it is collecting the amount of revenue needed to fund its forecast capital expenditures, the Commission considers that the adoption of the ATCO Electric proposal would amount to retaining cost of service regulation for all capital but with a four year forecast. The Commission would not only be required to test the projects that comprise the ATCO Electric K factor, but it would also need to test the projects covered by the 4.9 per cent. If the projects that make up the 4.9 per cent were not tested, ATCO Electric could select which projects and types of capital expenditures should be included in the 4.9 per cent thereby avoiding scrutiny of possible double-counting of costs already in the K factor. If the Commission were to direct ATCO Electric to provide details for all capital projects including those captured by the 4.9 per cent, it would represent a return to cost of service regulation for all capital for a four year forecast term, reducing the efficiency incentives that PBR creates and failing to reduce the regulatory burden.

[689] Transcript, Mr. Freedman, Volume 4, pages 685-686.
[690] Exhibit 634.02, UCA argument, Section 8.2, paragraph 180, page 32.

7.3.2.2 Modifying the X factor to accommodate the need for higher capital spending

564. There was some discussion that that the X factor could be modified to provide sufficient revenues to cover a higher level of capital investment growth than provided for in the I-X mechanism.

565. In the view of Dr. Carpenter, when developing the X factor from a TFP study it is necessary to take into account the forecasted investment needs of the specific company for which the PBR plan is being designed.[691] As such, Dr. Carpenter appeared to suggest that a smaller X factor was required for the companies that expect a higher than usual level of capital expenditures during the PBR term. At the same time, Dr. Carpenter explained that he did not recommend this adjustment, since the ATCO companies proposed to deal with higher than usual capital expenditures by means of their K factor:

> DR. CARPENTER: ...And I think we also would have to take into account whether or not unusually high [capital expenditures] growth requirements over the plan term would require an X adjustment. Now, in ATCO's case X is not being adjusted for [capital expenditures]. Instead in ATCO Electric's case a K factor has been employed to deal with that issue.
> Q. And in the absence of the K factor you would be recommending an adjustment to the X in addition to the productivity gap?
> A. DR. CARPENTER: One may have to, yes.[692]

566. Fortis and AltaGas stated that if the Commission were to decide not to include capital flow-through factors in the PBR formula, it would be necessary to adjust the X factor to allow the financing of these capital projects under the I-X mechanism.[693] The CCA stated that it would be open to experimentation with such an approach because it has been used in PBR plan designs in other jurisdictions.[694]

567. At the same time, AltaGas acknowledged that this approach would be a “British-style building blocks” approach to developing the X factor, and would unnecessarily complicate the derivation of the formula.[695] Similar to the ATCO Companies, EPCOR, Fortis and AltaGas preferred to deal with unusual capital expenditures by way of flow-through factors, and not by adjusting the X factor.[696]

568. NERA explained that under this approach, the X factor is calculated as the value that would set the customer rates at a level to recover the company’s cost of service revenue requirement over a forecast period.[697] In Dr. Makholm’s view, forecasts that extend as far into the future as the length of a PBR term become vague, and undermine the effectiveness of a PBR plan.[698] Dr. Makholm concluded:

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[691] Exhibit 476.01, Carpenter rebuttal evidence, page 10.
[692] Transcript, Volume 3, page 592, lines 4-13.
[693] Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 138.
[694] Exhibit 636.01, CCA argument, Section 8.4, paragraph 136, page 55
[695] Exhibit 628, AltaGas argument, page 32 and Exhibit 247.01, AUC-ALLUTILITIES-AUI-7(a).
[696] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(b); Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 139.
[697] Exhibit 391.02, NERA second report, pages 27-28.
[698] Transcript, Volume 1, page 160 and Volume 3, page 502, lines 9-17.

> I think as I've -- as we have tried to distinguish between adjustments to X -- that is, Y factors or K factors -- cognizant of what goes on in Britain, where X is a true-up measure for long-term forecasts, it's our conclusion that it is better to leave X to do what X is designed in North America to do, which is to reflect total factor productivity growth and let other elements of ratemaking reflect unusual or special-case or needed capital expenditures.[699]

Commission findings

569. The companies acknowledged that any attempt to adjust the X factor for the investment needs of a specific company requires a detailed forecast of a company's capital expenditures and the associated revenue requirement, billing determinants, and even inflation over the PBR term.[700] As NERA and AltaGas pointed out, this approach essentially amounts to adopting the building blocks method employed by the regulators in the U.K.[701]

570. In Section 6.2 above, the Commission rejected the use of a building blocks approach and restated its preference for an approach to setting the X factor based on the long term average rate of productivity growth in the industry. Accordingly, the Commission finds that the X factor should not include any adjustments to deal with company-specific forecast capital expenditures.

7.3.2.3 Exclude all capital from going-in rates and the I-X mechanism

571. Due to the complexities of establishing what capital spending should be included and excluded from the I-X mechanism, EPCOR recommended that, in its case, all capital should be excluded from going-in rates and consequently not be subject to the I-X mechanism. Such an approach essentially splits the revenue requirement of the company so that capital is dealt with in a traditional cost of service manner, and the remainder of the revenue requirement is subject to the I-X mechanism and other PBR formula variables. The K factor proposed by EPCOR encompasses all capital.

572. EPCOR was unique amongst the companies in its proposal to exclude all capital from the I-X mechanism. The other companies proposed a limited number of capital factors that were more targeted at specific types of projects. EPCOR argued that it is faced with unique circumstances in that it must replace a more significant portion of its system during the PBR term.[702] While EPCOR considered the options of including all capital within the I-X mechanism and using capital trackers for special circumstances, EPCOR concluded that the regulatory burden would be significantly reduced if it excluded all of its capital from the I-X mechanism because there are too many projects that have complex interrelationships requiring capital tracker treatment.[703]

573. NERA expressed the view that the negative impact on incentives that excluding a significant portion of capital has is significant enough to bring into question whether PBR should

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[699] Transcript, Volume 1, page 119, lines 9-17.
[700] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(a), Exhibit 201.01, AUC-ALLUTILITIES-AE-7(a), Exhibit 633, Fortis argument, paragraph 78.
[701] Exhibit 247.01 AUC-ALLUTILITIES-AUI-7(a).
[702] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraphs 105-107, pages 39-41.
[703] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.

be allowed to proceed. Several interveners supported the opinion of NERA.[704] Dr. Makholm addressed the issue saying:

> It would call into question the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.[705]

Commission findings

574. The Commission has previously considered the EPCOR approach for the complete exclusion of capital from its PBR plan, and rejected this approach for the reasons set out in Section 2.3. The Commission is concerned that excluding all capital or a large portion of the company's capital expenditures from going-in rates and the I-X mechanism would significantly dampen the efficiency incentives of a PBR plan.

7.3.2.4 Capital trackers

575. In its second report and in response to the capital factor proposals made by the companies, NERA referred the Commission to the growing use by some U.S. regulators of capital trackers that allow a regulated firm to track and begin to recover the costs associated with certain capital projects more quickly and more efficiently than in a normal rate case.[706] NERA indicated that capital trackers are "used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure."[707] NERA indicated that capital trackers could be used in conjunction with a PBR plan to deal with certain special capital requirements. NERA described the purpose and use of capital trackers as follows:

> Capital trackers are used to recover the costs of a classified, pre-approved set of infrastructure investments. The tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are recovered in the company's next rate case proceeding. A "qualified investment" is an investment that meets the pre-set conditions for inclusion in the asset tracker. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. Qualified investments are specific, non-routine investments recovered outside of the normal rate case proceeding.[708]

576. NERA favoured an approach that did not rely on calculating the dollar amount of capital that could or could not be accommodated by the I-X mechanism. Rather, it focused on the nature of the projects and whether those projects are consistent with the past practices of the company. NERA said that unusual projects may need special capital treatment, but "because everybody's rates are based on their own books and records in base rates, and if the company has been doing

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704 Exhibit 629.01, Calgary argument, Section 8.6, page 41; Exhibit 636.01, CCA argument, Section 8.6, paragraph 138, page 56; Exhibit 634.02, UCA argument, Section 8.2, paragraph 175, page 31.
705 Transcript, Dr. Makholm, Volume 1, page 143.
706 Exhibit 391.02, NERA second report, Section 4, paragraphs 86-91, pages 41-43.
707 Exhibit 391.02, NERA second report, Section 4, paragraph 88, page 42.
708 Exhibit 391.02, NERA second report, Section 4, paragraph 90, page 43.

whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense."[709]

577. NERA described the capital tracker mechanism by stating that "the basic idea of a capital tracker is to recover the costs of qualified infrastructure investments incurred between rate cases through an asset tracker."[710] This means that once a capital project has been identified as a capital tracker the costs associated with the project are tracked and a cost of service revenue requirement calculation is performed for the project to determine the amount of revenue the company requires. That revenue requirement is collected by the company through rate adjustments outside of the I-X mechanism.

578. When asked why a capital tracker is any better than any other exclusion of capital from the I-X mechanism, and in particular a PBR plan which excludes capital entirely, Dr. Makholm stated:

> That's a fair question. Capital trackers are there because there's not an administrative and practical way in the commission's judgment to deal with certain kinds of aged infrastructure any other way than to have a rate base case. That issue of capital affects PBR jurisdictions as much as it affects any other jurisdiction.
>
> The difference between that kind of targeted engineering-based approach to particular kinds of aged infrastructure or lumpy prospective capital and the proposals from one of the utilities to do an O&M only rate cap plan I think are large and manifest.
>
> One takes a piece of prospective capital expense and subjects it to the microscope of justification and engineering so that the public is well served through the efficient replacement of infrastructure that the public needs. That is specific and targeted.
>
> The other type, which is apply PBR only to O&M, is neither specific nor targeted, it's general. And for practical purposes, I think observers can distinguish between those two kinds of methods of regulation.[711]

579. NERA stated that one of the main benefits of the capital tracker approach is that, by limiting the trackers to a few very specific items it maintains the incentive properties of PBR for most of the plan, while still recognizing that some relief may be required for companies to handle lumpy investments.[712]

580. The capital tracker approach was supported by several other parties.[713] In addition, most of the parties agreed that a capital tracker approach is reasonable for inclusion in a PBR plan. Even EPCOR, which discarded capital trackers as a viable option for its own plan, acknowledged that the incentive properties of capital trackers are superior to the exclusion of all capital from the I-X mechanism it proposed.[714]

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[709] Transcript, Volume 1, page 162.
[710] Exhibit 391.02, NERA second report, Section 4, paragraph 89, page 42.
[711] Transcript, Dr. Makholm, Volume 1, pages 146-147.
[712] Transcript, Dr. Makholm, Volume 1, pages 146-147.
[713] Transcript, Dr. Weisman, Volume 10, pages 1906-1907; Transcript, Mr. Camfield, Volume 8, page 1457; Transcript, Ms. Frayer, Volume 12, page 2395; Transcript, Dr. Lowry, Volume 13, page 2627; Transcript, Mr. Bell, Volume 18, pages 3274-3275.
[714] Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 106, page 33.

581. While agreeing with the underlying premise for a capital tracker, ATCO Electric expressed its concern about the inability to determine the amount of capital that can be funded outside of the I-X mechanism.[715] EPCOR raised a related concern when it argued that its analysis had shown that a capital tracker approach "proved unworkable due to the complex interrelationships between baseline capital and new capital and the lack of any credible basis upon which to separate the two in a well-defined, defensible manner."[716] EPCOR concluded that the issues around splitting capital costs were substantial enough to warrant excluding all capital from the I-X mechanism.

582. ATCO Electric stated that the capital tracker approach is an alternative it could work with.

> However, if ATCO Electric's approach is not acceptable to the Commission then a well defined tracker mechanism that encompasses ATCO Electric's programs currently included in ATCO Electric's K factor would be an alternative that ATCO Electric could work with.[717]

583. Some companies proposed to deal with some capital expenditures through capital Y factors on the basis that the level of expenditures was so significant that the I-X mechanism could not handle them. The ATCO Electric and ATCO Gas material-capital-unique-in-nature Y factors and the AltaGas AMR (automated meter reading) implementation Y factor are examples of this. There was some recognition by ATCO Gas,[718] ATCO Electric[719] and AltaGas,[720] that their proposed Y factor capital costs may not meet the typical criteria for assessing capital trackers or Y factors but they argued that the significance of the costs is so substantial that the projects can be justified on the basis of materiality alone given that there is an assumption that the projects are in the public interest.

584. The UCA recommended that these types of capital Y factors not be allowed on the basis that "[t]he creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market."[721] The CCA also expressed concern with the impact of these capital Y factors on the incentive properties of PBR, saying that "to the extent these costs are recovered as incurred, the de-linking of revenues from costs, being one of the foundations of any PBR plan, is weakened."[722]

585. Several companies requested capital Y factors for capital expenditures that are outside of the control of the company. Examples of this are the Fortis externally driven capital Y factor,[723] the ATCO Electric distribution contributions to transmission,[724] and the ATCO Gas transmission driven costs.[725] One of the arguments used to support the flow-through treatment of these particular capital costs was that utility companies have unique obligations to undertake such

715 Exhibit 631.01, ATCO Electric argument, Section 8.2, paragraph 125, page 35.
716 Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.
717 Exhibit 631.01, ATCO Electric argument, paragraph 163, page 49.
718 Exhibit 632.01, ATCO Gas argument, Section 8.3, paragraph 190, page 61.
719 Exhibit 211.01, NERA-AE-17.
720 Exhibit 247.01, AUC-ALLUTILITIES-AUI-10.
721 Exhibit 634.02, UCA argument, Section 8.3, paragraphs 193 and 196, page 35.
722 Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 167, page 69.
723 Exhibit 100.02, Fortis application, Section 6.2, paragraphs 103-105, pages 29-30.
724 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 104-112, pages 6-6 to 6-7.
725 Exhibit 99.01, ATCO Gas application, Section 2.5.2.2, paragraphs 93-102, pages 34-36.

projects that a competitive firm would not encounter. Fortis explained that "as a result of its obligation to serve, FortisAlberta does not have the discretion to decline or delay such expenditures, unlike competitive firms."[726]

Commission findings

586. The Commission has determined that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required. In the preceding sections the Commission has generally rejected the methodologies proposed by the companies for addressing this requirement. The Commission considers that the potential erosion of the incentive properties of PBR that arise from adopting the approaches to capital factors proposed by the companies are significant enough to warrant the use of the capital tracker approach to address special capital funding requirements. The Commission considers that the targeted criteria-based nature of a capital tracker limits the number of projects that are outside of the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible. Therefore, the Commission accepts that the use of capital trackers, as proposed by NERA and as recognized by several other parties as a viable option, is the best of the alternatives proposed for dealing with capital expenditures outside of the I-X mechanism. Accordingly, the Commission will include a capital tracker mechanism in the PBR plans.

587. A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be recovered through the I-X mechanism. The Commission concludes that a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.

588. Many of the proposals for capital factors in the form of K factors, the AltaGas MP factor, or Y factored capital expenditures are PBR plan variables that attempt to track the costs and corresponding revenue requirement of specific assets, and recover the revenue requirement outside of the I-X mechanism. Regardless of what a company originally called the capital factor variable, as long as the variable isolates the revenue requirement impact of the underlying qualifying assets (including depreciation, return on equity, cost of debt and income tax) to be incorporated into the PBR plan outside of the I-X mechanism, the factor is in the nature of a capital tracker and will be considered and tested as a capital tracker. The non-specific K factor proposed by EPCOR[727] is an obvious exception because it does not involve tracking specific capital assets. For consistency, all capital trackers will be recovered through a K factor variable in the PBR formula for all companies.

589. Dr. Makholm discussed the types of considerations the Commission should take into account in establishing the criteria for a capital tracker:

> Q Well, the incentive formula will produce a certain revenue stream and the incentives that result from the imposition of this regime will create savings through efficiencies through the company. So the effective revenue that a utility would have would be a mixture of the I minus X portion of the formula; it would be a function of growth in revenues, growth in customers, growth in revenues; a function of depreciation that has fallen off -- assets that are fully depreciated but yet the depreciation expense remains in rates. It would also be a function of all the efficiencies that can be achieved throughout

[726] Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 76, page 14.
[727] Exhibit 630.02, EPCOR argument, Section 8.1, paragraph 91, page 34.

the term. How does a regulator know when a ring fenced proposal for a tracker comes to them whether or not there's sufficient resources available through the operation of the PBR formula with all the incentives that are instilled through to it to cover the costs of that and how will they know when there isn't enough revenue to cover that?

A. DR. MAKHOLM: They'll know if the company can make good enough case that the derogation from a plan inherent in employing a tracker is genuine and worth the effort. And we have seen cases where that is the case, and one of them, a prime one, is cast iron pipe.

Q. We're all kind of dancing around the same question, but it's a very interesting discussion, so I'll try to advance it a bit further. So assume with me for a moment that a utility is able to put together the state of the art capital tracker application, ring fenced, engineering data to support it, and it has been doing that same type of activity for many years.

A. DR. MAKHOLM: Well, why then would they require a tracker if they've been doing that activity for many years? If they have been -- I don't mean to butt in, but if they have done, then that activity will be reflected in their base rates.

Q. And that's -- okay. So, in other words, it has to be something unusual, out of the normal course of the utility as opposed to what the industry group that formed the basis for the TFP study that carries on?

A. DR. MAKHOLM: Well, sure. Because everybody's rates are based on their own books and records in base rates, and if the company has been doing whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense. It's what isn't in base rates that's idiosyncratic and out of phase and deferred and lumpy that the formula wouldn't be able to cover, and that's the dividing line for derogating from a formula that's supposed to cover everything, is whether or not you decide by looking that there's a certain category of costs or a certain practical nature of any particular company's activities that lead it to conclude and convince the Commission that a straight-forward formula of the RPI minus X plus Z variety won't do.[728]

590. In an exchange with Calgary's counsel, Dr. Makholm clarified several qualifying criteria for capital trackers:[729]

Q. There was discussion yesterday with Mr. McNulty that these kinds of trackers would not – would not be or were not included in the base or the going-in rates; correct?
A. DR. MAKHOLM: Yes.
Q. And that they were idiosyncratic in nature. Yes?
A. DR. MAKHOLM: Yes.
Q. That, again referencing the between-rate-cases aspects, they were outside -- or were incurred outside of a rate case proceeding. Yes?
A. DR. MAKHOLM: Yes.
Q. They were incurred outside the ordinary course of business of the utility?
A. DR. MAKHOLM: Yes.

[728] Transcript, Volume 1, pages 160-163.
[729] Transcript, Volume 2, page 339.

Q. And they were incurred outside of or unrelated to past practices of the utility. Did I hear that right yesterday?
A. DR. MAKHOLM: Yes.
Q. Are there any others that I've missed?
A. DR. MAKHOLM: No, not that I can recall.

591. In addition to the criteria identified above, there was some discussion of other characteristics that should be exhibited by projects that qualify for special capital treatment. For projects to be considered atypical, NERA stated that the costs associated with the projects should be substantial.[730] NERA also suggested that any projects should be supported by an engineering analysis.[731] In addition, as stated by the CCA "investments to meet customer and load growth trigger revenue growth and are largely self-funding,"[732] therefore these projects should not be eligible for capital tracker treatment if they result in customer and load growth because the incremental costs should be funded by other features of the PBR formula.

592. Based on the foregoing, the Commission adopts the following criteria for capital trackers:

(1) The project must be outside of the normal course of the company's ongoing operations.
(2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
(3) The project must have a material effect on the company's finances.

593. The Commission considers that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project to receive consideration as a capital tracker. Accordingly, the Commission rejects the proposals to permit capital factors on the basis of materiality alone or on the basis that the project is externally driven alone, as was suggested by some of the companies proposing capital-related Y factors.

The project must be outside of the normal course of the company's ongoing operations

594. The first criterion is required to avoid double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. This criterion is also required to ensure that capital tracker projects are of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. Projects that do not carry this level of importance are likely subject to a reasonable level of management discretion, therefore allowing special treatment for this type of capital would eliminate the incentive for the company to examine all alternatives.[733] Therefore, this criterion would require that an engineering study be filed to justify the level of capital expenditures being proposed. That is, the company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels. The company will also be required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program.

730 Transcript, Dr. Makholm, Volume 1, page 171.
731 Transcript, Dr. Makholm, Volume 1, page 147.
732 Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
733 Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, page 36.

Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

595. The second criterion generally limits the scope of eligible capital projects to those required for replacement of aged infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth,[734] and also through contributions in aid of construction as prescribed by maximum investment level (MIL) policies.[735]

596. NERA stated that just because a capital expenditure is externally driven is not sufficient to justify a separate capital factor for it. Dr. Makholm identified the fact that even though it may be externally driven, the items may already be covered by the I-X mechanism if a similar level of costs is reflected in going-in rates.

> I would have to agree only on the condition that I've stated before, which is they're not reflected in the normal course of business reflected in the revenue requirement. They are specific and unusual enough to carve out and deal with separately. You have to appreciate our perspective, that for a distribution company everything is externally driven in one fashion or another. It's driven by the public services need for lights, and that the quantity of service that a utility provides isn't up to it; it's up to what the public requires, because all these distributors are set up to serve all-comers. So just saying externally driven doesn't do it for me. You would have to say externally driven, unusual enough not to be reflected in the cost of service as a going-forward exercise, and capable of being carved out as a limited feature so as not to disrupt unnecessarily the basic features of the PBR plan, which is to provide some regulatory lag and incentives.[736]

597. The UCA stated that externally driven capital expenditures do not meet the test of a capital tracker on the basis that the projects are not limited in nature, externally driven capital is included in going-in rates, the projects are not outside the ordinary course of utility business, and externally driven capital is related to the past practices of a utility.[737]

598. The CCA argued that supplemental capital expenditure funding may be required if it can be substantiated by solid evidence for investments "due to events beyond the utility's control such as highway relocations or the construction of a new transmission line."[738]

599. The Commission is aware that some of the capital costs for distribution utilities would otherwise not be required were it not for the activities of transmission or system operator entities or other external parties, and that the costs to the distribution utilities can be material and can vary significantly from year-to-year. Due to a company's obligation to provide service there is no opportunity for the company to turn down the project on the basis that company could not recover its costs because the project may not meet the capital tracker criteria, and therefore the company would be exposed to not receiving adequate compensation for undertaking the project.

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[734] Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
[735] Transcript, Volume 7, page 1310.
[736] Transcript, Dr. Makholm, Volume 2, page 330.
[737] Exhibit 634.02, UCA argument, Section 8.3, paragraph 199, page 36.
[738] Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 50

600. Fortis indicated that the expenditures included in its Y factor for externally driven capital arise in the normal course of business.[739] While the obligations to perform the work exist for the companies, the Commission considers that a company must demonstrate that such costs are significantly different than historical trends to qualify for capital tracker treatment, otherwise there is a likelihood for double-counting.

The project must have a material effect on the company's finances

601. The third criterion is required to limit the use of capital trackers. NERA stated that the costs associated with capital trackers should be substantial due to the regulatory burden associated with the administration of the tracker.[740] The Commission considers that a utility may be frequently undertaking a number of small projects that may have the appearance of being atypical. However, the fact that the utility is undertaking a certain level of atypical projects on a consistent basis may result in that level of small unique projects being considered to be in the normal course of operations. The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

7.3.3 Implementation of capital trackers

7.3.3.1 Isolation of capital trackers from other fixed assets

602. The inclusion of capital trackers in the PBR plan presents a potential for double-counting if capital costs that should be funded by the I-X mechanism are also funded by the revenue provided through a capital tracker. To avoid the possibility of double-counting some parties proposed a method whereby the revenue requirement associated with historical costs (depreciation, return on capital and taxes) are removed from the going-in rates, thereby eliminating any possible impact of dealing with the capital tracker-related expenditures outside of the I-X mechanism.

603. Some of the proposed PBR plans proposed to isolate historical capital costs associated with certain capital expenditures for the PBR term. Fortis proposed to isolate the historical AESO contributions from going-in rates, and then take the revenue requirement associated with all AESO contributions to calculate that portion of its externally driven capital expenditures Y factor.[741] Fortis stated that it is not able to isolate the historical costs for the other types of capital expenditures that comprise the externally driven capital expenditures Y factor, due to the level of detail available in its asset ledgers.[742] AltaGas proposed a different form of adjustment to its major projects factor with the same underlying purpose, to avoid double-counting. To achieve this AltaGas proposed a reduction to the annual major projects factor calculation to exclude the revenue requirement impact associated with similar capital expenditures made between December 31, 2009 and December 31, 2012.[743]

604. Because capital trackers typically represent a surge in capital spending that will be followed by a period of slower than average capital spending, and therefore the company's future revenue requirements should be less than they otherwise would have been in the absence of the

739 Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 73, page 14.
740 Transcript, Dr. Makholm, Volume 1, page 171.
741 Exhibit 100.02, Fortis application, Section 6.2, paragraph 105, page 30.
742 Exhibit 222.17, CCA-FAI-8(b).
743 Exhibit 110.01, AltaGas application, Section 6.0, paragraph 69, page 19.

capital tracker, there were some concerns raised over how long the projects should remain outside of the I-X mechanism. PEG suggested that if certain capital expenditures are excluded from the I-X mechanism in a PBR plan, then those capital expenditures should remain outside of the I-X mechanism in the next rate plan as well. PEG explained:

> The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue (requirement) growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (e.g. depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.[744]

605. Other parties generally objected to this suggestion by PEG because it creates unnecessary complexity in subsequent PBR plans. These parties recommended that, the capital expenditures associated with the capital tracker should be included with the rest of rate base in the rebasing process.[745]

Commission findings

606. The Commission considers that the reduction to the capital tracker to eliminate the impact of similar expenditures included in going-in rates as proposed in the AltaGas major projects factor may be a reasonable method for addressing the issue of double-counting. However, the merits of any such proposal would need to be assessed as part of the approval process for individual capital trackers.

607. The Commission does not find that a company should remove the impact of historical costs associated with expenditures similar in nature to approved capital trackers from going-in rates as proposed by Fortis for its AESO contributions. The Commission considers that it is necessary to maintain the incentive properties of PBR to the greatest extent possible by keeping the maximum amount of capital expenditures subject to the I-X mechanism.

608. The Commission accepts the arguments that the complexity of isolating certain capital expenditures in perpetuity beyond the PBR term outweighs the benefits suggested by PEG. Therefore, the Commission requires that the revenue requirement impact of the capital tracker expenditures be recorded outside of the I-X mechanism only during the course of the current PBR term.

7.3.3.2 Method for determining capital tracker amounts

609. Some parties have objected to the use of capital trackers on the basis that they result in too much regulatory burden.[746] On the other hand, capital trackers are a reasonable method for retaining the efficiency incentive properties of PBR as discussed in Section 7.3.2.4.

[744] Exhibit 307.01, PEG evidence, Section 2.2.6, page 24.

[745] Exhibit 631.01, ATCO Electric argument, Section 8.5, paragraphs 201-202, page 53; Exhibit 632.01, ATCO Gas argument, Section 8.5, paragraph 212, page 68; Exhibit 628.01, AltaGas argument, Section 8.5, page 43.

[746] Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 108, page 34; Exhibit 634.02, UCA argument, Section 8.4, paragraph 205, page 37.

Dr. Makholm stated that if a capital tracker is required to address the legitimate concerns of a company, the negative impact on administrative burden should not be a concern.[747] Given the criteria outlined for capital trackers in Section 7.3.2.4 it is clear that a relatively rigorous testing of capital trackers must occur.

610. Some of the companies have suggested that it would be administratively more efficient to not review the forecast for capital factors on an annual basis. The ATCO Electric K factor proposed to use forecasts at the outset of the PBR term that remain unchanged for the duration of the plan.[748] ATCO Electric and ATCO Gas suggested that not truing up the forecasts for capital factors introduces some superior incentive properties by allowing the companies to beat their approved forecasts.[749] The CCA supported the use of fixed forecasts on the basis that fixing the forecast would provide strong capital expenditure containment incentives. However, the CCA acknowledged that there would be an incentive for the companies to exaggerate their capital needs and therefore there would need to be a strong evidentiary record supporting the capital forecasts.[750]

611. Some of the companies suggested that their capital factors be reforecast periodically. Examples of this include the ATCO material-investments-unique-in-nature,[751] the Fortis externally-driven-capital Y factor,[752] and the AltaGas system reliability projects component of the major projects factor.[753] AltaGas also proposed a formulaic annual adjustment mechanism for the system safety projects component of its major projects factor.[754]

612. Another approach proposed to avoid the regulatory burden of reviewing forecasts is to only deal with capital trackers on a retrospective basis after the company has decided to proceed with the project and has made the capital expenditure. ATCO Gas proposed that this approach be used for its urban mains replacement (UMR) Y factor project.[755] Dr. Makholm suggested that a capital tracker should be based on items that are known and measurable rather than general forecasts to ensure that the tracker is specifically targeted.[756] Dr. Makholm suggested that if a tracker is limited to costs that are truly required to be recovered outside of the I-X mechanism, the efficiency incentives of a PBR formula will be lost.[757] Dr. Makholm explained one of the shortcomings of relying on capital forecasts is the incentive to overstate capital forecasts in saying:

> The other way is to find a formula that perhaps has incentives that are like the incentives in the UK that I described, that leave rise five years from now to the commission feeling that it's been hoodwinked with forecasts that haven't turned out to be what was actually spent. They may not have been hoodwinked, but how are you going to tell?[758]

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[747] Transcript, Dr. Makholm, Volume 3, page 506.
[748] Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 39, page 13.
[749] Transcript, Ms. Wilson, Volume 7, page 1280.
[750] Exhibit 636.01, CCA argument, Section 8.3.2, paragraph 127, page 52.
[751] Transcript, Ms. Wilson, Volume 4, page 759.
[752] Transcript, Mr. Delaney, Volume 11, pages 2152-2154.
[753] Exhibit 110.01, AltaGas application, Section 6.3, paragraph 78, page 22.
[754] Exhibit 110.01, AltaGas application, Section 6.2, paragraphs 75-76, pages 21-22.
[755] Exhibit 389.01, ATCO Gas application updates, Section 2.3, paragraph 12, page 7.
[756] Transcript, Dr. Makholm, Volume 1, page 175.
[757] Transcript, Dr. Makholm, Volume 1, page 168.
[758] Transcript, Dr. Makholm, Volume 3, page 506.

Commission findings

613. The Commission acknowledges that a reduction in the frequency of capital reviews would achieve a reduction in administrative burden. In addition, the Commission acknowledges that the use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs, as identified by the CCA, to be a major drawback to such an approach, and accordingly on that basis long term forecasts will not be used for capital trackers.

614. The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker. However, the Commission recognizes that parties and the Commission have very little experience with capital trackers and, therefore, will not require that this approach be used by the companies during the first PBR term.

615. Accordingly, unless a company chooses to undertake investment prior to applying for recovery of its costs by way of a capital tracker, the company will be expected to provide a forecast with its capital tracker application. The company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. As a result, these companies will still have some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred.

7.3.4 Commission findings on the capital factors proposed by the companies

616. The capital projects proposed by the companies for capital factor or capital Y factor treatment may or may not satisfy the criteria for a capital tracker established by the Commission in this decision. Neither the companies nor other parties have had the opportunity to evaluate whether these projects satisfy the Commission’s criteria. Accordingly, the Commission makes no finding as to whether any of the capital projects proposed by the companies satisfy the Commission’s criteria. The companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission’s capital tracker criteria

7.4 Y factor

617. In a PBR plan, Y factor costs are those costs that do not qualify for capital tracker treatment or Z factor treatment and that the Commission considers should be directly recovered from customers or refunded to them. Y factor costs in turn, could either be costs the company is required to pay to a third party (such as the AESO) or other Commission-approved costs incurred by the company for flow through to customers.

618. In Decision 2009-035 the Commission approved the flow-through of certain costs incurred by ENMAX along with the established collection of these costs outside the I-X mechanism. The Commission stated:[759]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them. The Commission approves the following three items for flow-through treatment.
>
> - SAS rates in the distribution tariff
> - TAC Deferral Account
> - AESO load settlement costs

619. In Decision 2010-146[760] (the ENMAX compliance filing decision), the Commission approved the addition of the Commission's own administrative fee as a flow-through cost. Although not considered material, the Commission found it to be similar in nature to other flow-through amounts approved by the Commission.[761]

620. As a result of these criteria, under the ENMAX FBR plan, a cost might qualify to be collected as a flow-through cost outside of the I-X mechanism if the amount was foreseeable and regularly incurred in the normal course of business but the quantum and requirement to pay the cost was outside of the control of management. In addition, the amounts approved by the Commission should be material.

621. In this proceeding, each of the companies proposed the treatment of several accounts outside of the I-X mechanism. The companies designated all of these costs as Y factors. The Y factor accounts proposed by the companies substantially exceeded the number of flow-through items approved in Decision 2009-035.

622. The proposed Y factor costs included existing flow-through accounts similar to those approved in the ENMAX decision, deferral accounts that had been approved under cost of service rate regulation, new deferral accounts and unusual capital expenditures. The companies argued that all of these costs should be recovered as Y factors because these costs are highly volatile, recurring or have previously been approved by the Commission for flow-through treatment. More importantly, all of these costs were considered by the companies to be outside the funding capacity of the I-X mechanism.

623. In its review of these companies' Y factor proposals, NERA commented that the inclusion of a comprehensive set of deferral accounts was unusual in PBR plans,[762] and that an

759 Decision 2009-035, Section 9.3, paragraph 251, page 55.
760 Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010
761 Decision 2010-146, Section 9.1.1, paragraph s 97-100, page 16.
762 Exhibit 391.02, NERA second report, Section IV-D-2, paragraph 83, page 40.

overly broad set of Y factor accounts reduces efficiency incentives under PBR.[763] Interveners generally agreed with NERA's observations.

624. The CCA noted "that some utilities (most notably AE and AG) propose excessive use of Y factors."[764] The UCA recommended "that the ENMAX type flow-through items, like system access charges, AESO load settlement costs, transmission costs from upstream pipelines, the UCA assessment, the AUC assessment should continue as flow-through"[765] but objected to the wide use of deferral accounts. The UCA submitted that the Commission should not approve a number of the proposed Y factor accounts, stating that the Commission has previously ruled that deferral accounts should be approved only when they are demonstrably necessary.[766] IPCAA generally supported the recommendations of the UCA with respect to Y factors.[767] Calgary suggested that the ATCO Gas PBR plan should "retain the integrity of PBR through the reliance on the (I – X) mechanism, to the greatest extent possible."[768]

625. All of the companies commented that changes to their risk profiles could occur if deferral accounts that exist under cost of service were not continued as Y factors under PBR.[769] IPCAA also identified this as a factor to be considered.[770] The companies also expressed a preference for the use of Y factors instead of Z factors because of the greater uncertainty associated with approval of Z factors.[771]

626. Several parties suggested that the exogenous adjustment criteria approved in Decision 2009-035 could also be used to evaluate the deferral accounts proposed as Y factors under PBR.[772] While parties acknowledged the suitability of utilizing a set of criteria for evaluating Y factors, there was some discrepancy regarding how to apply the criteria. Some companies argued that Y factors should be approved if some, but not necessarily all, of the Y factor criteria were met. The criterion suggested by some of the companies as not needing to apply in all circumstances is the "outside-of-management-control" criterion.[773] Some interveners disagreed with the companies, and argued that items that are within management's control should not be eligible for Y factor treatment.[774]

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[763] Exhibit 391.02, NERA second report, Section IV-E-7, paragraph 113, page 51.
[764] Exhibit 636.01, CCA argument, Section 10.1, paragraph 159, page 64.
[765] Exhibit 634.02, UCA argument, Section 10.1, paragraph 231, page 41.
[766] Exhibit 300.02, UCA evidence of Russ Bell, A20, page 23.
[767] Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
[768] Exhibit 629.01, Calgary argument, Section 10.1, page 46.
[769] Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 35, page 11; Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 28-29, page 8; Exhibit 473.02, EPCOR rebuttal evidence, A19, page 25; Exhibit 477.01, AltaGas rebuttal evidence, Section 7, paragraph 82, page 29; Exhibit 633.01, Fortis argument, Section 1.0, paragraph 36, page 9.
[770] Exhibit 369.01, AUC-IPCAA-4.
[771] Exhibit 633.01, Fortis argument, Section 10.5, paragraph 207, page 96; Exhibit 631.01, ATCO Electric argument, Section 10.4, paragraph 244, page 61; Exhibit 632.01, ATCO Gas argument, Section 10.5, paragraph 271, page 84; Transcript, Mr. Mantei, Volume 9, page 1550; Transcript, Mr. Gerke, Volume 11, page 1792.
[772] Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a); The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.
[773] Exhibit 211.01, NERA-AE-17; Exhibit 204.02, AUC-ALLUTILITIES-AG-11; Exhibit 248.02, AUC-ALLUTILITIES-AUI-10.
[774] Exhibit 629.01, Calgary argument, Section 10.2, page 47; Exhibit 634.02, UCA argument, Section 10.1, paragraph 230, page 41.

Commission findings

627. There was no dispute among the parties that certain third party costs similar to those approved in Decision 2009-035 should qualify to be flowed through to customers. As well, most parties supported the flow through of costs similar to the Commission's administration fee.

628. The Commission agrees that the criteria approved in Decision 2009-035 should apply be to Y factor costs in this decision. The Commission agrees with parties that the types of third party flow-through costs approved in Decision 2009-035 should also be approved on a flow-through basis in this proceeding.

629. For Y factor costs that are not third party flow-through costs, some parties suggested that the deferral account criteria set out by the EUB in Decision 2003-100[775] be used as the criteria for approval.[776] In Decision 2003-100 the EUB stated:[777]

> The Board does not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice has been to evaluate the use of a deferral account on a case-by-case basis, on its own merit. The Board notes that ATCO Pipelines and the interveners suggested several criteria for the Board to consider in this situation including:
>
> - Materiality of the forecast amount,
> - Uncertainty regarding the accuracy and ability to forecast the amount,
> - Whether or not the factors affecting the forecast are beyond the utility's control,
> - Whether or not the utility is typically at risk with respect to the forecast amount.
>
> The Board notes that the criteria were suggested to address differing views with respect to risk, rate fluctuations, intergenerational inequity, and the Board's historical approach to deferral accounts. The Board considers that the suggested criteria are reasonable…

630. The criteria in Decision 2003-100 are similar to the exogenous adjustment criteria approved by the Commission in Decision 2009-035.[778] In both decisions the lists included criteria related to materiality and the events being beyond management's control. There was recognition from several parties that the exogenous adjustment criteria from Decision 2009-035 could be used to evaluate the deferral accounts proposed as Y factors under PBR.[779]

631. The ability to recover costs outside of the I-X mechanism should be an extraordinary remedy for cost recovery. If however, the company has no ability to influence the amount of certain costs and those costs are material in nature and not otherwise recoverable under the I-X mechanism, incentives are unaffected. Accordingly, the Commission adopts and clarifies the criteria established in Decision 2009-035 for the identification of eligible Y factor costs as follows:

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775 Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application No. 1292783, December 2, 2003.
776 Exhibit 632.01, ATCO Gas argument, Section 10.2, paragraph 226, page 73; Exhibit 300.02, UCA evidence of Russ Bell, A20, page 22.
777 Decision 2003-100, Section 7.2.1, pages 115-116.
778 Decision 2009-035, Section 9.3, paragraph 247, page 54.
779 Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a). The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the PBR formulas.
4) The costs must be prudently incurred.
5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

632. The Commission considers that all criteria must ordinarily be satisfied before a cost will be considered for Y factor treatment. In addition to those Y factors that meet the above criteria, the Commission will allow companies to recover as Y factor rate adjustments specific costs incurred at the direction of the Commission and flow-through costs that are similar in nature to the flow-through items approved for ENMAX in Decision 2009-035. The Commission considers that having fewer Y factor accounts will make the PBR plans easier to administer. Y factors will only be approved in circumstances where there is a demonstrable need for them.

633. The Commission acknowledges the arguments made by some parties that denying certain Y factor accounts could impact the risk profiles of the companies. The Commission addresses consideration of the potential for risk impacts of PBR in Section 7.4.2.6.1 of this decision.

7.4.1 Materiality of Y factors

634. The UCA recommended the disallowance of several Y factor accounts on the basis that the amounts associated with the accounts are not material. The UCA suggested that "only if a proposed deferral account is to account for the potential of an error in forecasting that could produce a gain or loss of substantial magnitude, should the Commission then use the other criteria to determine if deferral treatment is warranted."[780]

635. While most parties acknowledged that assessing the materiality of Y factors is appropriate, EPCOR disagreed stating that:

> EDTI's proposed Y factor does not include a materiality threshold limit. Such a threshold limit is not required as the deferral accounts and reserve accounts included in EDTI's Y factor are related to costs that are material. These deferral and reserve accounts have already been approved by the Commission using materiality as one of the criteria for approval. Generic proceedings do not require a materiality threshold as, if the subject matter of the proceeding were not material, the Commission would not hold a generic proceeding in relation to it.[781]

Commission findings

636. Due to the high degree of similarity in the purpose and assessment of Y factors and Z factors, unless otherwise determined by the Commission, the Commission considers that the materiality threshold established in Section 7.2.1 for Z factors should also apply to Y factors.

[780] Exhibit 300.02, UCA evidence, A20, page 23.
[781] Exhibit 237.01, CCA-EDTI-5.

7.4.2 Specific proposed Y factors

637. The companies proposed a variety of different Y factor accounts in this proceeding, some of which existed, as flow-through accounts and deferral accounts, prior to the implementation of PBR and others which are new. Interveners raised many concerns over the proposed Y factor accounts. In general, the objections raised by interveners were raised on the basis that the proposed accounts did not meet certain eligibility criteria.

638. The UCA provided many recommendations with respect to specific Y factor accounts in its evidence. Specifically the UCA recommended the denial of the following Y factors accounts proposed by the companies:[782]

- Variable Pay Program
- Expansion of Defined Benefit Pension plan
- Changes in Weather Deferral Account
- Changes in Load Balancing Deferral Account
- Production Abandonment Costs
- Distribution to Transmission Contributions
- Vegetation Management
- Head Office Cost Allocation Percentages
- AUC Rule 026 Deferrals-IFRS
- Exchange Rate Deferral
- Design, Development and implementation of a Demand Side Management (DSM) Program.
- ATCO Centre Calgary Lease.

639. Calgary only commented on ATCO Gas' accounts, and had a more general approach of only recommending the continued use of two deferral accounts with the belief that all other accounts are not appropriate to be used under PBR. Calgary recommended that only transmission costs and income tax deductible capital costs should be allowed.[783]

640. IPCAA recommended "that only those deferral accounts considered in the recent GCOC proceeding should be approved in this proceeding, in order to maintain consistency between the Commission's findings in the GCOC decision and the risk profile of the utilities."[784] In addition, in reply argument, IPCAA stated that it generally supported the UCA's arguments concerning all matters related to Y factor accounts (such as deferral accounts, reserves and flow-through items).[785]

641. The CCA provided a number of specific recommendations in its argument,[786] however several companies objected to the inclusion of the recommendations in argument on the grounds that the recommendations could not be properly tested due to the lateness of their introduction to the proceeding.[787] The Commission will only give weight to the CCA recommendations it

782 Exhibit 634.02, UCA argument, Section 10.1, paragraph 228, page 41.
783 Exhibit 629.01, Calgary argument, Section 10.1, page 46.
784 Exhibit 369.01, AUC-IPCAA-4.
785 Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
786 Exhibit 636.01, CCA argument, Section 10, pages 64-110.
787 Exhibit 644.01, Fortis reply argument, Section 1.0, paragraph 19, page 3; Exhibit 648.02, ATCO Gas reply argument, Section 10.2, paragraph 327, page 93; Exhibit 647.01, ATCO Electric reply argument, Section 1, paragraph 31, page 10.

determines are based on the prior record of the proceeding, and will not consider new proposals or supporting evidence that were introduced for the first time in argument.

Commission findings

642. The Commission has reviewed the various Y factor accounts requested by the companies, and has grouped the accounts into seven different categories:

(1) Accounts that should be approved for flow-through treatment on the basis that they are similar to the flow-through items approved for ENMAX based on the Commission's findings in Section 7.4 above.

(2) Accounts that are a result of Commission directions, and therefore are eligible for flow-through treatment even though they may not satisfy certain criteria for Y factors.

(3) Accounts that meet the Y factor criteria, and therefore are eligible for flow-through treatment.

(4) Events where the impacts are unforeseen, and therefore are better to be assessed as Z factors.

(5) Accounts that are not eligible for Y factor treatment because they do not satisfy the outside-of-management-control criterion.

(6) Accounts that are not eligible for Y factor treatment because they do not satisfy the inflation criterion.

(7) Accounts that involve capital expenditures and are therefore better to be assessed as capital trackers.

643. The Commission considers that in many cases companies have asked for Y factors that are common amongst them. Because these accounts can be grouped together, the Commission will assess groupings of similar Y factor accounts for several companies in the sections that follow.

644. Some of the companies withdrew their requests for certain Y factor accounts during the course of the proceeding.[788] Accounts that the companies have removed have not been included in the assessments in the following sections because it is assumed that the accounts will not be utilized during PBR.

[788] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8 (withdrew deferral account for production abandonment costs and short term deferral accounts for IFRS implementation, NGTL/AP integration, Calgary head office lease); Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4 (withdrew deferral accounts for demand side management and natural gas system settlement code); Exhibit 633.01, Fortis argument, Section 10.2, paragraph 193, page 89 (withdrew exchange rate deferral account).

7.4.2.1 Accounts that are similar in nature to flow-through items approved for ENMAX

7.4.2.1.1 AESO flow-through items

645. All electric distribution companies accessing the electric transmission system in the province are charged by the AESO[789] for transmission services provided in relation to customers in their distribution service area. Accordingly, the distribution tariff of the electric distribution companies in this proceeding includes two components:[790]

- the distribution component, designed to recover the costs of owning and operating the distribution system; and
- the transmission component, designed to recover the AESO tariff charges to the distribution company.

646. ATCO Electric, Fortis and EPCOR indicated that while the rates covering the distribution component will be determined by the I-X mechanism, the AESO transmission access charges should be treated as flow-through items. The companies pointed out that the AESO charges have been subject to deferral account treatment under cost of service rate regulation and they proposed to continue using the existing deferral account mechanisms (with one modification, as further discussed below) to recover these costs under PBR. Historically, the companies used slightly different names for deferral accounts for the AESO charges, but the purposes for the costs are essentially the same:

Table 7-2 AESO flow-through items for electric distribution utilities

ENMAX[791]	ATCO Electric	EPCOR	Fortis
AESO load settlement costs	AESO load settlement costs[792]	AESO load settlement deferral account[793]	AESO load settlement cost reserve[794]
SAS rates in the distribution tariff	System access service payments[795]	System access service rates[796]	AESO system access service[797]
TAC deferral account		Transmission charge deferral account[798]	AESO charges deferral account[799]
Balancing Pool allocation refund rider	Balancing Pool adjustment[800]	Balancing Pool rider	Balancing Pool adjustment rider[801]

789 The AESO is a not-for-profit organization that plans and operates the transmission system in Alberta. http://www.aeso.ca/index.html.
790 Exhibit 633, Fortis argument, page 142.
791 Decision 2009-035, Section 9.3, paragraph 251, page 55.
792 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 119-122, page 6-10.
793 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
794 Exhibit 100.02, Fortis application, Section 6.1.1, page 26.
795 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 92-103, pages 6-2 to 6-6.
796 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
797 Exhibit 100.02, Fortis application, Section 13.1, paragraph 160, page 45.
798 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
799 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 163-165, pages 46-47.
800 Exhibit 98.02, ATCO Electric application, Section 14, paragraph 265-266, page 14-2.
801 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 166-168, page 47.

Commission findings

647. In Decision 2009-035, the Commission agreed with ENMAX that the company has no control over the AESO charges and approved flow-through treatment of these costs for the purposes of ENMAX's FBR plan.[802] All of the electric distribution companies are subject to the same types of costs and therefore the Commission considers that these costs satisfy the Y factor criteria enumerated above. The Commission also considers that achieving consistency with the flow-through items approved in the ENMAX FBR plan is fair and reasonable. Accordingly, the Commission finds that the AESO related cost items, as presented in Table 7-2 above, will be treated as flow-through items for the purposes of the PBR plans of Fortis, EPCOR and ATCO Electric.

648. To the extent that the companies have existing rider mechanisms to pass through these costs to customers, for billing consistency those existing mechanisms will continue under PBR.

7.4.2.1.2 Inclusion of volume variance in the transmission access charge deferral accounts

649. In their PBR proposals, the electric distribution companies proposed one modification to their existing transmission access charge deferral accounts. Currently, these deferral accounts reconcile only forecast to actual variances related to the AESO price changes. The companies bear the risk of forecast to actual variances related to transmission volumes (as measured by certain billing determinants such as metered energy, customer load, peak demand, etc.). In other words, if the AESO were to change its rates, the companies would be kept whole across its forecast volumes through a deferral account. However, the companies accept the risk of the actual volumes being lower or higher than forecast.[803] This arrangement can be generally represented as:

Transmission Access Deferral =
Forecast volume × (Actual AESO prices - Forecast AESO prices)

650. The companies indicated that they do not have any meaningful control over transmission volumes as they are completely driven by customer load requirements that can vary from year to year and month to month.[804] IPCAA agreed that the companies have "little if any control over customer loads."[805] IPCAA also observed that the only practical option to control transmission volumes can create risks that customer loads will be interrupted:

> Since utilities have and should have no direct control over customer load, their only practical option is to shift load between summer and winter peaking PODs [points of delivery] to minimize AESO tariff demand ratchets. Since distribution is largely radial in nature [Exhibit 306.01 page 2], this is rarely possible; urban utilities, with their denser service areas, are the only entities with meaningful substation switching options. However such switching creates significant risks that customer loads will be interrupted.[806]

651. Furthermore, the companies indicated that transmission volumes have become increasingly difficult to forecast due to a more complex AESO tariff structure. ATCO Electric

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[802] Decision 2009-035, paragraph 251.
[803] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 95-97.
[804] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 98; Exhibit 633, Fortis argument, page 142.
[805] Exhibit 635, IPCAA argument, paragraph 99.
[806] Exhibit 635, IPCAA argument, paragraph 102.

noted that the structure of the AESO's tariff has changed over the years shifting from energy related costs to demand-related costs which are more difficult to forecast.[807] In particular, ATCO Electric observed that the change in demand-related costs has increased from 42 per cent of the total AESO costs in 2004 to 78 per cent of the total system access service (SAS) costs.[808] Fortis shared these concerns.[809]

652. ATCO Electric and Fortis also expressed their view that the complexity of forecasting the transmission volumes will be more pronounced under PBR, since the companies will be forecasting billing determinants over longer periods of time (i.e., over the PBR term).[810] In that regard, Fortis submitted that in the absence of volume true-up, the company would need to update its transmission volumes forecast annually to effectively attempt to manage this transmission risk. In Fortis' view, this annual update was not consistent with "regulatory streamlining envisioned for PBR."[811]

653. Fortis also observed that one of the reasons the Commission relied upon for imposing volume risk on Fortis in Decision 2012-108[812] was that it might provide an additional incentive for the company to more accurately forecast its distribution billing determinants. In that regard, Fortis submitted that this determination was made in the context of a cost of service regime and would be less applicable to PBR. In Fortis' view, under PBR, forecasting of transmission volumes will be less critical in terms of sharing any risks between customers and the company.[813] ATCO Electric also agreed that the "circumstances associated with forecasting risk under PBR are significantly different than under cost of service regulation."[814]

654. Based on these considerations, EPCOR, ATCO Electric and Fortis proposed that their transmission access charge deferral accounts include both price and volume variances under PBR.[815] In other words, the companies requested that the AESO charges be treated as a full dollar-for-dollar flow-through item in their PBR plans. Under this arrangement, the actual transmission costs incurred will equal the actual transmission revenues received. This arrangement can be generally represented as:

Transmission Access Deferral =
(Actual volume - Forecast volume) × (Actual AESO prices - Forecast AESO prices)

655. The CCA noted that in two recent decisions, Decision 2011-375[816] and Decision 2012-108, the Commission determined that volume variances should not be included in the transmission cost deferral accounts in a cost of service rate design regime. In the CCA's

807 Transcript, Volume 4, pages 728-729.
808 Exhibit 631, ATCO Electric argument, paragraph 336.
809 Transcript, Volume 12, page 2243, lines 5-23.
810 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 99; Exhibit 633, Fortis argument, pages 143-144.
811 Exhibit 633.01, Fortis argument, pages 143-144.
812 Decision 2012-108: FortisAlberta Inc. Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
813 Transcript, Volume 12, page 2242, lines 5-16 and page 2244, lines 7-14.
814 Exhibit 639, ATCO Electric reply argument, paragraph 369.
815 Transcript, Volume 10, page 1874, lines 19-21 (EPCOR); Exhibit 633, Fortis argument, pages 143-144; Exhibit 631, ATCO Electric argument, paragraph 337.
816 Decision 2011-375: EPCOR Distribution & Transmission Inc. 2010-2011 Phase II Distribution Tariff Application, Application No. 1606833, Proceeding ID No. 980, September 15, 2011.

view, the Commission's determinations "apply as much in a cost of service environment as they do in the PBR regime."[817] Accordingly, the CCA argued that the companies' transmission access charge deferral accounts should continue to include price variance only.[818]

656. The UCA noted that in Decision 2012-108, the Commission indicated that it will "consider the merits of volume reconciliation for distribution utilities under the PBR regime in due course, following the issuance of a decision on Proceeding ID No. 566."[819] As such, the UCA recommended that the Commission continue with a generic proceeding for examining the issue of volume true-up as referenced in Decision 2012-108.[820]

657. IPCAA also noted the Commission's determination in Decision 2012-108 referenced by the UCA and recommended that the implementation of comprehensive PBR be delayed until incentives are developed that will encourage the distribution companies "to prudently minimize the transmission and distribution facilities installed in their service area."[821]

Commission findings

658. As observed by the UCA and IPCAA, in Decision 2012-108 the Commission reaffirmed its intention to consider the issues related to volume reconciliation under the PBR framework on a consistent basis for all distribution companies following the issuance of a decision in this proceeding.[822] However, having considered the evidence filed by the parties, the Commission agrees with Fortis' and ATCO Electric's view that a determination on volume reconciliation under PBR can be made in this proceeding.[823]

659. The Commission agrees with ATCO Electric's and Fortis' explanation that transmission volumes are driven by customer load requirements. Furthermore, as stated in a number of recent decisions, the Commission agrees with the electric distribution companies' assessment that they have no meaningful control over transmission volumes due to the specifics of the current structure of the AESO system access rates (more heavily oriented to demand-related charges versus energy-related charges) and the companies' limited ability to undertake seasonal switching of loads between points of delivery.[824] IPCAA came to the same conclusion.[825]

660. Nevertheless, analysing EPCOR's and Fortis' cost of service rate applications, the Commission concluded that these companies were able to forecast transmission volumes with reasonable accuracy, as demonstrated by relatively small volume variances in their respective deferral accounts.[826] However, in that case the companies were updating their billing determinants forecasts every two years, in their rate applications. The Commission agrees with ATCO Electric's and Fortis' arguments that the same level of precision will not likely be attainable if the companies will be forecasting their billing determinants for the duration of the

[817] Exhibit 636, CCA argument, paragraph 402.
[818] Exhibit 636, CCA argument, paragraphs 404-405.
[819] Decision 2012-108, paragraph 127.
[820] Exhibit 634.02, UCA argument, paragraph 433.
[821] Exhibit 635, IPCAA argument, paragraph 104 and Exhibit 642, IPCAA reply argument, paragraph 608.
[822] Decision 2012-108, paragraph 127.
[823] Exhibit 644, Fortis reply argument, paragraphs 182-183; Exhibit 639, ATCO Electric reply argument, paragraph 368.
[824] Decision 2011-375, paragraph 188 and Decision 2012-108, paragraph 115.
[825] Exhibit 635, IPCAA argument, paragraphs 99 and 102.
[826] Decision 2011-375, paragraph 189 and Decision 2012-108, paragraph 117.

PBR term. Therefore, the Commission will require the companies to file forecast billing determinants for the following year as part of their annual PBR rate adjustment filings.

661. More importantly, the Commission explained in recent decisions dealing with EPCOR's and Fortis' rate applications, that under a cost of service regulatory framework, the distribution revenue requirement established in Phase I applications is divided by the forecast billing determinants for the test period to design customer rates. In other words, the accuracy of customer rates and the companies' ability to recover their approved revenue requirement is highly dependent on the accuracy of their billing determinants forecasts.

662. Furthermore, under the current regulatory framework, the electric distribution companies accept the risk related to the difference between the forecast and actual billing determinants when recovering their approved distribution revenue requirement. In these circumstances, the Commission determined that under a cost of service rate making framework, the absence of volume true-up on transmission charges would provide a stronger financial incentive to the companies to accurately forecast their billing determinants to ensure reasonable recovery of both the distribution tariff revenue and transmission access charges. Overall, taking into account the impact of forecast billing determinants on customer rates and the companies' revenues, the Commission considers that under cost of service rate making, regulatory efficiencies stemming from a more rigorous billing determinants forecast outweigh the potential disadvantages of the companies bearing risk on transmission volumes.[827]

663. In contrast, under PBR, the companies' costs will not be driving their revenues. As set out in Section 4 of this decision, under the price cap plans approved for ATCO Electric, EPCOR and Fortis, customer rates for each year will be established by way of the I-X mechanism, regardless of a company's actual costs and the amount of energy transported through a company's system. In these circumstances, forecasting of billing determinants will have a minimal impact on customer rates.[828] As Fortis observed:

> And we would note that under PBR that all falls away. Under PBR we essentially have rates for the distribution component of costs increasing I minus X. We have billing determinant volumes growing on an actual basis, and the product of those two things are really the revenues that FortisAlberta will receive for its distribution service.[829]

664. Accordingly, the Commission agrees with Fortis' view that under PBR, there is no purpose for maintaining the true-up of transmission flow-through accounts of electric distribution companies limited to price-only.

