Enbridge Gas Distribution's Customized Incentive Regulation Proposal

Assessment and Recommendations

October 2013

Pacific Economics Group Research, LLC

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1.1 Introduction

In June 2013, Enbridge Gas Distribution Inc. ("EGD," or "the Company") filed a customized incentive regulation ("Customized IR") proposal with the Ontario Energy Board ("OEB" or "the Board"). EGD's Customized IR plan would set gas distribution rates for EGD that recover the Company's projected costs of providing gas distribution services over the term of the plan.

Board staff asked Pacific Economics Group Research ("PEG") to provide a written assessment of the merits of EGD's Customized IR proposal. This assessment would address whether the proposed IR plan was consistent with sound principles for incentive regulation and the Board's IR criteria. It would also include a preliminary analysis of the empirical research that EGD and its advisor Concentric Energy Advisors ("CEA") provided in support of the IR proposal.

This report presents the findings of PEG's analysis. Chapter Two addresses the design and incentive consequences of EGD's Customized IR proposal. Chapter Three analyzes the empirical research presented in support of this proposal. Chapter Four presents concluding remarks.

1.2 Executive Summary

Our analysis can be briefly summarized. Regarding the regulatory design issues, PEG's review leads us to conclude that the Company's IR proposal is flawed. EGD's Customized IR plan has some similarities to the Company's first generation, "targeted" IR plan which the Board found in the Natural Gas Forum ("NGF") Report did not work effectively. EGD's IR proposal exacerbates the disparate treatment of capital and operation, maintenance and administrative ("OM&A") costs and thereby tends to create unbalanced incentives similar to those identified by the Board in the NGF.

EGD's IR proposal is based on a three-year forecast of the Company's costs, which falls short of the Board's minimum term of five years for a Custom IR plan. EGD says it cannot present a five year cost forecast because of the uncertainty of forecasting its 2017-18 investment needs. EGD plans to adjudicate revenue requirements for these years within the term of its proposed Customized IR proposal. Re-setting revenue requirements in the middle of an IR plan is inconsistent with the rationale for incentive regulation, which is designed to be an alternative to COSR that creates stronger performance incentives by extending the period between cost-based rate reviews. Because re-setting rates within the term of a multi-year IR plan will impose monetary and opportunity costs on the Company, the Board and intervenors, this provision of EGD's IR proposal is not consistent with the Board's objective of creating incentives that promote sustainable efficiency improvements.

EGD says its Customized IR proposal is an example of "building block" regulation, but it is a version of building blocks that the UK energy regulator abandoned nearly a decade ago because of its poor incentive properties. The EGD's Customized IR proposal creates the same perverse *ex ante* incentives to inflate capital cost projections as the early UK building block plans. Because the Company's capital expenditure *forecasts* are not supported by independent and external benchmarking evidence, the inherent incentive to inflate these forecasts under the Customized IR proposal can generate unreasonably high prices and shift risks to customers.

EGD claims its proposed ESM provides assurance to the Board that its cost forecasts are reasonable, but PEG disagrees. The ESM does not provide any independent verification that the *ex ante* cost forecasts reflected in rates are reasonable. The Customized IR can also create incentives for EGD to act inefficiently in order to avoid triggering the off-ramp and a review of the Company's cost projections

EGD's proposed Z-factor language is also problematic. The Company's amended Z factor would allow rate adjustments for cost increases or decreases demonstrably linked to an unexpected, non-routine cause. This "unexpected cause" language could plausibly be interpreted to mean *any* cost change that is not reflected in Company's cost forecasts, since the forecasts themselves presumably reflect the expected causes. This amended Z factor language has the potential to expand the frequency, contentiousness, and cost of Z factor proceedings.

EGD's proposal includes an AU factor and several new variance and deferral accounts, which PEG does not oppose. We note, however, that these provisions protect EGD shareholders against some of the most important risks the Company will face over the term of its IR plan. These features of the proposal further shift the risk-reward balance under the plan towards protecting EGD shareholders. It should also be recognized that if these mechanisms were part of an IR plan that included an "inflation minus X" rate adjustment rather than a Customized IR approach, the plan would continue to offer substantial risk protection to EGD shareholders.

EGD's sustainable efficiency incentive mechanism ("SEIM") is incompatible with the Board's objectives for incentive regulation. The SEIM inverts the design and rationale of appropriate efficiency carry-over mechanisms and it would weaken, not strengthen, performance incentives. It also creates a new risk and shifts that risk to customers. As currently designed, the SEIM should be rejected.

PEG also concludes that EGD's IR proposal is more akin to a three-year IR than a five-year IR plan. In the NGF, the Board found that three years is the minimum term that is expected to give rise to productivity incentives, and its preference is for IR plans of five years. The relatively shorter duration of the Company's IR proposal will have a negative impact on EGD's ability to implement sustainable efficiency initiatives.