665. IPCAA expressed concerns that the current deferral account mechanism creates "unnecessary cost uncertainty, delay, and administrative costs."[830] In that regard, as outlined in Bulletin 2012-04,[831] the Commission had initiated a review of the electric distribution companies'

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[827] Decision 2011-375, paragraph 191 and Decision 2012-108, paragraphs 120-121.
[828] As set out in Section 4, under a price cap plan, billing determinants will be used nonetheless to apportion to customers other components of the PBR formula, outside of the (I-X) mechanism such as flow-through items, capital trackers, Z factors, etc.
[829] Transcript, Volume 12, page 2242, lines 5-16.
[830] Exhibit 635, IPCAA argument, paragraph 103.
[831] Bulletin 2012-04, Commission-initiated electric transmission quarterly rider process review, Proceeding ID No. 1678, March 29, 2012.

transmission quarterly rider mechanisms.[832] As part of that review, ATCO Electric, ENMAX, EPCOR and Fortis filed their applications to standardize their respective transmission access charge rider mechanisms. In the Commission's view, these applications address, among other things, the types of issues identified by IPCAA in this proceeding. For example, the companies are proposing to move to a prospective approach to setting their quarterly riders. Under this method, the transmission component of the companies' rates in any quarter will be reflective of the AESO charges in that particular quarter. As such, it will no longer be the case that transmission charges will be based on a calculation "whose results are unknowable until the utility releases them months after the fact."[833] Furthermore, the companies are proposing to standardize and simplify their quarterly riders, so that these applications can be reviewed with minimal scrutiny, reducing time delay and the administrative cost of dealing with these riders.[834] The Commission intends to address IPCAA's concerns in Proceeding ID No. 1678.

666. In light of the above considerations, the Commission approves the inclusion of volume variance in the transmission flow-through accounts of the electric distribution companies for the purposes of their PBR plans. The Commission expects that with this modification, the AESO related cost items will be dollar-for-dollar flow-through items in the companies' PBR plans. At the time of their annual transmission deferral reconciliation, the companies must ensure that the actual transmission revenues received equal the actual transmission costs incurred. As noted in the previous section of this decision, subject to this modification, the Commission directs Fortis, EPCOR and ATCO Electric to use their existing deferral mechanisms to flow through the transmission access costs to customers under PBR.

667. As indicated in Decision 2012-108, the Commission is committed to considering the issues related to volume reconciliation under the PBR regime on a consistent basis for all electric distribution companies.[835] The Commission considers that the same reasoning for including volume variances in ATCO Electric's, EPCOR's and Fortis' transmission charge deferral accounts under PBR applies to ENMAX as well. As such, the Commission directs ENMAX to bring this matter forward to the Commission as part of the next application dealing with the company's transmission access charge deferral account.

7.4.2.1.3 Transmission flow-through for gas utilities

668. The Commission considers that certain flow-through items requested by the gas companies serve a similar purpose, and have similar mechanisms to the AESO flow-through items approved for the electric distribution utilities. The transmission costs deferral account requested by ATCO Gas[836] falls into this category. ATCO Gas simply flows through the transmission rates charged by the transmission service provider to customers. ATCO Gas has requested volume variances to be included in this account under PBR for reasons that are similar to the electric distribution companies' requests to include volume variances in the transmission flow-through accounts. The Commission approves flow-through treatment using the existing rider mechanism for the transmission costs deferral account, and also approves the inclusion of volume variances in the account. AltaGas has also proposed to continue to address its gas procurement function and costs related to transportation by third parties separately from the

832 Proceeding ID No. 1678.
833 Exhibit 635, IPCAA argument, paragraph 103.
834 Proceeding ID No. 1678, Exhibit23.02, Exhibit 24.01, Exhibit 25.01 and Exhibit 26.02.
835 Decision 2012-108, paragraph 127.
836 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, pages 24-25.

I-X mechanism through its existing gas costs recovery rate and third party transportation rate mechanisms.[837] The Commission approves AltaGas' treatment.

7.4.2.1.4 Farm transmission costs

669. Fortis intends to continue its existing practice of flowing through farm transmission costs to the AESO based on a prescribed formula.[838] Other flow-through items associated with AESO transactions have been approved as part of this decision, and it is therefore suitable for these costs to receive flow-through treatment.

7.4.2.2 Accounts that are a result of Commission directions

670. All of the companies included Y factor accounts or indicated the requirement for future Z factors related to future decisions issued by the Commission. The UCA acknowledged the need for a utility to have the opportunity to recover the costs related to changes in regulation.[839] As discussed in Section 7.4, an exemption to certain Y factor criteria will be permitted for certain cost items that have been incurred by a company in compliance with a direction of the Commission.

7.4.2.2.1 AUC assessment fees

671. In Decision 2010-146, the Commission approved flow-through treatment of AUC assessment fees for ENMAX under its FBR plan.[840] AUC assessment fees are common to all of the companies, and all of them asked for deferral or flow-through treatment of these fees.[841] Some of the companies did not request a specific flow-through account for these costs, as they had grouped these costs together with their hearing costs deferral account. The Commission will continue with flow-through treatment of AUC assessment fees. For those companies that included these fees in another deferral account with other types of costs, these companies are directed to separately identify the AUC assessment fees component in their Y factor calculations.

7.4.2.2.2 Effects of regulatory decisions

672. Several companies requested Y factors to flow through the impacts of regulatory decisions.[842] The Commission finds that regulatory efficiency would be achieved if the companies are able to treat the financial impact of items the Commission has already determined to be necessary as Y factor adjustments. The Commission therefore finds that the financial effects to companies that are clearly identified in a Commission direction may, with approval of the Commission, be included as Y factor adjustments in the annual PBR rate adjustment filings process. Specific changes related to generic cost of capital proceedings are discussed in Section 7.4.2.6.1 below.

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[837] Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.
[838] Exhibit 100.02, Fortis application, Section 6.3, paragraphs 106-108, page 30.
[839] Exhibit, 300.02, UCA evidence of Russ Bell, A21, page 33.
[840] Decision 2010-146, Section 9.1.1, paragraph 100, page 16.
[841] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 152, page 6-16; Exhibit 100.02, Fortis application, Section 6.1.3, paragraph 95, page 27; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23; ATCO Gas includes AUC administration costs in hearing costs according to Transcript, Volume 6, pages 918-919.
[842] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 200-203, page 6-28; Exhibit 99.01, ATCO Gas application, Section 2.5.2.6, paragraph 108-109, page 38; Exhibit 100.02, Fortis application, Section 6.4.4, paragraphs 114-115, page 32; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.

7.4.2.2.3 Hearing costs

673. All of the companies requested Y factor treatment for hearing costs presently collected through their hearing cost deferral accounts.[843] The Commission considers that intervener costs approved to be paid pursuant to AUC cost decisions are a result of directions from the Commission, and therefore are eligible for collection through a Y factor adjustment. The Commission considers that management has a reasonable level of control over its internal hearing costs, and therefore the company portion of hearing costs will be subject to the I-X mechanism.

674. The company portion of the hearing costs that will be subject to the I-X mechanism will be the average awarded company hearing costs for the years 2009, 2010 and 2011. This amount will be included in going-in rates for the purpose of determining the rates for 2013 replacing the amounts presently included in the revenue requirement for 2012 for the hearing cost deferral account. Intervener costs will be treated as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.4 AUC tariff billing and load settlement initiatives

675. EPCOR included a Y factor for AUC tariff billing and load settlement initiatives.[844] The Commission considers that because these costs are a result of Commission directions they will be approved as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.5 UCA assessment fees

676. The gas companies are required to make payments for UCA assessment fees. These are similar in nature to the AUC assessment fees and accordingly the Commission considers flow-through treatment to be warranted. The Commission understands that ATCO Gas included UCA fees as part of its hearing costs[845] and that AltaGas has requested a PBR deferral account that includes both AUC and UCA assessments.[846] To the extent that ATCO Gas and AltaGas included these fees in another deferral account with other types of costs, these companies are directed to separately identify the UCA assessment fees component in their Y factor calculations.

7.4.2.3 Accounts that meet the Y factor criteria and are eligible for flow-through treatment

677. The Commission has examined the following proposed Y factor accounts and finds that they satisfy the Y factor criteria established in Section 7.4 and therefore are eligible for flow-through treatment.

7.4.2.3.1 Municipal fees

678. Several companies indicated that they intend to continue with either a deferral account or flow-through treatment for franchise fees and property taxes. Fortis requested that its municipal

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[843] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 152-155, page 6-16 to 6-17; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23; Exhibit 100.02, Fortis application, Section 6.1.3, paragraphs 95-96, pages 27-28; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

[844] Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

[845] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23.

[846] Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

franchise fee riders and its Rider A-1 municipal assessment riders continued.[847] Continuation of existing rider mechanisms to collect municipal fees was also proposed by ATCO Electric[848] and ATCO Gas.[849] In addition, EPCOR requested a property, business and linear tax deferral account.[850] Because these costs satisfy the Y factor criteria they will be treated as a flow-through item. Where there is an existing rider mechanism the companies are directed to use that mechanism and, in the absence of an existing rider mechanism, the companies will dispose of balances in a deferral account as part of the annual PBR rate adjustment filings process.

7.4.2.3.2 Load balancing

679. ATCO Gas requested continuation of its load balancing deferral account (LBDA). The UCA recommended the continued use of the load balancing deferral account, but recommended that ATCO Gas' suggestion to true-up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[851] Because the account meets the Y factor criteria, the Commission determines that ATCO Gas may continue to use its load balancing deferral account in its current form. The Commission considers that the continued use of a threshold approach, as proposed by the UCA, is necessary to minimize the regulatory burden of reviewing applications. Therefore, during the PBR term, the existing process for dealing with the load balancing deferral account will continue as described by ATCO Gas where "the recovery or refund of the LBDA balance is triggered if either of the North or South accounts exceeds $5 million (receivable or payable) for six consecutive months, or if either account exceeds $10 million in any one month."[852] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.3 Weather deferral

680. ATCO Gas requested continuation of its weather deferral account (WDA). The reduction to the risk that ATCO Gas faces with respect to weather was recognized in a previous GCOC proceeding in the form of a 100 basis points reduction to the equity thickness of ATCO Gas.[853] The weather deferral account not only protects ATCO Gas in years when its earnings would otherwise be negatively impacted by warmer than normal weather, but it also protects customers in years when colder than normal weather would require them to pay higher utility bills. The UCA recommended the continued use of the weather deferral account, but recommended that ATCO Gas' suggestion to true up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[854] Because the adjustment to risk has already been reflected in going-in rates, because the account meets the Y factor criteria, and because the account can have benefits for both the company and customers, ATCO Gas may continue to use its weather deferral account in its current form without annual true-ups. ATCO Gas described the current process as follows: "a WDA rate rider application is triggered to recover or refund the balance if and when either the North or South accounts is at or greater than $7 million

847 Exhibit 100.02, Fortis application, Section 13.1, paragraph 149, page 41.
848 Exhibit 207.01, AUC-BOTHATCO-AE-6.
849 Exhibit 206.02, AUC-BOTHATCO-AG-6.
850 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
851 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.
852 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.7, paragraph 72, page 28.
853 Transcript, Ms. Wilson, Volume 7, page 1321.
854 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.

(receivable or payable) on April 30 of each year."[855] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.4 Production abandonment

681. ATCO Gas withdrew its request for this account in its application update subject to the results of the review and variance on Decision 2011-450.[856] The issue is currently under consideration in other proceedings, and the Commission considers that in the interim this deferral account will continue as a Y factor. Pending the results of other proceedings reviewing the recoverability of production abandonment costs, the Commission will reassess whether the continuation of this Y factor under PBR is necessary. In the interim, while the issues around this deferral account are being addressed in other proceedings, ATCO Gas is directed to continue to track the balance associated with this deferral account. The settlement of the balance will not occur until the other proceedings have determined the proper treatment.

7.4.2.3.5 Income tax impacts other than tax rate changes

682. Several companies requested various income tax Y factor accounts. These accounts include:

- The income tax deductible capital cost deferral account and the deduction of deferrals for income taxes requested by ATCO Electric.[857]
- The income tax deductible capital costs requested by ATCO Gas.[858]
- The CRA re-assessment deferral and the income tax payable flow-through requested by Fortis.[859]
- The income tax timing differences flow-through account requested by AltaGas.[860]

683. The Commission will address the portion of the Y factor account relating to income tax rate changes in Section 7.4.2.6.2. All of the remaining income tax Y factor accounts relate to the treatment of temporary tax differences or the reassessment of prior income tax returns. The Commission understands that these types of adjustments only affect the earnings of regulated entities due to the use of the flow-through income tax method, and that most companies in other industries normalize their income tax expenses to reflect the impact of changes to future income tax liabilities and assets.

684. Calgary proposed that ATCO Gas should continue with deferral treatment for income tax deductible capital costs on the basis "that utility management cannot manage the level of expenditure for these items despite bona fide, competent and good faith efforts."[861] The UCA suggested that the continuation of income tax deferral accounts is appropriate, and noted that in

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855 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.6, paragraph 69, pages 27-28.
856 Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
857 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 123-145, pages 6-10 to 6-15, and paragraph 147, page 6-15.
858 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.8, paragraph 75, page 29.
859 Exhibit 100.02, Fortis application, Section 6.1.5, paragraphs 99-100, page 28 and Section 6.4.3, paragraph 113, page 32.
860 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
861 Exhibit 629.01, Calgary argument, Section 10.2, page 48.

Decision 2009-214,[862] the Commission expressed its intention to initiate a proceeding which will address consistent income tax methodologies for all utilities.[863]

685. As noted by the UCA, the Commission, in Decision 2009-214, indicated that it intends to initiate a proceeding which will address consistent income tax methodologies for all utilities. The Commission confirms its intention to initiate a generic income tax proceeding following the release of this decision. In the interim, the Commission considers that material changes in income tax expenses that result from the treatment of temporary tax differences or the reassessment of prior income tax returns should be passed on to customers until such time as any change in income tax methodology may be directed by the Commission. Accordingly, the income tax Y factor accounts respecting the treatment of temporary tax differences or the reassessment of prior income tax returns requested by ATCO Gas, ATCO Electric, Fortis and AltaGas are approved. These changes will be addressed through Y factor adjustments as part of the annual PBR rate adjustment filings.

7.4.2.4 Accounts that are unforeseen events, and therefore should be assessed as Z factors instead

686. The discussion on specific items in this section is not intended to obligate the Commission to approve Z factor treatment in future proceedings for any of the items discussed. This section simply identifies the types of items that have been proposed as Y factors by the companies, but which should be tested as Z factors because of their unforeseen and infrequent nature. When Z factor applications are submitted the merits of each item will be tested in detail as to whether or not they actually qualify. The following accounts fall into this category.

7.4.2.4.1 Self-insurance/reserve for injuries and damages

687. Fortis,[864] EPCOR,[865] ATCO Electric[866] and ATCO Gas[867] all requested that their self-insurance deferral accounts be continued as Y factors. While there may be some activity in these accounts on an annual basis, the primary purpose of these accounts is to capture the effects of major events that are not covered by insurance. The Commission considers that during the PBR term the significant events that the companies are concerned about could be addressed as Z factors while the non-significant events should be covered by the I-X mechanism. The Commission will allow the companies to include a provision in their going-in rates calculated as follows. The provision will be equal to the average value of each event that was included in their deferral account or as an adjustment to their reserve account for the most recent five-year period. This amount is to be reflected in the companies going-in rates. The companies are directed to identify this adjustment to going-in rates in their compliance filings and the Commission will make a determination in the compliance filing decision as to whether or not the adjustment is reasonable.

[862] Decision 2009-214: ATCO Gas, 2008-2009 General Rate Application Phase I, Income Tax Module, Application No. 1553052, Proceeding ID. 11, November 12, 2009.
[863] Exhibit 300.02, UCA evidence of Russ Bell, A21, page 30.
[864] Exhibit 100.02, Fortis application, Section 6.1.4, paragraphs 97-98, page 28.
[865] Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.
[866] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 156-162, pages 6-17 to 6-18.
[867] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.2, paragraph 59, page 24.

7.4.2.4.2 Depreciation rate changes

688. Fortis,[868] ATCO Electric,[869] ATCO Gas[870] and AltaGas[871] all requested Y factors related to depreciation changes. The companies requesting these Y factors indicated that depreciation studies do not occur on an annual basis. However, even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result. If a substantial change does occur, the change may be a result of changes in management assumptions, which would cause the change to not be eligible for flow-through treatment in the form of either a Y factor or Z factor. However, if the change results from some circumstance that is outside of management control, the change may be eligible for Z factor treatment. Due to the unforeseeable nature of depreciation changes, the infrequent occurrence, and the uncertainty as to whether the changes would be eligible for flow-through treatment, depreciation changes will not be treated as a Y factor.

7.4.2.4.3 International Financial Reporting Standards (IFRS)/accounting changes

689. Fortis[872] and AltaGas[873] requested Y factor treatment for accounting changes. The Commission considers that impacts associated with major changes to accounting standards, whether it is the initial adoption of IFRS or any other modifications to accounting standards, should be infrequent. Other than the initial adoption of IFRS, it is unforeseeable when subsequent major changes to accounting standards will occur. In addition, Fortis recognized that the majority of the AUC Rule 026[874] changes it would need to make are required for financial reporting purposes, and that regulatory reporting would likely not be affected.[875] As a result, the Commission determines that because of the infrequent and unforeseeable nature of accounting changes, they should be assessed as Z factors.

7.4.2.4.4 Acquisitions

690. ATCO Electric,[876] ATCO Gas[877] and AltaGas[878] all requested several different types of acquisitions to be treated as Y factors including: REA acquisitions, gas co-op acquisitions, and municipal annexations. The UCA objected to the flow-through treatment of these accounts on the basis that a company should only make an acquisition when it is economically beneficial for the company to do so, and therefore allowing flow-through treatment is not necessary.[879] The Commission considers that under certain circumstances it may not actually be left to the discretion of management as to whether or not the acquisition is made. In those circumstances, it may be necessary to assess the impact of an acquisition through a Z factor application. Acquisitions within the control of management would not generally qualify as either a Z factor or a Y factor.

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868 Exhibit 100.02, Fortis application, Section 6.4.1, paragraph 110, page 31
869 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 194-195, pages 6-26 to 6-27.
870 Exhibit 99.01, ATCO Gas application, Section 2.5.2.4, paragraph 104, page 37.
871 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
872 Exhibit 100.02, Fortis application, Section 6.1.2, paragraph 92-94, pages 26-27.
873 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
874 Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the Internal Financial Reporting Standards*, effective December 20, 20122 (Rule 026).
875 Transcript, Mr. Lorimer, Volume 11, page 2161.
876 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 191-191, page 6-26.
877 Exhibit 99.01, ATCO Gas application, Section 2.5.2.3, paragraph 103, page 37.
878 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
879 Exhibit 634.02, UCA argument, Section 10.1, paragraphs 277-282.

7.4.2.4.5 Defined benefit pension plan

691. In its 2010 Pension Common Matters application the ATCO utilities (ATCO Gas, ATCO Electric and ATCO Pipelines) applied for deferral account treatment for their pension expenses. In Decision 2010-189,[880] the Commission approved a deferral account for each ATCO utility to recover the special payments required to amortize an unfunded liability associated with the defined benefit portion of the Canadian Utilities Limited defined benefit pension plan.[881] In Decision 2010-553,[882] the Commission further explained that the purpose of the special payment deferral accounts is to capture the impact of timing differences that may arise between when special payment amounts are approved by the Alberta Superintendent of Pensions and consequently paid by the ATCO utilities and when amounts are approved by the Commission for inclusion in revenue requirement.[883] These differences were captured in a deferral account to keep both customers and shareholders whole.

692. ATCO Gas and ATCO Electric requested an expansion of their special payment deferral accounts by way of Y factor treatment associated with their defined benefit pensions plans.[884] AltaGas requested the creation of a pension deferral account with respect to their defined benefit pension plan costs.[885] These companies argued that when actuarial evaluations are made they can result in significant changes to the funding of the plan. Further, it is not simple to isolate changes resulting from special payment requirements resulting from an under funding of the plan from current service or other funding requirements.

693. The UCA recommended denial of the expansion of existing pension deferral accounts. The UCA referenced Decision 2010-189 where the Commission recognized the difference between special payments and current service pension costs, and the Commission determined that current service pension costs are no different than other compensation costs and therefore should not receive deferral treatment.[886]

694. The Commission agrees with the UCA that current service pension costs are no different from other compensation costs and accordingly denies the requested expansion of the ATCO Gas and ATCO Electric special payment deferral accounts and the creation of a pension deferral account for AltaGas.

695. With respect to the existing special payment deferral accounts of ATCO Gas and ATCO Electric distribution, the Commission considers that under a PBR environment there is no need to monitor the timing differences for which the deferral accounts were created. Accordingly, the existing special payment deferral accounts for ATCO Gas and ATCO Electric distribution will be discontinued upon implementation of PBR.

880 Decision 2010-189: ATCO Utilities, Pension Common Matters, Application No. 1605254, Proceeding ID. 226, April 30, 2010.

881 Decision 2010-198, paragraph 94.

882 Decision 2010-553: ATCO Utilities, Compliance Filing Pursuant to Decision 2010-189, ATCO Utilities Pension Common Matters, Application No. 1606289, Proceeding ID. 693, December 1, 2010.

883 Decision 2010-553, Section 3.1, paragraph 17, page 4.

884 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 113-118, pages 6-8 to 6-10; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.5, paragraphs 65-68, pages 26-27.

885 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.

886 Exhibit 634.02, UCA argument, Section 10.1, paragraph 244, page 44.

696. In the event of a material change to a company's special payment obligations (either positively or negatively), a Z factor application would be available to address this change.

7.4.2.4.6 Insurance proceeds

697. ATCO Gas proposed a deferral account for insurance proceeds in compliance with AUC Rule 026.[887] The Commission considers that if an event involving insurance proceeds that would have a material impact on operating costs occurs, then ATCO Gas may apply for flow-through treatment as a Z factor.

7.4.2.5 Accounts that do not meet the outside-of-management-control criterion

7.4.2.5.1 Variable pay

698. ATCO Gas[888] and ATCO Electric[889] proposed the continued use of deferral accounts for variable pay and AltaGas proposed the continued use of its short term incentive plan deferral account as Y factors.[890] The UCA argued that variable pay is only one component of compensation and is subject to the same management control as all other components of compensation.[891] The Commission considers that companies should be left to develop employee compensation programs that will have the best impact on their performance, and therefore Y factor accounts related to variable pay are not approved. The Commission considers that such an approach complies with PBR Principle 1 that states that "a PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality."[892]

7.4.2.5.2 Vegetation management

699. ATCO Electric requested Y factor treatment for vegetation management costs on the basis that the costs are outside of the control of management because there are a limited number of contractors that do the work, and that competition for services significantly increases the rates that the contractors charge.[893] The UCA indicated that "the creation of a Vegetation Management deferral account reduces the incentive to find creative and innovative ways to manage this function, and reduce costs."[894] The Commission does not accept ATCO Electric's argument. Vegetation management costs are entirely within the control of management.

7.4.2.5.3 Head office allocation changes

700. ATCO Gas[895] and ATCO Electric[896] requested Y factor treatment for changes to head office allocation percentages. The UCA expressed concern about the possibility of cost shifting under PBR between affiliates and the companies and proposed that significant changes in corporate structure and affiliate agreements should be reviewed by the Commission and, if approved, the effects of the change should be flowed through to customers.[897] Several of the

[887] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
[888] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.3, paragraph 60, page 24.
[889] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 148-151, page 6-16.
[890] Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
[891] Exhibit 634.02, UCA argument, Section 10.1, paragraph 243, page 44.
[892] Bulletin 2010-20, Rate Regulation Initiative, Section 3, page 2.
[893] Transcript, Mr. Freedman, Volume 4, page 755.
[894] Exhibit 634.02, UCA argument, Section 10.1, paragraph 261, page 48.
[895] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 171-176, pages 6-20 to 6-22.
[896] Exhibit 99.01, ATCO Gas application, Section 2.5.1.3.1, paragraphs 79-80, page 30.
[897] Exhibit 634.02, UCA argument, Sections 11.3 and 11.4, paragraphs 299-309, pages 55-56.

companies indicated that they would be willing to apply for Commission approval of material changes to affiliate agreements.[898]

701. The Commission finds that head office allocations are not outside of the control of the companies' management or that of their parent company and do not qualify as a Y factor.

702. EPCOR's witness, Dr. Weisman, indicated that the exclusion of earnings sharing mechanisms from a PBR plan should eliminate the need for strict monitoring of affiliate transactions because the incentive to shift costs to affiliates to avoid sharing earnings is eliminated.[899] The Commission agrees. As the Commission has not approved earnings sharing mechanisms in this decision, the need to isolate changes to affiliate agreements in a Y factor account has been substantially mitigated. However, the Commission has approved re-opener provisions and an efficiency carry-over mechanism that rely on the calculation of a return on equity. Therefore, the companies are directed to file all new material affiliate agreements, material changes to affiliate agreements and significant changes to corporate structure that have a substantial impact on the operating costs of the company.

7.4.2.5.4 AMR implementation

703. AltaGas requested Y factor treatment for the implementation of AMR (automated meter reading). AltaGas believes that if it were to implement AMR during the PBR term that the payoff for the investment would not be possible during a single PBR term. The UCA objected to the inclusion of an AMR deferral account indicating that "[t]he type of innovation covered by AMR is the same type of efficiency gains that is intended by PBR Principle 1, that a PBR should provide the same incentives as a competitive market."[900] The Commission agrees. AMR should be undertaken only if it will achieve efficiencies that will outweigh the costs. This decision is not outside of management control. Therefore there is no need for Y factor treatment.

7.4.2.6 Accounts that do not meet the inflation factor criterion

7.4.2.6.1 Changes in the cost of capital

704. Some of the companies asked for a Y factor adjustment to rates to account for changes to the Commission approved rate of return on equity.[901] Fortis,[902] ATCO Gas[903] and ATCO Electric[904] requested a Y factor adjustment to recover the impacts of changes in financing rates (i.e., cost of debt).

705. In its GCOC decisions, the Commission establishes an approved ROE for the companies under its jurisdiction. As well, it has been the Commission's practice to account for the differences in risk among the individual companies by adjusting their capital structures (i.e., the

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898 Transcript, Ms. Wilson, Volume 4, page 780; Exhibit 384.02, AUC-ALLUTILITIES-FAI-25(b); Exhibit 381.01, AUC-ALLUTILITIES-AUI-25(a).
899 Transcript, Dr. Weisman, Volume 9, page 1765.
900 Exhibit 634.02, UCA argument, page 35, paragraph 193.
901 Exhibit 98.02, ATCO Electric application, page 6-28, paragraph 202; Exhibit 99.01, ATCO Gas application, page 38, paragraph 109; Exhibit 100.02, Fortis application, page 32, paragraph 114; Exhibit 103.02, EPCOR application, page 51, table 2.3.5-2; Exhibit 110.01, AltaGas application, page 24, paragraph 82.
902 Exhibit 100.02, Fortis application, Section 6.4.2, paragraphs 111-112, pages 31-32.
903 Exhibit 99.01, ATCO Gas application, Section 2.5.2.5, paragraphs 105-107, pages 37-38.
904 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 196-199, page 6-27.

ratio of equity to debt).[905] Under cost of service regulation, the Commission approves a forecast of the company's cost of debt in its revenue requirement.

706. Both the I and the X in the PBR formula apply to the companies' distribution rates that are established through a cost of service proceeding. All of the distribution costs that are recovered through those rates, including the cost of debt and the cost of equity, are included in the going-in rates. In Section 5.2.1 of this decision the Commission determined that changes in the cost of capital (both debt and equity) are captured in the approved I factor. This means that the approved I factor in the I-X mechanism reflects changes in all of the companies' costs over time, including the cost of debt and equity. Therefore, the Commission finds that no specific changes to customer rates should be made to take into account changes in the Commission's approved generic ROE or changes in the cost of debt during the PBR term.

707. The Commission agrees with Dr. Lowry when he stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[906]

708. It follows that including a separate flow-through component for changes in the ROE would also amount to double-counting.

709. The Commission recognizes that the conclusions it has reached with respect to the treatment of the cost of equity in the PBR framework are different than the approach taken by the Commission in the ENMAX FBR framework. The Commission has benefited from the evidence and testimony on this matter that was not available to it in the ENMAX FBR proceeding.

710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.

7.4.2.6.2 Income tax rates

711. ATCO Electric[907] proposed Y factor treatment to recover any changes to income tax rates. AltaGas' witness, Mr. Retnanandan, discussed why AltaGas would not try to recover the impact of tax rate changes from customers, stating "potentially on the PBR, the changes in tax rates would be covered under something like the inflation factor. So that would be duplicating, if you would, to recognize the income tax rate changes as part of the AUI Z factors."[908] The Commission considers that major changes to the calculation of income tax payments, such as a change in income tax rates, should impact the entire economy, and as such, should be captured

[905] See for example, Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011, paragraph 169.
[906] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[907] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 146, page 6-15.
[908] Transcript, Mr. Retnanandan, Volume 9, page 1614.

by the I factor. To the extent that a change could occur that only impacts a select group of companies, and therefore not be captured by the I factor, it may be warranted to consider the change as a Z factor. However, due to the infrequent nature of such changes, it is not necessary to establish a Y factor account.

7.4.2.7 Requested capital project Y factors

712. Some items classified as Y factors by the companies relate to specific capital programs that may or may not proceed at some point during the PBR term that the companies considered to fall outside of the revenues that would be available to fund the project through the application of the I-X mechanism and customer growth. These proposed Y factors are listed in the following table.

Table 7-3 Capital-related flow-through items requested by utilities

AltaGas	ATCO Electric	ATCO Gas	EPCOR	Fortis
n/a	Material investments unique in nature	Material investments unique in nature	n/a	Externally driven capital expenditures
n/a	Distribution to transmission contributions	Transmission driven costs (capital component)	n/a	n/a
n/a	n/a	Urban mains replacement expenditures	n/a	n/a

713. The Commission considers that eligibility for these capital-related items should be assessed by way of a capital tracker application. See Section 7.3.2.4.

7.4.3 Collection mechanism for third party flow-through items

714. For flow-through items that have existing rider mechanisms in place, the companies generally suggested the continuation of the existing mechanisms. The changes to the rate riders associated with these mechanisms are separate from the rate adjustments resulting from the I-X mechanism. Due to the material nature of costs and the processes that are already in place for certain flow-through items, true-ups may be required more frequently than the annual PBR filings. One example is quarterly applications for SAS (system access service) riders. Some other flow-through items have traditionally been structured to have less than annual true-up mechanisms to avoid frequent true-up applications. Examples include the load balancing deferral account and weather deferral account for ATCO Gas. These deferral accounts have historically relied on a threshold triggering mechanism to determine when applications are submitted.

715. The companies proposed the continuation of several existing riders outside of the I-X mechanism:

- Fortis proposed to continue to use its transmission adjustment rider to flow through AESO charges, Rider A-1 Municipal Assessment Rider, Municipal Franchise Fee Riders, and the Balancing Pool Allocation Rider.[909]
- EPCOR proposed to continue to deal with its SAS rates and its transmission charge deferral account through separate applications.[910]

909 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 148-149, page 41.
910 Exhibit 103.02, EPCOR application, Section 3.3, paragraph 255, page 82.

- ATCO Electric proposed continued use of its Rider S for its SAS deferral account.[911]
- ATCO Gas proposed to recover its transmission costs through its existing Rider T mechanism.[912]
- AltaGas proposed to continue to address its gas procurement function and costs related to transportation by third parties through its existing gas costs recovery rate and third party transportation rate mechanisms.[913]

Commission findings

716. The Commission considers that to the extent there are existing processes in place that are working well for addressing changes to the approved flow-through items, and those processes do not correspond to the timing of the annual PBR rate adjustment proceedings, these applications should continue to be dealt with as they are today.

7.4.4 Collection mechanism for other Y factor amounts

717. Unless otherwise directed, all Y factor costs incurred by a company other than the flow-through accounts that are collected through separate rate riders addressed in sections 7.4.2.1 and 7.4.2.3 above should be tracked and settled as a Y factor adjustment in its annual PBR rate adjustment filings.

718. The Y factor portion of the annual PBR rate adjustment filings will be comprised of two parts, the first being a provision for the Y factor amounts to be included in rates for the upcoming year, and the second being a true-up between the provision included in rates for the Y factor in the prior year and the actual amounts incurred in the prior year.

719. The provision for the first year of the PBR term which will be included in the compliance filing to this decision will generally be based on the amount that would have been approved for the 2012 test year of the GTA or GRA proceeding that forms the going-in rates (unless a different amount is specified elsewhere in this decision). Because these items will not be subject to the I-X indexing, the companies are directed to remove the amounts included in the 2012 revenue requirement from going-in rates in their compliance filing.

720. The Commission recognizes that addressing the impact of certain Commission directions impacting rates may be better suited to an adjustment to the rates that will be subject to the I-X mechanism rather than through a Y factor. The Commission will make the determination of how to incorporate the result of any directed rate adjustment at the time it makes the relevant decision.

721. The Commission also recognizes that some of the companies may have placeholders in place for certain expenses as part of the GTA or GRA proceedings that form the going-in rates for PBR. To the extent that other proceedings in front of the Commission will establish the approved expenses, and the companies will need to adjust their going-in revenue requirements, the Commission considers that the differences that exist between the placeholder amounts and the final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

911 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 101, page 6-5.
912 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, paragraph 64, page 25.
913 Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

7.4.5 Other existing deferral accounts, reserve accounts or flow-through mechanisms

722. Companies may not have identified all of the items they plan to flow through to customers in their PBR plans. For example ATCO Gas and ATCO Electric did not mention the continued use of existing riders to collect franchise fees and property taxes in their applications, but clarified that the existing treatment would continue in IR (information request) responses.[914] Similar omissions may have occurred for other PBR proposals because of assumptions made by the companies that the existing treatments will continue. Therefore, the Commission directs the companies to identify all of the riders that they intend to utilize during the PBR term that are outside of the I-X mechanism, describe the costs that are being collected on the riders, and explain why it is reasonable to continue to flow through the costs. Any items that have not been approved as a Y factor in this decision or are not identified as separate riders outside of the I-X mechanism by the companies in their compliance filings will be subject to the I-X mechanism.

8 Re-openers and off-ramps

723. A re-opener serves as a safeguard against unexpected results in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable. All of the companies proposed that their PBR plans include a re-opener. As well, Calgary proposed a re-opener for ATCO Gas.[915]

724. An off-ramp is likewise intended to provide a safeguard against unexpected results in the operation of the PBR plan. Proponents of an off-ramp distinguished it from other forms of re-openers; arguing that once triggered, an off-ramp allows for the whole of the PBR plan to be examined and possibly terminated, whereas a re-opener is generally intended to provide an opportunity to investigate and modify a particular component in the operation or design of the PBR plan.[916] NERA stated that re-openers and off-ramps are common features of incentive plans and recommended their inclusion.[917]

725. As with the ENMAX FBR plan, EPCOR and AltaGas distinguished between unforeseen events that impact one or more elements of a PBR plan (to be considered by way of a re-opener) from events that jeopardize the PBR plan in its entirety (to be considered by way of an off-ramp) and accordingly both proposed separate re-opener and off-ramp. The UCA and the CCA simply urged the Commission to adopt the off-ramp that was approved for ENMAX in Decision 2009-035.

726. Fortis, ATCO Electric and ATCO Gas did not include specific off-ramp proposals in their respective PBR plans.[918] They instead proposed that provisions for a re-evaluation of their entire PBR plans be addressed as part of the process for re-opening and reviewing a PBR plan, if necessary. Fortis also noted that any "event material enough to merit consideration as to plan

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[914] Exhibit 207.01, AUC-BOTHATCO-AE-6; Exhibit 206.02, AUC-BOTHATCO-AG-6
[915] Exhibit 298.02, Calgary evidence, page 29.
[916] Exhibit 103.02, EPCOR application, page 77; Exhibit 634, UCA argument, page 58 (taken from Exhibit 228.01, page 55).
[917] Exhibit 391.02, NERA second report, page 48, paragraph 104.
[918] Exhibit 631.01, ATCO Electric argument, paragraph 265; Exhibit 632.01, ATCO Gas argument, paragraph 290; Exhibit 633.01, Fortis argument, paragraphs 228-229

change or potential termination could be brought forward under a Z factor application."[919] The UCA, the CCA and IPCAA all supported the inclusion of a re-opener. With respect to off-ramps, Calgary[920] agreed with the approach advanced by ATCO Gas.

Commission findings

727. A re-opener is commonly included in a PBR plan in order to address specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. No party recommended proceeding with a PBR plan without including the facility for a re-opening and review of the plan if it is determined that there may be a problem with the plan. The Commission agrees that a facility to re-open and review the plan is a necessary element of any PBR plan.

728. However, the Commission agrees with Fortis, ATCO Electric and ATCO Gas that a specific facility for an off-ramp, as distinct from a re-opener, is not required in a PBR plan. All that is required, in the Commission's view, is an opportunity to re-open and review a PBR plan if a design or application flaw comes to light during the term of the PBR plan.

729. Accordingly, the Commission finds that any party, including the Commission on its own motion, will be permitted to bring an application to re-open and review a PBR plan, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan. In this regard, the Commission has approved in the PBR plans a number of mechanisms, including Z factors, K factors and various Y factors that allow for adjustments to rates outside of the adjustments required by the application of the I-X mechanism.

8.1 Specific proposals for re-openers

730. Parties to the proceeding proposed a number of events that should, in their view, lead to a re-opening and review of a PBR plan. The Commission has considered each of these events and made a determination as to whether each constitutes sufficient evidence that there is a problem with a PBR plan that can only be remedied by re-opening and review the plan.

731. Both the UCA and the CCA recommended that the Commission adopt a re-opener and proposed that the events leading to a re-opener as approved for ENMAX in Decision 2009-035 be adopted in this decision. In Decision 2009-035, the Commission accepted that the following events would generally require a re-opening of the ENMAX plan: if circumstances changed in a substantial or unforeseen manner; changes in regulatory status; changes to ENMAX's controlling ownership; or a misrepresentation by ENMAX.[921] With regard to specific events that would require a re-opening and review of the ENMAX plan, the Commission accepted the following: a failure to meet a specific performance standard for two consecutive years; material changes in accounting standards that have an annual impact greater than $5 million; expansion of ENMAX's service area where more than 10,000 customers are included within the expanded area; ROE results that are more than 300 basis points above or below the approved ROE for two

919 Exhibit 633.01, Fortis argument, page 102.
920 Exhibit 629.01, Calgary argument, page 54.
921 Decision 2009-035, page 50

consecutive years; and an actual ROE result that is 500 basis points above or below the approved ROE for one year.[922]

732. Additionally, the CCA requested that, in the event that EPCOR's parent acquired additional businesses which had an impact on the amount of shared services allocated to EPCOR, a deferral account should be established and that it should not be included as a re-opener.[923] IPCAA specifically proposed that a re-opener should address any material degradation in customer service and urged the Commission to establish service quality standards in advance of any implementation of a PBR plan.

733. For ease of reference, the events that were proposed by each distribution company and by Calgary as evidence that a PBR plan should be re-opened and reviewed are set out in the table below:

Table 8-1 Summary of proposed re-opener mechanisms

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
ROE Re-opener	ROE before ESM is +/- 300 basis points above or below approved ROE.*	ROE is +/- 300 basis points* above/below approved ROE in two consecutive years. OR Actual ROE is +/- 500 basis points above/below approved ROE for one year.	If ESM, ROE before ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE.*[927]	Actual weather normalized ROE is +/- 300 basis points above/below approved ROE in two consecutive years. OR Actual ROE is +/- 400 basis points above approved ROE for one year.	If ESM, actual ROE after ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE. Actual ROE will be normalized. If no weather deferral account or if weather deferral account is a Z factor, then use actual ROE.[928]	Actual ROE is 300 basis points below approved ROE.
Default supplier Re-opener			Directed to resume role of default energy supplier.[929]	Material change in the default supply regulations.	Directed to resume role of default energy supplier.[930]	

922 Decision 2009-035, page 50.
923 Exhibit 636.01, CCA argument, at paragraphs 331-333.
924 Exhibit 100.02, Fortis application, page 35, paragraphs 126.
925 Exhibit 103.02, EPCOR application, page 79, paragraph 241.
926 Exhibit 110.01, AltaGas application, page 27, paragraph 87.
927 Exhibit 292.01, AUC-ALLUTILITIES-AE-16.
928 Exhibit 632.01, ATCO Gas argument, page 88, paragraph 285.
929 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
Customer size/service area Re-opener		Expansion of service area of more than 10,000 additional customers in expansion area.	Loss of a franchise resulting in loss of 20,000 or more customers.[931]	Loss of 1000 service sites, excluding service site additions.	Loss of a franchise resulting in loss of 20,000 or more customers.[932]	
Accounting standard Re-opener		Material changes in accounting standards causing an annual impact on total revenue or expenses of >$2.5 million in aggregate in any one year.				
Service quality Re-opener		Failure to meet service quality performance target for two consecutive years.				
Cost of debt Re-opener				Spread between the embedded cost of debt and the I factor is ≥400 basis points.		
Z factor Re-opener				Cumulative, net, annual impact of Z factors on actual weather normalized ROE is ≥ ± 75 basis points in a single year.		
Management structure Re-opener				Material change in the management structure of AltaGas.		

* Approved ROE is the ROE approved by the Commission, generally in a generic cost of capital decision; most recently in Decision 2011-474.

930 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.
931 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.
932 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.

734. Additionally, and for ease of reference, the specific events that were proposed to initiate an off-ramp proposed by EPCOR, AltaGas, the UCA and the CCA are set out in the table below:

Table 8-2 Summary of proposed off-ramp mechanisms

Proposed off-ramp	EPCOR[933]	AltaGas	ENMAX off-ramps supported by CCA[934] / UCA[935]
Substantial change in circumstances	Substantial and unforeseen change in circumstance that renders continuation of PBR unjust or unreasonable. A substantial change in circumstance is defined as a change that increases distribution or transmission costs by $1 million or $0.50 million, respectively and these costs cannot be addressed as a Z factor.		Circumstances change in a substantial or unforeseen manner.
Regulatory status	Change in regulatory status if EPCOR no longer regulated by the Commission or a successor of the Commission.		Change in regulatory status.
Change in tax status	Change that results in a change in EPCOR'S taxable status.		
Change in control		Sale in controlling interest of AltaGas shares or disposition of all assets.[936]	Change in control.

Commission findings

735. In keeping with the Commission's finding that a specific facility for an off-ramp (as distinct from a re-opener) is not required in a PBR plan, the Commission will consider together the proposals made by parties for events that would result in either a re-opener or an off-ramp and determine whether each of these is sufficient to result in a re-opening and review of a PBR plan.

8.1.1 Return on equity

736. Common among the companies and the interveners were proposals to re-open and review a PBR plan if the actual ROE earned by a company exceeded the approved ROE by more than a pre-determined amount and, in some cases, fell below the approved ROE by a pre-determined amount.[937] It was generally argued that earning an actual ROE that is 300 basis points above or below the approved ROE is a sufficient indication that the PBR plan should be re-opened and reviewed. However, the parties differed as to whether the 300 basis point variance needed to be

933 Exhibit 103.02, EPCOR application, page 77.
934 Exhibit 636.01, CCA argument, page 115.
935 Exhibit 634.01, UCA argument, page 57, paragraph 320.
936 Exhibit 628.01, AltaGas argument, page 64.
937 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 233; Exhibit 99.01, ATCO Gas application, page 42, paragraph 123; Exhibit 100.02, Fortis application, page 36, paragraph 126; Exhibit 103.02, EPCOR application, page 79, paragraph 241; Exhibit 110.01, AltaGas application, page 27, paragraph 87; Exhibit 298.02, Calgary evidence, page 48, paragraph 169; Exhibit 634.02, UCA argument, page 58, paragraph 321; Exhibit 636.01, CCA argument, pages 112-113, paragraph 326.

recurring and whether the application of the measure should be symmetrically applied to both over and under-earning. EPCOR also proposed that a 500 basis point variance in one year should result in a re-opening of a PBR plan.[938]

Commission findings

737. The Commission finds that a material variance in the actual ROE achieved by a company when compared to the approved ROE may be an indicator that a PBR plan should be reviewed. The Commission expects that earnings may fluctuate from year to year and therefore finds that an earned ROE 300 basis points above or below the approved ROE in a single year is not sufficient evidence, on its own, that a PBR plan should be reviewed. However, the Commission does agree with the proposal of the CCA and EPCOR that an earned ROE that is 500 basis points above or below the approved ROE in a single year is sufficient to warrant consideration of a re-opening and review of a PBR plan. The Commission also agrees with the CCA, EPCOR and AltaGas that an earned ROE that is 300 basis points above or below the approved ROE for two consecutive years would constitute sufficient evidence to warrant consideration of a re-opening and review of a PBR plan. Both of the gas distribution companies have indicated that weather normalized ROE should be used in the assessment of re-openers. The Commission considers that the fluctuations in earnings caused by variations from normal weather typically experienced by the gas distribution companies would not be an indication that the operation of a PBR plan needs reconsideration. Therefore, the Commission accepts the use of a weather normalized ROE, as proposed by the gas distribution companies, to eliminate the possibility that variations in weather might trigger a re-opener.

738. The Commission has considered whether the rate of return on equity to be used for the purposes of determining if a company's earnings exceed the +/-300 or +/-500 basis point thresholds should be the ROE included in the going-in rates or the approved generic ROE for the year(s) in which the need for a re-opener is to be considered. Consistent with the Commission's determinations in Decision 2009-035[939] and Decision 2010-146,[940] dealing with the ROE used for the purpose of the ENMAX earning sharing mechanism, the Commission will utilize the Generic Cost of Capital ROE which may be determined from time to time by the Commission, as the ROE from which to calculate the +/-300 or +/-500 basis point re-opener thresholds.

739. The actual ROE of the companies to be used to determine whether a re-opener is warranted, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

8.1.2 Change in service area

740. All of the companies, with the exception of Fortis, proposed that a material change to their service area or the number of customers to be served in their service area should result in a re-opening and review of their PBR plans. In this regard, EPCOR expressed concern with the potential for an unanticipated expansion in its service territory, while ATCO Electric, ATCO Gas and AltaGas were concerned with the potential for a material loss of customers.

741. Although a material change in service territory or number of customers may not signal that there is something wrong with the design or operation of a PBR plan, the Commission

938 Exhibit 103.02, EPCOR application, page 79, paragraph 241.
939 Decision 2009-035, paragraphs 418-419.
940 Decision 2010-146, paragraphs 118-119.

agrees that such an event may warrant a re-opening and review of the affected company's PBR plan because the event may have a material impact on the company. The Commission considers that both a material contraction and expansion of customers or service territories may indicate that a re-opening and review of a PBR plan is required. With regard to the materiality thresholds proposed for the expansion or contraction of a company's service territory or customer base, the Commission considers that it is preferable to determine materiality on a case by case basis because materiality will vary from company to company and over time. However, in some cases a Z factor application may be sufficient, see Section 7.4.2.4.4.

8.1.3 Default supply obligations

742. ATCO Electric, ATCO Gas and AltaGas all identified, as events that would result in a re-opening and review of their respective plans, changes to the default supply regulation or a regulatory direction with respect to the assumption of default supply obligations in the case of ATCO Gas and ATCO Electric. The Commission has approved the creation of a Z factor in the PBR plans as more particularly set out in Section 7.2 of this decision. The Commission considers matters related to a change in law or a regulatory direction requiring a company to assume default supply obligations are best dealt with by way of an application for a Z factor adjustment, rather than as a re-opener. Nevertheless, if the event is such that it cannot be dealt with through a Z factor or other mechanism in the plan, an application for consideration of a re-opener could be filed.

8.1.4 Accounting standards

743. EPCOR proposed that material changes in accounting standards be included as an event that would signal the requirement for a re-opening and review of a PBR plan. Fortis[941] and AltaGas[942] identified material changes in accounting standards as a matter that should be addressed through a Y factor. The Commission agrees that material accounting changes may require an adjustment to rates under a PBR plan, but the impact of accounting changes should properly be considered in a Z factor application and do not necessarily signal that there is a problem with the design or operation of a PBR plan. Accordingly, the Commission finds that any rate adjustments required in response to material changes to accounting standards should be dealt with by way of a Z factor application.

8.1.5 Quality

744. IPPCA recommended that any material degradation in customer service should require a re-opening and review of a PBR plan. As well, EPCOR proposed that failure to meet service quality performance targets for two consecutive years should also require a re-opening and review of the company's PBR plan. These matters have been addressed in Section 14 of this decision in the Commission's findings regarding service quality.

8.1.6 Change of control

745. AltaGas proposed two events with respect to a change of ownership or control that would warrant a re-opening and review of its PBR plan leading, in its view, to an end to its PBR plan. These events are the sale of a controlling interest in AltaGas shares or the disposal of all or substantially all of its assets. The Commission considers that any change in controlling interest in AltaGas shares or the disposal of all or substantially all of the AltaGas assets is within the

941 Exhibit 100.02, Fortis application, Section 6.1.2, paragraphs 92-94, pages 26-27.
942 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

control of the AltaGas shareholder, the companies' parent business entities or the management of AltaGas. That is, the owners or management of AltaGas have a choice with respect to transactions of this nature. The Commission does not consider that the PBR plan should be terminable as a result of a voluntary event of this nature. Further, it is expected that any new share or asset purchaser would, as part of its due diligence, be aware of the PBR plan and would take that into consideration as part of its purchase decision. There is no obvious correlation between a change in the ownership structure of a company or the sale of its assets, and a design or operational failure of a PBR plan. In any event, for rate setting purposes, the assets of a company must be transferred at net book value and the same assets would continue to be used to provide utility service both before and after the share or asset transfer. Accordingly, the proposal to end the PBR plan in the event of a change of ownership or control is denied

8.1.7 Change in regulatory status

746. EPCOR proposed that a change in regulatory status should result in a re-opening of the PBR plan, leading to an end to the plan. It is not clear to the Commission why a change in regulatory status would indicate a failure of the operation of the PBR plan. In any event, any issues arising from a change in regulator would, in the Commission's view, be a matter for the regulator of jurisdiction to consider.

8.1.8 Change in taxable status

747. EPCOR also proposed that a change in the taxable status of the company should result in a re-opening of the company's PBR plan with a view to ending the plan. It is also unclear to the Commission why such a change in the taxable status of the company would require the abandonment of the entire PBR plan. In the Commission's view, a change in taxable status would be a matter for consideration pursuant to a Z factor application.

8.1.9 Spread between debt costs and the I factor

748. AltaGas proposed that a material change in the spread between the cost of debt and the I factor should warrant a re-opening of its PBR plan. The Commission understands that, generally, any material changes in the spread between the cost of debt and the I factor should be occasioned by changes in interest rates in the economy and would therefore be eventually reflected in the indexes that make up the I factor, as discussed in Section 7.4.2.6.1. Otherwise, any company-specific changes to debt costs that are not a result of changes to interest rates in the economy as a whole are the result of actions taken by management and should not be the subject of a re-opener. Accordingly, the Commission does not agree with AltaGas that a material change in the spread between the cost of debt and the I factor should be an event that occasions a re-opening of the PBR plan.

8.1.10 Cumulative impact of Z factors

749. AltaGas also proposed that the cumulative impact of Z factors may warrant a re-opening of a PBR plan. The Commission considers that each Z factor application must be considered on its own merits and, if warranted, rates will be adjusted accordingly. The fact that there may be many Z factors approved for a company under its PBR plan is not, in and of itself, an indication that the PBR plan should automatically be re-opened and reviewed.

8.1.11 Organizational structure changes

750. AltaGas also proposed that changes to a company's organizational structure should result in a re-opening of a PBR plan. However, the Commission considers that changes to the organizational structure of the company are within the control of the company or its shareholder and would not, in the Commission's view, signal the need for the PBR plan to be re-opened and reviewed.

8.1.12 Material misrepresentation

751. The CCA and the UCA proposed that a PBR plan should be re-opened and reviewed with a view to ending the plan in the face of a deliberate material misrepresentation by management. The Commission has not been persuaded that this circumstance would signal a failure of the PBR plan that cannot be remedied. Accordingly, the Commission considers that a re-opening and review of the plan may be warranted in this circumstance, but the Commission cannot conclude that such an event would warrant ending the plan. In any event, the Commission considers that, if faced with such a misrepresentation, there are other remedies available to the Commission through the plan itself as well as the imposition of an administrative penalty pursuant to Section 63 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, which can be imposed to address such a serious matter.

8.1.13 Substantial change in circumstances

752. EPCOR proposed that a substantial change in circumstances should result in a re-opening and review of a PBR plan, leading in the company's view to an end to the plan. The Commission observes that a Z factor application is generally intended to consider a substantial change in circumstances. The Commission considers that, in the interests of regulatory efficiently and easing of the regulatory burden, the number of occasions for adjustments to rates by way of a Z factor or a re-opening and review of a PBR plan should be limited so as to allow the plans to generate the incentives that they are intended to create.

753. Nonetheless, the Commission recognizes that it is not possible to predict every circumstance that might legitimately be the subject of a re-opening and review of a PBR plan. Accordingly, should a substantial change in circumstances occur that does not, in the applicant's view, qualify for a Z factor application (as defined in Section 7.2 this decision) then an applicant may bring a re-opener application before the Commission for consideration. In this regard, the Commission is cognizant that, given a material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan, it would be incumbent upon the Commission to re-open and review the plan.

8.2 Implementation

754. Several parties proposed that a re-opening of the PBR plan should be automatic following any of the events designated by the Commission as warranting a re-opening and review of a plan.

755. Calgary argued that "the design for re-openers contemplates a formulaic approach, once the utility is able to conclusively demonstrate that the achieved ROE is 300 basis points or more below the approved ROE, then the re-opener would be triggered automatically and parties would

begin discussions regarding potential changes to the existing PBR plan (either one-time or prospective or ongoing)."[943]

756. ATCO Electric and ATCO Gas stated that a re-opener should be automatic, once a triggering event is identified. Moreover, they suggested that, because the company is in the best position to be aware of an event that would signal the need for a re-opening of the PBR plan, it is the company that should notify the Commission that a re-opener of the PBR plan had been triggered.[944] Likewise, Fortis also proposed the automatic triggering of a re-opener if the upper or lower bounds of the earnings sharing mechanism it had proposed were exceeded.[945]

Commission findings

757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.

758. As noted above, the Commission finds that any party, including the Commission on its own motion, should be permitted to bring an application to re-open and review a PBR plan if there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan. The Commission will consider applications to re-open and review a PBR plan and make a determination on the merits of the application as to whether a re-opening of the plan is warranted. In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling.[946]

9 Efficiency carry-over mechanism

9.1 Purpose and rationale for an efficiency carry-over mechanism

759. A company's incentive to find efficiencies weakens as the end of the PBR term approaches, because there is less time remaining for the company to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the company to continue to benefit from any efficiency gains after the end of the PBR term.

760. The CCA described an ECM as "a ratemaking mechanism designed to strengthen incentives for cost containment in the later years of a PBR period by permitting the utility to carry over some of the benefits of efficiency gains achieved in one PBR plan to the subsequent plan."[947] EPCOR, ATCO Gas and ATCO Electric proposed an ECM as part of their PBR plans.

943 Exhibit 629.01, Calgary argument, page 53.
944 Exhibit 631.01, ATCO Electric argument, paragraph 262 and Exhibit 632.01, ATCO Gas argument, paragraph 286.
945 Exhibit 633.01, Fortis argument at paragraph 226 citing the evidence of Lorimer at Transcript, Volume 11, page 2173.
946 Decision 2009-035, ENMAX FBR contains a similar provision in paragraph 257.
947 Exhibit 636.01, CCA argument, paragraph 344.

To support the inclusion of an ECM, ATCO Electric and ATCO Gas explained that "…the incentive for identifying and implementing efficiency measures is strongest in the earlier years of the PBR Plan as the utility will then have several years in which to take advantage of the efficiency improvements."[948] EPCOR's witness Dr. Weisman explained that "[t]he regulated firm will have less than ideal incentives to innovate and discover efficiencies if it believes that the regulator will simply claw back these efficiency gains at the end of the PBR regime and pass them on to consumers in the form of lower rates. These adverse incentives are particularly pronounced toward the end of the PBR regime."[949] AltaGas stated it "recognizes the purpose of such a mechanism is to maintain incentives for investment in efficiency initiatives throughout the IR [incentive regulation] term, particularly where the benefits are not expected to be recovered during that term."[950]

9.1.1 ATCO Electric's capital efficiency carry-over mechanism

761. ATCO Electric proposed two forms of efficiency carry-over mechanisms, one based on rate of return and one for capital. ATCO Electric's K factor efficiency incentive mechanism (KFEI) was also initially requested by ATCO Gas,[951] but ATCO Gas subsequently withdrew its request for a KFEI mechanism in its updated filing.[952]

762. ATCO Electric's KFEI is calculated as any positive difference between the forecast cost of a capital project qualifying for a K factor (discussed in Section 7.3.3.2) and the actual cost of the capital project at the end of the term. Under its proposal, ATCO Electric would carry forward one-half of this positive difference into the first year following the end of the PBR term and one-third of the difference into the second year following the end of the PBR term.[953] The proposed KFEI is intended to ensure that the company has an incentive to look for efficiencies in its K factor capital programs over the course of the entire PBR term.[954]

763. The UCA did not support ATCO Electric's request for a KFEI "[a]s the UCA is not supporting the inclusion of any Capital adjustments outside specific Capital Trackers."[955]

Commission findings

764. The Commission considers that the KFEI proposed by ATCO Electric does not promote additional efficiency. The Commission finds that the structure of ATCO Electric's KFEI would provide an incentive for the company to over forecast its capital programs. When its actual costs are subsequently less than the over-forecast amount, the company would benefit, but not necessarily as a result of efficiency gains. For this reason, ATCO Electric's KFEI is denied.

9.1.2 Return on equity (ROE) efficiency carry-over mechanisms

765. EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans. EPCOR explained that its ECM would be balanced. This means that it would carry

[948] Exhibit 98.02, ATCO Electric application, page 11-1, paragraph 236, Exhibit 99.01, ATCO Gas application, page 43, paragraph 127.
[949] Exhibit 103.03, written evidence of Dr. Weisman, paragraph 60.
[950] Exhibit 628.01, AltaGas argument, page 74.
[951] Exhibit 99.01, ATCO Gas application, Section 2.10.1, paragraph 128, page 44.
[952] Exhibit 389.01, ATCO Gas updated filing, Section 2.8, paragraph 20, page 10.
[953] Exhibit 98.02, ATCO Electric application, Section 11, paragraph 237, page 11-1.
[954] Transcript, Volume 7, page 1280, Ms. Wilson.
[955] Exhibit 634.01, UCA argument, paragraph 352.

over half of any earnings above its approved ROE for a period of two years following the end of the PBR term. It would also receive 100 per cent of any shortfall below the approved ROE for a period of two years following the end of the PBR term.[956] EPCOR also linked the size of its rate of return adjustment to its service quality measures, with lower service quality leading to a lower percentage adjustment.[957] EPCOR did not indicate whether there was a limit on the amount of the earnings or losses to be carried over.

766. In contrast to EPCOR's ROE ECM, the ATCO companies did not include an adjustment for earnings deficiencies in their ECM proposals and did not link their ECM to service quality measures. ATCO Electric and ATCO Gas described their proposed ROE ECM as follows:

> a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan.[958]

767. Some parties noted that it does not appear that ECMs are common in North America. Very few examples of existing ECMs were cited or discussed in the hearing.[959] NERA indicated that ECMs are uncommon in PBR plans and stated that ECMs appear to be a desire to have the profit incentives of a PBR plan transcend to some degree beyond the end of the PBR term, "when rates would otherwise be squared with costs and profitable innovations capitalized for ratepayers."[960] Dr. Makholm suggested that in order to strengthen incentives, the term should be extended rather than including an ECM in a PBR plan.[961] NERA indicated that it has not seen evidence that adopting ECMs, as a partial lengthening of regulatory lag, "is worth the additional complications it would pose for the periodic future base rate cases."[962]

768. Some of the companies argued that ECMs provide a strengthening of incentives that outweigh any of the shortcomings of ECMs identified by NERA.[963] In addition, Dr. Lowry, the CCA and the ATCO companies submitted that an ECM is a deterrent to the gaming that might be associated with the timing of capital investments.[964]

769. Interveners, with the exception of Calgary, supported the general concept of ECMs, but they did not support the specific ECMs proposed by EPCOR and the ATCO companies.[965] The

[956] Exhibit 630.02, EPCOR argument paragraph 264.
[957] Exhibit 103.02, EPCOR application, paragraph 46 and Exhibit 630.02, EPCOR argument, paragraph 265.
[958] Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.
[959] Exhibit 391.02, NERA second report, paragraph 65. In its survey of PBR plans, NERA identified two that had an ECM. Exhibit 199.02, Cal-ATCO Gas I-32 identified one plan.
[960] Exhibit 391.02, NERA second report, page 9, paragraph 13.
[961] Transcript, Volume 1, Dr. Makholm's evidence, pages 194 and 195.
[962] Exhibit 391.02, NERA second report, paragraph 13.
[963] Exhibit 630.02, EPCOR argument, paragraph 270; Exhibit 631.01, ATCO Electric argument, paragraph 281; Exhibit 632.01, ATCO Gas argument, paragraph 303.
[964] Transcript, Volume 13, Dr. Lowry, page 2642; Exhibit 631.01, ATCO Electric argument, page 70; Exhibit 648.02, ATCO Gas argument, page 131, paragraph 480; Exhibit 636.01, CCA argument, paragraphs 342-347.
[965] Exhibit 634.01, UCA argument, paragraphs 356 to 359; Exhibit 642.01, IPCAA reply, paragraph 21. IPCAA states that it concurs with the UCA argument for ECMs and Exhibit 636.01, CCA argument, paragraph 342.

UCA argued that ATCO Gas and ATCO Electric have achieved ROEs prior to PBR that are in excess of approved levels. Therefore, the UCA recommended that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period because this level of ROE "represents the current level of efficiency."[966] The UCA stated, "[b]y basing the target on the actual achievement, the intent of the PBR to incent greater efficiency is maintained. If a lower target is used, the incentive to improve efficiency is lessened."[967]

770. While supporting the concept of an ECM based on actual ROE performance, the UCA also suggested that there must be recognition of any efficiency gains achieved prior to the commencement of PBR that are not reflected in the going-in rates. The UCA stated, "[s]ince there are identified efficiency gains coming out of the COS environment, there should be an ECM for both going-in-rates and for the end of term."[968] The UCA proposed addressing the going-in portion of its proposed ECM through an adjustment to going-in rates. If no efficiency gains are recognized in going-in rates, the UCA argued that there should be no ECM included in the PBR plans.[969]

771. The CCA stated that it supports a Commission directed "generic ECM module, preferably by negotiation, in the early part of the PBR term."[970] The CCA also stated that the record was insufficient to approve an alternative ECM.[971]

772. Calgary also rejected the inclusion of an ROE ECM in ATCO Gas' PBR plan, providing among its reasons that there is no evidence that lengthening the period for recovery guarantees incentives or results in improved efficiencies, that there is no guarantee that efficiencies are passed on to ratepayers and that an ECM only spreads the incentives over a longer period but does not strengthen the incentives.[972]

773. Dr. Weisman discussed that alternatively an open-ended term operates as an efficiency carry-over mechanism because rates are not reset.[973] AltaGas stated that "its proposal to include an option to extend the term of its IR [incentive regulation] Plan may be considered a form of ECM, as it potentially allows AUI to continue operating under the approved IR [incentive regulation] Plan for an additional two years."[974]

Commission findings

774. In Decision 2009-035, the Commission recognized "that the longer the term of an FBR plan, the stronger the incentives for utilities to improve their efficiency."[975] In recognition of this issue the Commission stated in its February 26, 2010 letter initiating the PBR initiative that:

> The Commission will initiate a proceeding during the first PBR term to consider how the success of the PBR plan should be judged and how it might be re-initiated, or rates re-

966 Exhibit 634.01. UCA argument, paragraph 359.
967 Exhibit 634.01, UCA argument, paragraph 357.
968 Exhibit 634.01, UCA argument, paragraph 346.
969 Exhibit 634.01, UCA argument, paragraph 360.
970 Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
971 Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
972 Exhibit 629.01, Calgary argument, pages 61 to 62.
973 Transcript, Volume 10, Dr. Weisman, page 1827, lines 2 to 5.
974 Exhibit 628.01, AltaGas argument, page 74.
975 Decision 2009-035, paragraph 116.

based, at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives

775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term.[976] The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.

776. EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions.[977] The Commission agrees. As discussed above, the Commission supports a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission finds that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.

777. With respect to EPCOR's proposal to include service quality as part of its ECM, the Commission will be relying on AUC Rule 002 along with administrative penalties under Section 63 of the *Alberta Utilities Commission Act* to ensure that service quality is maintained. In Section 14, the Commission has determined that these measures are sufficient to address service quality. Accordingly, EPCOR's proposed service quality adjustments to its ECM formula are not required.

778. The Commission rejects the UCA's recommendation that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period. The Commission has already made its determinations on the 2012 going-in rates in Section 3 of this decision. The purpose of the ECM is to provide an incentive to the companies to continue to achieve efficiencies in the latter part of the PBR term. If the Commission were to adopt the UCA's proposal, this incentive would be distorted because it would require the assessment of the efficiencies gained during the PBR term against financial results from the past and under a different regulatory framework.

779. In the Commission's view, the correct ROE to use for the purposes of calculating the amount of the ECM is the average approved generic ROE in place for each year during the PBR term.

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976 Exhibit 636.01, CCA argument, paragraph 344; Transcript, Volume 13, pages 2647-2648; Exhibit 103.03, evidence of Dr. Weisman, paragraphs 59 and 60; Transcript Volume 10, page 1820; Exhibit 628.01, AltaGas argument, page 74; Exhibit 647.01, ATCO Electric reply argument, page 70, paragraph 281; Exhibit 648.02, ATCO Gas reply argument, page 95, paragraph 303; Exhibit 630.02, EPCOR argument, paragraph 270.

977 Exhibit 634.01, UCA argument, paragraphs 358-359.

780. The actual ROE of the companies to be used for the purposes of calculating the amount of the ECM, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

9.1.3 Authority to approve an ECM

781. In its argument, Calgary questioned whether ECMs comply with the statutory framework in Alberta and raised issues of jurisdiction. Calgary stated that the equitable allocation or sharing with customers of benefits from incentives to be approved by the Commission is a matter of jurisdiction. Calgary argued that the Commission does not have jurisdiction to approve ATCO Gas' ECM as it is not a sharing of benefits from incentives and it is contrary to law. Calgary referenced AUC PBR Principle 5,[978] Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*, RSA 2000, c. G-5, in support of the equitable sharing of benefits derived from utility incentives being required for ESMs (earnings sharing mechanism) and ECMs (efficiency carry-over mechanism).[979] Calgary also argued that ATCO Gas' ECM will operate outside of the five-year PBR plan term. Calgary stated:

> There is no rate base determined for such post PBR term as part of this Proceeding, and as a result, the Commission's approval of ATCO's ECM will be contrary to Section 37 (1) of the GUA, which requires the Commission to determine the rate base of the gas utility and fix a fair return on that rate base at the same time. Since the rate base to which the ECM would apply will be determined at the ti[m]e of rebasing, there is obviously a time disconnect between setting ROE elements today (in this Proceeding) and determining the rate base in the future to which the ECM would apply.[980]

782. Section 45(1) of the *Gas Utilities Act* states:

> 45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Commission, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,
>
> (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
>
> (b) that are otherwise in the public interest.

783. Section 120(2)(d) of the *Electric Utilities Act* reads:

> 120(2) A tariff may provide
> ….
> (d) for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the owner of the electric utility and customers.

784. ATCO Gas responded to Calgary's questioning of whether ECMs comply with the statutory framework in Alberta. ATCO Gas stated that its ROE ECM is a sharing of benefits

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978 Bulletin 2010-20, page 3, Principle 5: "Customers and the regulated companies should share the benefits of a PBR plan."
979 Exhibit 629.01, Calgary argument, pages 56 and 62.
980 Exhibit 629.01, Calgary argument, page 62.

from incentives of 50 per cent of the difference between the average ROE and the approved ROE over the plan term, if the difference is positive.[981] Section 45(1)(a) of the *Gas Utilities Act* does not indicate when the intended cost savings or other benefits are to be allocated to customers. This section only addresses that cost savings or other benefits are intended to result in cost savings or other benefits to be allocated between the owner of a gas utility and its customers.[982] ATCO Gas pointed out that this is also the case for Section 120(2)(d) of the *Electric Utilities Act*[983] and both of these sections do not indicate that benefits have to be shared equally. Additionally, the Commission has been determining the fair rate of return for Alberta gas and electric utilities distinctly from determining rate base since Decision 2004-052,[984] which established a generic formula for the establishment of ROE. ATCO Gas argued that Section 37(1) has not been an issue since Decision 2004-052, and it will not be an issue under PBR.

785. With respect to the approval of its ROE ECM, ATCO Gas stated that the ROE ECM establishes the way in which a potential increase to a future ROE will be calculated. It does not establish the ROE for the utility. There is no inconsistency for the ROE ECM as the application of the effect of the ROE ECM will occur at the same time as the future ROE will be applied.[985]

Commission findings

786. Upon review of the legislation as well as the arguments of Calgary and ATCO Gas, the Commission finds that Section 45(1)(a) of the *Gas Utilities Act* and Section 120(2)(d) of the *Electric Utilities Act* allow for the approval of rates and tariffs that result in cost savings and other benefits to be allocated between utilities and their customers. Further, Section 5(h) of the *Electric Utilities Act* states that one of the purposes of the Act is “to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.” Section 102(2)(d) of the *Electric Utilities Act* specifically refers to incentives for efficiencies and allows the Commission to include incentives for efficiencies that result in cost savings or other benefits, which is consistent with PBR. In addition, Section 121(3) of the *Electric Utilities Act* provides that “[a] tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.”

787. By Order of the Lieutenant Governor in Council, the Commission has the authority under Section 45(1) of the *Gas Utilities Act* “to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act.”[986]

788. ATCO Gas has correctly indicated that its ROE ECM would result in a sharing of any differences between its average ROE over the plan term and approved ROE, in the case where the average ROE over the term is higher than the approved ROE. Any benefits of a higher ROE

981 Exhibit 648.02, ATCO Gas reply argument, page 131 of 152, paragraph 482.
982 Exhibit 648.02, ATCO Gas reply argument, page 123 of 152, paragraph 455.
983 Exhibit 648.02, ATCO Gas reply argument, page 124 of 152, paragraph 456.
984 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), Nova Gas Transmission Ltd., Application No. 1271597, July 2, 2004.
985 Exhibit 648.02, ATCO Gas reply argument, page 132 of 152, paragraph 483.
986 O.C. 235/2011 June 1, 2011.

would be shared with customers under ATCO Gas' ECM proposal. Further, the entire rationale for an ECM is to incent the company to pursue additional cost savings particularly through capital investment that it might not be otherwise inclined to do in the latter part of the PBR term. Customers will directly benefit from these additional cost savings when utility costs and revenues are next reviewed and rates are adjusted.

789. The Commission has considered the ECMs proposed by the companies in light of the legislative requirements under the *Electric Utilities Act* and the *Gas Utilities Act*. The ECMs as approved above provide for incentives for efficiencies, or are intended to result in cost savings or other benefits to be allocated between the owner of the utility and its customers.

790. Calgary argued Section 37(1) of the *Gas Utilities Act* requires that rate base and rate of return be approved at the same time. Section 37(1) stated that the Commission shall determine a rate base and "upon determining a rate base it shall fix a fair return on the rate base." Section 45(1) of the *Gas Utilities Act* states that instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44 of the Act, the Commission may approve rates that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers. This includes the jurisdiction to approve the provisions of an incentive plan that are intended to create incentives during the PBR term to achieve cost savings or other benefits to be allocated between the owner of the gas utility and its customers in a period beyond the initial plan term.

791. The Commission concludes that ECMs are consistent with the governing legislation and it is within the Commission's jurisdiction to consider ECMs as part of the PBR plan under Section 45(1) of the *Gas Utilities Act* and under sections 5(h), 120(2)(d) and 121(3) of the *Electric Utilities Act*.

10 Earnings sharing mechanism

792. An ESM (earnings sharing mechanism) is intended to address the potential that a regulated company will earn a return significantly above or below the approved ROE (return on equity) during the PBR term. An ESM generally establishes a formula for sharing with the company's customers earnings in excess of a designated amount and may provide for a sharing of any shortfall below a designated amount. The implementation of an ESM generally requires annual filings of ROE results and sharing calculations and some form of verification of these filings. An ESM is a common feature of first generation PBR plans.

793. The Commission approved an ESM in Decision 2009-035 as part of ENMAX's FBR plan. ENMAX's approved ESM provides for an annual sharing mechanism equal to 50 per cent of ENMAX's earnings that are over 100 basis points above the approved ROE established by the Commission. Sharing of these earnings is given effect by way of a reduction in rates in the year following the year in which the excess earnings were realized. The ENMAX ESM provides for a sharing of earnings above the approved ROE but not for a sharing of any earning below the approved ROE.

794. In approving the ESM for ENMAX, the Commission acknowledged that an ESM blunts efficiency incentives but recognized that performance-based regulation was a relatively new

development in Alberta utility regulation and considered that, in the circumstances, it provided a useful safeguard in the early stages of a PBR plan.[987]

795. Fortis and the ATCO companies proposed including an ESM in their PBR plans. Additionally, the UCA, the CCA and Calgary supported the inclusion of ESMs in the companies' PBR plans.

796. Fortis proposed a symmetrical deadband range of 100 basis points above and below the approved ROE. Any return within 100 basis points of the approved ROE would not be shared with customers, and any shortfall up to 100 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. However, any return above the 100 basis point threshold would be shared equally with customers by way of a rate reduction in the following year, while any shortfall below the 100 basis point threshold would be shared equally with customers by way of a rate increase in the following year. Under the Fortis proposal, the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE in one year.[988]

797. Fortis stated that "given that this is the first time that FortisAlberta is applying for a PBR plan, an ESM will serve as a safeguard to buffer the earnings results during PBR implementation, in a manner beneficial to both customers and the Company."[989]

798. When asked by the Commission how its PBR proposal would need to change if its ESM were eliminated, Fortis stated:

> FortisAlberta's PBR Proposal would not otherwise change if the ESM component were eliminated. The proposed re-opener mechanism is based on the actual ROE before the ESM is applied.[990]

799. ATCO Electric and ATCO Gas proposed an ESM in each of their plans similar to the Fortis proposal. However, the ATCO companies proposed a symmetrical deadband range of 200 basis points above and below the approved ROE. Any return within 200 basis points of the approved ROE would not be shared with customers, and any shortfall up to 200 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. Actual results beyond the 200 basis point threshold would be shared equally with customers by way of a rate reduction or rate increase in the following year, as required.

800. Under the ATCO companies' proposals,[991] the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE, after accounting for the implementation of the ESM. Ms. Wilson for the ATCO companies described the relationship between the companies' ESM and the re-opener proposal as follows, "[g]enerally earnings-sharing mechanisms and reopener clauses are viewed more as ensuring that if some of the parameters in the plan haven't been completely specified correctly or if something unexpected comes out of the PBR plan that was not -- the plan somehow doesn't have the ability

987 Decision 2009-035, paragraphs 280 and 281.
988 Exhibit 100.02, Fortis application, paragraph 126.
989 Exhibit 100.02, Fortis application, page 35, paragraph 121.
990 Exhibit 219.02, Fortis, AUC-ALLUTILITIES-FAI-16.
991 Exhibit 98.02, ATCO Electric application, paragraph 233; Exhibit 99.01, ATCO Gas application, paragraph 123.

to address, those mechanisms ensure that the plan will not result in extreme outcomes for either customers or the utility."[992]

801. In addition to the above, ATCO Gas added the following caveat regarding its ESM and weather deferral account:

> In the event that ATCO Gas no longer has a Weather Deferral Account (WDA) during the course of the PBR Plan, the ROE to be used [for earnings sharing] will be the actual utility ROE, including the effects of deviations from normal weather.[993]

802. ATCO Electric and ATCO Gas submitted in argument that their ESMs have sufficiently wide deadbands to address any blunting of efficiency incentives that an ESM might cause.[994] The ATCO companies did not propose any changes to their PBR plans if ESMs were not approved. Specifically, the ATCO companies indicated that, if their plans were not to include an ESM, the 300 basis point threshold for re-openers would remain unchanged.[995]

803. Initially, AltaGas proposed an ESM as part of its PBR plan.[996] AltaGas proposed a symmetrical ESM with 50/50 sharing of earnings between 100 and 200 basis points above and below the approved ROE and 60(company)/40(customer) sharing of earnings over 200 basis points above and below the approved ROE.[997] AltaGas also submitted that, if achieved earnings are significantly greater than the approved ROE (i.e., above or below 300 basis points for two consecutive years or above or below 400 basis points in a single year), customers or AltaGas may apply for a re-opening of the PBR plan.[998]

804. AltaGas initially indicated that, if there was no ESM, three adjustments to the PBR formula would be required. First, the rates at the beginning of the PBR period would need to be adjusted upward. Second, the Y and Z factors might need to be carefully evaluated, and perhaps more broadly defined, given the potential effect of higher risks on the willingness of AltaGas to fund capital and commit resources. Third, AltaGas stated that "provided the rate of return reflects the impacts of higher financial risks, the Company faces stronger incentives to increase efficiency, without a provision for earnings sharing. Under these circumstances, it would be appropriate to consider a stretch component to the X Factor."[999] During the hearing, AltaGas confirmed that it is prepared to dispense with an ESM in its PBR plan with the addition of a stretch factor of between 0.1 and 0.2 per cent.[1000]

805. EPCOR did not propose an ESM as part of its PBR plan. EPCOR argued that ESMs are not consistent with AUC PBR principles 1, 3, and 5.[1001] As part of its application, EPCOR stated that a pure price cap approach has several advantages over a price cap plan with an ESM,

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992 Transcript. Volume 3, page 568, Ms. Wilson.
993 Exhibit 99.01, ATCO Gas application, page 41, paragraph 118.
994 Exhibit 631.01, ATCO Electric argument, paragraph 267 and Exhibit 632.01, ATCO Gas argument, paragraph 292; Dr. Carpenter, Transcript, Volume 7, page 1308, lines17 to 22.
995 Exhibit 631.01, ATCO Electric argument, paragraph 269 and Exhibit 632.01, ATCO Gas argument, paragraph 294.
996 Exhibit 110.01, AltaGas application, paragraph 89.
997 Exhibit 110.01, AltaGas application, paragraph 89.
998 Exhibit 628.01, AltaGas argument, page 67.
999 Exhibit 247.01, AltaGas, AUC-ALLUTILITIES-AUI-16.
1000 Exhibit 529.01, AltaGas letter on corrections and amendments to its incentive regulation application, 2012-04-18, page 4.
1001 Exhibit 630.02, EPCOR argument, paragraph 238.

because a pure price cap plan provides for greater incentives for efficiency that are more aligned with those in a competitive market.[1002]

806. EPCOR pointed to Dr. Weisman's evidence, stating that the gains from a pure price cap plan should exceed those from a PBR plan with earnings sharing. A plan without an ESM would also largely eliminate concerns with respect to gaming. Dr. Weisman stated:

> First, consumers bear less risk under pure price cap regulation that under a PBR with earnings sharing because prices do not vary directly with either the costs or the earnings of the regulated firm. Second, at least as a theoretical matter, because the incentives for cost reducing innovation are more pronounced under pure price cap regulation, the X factor should be higher than under a PBR regime that incorporates earnings sharing, *ceteris paribus*. Third, the incentives for strategic cost shifting, cost misreporting and abuse are mitigated under a pure price cap regime and this further lessens consumer exposure to prices that may reflect higher costs associated with such inefficiencies. As a corollary to this third observation, the pure PBR framework obviates the need for regulatory intervention with respect to cost allocations under a shared services model as rates are invariant to changes in such allocations over the course of the PBR regime. Finally, as the ongoing administration of a pure price regime economizes on both Commission and company resources, consumers benefit from the flow through of such efficiencies in the form of lower prices over time.[1003]

807. When questioned by the Commission about how its PBR plan would change if an ESM were adopted, EPCOR stated:

> At a minimum, if an earnings sharing mechanism were added to EDTI's PBR Plan, EDTI's proposed stretch factor would need to be eliminated, EDTI's proposed X factor would need to be reduced (i.e., made more negative) and the proposed timeline for the annual rate adjustment process would need to be adjusted due to the significant regulatory burden that earnings sharing mechanisms entail.[1004]

808. Dr. Schoech for AltaGas argued that the determination of earnings to be shared would result in a situation akin to cost of service regulation. Dr. Schoech stated:

> The earnings-sharing formulas introduce a bit of cost of service – I emphasize a bit of cost of service back into the regulation because earnings sharings looks [sic.] at the actual rates of return that the company achieves which, in turn, are based upon the company's costs. A pure revenue per customer cap with no earnings sharing completely decouples rates from the utility costs. And it's the disincentive or the reduced incentives, I guess I should say, arise from that reintroduction of an element of cost of service.[1005]

809. The interveners generally supported ESMs as part of PBR plans. The UCA indicated that its proposed menu approach for the X factor, which has been described in Section 6.2, has an ESM embedded into the menu options. However, if the menu approach is not adopted for the X factor, the UCA supported adoption of the ESM approved for ENMAX,[1006] including

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1002 Exhibit 103.02, EPCOR application, paragraph 16.
1003 Exhibit 103.03, EPCOR application, Appendix A: The EDTI PBR Framework: Commission Principles and Economic Foundations, paragraph 78.
1004 Exhibit 233.01, EPCOR, AUC-ALLUTILITIES-EDTI-16, page 49.
1005 Transcript, Volume 8, page 1376, lines 6 to 15.
1006 Exhibit 634.02, UCA argument, paragraphs 329 and 330.

independent verification of the ROE with attestation by an officer of the company, with the same filing requirements as established for ENMAX.[1007]

810. The CCA also recommended that the PBR plans include ESMs similar to ENMAX's asymmetrical ESM[1008] and that a corporate sign-off be required on any data relied upon for the calculation of the earnings to be shared.[1009]

811. Calgary recommended adoption of an ESM for ATCO Gas but proposed that it be asymmetrical, providing for a sharing only of earnings above the approved ROE. Calgary questioned whether an ESM with a deadband is genuinely a sharing with ratepayers that would meet AUC Principle 5 and the legislative requirements of the *Electric Utilities Act*. Calgary argued that the equitable sharing or allocation of benefits derived from utility incentives with customers is required under Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*.[1010]

812. ENMAX did not take a position on the inclusion of ESMs in the proposed PBR plans of the companies, other than to state that an ESM should be symmetrical. However, ENMAX commented on the operation of the ESM in its FBR plan. In its evidence, ENMAX stated that although the ENMAX ESM has benefited customers, it has not benefited the company due to the unexpectedly high costs to establish, review and independently verify its ESM calculations. This verification process resulted in additional filing requirements over and above the requirements under AUC Rule 005.

813. Parties also pointed to concerns with gaming in ascertaining the actual returns to be shared.[1011] ENMAX proposed that, if the Commission approves an ESM for the companies, the Commission should determine in advance the necessary information required to ensure customers are receiving their share of the benefits.[1012] In this regard, most parties agreed that AUC Rule 005 would be the best vehicle to measure annual earnings sharing.[1013] ATCO Electric and ATCO Gas stated that the Commission's current safeguards in AUC Rule 005 are sufficient to address any concerns with administration and gaming.[1014]

814. Ms. Frayer, in her evidence for Fortis, noted that ESMs have other benefits to counter the weakening of incentives. These include the avoidance of unscheduled regulatory interventions, such as windfall profit taxes or other forms of claw-back, which distort patterns of investment and return.[1015]

815. IPCAA stated that an annual sharing of benefits would not be necessary as "[a]n annual benefit-sharing calculation based on net income would require a review of all revenues and costs, since net income is a comprehensive financial calculation. This in turn would require detailed variance analysis by management and extensive review, knowing that litigation is a possibility. It

[1007] Exhibit 634.02, UCA argument, paragraph 338.
[1008] Exhibit 636.01, CCA argument, paragraph 337.
[1009] Exhibit 636.01, CCA argument, paragraph 341.
[1010] Exhibit 629.01, Calgary argument, pages 55 and 56.
[1011] Exhibit 298.02, Calgary evidence, paragraph 165; Exhibit 630.02, EPCOR argument, paragraph 13,
[1012] Exhibit 297.01, EPCOR evidence, paragraphs 41 to 45.
[1013] Exhibit 100.02, Fortis application, page 35, paragraphs 122-123; Exhibit 98.02, ATCO Electric application, pages 9-1-9-2, paragraph 228; Exhibit 629.01, Calgary argument, page 59 of 72.
[1014] Exhibit 631.01, ATCO Electric argument, paragraph 272 and Exhibit 632.01, ATCO argument, paragraph 297.
[1015] Exhibit 100.02, Fortis application, Performance Based Regulation Evidence attachment, page 82, lines 17 to 21

thus appears that annual benefits sharing could perpetuate the regulatory burden."[1016] IPCAA made no specific recommendations with respect to the structure of earnings sharing except to state that "any sharing calculations should occur at the end of the PBR period rather than annually" and that the scope of review should be clearly defined in advance.[1017]

Commission findings

816. The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled. The Commission notes Dr. Weisman's concerns with respect to ESMs.

> And when I say that earnings sharing has problems, it has problems I think on both sides. I don't think, as I mentioned in my rebuttal testimony, it brings forth the best behaviour on the part of regulators or the firms they regulate. I think that there are incentives for cost misreporting; cost shifting; the incentives are blunted with regard to managerial effort, and the reason for that is that the firm bears the entire costs of its effort at reducing costs but only retains a share of the fruits from those efforts.[1018]

817. The Commission agrees with EPCOR, AltaGas, ENMAX and IPCAA that increased scrutiny on an annual basis would be required for earnings sharing and would result in a greater regulatory burden. Accordingly, the Commission is concerned that including an ESM in the PBR plans of the companies would not be consistent with the objectives of Principle 3 to reduce the regulatory burden over time.

818. In the Commission's view, the safeguards offered by an ESM do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the incorporation of an ESM.

819. The Commission has approved safeguards in Section 8 of this decision that provide for a re-opening and review of the companies' PBR plans if the reported ROE of a company significantly exceeds the approved ROE or if the company experiences a significant shortfall in earnings. These safeguards are comparable to those provided for by an ESM but do not, in the Commission's view, exhibit the disincentives that arise with ESMs. The Commission finds that the safeguards set out in Section 8 are adequate to protect both the companies and consumers.

820. In addition, the Commission notes that the companies' reported earnings will generally vary, sometimes significantly, from year to year during the PBR term. The effect of this variability in earnings coupled with an ESM was demonstrated by the operation of ENMAX's ESM for transmission and distribution:

> EPC's customers benefited from \$0.331 million of earnings sharing for Transmission in 2008 and \$0.563 million of earnings sharing for Distribution in 2009. As EPC is forecasting that it will earn below the AUC approved ROE for the remainder of the FBR term for both Distribution and Transmission, EPC expects that there will be no earnings sharing payments for the period 2011 to 2013.[1019]

[1016] Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-26.
[1017] Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-29.
[1018] Transcript, Volume 9, page 1765, Dr. Weisman.
[1019] Exhibit 297.01, ENMAX evidence, paragraph 41.

821. The Commission finds that this volatility of earnings argues against the introduction of ESMs. This is because the company may have sufficient earnings in one year to trigger a sharing with customers and then experience earnings below the approved ROE in subsequent years but not sufficient to trigger a sharing of the shortfall with customers. This deprives the company of a reasonable opportunity to earn its approved ROE over the PBR term. Conversely, the company may have insufficient earnings in one year, triggering a sharing of the shortfall with customers and then experience earnings above the approved ROE in subsequent years but not sufficient to trigger sharing with customers. This results in customers paying rates higher than necessary to give the company a reasonable opportunity to earn its approved ROE over the PBR term.

822. Accordingly, the Commission finds that ESMs, as proposed by the parties, are not warranted as an additional safeguard and the disincentives they will introduce are inconsistent with the objectives of PBR.

11 Term

823. The PBR term establishes the period over which a company must operate under the parameters of the formula in the PBR plan.

824. All of the parties recognized that, in setting the term of a PBR plan, the Commission must achieve a balance between two competing interests, namely, ensuring that the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues are substantially out of sync with costs. As NERA stated, "ultimately we base rates for North American ratepayers on cost, and while we want to -- while it is a praise-worthy pursuit to want to avoid a disruption of frequent base rate cases, it is hard over the course of years to base rates on cost if you don't once in a while look at the costs."[1020]

825. The Commission noted this relationship in Decision 2009-035, when it rejected ENMAX's application for a10-year term as too long and approved a seven-year term which, given the passage of time, resulted in a five-year operational FBR term.[1021]

826. Each of the distribution companies, with the exception of ATCO Electric, proposed a PBR plan with a five-year term. ATCO Electric proposed a term of four years; stating, among other reasons, that staggering the filing of a second generation PBR plan with other companies would ease the regulatory workload for both the company and the Commission.[1022] In addition, ATCO Electric,[1023] ATCO Gas[1024] and AltaGas[1025] also proposed an optional two-year extension to the term, exercisable at the companies' election. Fortis stated in argument that it was open to an extension if the plan was working well.[1026]

827. Some of the companies, in proposing the terms for their PBR plans, also requested some form of rebasing or adjustment for capital expenditures during the PBR term.[1027] The

[1020] Transcript, Volume 1, page 197, lines 11-16.
[1021] Decision 2009-035, paragraph 118.
[1022] Exhibit 205.01, AUC-AE-13(a).
[1023] Exhibit 632.01, ATCO Gas argument, page 9, paragraph 28.
[1024] Exhibit 205.01, AUC-AE-13(b); Exhibit 0212.02, AUC-AG-3(a).
[1025] Exhibit 110.01, AltaGas application, page 15, paragraph 54.
[1026] Exhibit 633.01, Fortis argument, page 12, paragraphs 50 and 51.
[1027] See Section 7.3.3.2.

Commission has addressed the treatment of capital expenditures and adjustments in Section 7.3 of this decision.

828. The CCA supported the companies' applied-for terms but stated that, if the Commission preferred a shorter term such as three or four years, the CCA would not be opposed. In its view, a shorter term could reduce or eliminate some of the requests for supplemental capital budgets with less concern about untoward safety or reliability consequences during the PBR term. Nonetheless, the CCA stated that, whatever term is determined by the Commission, the length of the plans should be consistent among all companies.[1028] With regard to the proposals from ATCO Electric, ATCO Gas, and AltaGas to include an extension option to their plans' term, the CCA stated that "extensions should be allowed only with the consent of most parties"[1029] and that, if the plan is viewed as a success by all parties, there could potentially be an extension for up to five years.[1030]

829. Calgary supported a term of five years[1031] for ATCO Gas and indicated that a five-year term coincides with the Commission's efficiency, fair return and simplicity principles.[1032] However, Calgary did not support a unilateral extension of the ATCO Gas five-year term proposal.[1033]

830. The UCA did not support pursuing PBR because it considered that the risks of implementation outweigh the benefits of doing so.[1034] However, accepting that the Commission may nonetheless move forward with PBR, the UCA recommended that, as a first generation plan, the Commission adopt a term of three years.[1035] A period of four years was proposed for the second generation. In both cases, the UCA also recommended the imposition of a mid-term assessment to examine the PBR plans to date and to structure the design of the next term.[1036] Dr. Cronin, on behalf of the UCA, also opposed term extensions.[1037]

831. IPCAA submitted that it is too early for the Commission to implement a full PBR plan, and limited its recommendation to what it considered would be a suitable term for its limited G&A PBR plan. IPCAA stated that its limited G&A PBR plan "could run for a two-year term so that a comprehensive plan could be initiated when the limited plan expires."[1038]

Commission findings

832. One of the purposes of PBR is to start with cost of service-based rates and then sever the link between revenues and costs as a means of strengthening incentives for the companies to seek productivity improvements, and achieve lower costs than would otherwise be realized under cost of service regulation. PBR regulation allows regulated prices to change without a review of the company's costs, thereby lengthening regulatory lag. This better exposes the companies to the types of incentives faced by competitive firms. However, periodic review of the plans will be

[1028] Exhibit 636.01, CCA argument, page 12, paragraph 33-38.
[1029] Exhibit 636.01, CCA argument, page 12, paragraph 35.
[1030] Exhibit 636.01, CCA argument, page 14-15, paragraphs 42-43.
[1031] Exhibit 298.02, Calgary evidence, page 29.
[1032] Exhibit 64.01, PBR Principles Bulletin 2010-20.
[1033] Exhibit 629.01, Calgary argument, PDF page 20.
[1034] Exhibit 634.01, UCA argument, paragraphs 28-53.
[1035] Exhibit 299.02, Cronin and Motluk UCA evidence page 14, lines 15-23.
[1036] Exhibit 634.01, UCA argument, page 12, paragraphs 68-71.
[1037] Transcript, Volume 17, page 3322, lines 1-17.
[1038] Exhibit 635.16, IPCAA argument, page 2, paragraphs 8-9.

required. What the correct timing of a review will be and what the nature of the review should be will depend on the circumstances at the time.

833. The length of a typical PBR term in North America is from three to five years after which there is typically a rebasing and a recalculation of rates.[1039]

834. During the proceeding, the Commission asked parties to explore options for establishing a term.[1040] One option which was considered was whether it was possible to implement an open-ended term where there is no fixed date for the end of the PBR plan. The utilities and interveners were asked whether or not they supported an open-ended term during the hearing.

835. While most parties agreed that an open-ended term would have a positive impact on incentives,[1041] they also considered this proposal to be problematic.[1042] No party supported such a proposal, particularly for a first generation PBR plan.[1043] Dr. Weisman, on behalf of EPCOR, stated, "I think you, more generally, see that [open-ended term] in second and third-generation plans than you do the initial ones."[1044] As well, NERA concluded that such a proposal would be impractical and in their experience, they had not seen such a proposal implemented by other North American regulators.[1045] The Commission agrees that an open-ended term for the first generation PBR plans is not warranted.

836. The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America. Although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect.

837. The Commission does not approve the recommendation of the UCA for a mid-term review half-way through the PBR term because doing so effectively shortens the term to two years, thereby eliminating the benefits achieved from lengthening the regulatory lag.

838. In order to ensure that all utilities are treated consistently, the Commission rejects ATCO Electric's four-year term proposal and directs all companies to proceed with a five-year fixed term. The Commission denies the proposals of ATCO Gas, ATCO Electric and AltaGas for a unilateral option to extend their plan term.

839. The Commission will not make a determination at this stage as to how it will go forward following the end of the five-year term. As the Commission noted in its February 26, 2010 letter; "[t]he Commission will initiate a proceeding during the first PBR term to consider how the

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1039 Exhibit 100.02, LEI evidence, pages 31-32, PDF page 97; Exhibit 103.02, EPCOR application, page 19, paragraph 45; Exhibit 205.01, AUC-AE-13(a); Exhibit 391.02, NERA second report, Table 3, page 30 for a comprehensive list of PBR term lengths in Canada and the United States; Exhibit 629.01, Calgary argument, calculated the NERA example plan average as 4.9 years.
1040 Exhibit 80.02, NERA first report, PDF page 8.
1041 Dr. Carpenter, Transcript, Volume 5, page 832; Ms. Frayer, Transcript, Volume 11, pages 2188-2189.
1042 Ms. Frayer, Transcript, Volume 11, pages 2188-2189.
1043 Dr. Carpenter, Transcript, Volume 5, page 832; Dr. Makholm, NERA, Transcript, Volume 1, page 197; Exhibit 636.01, CCA argument, page 15, paragraph 42.
1044 Transcript, Volume 10, page 1826.
1045 Transcript, Volume 1, page 197 at lines 9 and 22.

success of the PBR plan should be judged and how it might be re-initiated, or rates 're-based,' at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives."[1046]

12 Maximum investment levels

840. The customer and retailer terms and conditions of electric distribution service form part of the distribution tariffs of the electric distribution companies. Over the PBR term, it is expected that there may be changes required to these terms and conditions of service. Among the elements in the terms and conditions of service of the electric distribution companies which may change are the maximum investment levels (MILs) and the service fee schedule. MILs are the maximum amounts of money that an electric distribution company can invest in a new service for a customer. This investment level is added to the electric distribution company's rate base. The remaining cost of a new connection, if any, must be supplied by the customer as a contribution.

841. Recently, the electric distribution companies, with the participation of stakeholder groups, developed a common approach to managing changes to MILs. This common approach was approved for Fortis,[1047] ATCO Electric,[1048] and EPCOR.[1049]

842. Gas distribution companies do not have MILs but do have specified customer contribution levels. The specified customer contribution levels for ATCO Gas can be found in Schedule C to its terms and conditions of service. AltaGas also provides for specific customer contribution levels as part of its terms and conditions of service.

843. Each of the distribution companies proposed an automatic adjustment to their MILs/customer contribution levels during the term of the PBR. AltaGas proposed that its customer contribution levels be adjusted annually by the I-X mechanism. With the exception of the residential and street lighting customer groups, Fortis also proposed that its MILs be indexed annually by the I-X mechanism. For the residential and street lighting customer groups, Fortis proposed an increase of I-X plus10 per cent.[1050] EPCOR proposed that the MILs would be included in its annual capital forecast in its capital factor (K factor) stating that its MILs would be based on the historical actual costs, adjusted to keep pace with forecast construction costs.[1051] ATCO Electric proposed that its MILs be adjusted by the I factor only because it considered that the I-X mechanism would not offset the effect of the company's investment. Rather, AE argued that increasing MILs by the I factor ensures future customers receive equitable company investment and mitigates intergenerational equity issues.[1052] Similarly, ATCO Gas proposed that its specified customer contributions be adjusted only by the I factor. Both ATCO Electric and ATCO Gas submitted that changes to MILs or customer contribution policies could have a material impact on whether future capital expenditures can reasonably be expected to be covered

[1046] Exhibit 1.01.
[1047] Decision 2010-309: FortisAlberta Inc., 2010-2011 Distribution Tariff – Phase I, Application No. 1605170, Proceeding ID No. 212, July 6, 2010.
[1048] Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.
[1049] Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, Application No. 1605759; Proceeding ID No. 437, October 28, 2010.
[1050] Exhibit 100.02, Fortis application, page 53, paragraph 187-188.
[1051] Exhibit 238.01, UCA-EDTI-08 b).
[1052] Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256.

by the I-X mechanism.[1053] Both utilities also argued that this proceeding is not the proper forum to address changes to MILs and customer contribution policies.

844. The UCA opposed ATCO Gas and ATCO Electric's proposals to adjust its specified customer contributions/MILs by I only and recommended that any adjustment be made by the I-X mechanism as, in its view, these costs should be subject to the same efficiency incentives as any other utility cost.[1054] Calgary also rejected ATCO Gas' proposal and recommended that ATCO Gas adjust its specified customer contributions by I-X. Neither the CCA nor IPCAA provided any specific comments or recommendations regarding customer contributions/MILs.

845. For ease of reference, a summary of the proposed treatment for adjusting MILs/customer contributions is provided in the table below:

Table 12-1 Summary of proposed maximum investment levels

Category	Fortis[1055]	ATCO Electric/Gas[1056 1057]	AltaGas[1058]	EPCOR[1059]	UCA[1060]	Calgary[1061]
Residential	I-X+10%	I	I-X	Part of K factor adjustments	I-X	I-X
Street lighting	I-X + 10%	I	I-X	Part of K factor adjustments	I-X	I-X
All other customers	I-X	I	I-X	Part of K factor adjustments	I-X	I-X

Commission findings

846. It is evident from the submissions that the electric distribution companies want to continue to manage changes to their MILs in accordance with the common approach that was reached among the companies and stakeholders. However, this common approach was developed and approved by the Commission under cost of service rate regulation.

847. The Commission has considered the submissions of ATCO Electric and ATCO Gas regarding changes to MILs or customer contribution policies and agrees that this is not the forum to determine such a policy. Customer contribution policy considerations will be addressed in a future generic proceeding as directed by the Commission.

848. However, with regard to providing for the automatic escalation of MILs and specific customer contributions during the PBR term, the Commission considers that these contributions should be escalated by I-X.

849. In Decision 2000-01,[1062] the Commission's predecessor, the Alberta Energy and Utilities Board stated "an appropriate contribution policy … provides a suitable balance to an unlimited

1053 Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256; Exhibit 648.02, ATCO Gas reply argument, page 149, paragraphs 540-543.
1054 Exhibit 300.02, UCA evidence of Russ Bell at page 56, A52.
1055 Exhibit 100.02, Fortis application, page 53, paragraph 188.
1056 Exhibit 476.01, ATCO Electric rebuttal evidence, page 66, paragraphs 203-204.
1057 Exhibit 632.01, ATCO Gas argument, page 87, paragraph 282.
1058 Exhibit 628.01, AltaGas argument, page 60.
1059 Exhibit 238.01, UCA-EDTI-08 b).
1060 Exhibit 634.01, UCA argument, page 57, paragraph 314.
1061 Exhibit 629.01, Calgary argument, page 52.

obligation to service by imposing economic discipline on siting decisions."[1063] The Commission agrees. As MILs increase, so do the capital costs of the companies. Therefore, MILs should be subject to the same incentives as other capital costs faced by the companies. As such, the Commission considers that to escalate MILs by I only removes incentives to seek additional efficiencies. This would be contrary to Principle 1 as incentives to seek efficiencies in the competitive market would be effectively lessened by escalating MILs by I only. Therefore, subject to the discussion of Fortis' MILs proposal below, the Commission directs that MILs be escalated by I-X throughout the PBR term.

850. Fortis proposed to escalate the MILs of residential (Rate 11) and street lighting (Rate 31) classes by an additional 10 per cent per year of the PBR term. The Commission finds that this proposal is consistent with Fortis' approach to MILs which was approved in Decision 2012-108 and necessary to bring its MILs in line with the other electric distribution companies.[1064] Therefore, the Commission directs that Fortis' MILs for these two classes be escalated by I-X plus 10 per cent per year throughout the PBR term.

13 Financial reporting requirements

851. Each utility proposed to file a copy of its Rule 005[1065] report in its annual PBR filing.[1066] AUC Rule 005 requires a utility to file schedules of financial and operational information including return on equity, detailed explanations of variances and audited financial statements complete with notes and an audit report. Under AUC Rule 005, all utilities are required to file their financial results by either May 1 for electric utilities or May 15 for gas utilities.

852. The UCA in its evidence noted that the minimum filing requirement (MFR)[1067] and general rate application (GRA) schedules, respectively filed by electric and gas utilities in their GRAs, provide much more detail than the Rule 005 schedules.[1068] Therefore, the UCA proposed that electric utilities be ordered to provide MFR schedules as part of their annual PBR filing, and that each gas utility file all the schedules included in its last GRA.[1069] The UCA argued that, if only the Rule 005 schedules were to be filed throughout a utility's PBR term, rebasing at the end

1062 Decision 2000-01: ESBI Alberta Ltd., 1999/2000 General Rate Application Phase I and Phase II, Application No. 990005, File Nos. 1803-1, 1803-3, February 2, 2000.
1063 Decision 2000-01, page 270.
1064 Decision 2012-108, paragraphs 104-105.
1065 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
1066 Exhibit 110.01, AltaGas PBR application, paragraphs 109 and 122; Exhibit 631.02, ATCO Electric argument, paragraph 328 and Exhibit 476.02, ATCO Electric rebuttal evidence, paragraphs 208-213; Exhibit 632.01, ATCO Gas argument, paragraph 343 and Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 152-154; Exhibit 633.02, Fortis argument, paragraph 288(88); Exhibit 103.02, EPCOR PBR application, paragraph 256.
1067 The minimum filing requirements were approved in Decision 2007-017: EUB Proceeding, Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities, Application No. 1468565, March 6, 2007. This decision was the culmination of a consultation to determine a uniform system of accounts for electric utilities to implement, and the minimum filing requirements electric utilities must comply with in their general rate applications. See USA & MFR on the AUC's website under Items of Interest.
1068 Exhibit 300.02, UCA evidence, Question 60.
1069 Exhibit 634.02, UCA argument, paragraphs 417 to 421.

of the term would be far more difficult and it would be far more difficult to return to cost of service regulation.[1070]

853. The UCA further argued that the continuity of actual data would be lost over a utility's PBR term if the companies were not required to file annually the more detailed MFR and GRA schedules. This is because companies subject to the MFR are required to provide only two years of actual data in a cost of service general rate application.[1071]

854. Fortis and the ATCO companies argued being required to file the MFR and GRA schedules on an annual basis would increase regulatory burden.[1072] The UCA responded that the additional cost to provide the extra detail in the MFR and GRA schedules would be minimal.[1073] IPCAA stated that customers have paid and are paying for data collection in the USA/MFR format and should be afforded the right to receive all such data on an ongoing basis.[1074]

855. The UCA also recommended that "all utilities continue to exclude costs previously disallowed from the calculation of actual results and ROE during the PBR term."[1075] The UCA proposed that, to address its concern with respect to excluding disallowed costs, companies should file the two tables it had provided in ENMAX's FBR proceeding and which ENMAX was subsequently directed to provide in its annual rate applications. These two tables consist of a reconciliation of financial and utility returns, and a summary of disallowed and inappropriate costs.[1076]

13.1 Audits and senior officer attestation

856. AUC Rule 005 requires a reconciliation of the utility's financial results to its audited financial statements. Audited financial statements are intended to provide independent assurance on the accuracy and completeness of a utility's financial results. AUC Rule 005 does not require an audit of the Rule 005 schedules themselves. Because of disallowed costs, non-regulated operations, changes in accounting policies and other factors, the financial results reported by a utility in its audited financial statements may be different than those reported in AUC Rule 005 or may differ over several years.

857. AltaGas, in its application, proposed that as part of its annual rate application it would provide a senior officer attestation, in addition to a copy of its Rule 005 filing (which includes audited financial statements).[1077] AltaGas' proposed senior officer attestation appears to be based on the nine issues that the Commission directed ENMAX to have reviewed and commented on by an independent auditor in Decision 2010-146.[1078] The attestation by an AltaGas senior officer would provide assurance as to the veracity of the reported numbers and the calculations used, and transparency with respect to any changes in methods, policies or parameters affecting the reported results.

[1070] Exhibit 634.02, UCA argument, paragraph 420.
[1071] Exhibit 634.02, UCA argument, paragraph 419.
[1072] Exhibit 644.01, Fortis reply argument, paragraphs 174 and 175; Exhibit 648.02, ATCO Gas reply argument, paragraphs 529 and 530; Exhibit 647.01, ATCO Electric reply argument, paragraph 354.
[1073] Exhibit 300.02, UCA evidence, Question 65 on page 67.
[1074] Exhibit 642.01, IPCAA reply argument, paragraph 19.
[1075] Exhibit 634.02, UCA argument, paragraph 422.
[1076] Exhibit 300.02, UCA evidence, Question 69 and Question 70.
[1077] Exhibit 110.01, AltaGas Incentive Regulation application, paragraph 123.
[1078] Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010, paragraph 132.

858. The Commission in Decision 2009-035 directed ENMAX as follows:

> … to have its reported ROE independently verified and to have an officer of the company attest to its validity. The Commission also directs EPC to include in its annual filings the reconciliation tables proposed by UCA.[1079]

859. Subsequently, in Decision 2011-260, the Commission directed ENMAX to provide attestations and certifications by one of its senior officers for the following matters:[1080]

- that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- regarding the accuracy and/or completeness of the nine issues identified
- that the numbers, assumptions and proposed rates are reasonable, fair and accurate

Commission findings

860. The Commission agrees that the utilities' proposal to include the AUC Rule 005 schedules in their annual PBR filings is reasonable and accordingly directs each company to include in its annual PBR filing a copy of its AUC Rule 005 filing.

861. To maintain transparency and consistency, the Commission agrees with the UCA that disallowed costs should continue to be identified and excluded from a company's ROE. The Commission directs each utility to include in its annual PBR rate adjustment filing a schedule including the two UCA tables put forth by the UCA.[1081]

862. The Commission directs each company to include in its annual PBR rate adjustment filing an attestation signed by a senior officer of the company as proposed by AltaGas. The senior officer attestation should include, as applicable, not only those items proposed by AltaGas, but also certifications on the accuracy, completeness and reasonableness of the numbers and assumptions included in the company's application. The required attestations and certifications by a senior officer of each company are as follows:

- confirm the reported ROE used to determine if a re-opener exists, either actual or weather normalized
- describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts
- describe any changes in the depreciation parameters and associated impacts
- describe any changes in the allocation of shared services costs and associated impacts
- confirm the inflation parameters used, including calculation and application of the rates formula to rates
- confirm the calculation of flow-through costs (Y factors) and associated riders conform to Commission directions
- confirm the calculation of exogenous (Z factor) adjustments and associated riders conform to Commission directions

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[1079] Decision 2009-035, paragraph 283.
[1080] Decision 2011-260: ENMAX Power Corporation, 2011 Formula Based Ratemaking Annual Rates and Technical Report, Application No. 1607203, Proceeding ID No. 1169, June 20, 2011, paragraph 58(5).
[1081] Exhibit 300.02, UCA evidence, page 74.

- confirm the calculation of capital trackers (K factor) and associated riders conform to Commission directions
- identify any material changes in the components of costs or revenues
- confirm that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- confirm that the numbers, assumptions and proposed rates are reasonable, fair and accurate

863. For a company under PBR, the requirement to file the AUC Rule 005 schedules in both its annual PBR rate adjustment filing and a separate AUC Rule 005 application, does not exempt the company from its obligation to maintain detailed accounts in accordance with the acts, regulations, Commission rules, or Commission decisions applicable to the company. Therefore, unless otherwise directed or exempted by the Commission, the companies are directed to maintain the ability to file a complete set of MFR and GRA schedules with actual results for all years within the term of the company's PBR plan. The companies are not required, however, to file a complete set of MFR and GRA schedules annually.

14 Service quality

864. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures when needed.

865. The Commission has the legislative authority under both the *Electric Utilities Act*[1082] and the *Gas Utilities Act*[1083] to make rules respecting service standards for electric utilities and for gas distributors. The Commission is also authorized to investigate compliance with the rules respecting service standards and, if necessary, is empowered to take steps to enforce them. This authority exists regardless of the type of ratemaking regime in operation, be it cost of service or performance-based regulation.

866. The first of the five principles (Principle 1) states, "A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality." All of the companies provided assurances in their submissions that service quality would not decline with the adoption of their proposed PBR plans. Notwithstanding these assurances, each of the interveners identified service quality degradation as a significant risk under PBR.[1084]

[1082] *Electric Utilities Act*, Section 129.
[1083] *Gas Utilities Act*, Section 28.3.
[1084] Exhibit 634.01, UCA argument, paragraph 368; Exhibit 307.01, PEG evidence for CCA, PDF page 65; Exhibit 635.01, IPCAA argument, paragraph 53; Exhibit 629.01, Calgary argument, PDF page 64.

867. In his evidence submitted on behalf of the UCA, Dr. Cronin reported the results of a study where he compared reliability statistics from Alberta electric distribution companies with selected companies in Ontario and the United States. Of the 22 companies Dr. Cronin described as higher density, ENMAX and EPCOR ranked first and third respectively for reliability. Among the lower density companies, Dr. Cronin described ATCO Electric and Fortis as having "superior reliability" compared to the 10 companies he examined. Dr. Cronin concluded from this analysis that "the AUC must be careful that the gains achieved to date are not put at risk for what could be limited potential gains under PBR."[1085]

Commission findings

868. The Commission has reviewed the service quality and reliability annual reports of the companies and agrees with the UCA that the service levels currently provided by the companies are acceptable.[1086] The Commission will require the companies to maintain their current levels of service quality throughout the PBR term.

14.1 Mechanism to monitor and enforce service quality

869. Currently, the Commission monitors service quality performance through AUC Rule 002.[1087] AUC Rule 002 sets out the service quality reporting requirements for electric utilities and gas distributors. Pursuant to this rule, all gas distributors and electric utilities under the jurisdiction of the Commission are required to file quarterly and annual performance reports.

870. Parties were divided as to whether the Commission should continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or whether the Commission should implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula. This latter approach, which is often referred to as a "Q factor" in the PBR formula, was adopted by the Commission in Decision 2009-035 for the ENMAX FBR plan. In the ENMAX FBR, the service standards were set out for the FBR plan and the penalties for failure to meet the standards were included as an adjustment to the formula.[1088]

871. ATCO Electric, ATCO Gas, AltaGas and Fortis favoured continued use of AUC Rule 002 for service quality reporting.[1089] The UCA stated that "Rule 002 should form the basis for service quality reporting under PBR."[1090] The CCA supported this approach.[1091]

872. EPCOR was in favour of the approach approved for the ENMAX FBR plan. In its view, AUC Rule 002 has significant limitations including the fact that it did not set out specified penalties, and it used the All Injury Incidence Frequency Rate metric instead of the Total Recordable Injury Frequency Rate metric that EPCOR proposed. EPCOR also argued in favour of its proposal because AUC Rule 002 applies only to owners of electric distribution systems and

1085 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 11-12.
1086 Service quality and reliability annual reports on AUC website.
1087 AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective date July 1, 2010 (Rule 002).
1088 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009, paragraphs 302-304.
1089 Exhibit 631.01, ATCO Electric argument, paragraph 284; Exhibit 632.01, ATCO Gas argument, paragraph 306; Exhibit 628.01, AltaGas argument, PDF page 80; Exhibit 474.01, Fortis rebuttal evidence, paragraph 58.
1090 Exhibit 634.01, UCA argument, paragraph 369.
1091 Exhibit 636.01, CCA argument, paragraph 357.

to gas distributors but not to transmission, whereas, EPCOR's proposal, like that of ENMAX, included metrics for transmission.[1092] EPCOR's proposal to adopt the approach approved for the ENMAX FBR aligned with EPCOR's proposal to include transmission in its PBR plan.

873. IPCAA was also critical of adopting AUC Rule 002 as, in its view:[1093]

> Traditional service quality metrics such as those contained in AUC Rule 002 have been accepted in the context of traditional rate-base regulation. For example, SAIDI [System Average Interruption Duration Index] and SAIFI [System Average Interruption Frequency index] provide a broad sense of "position in the pack," relative to other utilities across Canada (and elsewhere), but that is all the precision that they can potentially provide. [T16:3039.3].They are biased metrics, which over-report some phenomena and under-report other phenomena. [T16:3061.22]
>
> …
>
> Since these metrics are based on number of customers affected, they can lead to poor incentives. For example, a utility might have two projects to reduce these metrics: one to trim trees around ten summer cottages and one to maintain ten large sites' high voltage equipment. If optimizing to cost and CAIDI [Customer Average Interruption Duration Index] was the goal, the cottage project might seem far superior even though the social and economic costs of outages to the large sites are much greater. [T16:3039.6]
>
> …
>
> AUC Rule 002 does not provide for any financial incentives, and the penalties provided by the EUA [sic. AUCA] at section 63 do not allow for a performance bonus. A symmetrical incentive plan would therefore have to be incorporated into the PBR plans. [T06, p.1090.22]

874. Calgary also rejected the use of AUC Rule 002, because it generally requires ATCO Gas to report its operations, rather than requiring the company to meet "specific performance criteria or standards."[1094]

Commission findings

875. The Commission has considered the advantages and the disadvantages of each of the two alternative proposals for monitoring and enforcing service quality: to continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or to implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula.

1092 Exhibit 630.02, EPCOR argument, paragraph 296.
1093 Exhibit 635.01, IPCAA argument paragraphs 50, 51 and 93.
1094 Exhibit 629.01, Calgary argument, PDF page 65.

876. The following table sets out the metrics that are currently required to be reported by electric distribution utilities under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-1 Current AUC Rule 002 metrics for electric distribution utilities

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Monthly billing and meter reading performance	No
	Cumulative meters not read within six months	Yes
	Identified meter errors	No
	Monthly tariff billing performance	Yes
Work completion performance measures	Energizing sites	No
	De-energizing sites	No
	Performing off-cycle meter reads	No
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Reliability performance measures	System average interruption frequency index (SAIFI)	No
	Customer average interruption duration index (CAIDI)	No
	System average interruption duration index (SAIDI)	No
	SAIDI of worst-performing circuits on the system	No
Post-final adjustment mechanism (PFAM) adjustments processed	Post-final adjustment mechanism (PFAM) adjustments processed	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

877. The following table sets out the metrics that are currently required to be reported by gas distributors under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-2 Current AUC Rule 002 metrics for gas distributors

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Cumulative meters not read within four months and one year	No
	Monthly tariff billing performance	Yes
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

878. The Commission also monitors call centre statistics, such as call answer time and abandon rates, in AUC Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* (Rule 003) because, in Alberta, call centre and billing functions are performed by competitive retailers, regulated rate providers and default supply providers. The electric utilities and gas distributors generally only field emergency calls from customers or calls from retailers.