The empirical research presented in support of the proposed plan is primarily used to evaluate whether conventional IR rate adjustment formulas would recover EGD's projected costs. Whenever CEA finds revenues under a potential rate adjustment formula are below EGD's costs, it concludes that the rate adjustment formula is inappropriate, not the cost levels reflected in the Customized IR proposal. CEA is therefore using the Company's cost proposals to "benchmark" the reasonableness of IR rate adjustment formulas, not the other way around.

CEA's research does not support the efficiency of EGD's projected costs or the reasonableness of the Customized IR proposal itself. CEA takes the reasonableness of EGD's cost forecasts as given and simply evaluates whether alternate rate adjustment formulas calibrated with its research would allow EGD to recover these projected costs. CEA has not developed any independent evidence that can be used to confirm, reject or otherwise test the reasonableness of EGD's forecast costs over the term of its Customized IR proposal. The reasonableness of EGD's Custom IR application depends on the reasonableness of its cost projections. Since CEA's empirical analysis provides no evidence on the latter issue, it does not affirm the reasonableness of EGD's Customized IR proposal.

Although CEA has not benchmarked EGD's cost projections, it has benchmarked the Company's historical costs, but no conclusions can be drawn about EGD's cost efficiency from this analysis. CEA's benchmarking methodology provides no persuasive evidence on EGD's cost efficiency for four main reasons. First, CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency. Second, CEA provides no justification for the similar-weather criterion it uses to select its peer group. This criterion tilts the peer group towards a high-cost set of US "rust belt" distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks. Third, CEA's benchmarking methodology does not control for differences in scale economies among the distributors that are selected for its peer group; all else equal, this will tend to improve benchmarking assessments for larger distributors in the group, like EGD. Fourth, CEA does not attempt to undertake comprehensive cost comparisons even though such comparisons are feasible given its methodology. The partial OM&A cost comparisons that CEA relies on provide an incomplete and potentially misleading measure of relative cost efficiencies.

CEA has also undertaken a productivity study for EGD and a group of US utilities. This study yields markedly lower estimates of total factor productivity ("TFP") growth for the Company and the industry than credible estimates of these TFP trends that have been presented elsewhere. A likely explanation (at least in part) for CEA's anomalous results is that its sample is tilted towards slow-growth rust belt utilities. Economic and output growth for these gas distributors will be below the industry norm. All else equal, slower output growth will be reflected in slower TFP growth.

A TFP study like CEA's that arbitrarily rules out half of the US gas distribution industry cannot yield a credible estimate of the industry's TFP trend. Such a trend is also not relevant for EGD, since the Company continues to experience rapid customer and output growth. PEG is likely to have further comments on CEA's TFP results after we have had an opportunity to review CEA's work in detail.

CEA also excludes a stretch factor from the empirical analyses it uses to evaluate alternate rate adjustment mechanisms. PEG believes this conclusion is unwarranted for four reasons: 1) there is no persuasive evidence that EGD is actually an efficient cost performer; 2) the Board has rejected the view that stretch factors are appropriate only for distributors under a "first generation" IR plan in its findings for both 3rd Generation IR and 4th Generation IR for electricity distributors; 3) the Board cannot be assured that EGD's proposed ESM will either protect customers or allow them to share in EGD efficiency gains under the Company's proposed Custom IR plan; and 4) CEA's TFP evidence is inconsistent with credible TFP evidence that has been presented elsewhere.

The industry-specific inflation factor used in CEA's empirical research is unacceptable (as currently designed) because it excludes the rate of return on a utility's capital stock, as well as depreciation of that capital stock. These are large components of capital input prices, and any input price inflation measure that excludes them is not a credible measure of input prices for the gas distribution industry. The Board should reject CEA's proposed inflation factor.

EGD also discusses the process used to develop its forecasts for OM&A and capital expenditures. While the Company's testimony on these issues is interesting, it ultimately provides no assurance that the cost projections embedded in the Customized IR proposal are efficient. If the capital cost forecasts submitted at the outset of the budget process are inflated, the capital cost projections at the end of the process can also be inflated. Given the Company's incentives to err on the "high" side when forecasting capital expenditures for a Customized IR plan, PEG believes EGD must provide compelling evidence to the Board that both its initial and final capital cost projections are efficient and will generate reasonable prices. PEG does not believe EGD's application contains such evidence.

Overall, PEG finds that EGD's Customized IR proposal raises serious concerns. The proposed plan has poor incentive properties that may generate unreasonable prices and shift risks to customers. The empirical analysis presented in support of the proposed plan is also not compelling and does not allay PEG's fundamental concerns with the Customized IR proposal.

PEG notes that our analysis of the Company's previous IR plan indicated that it generated benefits for both shareholders and customers and was consistent with the Board's criteria for effective regulation. We believe that an IR plan for the 2014-18 period that is calibrated using objective measures of industry TFP growth, appropriate benchmarking studies, and well-designed benefit sharing provisions will also be effective. This plan can also contain Y factors that recover the costs of large capital projects. PEG believes the input price and TFP research for US gas distributors that was presented in Alberta can be used to assess the appropriateness of the elements of an IR plan for EGD.