879. In addition to filing quarterly and annual performance reports, another AUC Rule 002 requirement is for the company to meet with the Commission at least once annually after submission of its AUC Rule 002 annual report to discuss:

- service quality issues
- trends in service quality data reported by the owner, including any corrective action plans proposed by the owner to remedy failing performance standards
- issues raised by customer complaints filed with the Commission
- other policy issues related to customer service[1095]

880. In the Commission's view, using AUC Rule 002 together with a penalty provision has the following advantages:

- As a rule, the performance metrics already included in AUC Rule 002 were developed and updated in consultation with industry stakeholders.
- Continuity of the metrics and how they are reported will allow for trend analysis, especially for those metrics which have been in place since 2004. The Commission can rely upon historical databases to identify any negative trends in service quality and take corrective action if service levels decline.
- Companies may make decisions and take actions during the PBR term which may have consequences not readily apparent during the term. Using AUC Rule 002 will enable the

[1095] AUC Rule 002, Section 2.3.

Commission to monitor the consequences of those actions after the PBR term expires, regardless of the rate-setting mechanism in place after the end of the term.

- As is discussed further in Section 14.2, if AUC Rule 002 is accompanied by a penalty provision rather than including penalties as an adjustment to the PBR formula, unexpected and potentially undesirable impacts to consumer behaviour can be avoided. For example, if rates were lowered because of a penalty that adjusted the formula, certain price sensitive consumers may react by choosing to consume more energy which, in turn, could potentially increase revenues for the company. In such an event, incurring a penalty may result in a financial benefit to the company.

881. Having considered both the advantages and disadvantages of the two mechanisms proposed, the Commission finds that adopting AUC Rule 002 to determine performance standards and targets, and applying penalties in the event of non-compliance with the performance targets established, is the best approach for ensuring that the companies have an adequate incentive to maintain service quality under PBR.

882. The Commission is satisfied that, with the addition of new metrics and with the establishment of defined targets for those metrics currently without them, AUC Rule 002 will satisfactorily address the requirement for service quality measurement and reporting under PBR. As the Commission has determined in Section 2.4 of this decision that it will not include transmission as part of any PBR plan, it will, therefore, not be necessary to develop any performance measures for transmission at this time.

883. Accordingly, the Commission will initiate a consultation process before the end of 2012 to review and revise AUC Rule 002 in a timely manner. The companies and interveners will be invited to participate in the consultation process.

14.2 Penalties and rewards

884. AUC Rule 002 does not include provisions for penalties in the event that performance standards are not met. All parties agreed that some kind of enforcement mechanism is necessary. None of the companies argued against penalties for failure to meet service quality targets, when the failure was within their control.[1096]

885. Calgary recommended penalties and stated "the PBR plan should include direct fines paid by the utility for specific infractions; the fines should be treated as an addition to the next ESM payment or at the end of the PBR term."[1097]

886. The UCA recommended specified penalties of 10 per cent of earnings and stated:

> In a competitive market, poor performance is met with a lawsuit or more likely the loss of a customer, without any process to explain the reason for poor performance. As customers of a regulated utility have no choice to change suppliers, a specified penalty, with certainty as to the impact of poor performance is simpler to administer. Also, there

[1096] Exhibit 219.02, Fortis response to AUC-FAI-020 ALLUTIL (b), PDF page 35; Exhibit 628.01, AltaGas argument, PDF page 84; Exhibit 103.02, EPCOR PBR application, paragraph 91; Exhibit 631.01, ATCO Electric argument, paragraph 308; Exhibit 632.01, ATCO Gas argument, paragraph 326.

[1097] Exhibit 629.01, Calgary argument, page 63.

> is no evidence that customers want or are willing to pay for improved service levels, so the concept of a reward is not supported by the evidence.[1098]

887. IPCAA recommended a symmetrical approach to address service quality issues. That is, IPCAA proposed that penalties for degradations to service quality be instituted but also, if service quality improves, that a performance bonus plan be instituted.[1099]

888. EPCOR stated in its application that it "will explain the reasons for failing to meet the target as well as any future corrective actions EDTI proposes to take."[1100] While EPCOR only implied that the penalty would not apply if it adequately justified the failure, the other companies clearly argued for an opportunity to have their failures reviewed prior to a penalty being administered.[1101]

889. ATCO Electric and ATCO Gas expressed concerns that they would be penalized for events outside of their control and, therefore, recommended that, if they would be subject to penalties for events outside of their control, they should also be entitled to receive rewards where service targets are exceeded due to events outside their control in order to balance the increased risk, if penalties were automatic without opportunity for review.[1102] Fortis, in its application, did not request rewards for higher than standard service quality[1103] but on cross-examination recommended an approach with both penalties and rewards.[1104] AltaGas submitted that higher than required service quality levels should be met with rewards if a system of penalties is in place.[1105]

890. EPCOR proposed a reward for meeting its service quality standards throughout the five-year PBR term, to be specifically included in an efficiency carry-over mechanism for two years after the end of the PBR term.[1106]

891. Regarding the size of the penalties, ATCO Electric stated:

> The Commission makes the determination of whether a penalty is required and the appropriate amount would be commensurate with the benefit gained by the utility as a result of its actions.[1107]

892. ATCO Gas made a statement similar to the one made by ATCO Electric[1108] and continued:

> The magnitude of 10% of earnings recommended by the UCA is unreasonable. As ATCO Gas has already stated, there is a realistic likelihood that it will be penalized for events

[1098] Exhibit 649.02, UCA reply argument, paragraph 246.
[1099] Exhibit 635.01, IPCAA argument, paragraph 93.
[1100] Exhibit 103.02, EPCOR PBR application, paragraph 93.
[1101] Exhibit 628.01, AltaGas argument, PDF page 83; Exhibit 631.01, ATCO Electric argument, paragraph 306; Exhibit 632.01, ATCO Gas argument, paragraph 324; Exhibit 100.02, Fortis PBR application, paragraph 131.
[1102] Exhibit 647.01, ATCO Electric reply argument, paragraph 330; Exhibit 648.02, ATCO Gas reply argument, paragraph 502.
[1103] Exhibit 100.02, Fortis PBR application, paragraph 138.
[1104] Transcript Volume 11, page 2182.
[1105] Exhibit 650.01, AltaGas reply argument, paragraph 265.
[1106] Exhibit 103.02, EPCOR PBR application, paragraph 272.
[1107] Exhibit 647.01, ATCO Electric reply argument, paragraph 331.
[1108] Exhibit 648.02, ATCO Gas reply argument, paragraph 503.

> that were not within its ability to control. A penalty of 10% of earnings, which is in the order of $6 million for ATCO Gas, related to something ATCO Gas could not control is absurdly confiscatory. Penalties must not be so great as to have a significant negative impact on ATCO Gas' ability to recover its prudently incurred costs, including a Fair Return on its investments. The penalty should be commensurate with the benefit gained…[1109]

893. ATCO Electric, too, had concerns with having penalties as high as 10 per cent of earnings.[1110] Fortis and AltaGas did not discuss the size of the penalties in their final arguments or reply arguments.

894. EPCOR, however, proposed that a failure to reach any one service quality metric should result in a $250,000 penalty per year. Under EPCOR's proposed PBR plan, it would be penalized $1 million in 2013 if it failed to reach all four of its proposed metrics, and the $1 million would be escalated by I-X in subsequent years.[1111] However, EPCOR indicated that it would be applying to the Commission for an adjustment to two of its four performance targets and for relief from those targets for 12 months after implementation of its Outage Management System/Distribution Management System.[1112]

895. The UCA, in its reply argument, expressed concerns over EPCOR's proposal to be penalized $250,000 per failed target, stating:

> Further, having the penalty split between four measures, means that failing to meet one measure would result in a penalty of only $0.25 million, which is not material, and may not be sufficient to deter the conduct. It may well lead to the concern raised by the Chair that the utility will simply factor the fine into the economics of their decisions.[1113]

Commission findings

896. Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act* provide the legislative authority for the Commission to take any or all of the following actions when the Commission is of the opinion that an owner of an electric utility or a gas distributor has failed or is failing to comply with its rules respecting service standards. These provisions state as follows:

> *Electric Utilities Act*
> 129(3) If the Commission is of the opinion that the owner of an electric utility has failed or is failing to comply with the rules respecting service quality standards, the Commission may by order do all or any of the following:
>
> (a) direct the owner to take any action to improve services that the Commission considers just and reasonable;
> (b) direct the owner to provide the customer with a credit, of an amount specified by the Commission, to compensate the customer for the owner's failure to comply with the rules respecting service quality standards;

1109 Exhibit 648.02, ATCO Gas reply argument, paragraph 509.
1110 Exhibit 647.01, ATCO Electric reply argument, paragraph 337.
1111 Exhibit 630.02, EPCOR argument, paragraph 316.
1112 Exhibit 630.02, EPCOR argument, paragraph 294.
1113 Exhibit 649.02, UCA reply argument, paragraph 258.

(c) prohibit the owner from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

Gas Utilities Act
28.3(3) If the Commission is of the opinion that the gas distributor or default supply provider has failed or is failing to meet the service standards rules, the Commission may by order do all or any of the following:

(a) direct the gas distributor or default supply provider to take any action to improve services that the Commission considers just and reasonable;
(b) direct the gas distributor or default supply provider to provide the customer with a credit, in an amount specified by the Commission, to compensate the customer for the gas distributor's or default supply provider's failure to meet the service standards rules;
(c) prohibit the gas distributor or default supply provider from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

897. An administrative penalty under Section 63 of the *Alberta Utilities Commission Act* may require the person to whom it is directed to pay either or both of the following:

(a) An amount not exceeding $1 million for each day or part of a day on which the contravention occurs or continues.

(b) A one-time amount to address economic benefit where the Commission is of the opinion that the person has derived an economic benefit directly or indirectly as a result of the contravention.

898. The Commission considers that these legislative remedies provide the following benefits in dealing with a failure to maintain service quality standards during the PBR term:

- The potential size of the penalties under Section 63 along with the power to direct disgorgement of any economic benefits discourages service quality degradation.
- If service quality failures occur, the size of the penalty can be tailored to match the benefit gained by the company as a result of its action.
- The review process in administering the penalty allows the company the opportunity to explain the source or cause of the failure and argue that a penalty is not warranted or should be lessened.

899. The Commission rejects any proposal that a performance bonus should be available to the companies in the event that service quality targets are exceeded. As noted throughout this decision, the objective of a PBR plan is to incent behaviour that would be similar to that of a company in a competitive market. But, in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher

price for a service quality level that they may not want or cannot afford.[1114] Further, if the industrial customers that IPCAA represents want a higher level of service quality, they can elect to contract directly with the companies for that purpose at a negotiated price.

900. For the above reasons, the Commission will continue to rely on these legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade.

14.3 Consultation process

901. The Commission in this decision is setting out directions for the AUC Rule 002 consultation for the following issues to assist parties participating in the consultation process:

a. Annual review meetings
b. Additional service quality metrics
c. Setting targets and penalties
d. Asset management reporting
e. Line losses (electric distribution companies only)

14.3.1 Annual review meetings

902. Parties provided their views on the format and content of the AUC Rule 002 annual review meetings. With respect to format, parties discussed the inclusion of interveners at the meetings, which previously only included the Commission and company staff. While some parties had no objection to including customer groups at the meetings,[1115] others expressed concern that such a change would be better addressed in a consultative process.[1116]

903. With respect to content, Fortis proposed expanding the scope of the review meetings to include an evaluation of outage causes and a discussion of asset management programs.[1117]

Commission findings

904. The Commission is not opposed to the inclusion of interveners at the annual review meetings. Proposed changes to the process and scope of the annual review meetings, including intervener attendance, will be further discussed in the upcoming AUC Rule 002 review consultative process referenced in Section 14.1, at which the roles of parties in the annual review meeting will be established.

14.3.2 Additional service quality performance metrics

905. Several interveners urged the Commission to adopt additional service quality performance metrics beyond those already identified under AUC Rule 002.

[1114] See discussion at Transcript, Volume 14, page 2892 to 2894.
[1115] Exhibit 628.01, AltaGas argument, page 79, Exhibit 631.01, ATCO Electric argument, paragraph 309, Exhibit 633.01, Fortis argument, paragraph 274.
[1116] Exhibit 629.01, Calgary argument, PDF page 68, Exhibit 648.02, ATCO Gas reply argument, paragraph 510, Exhibit 635.01, IPCAA argument, paragraph 94.
[1117] Exhibit 633.01, Fortis argument, paragraph 274.

906. The UCA recommended three new service quality performance metrics:

- service appointments met/time
- response time for emergency calls
- reconnect after cut off for nonpayment (CONP) response time[1118]

907. The CCA recommended that line losses be monitored and that additional metrics be put in place for transmission.[1119]

908. IPCAA was interested in having the following metrics or data sources included in the reporting requirements:

- system-level outage data
- outage information sent to customers as a part of the interval meter data set
- transmission measures[1120]

909. Calgary recommended that the Commission look to other jurisdictions for best practices and referenced the Gaz Métro Performance Incentive Mechanism Decision and Analysts' Presentation. The referenced document contains the following metrics:[1121]

- preventive maintenance
- emergency response time
- telephone response time
- meter reading frequency
- ISO 14001 (environmental management systems)
- greenhouse gas emissions
- customer satisfaction by customer class
- collection & service interruption procedure

910. EPCOR, ATCO Electric, ATCO Gas and Fortis did not favour the addition of the new metrics proposed by the UCA.[1122] AltaGas was not opposed to the addition of the metrics proposed by the UCA but indicated that any additions should be accomplished through a consultation process.[1123]

911. Fortis,[1124] ATCO Electric[1125] and EPCOR[1126] also opposed the addition of the metrics proposed by IPCAA.

1118 Exhibit 634.01, UCA argument, paragraph 383.
1119 Exhibit 636.01, CCA argument, paragraphs 358-360.
1120 Exhibit 635.01, IPCAA argument, paragraph 59-75.
1121 Exhibit 546.01, undertaking Carpenter to McNulty, PDF page 25.
1122 Exhibit 630.02, EPCOR argument, paragraphs 305 and 306; Exhibit 631.01, ATCO Electric argument, paragraph 294; Exhibit 632.01, ATCO Gas argument, paragraph 316; Exhibit 633.01, Fortis argument, paragraph 263.
1123 Exhibit 650.01, AltaGas reply argument, paragraph 259.
1124 Exhibit 644.01, Fortis reply argument, paragraphs 158 and 161.
1125 Exhibit 647.01, ATCO Electric reply argument, paragraph 321.
1126 Exhibit 473.02, EPCOR rebuttal evidence, page 32.

Commission findings

912. The Commission has considered the recommendations of the parties as well as information they provided on the record of the proceeding with respect to the practices in other jurisdictions. Based on this review, the Commission considers that there is insufficient evidence for the Commission to make a determination as to whether it is in the public interest to impose the new metrics proposed by the parties. Therefore, the Commission will be seeking further information on the metrics proposed as additions to AUC Rule 002 in the upcoming AUC Rule 002 consultation process.

14.3.3 Target setting and penalties

913. Several parties recommended that the Commission adopt a specific approach to set targets for those metrics under AUC Rule 002 that do not currently have defined performance targets.

914. In his evidence for the UCA, Dr. Cronin recommended the use of a willingness-to-pay study to set a socially optimal level of reliability or, as Dr. Cronin explained, "the level of reliability where the marginal benefits from improvements equal the marginal costs of implementation."[1127] In testimony, Dr. Cronin described it as "trying to elicit from, say customers in this instance, how they value the reliability they receive from the company."[1128] Dr. Cronin also indicated in testimony that different customer classes would be willing to pay differing amounts for reliability improvements and that customers' willingness to pay would change over time.[1129]

915. In his rebuttal testimony on behalf of EPCOR, Dr. Weisman expressed his concerns with Dr. Cronin's recommendation:

> …this approach would seem to be ruled out by AUC PBR Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality. With this principle, the Commission has seemingly carved out a special exception for service quality. To wit, the AUC wishes to implement PBR regimes that replicate the incentive structure of a competitive market, "while maintaining service quality." Hence, even if service quality for Alberta utilities is currently over-provisioned from a social welfare perspective—service quality is "too good"—the Commission does not wish to see any fall off in the level of service quality that Albertans currently enjoy.[1130]

916. ATCO Electric also commented on Dr. Cronin's recommendation stating:

> ATCO Electric notes that the costs associated with providing the current level of service quality and reliability have been incurred and approved as prudent by the AUC, and cannot simply be undone if a WTP [willingness-to-pay] study indicates that the "socially optimal" level of service is something lower than the current level. While the results of these kinds of studies might be interesting, ATCO Electric is unsure of how they might actually be used and it is unclear as to how the costs of these studies will be addressed.[1131]

[1127] Exhibit 299.02, Cronin and Motluk UCA evidence, page 205.
[1128] Transcript, Volume 17, pages 3293-3296.
[1129] Transcript, Volume 17, pages 3293-3296.
[1130] Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., pages 13-14.
[1131] Exhibit 631.01, ATCO Electric argument, paragraph 292.

917. For the interim period, prior to completion of the proposed willingness-to-pay research, the UCA proposed the following approach for setting targets:

> …the target for service levels should be based on current levels achieved. These are the levels included in going-in rates, and are the levels that customers are paying for. A five year average of actual achieved performance prior to the start of PBR is the best indication of the current level of performance achieved.[1132]

918. EPCOR,[1133] ATCO Gas[1134] and ATCO Electric[1135] argued that a target based on a simple five-year average would require improvements in service quality to avoid penalties half the time, and therefore the companies proposed setting a threshold of one standard deviation above the average to account for the volatility of the measurements due to factors outside of their control. In addition, EPCOR was concerned that the reporting of annual numbers against the five-year average plus one standard deviation would incent a company to further reduce its costs in years where it had no hope of achieving a performance target, since the poor measurement in one year would not impact future years' measurements. EPCOR, therefore, proposed that it report a five-year rolling average against the target so that "poor performance in one year would be reflected in the rolling average for the next four years, incenting the utility to continue to take steps and spend dollars to minimize the extent of its poor performance in the original year."[1136]

919. The UCA expressed concern over EPCOR's proposal to report a five-year rolling average, stating, "While I understand that an average will allow the impact of anomalies to be minimized, it will also mask any trends in degradation of service levels."[1137] In final argument, the UCA suggested that the removal of major events from the average would resolve the problem of volatility in the data and the likelihood of a penalty being imposed while service quality remained the same.[1138]

920. ATCO Gas and ATCO Electric rejected the UCA's suggestion to remove major events stating that removing " 'major events' just means that there is a requirement to make improvements over the current level on all other events."[1139] EPCOR provided a similar response and indicated that "service quality can be significantly impacted in a given year by varying volumes of smaller outages that, just like MEDs [major event days], are beyond EDTI's ability to control."[1140]

921. For the new service measures that the UCA wanted introduced, it stated that the measures should be tracked initially to establish a performance history because without history "there can

[1132] Exhibit 634.01, UCA argument, paragraph 381.
[1133] Exhibit 473.02, EPCOR rebuttal evidence, PDF page 21.
[1134] Exhibit 648.02, ATCO Gas reply argument, paragraph 493.
[1135] Exhibit 647.01, ATCO Electric reply argument, paragraph 316.
[1136] Exhibit 473.02, EPCOR rebuttal evidence, A12, PDF page 23.
[1137] Exhibit 300.02, UCA evidence of Russ Bell, A9, PDF page 14.
[1138] Exhibit 634.01, UCA argument, paragraph 382.
[1139] Exhibit 648.02, ATCO Gas reply argument, paragraph 494; Exhibit 647.01, ATCO Electric reply argument, paragraph 317.
[1140] Exhibit 646.02, EPCOR reply argument, paragraph 296.

be no meaningful targets set and therefore no penalties should be associated with the measures at this time."[1141]

922. The CCA, like the UCA, did not support setting a target with a standard deviation above average and recommended that "the performance measure, in each of the PBR test years, simply be the rolling average of the last 5 years of actual reported data."[1142] In other words, the target would change every year as the average changes over time.

923. In addition to concerns with the lack of a threshold above the average, EPCOR also argued that the CCA recommended approach "could result in degradation of service quality over time contrary to PBR Principle 1, as the targets could degrade as performance degrades."[1143] Fortis, ATCO Electric, ATCO Gas and AltaGas did not comment on the CCA's recommended approach.

924. Calgary in argument stated:

> There is no evidence on the record that ratepayers are seeking service levels superior to the existing service, particularly for residential and general commercial customers. Moreover, as was recognized by an AltaGas witness, the marginal cost of improving quality of service may well exceed the benefit.[1144]

925. IPCAA recommended "a consultative process be initiated to disclose what system-level outage data is retained by each utility, and explore efficient ways of using that data to set reliability targets and incentives."[1145]

926. An additional concern was raised by ATCO Electric,[1146] Fortis and EPCOR[1147] regarding how adjustments were to be made to setting targets as a result of the more accurate and detailed level of reporting that would be made available as a result of the implementation of their respective outage management systems. Fortis stated in testimony:

> So FortisAlberta is now implementing an outage management system. So whereas before we had 350 PLTs [power line technicians] independently inputting data manually, we will now move to a centralized process that will give us much better data, and that will cause SAIDI and SAIFI to increase, which if we'd stuck with the statistic itself, would imply the reliability has gotten worse, but reliability hasn't changed.[1148]

927. Similarly, EPCOR indicated that it would be applying for revisions to its SAIDI and SAIFI performance targets after it implements its outage management system.[1149]

1141 Exhibit 634.01, UCA argument, paragraph 384.
1142 Exhibit 636.01, CCA argument, paragraph, 371.
1143 Exhibit 646.02, EPCOR reply argument, paragraph 297.
1144 Exhibit 629.01, Calgary argument, PDF page 67.
1145 Exhibit 635.01, IPCAA argument, paragraph 60.
1146 Exhibit 631.01.AE-566, ATCO Electric argument, paragraph 297.
1147 Exhibit 630.02, EPCOR argument, paragraph 294.
1148 Transcript, Volume 11, pages 2179-2180.
1149 Exhibit 630.02, EPCOR argument, paragraph 294.

Commission findings

928. The Commission has evaluated the various proposals put forward by the parties to set targets. With respect to the willingness-to-pay study proposed by the UCA, the Commission does not consider that such a proposal is necessary. Although a willingness-to-pay study may provide valuable information if the Commission were trying to ascertain whether Alberta distribution companies were providing a socially optimal level of reliability, at this time, the evidence on the record of this proceeding demonstrates that reliability standards are acceptable. Customer satisfaction scores are already provided by the companies on an annual basis as a part of the AUC Rule 002 results. The Commission is of the view that declining customer satisfaction scores will be a timely indicator of problems. For all of these reasons, the Commission rejects the UCA's proposal to use a willingness-to-pay study to set target measures at this time.

929. With respect to specific proposals of parties for setting service quality targets, the Commission will consider these proposals in the upcoming AUC Rule 002 consultative process.

930. In addition to establishing new measures and setting targets for those metrics currently without targets, the Commission considers that it is important that companies and Alberta customers understand the consequences that could result from a company's failure to meet service quality targets. This is particularly critical if a pattern of consistent failure arises. Therefore, through the upcoming AUC Rule 002 consultation process, the Commission will develop a penalty structure for these metrics as part of the administrative penalty scheme authorized under Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act*. The Commission expects that this penalty structure will include escalating penalty amounts commensurate with repeated violations of the targets up to and including the maximum administrative penalty set out in Section 63 of the *Alberta Utilities Commission Act.*

931. Following the completion of the consultative process the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties including a hearing or other proceeding.

14.3.3.1 Asset condition monitoring

932. Service quality and the physical condition of assets are linked. Companies cannot provide consistently reliable service without a well-functioning physical infrastructure. Parties suggested that the Commission must determine whether it is sufficient to monitor only the resulting service quality or whether it is necessary to also monitor the actions of the companies to ensure that the companies do not maintain service quality during the PBR term, but reduce their costs by allowing certain assets to degrade as a result of aging and deterioration, to then be replaced in capital programs that have been delayed to the post-PBR period.

933. In the proceeding, a number of approaches were proposed that ranged from companies simply reporting their current practices for increased transparency to recommendations that advocated Commission and intervener involvement in the development of policies and best practices for the companies.

934. The UCA proposed that the Commission "direct utilities to develop and file an asset management framework using the asset management discipline as envisioned by The Woodhouse Partnership Limited (TWPL)."[1150] The UCA was not in support of the type of asset

[1150] Exhibit 634.01, UCA argument, paragraph 387.

management study being conducted by EPCOR, which the UCA classified as a study of asset condition.[1151]

935. IPCAA proposed to exclude power system assets from PBR until such a time as service quality and asset condition metrics can be developed[1152] through a Commission-led consultation process.[1153] IPCAA's proposal is to include only general and administration costs in PBR.

936. In response to IPCAA's proposal, the CCA stated:

> In our view, if the AUC is not inclined to adopt IPCAA's recommendation, the AUC should convene a consultative process which would review the existing practices and lead to a determination of appropriate asset-condition metrics with the goal the metrics so determined would be applicable for the balance of the PBR term.[1154]

937. Calgary stated that asset management and data disclosure should be addressed in a collaborative process.[1155]

938. All of the distribution companies were opposed to the increased regulatory burden that could result with having asset management as a part of PBR. AltaGas submitted that "the monitoring of asset condition may be of limited value, particularly given the different vintages and terrains applicable to different service territories which may impact the results of such surveys."[1156]

939. ATCO Gas indicated in its final argument that asset management metrics would hamper its ability to be innovative:

> How can ATCO Gas try to find innovative, efficient ways of doing things like valve inspections, for example, if it is required to meet a standard that specifies exactly how it will undertake those valve inspections? ATCO Gas agreed with Dr. Makholm that the measures need to be objective and measurable and focus more on the output of the utility.[1157]

940. In EPCOR's opinion, "a process to review and assess asset condition data would be extremely complex, time consuming and costly resulting in substantial additional costs being borne by rate payers."[1158]

941. ATCO Electric stated in its final reply argument:

> IPCAA recommends a consultative process be initiated to identify key asset condition data which should be provided by the utility to customers and the regulator. ATCO Electric views this request to be without merit as the provision of the data by itself is without value as it requires an engineering analysis and assessment within an overall

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1151 Exhibit 634.01, UCA argument, paragraph 388.
1152 Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 3.
1153 Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 13.
1154 Exhibit 645.01, CCA reply argument, paragraph 216.
1155 Exhibit 629.01, Calgary argument, page 66.
1156 Exhibit 650.01, AltaGas argument, page 77.
1157 Exhibit 632.01, ATCO Gas argument, paragraph 321.
1158 Exhibit 630.02, EPCOR argument, paragraph 313.

asset management program as was described by Ms. Bayley during testimony. This is completely contrary to the AUC principle of reducing regulatory burden."[1159]

942. In an excerpt from Fortis' testimony, Mr. Delaney stated:

> We have a million poles, 100,000 kilometres of line. Coming from that, we've developed a number of programs. We have a pole management program where we do life extension of poles, and we are embarking on an effort to get 1940s and 1950s vintage poles out of our system that have 30 percent or more failure rates. We have an underground cable management program where we rejuvenate and extend the life of underground cables, pad mount transformer maintenance program with predicted maintenance, oil sampling. Well, I can go on. We have switch maintenance. We have a number of programs associated with all of our assets… And I understand certainly the Commission's point of view on this that -- but it's a tough thing to regulate without, you know, violating Principle 3, given the complexity of all these things. Now, there are avenues. There is envisioned an annual meeting, whether it's under Rule 2 or some other aspect that could be sort of a technical conference thing could be added on where utilities can give -- well, probably give things like a breakdown of what's happened in reliability over the past year, which we kind of do right now under Rule 2 in terms of what happened. Another -- but it's going to be a very, very complex exercise to establish input measures and then what do you make of them once you've established them. The utility must have the flexibility to move within its asset maintenance program to do what needs to be done prudently. And if we were to introduce process that involves information responses and thousands of -- a big process like that, then my engineers and people that were looking to find innovation and find good things to do to reduce our costs will be -- we'll take that regulatory burden.[1160]

Commission findings

943. While the companies are opposed to the increased regulatory burden from the introduction of asset management monitoring practices, the Commission sees potential benefits from asset management reporting. The purpose of asset management monitoring is to provide increased visibility into the asset management practices of the companies. It is not to replace the management of assets by the companies. Indeed, IPCAA's witness, Mr. Cowburn, acknowledged that this was not the purpose of asset condition disclosure.[1161] Rather, regular reporting of asset condition will give the Commission and stakeholders some insight into the condition of the companies' assets. Information about asset condition will improve the Commission's ability to develop quality of service metrics as well as assess capital tracker applications as discussed in Section 7.3.

944. Having determined that some asset management monitoring will be required, the Commission is of the view that stakeholders and the Commission would benefit from an AUC consultative process to develop reporting requirements. This consultation will be separate from the process discussed above with respect to AUC Rule 002. The Commission anticipates that it will conduct a distribution company round-table on this matter after the commencement of the PBR term.

[1159] Exhibit 647.01, ATCO Electric reply argument, paragraph 326.
[1160] Transcript, Volume 11, pages 2177-2179.
[1161] Transcript, Volume 16, pages 3131 to 3132

945. The Commission will, after consultation with stakeholders, develop an asset management monitoring process to report on the condition of distribution assets with the intention of providing transparency while allowing the companies to manage their assets and operations. In so doing the Commission will seek to limit any additional regulatory burden.

14.3.3.2 Line losses

946. Electricity retailers are charged for all electricity entering the distribution system from the transmission system. Some electricity is lost as a result of the transfer of energy across electric distribution systems, including distribution lines, transformers and regulators. This lost electricity is referred to as technical losses.[1162] Other electricity may be consumed but not recognized as used or sold for a variety of reasons, such as meter reading errors, meters not read, unmetered sites incorrectly estimated and energy theft. This type of loss is referred to as unaccounted-for-energy or non-technical losses.[1163]

947. ENMAX filed a line loss proposal as a complement to its FBR plan. This proposal had been developed in discussion with a number of interveners and was approved by the Commission in Decision 2009-226. The proposal created an incentive for ENMAX to reduce levels of line losses and assume the risk from investments made to reduce the losses. If there were savings from the reduction in line losses, ENMAX and the customers shared equally in those benefits.[1164] ENMAX reported that, as a result of this incentive plan, $0.854 million has been saved by its consumers in 2009 and 2010.[1165]

948. On behalf of the UCA, Dr. Cronin stated that for line losses "we find that the Alberta LDCs again compare very well" to the Ontario LDCs.[1166] However, IPCAA, the UCA and the CCA all expressed concerns regarding the potential risk that line losses could increase from current levels under PBR.[1167]

949. IPCAA recommended that the way to address the potential risk that line losses may increase under PBR was to "mitigate the potential drivers of such increases." IPCAA elaborated by stating:

> If asset management processes are made available and equipment selection criteria can be reviewed in an open, consultative process, any changes in utility equipment specifications leading to higher losses will be known and understood as they occur… Information transparency is preferred over blanket requirements in order to maintain line losses at a specific level [CCA-Exhibit 636, page 123], as there may be a good economic justification for the selection of different equipment."[1168]

1162 Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
1163 Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
1164 Exhibit 297.01, ENMAX evidence, PDF page16.
1165 Exhibit 297.01, ENMAX evidence, PDF page16.
1166 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF page 11.
1167 Exhibit 642.01, IPCAA reply argument, paragraph 60; Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 183-185; Exhibit 636.01, CCA argument, paragraph 360.
1168 Exhibit 642.01, IPCAA reply argument, paragraphs 60-61.

950. The UCA recommended that each applicant should develop a line loss proposal which should either involve a mechanism to adjust the rates or a set of incentives similar to the ENMAX approach.[1169]

951. The CCA submitted that EPCOR's plan should include:

> …a specific provision that its line losses during the PBR Term will not be any lower than that observed for the 3-year average period prior to the start of the PBR term i.e. average of 2.633% for the period 2009-2011, inclusive, per X239.01, UCA-ALLUTILITIES-4 (mm).[1170]

952. Fortis, EPCOR and ATCO Electric rejected the inclusion of a line loss proposal as suggested by the interveners. Fortis stated that it already "has ongoing system design and standards programs in place that focus on loss minimization, as well as an ongoing capital project that looks for loss reductions on specific lines. Any incremental line loss program would be duplicative and unnecessary."[1171] EPCOR expressed concern that it is already operating near the low end of what is physically achievable, that theft is outside of the direct control of the company and non-technical losses are already monitored by the AESO in support of AUC Rule 021: *Settlement System Code Rules* (Rule 021).[1172]

953. In its rebuttal evidence, ATCO Electric explained its engineering processes and the difficulty in isolating changes related to the reduction in line losses:

> ATCO Electric is not proposing to introduce a line loss module as it is unable to distinguish investments required to maintain the optimal operation of its distribution system from those that may provide a benefit to its line loss, which is a consequence of all the actions ATCO Electric undertakes. As the distribution network expands, ATCO Electric will continue to implement and deliver the appropriate types of distribution investment that considers all important aspects of ensuring a safe and reliable distribution system is in place. Failure of its duty will result in power quality and reliability degradation that will impact ATCO Electric's customers' ability to operate and connect to the distribution system. In addition, current Settlement System Code Rules under Rule 021 ensure utilities are aware and comply with specific unaccounted for energy tolerances that are monitored by the AESO.

Commission findings

954. The Commission considers that line losses are currently within acceptable levels. Nonetheless, the Commission has concerns about how PBR may provide incentives that have an adverse impact on line losses.

955. As a part of the consultative process to review and revise AUC Rule 002, the Commission will consider metrics for monitoring line losses and the establishment of targets for ensuring companies maintain their current levels of line loss performance. The Commission is also prepared to consider other approaches that parties may propose.

1169 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 184-185.
1170 Exhibit 636.01, CCA argument, paragraph 360.
1171 Exhibit 644.01, Fortis reply argument, paragraph 178.
1172 Exhibit 646.02, EPCOR reply argument, paragraphs 268-270.

14.4 Re-openers for failure to meet service quality targets

956. The UCA, the CCA, IPCAA and EPCOR each proposed that a re-opening of the PBR plan should be undertaken in the event that there is a dramatic decline in service quality.

957. In argument, both the UCA and the CCA recommended that failure to meet a specific performance standard for two consecutive years would be an issue that could trigger a re-opener.[1173] In the case of the CCA, the re-opener would be automatic or "alternatively at the request of an interested party or the AUC."[1174] IPCAA considered that if "customer service is materially degraded by any utility, the PBR plan should be re-opened or even terminated by an off-ramp."[1175] EPCOR's submission included a re-opener for failure to meet the same service quality target for two consecutive years and stated that adjustments to the PBR plan "could include such things as a change to the performance target, a change to the performance measure, or the termination of the measure."[1176]

958. Conversely, ATCO Gas and ATCO Electric were of the opinion that a re-opener clause that is linked to not achieving specific performance standards is not required, especially if service quality is addressed under AUC Rule 002[1177] while Fortis' proposed PBR plan did not include any provisions for re-openers or off-ramps as a result of service quality degradation.[1178]

Commission findings

959. The Commission has the ability under both the *Electric Utilities Act* and the *Gas Utilities Act* to make rules regarding service quality and to monitor and enforce those rules. If it should become apparent that the ways in which the companies are implementing their PBR plans are having a detrimental impact on service quality performance, the Commission can take whatever steps are necessary under the legislation to direct a change in behaviour without having to re-open the PBR plan. Accordingly, the Commission does not accept the proposal to include degradation in service quality as an event that would necessitate a re-opening of the PBR plans.

15 Annual filing requirements

960. The companies recognized a requirement for periodic filings to deal with various rate or capital factor applications during the PBR term. The proposals differed with respect to the number, content and frequency of applications. The companies were also in favour of maintaining existing application processes in respect of certain deferral accounts and flow-through accounts. In addition, some sections of this decision refer to PBR related annual filings under AUC Rule 002 and AUC Rule 005.

15.1 Annual PBR rate adjustment filing

961. Companies generally preferred an annual filing for the setting of the following year's rates. Some of the companies requested a second annual filing with respect to the true-up of

[1173] Exhibit 634.01, UCA argument, paragraph 321; Exhibit 636.01, CCA argument, paragraph 326.
[1174] Exhibit 636.01, CCA argument, paragraph 327.
[1175] Exhibit 635.01, IPCAA argument, paragraph 38.
[1176] Exhibit 103.02, EPCOR submission, paragraph 243.
[1177] Exhibit 648.02, ATCO Gas reply argument, paragraph 432; Exhibit 647.01, ATCO Electric reply argument, paragraph 278.
[1178] Exhibit 633.01, Fortis argument, paragraphs 221-233.

certain factors or amounts that would be included on a forecast basis in the annual rate application so as to adjust rates more than once each year. The Commission has determined above that a second rate adjustment adds unnecessary administrative complexity and is not required.

962. The Commission determines that the effective date for annual rate changes will be January 1st each year. In order to accommodate this date, a number of items will need to be considered leading up to the annual rate change. The annual PBR rate adjustment filing to establish the rates to be in effect on January 1st of the upcoming year is to be made by September 10th of each year.

963. The annual PBR rate adjustment filings for electric distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$R_t = \underbrace{BR_{t-1}(1 + (I - X))}_{\substack{\text{Base rates} \\ (BR_t)}} +/- Z +/- K +/- Y$$

964. The annual PBR rate adjustment filings for gas distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$RPC_t = \underbrace{BRPC_{t-1}(1 + (I - X))}_{\substack{\text{Base revenue} \\ \text{per customer class}}} +/- Z +/- K +/- Y$$

$$R_t = RPC_t / BDC_t$$

Where:

R_t	=	upcoming year's rates for each class
RPC_t	=	upcoming year's revenue per customer for each class
BR_{t-1}	=	current year's base rates for each class
$BRPC_{t-1}$	=	current year's base revenue per customer for each class
BDC_t	=	billing determinants for each class for the upcoming year
I	=	inflation factor
X	=	productivity factor
Z	=	exogenous adjustments
Y	=	flow-through items, collected through Y factor rate adjustments (not including Y factors collected through separate riders)
K	=	capital trackers collected through K factor rate adjustments

965. The items to be included in the annual PBR rate adjustment filings will therefore be:

- base rates from the current year by rate class that will be the starting point for the upcoming year's rates
- I factor calculation as described in Section 15.1.1 with supporting backup

- Z factors approved during the previous 12 months calculated as described in Section 15.1.2
- K factor adjustment related to approved capital trackers calculated as described in Section 15.1.3
- Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate items that are not subject to the I-X mechanism to rate classes as described in Section 15.1.5
- backup showing the application of the formula by rate class and resulting rate schedules
- a copy of the Rule 005 filing filed in the current year
- any other material relevant to the establishment of current year rates

15.1.1 I factor

966. As discussed in Section 5.4, the I factor to be included in the annual PBR rate adjustment filings will be calculated using the Alberta AWE (average weekly earnings) from July of the prior year to June of the current year and the Alberta CPI (consumer price index) from July of the prior year to June of the current year. The companies will be required to provide Statistics Canada data for each index and show how the I factor was calculated.

15.1.2 Z factors

967. As noted in Section 7.2.2 some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis in response to a Z factor application.

968. Where a Z factor adjustment has been directed to be included in rates as an adjustment to base rates, the company will make the required adjustment and provide details of the calculation as part of the annual PBR rate adjustment filing.

969. Where a Z factor adjustment has been directed to be included in rates but not as an adjustment to base rates and therefore outside of the I-X mechanism, each company will calculate a Z factor amount to be included in the annual PBR rate adjustment filing. All these Z factor amounts approved by the Commission since the last annual PBR rate adjustment filing will be aggregated as a single rate adjustment and included with the rate adjustment in the next annual PBR rate adjustment filing.

970. Parties should be aware of the Commission's performance standards for processing rate-related applications as prescribed by Bulletin 2010-16.[1179]

971. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Z factor rate adjustments associated with the Z factor revenue requirements by rate class.

[1179] AUC Bulletin 2010-16, Performance Standards for Processing Rate-Related Applications, Table 1.

972. Due to the time lag that may occur between the occurrence of a Z factor event and implementation of the necessary rate adjustments, the companies will be permitted to record carrying charges calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest. This interest rate is consistent with AUC Rule 023,[1180] however the regulatory lag and materiality requirements of Rule 023 will not apply.

15.1.3 Capital trackers

973. The complexity of capital tracker applications will require that these applications be submitted earlier. To promote regulatory efficiency the Commission considers that a single annual capital tracker application filing for each company will be made by March 1st each year.

974. A single application must be filed by March 1st of the current year with respect to all projects which may qualify for capital tracker treatment to be commenced in the upcoming year. The timing of the application is intended to provide sufficient time for processing of the application and inclusion of approved amounts as a K factor in the September 10th annual PBR rate adjustment filing. All of the capital trackers for each company will be collected in a pool that comprises a single K factor in the PBR formula for the company. As discussed in Section 7.3.3.2, the process for filing upcoming projects and associated K factor amounts is only to establish interim K factor rate adjustments. Interim amounts will be subject to true-up to actual costs as part of a prudence review following completion of the project.

975. The annual March 1st capital tracker filing must include a business case with respect to each proposed capital tracker. The business case will include forecast costs, being the amount proposed to be collected on an interim basis through the K factor in the upcoming year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project including the materiality of the entire project to be considered. Multi-year forecasts will be updated each year in the capital tracker application so that the forecast amounts to be included that year's K factor will reflect the most recent information available. In addition, the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.

976. The results of the prudence review and cost true-up will be an adjustment to the K factor included in the following year's rates. The companies will calculate the revenue requirements resulting from the actual capital tracker expenditures, and compare those to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirements for the prior year will form the basis for the K factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to include in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

[1180] AUC Rule 023: *Rules Respecting Payment of Interest* (Rule 023), Section 3, paragraph 2, page 2.

977. The calculation of the K factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. The weighted average cost of capital rate to be used in calculating the revenue requirements associated with capital trackers will be based on current rates established in the most recent GCOC proceeding rather than using the rates that were in place at the start of the PBR term. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the K factor rate adjustments associated with revenue requirements by rate class.

978. As discussed in Section 7.3.4, the companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria.

15.1.4 Y factor rate adjustments

979. The forecasts for the provision for each Y factor item to be included in the upcoming year's rates will be included in the annual PBR rate adjustment filing. As discussed in Section 7.4.4 the provisions will generally be based on the 2012 test year of the general tariff application or general rate application proceeding that forms the going-in rates. The true-up of the Y factor accounts, being the difference between the prior year provision and the prior year actual result, will also be identified in the September 10th PBR annual filing.

980. For any Commission directed items (e.g., AUC assessment fees, intervener portion of hearing costs, etc.) and the UCA assessment fees, the basis for determining the true-up to be included in the annual PBR rate adjustment filing will be the actual amounts that were incurred from August 1 of the prior year to July 31 of the current year.

981. The true-up process will also capture the impact of any Commission directed items that occurred from September 1 of the prior year to August 31 of the current year that were new and for which there was no provision in the Y factor for the current year.

982. All of the Y factor accounts that are not subject to flow-through treatment and collected by way of a separate rate rider will be collected in a pool that comprises a single Y factor in the PBR formula for the company. The most recent forecast of billing determinants along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Y factor rate adjustments associated with Y factor revenue requirements by rate class.

983. Carrying charges on balances that are subject to true up will be calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest on accounts that existed prior to implementation of PBR. This interest rate is consistent with AUC Rule 023,[1181] however the regulatory lag and materiality requirements of Rule 023 will not apply.

[1181] AUC Rule 023, Section 3, paragraph 2, page 2.

15.1.4.1 Flow-through items

984. As discussed in Section 7.4.3, flow-through items currently collected by way of separate rider will be collected using the existing methodology and rider mechanism outside of the annual PBR rate adjustment filing process to recognize that these flow-through items are currently processed throughout the year. As a result, applications related to flow-through items may be submitted throughout the year.

15.1.4.2 Clearing balances in deferral accounts that are not permitted to continue under PBR

985. To the extent that the companies had deferral accounts under cost of service regulation that have not been approved to continue under PBR in this decision, the Commission recognizes that the companies may have residual balances in the deferral accounts that need to be disposed of. The Commission determines that the companies will submit an application identifying the outstanding balances as of December 31, 2012 as part of their annual PBR rate adjustment filing for 2013.

15.1.5 Billing determinants and Phase II implications

986. Under PBR, the portion of electric distribution rates subject to the I-X mechanism is not impacted by changes to billing determinants. The portion of gas distribution rates subject to the I-X mechanism is impacted by changes in usage per customer. Rate adjustments outside of the I-X mechanism (Z factors, K factors and Y factors) for both electric and gas distribution companies will involve calculating a total amount of revenue requirement associated with the underlying items, and then allocating that revenue requirement to rate classes to determine the necessary rate adjustments. This will require the use of billing determinants and Phase II rate class allocation methodologies. In addition, a number of the companies identified the possibility of Phase II applications to revise the rate class allocation methodologies that may be required during the PBR term, which would also require the use of billing determinants.

987. Fortis proposed to use to a method consistent with that used in previous cost of service filings to establish its billing determinants under PBR. Fortis provided a forecast of the billing determinants to be used for the entire PBR term, and indicated that it will accept the risk on any variances between forecasts and actual.[1182] Fortis identified the potential for a Phase II application to transition towards 100 per cent revenue-to-cost ratios by rate class, and the billing determinant forecast would be used for this purpose.[1183]

988. ATCO Electric also provided a forecast for billing determinants for the entire PBR term. ATCO Electric followed the same methodology for preparing the billing determinants and load forecasts used in its 2011 to 2012 GTA. In addition, if a Phase II application is determined to be necessary during the PBR term, ATCO Electric proposed to use the billing determinant forecast provided in its PBR application for input into the cost of service and rate design.[1184]

989. EPCOR proposed that billing determinants be reforecast annually using a calculation methodology that relies on readily available historical billing determinants.[1185] EPCOR identified that Phase II rate rebalancing adjustments may be required as a result of the implementation of a

[1182] Exhibit 100.02, Fortis application, Section 2, paragraph 37, page 10.
[1183] Exhibit 100.02, Fortis application, Section 13.2, paragraph 181, pages 50-51.
[1184] Exhibit 98.02, ATCO Electric application, Section 16, paragraphs 290-291, page 16-3.
[1185] Exhibit 103.02, EPCOR application, Section 2.3.7.1, paragraphs 156-158, pages 53-54.

new geographic information system (GIS).[1186] Aside from the aforementioned adjustment from the implementation of GIS, as a result of the characteristics of its PBR plan, EPCOR identified that Phase II applications will no longer be required in the normal course.[1187]

990. ATCO Gas indicated that it would be providing a billing determinants forecast each year. ATCO Gas proposed to use the principles outlined in its Phase II negotiated settlement approved in Decision 2010-291 to determine the rates for each year. ATCO Gas proposed to use the same methodology as long as the negotiated settlement remains in place. In the event that the negotiated settlement is terminated for any reason, ATCO Gas proposed that a new Phase II application be filed, with the expectation that the determination of rates for the remainder of the PBR term would be governed by the outcome of that proceeding.[1188] Calgary supported the Phase II proposal of ATCO Gas.[1189]

991. AltaGas proposed that its billing determinants be reforecast annually in order to capture any declining usage per customer.[1190] AltaGas anticipated filing a Phase II application for its 2013 to 2017 PBR plan that will involve preparation of a revised cost of service study and rate design based on the revenue requirement approved for 2012, and adjusted pursuant to the proposed PBR formula to collect the forecast 2013 revenue cap amount.[1191]

992. The UCA proposed that each utility should be required to file a Phase II application by the end of 2015 or at the latest 2016. The UCA noted that several of the companies are in the process of performing an analysis on cost allocations and that there are also previous Commission directions that are still outstanding, and as a result it will be necessary to realign rates in the middle of the PBR term.[1192] The CCA generally supported the position of the UCA.[1193] IPCAA stated that "[c]ustomers deserve just, fair and reasonable rates, and a Phase II rates review should not be delayed or deferred by PBR."[1194]

Commission findings

993. The Commission considers that billing determinants will have limited use during the PBR term for electric distribution companies because the I-X mechanism results in rate changes that are separated from the costs of the company, therefore there is no revenue requirement that needs to be allocated to rate classes using billing determinants as was the case under cost of service regulation. The revenue-per-customer cap plans approved for the gas distribution utilities will, however, require usage-per-customer forecasts based on current billing determinants to perform the annual customer rates calculations. In addition, both electric and gas distribution companies will be required to allocate items outside of the I-X mechanism including Z factors, K factors and Y factors to rate classes, and those allocations will require billing determinant forecasts and Phase II methodologies.

[1186] Exhibit 103.02, EPCOR application, Section 4.3, paragraph 264, page 84.
[1187] Exhibit 103.02, EPCOR application, Section 3.0, paragraph 232, page 77.
[1188] Exhibit 99.01, ATCO Gas application, Sections 5.1.2-5.1.3, paragraphs 152-153, pages 53-54.
[1189] Exhibit 629.01, Calgary argument, Section 18.1, page 71.
[1190] Exhibit 110.01, AltaGas application, Section 2.3, paragraph 42, page 11.
[1191] Exhibit 110.01, AltaGas application, Section 13.0, paragraph 125, page 40.
[1192] Exhibit 634.02, UCA argument, Section 18.1, paragraphs 424-427, pages 75-76.
[1193] Exhibit 636.01, CCA argument, Section 18.2, paragraph 385, page 133.
[1194] Exhibit 635.01, IPCAA argument, Section 18.1, paragraph 96, page 15.

994. The Commission determines that long-term forecasts of billing determinants as proposed by Fortis and ATCO Electric are not necessary. As identified by Fortis, the use of long-term forecasts introduces forecasting risk into the PBR plan with respect to billing determinants. Because the billing determinants are generally used to allocate items that have been determined to be exceptions to the incentive properties of PBR, the Commission considers that it is necessary to achieve a greater degree of accuracy. The Commission does not consider that the company or its customers should benefit from, or be negatively impacted by, forecasting inaccuracies that may result from using forecasts that extend well into the future. Utilizing a shorter term for the forecasts will reduce the possibility for material forecasting inaccuracies. For this reason the companies will provide a revised forecast of their billing determinants annually as part of the September 10th annual PBR rate adjustment filings. In addition, the companies will provide the billing determinants forecast to be utilized for January 1, 2013 rates as part of their compliance filings to this decision.

995. Companies will be expected to utilize forecasting methodologies that are logical and easy to understand, and in most cases this will involve the continued use of forecasting methodologies utilized prior to PBR. Companies should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Companies will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision.

996. The Commission considers that PBR is unrelated to the requirement to periodically update rates through a Phase II process. However, during the PBR term the companies may file applications for Phase II adjustments to their rate design and cost allocation methodologies and the Commission will make a determination at that time as to whether the adjustments are warranted. For purposes of a cost of service study, the companies shall use the revenue requirement resulting from going-in rates adjusted by the PBR formula (including the I-X mechanism, K factors, Y factors and Z factors) and the latest updated billing determinants.

15.2 AUC Rule 002 and AUC Rule 005 annual filings

997. As discussed in Section 13, annual AUC Rule 005 filings will continue to be filed by the companies on May 1st for electric distribution utilities and May 15th for gas distribution utilities. In addition, a copy of the prior year AUC Rule 005 filings will be included with the September 10th annual PBR rate adjustment filing.

998. As discussed in Section 14.1, the service quality of the companies will continue to be monitored using the AUC Rule 002 process. Annual service quality filing requirements are set out in the provisions of the rule.

15.3 Summary of annual filing dates

999. Below is a summary of the key annual filing dates under the PBR plans.

Table 15-1 Summary of key PBR annual filing requirements

Date	Action
March 1	Submission of capital tracker applications
May 1 or 15	AUC Rule 005 annual filings (May 1 for electric utilities, May 15 for gas utilities)
September 10	Companies to file annual PBR rate adjustment filings
January 1	Effective date for approved rates that are subject to the PBR formula

16 Generic proceedings

1000. During the first PBR term, the Commission will conduct a number of generic proceedings to deal with issues that arose out of the cost of service regulatory regime, some of which are still relevant to the companies under PBR. These proceedings are "generic" because the issues affect more than one company, including issues such as the recognition of debt costs or the treatment of certain income tax expenses. These generic proceedings are intended to make regulation in Alberta, including regulation of those companies that remain under cost of service regulation, more efficient and more predictable.

1001. To the extent that the decisions coming out of these generic proceedings will impact the companies under PBR, prior to the end of the PBR term, the Commission will consider any necessary rate adjustments using the mechanisms set out in Section 15.1.4 of this decision, as matters arise.

1002. The Commission will shortly issue bulletins to commence a proceeding on the generic cost of capital and to either continue Proceeding ID No. 20 with respect to Utility Asset Dispositions or initiate a generic proceeding regarding asset disposition and stranded assets. Additionally, the Commission will initiate other generic proceedings and will seek input from interested parties on additional matters parties may wish to have considered in generic proceedings, the scope of the issues to be considered, and the format for these proceedings. With regard to the latter, the Commission expects that many of these generic proceedings can take the form of consultations.

17 Order

1003. It is hereby ordered that each of AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. shall file a compliance filing in accordance with the directions set out in this decision by November 2, 2012. The compliance filing shall include proposed distribution rate schedules to be effective January 1, 2013 with supporting documentation including:

- base rates for going-in rates by rate class that will be the starting point for 2013 rates
- I factor calculation as described in Section 15.1.1 with supporting backup
- provision component of the Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate Y factor provisions to rate classes
- backup showing the application of the formula by rate class and resulting rate schedules
- any other material relevant to the establishment of current year rates

Dated on September 12, 2012.

The Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd. (ATCO Electric or AE) L. Keough L. E. Smith L. Kizuk D. Werstiuk J. Teasdale V. Porter M. Bayley
AltaLink Management Ltd. J. Piotto T. Kanasoot E. Tadayoni J. Yeo J. Wrigley K. Evans
ATCO Gas (ATCO Gas or AG) L. E. Smith D. Wilson A. Green M. Bayley L. Fink
ATCO Pipelines L. E. Smith E. Jansen S. Mah D. Dunlop B. Jones A. Jukov
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie R. Koizumi J. Coleman C. Martin P. E. Schoech
The City of Calgary (Calgary) D. I. Evanchuk G. Matwichuk
Central Alberta Rural Electrification Association D. Evanchuk P. Bourne
Consumers' Coalition of Alberta (CCA) J. A. Wachowich J. A. Jodoin A. P. Merani

Name of organization (abbreviation) **counsel or representative**
Direct Energy Marketing Limited S. Puddicombe
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo D. Gerke P. Wong D. Tenney
ENMAX Power Corporation (ENMAX or EPC) D. Emes G. Weismiller K. Hildebrandt J. Schlauch J. Worsick
FortisAlberta Inc. (Fortis or FAI) J. Walsh
Graves Engineering Corporation J. T. Graves
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster T. Clarke R. Mikkelsen S. Fulton V. Bellissimo
City of Lethbridge M. Turner O. Lenz
National Economic Research Associates (NERA) J. Cusano L. Aufricht J. Markholm
The City of Red Deer M. Turner L. Gan
South Alta Rural Electrification Association D. Evanchuk B. Bassett

Name of organization (abbreviation) **counsel or representative**
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary S. Mattuli W. Taylor R. Bell

The Alberta Utilities Commission Commission Panel W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member Commission Staff B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller L. Ou D. Mitchell K. Schultz D. Ward B. Clarke S. Karim P. Howard J. Olsen B. Whyte W. Frost G. Scotton S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville

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Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
National Economic Research Associates, Inc (NERA) J. Cusano L. Aufricht	J. Makholm A. Ros
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie	P. Schoech R. Camfield G. Johnston A. Mantei R. Retnanandan
ATCO Electric Ltd. and ATCO Gas (ATCO) L. Smith, QC K. Illsey	P. Carpenter M. Bayley D. Wilson D. Freedman B. Goy J. Cummings N. Palladino
The City of Calgary (Calgary) D. I. Evanchuk E. W. Dixon	G. Matwichuk H. Johnson
Consumers Coalition of Alberta (CCA) J. Wachowich	M. Lowry
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo C. Bystrom	Panel 1 (PRB principles and structure) D. Weisman D. Gerke D. Cole J. Elford H. Haag Panel 2 (PBR inflation, productivity and formula issues) D. Ryan D. Gerke J. Baraniecki C. Cicchetti
FortisAlberta Inc. (Fortis or FAI) T. Dalgleish, QC	I. Lorimer P. Delaney M. Stroh J. Frayer
ENMAX Power Corporation (ENMAX or EPC) D. Wood L. Cusano	K. Hildebrandt G. Weismiller R. Lawton

Name of organization (abbreviation) **counsel or representative**	**Witnesses**
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn V. Bellissimo R. Mikkelsen
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. Parker	F. Cronin S. Motluk R. Bell

The Alberta Utilities Commission

Commission Panel
W. Grieve, QC, Chair
M. Kolesar, Vice-Chair
M. A. Yahya, Commission Member

Commission Staff
B. McNulty (Commission counsel)
C. Wall (Commission counsel)
A. Sabo (Commission counsel)
J. Thygesen
O. Vasetsky
B. Miller
S. L. Levin, Emeritus Professor of Economics
Department of Economics and Finance
School of Business
Southern Illinois University Edwardsville

Appendix 3 – Major procedural steps in rate regulation initiative: performance-based regulation

(return to text)

1. On February 26, 2010, the Commission wrote in a letter (Exhibit 1.01) sent to interested parties that it was "beginning an initiative to reform utility rate regulation in Alberta."

2. The Commission established a roundtable meeting of interested parties, which took place March 25, 2010 in the AUC hearing room in Edmonton. At the roundtable, the distribution companies said they could file PBR proposals by the end of the first quarter of 2011: March 31, 2011.

3. In an April 9, 2010 letter (Exhibit 6.01) to interested parties, the Commission outlined the discussions at the roundtable and notified them it had contracted the Van Horne Institute to organize a PBR workshop May 26 and May 27 in Edmonton.

4. On May 14, 2010, the Commission issued a letter (Exhibit 27.01) to interested parties on the process for development of guiding PBR principles, which the Commission planned to release via AUC bulletin on July 8, 2010. That letter established a process schedule to receive submissions on which specific incentive-based proposals would be evaluated, with initial submissions to be provided by June 10, 2010 and comments on the submissions to be provided by June 17, 2010.

5. The PBR workshop took place in Edmonton on May 26 and May 27, 2010. Material on the legal dimensions and regulatory evolution of PBR were distributed to roundtable participants ahead of the roundtable, on May 20, 2010.

6. On June 15, 2010, AltaGas Utilities Inc. (AltaGas) proposed a one-week extension to the June 17, 2010 deadline. In a letter (Exhibit 53.01) dated June 16, 2010, the Commission agreed to the request and adjusted the date for its PBR bulletin issuance to July 15, 2010.

7. On July 15, 2010, the Commission issued Bulletin 2010-20 (Exhibit 64.01). In that bulletin the Commission stated the five principles that would guide its examination of specific PBR proposals from regulated utilities.

8. In August, 2010, the Commission hired National Economic Research Associates Inc. (NERA) as an independent consultant to conduct a total factor productivity study or studies.

9. In a letter (Exhibit 71.01) to interested parties dated September 8, 2010, the Commission set out the terms of reference for NERA's engagement.

10. In letters (exhibits 76.01 and 78.01) to the Commission dated November 12 and November 25, 2010, respectively, ATCO Gas and ATCO Electric (jointly ATCO), and AltaGas requested extensions to both the previously established date for filing their PBR proposals of March 31, 2011 and the previously established date for implementation of PBR plans of July 1, 2012. Both requested implementation be delayed to January 1, 2013.

11. By correspondence (Exhibit 79.01) to interested parties on December 16, 2010, the Commission agreed to postpone ATCO and AltaGas' PBR plan filing dates to May 31, 2011 and their PBR implementations to January 1, 2013.

12. NERA filed its expert report (Exhibit 80.02) on total factor productivity with the Commission on December 30, 2010.

13. On February 7, 2011, the Consumers Coalition of Alberta (CCA) expressed concerns about the proposed proceeding schedule, including the May 31, 2011 deadline for filing of PBR plans, due to a heavy regulatory agenda (Exhibit 86.02).

14. On March 24, 2011 EPCOR Distribution & Transmission Inc. (EPCOR), AltaGas, FortisAlberta Inc. (Fortis), ATCO Electric and ATCO Gas submitted a joint letter (Exhibit 89.01) to the Commission requesting a further deadline extension.

15. In a letter (Exhibit 90.01) to the parties dated March 29, 2011, the Commission agreed to certain proceeding schedule changes, including proposing the postponement of filing of utility PBR plans to July 22, 2011. In the same letter the Commission proposed a simplified compliance filing process to ensure that PBR plans could be implemented by January 1, 2013.

16. Following responses from parties, the Commission in a letter (Exhibit 94.01) dated April 13, 2011 set a new proceeding schedule, with utility PBR plans to be submitted July 22, 2011 and a hearing scheduled to begin March 5, 2012.

17. On June 1, 2011, the Lieutenant Governor in Council issued an Order in Council, in which it authorizes the Commission:

> (a) to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act
>
> (i) pursuant to an application filed within the period from June 1, 2011 to December 31, 2013 with the Commission by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. pursuant to, or related to the provisions of, section 45 of the Gas Utilities Act, or
>
> (ii) on the Commission's own motion or initiative commenced within the period from June 1, 2011 to December 31, 2013,

and

> (b) to approve any related, ancillary, compliance or subsequent application arising out of an approval granted, or a direction issued, by the Commission pursuant to an application filed under clause (a)(i) or a motion or initiative of the Commission referred to in clause (a)(ii).

18. On July 22, 2011 PBR submissions and applications were filed by each of ATCO Electric, ATCO Gas, Fortis, EPCOR, and AltaGas.

19. Also on July 22, 2011, AltaGas submitted a letter (Exhibit 102.01) to the Commission requesting approval to negotiate its PBR application with its customer groups.

20. On July 26, 2011 the Commission issued a notice of proceeding (Exhibit 105.01), acknowledging the receipt of the PBR applications and soliciting statements of intention to participate (SIPs) from any party not already registered in the proceeding that wished to intervene or participate. The Commission also re-iterated the proceeding schedule it had issued in its letter to parties of April 13, 2011.

21. On August 12, 2011 the Commission wrote to registered parties in regard to AltaGas' request to negotiate a settlement of its PBR application with its customers (Exhibit 112.01). The Commission requested comment from AltaGas on its rationale for the request by August 19, 2011 and comment from other companies and interveners by August 26, 2011. AltaGas was afforded an opportunity to then reply to other companies' and interveners' forthcoming comments by August 30, 2011.

22. On August 25, 2011, the Commission informed proceeding parties by letter (Exhibit 114.01) that it had chosen to expand the role of NERA "to undertake the preparation of a second report to provide parties and the Commission with an independent, expert critical analysis and evaluation of the material aspects of the utility applications and intervener evidence in Proceeding ID No. 566."

23. On August 31, 2011, the Commission began Round 1 of information requests (IRs) related to the proceeding with questions circulated to all of the companies registered as parties and to NERA.

24. On September 30, 2011 in correspondence (Exhibit 181.01) to all parties, the Commission denied AltaGas' request to negotiate a settlement of its PBR application with its customers.

25. On the same day, ATCO Electric filed a letter (Exhibit 182.01) with the Commission objecting to the IRs filed by The City of Calgary (Calgary) directed to ATCO Electric and to Dr. Carpenter relating to the ATCO Electric application.

26. By letter (Exhibit 183.01) dated October 3, 2011, the Commission requested Calgary's comments on the ATCO Electric objection by October 5, 2011 and ATCO Electric's reply by October 6, 2011.

27. In its letter (Exhibit 186.01) to the parties dated October 11, 2011, the Commission allowed the Calgary IRs to stand and directed ATCO Electric and Dr. Carpenter to answer the IRs.

28. On November 9 and November 10, 2011, the Commission received several motions from each of the UCA, Calgary, and the CCA, requesting for full, responsive and adequate answers to certain IRs from the NERA, AltaGas, Fortis, EPCOR, Dr. Carpenter, and ATCO.

29. The Commission established a process by letter (Exhibit 263.01) dated November 10, 2011, to deal with the motions, which requested NERA and each of the companies or their experts to respond to the motions on November 16, 2011, and concluded with reply comments from the UCA, the CCA and Calgary on November 18, 2011.

30. On November 23, 2011, the Commission wrote to registered parties and provided its rulings on each of the individual motion items (Exhibit 282). In the same letter the Commission set a revised proceeding schedule, with intervener evidence to be submitted December 16, 2011 and a hearing scheduled to begin April 16, 2012.

31. On January 16 and 26, 2012, the Commission issued Round 2 and Round 3 of IRs.

32. On February 22, 2012, NERA filed its second report (Exhibit 391.02): *Update, reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative*.

33. Also on February 22, 2012, ATCO Electric and ATCO Gas filed updates (exhibits 389 and 390) to their respective PBR applications.

34. In a letter (Exhibit 392.01) to registered parties dated February 24, 2012, the Commission provided for a further evidentiary process to allow for information requests, responses and supplemental intervener evidence with respect to ATCO's application updates.

35. On February 29, 2012, the UCA filed a letter (Exhibit 395.01) objecting to the application update filed by ATCO Gas on various grounds and requesting the Commission to undertake certain steps, including the striking of portions of that evidence from the record of the proceeding.

36. On March 1, 2012, the Commission issued a letter (Exhibit 399.01) indicating that it would treat the UCA letter as a motion requiring a Commission decision following a reply to the ATCO response by the UCA not later than March 5, 2012.

37. On March 7, 2012 in correspondence (Exhibit 416.01) to the parties, the Commission permitted the amendment of the ATCO application updates and denied the UCA motion.

38. Also on March 7, 2012, the Commission began Round 4 of IRs in regard to NERA second report.

39. On March 8, 2012, the Commission issued Round 5 of IRs to ATCO in respect of its application updates.

40. By letter (Exhibit 470.01) dated April 4, 2012, the Commission advised parties of the details of oral hearing scheduled to commence April 16, 2012.

41. On April 12 and 13, 2012, the Commission issued Round 6 and Round 7 of IRs.

42. An oral hearing was held in the Commission's Calgary hearing room from April 16, 2012 to May 8, 2012. At the close of the hearing, the Commission directed parties to submit argument by June 8, 2012, and reply argument by July 6, 2012.

43. On June 5, 2012, multiple parties requested an extension of the deadline for filing argument from June 8, 2012 to June 13, 2012. In a letter (Exhibit 627.01) dated June 7, 2012, the Commission agreed to the request and adjusted the date for filing reply argument to July 11, 2012.

44. On July 6, 2012, ATCO proposed a two-day extension to the July 11, 2012 deadline. By letter (Exhibit 640.01) issued on the same day, the Commission agreed to postpone reply argument filing dates to July 13, 2012 for all parties.

45. On July 13, reply argument was received.

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Appendix 4 – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AG	ATCO Gas
AHE	average hourly earnings
AltaGas or AUI	AltaGas Utilities Inc.
AMR	automated meter reading
ATCO	ATCO Electric and ATCO Gas
ATCO Electric or AE	ATCO Electric Ltd.
AWE	average weekly earnings
CAIDI	customer average interruption duration index
capex	capital expenditures
Calgary	The City of Calgary
CCA	Consumers’ Coalition of Alberta
CPI	consumer price index
CSLS	Center for the Study of Living Standards
DSM	demand side management
ECM	efficiency carry-over mechanism
ENMAX or EPC	ENMAX Power Corporation
EPCOR or EDTI	EPCOR Distribution & Transmission Inc.
ESM	earnings sharing mechanism
EUCPI	electric utility construction price index
FBR	formula-based ratemaking
FERC	Federal Energy Regulatory Commission
Fortis or FAI	FortisAlberta Inc.
G&A	general and administrative expenses
GCOC or GCC	generic cost of capital
GDP-IPI	gross domestic product implicit price index
GDP-IPI-FDD	gross domestic product implicit price index for final domestic demand
G factor	growth factor
GRA	general rate application
GTA	general tariff application
I factor	inflation factor
IPCAA	Industrial Power Consumers Association of Alberta
IR	information request

Abbreviation	Name in full
KFEI	K factor efficiency incentive
kWh	kilowatt hours
LBDA	load balancing deferral account
LDC	local distribution company
MFP	multifactor productivity
MIL	maximum investment levels
MP factor	major projects factor
NAICS	North American Industry Classification System
NERA	National Economic Research Associates Inc.
NGSSC	Natural Gas System Settlement Code
O&M	operating and maintenance
PBR	performance-based regulation
PEG	Pacific Economics Group
PFAM	post-final adjustment mechanism
PFP	partial productivity factor
ROE	return on equity
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAS	(transmission) system access service
SQR	service quality regulation
TAC	transmission access charge
TFO	transmission facility owner
TFP	total factor productivity
TRIF	total recordable injury frequency rate
UCA	Office of the Utilities Consumer Advocate
UMR	urban mains replacement
USA/MFR	uniform system of accounts/minimum filing requirements
WDA	weather deferral account
X factor	productivity factor
Z factor	exogenous factor

Appendix 5 – Company descriptions

AltaGas Utilities Inc.

AltaGas Utilities Inc. is a Leduc-based provider of natural gas distribution services in more than 90 Alberta communities.[1195]

The company operates 20,000 line km of gas distribution pipelines serving more than 72,000 residential, rural and commercial customers in Alberta and employs 200 people. The company's roots stretch back to 1947 and operations in the Athabasca, St. Paul and Leduc areas. Today the company serves communities that also include Barrhead, Bonneyville, Drumheller, Hanna, Three Hills, Grande Cache, High Level, Morinville, Pincher Creek, Dunmore, Stettler, Two Hills, Elk Point and Westlock.

AltaGas Utilities also offers natural gas service for customers with annual load requirements of more than 20,000 gigajoules anywhere in Alberta, an alternative to communities that have existing natural gas service from another supplier, and provides natural gas service proposals to communities that do not currently have natural gas service.

AltaGas Utilities is a unit of AltaGas Ltd., a Calgary-based energy infrastructure company that among other things also operates natural gas utilities in British Columbia, Nova Scotia and has a one-third interest in a Northwest Territories utility. Together, the natural gas utility firms serve 115,000 customers.

[1195] All information in this summary was derived from company filings and the AltaGas Utilities (http://www.altagasutilities.com/) and AltaGas Ltd. (http://www.altagas.ca/) websites, accessed on August 16, 2012.

ATCO Electric Ltd.

ATCO Electric Ltd. is an Edmonton-based developer and operator of regulated electricity distribution and transmission infrastructure.[1196] In Alberta, the company operates in the northern and east-central regions of the province through 38 offices in its service area, which covers 245 Alberta communities and includes almost 213,000 customers. It has two divisions: capital projects and operations, with capital projects overseeing construction of major transmission projects and operations overseeing construction of large distribution projects and the management and operation of the company's existing transmission, distribution and technology assets.

Along with larger communities such as Grande Prairie, Fort McMurray, Jasper and Lloydminster, ATCO Electric's service area includes many rural and energy-rich areas of the province and covers the northern half of Alberta, an area west and north of Lloydminster and an area east of Calgary. This is about two-thirds of the geographic area of Alberta.

The company is a unit of publicly-listed ATCO Ltd. through ATCO Ltd. affiliates Canadian Utilities Ltd. and CU Inc. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd. Along with its core operations in Alberta, which stretch back 85 years, ATCO Electric also operates in the Canadian north, principally the Yukon and the Northwest Territories, through subsidiaries Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

ATCO Electric has an employee count of more than 2,000 people and operates approximately 10,000 km of transmission lines and 62,000 km of distribution lines. The company also operates roughly 10,000 km of distribution lines on behalf of 24 rural electrification associations (REAs) that are within its service territory. In fiscal 2011, the members of six REAs voted to sell their electric system assets to ATCO Electric. In the same year, the company experienced what it described as large-scale growth in transmission development and a similar level of distribution growth related to distribution extension and construction.

Major projects in fiscal 2011 included work on the proposed Eastern Alberta Transmission Line, which is the subject of an application currently before the AUC; the Hanna region transmission development project; and the northeast transmission development projects in the Fort McMurray area. Internally, the company was focused on customer service; operational excellence, talent attraction, development and retention and responding to a changing regulatory environment. The latter work centred around the AUC's Rate Regulation Initiative on Performance-Based Regulation.

[1196] All information in this summary is derived from the ATCO Ltd. 2011 annual report and the ATCO Ltd. (http://www.atco.com/),Canadian Utilities Ltd. (http://www.canadianutilities.com/) and ATCO Electric (http://www.atcoelectric.com/default.asp) websites accessed on August 16, 2012.

ATCO Gas

ATCO Gas is an Edmonton-based distributor of natural gas with more than one million customers in about 300 communities throughout Alberta.[1197] It operates approximately 38,000 km of distribution pipes and employs about 2,000 Albertans at its headquarters and across its province-wide network of more than 60 district offices.

The company is celebrating its 100th anniversary of founding in 2012. The roots of the company go back to the origins of natural gas service in the province of Alberta in 1912 with Canadian Western Natural Gas in southern Alberta and the Calgary area, and Northwestern Utilities Limited in northern Alberta and the Edmonton area in 1923.

Along with natural gas distribution, ATCO Gas provides expert advice to consumers through ATCO EnergySense and the ATCO Blue Flame Kitchen. It is the largest natural gas distribution utility in Alberta and serves municipal, residential, business and industrial customers.

The company is a division of ATCO Gas and Pipelines Ltd., which is in turn part of the publicly-listed ATCO Ltd. corporate group. ATCO Ltd. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd.

In 2011 ATCO Gas spent more than $287 million on capital projects it said enhanced system integrity and reliability and ensured public safety.

[1197] All information in this summary is derived from company filings, the ATCO Ltd. 2011 annual report and the ATCO. Ltd. (http://www.atco.com/) and ATCO Gas (http://www.atcogas.com/) websites, accessed on August 16, 2012.

EPCOR Distribution & Transmission Inc.

EPCOR Distribution and Transmission Inc. (EDTI) provides electricity distribution service through aerial and underground distribution lines and related facilities to its service area in the city of Edmonton.[1198]

The company is a wholly owned subsidiary of EPCOR Utilities Inc., a provider of electricity and water services to customers in Canada and the United States, and is owned by the City of Edmonton. Both EDTI and its corporate parent are based in Edmonton. The parent was founded in October 1891 as the Edmonton Electric Lighting and Power Company and became municipally owned in 1902.

EDTI provides electricity distribution services to more than 308,000 residential and 35,000 commercial consumers in Edmonton, distributing roughly 14 per cent of Alberta's electricity consumption. The company operates 72-kV, 138-kV, 240-kV and 500-kV lines and cables. It distributes electricity in Edmonton through a network of eight distribution substations, 287 distribution feeders and approximately 5,000 circuit km of primary distribution lines.

Along with distribution services, EDTI also operates high-voltage substations and high-voltage transmission lines in the Edmonton area, including 203 circuit km of transmission lines and 29 transmission substations. These form part of the Alberta interconnected electric system. EDTI also provides services to the Alberta Electric System Operator, provides the distribution tariff and settlement services in Edmonton for the competitive electric market. It also manages and collects load data in the Edmonton area through meter reading, data collection and management.

The company employs approximately 629 people in its distribution arm and 139 individuals in its transmission operations.

[1198] All information in this summary is derived from company filings and the EPCOR Utilities Inc. website (http://corp.epcor.com/Pages/home.aspx) accessed on August 16, 2012.

FortisAlberta Inc.

FortisAlberta Inc. distributes electricity to nearly half-a-million Albertans living in 200 communities across central and southern Alberta.[1199]

The company's origins are as the distribution arm of TransAlta Corp., which TransAlta sold in 2000, and it operates 115,000 km of power lines across a 225,000-km service area that represents more than 60 per cent of Alberta's low-voltage distribution network.

Based in Calgary, FortisAlberta employs 1,000 people working at its headquarters and 52 service points in its service territory. The company operates a 24-hour outage repair and emergency response capability, builds, maintains and upgrades power lines and facilities, installs and reads electricity meters, provides consumption data to retailers that bill customers and promotes electrical safety in the communities it serves.

FortisAlberta is a subsidiary of publicly-listed Fortis Inc., Canada's largest investor-owned distribution utility and which among other things operates regulated electric utilities in five Canadian provinces and a natural gas utility in British Columbia. Fortis Inc. is based in St. John's, Newfoundland and Labrador and its shares trade on the Toronto Stock Exchange.

[1199] All information in this summary was derived from company filings, AUC records, and the FortisAlberta Inc. (http://www.fortisalberta.com/home.aspx) and Fortis Inc. (http://www.fortisinc.com/) websites, accessed on August 16, 2012.

Schedule 2B: ED1 Price Control Financial Handbook

Making a positive difference
for energy consumers

ED1 Price Control Financial Handbook

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Contact:	Ofgem Regulatory Finance Team
Tel:	020 7901 7000
Email:	regulatoryfinance@ofgem.gov.uk

Overview:

This is the ED1 Price Control Financial Handbook which forms part of Charge Restriction Condition 4A (Governance of ED1 Price Control Financial Instruments) of the electricity distribution licence held by each electricity distribution network operator that is a Distribution Services Provider.

This document consists of:

a) a description of the ED1 Price Control Financial Model (PCFM) and the Annual Iteration Process for it, used to update the licensee's Opening Base Revenue Allowances during the course of the RIIO-ED1 Price Control Period;

b) an overview of the ED1 Price Control Financial Methodologies under which revisions to the variable values in the PCFM are determined for the Annual Iteration Process, in accordance with the Charge Restriction Conditions of the Licence; and

c) a series of chapters containing the detailed methodologies relating to the revision of PCFM Variable Values.

The procedures relating to modification of this Handbook and the PCFM are contained in Charge Restriction Condition 4A.

An up to date version of this handbook and the PCFM (in Microsoft Excel® format) can be accessed on the Ofgem Website.

Context

The RIIO-ED1 price control arrangements are the first, in respect of electricity distribution, to apply Ofgem's RIIO framework (Revenue = Incentives + Innovation + Outputs). The aim of the RIIO approach is to incentivise network owners and managers to achieve the outputs needed to deliver sustainable energy networks at value for money for existing and future consumers.

The RIIO-ED1 price control period is longer than the previous electricity distribution price control (the DPCR5 Price Control), running for eight years instead of five. This provides for a longer period of price control arrangements with the aim of facilitating improved strategic planning and a long-term approach to electricity distribution infrastructure management.

Under the 'DPCR' price controls, base revenue allowances, were set up-front for the whole of the price control period, changing only with RPI indexation requiring certain adjustments to reflect activity levels and varying financial conditions to be left until the subsequent five-yearly review. Under RIIO-ED1, these adjustments to base revenue, along with RPI indexation, will be made each year in respect of the licensee's network business.

This new approach involves an annual iteration of the ED1 Price Control Financial Model using updated variable values. This gives rise to a requirement for licence conditions and methodologies to govern the determination of revised PCFM Variable Values and the Annual Iteration Process.

This document, The ED1 Price Control Financial Handbook, which forms part of Charge Restriction Condition 4A (Governance of ED1 Price Control Financial Instruments), sets out the methodologies for the revision of PCFM Variable Values. Up-to-date copies of both the handbook and the ED1 Price Control Financial Model will be maintained on the Ofgem Website.

Associated documents

a. Strategy decision for the RIIO-ED1 electricity distribution price control

   http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=120&refer=Networks/ElecDist/PriceCntrls/riio-ed1/consultations

b. Strategy decision for RIIO-ED1 - Financial issues

   https://www.ofgem.gov.uk/ofgem-publications/47071/riioed1decfinancialissues.pdf

c. ED1 PCFM

   www.ofgem.gov.uk – search term "ED1 PCFM"

Contents

Introduction

The ED1 Price Control Financial Handbook ('this handbook') is one of the Price Control Financial Instruments referred to in Charge Restriction Condition 4A (Governance of ED1 Price Control Financial Instruments) of the electricity distribution licence held by electricity distribution network operators. The Price Control Financial Instruments were included in the licence as a result of the same licence modification that included Charge Restriction Condition 4A in the licence.

This handbook describes the ED1 Price Control Financial Model (PCFM) and the Annual Iteration Process for it, by which annual adjustments to the licensee's base revenues will be calculated. It also contains the ED1 Price Control Financial Methodologies ('the methodologies'), specified in relevant Charge Restriction Conditions, which will be used to determine appropriate revisions to the variable values contained in the PCFM to facilitate calculations under the Annual Iteration Process.

This handbook, the constituent methodologies and the PCFM (together the Price Control Financial Instruments) form part of Charge Restriction Condition 4A. The Financial Instruments are subject to a formal change control process set out in that condition.

The Annual Iteration Process for the PCFM:

- incorporates 'real time' adjustments to financial allowances;
- uses a financial model for the purpose of computing interactions between financial adjustments rather than setting out the relevant algebra on the face of Charge Restriction Conditions;
- provides for consistent treatment of the Totex aspects of the price control;
- provides transparency on adjustments to base revenues, since the licence, methodologies, PCFM and variable values will be published; and
- allows stakeholders to have visibility of base revenue[1] levels to facilitate business sensitivity analysis.

In any case of conflict of meaning, the following order of precedence applies:

(i) the text of the relevant licence condition(s),

(ii) this handbook and its constituent methodologies, and

(iii) the PCFM.

[1] The PCFM only calculates base revenue and the annual adjustment to Opening Base Revenue Allowances (the MOD term). It does not calculate the total allowed revenues of the licensee which include additional components specified in CRC 2A (Restriction of Allowed Distribution Network Revenue).

Terms used in this handbook

References to the Authority and Ofgem

The Gas and Electricity Markets Authority ("the Authority") is established by section 1 of and Schedule 1 to the Utilities Act 2000. The Office of Gas and Electricity Markets ("Ofgem") is the office that supports the Authority.

Other terminology

Throughout this handbook:

(a) 'licence' means the relevant electricity distribution licence granted under section 6(1)(c) of the Electricity Act 1989 of which this handbook forms part;

(b) 'licensee' has the meaning given to that term in the licence of which this handbook forms part;

(c) 'Charge Restriction Condition' (abbreviated to 'CRC') means any one of the Charge Restriction Conditions contained in the licence as defined at (a) above;

(d) 'this handbook' means the ED1 Price Control Financial Handbook, which forms part of CRC 4A;

(e) PCFM means the ED1 Price Control Financial Model which forms part of CRC 4A; and

(f) 'Price Control Period' means the RIIO-ED1 price control period which runs from 1 April 2015 to 31 March 2023.

Other terms used in the text of this handbook that are capitalised are defined in the Glossary, where applicable by reference to the licence or a decision document published by the Authority. Where the meanings of other terms used in this handbook is not clear from the context, they will be explained in the chapter concerned or in the Glossary.

Part 1

1. The ED1 Price Control Financial Model and the Annual Iteration Process

Section 1 - Overview

1.1 CRC 2A (Restriction of Allowed Distribution Network Revenue) specifies the Opening Base Revenue Allowance for the licensee for each Regulatory Year of the Price Control Period, reflecting the Authority's Final Determination for the RIIO-ED1 price control settlement.

1.2 The licensee's Opening Base Revenue Allowances are set down against its name in Appendix 1 of CRC 2A and are included in the formula for Base Demand Revenue set out in that condition. Base Demand Revenue is the largest component of the licensee's overall allowed revenue but the other components, specified in the licence, must also be taken into account when assessing total revenue allowances.

1.3 The ED1 Price Control Financial Model (PCFM) calculates incremental changes to the licensee's Opening Base Revenue Allowance for each Regulatory Year so that the licensee's Base Demand Revenue reflects the adjustment schemes specified in the licence and referred to in the methodologies in this handbook. The adjustments fall into three broad categories:

- financial adjustments covering tax, pension and cost of debt issues;
- adjustments relating to actual and allowed total expenditure (Totex) and the Totex Incentive Mechanism (see chapter 6); and
- legacy price control adjustments – the close-out of schemes and mechanisms from preceding price control periods.

1.4 The calculations take place under the Annual Iteration Process for the PCFM which is specified in Part A of CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model) and described below. The calculations result in a PCFM output value for the term MOD which is then applied as shown in the simplified[2] formula below:

Base Revenue for year t = Opening Base Revenue Allowance for year t + MOD for year t.

Price base

1.5 The PCFM works in a constant 2012/13 price base, except in respect of some internal tax calculations (see paragraph 1.6). This is consistent with the Opening

[2] The full formula is shown in paragraph 2A.5 of CRC 2A (Restriction of Allowed Distribution Network Revenue).

Base Revenue Allowance values set down in the licence. The value of the term MOD is calculated in 2012/13 prices. Indexation is provided for in the formula set out in paragraph 2A.5 of CRC 2A.

1.6 Some tax calculations internal to the PCFM use nominal prices, based on embedded RPI forecast data. The use of nominal prices in the PCFM tax calculations is aimed at enabling revenue allowance calculations more accurately to reflect the profile of tax expenses of the licensee.

1.7 Where a methodology in this handbook calls for values to be deflated from a nominal price base, used in price control review information reporting, to the 2012-13 price base used in the PCFM, the following formula will be used:

$$\text{Value}_{\text{2012-13}} = \text{value}_{\text{nominal price year}} \times \frac{\text{RPI}_{\text{2012-13}}}{\text{RPI}_{\text{nominal price year}}}$$

where:

$\text{value}_{\text{2012-13}}$	means the deflated value in the 2012/13 price base;
$\text{value}_{\text{nominal price year}}$	means the value in nominal prices, used in price control review information reporting;
$\text{RPI}_{\text{2012-13}}$ `	means the arithmetic average of the Retail Prices Index (all items) figures published by the Office for National Statistics for each calendar month in Regulatory Year 2012/13 rounded to three decimal places; and
$\text{RPI}_{\text{nominal price year}}$	means the arithmetic average of the Retail Prices Index (all items) figures published by the Office for National Statistics for each calendar month in the Regulatory Year referred to in the price control review information in question rounded to three decimal places.

Temporal convention

1.8 The following conventions apply throughout this handbook.

Relative references

1.9 The MOD term is used to modify the licensee's Opening Base Revenue Allowance for each Regulatory Year t during the Price Control Period[3]. References in this handbook to Regulatory Years are made relative to that usage. For example, in a context where MOD_t applied in the formula for Base Demand Revenue in 2017/18,

[3] In 2015-16, the first year of the Price Control Period, the licence specifies that the value of MOD is zero.

a reference in the same context to Regulatory Year t-1 would mean 2016/17 and so on.

Absolute references

1.10 A reference to, for example, 'the EDE value for 2017/18' means the EDE value in the 2017/18 column of the PCFM Variable Values Table for the licensee contained in the PCFM[4].

Section 2 - The PCFM and the Annual Iteration Process

1.11 The PCFM exists as a constituent part of CRC 4A (Governance of ED1 Price Control Financial Instruments). It has an input area for the licensee containing both fixed values and a PCFM Variable Values Table. The base revenue figure for the licensee for each Regulatory Year of the Price Control Period is calculated using the fixed values, the PCFM Variable Values, and the formulae and functions embedded in the PCFM.

1.12 At the outset of the Price Control Period, the base revenue figures calculated by the PCFM, using the variable values subsisting at that time, are equal to the Opening Base Revenue Allowances for the licensee. .

1.13 Subject to paragraph 1.14, by 30 November in each Regulatory Year t-1, or as soon as is reasonably practicable thereafter, Ofgem will determine whether any PCFM Variable Values for the licensee should be revised in accordance with the Charge Restriction Conditions and the ED1 Price Control Financial Methodologies set out in chapters 3 to 16 of this handbook.

1.14 The last Regulatory Year in which there will be an Annual Iteration Process for the PCFM is Regulatory Year 2021/22 for the purpose of determining the value of the term MOD for Regulatory Year 2022/23. Some financial adjustments provided for under the RIIO-ED1 Final Proposals will remain outstanding at the end of the Price Control Period, because relevant data will not be available in time for inclusion in the last Annual Iteration Process. For example, adjustments under the Totex Incentive Mechanism (see chapter 6) relating to actual and allowed expenditure levels in Regulatory Years 2021/22 and 2022/23 will remain outstanding. For the avoidance of doubt, adjustments of this type will be addressed under the RIIO-ED2 price control arrangements.

1.15 In order to facilitate the determination of revised PCFM Variable Values by 30 November, Ofgem will normally expect to apply the following annual cut-off dates:

(a) 30 September in respect of functional changes to the PCFM; and

[4] EDE values are the PCFM Variable Values for Pension Scheme Established Deficit Expenditure allowances (see Table 2.1 in chapter 2).

(b) 31 October in respect of information submitted by the licensee and used under the ED1 Price Control Financial Methodologies.

1.16 In applying the cut-off referred to in paragraph 1.15(b), Ofgem will, through business correspondence, apprise the licensee of any provisionality it has attached to information submissions, that might entail a restatement of the information by the licensee for the purpose of making a further revision to the PCFM Variable Value(s) concerned for use in a subsequent Annual Iteration Process.

1.17 The Authority will give the licensee at least 14 days' notice of any revised PCFM Variable Values in accordance with requirements in the licence, to allow for any representations. The Authority will then (by 30 November in Regulatory Year t-1, or as soon as is reasonably practicable thereafter) specify any PCFM Variable Value revisions in a formal direction to the licensee. The direction will also include a copy of the PCFM Variable Values table for the licensee, showing the state of all PCFM Variable Values after the directed revisions, with revised values highlighted in bold typeface.

1.18 Having determined revisions to PCFM Variable Values for the licensee, Ofgem will carry out the Annual Iteration Process:

- revised PCFM Variable Values will be entered in the appropriate Regulatory Year columns of the PCFM Variable Values Table for the licensee;
- the PCFM calculation functions will be rerun;
- all calculated values within the PCFM will be updated, including:
  - the recalculated base revenue figure for the licensee for each Regulatory Year of the Price Control Period, and
  - the modelled RAV balance for the licensee;

  and
- the PCFM will output the value of MOD for Regulatory Year t for the licensee.

1.19 In the context of the Annual Iteration process for the PCFM, the expression 'recalculated base revenue figure' in respect of a particular Regulatory Year means a value calculated in the same way that the licensee's Opening Base Revenue Allowance for that Regulatory Year was calculated, but using revised PCFM Variable Values (see also paragraph 1.12).

1.20 The output value of MOD_t for the licensee will reflect:

(a) the difference between the recalculated base revenue figure for the licensee for Regulatory Year t (in the PCFM) and the Opening Base Revenue Allowance set down in the licence; and

(b) the difference between the recalculated base revenue figures held in the PCFM for Regulatory Years t-1 and earlier, before the Annual Iteration Process, and the recalculated base revenue figures for the licensee held in the PCFM for the same years after the Annual Iteration Process.

1.21 The PCFM calculations will apply Time Value of Money Adjustments to the calculation of MOD_t, to take account of the passage of time between adjustments to Base Demand Revenue in years prior to Regulatory Year t and the Regulatory Year for which MOD_t is being calculated.

1.22 PCFM Variable Values for Regulatory Years later than Regulatory Year t do not feed into the calculation of the term MOD_t. Therefore, calculated values in the PCFM for Regulatory Years later than Regulatory Year t represent only a forecast. This is without prejudice to the status of the PCFM Variable Values concerned, which may have been determined or directed under licence conditions and which may or may not be subject to subsequent revision.

1.23 Changes to base revenue figures calculated under the Annual Iteration Process may be upwards or downwards and, accordingly, the value of MOD_t may be positive or negative. Once the value of MOD has been directed for a particular Regulatory Year, it is not changed retroactively as a result of a subsequent Annual Iteration Process – the value becomes a matter of record alongside the Opening Base Revenue Allowance value for the same year. The steps of the Annual Iteration Process are specified in Part A of CRC 4B.

1.24 The Authority will issue a direction to the licensee giving the value of MOD_t by 30 November in each Regulatory Year t-1[5] or as soon as reasonably practicable thereafter. In practice, it is expected that the value of MOD_t will be included in the direction of revised PCFM Variable Values referred to in paragraph 1.17. The value of MOD_t in the direction will be stated in £m to one decimal place.

1.25 The deadline of 30 November in Regulatory Year t-1 for the direction of PCFM Variable Value revisions and for the value of MOD_t reflects

- the dates in Regulatory Year t-1 by which the licensee is required to submit its price control information returns (covering activity in Regulatory Year t-2) to Ofgem, and
- the need for the licensee to have confirmation of its Base Demand Revenue in time to calculate and issue its use of system charges.

1.26 Subject to the specification in paragraph 3 of CRC 4B that the last Regulatory Year in which there will be an Annual Iteration Process for the PCFM is Regulatory Year 2021/22, if the Authority does not direct a value for MOD_t by 30 November in Regulatory Year t-1, paragraphs 4B.12 to 4B.14 of CRC 4B specify that:

- the Annual Iteration Process will not have been completed;

[5] The first such direction will be given by 30 November 2015.

- the Authority will complete the Annual Iteration Process as soon as reasonably practicable after 30 November in the relevant Regulatory Year t-1 by directing a value for MOD_t for the licensee; and
- in the intervening period, the value of MOD_t will be held to be equal to the value ascertained by:
    - taking a copy of the PCFM in its state following the last completed Annual Iteration Process (excluding the effect of any functional modifications under CRC 4A made after the completion of that Annual Iteration Process);
    - using the selection facilities on the user interface sheet contained in that copy to select:
        - the name of the licensee; and
        - the Regulatory Year equating to Regulatory Year t; and
    - recording the value of the term MOD_t for the licensee that is shown as an output value.

1.27 Table 1.1 below summarises the timings for the Annual Iteration Process during the Price Control Period.

Table 1.1 - Summary of timings for the Annual Iteration Process

Annual Iteration Process (AIP)					
AIP month	**PCFM functional change cut-off**	**Regulatory reporting information cut-off**	**Notice of proposed PCFM Variable Value revisions by**	**AIP completed and MOD_t directed by**	**Regulatory Year t in which MOD_t applies**
Nov-2015	30 Sep 15	31 Oct 15	15 Nov 15	30 Nov 15	**2016/17**
Nov-2016	30 Sep 16	31 Oct 16	15 Nov 16	30 Nov 16	**2017/18**
Nov-2017	30 Sep 17	31 Oct 17	15 Nov 17	30 Nov 17	**2018/19**
Nov-2018	30 Sep 18	31 Oct 18	15 Nov 18	30 Nov 18	**2019/20**
Nov-2019	30 Sep 19	31 Oct 19	15 Nov 19	30 Nov 19	**2020/21**
Nov-2020	30 Sep 20	31 Oct 20	15 Nov 20	30 Nov 20	**2021/22**
Nov-2021	30 Sep 21	31 Oct 21	15 Nov 21	30 Nov 21	**2022/23**

State of the ED1 Price Control Financial Model

1.28 As stated in paragraph 1.11, the PCFM exists as a constituent part of CRC 4A and will be maintained by Ofgem in its official records. The state of the PCFM remains constant unless and until changed by either:

(a) an Annual Iteration Process - which will change PCFM Variable Values and recalculated values that are directly or indirectly dependent upon them; or

(b) a modification of the PCFM under the procedures set out in CRC 4A.

1.29 Ofgem will keep a log of modifications to the PCFM and publish this log on the Ofgem Website.

1.30 A copy of the PCFM in its latest state will be maintained on the Ofgem Website. This will allow the licensee and other stakeholders to make copies of the PCFM so that they can:

- use their own forecasts of PCFM Variable Value revisions to forecast base revenue positions and to conduct sensitivity analysis; and
- reproduce the calculation of MOD_t by 30 November in each Regulatory Year t-1.

1.31 Ofgem will upload an updated copy of the PCFM to the Ofgem Website by 30 November each year (after each Annual Iteration Process) with the electronic file name "ED1 PCFM November 20XX" in Regulatory Year 20XX/XX (where 20XX/XX is the format used for expressing Regulatory Year t-1).

Error of functionality in the PCFM

1.32 In the event that an error of functionality is discovered in the PCFM, the following procedure will be followed:

- the issue will be considered at the earliest opportunity by the ED1 PCFM Working Group (see next section) and a corrective modification proposed by Ofgem;
- if the functional error has distorted the calculation of a previously directed value of the term MOD, the determined modification would include any Time Value of Money adjustments necessary to correct for that distortion in the next calculation of the term MOD_t; and
- the procedure in CRC 4A for modifications to the PCFM would be followed.

Section 3 - The ED1 Price Control Financial Model Working Group

1.33 Ofgem will facilitate an industry expert working group to review issues arising with respect to the form or usage of the PCFM. The terms of reference for the ED1 PCFM Working Group ('the working group') are set out below.

1.34 In accordance with the provisions of Part A of CRC 4A, the Authority will have regard to any views expressed by the working group when assessing whether any proposed modification of the PCFM would be likely to have a significant impact on the licensee or other stakeholders.

Terms of reference

Purposes of the working group

1.35 The purposes of the working group are:

(i) to review the ongoing effectiveness of the PCFM in producing a value for the term MOD for each Regulatory Year;

(ii) to provide, when requested by the Authority, its views to the Authority on the impact of any proposal (or prospective proposal) to modify the PCFM in accordance with Part A of CRC 4A; and

(iii) to provide such views or recommendations to the Authority with regard to the PCFM (including as to proposals to modify the PCFM) as it sees fit.

Composition

1.36 The composition of the group will be:

- Ofgem (chair);
- Ofgem (secretary);
- one representative per licensee; and
- Energy Networks Association representative (optional).

Timing and duration of the group's work

1.37 The working group's incumbency will run from 1 April 2015 to 31 March 2023.

1.38 The group will meet at least once between 1 January and 31 July during each calendar year, but additional meetings may be convened by Ofgem:

- if it considers that such a meeting or meetings would be useful to achieve the purposes of the group; or

- if such a meeting is requested by at least two licensees (each from a different ownership group) for the purpose of putting forward a recommendation that a modification should be made to the PCFM.

1.39 In convening any meeting of the working group, Ofgem will give at least 10 working days' notice of the proposed meeting date to the licensee.

1.40 Representatives may attend meetings in person or, at the discretion of the chair, through video or telephone conferencing facilities.

1.41 A meeting of the working group will be quorate, for the purpose of expressing a view or recommendation in respect of the PCFM, when at least one representative from Ofgem, and at least four licensee representatives (each from a different ownership group) are present.

Resources

1.42 Meeting facilities will be provided or coordinated by Ofgem. Ofgem will keep a record of the discussion and views expressed at meetings, and of any recommendations made by the working group with respect to the PCFM. A copy of the record of each meeting will be provided to the licensee and to representatives who attended the meeting, and Ofgem will take account of any comments received in finalising the record.

2. The ED1 Price Control Financial Methodologies

2.1 The ED1 Price Control Financial Methodologies set out in this handbook ('the methodologies') describe the basis for a range of annual adjustments to the licensee's Opening Base Revenue Allowances under the RIIO-ED1 price control arrangements. The methodologies are presented in chapters 3 to 16 of this handbook, and are referenced in the associated Charge Restriction Conditions of the licence. As constituent parts of this handbook, the methodologies are part of CRC 4A (Governance of ED1 Price Control Financial Instruments) and are subject to the modification provisions set out in that condition.

2.2 Each methodology sets out the way in which one or more PCFM Variable Values are to be revised as part of the Annual Iteration Process for the ED1 Price Control Financial Model (PCFM) under which values of the term MOD_t are calculated (see chapter 1). The methodologies do not include details of the calculations carried out by the PCFM which are complex and interdependent. Stakeholders wishing to understand in detail the way in which PCFM Variable Values are processed and values for MOD calculated under the Annual Iteration Process should refer to the PCFM. The PCFM forms part of CRC 4A and is subject to the modification provisions set out in that condition.

2.3 Revised PCFM Variable Values determined under the methodologies will replace (overwrite) the existing values contained in the PCFM Variable Values Table for the licensee in the PCFM as part of the Annual Iteration Process. The PCFM Variable Values Table is on the 'Input' worksheet of the PCFM and has been shaded blue; this area is informally known as 'the blue box'. Alongside each row of the blue box is a description of the item and the PCFM Variable Value name detailed in table 2.1 below.

2.4 Each methodology is intended to be consistent with the provisions of any CRC to which it refers or relates. However, in the event of any inconsistency between a methodology and a provision set out on the face of a CRC, the provision in the CRC takes precedence.

Methodologies in this handbook

2.5 The PCFM Variable Values that can be revised under the terms of CRCs and the methodologies in this handbook are set out in Table 2.1 below.

Table 2.1 - PCFM Variable Values that can be revised under CRCs and the methodologies in this handbook

PCFM Variable Value	Charge Restriction Condition	Description	Type of variable value	Values at 1 April 2015	Revised values (where directed)
Specified financial adjustments					
EDE (chapter 3)	CRC 3C	Pension Scheme Established Deficit	revenue adjustment	Allowances for Pension Scheme Established Deficit repair used in the calculation of Opening Base Revenue Allowances.	Revised allowances for Pension Scheme Established Deficit repair.
TTE (chapter 4)		Tax liability – tax trigger events	revenue adjustment	Zero.	Incremental change to tax liability allowances.
TGIE (chapter 4)		Tax liability – gearing/interest costs	revenue adjustment	Zero.	Incremental change to tax liability allowances[6].
CDE (chapter 5)		Allowed percentage cost of debt	percentage	Opening allowed percentage cost of corporate debt.	Revised allowed percentage cost of corporate debt.
Totex Incentive Mechanism					
ALC (chapter 6)	CRC 3B	Actual load-related capex expenditure	actual expenditure	Equal to allowed expenditure level for load-related capex.	Actual load-related capex expenditure reported by licensee.
ANLR (chapter 6)		Actual non-load-related capex expenditure - asset replacement	actual expenditure	Equal to allowed expenditure level for non-load-related capex –	Actual non-load-related capex – asset replacement expenditure

[6] Subject to iterative modelling effect - see paragraph 4.6 in chapter 4.

PCFM Variable Value	Charge Restriction Condition	Description	Type of variable value	Values at 1 April 2015	Revised values (where directed)
				asset replacement.	reported by licensee.
ANLO (chapter 6)		Actual non-load-related capex - other	actual expenditure	Equal to allowed expenditure level for non-load-related capex - other.	Actual non-load-related capex - other expenditure reported by licensee.
AFE (chapter 6)		Actual faults expenditure	actual expenditure	Equal to allowed expenditure level for faults.	Actual faults expenditure reported by licensee.
ARP (chapter 6)		Actual 100% 'revenue pool' expenditure	actual expenditure	Equal to allowed 100% 'revenue pool' expenditure level.	Actual 100% 'revenue pool' expenditure reported by licensee.
ACO (chapter 6)		Actual controllable opex expenditure	actual expenditure	Equal to allowed expenditure level for controllable opex.	Actual control opex expenditure reported by licensee.
TRE (chapter 6)		Actual tree cutting expenditure	actual expenditure	Equal to allowed expenditure level for tree cutting.	Actual tree cutting expenditure reported by licensee.
Allowed Totex expenditure adjustments					
UCEPS (chapter 7)	CRC 3F	Uncertain costs – enhanced physical site security	allowed expenditure	Allowed expenditure level on enhanced physical site security used in the calculation of Opening Base Revenue Allowances.	Revised (total) allowed expenditure level on enhanced physical site security.

PCFM Variable Value	Charge Restriction Condition	Description	Type of variable value	Values at 1 April 2015	Revised values (where directed)
UCSSW (chapter 7)		Uncertain costs – specified street works	allowed expenditure	Zero.	Total additional allowed expenditure level on specified street works.
UCHVP (chapter 7)		Uncertain costs – high value projects	allowed expenditure	Allowed expenditure level on high value projects used in the calculation of Opening Base Revenue Allowances.	Revised (total) allowed expenditure level on high value projects.
SMAE (chapter 8)	CRC 3E	Smart Meter Roll-out costs	allowed expenditure	Baseline level of allowed expenditure on Smart Meter Roll-out costs used in the calculation of Opening Base Revenue Allowances.	Revised (total) allowed expenditure level on Smart Meter Roll-out costs.
LRRC (chapter 9)	CRC 3G	Load Related Expenditure	allowed expenditure	Allowed expenditure level on Load Related Expenditure used in the calculation of Opening Base Revenue Allowances.	Revised (total) allowed level of Load Related Expenditure.
VAA (chapter 10)	CRC 3J	Visual Amenity costs	allowed expenditure	Zero.	Revised (total) allowed expenditure level on Visual Amenity Projects.

PCFM Variable Value	Charge Restriction Condition	Description	Type of variable value	Values at 1 April 2015	Revised values (where directed)
WSCC (chapter 11)	CRC 3H	Worst Served Customer costs	allowed expenditure	Zero.	Revised (total) allowed expenditure level on Worst Served Customer Projects.
IRM (chapter 12)	CRC 3D	Innovation Roll-out mechanism	allowed expenditure	Zero.	Revised (total) allowed expenditure level on Innovation Roll-out.
RE (chapter 12A)	CRC3K	Rail electrification[7]	allowed expenditure	Allowed expenditure level on rail electrification used in the calculation of Opening Base Revenue Allowances.	Revised (reduced total) allowed expenditure level on rail electrification.
Legacy price control adjustments					
LTPG LTPS LTPD LTPC (chapter 14)	CRC 3A	Legacy adjustments to opening tax pool balances	balance adjustment	Zero.	Incremental change to tax pool balances.
OLREV		Legacy adjustments to revenue allowances	revenue adjustment	Zero.	Incremental change to recalculated base revenue figures.

[7] Applicable to WPD licensees only – see chapter 12A

PCFM Variable Value	Charge Restriction Condition	Description	Type of variable value	Values at 1 April 2015	Revised values (where directed)
OLRAV (chapter 15)		Legacy adjustments to RAV additions	RAV balance adjustment	Zero.	Incremental change to RAV balance as at 1 April 2015.
RIREV (chapter 16)		Legacy adjustments associated with the DPCR5 RAV Rolling Incentive mechanism	revenue adjustment	Zero.	Incremental change to recalculated base revenue figures.

Specified financial adjustments

2.6 Specified financial adjustments relate to adjustment mechanisms set out in the Authority's Strategy decision for RIIO-ED1 - Financial issues supplementary annex - see associated document b. Overviews of the adjustments and the methodologies for determining revisions to the associated PCFM Variable Values are contained in chapters 3 to 5 of this handbook.

Totex Incentive Mechanism

2.7 The Totex Incentive Mechanism applies to any overspend or under spend by the licensee against its RIIO-ED1 Totex expenditure allowances. An overview of the mechanism and the methodology for determining revisions to the associated PCFM Variable Values for actual expenditure levels are contained in chapter 6 of this handbook.

Allowed Totex expenditure adjustments

2.8 Allowed Totex expenditure adjustments cover a range of Totex adjustment schemes under which allowed expenditure can be adjusted under a specified formula or through an application and assessment process. The methodologies for determining revisions to the associated PCFM Variable Values are contained in chapters 7 to 12A of this handbook.

Legacy price control adjustments

2.9 Legacy price control adjustments relate to activities that took place in the price control periods prior to RIIO-ED1 ('the legacy period') but in respect of which a financial adjustment is required because:

- outturn data for Regulatory Years in the legacy period were not available when Opening Base Revenue Allowances for the licensee were set;
- adjustment determinations for items subject to true-up, logging-up or reopener mechanisms were not complete when Opening Base Revenue Allowances for the licensee were set; or
- there is an anomalous position, acknowledged by Ofgem and the licensee, that needs to be corrected.

2.10 The methodologies for determining revisions to the associated PCFM Variable Values are contained in chapters 14, 15 and 16 of this handbook.

Processing of different types of PCFM Variable Value under the Annual Iteration Process

2.11 In general terms, the different types of variable value specified in the fourth column of Table 2.1 are processed under the Annual Iteration Process for the PCFM in the following ways:

Actual expenditure and allowed expenditure

These variable values are used in Totex Incentive Mechanism calculations to determine the amounts that should, subject to the Totex Capitalisation Rate for the licensee, be processed as:

(a) Fast Money – flowing directly to the recalculated base revenue figure for the Regulatory Year to which the amount relates; and

(b) additions to the licensee's RAV in the Regulatory Year to which the amount relates, generating a slow money adjustment to allowed revenues through the return on RAV and depreciation.

Revenue adjustment

These amounts flow directly to the recalculated base revenue figure for the Regulatory Year to which the adjustment circumstance relates. Revenue adjustments relating to Legacy price control adjustments are applied to Regulatory Year 2015/16, but are spread over the eight years of the Price Control Period by functionality in the PCFM.

Allowed percentage cost of debt

This type of variable value applies to the cost of corporate debt. As well as return on RAV, interest and tax calculations, corporate debt costs influence net present value calculations. Revised values for a particular Regulatory Year t will flow into calculations of the return on RAV.

RAV balance adjustment

This type of variable value relates to adjustments to qualifying expenditure during the price control period prior to RIIO-ED1. Revised values are input, as applicable, to the 2013/14 or 2014/15 columns of the PCFM. They generate an element of Fast Money applicable to regulatory Year 2015/16 and feed into slow money adjustments to base revenue recalculations through the return on RAV and depreciation.

Tax pool balance adjustment

This type of variable value relates to adjustments to the opening tax pool balances for the licensee to reflect outturn expenditure levels in the legacy period.

Consequential adjustments

2.12 During the Annual Iteration Process, automatic adjustments are also made as a consequence of revisions to PCFM Variable Values. For example, in some circumstances, as a result of automatic updates to the licensee's net debt and RAV figures under the Annual Iteration Process, updated equity issuance allowances may also be included in recalculated base revenue figures for the Regulatory Years concerned.

A typical revision

2.13 The ED1 Price Control Financial Methodologies describe the expected timing sequence for each PCFM Variable Value. For example, in relation to Smart Meter Roll-out costs, the expected sequence would be:

- Activity takes place in Regulatory Year t-2.
- Financial or other values relating to activity reported to Ofgem by 31 July in Regulatory Year t-1.
- Revised PCFM Variable Value (SMAE) used in Annual Iteration Process to take place by 30 November in Regulatory Year t-1 (the variable value in the column equating to Regulatory Year t-2 on the PCFM Variable Values Table is the one that is revised, since that is when the activity level took place).
- Incremental change to recalculated revenue position for Regulatory Year t-2 flows through to value of MOD_t ie it affects base revenue in Regulatory Year t.

2.14 A number of the Charge Restriction Conditions provide for PCFM Variable Values to be directed for Regulatory Years outside the expected sequence. Where this is the case, the procedures are explained in the relevant methodologies in this handbook.

Part 2

ED1 Price Control Financial Methodologies

3. Pension Scheme Established Deficit repair allowances - financial adjustment methodologies

Section 1 - Overview

3.1 The Opening Base Revenue Allowances ('PU' values) for the licensee set down in the table at Appendix 1 to CRC 2A (Restriction of Allowed Distribution Network Revenue) include allowances for Pension Scheme Established Deficit (PSED) repair expenditure for each Regulatory Year of the Price Control Period[8].

3.2 These allowances are represented by the opening EDE values[9] held in the PCFM Variable Values Table for the licensee contained in the ED1 Price Control Financial Model (PCFM) and are expressed in 2012/13 prices. Opening EDE values are based on modelling assumptions and parameters applicable at the outset of the Price Control Period.

3.3 The allowance levels will be updated during the Price Control Period by revising EDE values for the purpose of the Annual Iteration Process for the PCFM. This chapter sets out:

- the reasons for updating allowances;
- the methodologies for determining revised EDE values;
- the expected timing of revisions; and
- the effect on the licensee's allowed revenue of revising EDE values for the Annual Iteration Process.

3.4 In the context of Pension Scheme Established Deficit repair expenditure we refer to 'allowances' rather than 'allowed expenditure'. This is because, subject to the Reasonableness Review referred to in this chapter, EDE values are included in full in recalculated base revenue figures in the PCFM under the Annual Iteration Process (ie these values are treated as 100% Fast Money).

Price control pension principles

3.5 Ofgem's price control pension principles were set out in Appendix 7 of the Authority's Strategy decision for RIIO-ED1 - Financial issues supplementary annex (see associated document b to which reference should be made). The principles,

[8]Ongoing Pension Service Costs (including Pension scheme administration and Pension Protection Fund (PPF) levy costs) are included as an element of labour costs in RIIO-ED1.

[9] As at 1 April 2015.

were specified in the Authority's final proposals for the DPCR5 Price Control[10] and are:

> Principle 1 - Efficient and Economic Employment and Pension Costs
>
> *Customers of network monopolies should expect to pay the efficient cost of providing a competitive package of pay and other benefits, including pensions, to staff of the regulated business, in line with comparative benchmarks.*
>
> Principle 2 - Attributable Regulated Fraction Only
>
> *Liabilities in respect of the provision of pension benefits that do not relate to the regulated business should not be taken into account in assessing the efficient level of costs for which allowance is made in a price control.*
>
> Principle 3 - Stewardship - Ante/Post Investment
>
> *Adjustments may be necessary to ensure that the costs for which allowance is made do not include excess costs arising from a material failure of stewardship.*
>
> Principle 4 - Actuarial Valuation/Scheme Specific Funding
>
> *Pension costs should be assessed using actuarial methods, on the basis of reasonable assumptions in line with current best practice.*
>
> Principle 5 - Under Funding/Over Funding
>
> *In principle, each price control should make allowance for the ex ante cost of providing pension benefits accruing during the period of the control, and similarly for any increase or decrease in the cost of providing benefits accrued in earlier periods resulting from changes in the ex ante assumptions on which these were estimated on a case-by-case basis.*
>
> Principle 6 - Severance - Early Retirement Deficiency Contributions
>
> *Companies will also be expected to absorb any increase (and may retain the benefit of any decrease) in the cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.*

Pension Scheme Established Deficit

3.6 For the purposes of CRC 3C (Specified financial adjustments) and this chapter, the term Pension Scheme Established Deficit (PSED) means the difference between the assets and corresponding liabilities within a defined benefit pension scheme (or schemes), sponsored by the licensee, that are:

- attributable to the licensee's distribution business; and
- attributable to pensionable service up to and including 31 March 2010 (the cut-off date).

[10] Electricity Distribution Price Control Review Final Proposals – Financial Methodologies

3.7 Ofgem will determine the licensee's PSED using:

(i) the triennial actuarial valuation of the pension scheme or schemes that contain the PSED described in paragraph 3.6;

(ii) the allocation of assets and liabilities in the scheme(s) referred to in subparagraph (i) to the PSED using the Pension Deficit Allocation Methodology published by Ofgem in the Pension RIGs[11]; and

(iii) its Reasonableness Review with respect to the price control pension principles which could, exceptionally, result in adjustments to the PSED figure.

3.8 Allowances for PSED repair are set at/revised to levels intended to allow the licensee to clear its PSED (by making payments to the pension scheme) over a 15 year period, which began on 1 April 2010 (immediately following the cut-off date) and ends on 31 March 2025.

3.9 The setting of PSED repair allowances will include adjustments relating to the licensee's actual PSED repair payments history compared to its allowances. With respect to payments made during the DPCR5 Price Control, the policy was set out in subparagraphs (iii) and (iv) of paragraph 1.15 of Appendix 6 of the Authority's Strategy decision for RIIO-ED1 - Financial issues supplementary annex (see associated document b).

3.10 The setting of PSED repair allowances may include adjustments resulting from Reasonableness Reviews (see paragraphs 3.22 to 3.31).

3.11 The Price Control Period ends on 31 March 2023, but EDE values will be determined having regard to the projected PSED repair completion date of 31 March 2025.

Costs and adjustments outside the scope of this chapter

Pension costs for service after 31 March 2010

3.12 The following costs are dealt with as Totex expenditure in the RIIO-ED1 price control and therefore fall outside the scope of CRC 3C and this chapter:

(a) pension costs associated with employee service after the start of the Price Control Period;

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[11] Energy Network Operators' Price Control Pension Costs - Regulatory Instructions and Guidance: Triennial Pension Reporting Pack supplement including pension deficit allocation methodology ("Pension RIGs")

http://www.ofgem.gov.uk/Networks/Documents1/NWO%20Triennial%20Pension%20RIGS%20supplements%20v1.0%2012Apr13.pdf

(b) accrued liability costs associated with employee service after the cut-off date (Pension Scheme Incremental Deficit costs); and

(c) pension scheme administration costs and Pension Protection Fund levy costs.