2. Analysis of Regulatory Design Issues

2.1 Overview of EGD IR Proposal

EGD was subject to an IR plan from 2008 through 2012. The Company's rates were rebased in 2013 when this plan expired. In June 2013, EGD filed a new incentive regulation proposal, and the main elements of this proposal are briefly summarized below:

- ***Base for Rate Adjustments*** 2013 approved rates

- ***Form of Plan*** The proposal would set rates that recover EGD's proposed revenue requirements in 2014, 2015 and 2016. EGD refers to the direct recovery of its proposed revenue requirements in these years as a "customized incentive regulation plan."

- ***Annual Adjustment Mechanism***. Rates would adjust to recover the Company's allowed revenue requirement in 2014, 2015, and 2016. The annual adjustment would take place on January 1 of each year.

- ***Inflation Factor.*** The rate adjustment mechanism does not use an inflation factor. However, Concentric Energy Associates (CEA) developed a three-factor, industry input price inflation factor that it used to evaluate whether alternate "inflation minus X" factor rate adjustment mechanisms would recover EGD's proposed allowable revenue amounts in 2014, 2015, and 2016. CEA concluded that none of the rate adjustment formulas it examined would recover EGD's proposed costs in these years.

- ***X Factor*** The rate adjustment mechanism does not use an X factor. However, CEA developed estimates of total factor productivity (TFP) trends for the gas distribution industry that it used to evaluate whether alternate "inflation minus X" factor rate adjustment mechanisms would recover EGD's proposed allowable revenue amounts in 2014, 2015, and 2016. CEA concluded that none of the rate adjustment formulas it examined would recover EGD's proposed costs in these years.

- ***Average Use***. EGD rates would adjust to reflect differences between forecast average natural gas usage per customer (AUPC) and actual AUPC in each year; this difference will be captured in a variance account. EGD's proposed average use factor is the same as what the Board approved for EGD's 2008-2012 incentive regulation plan.

- ***Plan Term***. The current proposal sets allowed revenue amounts for three years: 2014, 2015, and 2016. In 2016, EGD would file proposed revenue amounts for 2017 and 2018 to be recovered in rate adjustments that take place in those years.

- ***Y Factors***. The proposal does not include Y factors *per se* but does include a variety of deferral and variance accounts. These include a new proposed variance account to recover the full costs of the Greater Toronto Area Project Variance Account (GTAPVA), which is designed to reinforce infrastructure in the Greater Toronto area. It also includes new deferral accounts for Customer Care Services Procurement, Greenhouse Gas Emissions Impact, and a Constant Dollar Net Salvage adjustment.

- ***Z Factor***. EGD's proposed Z factor would be a non-routine adjustment intended to safeguard customers and the gas utility against unexpected cost increases or cost decreases that are outside of management control. To be eligible for Z factor recovery, a cost increase or decrease must meet the following criteria:
  - The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause.
  - The cause of the cost increase/decrease must not be reasonably within the control of utility management, and it must be a cause that utility management is unable to prevent by the exercise of due diligence
  - The cost at issue must be an increase or decrease from amounts included within the allowed revenue amounts and must meet a materiality threshold equal to $1.5 million in a fiscal year
  - The cost increase/decrease must be prudently incurred

- ***Earning Sharing Mechanism***. The Earnings Sharing Mechanism ("ESM") shares earnings between customers and shareholders when EGD's weather-normalized actual return on equity ("ROE") exceeds the Company's allowed ROE plus 100 basis points; 50% of the difference between actual ROE and allowed ROE plus 100 basis will be distributed to customers in the form of (negative) rate adjustments in the following year. The proposed ESM is identical to the ESM approved for EGD's 2008-2012 plan.

- ***Off-ramps***. Off-ramps refer to a set of pre-defined conditions which, when satisfied, could lead the IR plan to be terminated or modified before the scheduled end of the plan term. The Board will review EGD's IR plan if the Company's weather-normalized ROE differs from its approved ROE by +/- 300 basis points. The proposed off-ramp is identical to what the Board approved for EGD's 2008-2012 plan.

- ***Sustainable Efficiency Incentive Mechanism*** EGD's IR proposal also includes what the Company calls a Sustainable Efficiency Incentive Mechanism ("SEIM"). The SEIM is an *ex ante* incentive payment provided to the Company for qualified projects that the Board would review and approve in EGD's annual ESM application. The SEIM incentive payment would be equal to 20% of the estimated net present value (NPV) of the net benefits of qualified projects.

- ***Reporting Requirements***. EGD will file an annual Productivity Initiatives Report in ESM applications. This report will provide information on proposed productivity initiatives and the estimated, long-term benefits from those initiatives. EGD will also file a Performance Metrics Benchmarking Report at the end of the IR plan.

- ***Rebasing***. A rate rebasing will take place at the end of the IR plan. Rebased rates will be established through a comprehensive, cost of service proceeding and will be the foundation for rate adjustments in the succeeding IR plan. Rebasing is critical for ensuring that efficiency improvements achieved during the plan term are revealed, and these benefits are passed on to customers through rates in the next period.

EGD's proposed IR plan differs in several respects from the IR plan approved for the Company in 2008-2012. The most important of these differences are the following:

- ***Form of the Plan/Rate Adjustment Mechanism*** Rate changes in the "Customized IR" proposal directly recover the Company's proposed revenue requirements in 2014-2016. In EGD's 2008-2012 IR plan, the rate adjustment mechanism was equal to a pre-determined percentage of the annual change in the gross domestic product implicit price index for final domestic demand (GDP-IPI).[1]

- ***Z Factor*** The criteria for Z factor recovery of cost changes in the Customized IR proposal differ from the Z factor criteria approved in EGD's last IR plan; in particular:
    - The proposed Z factor recovers cost changes linked to unexpected, non-routine *causes*; the previous Z factor recovered the costs of unexpected *events*
    - The current proposal allows Z factor recovery for costs that are not reasonably within the control of utility management and that management is unable to prevent through due diligence; in the previous IR plan, Z factor recovery was allowed only for cost changes beyond the control of management and if the cost was a risk a prudent utility could not mitigate

[1] More precisely, the EGD annual adjustment mechanism in 2008-2012 was expressed as the product of GDP-IPI inflation and an "inflation coefficient." This inflation coefficient took values of 0.60 in 2008, 0.55 in 2009 and 2010, 0.50 in 2011, and 0.45 in 2012. Thus, under this approach, the annual adjustment mechanism increased EGD's allowed gas delivery rates by 60% of measured GDP IPI inflation in 2008, 55% of measured GDP IPI inflation in 2009 and 2010, 50% of measured GDP IPI inflation in 2011, and 45% of measured GDP IPI inflation in 2012. Because allowed prices increased by only a fraction of measured inflation, the EGD annual adjustment mechanism can be interpreted as having an "implicit X factor," where X is the amount by which rate adjustments are held below inflation, as in the more typical "inflation minus X" formula. The implicit X in the EGD mechanism depends directly on measured inflation and, in fact, is equal to one minus the inflation coefficient in that year. Therefore the implicit X values in the EGD adjustment mechanism were 40% of GDP IPI inflation in 2008, 45% of GDP IPI inflation in 2009 and 2010, 50% of GDP IPI inflation in 2011, and 55% of GDP IPI inflation in 2012.

- ***Sustainable Efficiency Incentive Mechanism*** EGD's Customized IR proposal includes an SEIM; the Company's 2008-2012 IR plan did not.

- ***Term*** The EGD proposal has two distinct, but linked, terms: an initial three-year term, where the Customized IR plan recovers expected revenue requirements in 2014-2016; followed by a two-year term, where the plan recovers 2017-18 cost forecasts that EGD files with the Board in 2016. The previous IR plan had a five-year term.

EGD's proposal also essentially eliminates Y factors but amends the variance and deferral accounts from the previous IR plan. The proposal also changes IR reporting requirements. The proposed AU term, off-ramp, and ESM are unchanged from the previous IR plan. However, PEG believes the ESM can lead to very different risk-sharing and customer benefit outcomes under the Company's Customized IR proposal than under previous IR plans and ESMs the Board has approved. We will address these issues in Section 2.3.

2.2 Form of Plan

EGD and its advisors London Economics International (LEI) and Concentric Energy Advisors (CEA) make a number of claims regarding the nature and form of the Company's IR proposal. PEG will address three of these claims. The first is that the Company's current proposal represents "second generation" incentive regulation for EGD. The second is that this proposal is consistent with the "Custom IR" alternative the Board introduced in the Renewed Regulatory Framework for Electricity (RRFE). The third is that EGD's proposal is an example of "building block" incentive regulation that has been implemented effectively, and led to positive outcomes, in the UK, Australia, and other jurisdictions. PEG will examine each of these claims in turn.

2.2.1 EGD's First Generation Plan and Board Incentive Regulation Criteria

The Company and its advisors repeatedly refer to EGD's current IR proposal as the Company's "second generation" IR plan. EGD's 2008-12 IR is called the Company's "first generation" IR plan.

PEG believes the references to EGD's "first generation" and "second generation" IR plans are not accurate because the Board approved a targeted IR plan for the Company in 1999. Properly accounting for this plan makes EGD's current proposal a "third generation" IR plan. Moreover, EGD's first generation IR experience is relevant for understanding the Board's criteria for effective IR and, therefore, EGD's current IR proposal. A brief review of EGD's first generation plan and its implications for incentive regulation in Ontario is therefore instructive.