Legacy true-up for ongoing pension service cost payments made by the licensee during the DPCR5 Price Control period

3.13 Under the terms of the price control that preceded the RIIO-ED1 Price Control Period (the DPCR5 Price Control), the licensee is entitled to a true-up amount derived using the difference between the level of ongoing pension costs included in its DPCR5 Revenue Allowances and the actual payments made by the licensee to the pension scheme relating to:

(a) the funding of defined benefit pension schemes in respect of pensionable service that took place on or after 1 April 2010;

(b) the funding of defined contribution schemes and Personal Accounts associated with Qualifying Workplace Pension Schemes under the provisions of the Pensions Act 2008; and

(c) pension administration costs.

3.14 Any outstanding adjustment in respect of the true-up described in paragraph 3.13, in relation to outturn expenditure levels for Regulatory years 2013/14 and 2014/15, not taken into account in the calculation of the licensee's Opening Base Revenue Allowances, will be applied in accordance with the DPCR5 Pension True-up legacy adjustment set out in part 3 of this handbook.

Section 2 - Updating Pension Scheme Established Deficit repair allowances through the Annual Iteration Process

3.15 The licensee's allowances for PSED repair costs will be updated during the Price Control Period to reflect:

(a) information contained in pension scheme actuarial valuation reports provided by the licensee to Ofgem;

(b) the licensee's updated PSED (defined in paragraph 3.6);

(c) information on the licensee's actual PSED repair payments history contained in price control review information submitted to Ofgem; and

(d) the outcomes of Reasonableness Reviews (see paragraphs 3.22 to 3.31).

3.16 CRC 3C requires the Authority to determine annually whether any EDE values should be revised. However, subject to paragraph 3.18, the intention is that the values will actually be revised on two occasions during the Price Control Period, driven by the triennial scheme valuation cycle indicated in the timetable in Table 3.1

below and as set out in Tables 3.2 and 3.3. It may, however, be necessary to revise EDE values at different times if, for example:

(a) a scheme valuation is delayed; or

(b) the completion of a Reasonableness Review (see paragraphs 3.22 to 3.31) has been delayed because a report commissioned by Ofgem on the reasonableness of costs associated with the licensee's pension deficit position:

- is outstanding; or
- has given rise to further review procedures,

3.17 For the avoidance of doubt, the revision of EDE values at a different time because of the delayed completion of a Reasonableness Review (see paragraph 13.16(b)) will not prevent the revision of EDE values on the two occasions referred to in paragraph 3.16 with respect to adjustments that can be taken into account at those times.

3.18 If any adjustments relating to the licensee's payment history (see paragraph 3.15(c)) for Regulatory Years up to 2014/15, were not fully taken into account in the licensee's opening EDE values, Ofgem will consider whether such adjustments should be included in proposed revisions to EDE values for the purpose of the Annual Iteration Processes that will take place by 30 November 2015 and 30 November 2016.

Table 3.1 - Expected timetable for EDE value revisions

Defined benefit pension scheme valuation as at	Expected receipt of Scheme Valuation Data Set by Ofgem	Pension Deficit Allocation Methodology information provided	Reasonableness Review completed	Revised EDE values directed for Annual Iteration Process no later than:	EDE values revised for Regulatory Year
31 March 2016	7 July 2017	30 September 2017	31 October 2017	30 November 2017	2018/19 onwards
31 March 2019	7 July 2020	30 September 2020	31 October 2020	30 November 2020	2021/22 onwards
31 March 2022	7 July 2023	30 September 2023	31 October 2023	see note	see note

Note: Information relating to the defined benefit pension scheme valuation as at 31 March 2022 will be taken into account in the setting of Pension Scheme Established Deficit repair cost allowances for the RIIO-ED2 price control.

3.19 Licensees whose scheme triennial valuation dates differ to those shown in the first column of Table 3.1 will be required to provide either a full valuation (provided it is also used to determine the scheme's deficit recovery plan) or an updated valuation as at these dates. The approach that should be used by the licensee to produce an updated valuation is set out in Ofgem's Pension Deficit Allocation Methodology.

3.20 As stated in paragraph 3.16, the Authority will direct revised EDE values at other times, if that is necessary to reflect any revised timetable of information availability or process completion. However, in those circumstances, EDE values would still be determined in a way that is consistent with the procedures set out in this chapter.

3.21 As set out in paragraph 3.4, revised EDE values feed directly into the recalculated base revenue figures in the PCFM for applicable Regulatory Years through the Annual Iteration Process. Incremental changes to recalculated base revenue figures for years earlier than Regulatory Year t will, subject to a Time Value of Money Adjustment, be brought forward and reflected in the calculation of the term MOD to be directed for Regulatory Year t. For the avoidance of doubt, such a revision will not have any retroactive effect on a previously directed value of the term MOD.

Reasonableness Reviews

3.22 After receiving the whole (or substantially the whole) of the licensee's Scheme Valuation Data Set (see paragraph 3.32) in respect of each defined benefit pension scheme, Ofgem will commission a report on the costs associated with the licensee's pension deficit position which it will review.

3.23 The report and review referred to in paragraph 3.22 cover overall costs and cost levels associated with over or under-payment (versus allowance) patterns. They do not cover the allocation of assets and liabilities to the PSED using the Pension Deficit Allocation Methodology.

3.24 The commissioning of the report, consideration of it and the carrying out of any further review procedures are, together, termed the Reasonableness Review.

3.25 The Reasonableness Review is referred to in paragraph 3C.5(b) of CRC 3C. The expected completion dates for the Reasonableness Reviews due to take place during the Price Control Period are shown in Table 3.1. The expected completion dates take into account Ofgem's review of the commissioned report, but they do not take into account any further review procedures (see paragraph 3.16).

3.26 Ofgem will consider the report referred to in paragraph 3.22 with respect to:

(a) the value of the PSED for the licensee;

(a) existing adjustment factors affecting EDE values that were put in place following a prior Reasonableness Review; and

(b) the need for any new adjustment factors,

for the purposes of the methodologies in this chapter.

3.27 In most instances, adjustment factors are applied after Base Annual PSED Allowance levels have been derived using an unadjusted PSED value. Exceptionally, the PSED value may be adjusted for the purpose of deriving Base Annual PSED Allowance levels.

New or extended adjustment factors

3.28 Ofgem will only introduce new adjustment factors or extend the scope or effect of existing adjustment factors (including any adjustment to the PSED value used for calculations) if the licensee is an outlier with regard to pension deficit costs in a material respect and that position is:

(a) to the detriment of consumers; and

(b) reasonably attributable to the licensee, recognising the responsibilities and independence of pension scheme trustees.

3.29 Before introducing any new adjustment factor or extending the scope or effect of any existing adjustment factor (including any adjustment to the PSED value used for calculations) Ofgem will:

(a) carry out further review procedures; and

(b) consult with the licensee.

Continuation or discontinuation of existing adjustment factors

3.30 If, after considering the report referred to in paragraph 3.22, Ofgem decides that existing adjustment factors (including any adjustment to the PSED value used for calculations) affecting EDE values that were put in place following a prior Reasonableness Review:

(a) should continue to be applied; or

(b) should be discontinued,

it will notify the licensee accordingly. However, subject to paragraph 3.31, a decision of this type will not necessitate further review procedures or consultation.

3.31 If an existing adjustment factor was due to expire and Ofgem considers that it should be continued beyond the expiry date, Ofgem will treat any continuation beyond the expiry date as if it were a new adjustment factor under paragraphs 3.28 and 3.29.

Scheme Valuation Data Set

3.32 The Scheme Valuation Data Set comprises:

- the actuarial valuation of each defined-benefit scheme in respect of which the licensee is a sponsoring employer, being either a full valuation or an update of the last preceding full triennial valuation, with the asset and liability values projected forward to the full valuation date on the basis set out in the Pension Deficit Allocation Methodology;
- each scheme’s statement of funding principles; and

- each scheme's statement of investment principles; and any other information reasonably required.

3.33 Pension Deficit Allocation Methodology tables are submitted separately.

Section 3 – Pension Scheme Established Deficit repair allowances

Determination and direction of revised EDE values by 30 November 2017

3.34 Revised EDE values will be determined by 30 November 2017 for each Regulatory Year from 2018/19 to 2022/23 using the process set out in Table 3.2 below.

Table 3.2 - Process for determining revised EDE values to be directed by 30 November 2017

Row	Timing	Event	Value
Determination of component relating to PSED value			
1	By 7 July 2017	i) Ofgem will obtain the licensee's Scheme Valuation Data Set for the valuation of the licensee's defined benefit pension schemes as at 31 March 2016 and commence a Reasonableness Review.	
2	By 31 July 2017	i) Ofgem will be in receipt of price control review information from the licensee for Regulatory Years up to and including 2016/17.	
3	By 30 September 2017	i) The licensee will submit Pension Deficit Allocation Methodology information and its indicative PSED figure as at 31 March 2016 showing the movements from 1 April 2013 to 31 March 2016.	
4	By 31 October 2017	i) Ofgem will: a) complete its review of the report commissioned for the purpose of a Reasonableness Review (see paragraph 3.22); and b) subject to the need for any further review procedures and consultation (see paragraphs 3.28 and 3.29) determine the PSED as at 31 March 2016.	A

Row	Timing	Event	Value
5		i) Ofgem will deflate the PSED to 2012/13 prices in accordance with paragraph 1.7.	B
6		i) Ofgem will establish the remaining deficit repair period as 7 years (2024/25 minus 2017/18).	
7		i) Ofgem will, subject to point ii), compute the licensee's Base Annual PSED Allowance (C1) in 2012/13 prices as: C1 = B / ((1-(1+DR)^ -7) / LN(1+DR)) where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined by Ofgem following a benchmarking review; and LN returns the natural logarithm of 1+DR. ii) If the valuation of the licensee's defined benefit pension schemes as at 31 March 2016 shows a surplus, Ofgem will set values B and C1 to zero and paragraph 3.36 below will apply.	C1
Determination of component relating to payment history in Regulatory Years up to 2009/10			
8	By 31 October 2017	i) Ofgem will determine the remaining amount (in 2012/13 prices) of any adjustment sum, previously determined, in respect of the licensee's actual payment levels in Regulatory Years up to and including 2009/10. The remaining amount means the amount of the total adjustment that has not been included in EDE values for Regulatory Years up to and including Regulatory Year 2017/18 and includes a Time Value of Money Adjustment through to Regulatory Year 2018/19.	RC
9	By 31 October 2017	i) Ofgem will calculate the portion (RA1) of the remaining amount referred to in row 8 that should be attributed to each of the seven remaining years of the notional 15-year PSED repair period in 2012/13 prices using the following formula:	

Row	Timing	Event	Value
		RA1 = RC / ((1-(1+DR)^ -7) / LN(1+DR)) where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined under the Reasonableness Review; and LN returns the natural logarithm of 1+DR.	RA1
Determination of component relating to adjustments for the licensee's payment history in the DPCR5 Price Control period and elapsed Regulatory Years in the Price Control Period			
10	By 31 October 2017	i) Ofgem will determine the actual PSED repair payments made by the licensee in Regulatory Years 2010/11 to 2016/17 by: (a) obtaining the relevant portion (attributable to the licensee's distribution business) of the actual PSED repair payments made by the licensee in each of those Regulatory Years, excluding any amounts relating to Contingent Asset costs; and (b) deflating the resulting value for each of those Regulatory Years to 2012/13 prices in accordance with paragraph 1.7.	$D_{2010/11}$ $D_{2011/12}$ $D_{2012/13}$ $D_{2013/14}$ $D_{2014/15}$ $D_{2015/16}$ $D_{2016/17}$
11		i) Ofgem will obtain the following values, in 2012/13 prices, from the Authority's final determinations for the DPCR5 Price Control and the RIIO-ED1 price control: (a) the licensee's Base Annual PSED Allowances for Regulatory Years 2010/11 to 2014/15; and (b) the licensee's Base Annual PSED Allowances for Regulatory Years 2015/16 and 2016/17 that were included in the calculation of the licensee's Opening Base Revenue Allowances.	$E_{2010/11}$ $E_{2011/12}$ $E_{2012/13}$ $E_{2013/14}$ $E_{2014/15}$ $E_{2015/16}$ $E_{2016/17}$

Row	Timing	Event	Value
12		i) Ofgem will calculate the adjustment amount to be applied in respect of the difference between actual PSED repair payments and Base Annual PSED Allowance values for each Regulatory Year from 2010/11 to 2016/17 by: (a) subtracting the Base Annual PSED Allowance (E) from the payment (D); (b) factoring in the tax impact in respect of any over/under payment; and (c) applying a Time Value of Money Adjustment through to Regulatory Year 2018/19. ii) Ofgem will calculate the total adjustment amount (F_{Total}) as the sum of the adjustment amounts for Regulatory Years from 2010/11 to 2016/17. The value of F_{Total} may be positive or negative. The process set out in steps i) and ii) is represented algebraically as:	$F_{2010/11}$ $F_{2011/12}$ $F_{2012/13}$ $F_{2013/14}$ $F_{2014/15}$ $F_{2015/16}$ $F_{2016/17}$ F_{Total}

$$F_{Total} = \sum_{2010/11}^{2016/17} F$$

where:

$$F_{2010/11} = \frac{\left(D_{2010/11} - E_{2010/11}\right) \times \left(1 - CT_{2010/11}\right) \times \left(1 + WACC_{DPCR5}\right)^5 \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2011/12} = \frac{\left(D_{2011/12} - E_{2011/12}\right) \times \left(1 - CT_{2011/12}\right) \times \left(1 + WACC_{DPCR5}\right)^4 \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2012/13} = \frac{\left(D_{2012/13} - E_{2012/13}\right) \times \left(1 - CT_{2012/13}\right) \times \left(1 + WACC_{DPCR5}\right)^3 \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2013/14} = \frac{\left(D_{2013/14} - E_{2013/14}\right) \times \left(1 - CT_{2013/14}\right) \times \left(1 + WACC_{DPCR5}\right)^2 \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2014/15} = \frac{\left(D_{2014/15} - E_{2014/15}\right) \times \left(1 - CT_{2014/15}\right) \times \left(1 + WACC_{DPCR5}\right) \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2015/16} = \frac{\left(D_{2015/16} - E_{2015/16}\right) \times \left(1 - CT_{2015/16}\right) \times \left(1 + WACC_{2015/16}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

$$F_{2016/17} = \frac{\left(D_{2016/17} - E_{2016/17}\right) \times \left(1 - CT_{2016/17}\right) \times \left(1 + WACC_{2016/17}\right) \times \left(1 + WACC_{2017/18}\right)}{1 - CT_{2018/19}}$$

and where:

$CT_{20XX/XX}$ means the actual or, with respect to Regulatory Year 2018/19, prospective rate of Corporation Tax applicable to the licensee in Regulatory Year 20XX/XX, unless the licensee had no modelled taxable profits in the Regulatory Year concerned in which case it takes the value zero;

$WACC_{DPCR5}$ means the Vanilla Weighted Average Cost of Capital applicable to the licensee during the DPCR5 Price Control period; and

$WACC_{20XX/XX}$ means the Vanilla Weighted Average Cost of Capital applicable to the licensee during Regulatory Year 20XX/XX, calculated using the allowed percentage cost of corporate debt (CDE value) for the licensee directed by the Authority for the Regulatory Year concerned.

Row	Timing	Event		Value
13	By 31 October 2017	i)	Any adjustment amount (in 2012/13 prices) relating to the licensee’s payment history in Regulatory Years 2010/11 to 2016/17, that was included in the calculation of the licensee’s Opening Base Revenue Allowances for Regulatory Years 2015/16, 2016/17 and 2017/18 will be deducted from the value of F_{Total} calculated under points i) and ii) in row 12.	RD

Row	Timing	Event	Value
14	By 31 October 2017	i) Ofgem will calculate the portion (G1) of the total adjustment amount (F_{Total}) that should be attributed to each of the seven remaining years of the notional 15-year PSED repair period in 2012/13 prices using the following formula: $G1 = (F_{Total} - RD) / ((1-(1+DR)^{-7}) / LN(1+DR))$ where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined under the Reasonableness Review; and LN returns the natural logarithm of 1+DR.	G1
Determination of component relating to adjustment factors resulting from Reasonableness Reviews			
15	By 31 October 2017	i) After considering the report on the costs associated with the licensee's pension deficit position referred to in paragraph 3.22, Ofgem will decide whether any existing adjustment factors affecting EDE values that were put in place following a prior Reasonableness Review: (a) should continue to be applied; or (b) should be discontinued (with or without retroactivity). ii) Having made the decision referred to in point i), Ofgem will calculate the adjustment that should be attributed to each of the seven remaining years of the notional 15-year PSED repair period in 2012/13 prices, having regard to the terms on which the adjustment factor was originally applied. If, after considering the report on the costs associated with the licensee's pension deficit position referred to in paragraph 3.22, Ofgem decides that a new adjustment factor should be applied or that the scope or effect of	AF1

Row	Timing	Event	Value
		an existing adjustment factor should be extended, it will follow the process described in paragraphs 3.28 and 3.29. In such a case, as part of the further review and consultation process, Ofgem will consider the basis and timing for any revision of EDE values for the licensee (see paragraph 3.16).	
Calculation of revised EDE values			
16		i) Ofgem will calculate the revised EDE value for each Regulatory Year from 2018/19 to 2022/23 as: EDE = C1 + RA1 + G1 + AF1.	EDE

3.35 The adjustments relating to the licensee's payment history (see rows 8 to 13 in Table 3.2) address a position where the licensee has paid amounts to the pension scheme in particular Regulatory Years that are greater than or lower than the Base Annual PSED Allowances it was given for the Regulatory Years concerned.

Scheme surplus

3.36 If the difference between the assets and corresponding liabilities referred to in paragraph 3.6 represents a surplus position for the PSED as at 31 March 2016, then values for C1 (see row 7 in table 3.2) for Regulatory Years from 2018/19 onwards will be revised to zero pending the next review process set out in Table 3.3. However, if applicable, the calculation of adjustment components relating to the licensee's payment history and to adjustment factors resulting from Reasonableness Reviews would still be carried out, giving values for RA1, G1 and AF1 respectively. Those values (which may be negative) would, in that circumstance, give the value of the term EDE for each Regulatory Year from 2018/19 to 2022/23 pending the next review process. The policy position with regard to pension scheme surpluses is set out in paragraphs 1.11 to 1.14 of the Authority's Strategy decision for RIIO-ED1 - Financial issues supplementary annex - see associated document b.

Determination and direction of revised EDE values by 30 November 2020

3.37 Revised EDE values will be determined by 30 November 2020 for Regulatory Years 2021/22 and 2022/23 using the process set out in Table 3.3 below.

Table 3.3 - Process for determining revised EDE values to be directed by 30 November 2020

Row	Timing	Event	Value
Determination of component relating to PSED value			
1	By 7 July 2020	i) Ofgem will obtain the licensee's Scheme Valuation Data Set for the valuation of the licensee's defined benefit pension schemes as at 31 March 2019 and commence a Reasonableness Review.	
2	By 31 July 2020	i) Ofgem will be in receipt of price control review information from the licensee for Regulatory Years up to and including 2019/20.	
3	By 30 September 2020	i) The licensee will submit Pension Deficit Allocation Methodology information and its indicative PSED figure as at 31 March 2019 showing the movements from 1 April 2016 to 31 March 2019.	
4	By 31 October 2020	i) Ofgem will: a) complete its review of the report commissioned for the purpose of a Reasonableness Review (see paragraph 3.22); and b) subject to the need for any further review procedures and consultation (see paragraphs 3.28 and 3.29) determine the PSED as at 31 March 2019.	A
5		i) Ofgem will deflate the PSED to 2012/13 prices in accordance with paragraph 1.7.	B
6		i) Ofgem will establish the remaining deficit repair period as 4 years (2024/25 minus 2020/21).	
7		i) Ofgem will, subject to point ii), compute the licensee's Base Annual PSED Allowance (C2) in 2012/13 prices as: C2 = B / ((1-(1+DR)^ -4) / LN(1+DR)) where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined by Ofgem following a	C2

Row	Timing	Event	Value
		benchmarking review; and LN returns the natural logarithm of 1+DR. ii) If the valuation of the licensee's defined benefit pension schemes as at 31 March 2019 shows a surplus, Ofgem will set values B and C2 to zero and paragraph 3.39 below will apply.	
Determination of component relating to payment history in Regulatory Years up to 2016/17			
8	By 31 October 2020	i) Ofgem will determine the remaining amount (in 2012/13 prices) of any adjustment sums, previously determined, in respect of the licensee's actual payment levels in Regulatory Years up to 2016/17. The remaining amount means the amount of the total adjustment that has not been included in EDE values for Regulatory Years up to and including Regulatory Year 2020/21 and includes a Time Value of Money Adjustment through to Regulatory Year 2021/22.	RC
9	By 31 October 2020	i) Ofgem will calculate the portion (RA2) of the remaining amount referred to in row 8 that should be attributed to each of the four remaining years of the notional 15-year PSED repair period in 2012/13 prices using the following formula: RA2 = RC / ((1-(1+DR)^ -4) / LN(1+DR)) where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined under the Reasonableness Review; and LN returns the natural logarithm of 1+DR.	RA2

Row	Timing	Event	Value
Determination of component relating to adjustments for the licensee's payment history in Regulatory Years 2017/18, 2018/19 and 2019/20			
10	By 31 October 2020	i) Ofgem will determine the actual PSED repair payments made by the licensee in Regulatory Years 2017/18, 2018/19, and 2019/20 by: (a) obtaining the relevant portion (attributable to the licensee's distribution business) of the actual PSED repair payments made by the licensee in each of those Regulatory Years, excluding any amounts relating to Contingent Asset costs; and (b) deflating the resulting value for each of those Regulatory Years to 2012/13 prices in accordance with paragraph 1.7.	$D_{2017/18}$ $D_{2018/19}$ $D_{2019/20}$
11	By 31 October 2020	i) Ofgem will obtain the licensee's Base Annual PSED Allowances for Regulatory Years 2017/18, 2018/19 and 2019/20.	$E_{2017/18}$ $E_{2018/19}$ $E_{2019/20}$
12		i) Ofgem will calculate the adjustment amount to be applied in respect of the difference between actual PSED repair payments and Base Annual PSED Allowance values for each Regulatory Year from 2017/18 to 2019/20 by: (a) subtracting the allowance (E) from the payment (D); (b) factoring in the tax impact in respect of any over/under payment; and (c) applying a Time Value of Money Adjustment through to Regulatory Year 2021/22. ii) Ofgem will calculate the total adjustment amount (F_{Total}) as the sum of the adjustment amounts	$F_{2017/18}$ $F_{2018/19}$ $F_{2019/20}$

Row	Timing	Event	Value
		for Regulatory Years from 2017/18 to 2019/20. The value of F_{Total} may be positive or negative. The process set out in steps i) and ii) is represented algebraically as:	F_{Total}

$$F_{Total} = \sum_{2017/18}^{2019/20} F$$

where:

$$F_{2017/18} = \frac{(D_{2017/18} - E_{2017/18}) \times (1 - CT_{2017/18}) \times (1 + WACC_{2017/18}) \times (1 + WACC_{2018/19}) \times (1 + WACC_{2019/20}) \times (1 + WACC_{2020/21})}{1 - CT_{2021/22}}$$

$$F_{2018/19} = \frac{(D_{2018/19} - E_{2018/19}) \times (1 - CT_{2018/19}) \times (1 + WACC_{2018/19}) \times (1 + WACC_{2019/20}) \times (1 + WACC_{2020/21})}{1 - CT_{2021/22}}$$

$$F_{2019/20} = \frac{(D_{2019/20} - E_{2019/20}) \times (1 - CT_{2019/20}) \times (1 + WACC_{2019/20}) \times (1 + WACC_{2020/21})}{1 - CT_{2021/22}}$$

and where:

$CT_{20XX/XX}$ means the actual or, with respect to Regulatory Year 2021/22, prospective rate of Corporation Tax applicable to the licensee in Regulatory Year 20XX/XX, unless the licensee had no modelled taxable profits in the Regulatory Year concerned in which case it takes the value zero; and

$WACC_{20XX/XX}$ means the Vanilla Weighted Average Cost of Capital applicable to the licensee during Regulatory Year 20XX/XX, calculated using the allowed percentage cost of corporate debt (CDE value) for the licensee directed by the Authority for the Regulatory Year concerned.

Row	Timing	Event	Value
13		i) Ofgem will calculate the portion (G2) of the total adjustment amount (F_{Total}) that should be attributed to each of the four remaining years of the notional 15-year PSED repair period in 2012/13 prices using the following formula: $G2 = F_{Total} / ((1-(1+DR)^{-4}) / LN(1+DR))$ where: DR is the discount rate specified in the licensee's Scheme Valuation Data Set or, if applicable, a different rate determined under the Reasonableness Review; and LN returns the natural logarithm of 1+DR.	G2
Determination of component relating to adjustment factors resulting from Reasonableness Reviews			
14	By 31 October 2020	i) After considering the report on the costs associated with the licensee's pension deficit position referred to in paragraph 3.22, Ofgem will decide whether any existing adjustment factors affecting EDE values that were put in place following a prior Reasonableness Review: (a) should continue to be applied; or (b) should be discontinued (with or without retroactivity). ii) Having made the decision referred to in point i), Ofgem will calculate the adjustment that should be attributed to each of the four remaining years of the notional 15-year PSED repair period in 2012/13 prices, having regard to the terms on which the adjustment factor was originally applied. If, after considering the report on the costs associated with the licensee's pension deficit position referred to in paragraph 3.22, Ofgem decides that a new adjustment	AF2

		factor should be applied or that the scope or effect of an existing adjustment factor should be extended, it will follow the process described in paragraphs 3.28 and 3.28. In such a case, as part of the further review and consultation process, Ofgem will consider the basis and timing for any revision of EDE values for the licensee (see paragraph 3.16).	
Calculation of revised EDE values			
15		i) Ofgem will calculate the revised EDE value for Regulatory Years 2021/22 and 2022/23 as: EDE = C2 + RA2 + G2 + AF2.	EDE

3.38 The adjustments relating to the licensee's payment history (see rows 8 to 13 in Table 3.3) address a position where the licensee has paid amounts to pension scheme trustees in particular Regulatory Years that are greater than or lower than the Base Annual PSED Allowances it was given for the Regulatory Years concerned.

Scheme surplus

3.39 If the difference between the assets and corresponding liabilities referred to in paragraph 3.6 represents a surplus position for the PSED as at 31 March 2019, then values for C2 (see row 7 in table 3.3) for Regulatory Years from 2021/22 onwards will be revised to zero pending the next review process. However, if applicable, the calculation of adjustment components relating to the licensee's payment history and to adjustment factors resulting from Reasonableness Reviews would still be carried out, giving values for RA2, G2 and AF2 respectively. Those values (which may be negative) would, in that circumstance, give the value of the term EDE for Regulatory Years 2021/22 and 2022/23 pending the next review process. The policy position with regard to pension scheme surpluses is set out in paragraphs 1.11 to 1.14 of the Authority's Strategy decision for RIIO-ED1 - Financial issues supplementary annex - see associated document b.

Direction of revised EDE values

3.40 The Authority will direct revised EDE values by no later than 30 November 2017 and 30 November 2020 in accordance with the procedure set out in Part D of CRC 3C (but see also paragraphs 3.16 and 3.18).

Section 4 - Processing of revised EDE values under the Annual Iteration Process

3.41 EDE values, as revised, are included in full in recalculated base revenue figures in the PCFM under the Annual Iteration Process and are treated as 100 per cent Fast Money.

3.42 Incremental changes to recalculated base revenue figures for years earlier than Regulatory Year t will, subject to a Time Value of Money adjustment, be brought forward and reflected in the calculation of the term MOD to be directed for Regulatory Year t. For the avoidance of doubt, such a revision will not have any retroactive effect on a previously directed value of the term MOD.

3.43 EDE values are not added to RAV and are not subject to the Totex Incentive Mechanism.

4. Tax liability allowances - financial adjustment methodologies

Section 1 - Overview

4.1 The Opening Base Revenue Allowances ('PU' values) for the licensee set down in the table at Appendix 1 to CRC 2A (Restriction of Allowed Distribution Network Revenue) include tax liability allowances that are modelled at the outset of the Price Control Period to take account of:

(a) existing and announced corporation tax rates and writing down allowance rates;

(b) existing legislation, case law, accounting standards and HM Revenue & Customs (HMRC) policy; and

(c) modelled levels of gearing and corporate debt interest payments for the licensee.

4.2 Part B of CRC 3C (Specified financial adjustments) provides for adjustments to be made to the licensee's tax liability allowances[12] during the Price Control Period through the Annual Iteration Process for the ED1 Price Control Financial Model (PCFM). Changes to the factors referred to at subparagraphs 4.1(a) and (b) are referred to as 'tax trigger events' and the methodology for adjustments that may result from these is set out in section 2 of this chapter. Adjustments that are the result of changes to the factors referred to at subparagraph 4.1(c) are referred to as 'tax clawbacks' and the methodology for such adjustments is set out in section 3 of this chapter.

Annual Iteration Process

TTE and TGIE values

4.3 The adjusting of the licensee's tax liability allowances and regulatory tax losses balance (see paragraph 4.11) is carried out through the Annual Iteration Process for the PCFM. The PCFM Variable Values Table for the licensee contains rows for PCFM Variable Values for tax liability allowance adjustments relating to:

- tax trigger events ('TTE' values); and
- tax clawbacks ('TGIE values').

[12] References in this chapter to tax liabilities are references to liabilities for corporation tax only and not to any other type of taxation.

4.4 TTE and TGIE values represent £m amounts. As at 1 April 2015, the TTE and TGIE values for the licensee, for each Regulatory Year will be zero. Part B of CRC 3C provides for any revisions to TTE and TGIE values to be directed after determination under the methodologies in this chapter.

4.5 Subject to paragraph 4.7, revisions to TTE and TGIE values feed into the recalculated base revenue figures and/or the regulatory tax loss balances for applicable Regulatory Years in the PCFM through the Annual Iteration Process. Incremental changes to recalculated base revenue figures for years earlier than Regulatory Year t are, subject to a Time Value of Money Adjustment, brought forward and reflected in the calculation of the term MOD to be directed for Regulatory Year t. For the avoidance of doubt, such changes will not have any retroactive effect on a previously directed value of the term MOD.

4.6 Any recalculation of the licensee's tax liability allowances necessarily includes an iterative modelling aspect: an increased allowance gives rise to an increased liability which requires an increased allowance and so on. The effect can be either positive or negative. This 'tax allowance on tax allowance' issue is dealt with as follows:

- In respect of tax trigger adjustments, revised TTE values (determined using the tax trigger calculation tool referred to in the methodology in section 2 of this chapter) incorporate the iterative calculations and no further processing is required as part of the Annual Iteration Process.
- In respect of tax clawback adjustments, revised TGIE values (determined under the methodology in section 3 of this chapter) do not incorporate the iterative calculations and these are instead factored into recalculated base revenue figures by functionality within the PCFM as part of the Annual Iteration Process.

4.7 It should be noted that underlying tax liability allowances for the licensee within the PCFM may also be changed under the Annual Iteration Process as a consequence of other variable value changes, such as increases in allowed Totex expenditure. However, these changes are distinct from the specific adjustments to tax liability allowances under the methodologies in this chapter.

Legacy price control adjustments to opening tax pool balances

4.8 Tax liability allowance calculations under the Annual Iteration Process make use of regulatory tax pool balance figures held within the PCFM. The opening balances (as at 1 April 2015) for these tax pools may be subject to legacy price control adjustments through revisions to LTPG, LTPS, LTPD and LTPC PCFM Variable Values. These adjustments are covered in chapter 14. The allocation of component elements of allowed DPCR5 Price Control totex expenditure to capital allowance pools and revenue expenditure in the PCFM was fixed at the outset of the Price Control Period and will not be updated during the Price Control Period.

Price bases for tax calculations

4.9 The PCFM works predominantly in constant 2012/13 prices, with all inputs and outputs in this price base. The methodologies in this chapter provide for values that are expressed in nominal prices to be deflated to 2012/13 prices in accordance with paragraph 1.7 in chapter 1 before being used to determine revised TTE and TGIE values.

4.10 The PCFM uses nominal prices for some internal tax calculation functions. For this purpose, the PCFM refers to RPI forecast values set at the outset of the Price Control Period.

Regulatory tax losses

4.11 In some instances, the approach to calculating tax liability allowances could imply that the licensee could receive a negative allowance. In such cases, the price control treatment is to model a zero allowance and to record the tax loss arising as a 'regulatory tax loss' figure, to be deducted from the taxable profits before the tax is calculated for any tax liability allowances that would otherwise be allocated to the year concerned or later years. The regulatory tax loss balance attributable to each Regulatory Year (together with a running total) is held within the PCFM and regulatory tax losses are referred to where applicable in the methodologies in this chapter.

Group tax arrangements

4.12 For the purposes of the methodology set out in section 2 of this chapter, tax liabilities, allowances and trigger events are considered on a notional 'licensee business' basis, and consequently the following are disregarded in the assessment of tax liabilities and allowances for price control purposes:

- the claim or surrender of group tax relief (including consortium relief);
- interest payments (including any coupons on debt instruments or preference share dividends) and receipts that are not tax deductible or chargeable under HMRC rules for the purposes of computing the licensee's taxable profits, including but not limited to adjustments for transfer pricing and the 'worldwide debt cap'; and
- any other adjustments required in appendix 1 of Ofgem's open letter dated 31 July 2009 (Clawback of tax benefit due to excess gearing)[13].

4.13 For the purposes of the methodology set out in section 3 of this chapter, levels of debt, interest and gearing are considered at licensee level, as opposed to

[13] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=49&refer=Networks and as amended for the treatment of hybrid financial instruments

any other level with respect to the corporate or ownership group of which the licensee is a member.

Section 2 - Adjustments driven by tax trigger events - methodology

4.14 The methodology set out in this section provides for the licensee's tax liability allowances to be adjusted (subject to a threshold described below) to take account of tax trigger events. This means that consumers will derive a benefit when tax liability costs fall materially, and the licensee will be appropriately reimbursed when they rise.

Tax trigger events

4.15 There are two types of tax trigger event for the purposes of tax liability allowance adjustments:

<u>Type A</u>

Type A events consist of:

- changes to corporation tax rates, applicable to one or more Regulatory Years, that have been enacted into law; and
- changes to capital allowance rates applicable to one or more Regulatory Years, that have been enacted into law.

<u>Type B</u>

Type B events consist of other factors (exogenous to the licensee, its owners or controllers) that cause a change to the licensee's notional tax liabilities[14] for one or more Regulatory Years including:

- changes to applicable legislation;
- the setting of legal precedents through case law;
- changes to HMRC interpretation of legislation; and
- changes in accounting standards.

4.16 Where a Type B event consists of changes to statutory capital allowance pools, or to the allocation of expenditure to such pools, an appropriate £m adjustment (from the effective date of the new requirement) will be factored into

[14] The tax liability which would be modelled if the event was taken into account.

subsequent TTE value revisions for the licensee. Ofgem will work with licensees to agree the financial effect of revised tax pool allocation requirements where these are not straightforward.

4.17 Type B events will only be taken into account for the purposes of increasing the licensee's tax liability allowances where the licensee has demonstrably used its reasonable endeavours to minimise any increase in its tax liabilities.

Materiality threshold and 'deadband'

4.18 A materiality threshold is applied to tax trigger events during the Price Control Period and a £m threshold amount for each Regulatory Year is included amongst the fixed values on the Tax Trigger sheet for the licensee in the PCFM.

4.19 A change to the licensee's notional tax liability allowance for a particular Regulatory Year is only applied where one or more trigger events would result in a tax liability allowance change for that year whose absolute value is greater than the threshold amount. Furthermore, any change to the tax liability allowance (upward or downward) is limited to the amount that is in excess of the threshold amount for the Regulatory Year concerned.

4.20 Where the change to the licensee's tax liability allowance for a particular Regulatory Year is below the threshold, subsequent tax trigger events, relating back to that Regulatory Year, could cause the threshold amount to be exceeded. In that case, a change to the licensee's tax liability allowance for the Regulatory Year concerned (a revised TTE value) would be determined once the threshold had been exceeded. It should be noted that there is no retrospective adjustment to the value of MOD terms already directed: adjustments would instead be included in the calculation of a subsequent value for the term MOD.

4.21 For the avoidance of doubt, a regulatory tax loss figure attributable to a particular Regulatory Year is not taken into account for the purposes of deciding whether the threshold amount has been exceeded for that year.

4.22 The licensee's tax liability calculations are subject to:

- changes to applicable legislation;
- the setting of legal precedents through case law;
- changes to HMRC interpretation of legislation; and
- changes in accounting standards applicable to preparation of the licensee's statutory accounts[15].

[15] Section 385 of the Companies Act 2006 refers.

4.23 The accounting framework to be applied by the licensee for the purpose of computing tax liabilities is either:

- EU-IFRS, if adopted for use by the licensee; or
- UK GAAP under Financial Reporting Standard 102.

Notification of tax trigger events

Type A trigger events

4.24 Ofgem will, by 30 September in each Regulatory Year t-1, notify the licensee of the Type A trigger events that it proposes to take into account in determining any revised TTE values for use in the Annual Iteration Process that is required to take place by 30 November in that same Regulatory Year t-1. It is, however, open to the licensee to contact Ofgem in advance of 30 September in each Regulatory Year t-1 to discuss the current view of Type A events. The notification from Ofgem will specify the corporation tax rate change(s) or changes to rates of capital allowances concerned and the Regulatory Years to which they relate.

4.25 If, after receiving the notification referred to in paragraph 4.24, the licensee considers that a Type A trigger event has occurred that has not been included in the notification, it should contact Ofgem within 14 days and provide details of the event concerned. If Ofgem agrees that a further Type A trigger event has occurred, it will notify the licensee by 31 October in the same Regulatory Year t-1.

4.26 If any Type A trigger event is left out of account when it ought to have been included in the determination of a revised TTE value (either because it was not included in a notice or otherwise) the position will be rectified in a subsequent revision of the TTE value(s) concerned. In such a case, the functionality of the PCFM means that a Time Value of Money Adjustment would be applied.

Type B trigger events

4.27 The licensee must notify Ofgem on or before 30 September in each Regulatory Year t-1 of all the Type B trigger events that it has become aware of by that time, except those that have been previously notified. This requirement applies equally to events that could be expected to increase or to reduce the licensee’s tax liability allowances.

4.28 For the purpose of complying with the requirement set out in paragraph 4.27, the licensee must use its reasonable endeavours to identify and record Type B trigger events.

4.29 The notification referred to in paragraph 4.27 should include, in respect of each Type B trigger event:

(a) a description of the event;

(b) the changes in tax liability allowances that the event is considered to have caused and the Regulatory Years to which they relate;

(c) the calculations (including all relevant parameters and values) that the licensee used to arrive at the amounts referred to in subparagraph (b) – in performing these calculations the licensee should include a 'tax allowance on tax allowance' factor as explained in paragraph 4.6 but should ignore the tax trigger deadband which is adjusted for in paragraph 4.39;

(d) any relevant information provided by HMRC in relation to the event;

(e) evidence of mitigating measures that the licensee has taken to minimise any additional liabilities arising from the event; and

(f) comments by the licensee on:

- the relevance of the event to its tax position,
- whether grounds exist to contest the applicability of the event to the licensee, and
- the reporting treatment the licensee expects to apply in its tax submissions to HMRC and in its Regulatory Accounts.

4.30 The licensee's notification should also state whether it considers that the materiality threshold (see paragraph 4.18) has been exceeded for the Regulatory Year(s) concerned, taking into account the total net amount of tax liability changes (upward and downward) included in the current notification and any previous notifications.

4.31 Ofgem will review any notifications given to it by the licensee under paragraph 4.27 and may ask the licensee:

- for additional information in respect of one or more of the notified events; and/or
- to submit the results of agreed upon audit procedures specified by Ofgem and carried out by the licensee's Appropriate Auditor, to assist in confirming the appropriateness and accuracy of the licensee's calculations.

4.32 Ofgem will inform the licensee by 31 October in the same Regulatory Year t-1 whether, in respect of each Type B trigger event:

(a) it has agreed (on a provisional or confirmed basis) the change in tax liabilities figure calculated by the licensee;

(b) it has determined (on a provisional or confirmed basis) a different change in tax liabilities figure from that calculated by the licensee; or

(c) it has decided that consideration of any change in tax liabilities should be deferred until further/better information is available.

4.33 In deciding which of the actions set out in paragraph 4.32 should be taken, Ofgem will, without limitation, take account of whether the licensee has conclusively agreed its tax liabilities for the Regulatory Year concerned with HMRC. Where there has been a provisional agreement/determination or a deferral of consideration, the TTE values concerned will be subject to further revision for the purposes of a later Annual Iteration Process (see also paragraph 4.43).

4.34 Where Ofgem determines a different change in tax liabilities figure from that calculated by the licensee or decides that consideration of any change in tax liabilities should be deferred, it will set out its reasons and/or calculations. The licensee has the right to reply setting out its objections, which Ofgem will consider.

4.35 Ofgem will also notify the licensee by 31 October in each Regulatory Year t-1 of any Type B trigger events that it proposes to take into account that have not been included in a notification sent to Ofgem by the licensee. The licensee has the right to reply setting out its objections, which Ofgem will consider.

4.36 If Ofgem has not finished considering any matters raised by the licensee under paragraph 4.34 or paragraph 4.35 before giving the licensee the Notice required under paragraph 3C.23 of CRC 3C, the Authority will through business correspondence, apprise the licensee of any provisionality it has applied in determining the revised TTE values that it proposes to direct, that might entail a further revision to those values for use in the next Annual Iteration Process.

Logging of trigger events

4.37 Ofgem will keep a log of tax trigger events that have been subject to notifications by it or by the licensee showing for each event:

- a description of the event and whether it was Type A or Type B;
- the name of the party who notified the event (Ofgem or licensee);
- the date of notification;
- the amount of any change in the licensee's tax liabilities that has been determined under the procedures set out below; and
- details of any events for which a determination is in abeyance and a description of the outstanding actions to be taken.

Determination and direction of revised TTE values

Determination of revised TTE values using the tax trigger calculation tool

4.38 The design of the PCFM includes additional functionality meaning that a copy of the PCFM can be used as a tax trigger calculation tool, as an adjunct to the Annual Iteration Process.

4.39 Once a tax trigger event has taken place at any point in the RIIO-ED1 Price Control Period, then after 31 October in each Regulatory Year t-1, Ofgem will generate a duplicate copy of the PCFM, in its state following the last completed Annual Iteration Process (but including any subsequent functional modifications made under the provisions of CRC 4A (Governance of ED1 Price Control Financial Instruments)) for use as the tax trigger calculation tool. It will then take the following steps to determine TTE values for each licensee:

(i) All of the other PCFM Variable Value revisions that have been determined for use in the prospective Annual Iteration Process (and which Ofgem expects to include in the notices of proposed Variable Value revisions to licensees) will be input into the PCFM Variable Values Table for the licensee. The correct Regulatory Year will be selected using the PCFM 'year t selector' on the User Interface worksheet of the PCFM.

(ii) All of the existing TTE values in the PCFM Variable Values Table for the licensee will be reset to zero.

(iii) Any existing values in the yellow input cells on the tax trigger worksheet will be cleared with the exception of the tax trigger deadband values.

(iv) The 'Tax allowance before tax trigger' amount for the licensee for each Regulatory Year shown on the tax trigger worksheet will be noted.

(v) The PCFM copy will be put into 'tax trigger tool mode' using the selector on the Tax Trigger worksheet.

(vi) Changes to corporation tax rates or writing down allowance rates (reflecting Type A trigger events) will be input into the yellow input cells in the appropriate rows and Regulatory Year columns on the tax trigger worksheet.

(vii) The tax trigger macro calculation programmed into the workbook will be run.

(viii) The aggregate changes to the licensee's tax liability allowances determined in respect of all Type B trigger events (whether notified during Regulatory Year t-1 or on an earlier occasion) will be input into the yellow input cells on the 'Type B event values' row in the appropriate Regulatory Year columns on the tax trigger worksheet. This value should include the iterative tax allowance on tax allowance factor referred to in paragraph 4.6.

(ix) The tax trigger macro calculation will be rerun.

(x) The 'Tax allowance before tax trigger' referred to at step (iv) will be deducted from the 'Tax allowance' that has been calculated based on the new inputs (including both Type A and Type B trigger events).

(xi) The absolute value of the amount obtained under step (x) will be ascertained.

(xii) If the absolute value ascertained at step (xi) is less than the deadband amount (which is a fixed amount for each Regulatory Year), the tax trigger adjustment is shown as zero; otherwise step (xiii) applies.

(xiii) If the value calculated at step (xi) is greater than the deadband amount then:

  (i) if the amount obtained under step (x) is negative, the tax trigger adjustment is shown as that amount plus the deadband; or

  (ii) if the amount obtained under step (x) is positive, the tax trigger adjustment is shown as that amount minus the deadband.

4.40 Subject to paragraph 4.43, the relevant amounts obtained under step (xii) or (xiii) will then be determined to be the TTE values for the licensee for each Regulatory Year where the deadband has been exceeded. Where these values differ from the TTE values shown on the PCFM Variable Values Table for the licensee (following the last completed Annual Iteration Process), the Authority will direct that the TTE values concerned are to be revised in accordance with the process set out in Part D of CRC 3C (Specified financial adjustments) and referred to below.

4.41 The two stage calculation process referred to in steps (vii) and (ix) allows the tax trigger calculation tool to take full account of the interrelationship between Type A and Type B events. The nullification of existing TTE values referred to in step (ii) together with the inclusion of all determined changes to the licensee's tax liabilities referred to in step (viii) ensures that the determination of TTE values under step (xiii) is on a consistent basis and accurately applies the materiality threshold/ deadband applicable to each Regulatory Year. The inclusion of all available revisions to other PCFM Variable Values under step (i) ensures that the tax allowance calculation is as up to date as possible for each Regulatory Year.

4.42 Once a tax trigger event has occurred in any year, the tax trigger calculation, including the materiality assessment, will need to be run in respect of all subsequent Annual Iteration Processes, even if no further tax trigger event has occurred.

4.43 The process set out in paragraph 4.39 will be reperformed if any of the prospective PCFM Variable Value revisions referred to at step (i) are changed, to ensure that accurate TTE values are available for the Annual Iteration Process.

Direction of revised TTE values

4.44 The Authority will direct any revisions to TTE values for the licensee by 30 November in each Regulatory Year t-1, having given the licensee at least 14 days' notice of the values that it proposes to direct in accordance with Part D of CRC 3C.

4.45 Revised TTE values can be directed in respect of a particular Annual Iteration Process for any Regulatory Year during the Price Control Period, including for years later than Regulatory Year t.

4.46 The procedure for the Authority's direction of revised TTE values is set out in Part D of CRC 3C.

Section 3 - Adjustments driven by gearing levels and corporate debt interest costs ('tax clawback') - methodology

4.47 At the outset of the Price Control Period, modelling assumptions are made about financing requirements, gearing levels and corporate debt costs for the licensee's business. These assumptions result in modelled levels of tax-deductible interest costs and associated tax relief for the licensee.

4.48 If the licensee operates at a higher level of gearing than the modelled level, it stands to benefit from the tax value of higher levels of deductibility. Ofgem applies a mechanism that 'claws back' this benefit for consumers by updating the licensee's tax liability allowances using the methodology set out in this section. It should be noted that there is no provision to give additional tax allowances to the licensee if it chooses to operate at a level of gearing lower than the modelled one.

Determination and direction of revised TGIE values

4.49 As a function of each Annual Iteration Process for the PCFM, the expected (modelled) amount of tax deductible interest payable by the licensee is recalculated for each Regulatory Year in the Price Control Period. Recalculated interest figures are shown at row 233 on the Finance and Tax worksheet of the PCFM and it is the 'core' amount of interest associated with base revenue calculations that is relevant for tax clawback considerations and which is referred to in the remainder of this section.

4.50 After 30 September in each Regulatory Year, Ofgem will obtain the following values from a copy of the PCFM, in its state following the last completed Annual Iteration Process (and including any functional modifications under CRC 4A)[16]:

[16] The determination in respect of Regulatory Year t-2 will use the data subsisting immediately after the preceding Annual Iteration Process, which will have taken place by 30 November in

(i) the most recently modelled figure for tax-deductible interest payable by the licensee in Regulatory Year t-2; and

(ii) the licensee's indicative RAV balance in 2012/13 prices as at 31 March in Regulatory Year t-2.

4.51 The indicative RAV balance referred to in paragraph 4.50(ii) will then be inflated to year-end prices for Regulatory Year t-2, using the arithmetic average of the RPI data for March of Regulatory Year t-2 and April of Regulatory Year t-1.

4.52 Ofgem will obtain from the tax clawback worksheet in the licensee's price control cost information return the reported figures for:

(i) adjusted net debt as at 31 March in Regulatory Year t-2, in nominal prices; and

(ii) tax deductible net interest paid during Regulatory Year t-2, in nominal prices, measured on an accruals basis.

4.53 The tax-deductible net interest paid figure referred to in paragraph 4.52(ii) is ascertained on an accruals basis. The criteria for reporting the figures are set out in the RIGs.

4.54 The figures referred to in paragraph 4.52 will be deflated to 2012/13 prices using the approach set out in paragraph 1.7.

<u>Applicability tests</u>

4.55 Ofgem will use two tests: a gearing level test and a positive tax benefit test, to determine the TGIE value for the licensee in respect of Regulatory Year t-2.

Gearing level test

4.56 Ofgem will divide the licensee's net debt figure as at 31 March in Regulatory Year t-2 (see paragraph 4.52(i)) by the licensee's indicative PCFM RAV balance (see paragraph 4.51 as at 31 March in Regulatory Year t-2 to calculate the licensee's gearing ratio.

4.57 If the calculated gearing ratio established under paragraph 4.56, expressed as a percentage, is greater than the notional level of gearing for the licensee (shown as a fixed input value on the Inputs sheet of the PCFM) then the positive benefit test set

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Regulatory Year t-2. It will not therefore have been updated in respect of information reported by the licensee during Regulatory Year t-1. However, the annual re-performance of the determination for preceding years will ensure that finalised figures are subsequently taken into account.

out below will be performed. If the calculated gearing ratio is lower than the notional level of gearing, then the positive benefit test is not performed and the value of TGIE for Regulatory Year t-2 will be determined to be zero.

Positive benefit test

4.58 Ofgem will subtract the modelled figure for tax-deductible interest payable by the licensee in Regulatory Year t-2 (see paragraph 4.50(i)) from the licensee's reported figure for tax deductible net interest paid during Regulatory Year t-2 (see paragraphs 4.52(ii) and 4.53). For the purpose of this calculation, amounts of interest payable are treated as positive numbers.

4.59 If the result of the calculation set out in paragraph 4.58 is a positive value, demonstrating a positive benefit, then a tax clawback adjustment is applicable. In this case Ofgem will multiply the positive value by the corporation tax rate for Regulatory Year t-2 , being the rate held in the PCFM as a fixed input value. The result of this calculation will be determined to be the revised value of TGIE for Regulatory Year t-2 in 2012/13 prices. The functionality of the PCFM processes this positive value as a tax liability allowance reduction and/or addition to the licensee's regulatory tax losses balance (see paragraph 4.11).

4.60 If the result of the calculation set out in paragraph 4.58 is zero or a negative value, then no positive benefit has been demonstrated and no tax clawback adjustment is applicable. In this case, the value of TGIE for Regulatory Year t-2 will be determined to be zero.

4.61 TGIE can only be zero or positive; the functionality of the PCFM will produce a negative revenue adjustment in relation to a positive TGIE value.

Reperformance of TGIE determinations

4.62 Ofgem will reperform the determination of TGIE values for Regulatory Years prior to Regulatory Year t-2 to take account of:

- updated information reported by the licensee under the normal cost reporting information cycle;
- any restatements of cost information required under any provision of the licence; and
- any changes to the values referred to in paragraph 4.49 as a result of an Annual Iteration Process.

Interaction with unutilised regulatory tax losses

4.63 If for any Regulatory Year a tax clawback adjustment is applicable to the licensee but the licensee has no modelled profits subject to tax, then the TGIE value calculated under paragraph 4.59 is grossed up with reference to the corporation tax rate and added to the regulatory tax losses balance for the licensee. This is carried out automatically by functionality within the PCFM. This regulatory tax losses balance will be utilised against future taxable profit as set out in section 4 below.

Direction of TGIE values

4.64 The Authority will direct revised TGIE values in respect of Regulatory Year t-2 and where appropriate earlier Regulatory Years, by 30 November in Regulatory Year t-1, having given the licensee at least 14 days' notice of the values that it proposes to direct.

4.65 If, for any reason, net debt or tax deductible interest figures submitted by the licensee or the RAV used in the PCFM or modelled interest costs that have been used in determining TGIE values are subject to amendment, Ofgem will follow the procedure in the next paragraph to determine revisions to the TGIE values concerned for use in the next Annual Iteration Process.

4.66 Ofgem will re-perform the gearing level test and, if applicable, the positive tax benefit test, to determine any revisions to the TGIE value(s) for the Regulatory Year(s) to which the amended figures relate. For this purpose Ofgem will use a copy of the PCFM in its state following the last completed Annual Iteration Process to obtain an updated RAV value and modelled figure for tax deductible interest payable by the licensee.

4.67 If a revised TGIE value is directed for a Regulatory Year earlier than Regulatory Year t-2, any resultant changes to recalculated base revenue figures for years earlier than Regulatory Year t-2 calculated under the Annual Iteration Process will, subject to a Time Value of Money Adjustment, be brought forward and reflected in the calculation of the term MOD to be directed for Regulatory Year t. For the avoidance of doubt, such a revision will not have any retrospective effect on a previously directed value of the term MOD.

4.68 The procedure for the Authority's direction of revised TGIE values is set out in Part D of CRC 3C.

Section 4 - Processing of revised PCFM Variable Values under the Annual Iteration Process

TTE and TGIE values

4.69 Subject to paragraph 4.73, a positive TTE value will increase the recalculated base revenue figure for the Regulatory Year concerned by the same amount.

4.70 Subject to paragraph 4.73, a negative TTE value will decrease the recalculated base revenue figure for the Regulatory Year concerned by the equivalent amount.

4.71 Subject to paragraph 4.73, a positive TGIE value will decrease the recalculated base revenue figure for the Regulatory Year concerned by:

- the amount of the value[17]; and
- a ‘tax allowance on tax allowance’ factor calculated by functionality within the PCFM (see paragraph 4.6).

4.72 As noted at paragraph 4.61, TGIE values can only be zero or positive.

4.73 If there is any unutilised regulatory tax losses balance for the licensee, any change to recalculated base revenue under paragraph 4.69, 4.70 or 4.71 will be partially or fully abated to take account of that balance and the regulatory tax losses balance held within the PCFM will be updated accordingly.

4.74 For the avoidance of doubt, regulatory tax losses are not carried back and offset against tax liability allowances for Regulatory Years earlier than the Regulatory Year to which the regulatory tax loss concerned is attributable.

[17] Subject to a price base adjustment factor applied under the PCFM functionality (see paragraph 1.5 in chapter 1).

5. Corporate debt allowed percentage cost - financial adjustment methodology

Section 1 - Overview

5.1 The licensee's Opening Base Revenue Allowances include amounts to cover the efficient cost of raising finance for the distribution business from external sources. This is commonly referred to as the 'cost of capital'. Cost of capital allowances are calculated as a percentage return on the licensee's Regulatory Asset Value (RAV). The percentage represents Ofgem's estimate of the weighted average cost of capital (WACC)[18] for the distribution business. The Vanilla WACC is determined using a pre-tax allowed cost of corporate debt percentage, a post-tax real cost of equity percentage and a notional gearing percentage weighting.

5.2 Under the RIIO-ED1 price control, the cost of equity and notional gearing percentages are fixed for the whole of the Price Control Period. However, the corporate debt cost percentage is updated on an annual basis with reference to a trailing average index of debt costs. The update is effected through the Annual Iteration Process.

5.3 The basis for updating the cost of debt index percentage value by revising PCFM Variable Values for the licensee's allowed percentage cost of corporate debt ('CDE' values) is established in CRC 3C (Specified financial adjustments). CRC 3C requires revised CDE values to be determined in accordance with the methodology in this chapter.

Section 2 - Methodology for determining revised PCFM Variable Values for the cost of corporate debt

5.4 The ED1 Price Control Financial Model (PCFM) in its state as at 1 April 2015 includes opening CDE values for the licensee for every Regulatory Year of the Price Control Period.

5.5 Revised CDE values will be determined by Ofgem using the pounds sterling indices of bonds issued by non-financial institutions that have a remaining maturity of 10 or more years contained in the Markit iBoxx® database of bond market data.

5.6 Revised CDE values for Regulatory Year t and later Regulatory Years will be determined in accordance with the methodology set out below and directed in respect of each Annual Iteration Process.

[18] see Glossary

5.7 The steps to be followed for determining revised CDE values are:

Step 1

Establish the trading days period[19] to be used in relation to the particular Annual Iteration Process:

Annual Iteration Process taking place not later than:	Trading days period	Regulatory Year t from which revised EDE value applies
30 November 2015	1 November 2005 to 31 October 2015	2016/17
30 November 2016	1 November 2006 to 31 October 2016	2017/18
30 November 2017	1 November 2007 to 31 October 2017	2018/19
30 November 2018	1 November 2008 to 31 October 2018	2019/20
30 November 2019	1 November 2009 to 31 October 2019	2020/21
30 November 2020	1 November 2010 to 31 October 2020	2021/22
30 November 2021	1 November 2011 to 31 October 2021	2022/23

Step 2

For each day in the trading days period ascertained under Step 1, calculate the average of the annual yield figures from the following two iBoxx Sterling Non-Financial Indices:

(i). A 10+ index Markit iBoxx series reference: DE000A0JY837; and

(ii). BBB 10+ index Markit iBoxx series reference: DE000A0JZAH1

[19] Trading days as published in the Markit iBoxx® database

The above indices will be sourced from the Markit data service, to which Ofgem is subscribed. The A 10+ index covers bonds rated "A+", "A", and "A-" according to Markit iBoxx's published methodology and the BBB 10+ index covers bonds rated "BBB+", "BBB", and "BBB-". Each index only produces one annual yield figure for each day. Therefore, the average for each day ("iBoxx") is calculated as:

$$\frac{\text{"A 10+ index" annual yield figure for day + "BBB 10+ index" annual yield figure for day}}{2}$$

Step 3

For each day in the trading day period ascertained under Step 1, obtain a breakeven inflation figure for 10-year government-issued bonds by applying the following formula:

$$\pi = (1 + \mathrm{i})/(1 + \mathrm{r}) - 1$$

where:

π	is the Ofgem imputed breakeven inflation figure.
i	is the 'Yield From British Government Securities, 10 Year Nominal Zero Coupon' – series reference IUDMNZC expressed as a Decimal Percentage; and
r	is the 'Yield From British Government Securities, 10 Year Real Zero Coupon' – series reference IUDMRZC expressed as a decimal percentage.