In 1999, the OEB approved a targeted performance based regulation ("TPBR") plan that adjusted EGD's allowed OM&A expenses over the 2000-2002 period using an indexing formula.[2] At the time, the Board described this as an important step on the transition to comprehensive IR that applies to all gas distribution costs. While the TPBR was in effect, however, EGD's capital costs continued to be subject to cost of service regulation ("COSR").

The TPBR generated a considerable amount of controversy. Accordingly, when the plan expired in 2002, Enbridge did not present an updated PBR proposal. Instead it filed a series of one-year, traditional COSR rate cases.

In 2004-05, the Board undertook a comprehensive review of Ontario's natural gas sector called the Natural Gas Forum (NGF). A key issue in the NGF was whether incentive regulation should remain part of the ratemaking framework in Ontario. This was a focus for the Board partly because EGD's first generation IR plan was considered to be unsuccessful, and the Company reverted to COSR when this first generation IR plan expired.

The NGF Report considered the merits of EGD's targeted IR approach and comprehensive IR plans that are applied to all costs. The Board wrote that

> "Most PBR plans are comprehensive, to create stronger and more balanced incentives. For example, a plan that focuses only on operating and maintenance expenses may weaken incentives to control capital costs, with the effect that overall performance incentives may not be improved. A plan that targets only certain areas may unintentionally create incentives for firms to allocate costs differently than they otherwise would. The targeted nature of the Enbridge PBR plan may have played a role in the general dissatisfaction for this type of plan."[3]

[2] The inflation factor in the formula was the Ontario Consumers Price Index (CPI). The X factor of 1.1%, was equal to a 0.63% OM&A partial factor productivity (PFP) growth trend plus a stretch factor of 0.47%.

[3] Ontario Energy Board, *op cit*, p. 15-16.

The Board concluded that "the targeted approach did not work effectively because it diluted and distorted the incentives, and that a comprehensive model is preferable."[4] The Board also found that "utilities should not alternate between COSR and an IR framework. Switching between rate frameworks could make robust benefit sharing harder to achieve and introduce confusion and mistrust."[5]

Notwithstanding the Board's stated concerns with EGD's first generation IR plan, the outcome of the NGF was a re-commitment by the Board to IR. The Board found that

> "…a multi-year incentive regulation plan can be developed that will meet its (the Board's) criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment…The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan."[6]

The Board also found that an effective ratemaking framework that fulfills its legislated objectives must satisfy the following criteria:[7]

- Establish incentives for sustainable efficiency improvements that benefit both customers and shareholders
- Ensure appropriate quality of service for customers
- Create an environment that is conducive to investment, to the benefit of both customers and shareholders

EGD's current, third generation IR proposal has some similarities to the Company's first generation IR plan that the NGF Report found "did not work effectively." Although EGD's current proposal is not targeted solely on adjusting allowed OM&A costs, the Customized IR would (like EGD's first generation IR plan) have different regulatory treatment for OM&A and capital expenditures. After the third year of the plan, EGD proposes to "true up" the regulated

[4] Ontario Energy Board, *op cit*, p. 22.
[5] Ontario Energy Board, *op cit*, p. 22.
[6] Ontario Energy Board, *op cit*, p. 22.
[7] In particular, the Board said an effective regulatory framework must take account of the following legislated objectives: 1) to protect the interests of consumers with respect to prices and the reliability and quality of gas service; 2) to facilitate rational expansion of transmission and distribution systems and rational development and safe operation of gas storage; and 3) to facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

net asset value to the lower of either the actual or forecast value of net assets. The variance account on the GTA reinforcement project will also effectively true up rates to recover expenditures on this project. These true-up mechanisms are clearly reminiscent of COSR rather than IR, and they apply only to capital rather than OM&A costs. It is also important to recognize that these true-ups will occur within what EGD considers the five-year term of its IR plan. EGD's IR proposal therefore accentuates the role of COSR-type capital cost true-ups during the term of a purportedly multi-year IR framework, rather than deferring such true-ups until the end of the plan when rates are rebased to reflect costs.

By exacerbating the disparate treatment of capital and OM&A costs, and placing more emphasis on COSR-type mechanisms within an IR framework, EGD's Customized IR proposal tends to create unbalanced incentives similar to those identified by the Board in the NGF. In particular, EGD's proposal places more weight on cost-based regulation of capital costs than on OM&A expenditures. These provisions, in turn, create relatively weaker incentives to control capital costs. EGD's Customized IR proposal therefore has the potential to generate "diluted and distorted incentives" like those of the Company's first generation, targeted IR plan, which the Board found had undermined the success of that earlier plan.[8]

2.2.2 The "Customized" Incentive Regulation Option

As discussed, EGD describes its IR proposal as a customized IR approach. The Company specifically relates this proposal to the "Custom IR" option that the Board introduced in the RRFE. For example, EGD says that "at a high level…Enbridge's Customized IR plan is aligned with the 'Custom IR' model" that was established in the RRFE.[9]

However, in the RRFE, the Board established minimum requirements that a Custom IR proposal must satisfy, and EGD's proposal does not meet these requirements. The Board states that

[8] In its RRFE Report, the Board re-iterated the importance of comprehensive IR for creating balanced incentives. For example, the Board says that it "…continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework"; Ontario Energy Board, *Report of the Board: Renewed Regulatory Framework for Electricity: A Performance-Based Approach*, October 18, 2012, p. 9.