The above series will be sourced from the statistics page on the Bank of England's website.[20] In the event that the above data series does not include an entry that exactly matches the date from the Markit iBoxx series, the nearest older entry is to be used.

Step 4

For each day in the trading day period ascertained under Step 1, deflate the average of the annual yield figures obtained under Step 2 using the Bank of England's breakeven inflation figure obtained under Step 3, using the following formula:

[20] http://www.bankofengland.co.uk

$$CoD = (1 + iBoxx) / (1 + \pi) - 1$$

where:

CoD is the daily real average of the annual yield figures;

$iBoxx$ is the average of the annual yield figures obtained under Step 2 expressed as a Decimal Percentage; and

π is the Ofgem imputed breakeven inflation figure obtained under Step 3.

This step converts the nominal bond yields in the iBoxx data to a real cost of debt value.

Step 5

Calculate the arithmetic average value of CoD across the trading days period ascertained under Step 1.

This average, expressed as a percentage and stated to two decimal places constitutes the revised PCFM Variable Value for the cost of corporate debt (CDE value) for Regulatory year t and subsequent Regulatory Years.

Non-availability of iBoxx or Bank of England data

5.8 If, for any reason, iBoxx data or Bank of England data is unavailable for an entire trading days period in time to determine revised PCFM Variable Values for the cost of corporate debt for any Annual Iteration Process then, for that Annual Iteration Process only, the trading days period concerned shall be deemed to have ended on the last trading day for which data has been published. If the data concerned is subsequently published, revised PCFM Variable Values for the affected Regulatory Years will be directed.

5.9 If, for any reason, the iBoxx or Bank of England series identified above ceases to be published, or if there is a material change in the basis of those indices, Ofgem will consult on alternatives, as well as on any reconciliation that may need to be undertaken between the above series and any replacements.

Section 3 - Use of revised PCFM Variable Values in the Annual Iteration Process

5.10 The Authority will direct revised CDE values for Regulatory Year t and subsequent Regulatory Years by no later than 30 November in each Regulatory Year t-1 in accordance with Part D of CRC 3C. Notice of proposed revised values will be given to the licensee at least 14 days before the date of the direction. Ofgem will provide the licensee with a copy of the spreadsheet used to calculate revised CDE values at the same time as giving the notice.

5.11 PCFM Variable Values for the cost of corporate debt will be directed together with all other types of PCFM Variable Value. Further information on the process is given in chapters 1 and 2.

5.12 The data and spreadsheet used to calculate revised CDE values will be published on the Ofgem Website by 30 November in each Regulatory Year.

6. Totex Incentive Mechanism – financial adjustment methodology

Section 1 - Totex Incentive Mechanism

6.1 The term Totex Incentive Mechanism means the incentive mechanism described in this section. The term Totex Incentive Mechanism Adjustment means an adjustment to the Totex figure used in the fast/slow money modelling of recalculated base revenue figures under the Annual Iteration Process.

6.2 The licensee's Opening Base Revenue Allowances will have been modelled on the basis that actual Totex expenditure levels are expected to equal allowed Totex expenditure levels (allowances). When actual (outturn) expenditure differs from allowances, for any Regulatory Year during the Price Control Period, the Totex Incentive Mechanism (TIM) provides for a defined sharing of the incremental amount (whether an overspend or under spend) between consumers and the licensee.

6.3 The ED1 Price Control Financial Model (PCFM) contains values for both actual Totex expenditure and allowed Totex expenditure levels that, as mentioned above, are initially equal to each other. Both the actual and allowed expenditure values contained in the PCFM can be varied for the purposes of applying the TIM through the Annual Iteration Process.

Actual Totex expenditure

6.4 Actual Totex expenditure is divided into seven subdivisions to facilitate varying tax pool treatments under the Annual Iteration Process calculations (see Table 6.2). Before making any change to the categories of costs included in each subdivision through the operation of standard condition 46 (Regulatory Instructions and Guidance) of the electricity distribution standard licence conditions, as part of the consultation process under Part C of that condition the Authority will consult with the licensee on whether, if such a change were made, it would also be appropriate to make changes to the financial treatment of such cost category under the Annual Iteration Process.

6.5 This chapter sets out the process by which the actual Totex expenditure values in the PCFM can be revised. It also describes the way in which revised figures for Totex flow into the calculation of the term MOD_t.

6.6 CRC 3B (Determination of PCFM Variable Values relating to actual Totex expenditure for Totex Incentive Mechanism Adjustments) provides for the Authority to determine revised PCFM Variable Values for the licensee relating to actual Totex expenditure levels. It also sets out the procedures for the direction of those values so that they can be used for the Annual Iteration Process.

Allowed Totex expenditure

6.7 The procedures for determining and directing revised PCFM Variable Values relating to allowed Totex expenditure levels are covered in the chapters of this handbook shown in Table 6.1 below:

Table 6.1 – Charge Restriction Conditions with provisions to revise PCFM Variable Values relating to allowed Totex expenditure levels

Charge Restriction Condition	PCFM Variable Value	Relating to	Handbook chapter
CRC 3F	UCHVP UCEPS UCSSW	Uncertain Costs High Value Projects Uncertain Costs Enhanced Physical Site Security Uncertain Costs Specified Street Works	7
CRC 3E	SMAE	Smart Meter Roll-out Costs	8
CRC 3G	LRRC	Load Related Expenditure	9
CRC 3J	VAA	Visual Amenity (undergrounding)	10
CRC 3H	WSCC	Worst Served Customers	11
CRC 3D	IRM	Innovation Roll-out	12
CRC 3K[21]	RE	Rail Electrification	12A

Description of the Totex Incentive Mechanism (TIM)

6.8 The TIM applies adjustments to the Totex figure used in the fast/slow money modelling of recalculated base revenue figures under the Annual Iteration Process. The adjustments reflect the amount of under or over expenditure by the licensee against Totex allowances and the relevant Totex Incentive Strength Rate (TISR) for the licensee. The TISR is a percentage figure specified in CRC 3B. It represents the post-tax percentage that the licensee bears in respect of an overspend against allowances or retains in respect of an under spend against allowances. The adjustment that is made to the Totex figures is the Funding Adjustment Rate (often called the 'sharing factor') which is calculated as (1 – TISR). Applying the Funding Adjustment Rate to the over (or under spend) gives the amount that is added to (or subtracted from) the Totex allowances that were used to calculate Opening Base Revenue Allowances.

[21] Applicable to WPD group licensees only – see paragraph 12A.1 of chapter 12A.

6.9 The TIM uses the licensee's actual Totex expenditure values for Regulatory Year t-2, reported to Ofgem in accordance with Regulatory Instructions and Guidance (RIGs). It adjusts allowed revenue via the MOD term with adjustments to MOD in year t relating to performance in year t-2. The incentive mechanism therefore operates with a two year lag.

6.10 Totex, once ascertained under the TIM, is apportioned using the Totex Capitalisation Rate for the licensee as:

- Fast Money – flowing directly to the recalculated base revenue figure for the Regulatory Year to which the allowed expenditure relates; and
- Slow Money - additions to the licensee's RAV in the Regulatory Year to which the allowed expenditure relates; the return on RAV and depreciation flows to the recalculated base revenue figure for the Regulatory year.

6.11 The Totex Capitalisation Rate for the licensee is specified at Appendix 1 to CRC 3B and is a fixed input value for the licensee in the PCFM. The rate is fixed for the Price Control Period.

6.12 Under the Annual Iteration Process, the effects of this modelling treatment (including any ancillary effects such as the impact on tax allowances) are reflected in the value of the term MOD_t.

Totex Incentive Mechanism - illustrative examples

6.13 Simplified, illustrative examples of the calculation approach are set out below:

Opening position:

allowed Totex expenditure:	110
assumed actual Totex expenditure:	110
over/under-spend:	nil
Totex amount for Fast/Slow Money treatment	110

Outturn position – scenario 1:

allowed Totex expenditure:	110
actual Totex expenditure	90
under spend:	20
incentive strength say 70% (or 0.7)	
Totex adjustment (1 - 0.7) X 20	6
Totex amount for Fast/Slow Money treatment 110 – 6	104

Outturn position – scenario 2:

allowed Totex expenditure:	110
actual Totex expenditure	120
overspend:	10
incentive strength say 70% (or 0.7)	
Totex adjustment (1 – 0.7) X 10	3
Totex amount for Fast/Slow Money treatment 110 + 3	113

6.14 The reduced Totex amount for fast/slow money treatment in scenario 1 represents a clawback of part of the under spend achieved by the licensee to benefit consumers. The increased Totex amount for fast/slow money treatment in scenario 2 represents a reimbursement of part of the overspend incurred by the licensee.

Application of the TIM under the Annual Iteration Process

6.15 Under the Annual Iteration Process, Ofgem will revise the opening values for actual Totex expenditure contained in the PCFM using the methodology set out in this chapter to reflect outturn values (in 2012/13 prices) reported annually by the licensee in accordance with the RIGs. The normal revision cycle will be:-

Regulatory Year t-2:	Totex expenditure incurred.
Regulatory Year t-1:	Outturn expenditure levels reported to Ofgem in accordance with the RIGs.
Regulatory Year t-1:	31 October – cut off date for data relating to actual Totex expenditure levels to be taken into account in determination of revised PCFM Variable Values.
Regulatory Year t-1:	Authority gives licensee at least 14 days' notice of proposed revisions to PCFM Variable Values.
Regulatory Year t-1:	Revised PCFM Variable Values for actual Totex expenditure determined and directed by the Authority by 30 November or as soon as reasonably practicable thereafter.
	Note that revised PCFM Variable Values for categories of allowed Totex expenditure will also have been determined/directed by 30 November where that is required by relevant Charge Restriction Conditions and associated chapters in this handbook (see Table 6.1).
Regulatory Year t-1:	Value for MOD_t directed by the Authority by 30 November.
Regulatory Year t:	Value for MOD_t effective in formula for licensee's Allowed Distribution Network Revenue.

6.16 Allowed Totex expenditure levels will be revised in accordance with the provisions of applicable Charge Restriction Conditions and the associated methodologies in this handbook. In instances where allowed Totex expenditure levels are revised for Regulatory Year t-1 or later, the PCFM will automatically update expected actual Totex expenditure levels to equivalent amounts for those years. This is consistent with the modelling rationale described in paragraph 2 of this chapter.

6.17 It should be noted that:

- each Annual Iteration Process reruns the TIM calculations for each Regulatory Year of the Price Control Period up to Regulatory Year t-2 (for later years the TIM is neutral – see paragraph 6.16);
- the outstanding effect of those calculations is reflected in the value of MOD_t; and
- the PCFM works in a 2012/13 price base and applies a Time Value of Money Adjustment when the revision of a PCFM Variable Value for a particular Regulatory Year is reflected in the value of the term MOD for a later Regulatory Year.

Total expenditure (Totex)

6.18 In summary Totex consists of all expenditure by the licensee with the exception of:

- costs relating to De Minimis Business activities as defined in Standard Condition 29 (Restriction of activity and financial ring-fencing of the Distribution Business) of the licence;
- costs relating to Directly Remunerated Services;
- pension deficit repair payments relating to the Pension Scheme Established Deficit and all post 1 April 2004 unfunded early retirement deficiency costs (ERDC);
- the non-cash element of current service pension costs charged to the income statement in accordance with accounting standards;
- statutory or regulatory depreciation and amortisation;
- profit margins from related parties (except where permitted);
- costs relating to rebranding a company's assets or vehicles following a change of trading name or logo;
- fines and penalties incurred by the licensee (including all tax penalties, fines and interest) except if Traffic Management Act penalty costs can be shown to be efficient;
- compensation payments made in relation to standards of performance;
- bad debt costs and recoveries (which are subject to separate review);
- costs relating to the network innovation allowance and network innovation competition;
- costs reported other than on a normal accruals basis;
- costs relating to pass-through items; and
- interest, other financing and corporation tax costs.

6.19 Further details on the reporting of expenditure items that are eligible for Totex treatment are given in the Regulatory instructions and guidance (RIGs) referred to in Standard Condition 46 (Regulatory instructions and guidance) of the licence.

6.20 It should be noted that CRC 5C (Directly Remunerated Services) and CRC 5F (Treatment of income from recovery in respect of Relevant Theft of Electricity) provide for the licensee to deduct amounts from its reported totals for Actual controllable opex expenditure (ACO values – see Table 6.2 below) for the purpose of sharing income specified in those conditions with consumers via the TIM.

Section 2 - Determination of PCFM Variable Value revisions for actual Totex expenditure

6.21 Subject to paragraph 3B.17 of CRC 3B, the Authority will, by 30 November in each Regulatory Year t-1, determine that the PCFM Variable Values for Regulatory Year t-2, shown in the first column of Table 6.2 below, should be revised to match the equivalent actual expenditure values (after deflation to 2012/13 prices) reported by the licensee in accordance with the RIGs.

6.22 In accordance with the processes set out in the licence and this handbook, the Authority can determine and direct revised PCFM Variable Values for actual Totex expenditure for Regulatory Years in the Price Control Period earlier than Regulatory Year t-2 for use in any Annual Iteration Process, but only where necessary to address a restatement of, or correction to, price control cost information submitted by the licensee.

Table 6.2 – PCFM Variable Values for actual Totex

PCFM Variable Value	Totex subdivision
ALC	Actual load-related capex expenditure
ANLR	Actual non-load-related capex expenditure – asset replacement
ANLO	Actual non-load-related capex - other
AFE	Actual faults expenditure
ARP	Actual 100% 'revenue pool' expenditure
ACO	Actual controllable opex expenditure
TRE	Actual tree cutting expenditure

6.23 Each of the terms set out in column 2 of Table 6.2 means the value shown against that term name in the licensee's completed annual cost reporting return for the relevant Regulatory Year submitted to Ofgem under the RIGs.

Section 3 - Notification and direction of revised PCFM Variable Values

6.24 The PCFM is a constituent part of CRC 4A (Governance of ED1 Price Control Financial Instruments). It has an input area for each licensee containing both fixed values and variable values. The variable values relating to actual Totex expenditure are shown in the PCFM Variable Values table 6.2 above.

6.25 During each Regulatory Year t-1, the Authority will determine revised PCFM Variable Values for the licensee relating to actual Totex expenditure. Part B of CRC 3B, requires the Authority to give the licensee at least 14 days' notice of any such proposed revisions, to allow for representations or objections. The Authority is required to have due regard to any representations or objections received from the licensee and to give reasons for its decisions in relation to them.

6.26 The Authority is required to direct any PCFM Variable Value revisions by 30 November in Regulatory Year t-1, so the notice of proposed values must be given no later than 15 November in the same year. The Authority will give notice of the proposed values as soon as practicably possible in Regulatory Year t-1.

6.27 Paragraph 3B.17 of CRC 3B says that if, for any reason in any Regulatory Year t-1, the Authority does not make a direction in relation to revised actual Totex values by 30 November, it will direct the value or values concerned as soon as is reasonably practicable.

6.28 The Authority will then carry out the Annual Iteration Process in accordance with CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model) - see Chapter 1.

7. Uncertain costs allowed expenditure – financial adjustment methodology

Section 1 - Overview

7.1 At the outset of the Price Control Period, levels of allowed expenditure for the following categories of uncertain costs were set on a provisional basis because of uncertainties about requirements:

(a) High Value Project Costs;

(b) Enhanced Physical Site Security Costs; and

(c) Specified Street Works Costs.

The licensee's Opening Base Revenue Allowances were modelled using the provisional amounts.

7.2 CRC 3F (Arrangements for the recovery of uncertain costs) sets out the basis on which opening levels of allowed expenditure on uncertain cost activities can be revised through 'relevant adjustments'. It also sets out how the PCFM Variable Value associated with each uncertain cost activity should be revised.

7.3 At the start of the Price Control Period on 1 April 2015, the PCFM Variable Value for the licensee for each uncertain cost activity for each Regulatory Year of the Price Control Period was set to equal the level of allowed expenditure referred to in paragraph 7.1. These were the levels that were used to derive the licensee's Opening Base Revenue Allowances and, in respect of High Value Projects Costs and Enhanced Physical Site Security Costs, they are set out against the licensee's name in the tables contained in Appendices 1 and 2 to CRC 3F. Opening levels of allowed expenditure on Specified Street Works Costs are set at zero. The PCFM Variable Values for the uncertain cost categories can be revised so that they continue to match allowed expenditure levels following any relevant adjustments under the provisions of CRC 3F and this chapter.

7.4 The categories of uncertain cost activities together with their associated PCFM Variable Values are shown in Table 7.1. Under the Annual Iteration Process, allowed expenditure levels for uncertain cost activities represented by PCFM Variable Values, as revised, interact with actual expenditure information so that appropriate Totex Incentive Mechanism Adjustments are reflected in the calculation of values for the term MOD.

Table 7.1 – Uncertain cost activities

Uncertain cost category	PCFM Variable Value name	Charge Restriction Condition
High Value Project Costs	UCHVP	CRC 3F
Enhanced Physical Site Security Costs	UCEPS	
Specified Street Works Costs	UCSSW	

7.5 PCFM Variable Values relating to uncertain cost activities are stated in 2012/13 prices, consistent with the price base used in the ED1 Price Control Financial Model (PCFM) and the values for the term MOD. The allocation of allowed expenditure for uncertain cost activities into the Totex sub-divisions referred to in Table 6.2 in Chapter 6 is handled automatically under the Annual Iteration Process using fixed attribution rates contained in the PCFM.

7.6 CRC 3F provides for:

- the licensee to propose revisions to levels of allowed expenditure (relevant adjustments), but only during an application window specified in CRC 3F (see paragraph 7.8);
- the determination of relevant adjustments by the Authority; and
- the deeming of relevant adjustments in circumstances specified in CRC 3F,

in respect of each uncertain cost activity.

7.7 CRC 3F also provides for the Authority to propose relevant adjustments, in relation to High Value Project Costs during a notice window after the end of the Price Control Period, specified in CRC 3F (see paragraph 7.9).

7.8 The application window during which the licensee can propose relevant adjustments runs from 1 May 2019 to 31 May 2019.

7.9 The notice window during which the Authority can give notice of proposed relevant adjustments in respect of High Value Project Costs runs from 1 December 2023 to 31 December 2023. This window is after the end of the Price Control Period whose last day is 31 March 2023.

7.10 CRC 3F and this chapter set out the basis on which relevant adjustments can be proposed by the licensee and the Authority. However, this chapter only deals with:

(a) determinations with respect to relevant adjustments proposed by the licensee; and

(b) the determination and direction of revised PCFM Variable Values to give effect to determinations made under subparagraph (a).

7.11 Relevant adjustments proposed by the Authority will be addressed through adjustment mechanisms to be included in the RIIO-ED2 price control arrangements for the licensee and are not dealt with further under this chapter.

Determinations and directions with respect to relevant adjustments proposed by the licensee

7.12 The Authority will determine the relevant adjustments to the licensee's levels of allowed expenditure with respect to proposals made by the licensee within four months of the close of the application window referred to in paragraphs 7.8 – ie by 30 September 2019 unless the timetable is extended by the Authority in the circumstances and to the extent prescribed in CRC 3F. The determination of relevant adjustments will be made in accordance with the methodologies set out in sections 2, 3 and 4, as applicable, of this chapter.

7.13 If the Authority has not determined a relevant adjustment in relation to a proposal duly made by the licensee within four months of the close of the application window, and the proposal has not been withdrawn, then the relevant adjustment will be deemed to have been made.

7.14 CRC 3F also provides for the associated PCFM Variable Values to be revised for appropriate Regulatory Years in the Price Control Period so that relevant adjustments are reflected in the recalculation of base revenue figures for the licensee under the Annual Iteration Process for the ED1 Price Control Financial Model. It also sets out the procedures for the direction of revised PCFM Variable Values by the Authority.

General principles applicable to uncertain cost adjustment mechanisms

7.15 CRC 3F states that a proposed relevant adjustment to the level of allowed expenditure on an uncertain cost activity must:

- be based on information about the actual or forecast level of efficient expenditure on the uncertain cost activity that was either unavailable or did not qualify for inclusion when the licensee's Opening Base Revenue Allowance was derived;
- take account of any relevant adjustments previously determined under CRC 3F;
- constitute a material amount as specified for the licensee in Appendix 1, 2 or 3 (as the case may be) of CRC 3F;
- relate to costs incurred or expected to be incurred after 1 April 2015; and

- constitute an adjustment to allowed expenditure that (excluding any Time Value of Money Adjustment) cannot be made under the provisions of any other condition of the licence.

7.16 The stipulation that proposals must take account of any previously determined relevant adjustments is intended to ensure that relevant costs are not ignored on the one hand, or double counted on the other.

7.17 The PCFM Variable Value for any particular Regulatory Year, as revised represents the total amount of allowed Totex expenditure (in 2012/13 prices) for the uncertain cost activity concerned for that Regulatory Year.

Section 2 – Methodology for determining relevant adjustments in respect of High Value Project Costs

The uncertainty mechanism for High Value Project Costs

7.18 For the purposes of CRC 3F and this chapter, the term High Value Project Costs means a scheme of works and the associated costs incurred, or expected to be incurred, by the licensee on any investment project with respect to its Distribution System that is reasonably forecast to cost the licensee £25 million or more (in 2012/13 prices) during the Price Control Period, and for which clear outputs, a needs case, and a statement of costs have been provided and in respect of which there is no other mechanism for the adjustment of allowed expenditure levels during the Price Control Period.

7.19 Some High Value Project Costs were taken into account in the calculation of the licensee's Opening Base Revenue Allowances. The uncertainty mechanism does not provide for any further adjustment to the licensee's allowed expenditure in respect of these projects, but they remain relevant in two respects:

(i) Allowed expenditure (included in Opening Base Revenue Allowances) and actual efficient expenditure are taken into account in assessing whether the overall materiality threshold has been reached.

(ii) The Authority will review the licensee's achievement of outputs associated with High Value Project Costs when determining any relevant adjustment proposed by the licensee under CRC 3F.

Overall materiality threshold

7.20 An overall materiality threshold applies in respect of relevant adjustments for High Value Project Costs. The materiality threshold for the licensee, in 2012/13 prices, is specified in the table entitled 'Opening level of allowed expenditure for High Value Project Costs and the material amount for each licensee' in Appendix 1 to CRC 3F.

7.21 The amount to be tested against the materiality threshold in respect of a proposed increase in allowed expenditure levels will be determined in 2012/13 prices as:

(i) the total of the licensee's actual and forecast efficient expenditure on:

- High Value Project Costs included in the calculation of the licensee's Opening Base Revenue Allowances (if any); and
- additional High Value Project Costs included in any proposal by the licensee for a relevant adjustment,

for all Regulatory Years in the Price Control Period,

less

(ii) the total amount of allowed expenditure included in the calculation of the licensee's Opening Base Revenue Allowances in respect of High Value Project Costs,

for all Regulatory Years in the Price Control Period.

7.22 If the materiality threshold is passed, it is not further taken into account in the determination of relevant adjustments to allowed expenditure levels. If the materiality threshold is not passed, then any relevant adjustment proposal will be rejected.

7.23 If the materiality threshold is not passed the 'Strategy decision for the RIIO-ED1 electricity distribution price control – Uncertainty mechanisms' specifies how costs will be treated (eg whether they are subject to the TIM and logging up). [22]

Determination of a relevant adjustment proposed by the licensee

7.24 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of High Value Project Costs it will take the steps set out below to determine whether the proposed adjustment should be confirmed, rejected or amended.

Determination steps

(i) The Authority will check whether the Notice has been received during the application window referred to in paragraph 7.8. If the Notice has been received before 1 May 2019 the Authority will notify the licensee that the Notice has been submitted too early and should be resubmitted during May 2019. If the Notice has been received after 31 May 2019 the Authority will notify the licensee that the Notice has

[22] https://www.ofgem.gov.uk/ofgem-publications/47070/riioed1decuncertaintymechanisms.pdf

been received too late and that a relevant adjustment will not be determined.

(ii) The Authority will check in respect of each of the projects included in the relevant adjustment proposal whether:

a. costs incurred, or expected to be incurred, are reasonably forecast to cost the licensee £25 million or more;

b. each of the requirements set out in paragraphs 3F.8 and 3F.9 of CRC 3F have been met (except for the requirement in respect of a material amount – see step (iv));

c. the proposal by the licensee represents an efficient level of expenditure;

d. a need for the project to be carried out has been established; and

e. measurable outputs for the project have been identified.

(iii) The Authority will decide whether it requires any further information from the licensee in order to make a determination and, if it decides that further information is required, it will give Notice of that requirement to the licensee as soon as reasonably practicable and will allow such time for provision of that information as appropriate, taking account of:

a. the amount of time that the licensee will reasonably require to compile the information;

b. the four month period for determinations referred to in paragraph 3F.12 of CRC 3F; and

c. the need to consult the licensee on its proposed determination.

It should be noted that the issuing of a Notice as described above does not preclude the Authority from making further information, analysis and reformatting requests in respect of the proposal.

(iv) The Authority will check whether the overall materiality threshold has been passed in accordance with paragraphs 7.20 and 7.21. If it has not, the proposed relevant adjustment will be rejected.

(v) The Authority will consider whether the outputs associated with the High Value Project Costs included in the calculation of Opening Base Revenue Allowances have been or will be achieved.

(vi) Having carried out steps (i) to (v) above, the Authority will provisionally determine whether to:

a. reject the relevant adjustment proposed by the licensee;

b. confirm the relevant adjustment proposed by the licensee; or

c. amend the relevant adjustment proposed by the licensee.

If the Authority decides to amend or confirm the licensee's proposal it will, in respect of each of the projects included in the relevant adjustment proposal, provisionally determine the adjustments to allowed expenditure that should be made and the Regulatory Years to which those adjustments should be applied.

If the Authority decides to reject the licensee's proposal it will provisionally determine that no adjustments to allowed expenditure should be made.

(vii) The Authority will consult the licensee on its provisional determination, allowing the licensee at least 28 days in which to respond.

(viii) The Authority will consider any consultation responses from the licensee and will then make a relevant adjustment determination.

7.25 A determination by the Authority that confirms or amends a relevant adjustment proposed by the licensee in respect of High Value Project Costs will specify:

(a) the Regulatory Years to which the determination applies; and

(b) the revised total amounts of allowed Totex expenditure (in 2012/13 prices) for each of the Regulatory Years.

7.26 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of High Value Project Costs and does not make an relevant adjustment determination within the relevant time limit prescribed in CRC 3F, and the proposal has not been withdrawn, then paragraph 3F.19 of CRC 3F stipulates that the adjustments will be deemed to have been made.

7.27 The Authority will apply any relevant adjustment determined or deemed to have been made in the determination of revised UCHVP values under part 5 of this chapter.

Section 3 – Methodology for determining relevant adjustments in respect of Enhanced Physical Site Security Costs

The uncertainty mechanism for Enhanced Physical Site Security Costs

7.28 The term Enhanced Physical Site Security Costs means costs incurred, or expected to be incurred, by the licensee for the purposes of implementing any formal recommendation or requirement of the Secretary of State to enhance the physical security of any of the sites that form part of the licensee's Distribution System as may be further clarified in the Regulatory instructions and Guidance (RIGs). This definition is set out in CRC 3F.

7.29 Requirements for Enhanced Physical Site Security related to some sites were taken into account in the calculation of the licensee's Opening Base Revenue Allowances. The uncertainty mechanism only provides for adjustments to the licensee's allowed expenditure in the Price Control Period in respect of sites not included as part of ex ante allowances.

Overall materiality threshold

7.30 An overall materiality threshold applies in respect of relevant adjustments for Enhanced Physical Site Security Costs. The materiality threshold for the licensee, in 2012/13 prices, is specified in the table in Appendix 2 to CRC 3F.

7.31 If the materiality threshold is passed, it is not further taken into account in the determination of relevant adjustments to allowed expenditure levels. If the materiality threshold is not passed, then any relevant adjustment proposal will be rejected. However, in that case, costs reported by the licensee in accordance with the RIGs will be deferred up for consideration in respect of the RIIO-ED2 price control arrangements.

7.32 If the materiality threshold is not passed the 'Strategy decision for the RIIO-ED1 electricity distribution price control – Uncertainty mechanisms' specifies how costs will be treated (eg whether they are subject to the TIM and logging up).[23]

Determination of a relevant adjustment proposed by the licensee

7.33 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of Enhanced Physical Site Security Costs it will take the steps set out below to determine whether the proposed adjustment should be confirmed, rejected or amended.

Determination steps

(i) The Authority will check whether the Notice has been received during the application window referred to in paragraph 7.8. If the Notice has been received before 1 May 2019 the Authority will notify the licensee that the Notice has been submitted too early and should be resubmitted during May 2019. If the Notice has been received after 31 May 2019 the Authority will notify the licensee that the Notice has been received too late and that a relevant adjustment will not be determined.

(ii) The Authority will check in respect of each of the sites included in the relevant adjustment proposal whether:

 a. each of the requirements set out in paragraphs 3F.8 and 3F.9 of CRC 3F has been met (except for the requirement in respect of a material amount – see step (iv));

 b. works that have been carried out, or that are to be carried out, meet the security requirements specified in the relevant recommendation or requirement of the Secretary of State; and

[23] https://www.ofgem.gov.uk/ofgem-publications/47070/riioed1decuncertaintymechanisms.pdf

c. works that have been carried out, or that are to be carried out, represent an efficient level of expenditure.

In making the checks at points 'a.', 'b.' and 'c.', the Authority will take into account the results of any audit of the licensee's Enhanced Physical Site Security activity and the results of any benchmarking review that the Authority has carried out.

(iii) The Authority will decide whether it requires any further information from the licensee in order to make a determination and, if it decides that further information is required it will give Notice of that requirement to the licensee as soon as reasonably practicable and will allow such time for provision of that information as appropriate, taking account of:

a. the amount of time that the licensee will reasonably require to compile the information;

b. the four month period for determinations referred to in paragraph 3F.12 of CRC 3F; and

c. the need to consult the licensee on its proposed determination.

It should be noted that the issuing of a Notice as described above does not preclude the Authority from making further information, analysis and reformatting requests in respect of the proposal.

(iv) The Authority will check whether the overall materiality threshold has been passed in accordance with paragraph 7.30. If it has not, the proposed relevant adjustment will be rejected.

(v) Having carried out steps (i) to (iv) above, the Authority will provisionally determine whether to:

a. reject the relevant adjustment proposed by the licensee;

b. confirm the relevant adjustment proposed by the licensee; or

c. amend the relevant adjustment proposed by the licensee.

If the Authority decides to amend or confirm the licensee's proposal it will, in respect of each of the sites included in the relevant adjustment proposal, provisionally determine the adjustments to allowed expenditure that should be made and the Regulatory Years to which those adjustments should be applied.

If the Authority decides to reject the licensee's proposal it will provisionally determine that no adjustments to allowed expenditure should be made.

(vi) The Authority will consult the licensee on its provisional determination, allowing the licensee at least 28 days in which to respond.

(vii) The Authority will consider any consultation responses from the licensee and will then make a relevant adjustment determination.

7.34 A determination by the Authority that confirms or amends a relevant adjustment proposed by the licensee in respect of Enhanced Physical Site Security Costs will specify:

(a) the Regulatory Years to which the determination applies; and

(b) the revised total amounts of allowed expenditure (in 2012/13 prices) for each of the Regulatory Years.

7.35 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of Enhanced Physical Site Security Costs and does not make an relevant adjustment determination within the relevant time limit prescribed in CRC 3F, and the proposal has not been withdrawn, then paragraph 3F.19 of CRC 3F stipulates that the adjustments will be deemed to have been made.

7.36 The Authority will apply any relevant adjustment determined or deemed to have been made in the determination of revised UCEPS values under part 5 of this chapter.

Section 4 – Methodology for determining relevant adjustments in respect of Specified Street Works Costs

The uncertainty mechanism for Specified Street Works Costs

7.37 The term Specified Street Works Costs means costs incurred, or expected to be incurred, by the licensee in complying with obligations or requirements arising under any order or regulations made under Part 3 of the Traffic Management Act 2004 (or, in Scotland, the Transport (Scotland) Act 2005) that impose a permit scheme and comprise:

(a) permit fee costs;

(b) one-off set up costs;

(c) additional administrative costs arising from the introduction of permit schemes; and

(d) additional costs arising from the introduction of permit conditions,

as further clarified in the RIGs. This definition is set out in CRC 3F.

7.38 The uncertainty mechanism provides for relevant adjustments in respect of efficient costs that were not included in the calculation of the licensee's Opening Base Revenue Allowances.

Overall materiality threshold

7.39 An overall materiality threshold applies in respect of relevant adjustments for Specified Street Works Costs. The materiality threshold for the licensee, in 2012/13 prices, is specified in the table in Appendix 3 to CRC 3F.

7.40 If the materiality threshold is passed, it is not taken further into account in the determination of relevant adjustments to allowed expenditure levels. If the materiality threshold is not passed, then any relevant adjustment proposal will be rejected. This is without prejudice to any consideration of costs in respect of arrangements for the RIIO-ED2 price control.

7.41 If the materiality threshold is not passed the 'Strategy decision for the RIIO-ED1 electricity distribution price control – Uncertainty mechanisms' specifies how costs will be treated (eg whether they are subject to the TIM and logging up).[24]

Determination of a relevant adjustment proposed by the licensee

7.42 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of Specified Street Works Costs it will take the steps set out below to determine whether the proposed adjustment should be confirmed, rejected or amended.

Determination steps

(i) The Authority will check whether the Notice has been received during the application window referred to in paragraph 7.8. If the Notice has been received before 1 May 2019 the Authority will notify the licensee that the Notice has been submitted too early and should be resubmitted during May 2019. If the Notice has been received after 31 May 2019 the Authority will notify the licensee that the notice has been received too late and that a relevant adjustment will not be determined.

(ii) The Authority will check whether

   a. each of the requirements set out in paragraphs 3F.8 and 3F.9 of CRC 3F has been met (except for the requirement in respect of a material amount – see step (iv));

   b. the licensee has, or will be able to, provide 12 months' worth of costs data to support its proposal; and

   c. the proposal by the licensee represents an efficient level of expenditure.

(iii) The Authority will decide whether it requires any further information from the licensee in order to make a determination and, if it decides that further information is required it will give Notice of that requirement to the licensee as soon as reasonably practicable and will

[24] https://www.ofgem.gov.uk/ofgem-publications/47070/riioed1decuncertaintymechanisms.pdf

allow such time for provision of that information as appropriately takes account of:

a. the amount of time that the licensee will reasonably require to compile the information;

b. the four month period for determinations referred to in paragraph 3F.12 of CRC 3F; and

c. the need to consult the licensee on its proposed determination.

It should be noted that the issuing of a Notice as described above does not preclude the Authority from making further information, analysis and reformatting requests in respect of the proposal.

(iv) The Authority will check whether the overall materiality threshold has been passed in accordance with paragraph 7.39. If it has not, the proposed relevant adjustment will be rejected.

(v) In reviewing the level of permit fee costs included in any relevant adjustment proposal the Authority will take into account:

a. the number of permits that the licensee has been or will be required to obtain in respect of works schemes; and

b. the costs of permits that the licensee has been or will be required to obtain.

(vi) In reviewing the level of system set up costs and additional administration costs included in any relevant adjustment proposal, the Authority will take into account the results of any benchmarking or other comparative analysis that it has carried out or commissioned.

(vii) Having carried out steps (i) to (vi) above, the Authority will provisionally determine whether to:

a. reject the relevant adjustment proposed by the licensee;

b. confirm the relevant adjustment proposed by the licensee; or

c. amend the relevant adjustment proposed by the licensee.

If the Authority decides to amend or confirm the licensee's proposal it will provisionally determine the adjustments to the licensee's allowed expenditure that should be made and the Regulatory Years to which those adjustments should be applied.

If the Authority decides to reject the licensee's proposal it will provisionally determine that no adjustments to allowed expenditure should be made.

(viii) The Authority will consult the licensee on its provisional determination, allowing the licensee at least 28 days in which to respond.

(ix) The Authority will consider any consultation responses from the licensee and will then make a relevant adjustment determination.

7.43 A determination by the Authority that confirms or amends a relevant adjustment proposed by the licensee in respect of Specified Street Works Costs will specify:

(a) the Regulatory Years to which the determination applies; and

(b) the revised total amounts of allowed Totex expenditure (in 2012/13 prices) for each of the Regulatory Years.

7.44 If the Authority receives Notice of a proposed relevant adjustment from the licensee in respect of Specified Street Works Costs and does not make an relevant adjustment determination within the relevant time limit prescribed in CRC 3F, and the proposal has not been withdrawn, then paragraph 3F.19 of CRC 3F stipulates that the adjustments will be deemed to have been made.

7.45 The Authority will apply any relevant adjustment determined or deemed to have been made in the determination of revised UCSSW values under part 5 of this chapter.

Section 5 – Determination, notification and direction of revised PCFM Variable Values for uncertain cost activities

7.46 CRC 3F specifies that the PCFM Variable Value for the licensee for each uncertain cost activity as at 1 April 2015 (ie before any revisions to PCFM Variable Values have been made) for each Regulatory Year of the Price Control Period will be equal to the level of allowed Totex expenditure that was used in the calculation of the licensee's Opening Base Revenue Allowances. It also specifies that revised PCFM Variable Values relating to uncertain cost activities will be directed by the Authority by 30 November in Regulatory Year 2019/20 (ie by 30 November 2019).

Determination of revised PCFM Variable Values

7.47 On or before 31 October 2019, Ofgem will check to see whether any determinations of relevant adjustments have been made or have been deemed to have been made in respect of

(a) High Value Project Costs;

(b) Enhanced Physical Site Security Costs; and

(c) Specified Street Works Costs,

that change the level of allowed expenditure for the licensee and that have not previously been taken fully into account in the determination of revisions to the associated PCFM Variable Value for the Regulatory Year or Years concerned.

7.48 If any determination of a relevant adjustment has not previously been taken into account, the Authority will determine that the associated PCFM Variable Value (as set out in the next paragraph) for the Regulatory Year or Years concerned is to be revised so that it equals the revised total amount of allowed Totex expenditure (in 2012/13 prices) specified in the relevant adjustment determination.

7.49 The PCFM Variable Values referred to in paragraph 7.48 are:

(a) UCHVP values in respect of High Value Project Costs;

(b) UCEPS values in respect of Enhanced Physical Site Security Costs; and

(c) UCSSW values in respect of Specified Street Works Costs.

Notification and direction of revised PCFM Variable Values

7.50 The Authority will give Notice of any revisions to UCHVP, UCEPS and UCSSW values that it proposes to direct by 15 November in Regulatory Year 2019/20, being at least 14 days before the deadline date of 30 November for the direction of revised PCFM Variable Values. The Notice will confirm that:

- any revised PCFM Variable Value determinations have been made in accordance with Part B of CRC 3F, which cross refers to this chapter of this handbook; and
- the licensee has 14 days from the date of the Notice in which to make any representations concerning the proposed PCFM Variable Value revisions.

7.51 The Authority is required to have due regard to any representations or objections made by the licensee and to give its reasons for any decisions in relation to them.

7.52 The Authority will only direct PCFM Variable Value revisions for uncertain cost activities in accordance with the provisions of CRC 3F. However, the overall direction of PCFM Variable Value revisions in each Regulatory Year t-1 will include a copy of the PCFM Variable Values Table for the licensee showing the state of all PCFM Variable Values including those relating to uncertain cost activities.

Delay in direction of revised PCFM Variable Values

7.53 If the procedures set out in CRC 3F and this chapter call for the Authority to direct revised PCFM Variable Values for one or more uncertain cost categories by 30 November 2019, and the Authority does not make such a direction, then CRC 3F requires that the values concerned should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t for the licensee under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

8. Smart Meter Roll-out Costs- financial adjustment methodology

Section 1 - Overview

8.1 A large scale roll-out of smart meters will be carried out by electricity suppliers during the Price Control Period. The licensee will be required to intervene (make "Smart Meter Interventions") in a significant number of Smart Meter Installations where work on Distribution System assets is required to facilitate the fitting of smart meters. The provisions of CRC 3E (Smart Meter Roll-out Costs) and the methodology in this chapter will ensure that the licensee's level of allowed Totex expenditure for Smart Meter Roll-out Costs is commensurate with efficient management of that activity.

8.2 Opening levels of allowed Totex expenditure for Smart Meter Roll-out Costs for each Regulatory Year of the Price Control Period were set on a provisional basis because of uncertainties surrounding the number of Smart Meter Installations that would take place and the number of Smart Meter Installations where the licensee would be required to make a Smart Meter Intervention (see also paragraphs 8.5 and 8.17 below). The licensee's Opening Base Revenue Allowances were modelled using these provisional amounts.

8.3 At the outset of the Price Control Period on 1 April 2015, the PCFM Variable Values associated with Smart Meter Roll-out Costs for the licensee (SMAE values) for each Regulatory Year of the Price Control Period were set to equal the level of allowed Totex expenditure referred to in paragraph 8.2. These were the levels that were used in calculating the licensee's Opening Base Revenue Allowances and they are set out against the licensee's name in Table 1 in Part A of CRC 3E.

8.4 CRC 3E sets out the basis on which levels of allowed expenditure on Smart Meter Roll-out Costs and associated SMAE values are to be revised during the Price Control Period.

8.5 Opening levels of allowed expenditure and SMAE values for Regulatory Years 2021/22 and 2022/23 were set at zero and:

(a) for Regulatory Year 2021/22 are not subject to revision during the Price Control Period (unless the Authority directs otherwise under paragraph 3E.9 of CRC 3E); and

(b) for Regulatory Year 2022/23 are subject to revision only in respect of the tapering factor true-up referred to in section 3 below (unless the Authority directs otherwise under paragraph 3E.10 of CRC 3E).

8.6 Levels of allowed expenditure and SMAE values for Regulatory Years from 2015/16 to 2020/21 are to be revised using the formula set out in Part B of CRC 3E. The calculation under the formula uses:

(a) the total number of Smart Meter Interventions in the licensee's Distribution Services Area (DSA) during Regulatory Year t-2; and

(b) the licensee's allowed unit cost of Smart Meter Interventions, in 2012/13 price, specified for the licensee in Appendix 1 of CRC 3E (and subject to revision by direction of the Authority under paragraph 3E.8 of CRC 3E).

8.7 Under the Annual Iteration Process, allowed expenditure levels on Smart Meter Roll-out Costs, represented by SMAE values, as revised, interact with actual expenditure information so that appropriate Totex Incentive Mechanism Adjustments are reflected in the calculation of values for the term MOD (see chapter 6).

8.8 In the remainder of this chapter references to the revision of SMAE values are to be read as including revision of the associated allowed expenditure levels.

Section 2 - Determination of revised SMAE values for Regulatory Years 2015/16 to 2021/22

8.9 The formula contained in Part B of CRC 3E is expressed as calculating SMAE values for Regulatory Year t-2 and this is explained in paragraphs 8.10 to 8.12 below.

8.10 The Authority will determine a revised SMAE value for Regulatory Year 2015/16 by applying the number of Smart Meter Interventions the licensee was required to make during Regulatory Year 2015/16 to the formula contained in Part B of CRC 3E. This determination, and the direction of the revised SMAE value for 2015/16 will take place by 30 November 2016 for use in the Annual Iteration Process that will take place by the same date. This Annual Iteration Process will produce the value of the term MOD for Regulatory Year 2017/18 which, under the temporal convention set out in paragraphs 1.8 to 1.10 of chapter 1, is Regulatory year t. Therefore, in the context of this Annual Iteration Process, Regulatory Year 2015/16 is Regulatory year t-2.

8.11 The SMAE value for Regulatory Years 2016/17 to 2020/21 and the expected timetable for the revision of SMAE values and their use in the Annual Iteration Process is set out in Table 8.1 below.

8.12 The SMAE value for Regulatory Year 2021/22 will be zero, unless following consultation with the licensee, the Authority directs that it should be a different value to take account of circumstances unforeseen at ED1 Final Determination.

Table 8.1 – Routine timing for determination and use of revised SMAE values for Regulatory Years 2015/16 to 2020/21

Regulatory Year t-2 during which activity takes place	Revised SMAE value for Regulatory Year t-2 determined by	Reflected in value of MOD for Regulatory Year
2015/16	30 Nov 2016	2017/18
2016/17	30 Nov 2017	2018/19
2017/18	30 Nov 2018	2019/20
2018/19	30 Nov 2019	2020/21
2019/20	30 Nov 2020	2021/22
2020/21	30 Nov 2021	2022/23

8.13 Notwithstanding the routine timings set out in Table 8.1, the Authority may, in respect of any Annual Iteration Process, determine that the SMAE value for a Regulatory Year earlier than Regulatory Year t-2 should be revised, if that is necessary because the licensee has been required to restate the number of Smart Meter Interventions it was required to make in the Regulatory Year concerned. In those circumstances the revision to the SMAE value concerned would again be determined using the formula contained in Part B of CRC 3E, but using the restated Smart Meter Interventions number for the Regulatory Year in question.

Section 3 - Determination of revised SMAE value for Regulatory Year 2022/23

Tapering factor true-up

8.14 Revision of the SMAE value for Regulatory Year 2022/23 gives effect to a true-up mechanism that:

(a) corrects for any under or over statement of the numbers of Smart Meter Interventions used in the determination of SMAE values for Regulatory Years 2015/16 to 2020/21 under Part B of CRC 3E and section 2 of this chapter; and

(b) applies a tapering factor that was incorporated to recognise economies of scale and to incentivise the licensee to minimise intervention levels.

8.15 The outcome of the true-up mechanism and its impact on the revised SMAE value for Regulatory Year 2022/23 will be determined using the formula set out in Part C of CRC 3E. The calculation under the formula uses:

(a) the number of Smart Meter Interventions in each Regulatory Year from 2015/16 to 2020/21;

(b) the total number of Smart Meter Interventions in the licensee's DSA in each Regulatory Year from 2015/16 to 2020/21;

(c) the licensee's allowed unit cost of Smart Meter Interventions, in 2012/13 price, specified for the licensee in Appendix 1 of CRC 3E (which is subject to revision by direction of the Authority under paragraph 3E.8 of CRC 3E);

(d) the tapering factors for the licensee that are specified in Table 2 contained in Part C of CRC 3E (which is subject to revision by direction of the Authority under paragraph 3E.10 of CRC 3E); and

(e) the latest SMAE values directed for Regulatory Years 2015/16 to 2020/21.

8.16 The Authority will determine a revised SMAE value for Regulatory Year 2022/23 by 30 November 2021 for use in the Annual Iteration Process that will take place by 30 November 2021[25]. This Annual Iteration Process will produce the value of the term MOD for Regulatory Year 2022/23. This timing is set out in Table 8.2 below.

Table 8.2 – Timing for determination and use of a revised SMAE value for Regulatory Year 2022/23

Regulatory Year t-2 during which activity takes place	Revised SMAE value for Regulatory Year 2022/23 determined by	Reflected in value of MOD for Regulatory Year
-	30 Nov 2021	2022/23

8.17 Paragraph 3E.10 of CRC 3E specifies that the Authority can direct that the SMAE value for Regulatory Year 2022/23 is to be revised on a different basis.

Regulatory Years 2021/22 and 2022/23

8.18 It is expected that the roll-out of smart meters by electricity suppliers will be completed by the end of Regulatory Year 2020/21. Consequently there is no routine provision in CRC 3E or this chapter for SMAE values for Regulatory Years 2021/22 and 2022/23 to be revised in respect of Smart Meter Interventions in those years.

[25] Note that "SMAE value for Regulatory Year 2022/23" means the SMAE value in the 2022/23 column of the PCFM Variable Values Table, so there is no contradiction in stating that it will be revised by 30 November 2021 (see paragraph 1.10).

However, under paragraph 3E.9 of CRC 3E, the Authority can direct that the SMAE value for Regulatory Year 2021/22 can be a value other than zero.

Section 4 - Notification and direction of revised PCFM Variable Values

8.19 Paragraph 3E.16 of CRC 3E requires the Authority to give the licensee at least 14 days' notice setting out any revisions to SMAE values that it has determined, before directing the revisions. This means that the Authority will give notice to the licensee as shown in column 2 of Table 8.3 below.

Table 8.3 – Expected timings for SMAE value Notices and Directions

Regulatory Year for which SMAE value is being revised	Deadline for Notice of proposed revision to SMAE value	Deadline for direction of revised SMAE value
2015/16	15 Nov 2016	30 Nov 2016
2016/17	15 Nov 2017	30 Nov 2017
2017/18	15 Nov 2018	30 Nov 2018
2018/19	15 Nov 2019	30 Nov 2019
2019/20	15 Nov 2020	30 Nov 2020
2020/21	15 Nov 2021	30 Nov 2021
2021/22	-	-
2022/23	15 Nov 2021	30 Nov 2021

8.20 The Authority is required to have due regard to any representations made by the licensee in respect of proposed revisions to SMAE values and to give its reasons for any decisions in relation to them.

8.21 Having complied with the notice requirements referred to in paragraph 8.19, the Authority will direct revised SMAE values as shown in column 3 of Table 8.3.

Delay in direction of revised PCFM Variable Values

8.22 If, for any reason, the Authority does not give a required direction of an SMAE value by the date shown in column 3 of Table 8.3, CRC 3E requires that the value should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

9. Load Related Expenditure - financial adjustment methodology

Section 1 – Overview

9.1 The Authority's ED1 Strategy Decision document (see associated document a.) stated that the licensee's opening allowed levels of Load Related Expenditure might need to be adjusted during the Price Control Period to accommodate new and changing patterns of electricity use by electricity consumers. Accordingly, CRC 3G (Revising the allowed level of Load Related Expenditure) sets out a mechanism for 'relevant adjustments' to the licensee's allowed levels of Load Related Expenditure. Relevant adjustments may be positive or negative.

9.2 The licensee's opening allowed levels of Load Related Expenditure (in 2012/13 prices) were included in the calculation of its Opening Base Revenue Allowances and:

- set out against the licensee's name in the Table at Appendix 1 to CRC 3G; and
- represented by the opening values of the PCFM Variable Value for allowed Load Related Expenditure for the licensee (LRRC values).

9.3 CRC 3G sets out:

- the application windows during which relevant adjustment proposals can be made;
- the criteria for the proposal of relevant adjustments;
- the basis on which the Authority will determine relevant adjustments; and
- the basis on which the Authority will determine and direct revised LRRC values for the licensee.

9.4 The LRRC value for each Regulatory Year, revised as applicable, represents the licensee's total amount of allowed Load Related Expenditure (in 2012/13 prices) for that Regulatory Year.

9.5 The provisions of CRC 3G and this chapter mean that revised allowed levels of Load Related Expenditure (represented by revised LRRC values) can be included in the Annual Iteration Process for the ED1 Price Control Financial Model (PCFM) so that they interact with actual expenditure information and are appropriately reflected in Totex Incentive Mechanism adjustments and the calculation of values for the term MOD for the licensee.

9.6 The effects of revising LRRC values for Regulatory Years in the Price Control Period earlier than Regulatory Year t flow through to the determination of the value of MOD_t with appropriate Time Value of Money Adjustments under the functionality of the PCFM.

Section 2 – Determination of revisions to allowed levels of Load Related Expenditure

9.7 CRC 3G provides for:

- the licensee to propose revisions to allowed levels of expenditure (relevant adjustments), but only during two application windows specified in CRC 3G (see paragraph 9.9);
- the determination of relevant adjustments by the Authority; and
- the deeming of relevant adjustments in circumstances specified in CRC 3G.

9.8 CRC 3G also provides for the Authority to propose relevant adjustments in relation to allowed levels of Load Related Expenditure during a notice window after the end of the Price Control Period, specified in CRC 3G (see paragraph 9.10).

9.9 The application windows during which the licensee can propose relevant adjustments run from:

(i) 1 May 2017 to 31 May 2017; and

(ii) 1 May 2020 to 31 May 2020.

9.10 The notice window during which the Authority can give notice of proposed relevant adjustments runs from 1 September 2023 to 30 September 2023. This window is after the end of the Price Control Period whose last day is 31 March 2023.

9.11 CRC 3G and this chapter set out the basis on which relevant adjustments can be proposed by the licensee and the Authority. However, this chapter only deals with:

(a) the determination of relevant adjustments proposed by the licensee; and

(b) the determination and direction of revised LRRC values to give effect to determinations made under subparagraph (a).

9.12 Relevant adjustments proposed by the Authority are not effected through revisions to LRRC values for Regulatory Years in the Price Control Period and consequently are not dealt with further in this chapter.

Relevant adjustment proposals by the licensee

9.13 Relevant adjustments may be proposed by the licensee during both the first and second application windows provided that each proposal complies with the provisions of paragraphs 3G.6 to 3G.13 in CRC 3G.

9.14 A relevant adjustment proposal by the licensee must:

(i) be based on information about the licensee's level of efficient Load Related Expenditure over the Price Control Period that was not available when the licensee's Opening Base Revenue Allowances were determined;

(ii) take account of any relevant adjustments previously determined under CRC 3G;

(iii) constitute a material amount, being an amount that satisfies the test specified in paragraph 3G.7 of CRC 3G;

(iv) relate only to costs incurred and income from customer contributions received during the Price Control Period; and

(v) constitute an adjustment to allowed expenditure that cannot be made under the provisions of any other Charge Restriction Condition.

9.15 A relevant adjustment proposal by the licensee must set out:

(i) the changes to the licensee's allowed levels of Load Related Expenditure (LRRC values) that are proposed and the Regulatory Years to which those changes relate;

(ii) any change to the licensee's Specific Customer Funded Reinforcement Percentage Band that is proposed;

(iii) the basis on which proposed changes to the licensee's allowed levels of Load Related Expenditure have been calculated; and

(iv) appropriate supporting evidence including actual and forecast changes in network loading.

Determinations and directions with respect to relevant adjustments proposed by the licensee

9.16 In accordance with CRC 3G, the Authority will determine the relevant adjustments to the licensee's levels of allowed expenditure with respect to proposals made by the licensee within four months of the close of each of the application windows referred to in paragraph 9.9 – ie by 30 September 2017 and 2020 unless the timetable is extended by the Authority in the circumstances and to the extent prescribed in CRC 3G. The determination of relevant adjustments will be made in accordance with the provisions of CRC 3G and this chapter.

9.17 A determination under paragraph 3G.17 of CRC 3G may confirm, reject, or amend the proposed relevant adjustment. If allowed expenditure levels are revised, the Authority will also determine the Regulatory Years for which LRRC values are to be revised, which may be any of the Regulatory Years in the Price Control Period.

9.18 If the Authority has not determined a relevant adjustment in relation to a proposal duly made by the licensee in respect of Load Related Expenditure within the relevant time limit prescribed by CRC 3G, and the proposal has not been withdrawn, then the relevant adjustment, insofar as it relates to a revision to allowed expenditure levels and LRRC values for the licensee for the Regulatory Years specified in the proposals, will be deemed to have been made.

9.19 In determining any relevant adjustment, the Authority will:

(a) consult with the licensee and other interested parties and take account of any representations made in responses;

(b) have regard to the basis on which opening LRRC values were determined;

(c) take no account of the general financial performance of the licensee under the price control arrangements set out in the Charge Restriction Conditions of the licence;

(d) consider the value of any off-setting demand-side response solutions or use of other non-traditional reinforcement solutions, above the level incorporated in the licensee's business plan, that have avoided or, as may be, are reasonably expected to avoid, Load Related Expenditure;

(e) consider whether the licensee's Load Related Expenditure has fallen outside any Specific Customer Funded Reinforcement Percentage Band under CRC 5G (Net to gross adjustment for Load Related Expenditure); and

(f) check that the restriction specified in paragraph 3G.10 of CRC 3G has been included in the licensee's calculations (see paragraph 9.15 (iii)) and, if not, apply the restriction, if appropriate, in making its determination.

9.20 The stipulation in paragraph 9.19(d) means that the Authority may, in a relevant adjustment determination, include an uplift to the licensee's allowed expenditure levels in respect of expenditure by the licensee on demand-side response solutions and non-traditional reinforcement solutions, where it considers that such expenditure has avoided or is expected to avoid the need for Load Related Expenditure.

9.21 The restriction referred to in paragraph 9.19(f) is that a relevant adjustment proposed or made under CRC 3G must not exceed:

(a) $TLRRCF - TLRRC_{OV} - (20\% \times TLRRC_{OV})$

where $TLRRCF > TLRRC_{OV}$; or

(b) $TLRRCF - TLRRC_{OV} + (20\% \times TLRRC_{OV})$

where $TLRRCF < TLRRC_{OV}$

where:

TLRRCOV means the total of opening level of allowed levels Load Related Expenditure for the licensee; and

TLRRCF means the proposed revised total level of allowed Load Related Expenditure for the licensee.

9.22 Any determination of a relevant adjustment will specify:

(a) the Regulatory Years to which any changes to allowed levels of Load Related Expenditure apply;

(b) the revised allowed level of Load Related Expenditure for the licensee (in 2012/13 prices) for each of the Regulatory Years specified under subparagraph (a); and

(c) the revised LRRC values representing the allowed expenditure levels referred to in subparagraph (b).

Section 3 - Notification and direction of revised PCFM Variable Values for Load Related Expenditure (LRRC values)

9.23 The Authority will give Notice to the licensee of any revisions to LRRC values that it proposes to direct:

- by 15 November 2017 in respect of relevant adjustments proposed by the licensee during the first application window; and
- by 15 November 2020 in respect of relevant adjustments proposed by the licensee during the second application window.

9.24 The Notice will confirm that:

- any revised LRRC value determinations have been made in accordance with CRC 3G; and
- the licensee has 14 days from the date of the Notice in which to make any representations concerning the proposed LRRC value revisions.

9.25 The Authority is required to have due regard to any representations or objections made by the licensee and to give its reasons for any decisions in relation to them.

9.26 Having complied with the notice requirements, the Authority will direct revised LRRC values for the Regulatory Years specified in its determination (or in respect of a deemed adjustment – see paragraph 9.18) by 30 November in the Regulatory Year t-1 concerned.