[9] EB-2012-0459, Exhibit A2, Tab 1, Schedule 1, p. 29.

> In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes…The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.[10]

A related reason a Custom IR must have a minimum five year term pertains to the administrative costs and regulatory burdens associated with this option. The Board has found that

> The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination.[11]

EGD's IR proposal is based on a three-year forecast of the Company's costs, which falls short of the Board's "minimum term of five years." EGD has not presented a five year cost forecast because it says there is too much uncertainty regarding 2017-18 investment needs to be able to forecast these costs with confidence. The Company is proposing to calibrate rates for these years using 2017-18 capital expenditure forecasts it presents to the Board in 2016. Thus, EGD's plan requires "the adjudication of an application" *within the term* of its proposed Customized IR proposal, which is clearly incompatible with the Board's expectations and objectives for Custom IR. Re-setting revenue requirements in the middle of a multi-year IR plan is also inconsistent with the fundamental rationale for incentive regulation, which is designed to be an alternative to COSR that creates stronger performance incentives by extending the period between cost-based rate reviews.

2.2.3 Forecasts, Risks and "Building Block" IR

EGD is proposing a type of incentive regulation where forecasting plays an explicit, central role. Its Customized IR plan contrasts with the more typical IR approach in Ontario where rate adjustment mechanisms are calibrated using historical, industry-wide empirical parameters. However, at the same time that EGD is proposing a forecast-based IR method, the Company will not "commit" to revenue requirement forecasts beyond three years primarily

[10] Ontario Energy Board, *Report of the Board: Renewed Regulatory Framework for Electricity: A Performance-Based Approach*, October 18, 2012, pp. 18-19.

[11] Ontario Energy Board, *Report of the Board: Renewed Regulatory Framework for Electricity: A Performance-Based Approach*, October 18, 2012, pp. 19.

because of the risk of forecasting capital expenditures. The EGD application is also replete with references to the capital investment risks it faces and is assuming under its proposal.

PEG believes the importance of forecasts in EGD's Customized IR proposal raises (at least) three important issues. First, embedding forecasts in IR plans does not necessarily protect against risk, but it will affect the allocation of risk between customers and shareholders. Second, forecast-based IR approaches create potential incentive problems that are not encountered in standard, North American IR plans calibrated with historical information on industry input price and TFP trends. Third, EGD's Customized IR proposal does not confront these incentive concerns, which are evident in the experience with "building block" incentive regulation elsewhere.

On the first point, forecasts necessarily embody expectations, and the risks associated with cost forecasts depend on the extent to which cost outcomes comport with cost expectations. Under EGD's Customized IR proposal, if actual costs are greater than expected, the Company is (partly) at risk for the difference.[12] However, if actual costs are less than expected, customers are "at risk" since that they are now "committed" to a multi-year plan that generates unreasonably high prices.

Embedding forecasts into utility rates therefore does not automatically protect against risk. Indeed, as EGD notes, there is more risk associated with its multi-year, Customized IR proposal than there would be under conventional COSR. It does not follow, though, that EGD shareholders always assume these risks. If the cost forecasts reflected in the EGD proposal are excessive, the risks have been shifted to customers.

Regarding the second point, EGD argues that assuming risk can be a spur towards greater efficiency. It writes that

> "EGD is taking on significantly more forecast risk than would be the case in a cost of service application, and they represent hurdles to overcome simply to achieve the Allowed ROE. In other words, to make up for the differential between actual costs incurred, and those built into the forecast, the Company will have no choice but to find offsetting cost efficiencies elsewhere."[13]

[12] However, as explained in Sections 2.4 and 2.5, EGD's proposal contains other provisions to protect against unexpected cost changes and other unexpected developments, so the extent to which EGD shareholders would actually be at risk for cost changes under the plan cannot be determine *a prioi*.

[13] EB-2012-0459, Exhibit A2, Tab 1, Schedule 2, p. 6.

This is debatable regarding the Company's behavior *ex post*, or after cost forecasts would be built into the Company's rate adjustments. If this argument is accepted, though, then the opposite is also true. That is, suppose there is a *negative* differential between EGD's "actual costs incurred and those built into the forecast" because the Company's cost projections turn out to be too high. In this instance, EGD may be strongly incented *not* to find cost efficiencies. All else equal, embedding excessive cost forecasts into allowed rates will increase revenues and earnings. If the Company aggressively cuts costs at the same time its revenues are buoyed by excessive cost forecasts, its earnings could be pushed more than 300 basis points above EGD's allowed ROE. This could, in turn, trigger the off-ramp and a review of the plan that ends up reducing EGD's allowed rates. Since EGD would want to avoid such an outcome, its Customized IR proposal could actually encourage the Company to become *less efficient*, since such perverse behavior can promote long-run profitability and mitigate regulatory and business risk.

This analysis raises an important point regarding the incentives EGD faces when projecting its costs *ex ante*, or before its plan would take effect. This issue is irrelevant to most North American index-based IR plans, since rate adjustment formulas in these plans are typically calibrated using industry-wide trends in input price and TFP changes rather than a utility's own cost forecasts. In North American IR, the incentive properties of an IR proposal depend almost entirely on the utility's *ex post* behavior after the IR plan is in effect.

This is not the case with all IR applications, however. Some "building block" IR plans are based directly on utilities' forward-looking cost projections over the term of the upcoming IR. In these plans, it is important to evaluate the *ex ante* incentives a utility faces while developing its regulatory proposal, in addition to the *ex post* incentives generated by the plan after it takes effect.

EGD does not address this issue directly in its application, but the Company, CEA and LEI all agree that EGD's IR proposal is consistent with a "building block" IR application. There are many examples of building block IR plans outside North America. An examination of the *ex ante* forecasting incentives that have actually been observed under building block IR can therefore shed light on this important aspect of EGD's Customized IR proposal.

LEI discusses building block regulation in a report for EGD.[14] LEI writes that "the building blocks approach has been successfully applied in the UK for over 20 years and in Australia for almost the same length of time. These approaches have gone through extensive reviews and have remained in place with some adjustments to underlying parameters but not the overarching framework."[15]

PEG disagrees. We believe there have been substantial changes in the "overarching framework" used to implement building block regulation, particularly in the UK, which has far more experience with this IR method across a range of regulated industries (electricity and gas distribution, water distribution, airport management, rail infrastructure, telecom, and others) than Australia. Moreover, many changes to the UK building block model were motivated by problems that resulted from using utility forecasts to set allowed capital expenditures. The perverse incentives associated with linking rates directly to utilities' projected capital expenditure led the UK Office of Gas and Electricity Markets (Ofgem) to abandon this practice and use a very different approach for setting allowed capital expenditures.[16]

PEG discussed the UK's experience with building block regulation in an Appendix to our February 2008 Report on 3rd Generation Incentive Regulation for electricity distributors.[17] A copy of this chapter is also appended to this report. This Appendix discusses how, under the initial applications of the UK building block model, regulated utilities "gamed" their cost forecasts, particularly for capital expenditures. Utilities would present inflated cost forecasts to the energy regulator before the terms of new price controls were determined but "under-spend" after price controls were set.[18]

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[14] London Economics International, June 26, 2013, *The Building Blocks Approach to Incentive Regulation*, EB-2012-0459, Exhibit A2, Tab 10, Schedule 1, pp. 1- 24.

[15] LEI, *op cit*, p. 3.

[16] LEI makes passing references to some of these tools, such as the Information Quality Incentive Mechanism, but does not explain the motivation for or application of these methods in any detail. The LEI discussion of building blocks is therefore extremely selective, and it elides aspects of the UK's building block model that are central to the UK building block experience.

[17] Kaufmann, L. *et al* (2008), *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario: Report to the Ontario Energy Board*. This Appendix also discussed the experience with building block regulation in the Australian state of Victoria. While the UK chapter was written in early 2008 and therefore does not address developments in UK regulation since 2008, any updated discussion would show more, and not less, divergence between how the UK currently regulates electricity distribution and the description of the building block model in the LEI report.

[18] In UK building block regulation, there were no ESMs or "off-ramps," as in EGD's Custom IR proposal. These aspects of the EGD proposal tend to offset utilities' incentives to reduce costs *ex post* after price controls are established.

Because of these persistent problems, in 2005 the UK established a sliding scale mechanism (later renamed an Information Quality Incentive) for setting allowed capital expenditures under the building block framework. These mechanisms break the direct link between utility capex forecasts and the capital costs that Ofgem allows in regulated rates. The new mechanisms also potentially reward utilities for keeping capital cost projections relatively low. This is a significant change from earlier building block applications, where utilities had little or no incentive to present capital expenditure forecasts to the regulator that were not inflated. PEG summarized this aspect of the UK building block experience as follows:

> "…the building block model is susceptible to gaming on the part of companies. Prices are based on a company's projected costs. Companies therefore clearly have incentives to game the estimates of their projected costs that they present at the outset of the regulatory process. Regulators must attempt to "de-game" these forecasts and ascertain the "truth" about how much costs are actually expected to increase over the term of the controls. This is an inherently imprecise exercise which necessarily exposes regulators to the well-known "information asymmetry" problem, since regulators will know far less about the company's actual and projected costs than the companies themselves. Ironically, economists have long believed that information asymmetries are at the heart of problems with cost of service regulation. Incentive regulation is therefore designed to create regulatory institutions that encourage companies to use their superior information in a socially beneficial manner; it should not allow companies to profit by gaming this information through other channels. The UK has created elaborate sliding scale or information quality incentive mechanisms to counter this problem, but developing and implementing such mechanisms is likely to be difficult and costly in Ontario..."