9.27 Indicative timings for the determination and direction of revised LRRC values are summarised in Table 9.1 below.

Table 9.1 – Indicative timings for the revision of LRRC values

Application window	Revised levels of allowed expenditure determined by	Revised LRRC values determined and directed by	Reflected in value of MOD for Regulatory Year
May 2017	30 Sep 2017	30 Nov 2017	2018/19
May 2020	30 Sep 2020	30 Nov 2020	2021/22

Delay in direction of revised PCFM Variable Values

9.28 If the Authority does not make one of the directions required under paragraph 9.26 by 30 November in the Regulatory Year t-1 concerned, then CRC 3G requires that the values concerned should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t for the licensee under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

10. Visual Amenity Projects - financial adjustment methodology

Section 1 – Overview

10.1 Under the RIIO-ED1 price control arrangements the licensee has been allocated a total visual amenity allowed expenditure amount for the Price Control Period. CRC 3J (Allowed expenditure on Visual Amenity Projects) specifies:

- the licensee's total visual amenity allowed expenditure (TVAA) for the Price Control Period; and
- the basis for determining the licensee's allowed expenditure on Visual Amenity Projects (VAA values) for particular Regulatory Years.

10.2 A qualifying Visual Amenity Project is a scheme for placing existing overhead electricity distribution assets underground so as to improve the visual amenity of a National Park, Area of Outstanding Natural Beauty or National Scenic Area (the 'designated areas'). The Regulatory Instructions and Guidance (RIGs) provide further details regarding reporting and definitions relating to this scheme and 'designated areas'.

10.3 CRC 3J provides for the determination of the licensee's allowed expenditure levels on Visual Amenity Projects using a formula for deriving revised values for the PCFM Variable Value VAA term. At the outset of the Price Control Period on 1 April 2015, the VAA values for the licensee for each Regulatory Year of the Price Control Period are set at zero. VAA values are then subject to revision in accordance with the formula set out in paragraph 3J.5 of CRC 3J which is reproduced below:

$$\mathbf{VAA_{t-2} = min\left(VAE_{t-2}, TVAA - \sum_{2015/16}^{t-3} VAA_t\right)}$$

where:

TVAA	means the licensee's total visual amenity allowed expenditure for the Price Control Period, as specified for the licensee in Appendix 1 to CRC 3J, expressed in 2012/13 prices; and
VAE_{t-2}	means the amount spent by the licensee in Regulatory Year t-2 on Visual Amenity Projects expressed in 2012/13 prices.

10.4 Paragraphs 3J.7 and 3J.8 of CRC 3J respectively specify that:

- for the purposes of the first determination of a revised VAA value, by 30 November 2016, the value of VAA_{t-2} is equal to the lesser of TVAA and VAE_{t-2}; and
- in the formula set out in paragraph 3J.5 of CRC 3J, VAA values, for Regulatory Years earlier than Regulatory Year t-2, include any revisions to those values as determined by the Authority in accordance with Part B of CRC 3J.

Processing of VAA values under the Annual Iteration Process

10.5 As set out in chapter 1 of this handbook, the Annual Iteration Process for the ED1 Price Control Financial Model (PCFM) calculates values for the term MOD by recalculating base revenue figures for the licensee using revised PCFM Variable Values, including VAA values.

Section 2 - Determination, notification and direction of revised PCFM Variable Values for Visual Amenity Projects (VAA values)

Determination of revised VAA values

10.6 The formula for the licensee's allowed expenditure on Visual Amenity Projects (contained in CRC 3J and reproduced in paragraph 10.3 above) provides an updated level of allowed expenditure for each Regulatory Year t-2 (see note on temporal convention in chapter 1).

10.7 The amount spent by the licensee on Visual Amenity Projects in each Regulatory Year will be reported by the licensee in accordance with the RIGs.

Timing of determinations of revised VAA values

10.8 The first Regulatory Year of the Price Control Period is Regulatory Year 2015/16. The licensee will report its expenditure on Visual Amenity Projects for Regulatory Year 2015/16 to the Authority in accordance with the RIGs. Subject to the Notice requirements set out below, the first determination and direction of a revised VAA value for the licensee will take place by 30 November 2016 for the purposes of the Annual Iteration Process that will take place by 30 November 2016. Subsequent determinations will routinely follow the pattern shown in Table 10.1.

10.9 It should be noted that if the licensee has used up all of its total visual amenity allowed expenditure for the Price Control Period, the application of the formula in CRC 3J (reproduced in paragraph 10.3) will mean that VAA values for subsequent Regulatory Years will be determined to be zero.

Table 10.1 – Routine timings for determination of revised VAA values

Regulatory Year t-2 during which Visual Amenity Project expenditure takes place	Revised VAA value determined by	Reflected in value of MOD for Regulatory Year
2015/16	30 Nov 2016	2017/18
2016/17	30 Nov 2017	2018/19
2017/18	30 Nov 2018	2019/20
2018/19	30 Nov 2019	2020/21
2019/20	30 Nov 2020	2021/22
2020/21	30 Nov 2021	2022/23

10.10 The last Regulatory Year t-2 for which a revised VAA value will be determined during the Price Control Period is 2020/21. This is because expenditure reporting on Visual Amenity Projects for the last two Regulatory Years of the Price Control Period (2021/22 and 2022/23) will not be available in time to be included in a value for the term MOD. Therefore, adjustments to allowed expenditure on Visual Amenity Projects in 2021/22 and 2022/23 will be taken into account in the RIIO-ED2 price control arrangements for the licensee in a way that is consistent with the provisions for the calculation of VAA values in the licence and this handbook in the form they are in as at 31 March 2023. For the avoidance of doubt these arrangements will include Time Value of Money Adjustments and take into account the provisions relating to the licensee's total visual amenity allowed expenditure for the Price Control Period.

10.11 Notwithstanding the routine timings set out in Table 10.1, the Authority may, in respect of any Annual Iteration Process, determine that the VAA value for a Regulatory Year earlier than Regulatory Year t-2 should be revised, if that is necessary because the licensee has been required to restate any values relating to Visual Amenity Projects under any provision of the licence. In those circumstances the revision to the VAA value(s) concerned would again be determined using the formula contained in CRC 3J, but using the restated values for the Regulatory Year(s) in question.

Notification and direction of revised PCFM Variable Values

10.12 Paragraph 3J.13 of CRC 3J requires the Authority to give the licensee at least 14 days' notice setting out any revisions to VAA values that it has determined, before directing the revisions. This means that the Authority will give Notice to the licensee of any revisions of VAA values that it has determined by no later than 15 November in each Regulatory Year t-1. The Authority is required to have due regard to any representations made by the licensee and to give its reasons for any decisions in relation to them.

10.13 Having complied with the Notice requirements referred to in paragraph 10.12, and subject to paragraphs 10.8 and 10.10 above, the Authority will direct a revised VAA value for Regulatory Year t-2 (and for any earlier Regulatory Years for which relevant values have been restated) by 30 November in each Regulatory Year t-1.

Delay in direction of revised PCFM Variable Values

10.14 If, for any reason, the Authority does not give a required direction of a VAA value or values by 30 November in any Regulatory Year t-1, CRC 3J requires that the value or values should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

11. Worst Served Customer Projects - financial adjustment methodology

Section 1 – Overview

11.1 The associated Charge Restriction Condition for this chapter is CRC 3H (Allowed expenditure on improving services to Worst Served Customers).

11.2 The RIIO-ED1 price control arrangements include a general incentive for the licensee to improve supply interruption performance, contained in CRC 2D (Adjustment of licensee's revenues to reflect interruptions-related quality of service performance). However, the licensee has also been allocated a total amount of allowed expenditure on Worst Served Customer Projects. The definition of a Worst Served Customer is contained in CRC 3H and further information is contained in the Regulatory Instructions and Guidance (RIGs) which also set out the criteria that service improvement projects must meet.

11.3 The licensee's allowed expenditure level on Worst Served Customer Projects is capped by both:

(i) a total expenditure limit that is specified in Appendix 1 of CRC 3H, in 2012/13 prices; and

(ii) a limit on the maximum amount of expenditure per Worst Served Customer ("Worst Served Customer Cap Per Customer") that is specified in Appendix 2 of CRC 3H.

11.4 CRC 3H provides for the determination of the licensee's allowed expenditure levels on Worst Served Customer Projects using a formula for deriving revised values for the PCFM Variable Value "WSCC". At the outset of the Price Control Period on 1 April 2015, the WSCC value for the licensee for each Regulatory Year of the Price Control Period is set at zero. WSCC values are then subject to revision in accordance with the formula set out in paragraph 3H.5 of CRC 3H which is reproduced below:

$$\mathrm{WSCC}_{t-2} = \min\left(\mathrm{WSE}_{t-2}, \mathrm{TWSCC} - \sum_{2015/16}^{t-3} \mathrm{WSCC}_t\right)$$

where:

TWSCC	means the licensee's total amount of allowed expenditure on Worst Served Customer Projects for the Price Control Period, as specified for the licensee in Appendix 1 of CRC 3H, expressed in 2012/13 prices.
WSE_{t-2}	means, subject to paragraph 3H.8 in CRC 3H, the amount spent by the licensee in Regulatory Year t-2 on Worst Served Customer Projects, expressed in 2012/13 prices.

11.5 In addition, the licensee must:

(a) ensure that the total amount of expenditure on improving services to Worst Served Customers included in values for the term WSE for the Price Control Period does not exceed an amount calculated as:

$$WSCCPC \times TWSC$$

where:

WSCCPC means the Value for the Worst Served Customer Cap Per Customer for the licensee set out in Appendix 2 of CRC 3H; and

TWSC means the total number of Worst Served Customers included in Worst Served Customer Projects during the Price Control Period;

and

(b) seek to ensure that its expenditure on Worst Served Customer Projects delivers to Worst Served Customers the Required Performance Improvement set out in Appendix 3 of CRC 3H.

11.6 For the avoidance of doubt, the reference in paragraph 11.5(a) to the total amount of expenditure on improving services to Worst Served Customers included in values for the term WSE for the Price Control Period includes expenditure in Regulatory Years 2021/22 and 2022/23 (see also paragraph 11.13).

11.7 The RIGs will provide further details regarding the definitions and reporting criteria for values of the term WSE and in respect of the Worst Served Customer Cap Per Customer.

Processing of WSCC values under the Annual Iteration Process

11.8 As set out in chapter 1 of this handbook, the Annual Iteration Process for the ED1 Price Control Financial Model (PCFM) calculates values for the term MOD by recalculating base revenue figures for the licensee using revised PCFM Variable Values, including WSCC values.

Section 2 - Determination, notification and direction of revised PCFM Variable Values for projects to improve services to Worst Served Customers (WSCC values)

Determination of revised WSCC values

11.9 The formula for the licensee's allowed expenditure on Worst Served Customer Projects (contained in CRC 3H and reproduced in paragraph 11.4 above) provides an updated level of allowed expenditure for each Regulatory Year t-2 (see note on temporal convention in chapter 1).

11.10 The amount spent by the licensee on Worst Served Customer Projects in each Regulatory Year will be reported by the licensee in accordance with the RIGs.

Timing of determinations of revised WSCC values

11.11 The first Regulatory Year of the Price Control Period is Regulatory Year 2015/16. The licensee will report its expenditure on Worst Served Customer Projects for Regulatory Year 2015/16 to the Authority in accordance with the RIGs. Therefore, subject to the Notice requirements set out below, the first determination and direction of a revised WSCC value for the licensee will take place by 30 November 2016 for the purposes of the Annual Iteration Process that will take place by 30 November 2016. Subsequent determinations will routinely follow the pattern shown in Table 11.1 below.

11.12 It should be noted that, if the licensee has used up all of its total allowed expenditure (TWSCC) for the price control period the application of the formula in CRC 3H (reproduced in paragraph 11.4) will mean that WSCC values for subsequent Regulatory Years will be determined to be zero.

Table 11.1 – Routine timings for determination of revised WSCC values

Regulatory Year t-2 during which project expenditure takes place	Revised WSCC value determined by	Reflected in value of MOD for Regulatory Year
2015/16	30 Nov 2016	2017/18
2016/17	30 Nov 2017	2018/19
2017/18	30 Nov 2018	2019/20
2018/19	30 Nov 2019	2020/21
2019/20	30 Nov 2020	2021/22
2020/21	30 Nov 2021	2022/23

11.13 The last Regulatory Year t-2 for which a revised WSCC value will be determined during the Price Control period is 2020/21. This is because expenditure on Worst Served Customer Projects for the last two Regulatory Years of the Price Control Period (2021/22 and 2022/23) will not be available in time to be included in a value for the term MOD. Therefore, adjustments to allowed expenditure on Worst Served Customer Projects in 2021/22 and 2022/23 will be taken into account in the RIIO-ED2 price control arrangements for the licensee in a way that is consistent with the provisions for the calculation of WSCC values in the licence and this handbook in the form they are in as at 31 March 2023. For the avoidance of doubt these arrangements will include Time Value of Money Adjustments and take into account the provisions relating to the licensee's total amount of allowed expenditure on Worst Served Customer Projects for the Price Control Period and the Worst Served Customer Cap Per Customer set out in Appendix 2 of CRC 3H.

11.14 Notwithstanding the routine timings set out in Table 11.1, the Authority may, in respect of any Annual Iteration Process, determine that the WSCC value for a Regulatory Year earlier than Regulatory Year t-2 should be revised, if that is necessary because the licensee has been required to restate any values relating to Worst Served Customer Projects under any provision of the licence. In those circumstances the revision to the WSCC value(s) concerned would again be determined using the formula contained in CRC 3H, but using the restated values for the Regulatory Year(s) in question.

Notification and direction of revised PCFM Variable Values

11.15 Paragraph 3H.14 of CRC 3H requires the Authority to give the licensee at least 14 days' notice setting out any revisions to WSCC values that it has determined, before directing the revisions. This means that the Authority will give notice to the licensee of any revisions of WSCC values that it has determined by 15 November in each Regulatory Year t-1. The Authority is required to have due regard to any representations made by the licensee and to give its reasons for any decisions in relation to them.

11.16 Having complied with the Notice requirements referred to in paragraph 11.15, and subject to paragraphs 11.11 and 11.13, the Authority will direct a revised WSCC value for Regulatory Year t-2 by 30 November in each Regulatory Year t-1.

Delay in direction of revised PCFM Variable Values

11.17 If, for any reason, the Authority does not give a required direction of a WSCC value or values by 30 November in any Regulatory Year t-1, CRC 3H requires that the value or values should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

12. Innovation Roll-out Mechanism allowed expenditure – financial adjustment methodology

Section 1 - Overview

12.1 CRC 3D (The Innovation Roll-out Mechanism) sets out the basis for determining the licensee's allowed expenditure relating to Innovation Roll-out (IRM values) for particular Regulatory Years. All IRM values are stated in 2012/13 prices.

12.2 At the outset of the Price Control Period on 1 April 2015, the IRM value for the licensee for each Regulatory Year of the Price Control Period is set at zero and the licensee's Opening Base Revenue Allowances have been modelled on this basis.

12.3 CRC 3D sets out the basis on which allowed expenditure on the roll-out of proven innovations can be revised through "Relevant Adjustments". It also sets out how IRM values can be revised.

12.4 Under the Annual Iteration Process, allowed expenditure levels on Innovation Roll-out, represented by IRM values, as revised, interact with actual expenditure information so that appropriate Totex Incentive Mechanism adjustments are reflected in the calculation of values for the term MOD.

12.5 IRM values are stated in 2012/13 prices, consistent with the price base used in the ED1 Price Control Financial Model (PCFM) and the values for the term MOD.

12.6 CRC 3D provides for:

- the licensee to propose revisions to levels of allowed expenditure (Relevant Adjustments), but only during either or both of two application windows specified in CRC 3D (see paragraph 12.7); and
- the determination of Relevant Adjustments by the Authority.

12.7 The application windows during which the licensee can propose Relevant Adjustments run from:

(a) 1 May 2017 to 31 May 2017; and

(b) 1 May 2019 to 31 May 2019.

12.8 Any Relevant Adjustment resulting from a proposal made during the first application window may only provide for the revision of the IRM value for Regulatory Year 2018/19 and later Regulatory Years in the Price Control Period. Any Relevant Adjustment resulting from a proposal made during the second application window may only provide for the revision of the IRM value for Regulatory Year 2021/22 and Regulatory Year 2022/23.

12.9 Paragraph 3D.13 of CRC 3D specifies that a Relevant Adjustment proposal Notice by the licensee must:

(a) state any statutory obligations or any requirements of the licence to which the Notice relates;

(b) describe the Proven Innovation that the licensee proposes to roll-out;

(c) propose the amount of the Relevant Adjustment and set out, by reference to the Innovation Roll-out Costs, the basis on which the licensee has calculated the Relevant Adjustment;

(d) demonstrate that the costs to be recovered through the Relevant Adjustment will be a material amount for the purposes of paragraph 3D.9 of CRC 3D (see paragraph 12.10);

(e) demonstrate how each of the criteria set out in Part B of CRC 3D will be fulfilled by the roll-out using the additional funding sought;

(f) propose relevant outputs or other end products against which the roll-out will be assessed;

(g) set out the revisions to IRM values that the licensee considers should be made to implement the Relevant Adjustment; and

(h) state the date from which it is proposed that the Relevant Adjustment would have effect (“the adjustment date”) and the Regulatory Years to which the Relevant Adjustment would apply.

Materiality threshold

12.10 For the purposes of the requirement at subparagraph 12.9(d), the meaning of ‘material amount’ is given at paragraph 3D.9 of CRC 3D.

12.11 The Authority will determine Relevant Adjustments to the licensee's levels of allowed expenditure with respect to proposals made by the licensee within four months of the close of the application window concerned. Determinations will be made in accordance with the methodology set out in section 2 of this chapter. Section 3 of this chapter provides for the determination and direction of revised IRM values. The IRM value for any particular Regulatory Year, as revised, represents the total amount of allowed Totex expenditure (in 2012/13 prices) for Innovation Roll-out for that Regulatory Year.

Part 2 - Methodology for determining Relevant Adjustments in respect of Innovation Roll-out

12.12 If the Authority receives Notice of a proposed Relevant Adjustment from the licensee in respect of Innovation Roll-out costs it will take the steps set out below to determine whether the proposed adjustment should be confirmed, rejected or amended.

Determination steps

(i) The Authority will check whether the Notice has been received during one of the two application windows referred to in paragraph 12.7. If the Notice has been received before the start of an application window the Authority will notify the licensee that the Notice has been submitted too early and should be resubmitted during an application window. If the Notice has been received outside an application window the Authority will notify the licensee that the Notice has been received too late and that a Relevant Adjustment will not be determined.

(ii) The Authority will check whether each of the requirements set out in paragraph 3D.13 of CRC 3D has been met;

(iii) The Authority will decide whether it requires any further information from the licensee in order to make a determination and, if it decides that further information is required, it will give Notice of that requirement to the licensee as soon as reasonably practicable and will allow such time for provision of that information as appropriate, taking account of:

a. the amount of time that the licensee will reasonably require to compile the information;

b. the four month period for determinations referred to in paragraph 3D.15 of CRC 3D; and

c. the need to consult the licensee on its proposed determination.

(iv) The Authority will consider the factors set out in paragraph 3D.8 of CRC 3D, namely whether the innovation/proposed Relevant Adjustment:

a. will deliver Carbon Benefits or any wider environmental benefits;

b. will provide long-term value for money for electricity consumers;

c. will not enable the licensee to receive commercial benefits from the roll-out within the remainder of the Price Control Period (for instance, where the roll-out of a Proven Innovation will lead to cost savings (including benefits from other incentive mechanisms) equal to or greater than its implementation costs within the Price Control Period); and

d. will only be used to fund the roll-out of a Proven Innovation.

(v) Having carried out steps (i) to (iv) above, the Authority will provisionally determine whether to:

a. reject the Relevant Adjustment proposed by the licensee;

b. confirm the Relevant Adjustment proposed by the licensee; or

c. amend the Relevant Adjustment proposed by the licensee.

If the Authority considers that the licensee's proposal should be confirmed or amended it will provisionally determine the adjustments to allowed expenditure that should be made and the Regulatory Years to which those adjustments should be applied.

If the Authority considers that the proposed Relevant Adjustment should not be made it will provisionally determine that no adjustments to allowed expenditure should be made.

(vi) The Authority will consult the licensee on its provisional determination, allowing the licensee at least 28 days in which to respond.

(vii) The Authority will consider any consultation responses from the licensee and will then make a Relevant Adjustment determination.

12.13 A determination by the Authority that confirms or amends a Relevant Adjustment proposed by the licensee in respect of Innovation Roll-out will specify:

(a) the Regulatory Years to which the determination applies; and

(b) revised amounts of allowed expenditure (in 2012/13 prices) for the Innovation Roll-out for each of the specified years.

12.14 The Authority will apply any Relevant Adjustment determined under this section in the determination of revised IRM values under section 3 of this chapter.

Section 3 – Determination, notification and direction of revised IRM values

12.15 CRC 3D specifies that IRM values for the licensee as at 1 April 2015 for each Regulatory Year of the Price Control Period will be zero.

12.16 On or before 31 October in Regulatory Year 2017/18 and each subsequent Regulatory Year up to and including 2022/23, Ofgem will check to see whether any determinations of Relevant Adjustments have been made in respect of Innovation Roll-out that change levels of allowed expenditure for the licensee and that have not previously been taken fully into account in the determination of revisions to IRM values for the Regulatory Year or Years referred to in the determinations.

12.17 If determinations of Relevant Adjustments have not previously been taken into account, the Authority will determine that the IRM values for the Regulatory Years concerned are to be revised so that they take into account the revised allowed expenditure amounts (in 2012/13 prices) specified in the Relevant Adjustment determinations.

Notification and direction of revised IRM values

12.18 The Authority will give notice of any revisions to IRM values that it proposes to direct by 15 November in Regulatory Year 2017/18 and each subsequent Regulatory Year up to and including 2021/22, being at least 14 days before the deadline date of 30 November in each of those Regulatory Years for the direction of revised PCFM Variable Values. The notice will confirm that:

- any revised IRM value determinations have been made in accordance with Part G of CRC 3D; and
- the licensee has 14 days from the date of the notice in which to make any representations concerning proposed IRM value revisions.

12.19 The Authority is required to have due regard to any representations or objections made by the licensee and to give its reasons for any decisions in relation to them.

12.20 The Authority will only direct revisions to IRM values in accordance with the provisions of CRC 3D. However, the overall direction of PCFM Variable Value revisions in each Regulatory Year t-1 will include a copy of the PCFM Variable Values Table for the licensee showing the state of all PCFM Variable Values including IRM values.

Delay in direction of revised IRM values

12.21 If the procedures set out in CRC 3D and this chapter call for the Authority to direct revised IRM values by 30 November 2017 or by 30 November in a subsequent Regulatory Year, and the Authority does not make such a direction, then CRC 3D requires that the values concerned should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t for the licensee under CRC 4B (Annual Iteration Process for the PCFM).

12A. WPD Rail electrification allowed expenditure – financial adjustment

Section 1 - Overview

12A.1 The associated Charge Restriction Condition for this chapter is CRC 3K (Rail electrification adjustments). This chapter is only applicable to the following licensees:

- Western Power Distribution (East Midlands) plc;
- Western Power Distribution (West Midlands) plc;
- Western Power Distribution (South Wales) plc; and
- Western Power Distribution (South West) plc.

12A.2 The modelling of the licensee's Opening Base Revenue Allowances included allowed Totex expenditure amounts for asset diversion works (the movement of electrical lines or plant) necessitated by the rail electrification projects set out in Table 12A.1 below which are being undertaken by Network Rail.

Table 12A.1 – Rail electrification projects

Rail electrification project	West Midlands	East Midlands	South Wales	South West
Paddington-Swansea	✓	n/a	✓	✓
Cardiff- Valleys	n/a	n/a	✓	n/a
Midlands Mainline	n/a	✓	n/a	n/a
Birmingham-Plymouth	✓	n/a	n/a	✓

12A.3 The allowed Totex expenditure amounts referred to in paragraph 12A.2 were based on the expected level of diversion costs arising as a result of wayleave terminations by Network Rail and payable by the licensee during the Price Control Period ('expected diversion costs') in respect of the projects set out in Table 12A.1. These amounts were based on assumptions included in the licensee's business plan for the RIIO-ED1 price control. These amounts do not include diversion works that take place in public highways, where a proportion of asset diversion costs can be recharged to the person requiring the diversion to be made or to a third party. For this category of diversion, the licensee's business plan assumed that the funding would be 82% from payments from Network Rail and 18% from the licensee.

12A.4 If the Authority is notified that, or becomes aware that, some of the expected diversion costs will be met by another party (through 'additional contributions') it will determine that the licensee's allowed Totex expenditure should be reduced by an equivalent amount. The reduction is applied to the ANLR category of Totex (see Table 6.2 in chapter 6).

12A.5 CRC 3K provides for the Authority to direct changes to the PCFM Variable Values that relate to reductions in allowed Totex expenditure associated with additional contributions (RE values). Proposed changes must be made in accordance with the methodology set out in this chapter.

12A.6 The RE values for each Regulatory Year have opening values (at 1 April 2015) of zero. The following points apply to RE values:

(i) RE values can only be zero or negative; and

(ii) the RE value for any Regulatory Year in the Price Control Period can be revised at any time before 30 November 2021 where that is consistent with the methodology set out in section 2 of this chapter.

12A.7 Any revised RE values are processed under the Annual Iteration Process as changes to allowed expenditure (see paragraph 2.5 and Table 2.1 in chapter 2) with the effects flowing through to the calculation and determination of the value of the term MOD for Regulatory Year t.

12A.8 It should be noted that there is no provision to revise allowed levels of Totex expenditure for the licensee (upwards or downwards) in respect of outturn levels of diversion work activity – only in respect of the level of additional contributions.

Section 2 – Determination, notification and direction of revised PCFM Variable Values for rail electrification (RE values)

Determination of revised RE values

12A.9 The Authority will take no action with respect to the revision of RE values unless it is notified that, or becomes aware that, some expected diversion costs will be met by additional contributions.

12A.10 Subject to paragraph 12A.12, if the Authority is notified that, or becomes aware that, some expected diversion costs will be met by additional contributions, it will review the information and confer with the licensee to verify the actual level of additional contributions that apply to each Regulatory Year in the Price Control Period. Having done this, the Authority will determine that the RE value for each and every Regulatory Year in the Price Control Period should be revised to a value ascertained using the following formula:

Revised RE value = (-1 x aggregate amount of additional contributions)

12A.11 In the formula for revised RE values set out in paragraph 12A.10, the reference to the 'aggregate amount of additional contributions' means the sum (expressed in 2012/13 prices) of:

(i) any additional contributions for the Regulatory Year concerned that have been taken into account in a prior revision of the RE value for that Regulatory Year; and

(ii) any incremental additional contributions for the Regulatory Year concerned of which the Authority has been notified or become aware.

The aggregate amount of additional contributions is multiplied by negative 1, so that it is treated by the PCFM as a reduction in allowed Totex expenditure.

12A.12 Paragraph 3K.6 of CRC 3K specifies that the last date by which the Authority can direct that RE values for the licensee are to be revised is 30 November 2021, for the purpose of the Annual Iteration Process that will take place by 30 November 2021 (the last Annual Iteration Process during the Price Control Period). It is expected that all necessary revisions to RE values will be directed by this point. However, if the Authority is notified of, or becomes aware of, additional contributions too late to include in a revision of RE values, then those additional contributions will be addressed under the RIIO-ED2 price control arrangements.

12A.13 For the purpose of determining any revisions to RE values, additional contributions will be applied to the Regulatory Year in which the associated costs are reported. There is no materiality threshold with respect to the level of additional contributions that can be taken into account.

12A.14 The licensee is required to report all diversion costs and contributions in accordance with applicable requirements contained in the RIGs.

Notification and direction of revised RE values

12A.15 References to Regulatory Year t-1 in this section follow the convention set out in paragraph 1.7 of this handbook - ie each should be read as being relative to a Regulatory Year t in which the MOD term is used to adjust the licensee's Opening Base Revenue Allowance.

12A.16 Subject to paragraph 12A.12, if by 31 October in any Regulatory Year t-1, the Authority determines that one or more RE values should be revised, it will give notice to the licensee of the proposed revisions by 15 November in the same Regulatory Year t-1 (being at least 14 days before the deadline date for the direction of revised PCFM Variable Values). The notice will confirm that:

- any revised RE values have been determined in accordance with Part A of CRC 3K, which cross refers to this chapter of the ED1 Price Control Financial Handbook; and
- the licensee has 14 days from the date of the notice in which to make any representations concerning the proposed RE value revisions.

12A.17 The Authority is required to have due regard to any representations or objections made by the licensee and to give its reasons for any decisions in relation to them.

12A.18 Subject to paragraph 12A.12, if the Authority determines that one or more RE values should be revised after 31 October in any Regulatory Year t-1, then the Authority will give notice to the licensee of the proposed revisions by 15 November in the next Regulatory Year.

Delay in direction of revised RE values

12A.19 If the methodology set out in this section calls for the Authority to direct revised RE values by 30 November in a particular Regulatory Year t-1, and the Authority does not make such a direction, then paragraph 3K.10 of CRC 3K requires that the values should be directed by the Authority as soon as is reasonably practicable, to facilitate the notification and direction of the value of the term MOD_t under CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model).

Appendix 1 - Glossary

A

Annual Iteration Process

The Annual Iteration Process is the process set out in CRC 4B (Annual Iteration Process for the ED1 Price Control Financial Model) that uses revised PCFM Variable Values in the ED1 Price Control Financial Model to recalculate base revenue figures for the licensee for the Price Control Period. The product of each Annual Iteration Process is the value for the term MOD_t which is a component term in the formula for the licensee's Base Demand Revenue, representing the incremental change to the licensee's Opening Base Revenue Allowance for the Regulatory Year t. The Annual Iteration Process is completed by 30 November in each Regulatory Year t-1 during the Price Control Period.

B

Base Annual PSED Allowance

For the purposes of chapter 3 of this handbook, means an allowance derived in accordance with the formulae set out in row 7 of Tables 3.2 and 3.3 in chapter 3 and excludes the components of total PSED repair allowances that relate to:

- the licensee's under/over-payment history; and
- the application of adjustment factors resulting from Reasonableness Reviews.

Base Demand Revenue (BR_t)

The amount included in the licensee's Allowed Distribution Network Revenue for a particular Regulatory Year, that is derived in accordance with the formula set out in paragraph 2A.5 of CRC 2A (Restriction of Allowed Distribution Network Revenue).

C

Contingent Asset

For the purposes of the methodology in chapter 3 of this handbook, means an asset made subject to arrangements under which it might:

(a) be claimed by the pension scheme trustees;

(b) be reclaimed by the licensee; or

(c) remain subject to the arrangement,

depending on the circumstances arising/prevailing and the contractual terms of the arrangement.

An example of a Contingent Asset arrangement could be the payment of funds into an escrow account.

Cut-Off Date

In respect of the Pension Scheme Established Deficit for electricity distribution licensees, means 31 March 2010.

D

Decimal Percentage

For the purposes of chapter 5 of this handbook, means a percentage value expressed in decimal format so that, for example, five percent (5%) expressed as a Decimal Percentage is 0.05 and twenty percent (20%) expressed as a Decimal Percentage is 0.2.

Defined Benefit Scheme

A pension scheme where the benefits that accrue to members are normally based on a set formula taking into account the final salary and accrual of service in the scheme. It is also known as a final salary pension scheme.

Defined Contribution Scheme

A pension scheme where the benefits that accrue to members are based on the level of cash contributions made to an individual account; the returns on those funds are used to provide a cash amount to purchase an annuity on retirement.

Distribution Services Provider

Has the meaning given in Standard Condition1 (Definitions for the standard conditions) of the electricity distribution licence.

Distribution Services Area

Has the meaning given in Standard Condition1 of the electricity distribution licence.

DPCR5 Financial issues Data Tables

The data tables of that name referred to in the RIGs applicable to the licensee in the DPCR5 Price Control Period.

DPCR5 IQI Incentive Rate

Means the incentive rate set out in the table at Appendix 1 to Special Condition CRC 18 (Arrangements for the recovery of uncertain costs) of the licence in the form that it was in on 31 March 2015 which is reproduced below.

Licensee	**Incentive rate**
Western Power Distribution (West Midlands)	47%
Western Power Distribution (East Midlands)	47%
Electricity North West Ltd	45%
Northern Powergrid (Northeast) Limited	48%
Northern Powergrid (Yorkshire) plc	48%
Western Power Distribution (South Wales)	51%
Western Power Distribution (South West) plc	51%
London Power Networks plc	45%
South Eastern Power Networks plc	45%
Eastern Power Networks plc	45%
SP Distribution Ltd	45%
SP Manweb plc	45%
Scottish Hydro Electric Power Distribution plc	49%
Southern Electric Power Distribution plc	49%

DPCR5 Price Control

The price control arrangements applicable to Electricity Distributors from 1 April 2010 until 31 March 2015.

DPCR5 Revenue Allowance

In this handbook means the PU value sets against the licensee's name in Appendix 1 to Special condition CRC3 (Restriction of Distribution Charges: Use of System Charges) of the licence in the form which it was in on 31 March 2015 for a particular Regulatory Year in the DPCR5 price control period.

DPCR5 Time Value of Money Adjustment

A multiplier determined as $(1+X)^Y$ where:

- X is the WACC for the licensee applicable in the DPCR5 period, which is 4.69%; and
- Y represents the number of years over which the DPCR5 Time Value of Money Adjustment is to be applied.

E

Early Retirement Deficiency Contributions (ERDCs)

The cost of providing enhanced pension benefits granted under severance arrangements prior to 1 April 2004 that were not fully matched by increased contributions.

ED1 Price Control Financial Instruments

The collective term for the ED1 Price Control Financial Handbook and the ED1 Price Control Financial Model.

ED1 Price Control Financial Model Working Group

The working group whose terms of reference are set out in section 3 of chapter 1 of this handbook.

ED1 Price Control Financial Methodologies

The methodologies set out in sections 2 and 3 of this handbook that form part of CRC 4A (Governance of ED1 Price Control Financial Instruments) and that are used to determine revised PCFM Variable Values.

ED1 Price Control Financial Model (PCFM)

The model of that name (with a suffix referring to the month of November in Regulatory Year t-1 as that term is defined for the purposes of CRC 4A) that:

(a) was first published by the Authority on 21 May 2014 and came into effect on 1 April 2015;

(b) is represented by a workbook in Microsoft Excel ® format maintained under that name (with a Regulatory Year suffix) on the Authority's website; and

(c) will be used by the Authority to determine the value of the term MOD_t through the application of the Annual Iteration Process,

as modified from time to time in accordance with the provisions of CRC 4A (Governance of ED1 Price Control Financial Instruments).

Enhanced Physical Site Security Costs

Has the meaning given in CRC 3F.

F

Fast Money

In this handbook the term Fast Money refers to:

- allowance adjustments that flow directly into recalculated base revenue figures for the licensee; and
- the proportion of Totex which is not added to the licensee's RAV balance and is effectively included in the licensee's revenue allowance for the year of expenditure (see also Slow Money and Totex Incentive Mechanism).

Funding Adjustment Rate

The percentage calculated as (1 - Totex Incentive Strength Rate).

I

International Financial Reporting Standards (IFRS)

Accounting standards set by the International Accounting Standards board.

M

MOD

The term of that name included in the formula for Base Demand Revenue set out in CRC 2A (Restriction of Allowed Distribution Network Revenue). It represents the incremental change to be applied to the licensee's Opening Base Revenue Allowance for the Regulatory Year concerned. Values for the MOD term are calculated under the Annual Iteration Process for the ED1 Price Control Financial Model - see CRC 4B and chapter 2 of this handbook.

The value of MOD_t is specified in a direction given by the Authority by 30 November in each Regulatory Year t-1.

N

Notice

Has the meaning given in Standard Condition1 of the electricity distribution licence.

O

Ofgem Website

The website at the URL: www.ofgem.gov.uk

Ongoing Pension Service Costs (OPSC)

All pension costs incurred by the licensee except those relating to the Pension Scheme Established Deficit.

Opening Base Revenue Allowance

The amount in 2012/13 prices, represented by the term PU_t, included in the licensee's Base Demand Revenue for a particular Regulatory Year that is set down against the licensee's name in the table at Appendix 1 to CRC 2A (Restriction of Allowed Distribution Network Revenue).

P

PCFM Variable Value

means a value held in the PCFM Variable Values Table for the licensee contained in the ED1 Price Control Financial Model:

(a) that may be revised by a direction of the Authority following a determination under the relevant CRC; but

(b) the revision of which does not constitute a modification of the ED1 Price Control Financial Model for the purposes of CRC 4A.

PCFM Variable Values Table (for the licensee)

The table of blue shaded cells on the Input' worksheet of the ED1 PCFM containing the PCFM Variable Values for the licensee .

Pension Deficit Allocation Methodology

The methodology of that name contained in the Pension RIGs used by the Authority in the determination of the licensee's Pension Scheme Established Deficit.

Pension Principles

The principles set out in Appendix 7 of the Strategy decision for the RIIO-ED1 electricity distribution price control (Financial issues) published by Ofgem on 4 March 2013 under reference number 26d/13.

Pension Protection Fund (PPF)

The fund, established under the provisions of the Pensions Act 2004, to provide compensation to members of eligible defined benefit pension schemes, when there is a qualifying insolvency event in relation to the employer, and where there are insufficient assets in the pension scheme to cover the Pension Protection Fund level of compensation.

Pension Protection Fund (PPF) Levy

The levy on pension schemes by which the PPF is financed. This levy has a number of constituent elements including a fixed element (based on scheme liabilities) and a risk based element (based on the perceived insolvency risk of each scheme). Additionally there is an administration levy charged to cover the PPF running costs.

Pension RIGs

The Energy Network Operators' Price Control Pension Costs - Regulatory Instructions and Guidance: Triennial Pension Reporting Pack supplement including the Pension Deficit Allocation Methodology published by Ofgem on 12 April 2013.

Pension Scheme Administration

The range of activities that pension scheme trustees are required by legislation to undertake or commission in running the pension scheme. It includes, without limitation, the keeping of scheme records, scheme management and administration, scheme policy and strategy formulation, the provision of information to scheme members, the calculation and payment of benefits, liaison with tax and regulatory authorities and the preparation of valuations. It does not include the provision of advice to the licensee’s manager on the management of the scheme or any deficit position. Administration costs do not include investment management fees; these are considered to be deductions from investment returns.

Pension Scheme Established Deficit (PSED)

The difference between pension scheme assets and liabilities, as determined under periodic scheme valuations, that is attributable to:

- the regulated business; and
- pensionable service up to the end of the cut-off date, which for Electricity Distributors is 31 March 2010.

If the Pension Scheme Established Deficit figure becomes negative, it is referred to as a surplus relating to pensionable service up to the end of the cut-off date.

Pension Scheme Incremental Deficit (PSID)

The difference between pension scheme assets and liabilities, as determined under periodic scheme valuations, that is attributable to:

- the regulated business; and
- pensionable service after the cut-off date, which for electricity distributors is 31 March 2010.

If the incremental deficit figure becomes negative, it is referred to as a surplus relating to pensionable service after the cut-off date.

R

RAV – Regulatory Asset Value

A financial balance representing expenditure by the licensee that has been capitalised under regulatory rules. The licensee receives a return and depreciation on its RAV in its price control allowed revenues.

Reasonableness Review

A review by the Authority of the findings of an independent report commissioned by it on the reasonableness of costs associated with the licensee's pension deficit position (but not on the deficit allocation to the PSED) which may lead to further review procedures if the licensee is an outlier with respect to cost levels and that position is:

(a) to the detriment of consumers; and

(b) reasonably attributable to the NWO, recognising the responsibilities and independence of pension scheme trustees.

Regulatory Accounts

Has the meaning given in Standard Condition1 of the electricity distribution licence.

Regulatory Instructions and Guidance (RIGs)

The collective term for documents issued to licensee by the Authority that include:

- instructions regarding data and information that the licensee must report to Ofgem;
- guidance on the way in which data and information should be reported and the timing requirements for submissions; and
- templates, including workbooks in Microsoft Excel® format, for use by the licensee in making submissions.

Regulatory Year

A year beginning on 1 April and ending on the following 31 March in respect of which price control allowances are set. The RIIO-ED1 Price Control Period comprises the eight Regulatory Years from 1 April 2015 to 31 March 2023.

Relevant Adjustment

For the purposes of chapter 12 of this handbook, has the meaning given in CRC 3D (The Innovation Roll-out Mechanism).

RIGs

See Regulatory Instructions and Guidance.

RIIO

Revenue = Incentives + Innovation + Outputs.
Ofgem's framework for the economic regulation of energy networks.

RIIO-ED1

The price control arrangements applicable to Electricity Distributors from 1 April 2015 until 31 March 2023.

RIIO-ED2

The price control arrangements that will be applicable to Electricity Distributors after 31 March 2023.

S

Scheme Valuation Dataset

The items set out in paragraph 3.22 of chapter 3 of this handbook, provided to Ofgem by the licensee in accordance with the Pension RIGs.

Slow Money

The proportion of Totex that is added to the licensee's RAV balance on which the licensee receives a revenue allowance to cover finance (vanilla WACC) and depreciation costs.

Smart Meter Installation

Has the meaning given in CRC 3E (Smart Meter Roll-out Costs).

Smart Meter Intervention

Has the meaning given in CRC 3E.

Specific Customer Funded Reinforcement Percentage Band

Means the band of percentage values specified against the licensee's name in Table 2 of CRC 5G (Net to gross adjustment for Load Related Expenditure).

T

Time Value of Money Adjustment

A multiplier used when the award or application of a financial value, attributable to a particular year, is deferred until a later year, even where the deferral is routine and in accordance with a price control mechanism.

In basic terms, for any one year, the multiplier is (1+X) where:

- X is the WACC for the licensee applicable to the period of deferral.

See also DPCR5 Time Value of Money Adjustment

Totex

The term used to describe the licensee's total expenditure (with limited exceptions) on regulated business activities. It includes both capital and operating expenditure items. The Totex approach facilitates the equalisation of incentives (between capital and operating expenditure solutions) under the Totex Incentive Mechanism.

Totex Incentive Mechanism (TIM)

TIM is the mechanism under which adjustments are made to reflect differences between the licensee's allowed Totex and actual. The licensee's Opening Base Revenue Allowances have been modelled on the basis that actual Totex expenditure levels are expected to equal allowed Totex expenditure levels (allowances). If actual (outturn) expenditure differs from allowances, for any Regulatory Year during the Price Control Period, the TIM provides for an appropriate sharing of the incremental amount (whether an overspend or under spend) between consumers and the licensee in accordance with the licensee's Totex Incentive Strength Rate.

Totex Capitalisation Rate

The percentage of Totex which is added to RAV (see also "slow money").

Totex Incentive Strength Rate (TISR)

A percentage figure specified in CRC 3B (Determination of PCFM Variable Values for Totex Incentive Mechanism Adjustments) for the licensee. It represents the percentage of any overspend/under spend against Totex allowances that a licensee bears/retains.

Triennial (pension scheme) valuation

An actuarial valuation of a pension scheme which has been carried out to meet the requirements of Section 224(2)(a) of the Pensions Act 2004 and which results in a written report on scheme assets and liabilities by the scheme actuary. Interim updates to triennial valuations may also be produced.

U

Updated (pension scheme) valuation

A report by the scheme actuary which provides an update on scheme assets and liabilities between triennial valuations.

V

Vanilla WACC

See WACC.

Visual Amenity Project

Has the meaning given in CRC 3J (Allowed expenditure on Visual Amenity Projects).

W

WACC

The Vanilla Weighted Average Cost of Capital is Ofgem's preferred way of expressing the rate of return allowed on the Regulatory Asset Values (RAV) of price controlled network companies. The use of Vanilla WACC means that the company's tax cost is separately calculated as a discrete allowance so that only the following have to be factored in:

- the pre-tax cost of debt - ie the percentage charge levied by lenders; and
- the post tax cost of equity – ie the percentage return equity investors expect to actually receive,

  weighted according to the price control gearing assumption.

"Real Vanilla WACC" is used which gives a lower percentage than "Nominal Vanilla WACC" would (when inflation is positive). This is because inflation isn't taken into account in the determination of the Real Vanilla WACC percentage.

Worst Served Customer

Has the meaning given in CRC 3H (Allowed expenditure on improving services to Worst Served Customers).

Worst Served Customer Project

Has the meaning given in CRC 3H.

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-46

[Ex.10-C-p.12]

With respect to the proposed Total Cost Efficiency Carryover Mechanism (TCECM):

a) Please explain how the proposed TCECM incents sustainable efficiencies.

b) Why is the proposed carry-over mechanism not symmetrical so as to penalize the Applicant if it is not efficient?

c) Please confirm that in the AUC PBR Decision cited by the Applicant as a model, the efficiency carryover mechanism approved was in the context of a traditional price-cap performance-based regulation model.

d) Since the Applicant has proposed to remove capital expenditures that are part of the Controllable Capital Investment Efficiency Incentive Mechanism, what percentage of the annual revenue requirement for each year of the plan will be covered by the TCECM.

e) Does the proposed ROE rate rider for the first 2 years following the end of the Custom IR plan, apply to the entire rate base?

f) Please explain what the Applicant means by the statement that it “intends its TCECM mechanism to apply within the framework of the Board’s “off ramp” policy for electricity distributors…” (p.14)

g) Please provide a detailed numerical example to illustrate the TCECM.

Response:

a) The proposed TCECM is intended to address the weakening of the incentive to find efficiencies as the end of the rate plan term approaches by allowing for the utility to continue to capture the benefits of efficiencies realized throughout the plan term, including closer to the end, for a short time following the plan term.

OPUCN's proposal does not include a distinct evaluation of the precise nature, including the degree of sustainability, of the efficiencies reflected in "over earnings" during the plan term. OPUCN has noted that an attempt to provide for such an evaluation was found unsatisfactory in the Enbridge Gas Distribution (EGD) multi-year rate plan proposal [EB-2012-0459], and to date OPUCN has not derived a better approach to this issue.

b) Please see response to interrogatory 10.0-Staff-49.

c) Confirmed.

d) The percentage of the annual revenue requirement covered by the TCECM is approximately 98% in 2015 decreasing to approximately 84% in 2019.

e) OPUCN has proposed that any TCECM percentage reward would be applied to the entire OPUCN rate base in each of 2020 and 2021 to calculate the TCECM rate rider in each of those years.

f) The referenced statement is intended to indicate that any TCECM rate rider allowed to OPUCN in 2020 and 2021 would be included in calculating ROE earned by OPUCN in those test years, and, if applicable, in determining whether OPUCN's ROE in those years exceeds the multi-year incentive rate plan "off ramp" trigger applicable to OPUCN's subsequent rate plan.

g) The following was copied from the presentation submitted to the Board on April 1, 2015:

Total Cost Efficiency Carryover Mechanism ("TCECM")

Year	Forecast Rate Base	Deemed Equity (40%)	OEB ROE	OPUCN ROE	Difference %
2015	$104,991	$41,996	9.3%	9.7%	0.4%
2016	$112,853	$45,141	9.3%	10.0%	0.7%
2017	$119,891	$47,956	9.3%	8.9%	(0.4%)
2018	$127,128	$50,851	9.3%	9.3%	0.0%
2019	$133,201	$53,281	9.3%	9.7%	0.4%
Average Difference - Positive (Negative)					0.22%
Portion eligible for "rate rider" - 50% (to maximum of 0.50%)					0.11%

Incentive Calculation - $000's	2020	2021
Estimated Deemed Equity	$55,710	$58,139
	0.11%	0.11%
Incentive / Rate Rider Amount	$61	$64

*** OPUCN ROE/Rate Base are estimated amounts for illustration only ***

Oshawa PUC Networks, Inc. 33

OSHAWA PUC NETWORKS INC.

Response to School Energy Coalition (SEC) Interrogatory 10.0-SEC-47

[Ex.10-C, p.14]

With respect to the proposed Controllable Capital Investment Efficiency Incentive Mechanism (CCIEIM):

a) What percentage of the total proposed capital budget is covered by the CCIEIM in each year of the plan?

b) Why has the Applicant not included all of its controllable capital expenses?

c) Please confirm that the CCIEIM will be calculated on project by project basis, not a total eligible capital budget basis.

d) It would be expected that over the test period, some proposed capital projects will be substituted completely for others as needed. Please explain how this will affect the calculation of the CCIEIM.

e) It would be expected that over the test period, some proposed capital projects' scope will change. Please explain how this will affect the calculation of the CCIEIM.

f) Please provide a detailed numerical example to illustrate the CCIEIM.

Response:

a) The following table sets out, for each year of OPUCN's proposed Custom IR Plan term, what percentage of the total forecast capital budget is represented by the capital expenditure on the two programs (System Renewal and new MS9 Distribution Station) proposed for inclusion in the CCIEIM:

	2015	2016	2017	2018	2019	Total
System renewal	$ 4,053.00	$ 4,102.00	$ 3,642.00	$ 3,931.00	$ 4,021.00	$19,749.00
MS9	$ 750.00	$ 1,000.00	$ 3,250.00	$ 3,000.00	$ 1,000.00	$ 9,000.00
	$ 4,803.00	$ 5,102.00	$ 6,892.00	$ 6,931.00	$ 5,021.00	$28,749.00
Capital plan	$13,500.00	$11,600.00	$12,400.00	$12,500.00	$10,800.00	$60,800.00
	36%	44%	56%	55%	46%	47%

b) Please see response to interrogatory 10.0-Staff-45, part a.

c) Please see response to interrogatory 10.0-Energy Probe-71, part a).

d) Please see response to interrogatory 10.0-Energy Probe-71, part b).

e) Please see response to interrogatory 10.0-Energy Probe-71, part b).

f) The following was copied from the presentation submitted to the Board on April 1, 2015:

Controllable Capital Investment Efficiency Incentive Mechanism ("CCIEIM")

	Underspend	Overspend
Approved Capital	$28,750	$28,750
Actual Capital	$27,750	$29,750
Difference	$1,000	$(1,000)
Rate Base Impact for Incentive Calculation (50%)	$500	$(500)
Rate Rider Calculation (2020):		
Return on Equity ($500.0 * 40% * 9.3%)	$19	$(19)
Return on Debt ($500.0 * 60% * 4.45%)	$13	$(13)
Amortisation ($500.0 * 4.59%)	$23	$(23)
Incentive / Rate Rider Amount	$55	$(55)

1. Revenue impact beyond 2020 subject to depreciation of principal amount of rate base adjustment at average life of OPUCN 2020 rate base. Using average depreciation of 4.59% per PEG's Report to the OEB November 2013 (page 16).

Oshawa PUC Networks, Inc. 31

OSHAWA PUC NETWORKS INC.

Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatory 10.0-VECC-54

Reference: E10

The application does not appear to contain a comprehensive (complete) proposal of the rate adjustment formula. If a reference to a comprehensive rate formula description cannot be given, please provide a full description of the rate adjustment formula as it would be applied in subsequent years to the 2015 approved rate. For clarification provide an example table of the rate adjustments in each of 2016-2019 using OPUCN forecast of any exogenous variables.

Response:

OPUCN has not proposed a rate adjustment formula. OPUCN has applied for distribution rates for the test years 2015 through 2019 set on the basis of the detailed cost of service forecasts and supporting evidence provided in this Application. OPUCN has also developed a rate smoothing mechanism which utilizes rate riders calculated to effect a more constant year over year rate of growth in the effective rates (i.e. approved rates plus rate riders). OPUCN also proposes an annual rate adjustment process pursuant to which rates for each of the plan years 2016 through 2019 as determined in this application will be adjusted in advance of implementation to reflect revised forecasts of certain, limited, predefined external investment drivers the costs associated with which are beyond OPUCN's ability to predict or control.

A summary of the distribution rate and bill impacts of OPUCN's proposal, by rate class, is set out in tables 18 through 21 of Exhibit 1, Tab C (see pages 43 through 45 of that exhibit).

Also, please refer to 10.0-Staff-42.

OSHAWA PUC NETWORKS INC.

Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatory 10.0-VECC-55

Reference: E10/TC

a) Please identify any benchmarks that are used to adjust the rate that is calculated in years 2016 and onward.

b) Please show any productivity or stretch factors to be applied to the rate adjustment formula.

c) Please show any incentive adjustments that would be applied to the formula.

d) Please describe how this plan differs from a 5 years cost of service rate setting methodology.

e) Please explain in light of the Board's decision in EB-2013-0416 how OPUCN's proposal for setting rates in each year differs conceptually from that of Hydro One Distribution.

Response:

a) OPUCN has not proposed to adjust its rates by reference to "benchmarks". OPUCN has produced independent evidence which benchmarks its forecast costs against its peers, including econometric benchmarking through PEG's Ontario distributor cost models against predicted costs based on OPUCN's input parameters for that model. The benchmarking evidence provided will allow the Board to focus its evaluation of OPUCN's proposed rates on the appropriate regulatory "outcomes" and OPUCN cost performance, rather than detailed input cost assessment.

b) OPUCN has not proposed a rate adjustment formula. Please see the responses to interrogatory 10.0-Staff-43 and 10.0-Staff-44 for a discussion of how OPUCN's proposal compares to an "I-X" outcome.

c) OPUCN has not proposed a rate adjustment formula.

d) OPUCN's Custom IR Rate Plan is based on OPUCN's cost and revenue forecasts over a 5 year time horizon, including the cost and revenue requirement impacts of detailed infrastructure investment plans over that same time frame, all as contemplated by the Board's *Renewed Regulatory Framework for Electricity Distributors* (*RRFE*) [See page 19 of the *RRFE* report].

The Board's *RRFE* permits 3 approaches to electricity distribution rate setting. OPUCN has provided detailed evidence to demonstrate why setting its rates under either the IR Index or the 4th Generation IRM approach would be inappropriate. In short, under either of these approaches (neither of which contemplate ongoing capital module adjustments – see response to interrogatory 10.0-Energy Prove-72, part c), OPUCN would fail to earn a fair return on investment, and potentially fail to earn sufficient revenue even to sustain safe and reliable distribution system operations for Oshawa's rapidly growing base of electricity consumers. OPUCN has thus applied for rates under the 3rd permitted approach for electricity distribution rate making; Custom IR.

The basis on which OPUCN's Custom IR Rate proposal meets the parameters for Custom IR set out in the *RRFE,* as subsequently elaborated on by the Board in the Enbridge Gas Distribution EB-2012-0459 decision, is set out in detail at Exhibit 1, Tab C, pages 15 through 19. That basis includes;

1. committing to manage within rates set now for a 5 year plan term, subject only to certain pre-defined adjustments to balance the risks as between shareholder and ratepayers for certain uncontrollable material cost variances;

2. providing a rate smoothing proposal to help manage the pace of rate increases for customers;

3. providing independent benchmarking evidence, as well as statistical evidence benchmarking OPUCN's future performance to the current performance of its peers, all in order to allow the Board to focus its evaluation of OPUCN's proposed rates on the appropriate regulatory "outcomes" and OPUCN cost performance, rather than detailed input cost assessment;

4. proposing and committing to rates and associated revenues that anticipate continued superior efficiencies throughout the plan term;

5. proposing two novel mechanisms to incent further efficiencies; and

6. committing to ongoing plan term reporting to allow for, *inter alia*, monitoring by the Board and interested parties of OPUCN's performance during the plan term, and in particular its progress in executing its

comprehensive Distribution System Plan and associated Capital Investment Plan to be approved in this application.

e) As OPUCN understands Hydro One's application, and the basis for the Board's decision thereon:

1. Hydro One did not demonstrate to the Board's satisfaction continuing efficiency during it proposed plan term. OPUCN has provided detailed evidence of continuing, and in fact improving, efficiency during its proposed plan term. OPUCN has presented statistical analysis and comparison to other similar Ontario electricity distributors. OPUCN has also presented an independent, econometric benchmarking of its proposed versus econometrically expected efficiency as at the end of the plan term.

2. Hydro One did not produce external benchmarking evidence in support of its proposed Custom IR plan. OPUCN has produced robust external benchmarking evidence of both its proposed plan term costs and its Distribution System Plan and associated Capital Investment Program.

3. Hydro One failed to produce a consolidated distribution system plan. OPUCN has produced, and has based its 5 year rate proposal on, a comprehensive and externally reviewed Consolidated Distribution System Plan.

4. Hydro One failed to demonstrate the links between its capital investment planning and its capital expenditure proposals. OPUCN's evidence provides clear links between OPUCN's Asset Condition Assessment and resulting comprehensive Distribution System Plan on the one hand, and its Capital Investment Program on the other hand. OPUCN's Capital Investment Program reflects both pacing of its proposed investments and responsiveness to feedback from its customers, which feedback emphasizes the value that customers place on reliability of electricity service and outage restoration and outage status communication.

5. The Board also found concerns with Hydro One's cost levels, in particular in respect of compensation, vegetation management, and proposed CDM research and development. OPUCN has provided robust evidence of higher than average cost efficiency across its capital investment program and its operating plans and associated costs, both currently and through the proposed rate plan term.

OSHAWA PUC NETWORKS INC.

Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatory 10.0-VECC-56

Reference: E10/TD/pg.7

Please list all variance or deferral accounts being sought in this application as part of the rate adjustment proposal. For each account please describe how the account mitigates Utility or ratepayer risk in each year of the formula.

Response:

The requested deferral and variance accounts being sought are all detailed in the evidence at Exhibit 1, Tab C, pages 36 through 41. Full discussion of the proposed annual adjustments, and the risk balance achieved thereby, is provided at Exhibit 10, Tab D and is also discussed in response to interrogatory 10.0-Staff-42.

OSHAWA PUC NETWORKS INC.

Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatory 10.0-VECC-57

Reference: E10/TDpg.15

For clarity please provide a numeric example of how the TCECM would be applied over the 2015- 2019 rate year.

Response:

The TCECM would not be applied during the rate plan period. It would be applied following the conclusion of the rate plan period, and any resulting efficiency reward would be recovered during 2020 and 2021.

Please see response to interrogatory 10.0-SEC-46 for an example.

OSHAWA PUC NETWORKS INC.

Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatory 10.0-VECC-58

Reference: E10/TC/pg.15

For the CCIEIM program please provide:

- The forecast costs for each of 2015 through 2019 costs for each of the system renewal program and the municipal substation program.
- Provide the amount to be booked as a reference amount to be spent in each year of the program

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Response:

Please see interrogatory response 10.0-SEC-47, part a).