It should be recognized that when EGD, CEA and LEI say that EGD's Customized IR proposal is an example of "building block" regulation, they are not referring to the building block model currently used to regulate UK gas or electricity distributors, which includes an information quality incentive designed to reduce distributors' ability and incentive to game capital cost forecasts. Instead, they are harkening back to a version of building blocks that Ofgem abandoned nearly a decade ago because of its poor incentive properties. The EGD Customized IR proposal creates the same perverse *ex ante* incentives to inflate capital cost projections as the early UK building block plans. Because the Company's capital expenditure *forecasts* are not supported by independent and external benchmarking evidence, the inherent incentive to inflate capital expenditure forecasts under EGD's Customized IR proposal can generate unreasonably high prices and shift risks to customers.[19]

2.3 Earnings Sharing Mechanism

EGD claims that other aspects of its proposal will protect customers against excess cost forecasts. The most important means of customer protection is purportedly the Company's proposed earnings sharing mechanism ("ESM"). EGD says

> "…the ESM provides an assurance to the Board and stakeholders that Enbridge's costs are reasonable. If Enbridge were to materially underspend relative to the forecast in any given year, then there would be a disbursement to customers of a share of the savings. Alternatively, if Enbridge were to materially overerspend relative to the forecast, customers would not bear any incremental financial burden. Effectively, the ESM serves to assure that the utility does not earn excessive returns at ratepayer expense."[20]

PEG does not believe the ESM provides any assurance to the Board or stakeholders that EGD's cost forecasts are reasonable. At best, the ESM will reflect the relationship between *ex ante* cost projections and *ex post* actual costs. It does not provide any independent verification that the *ex ante* cost forecasts embedded in rates are reasonable. Moreover, as discussed in the previous section, the combination of the Customized IR and the ESM can actually create incentives for EGD to act unreasonably and inefficiently in an effort to avoid sharing earnings and, potentially, triggering the off-ramp and a review of the Company's cost projections.

PEG also does not believe the ESM would protect customers. All else equal, under EGD's IR proposal, excessive cost forecasts lead to excessive customer prices, and prices (not EGD earnings) are the real measure of customer welfare. In addition, under the ESM customers are fully "at risk" for the first 100 basis points of EGD returns above allowed ROE resulting from excessive prices. Customers would also be at risk for 50% of all incremental earning impacts resulting from inflated cost forecasts.

[19] In light of the uncertainties it faces, it would be imprudent if EGD – which has a fiduciary responsibility to maximize returns for shareholders - did *not* err on the high side when developing its capital expenditure forecasts for the Customized IR proposal. Information asymmetries also make it extremely difficult for the Board to ferret out any excess in the Company's forecasts *ex ante*, or determine whether any observed differences between forecast and actual capex under the plan would reflect inflated forecasts presented *ex ante* by the Company or real efficiencies achieved *ex post*.

[20] EB-2012-0459, Exhibit A2, Tab 7, Schedule 1, p. 1.

Indeed, under a Custom IR proposal where rates depend on company cost projections, the Board can only be assured that customers are not paying for excess cost forecasts if there is objective, external evidence that supports the efficiency of the cost *projections* themselves. The ESM may mitigate the impact of excessive cost forecasts on customer rates, but it can never entirely eliminate it. The most extreme form of such "assurance" would be an ESM that distributes 100% of earnings above allowed ROE back to customers. But even in this instance, the Company can potentially prevent excess earnings (resulting from inflated cost forecasts) from being returned to customers by not managing costs efficiently and thereby eliminating its "excess" earnings. In fact, since distributing 100% of earnings to customers would entirely destroy the Company's incentives to behave efficiently, there is a high probability that any attempts to ameliorate concerns about excess earnings through a redesigned and more aggressive ESM would be undermined and offset by the negative incentives that result from such a change. The concerns related to excess cost forecasts are endemic to the basic form of IR EGD is proposing, and they cannot be eliminated through earnings-sharing provisions.

2.4 Z Factor

EGD's proposal also includes amended language regarding Z factor applications. As discussed, there are two main changes to the Z factor in EGD's proposal. First, EGD's proposed Z factor would recover cost changes linked to unexpected, non-routine *causes*; the Z factor in the Company's 2008-2012 IR plan recovered the costs of unexpected *events*. Second, EGD proposes Z factor recovery for costs that are not reasonably within the control of utility management and that management is unable to prevent through due diligence; in EGD's previous IR plan, Z factor recovery was allowed only for cost changes beyond the control of management and if the cost was a risk a prudent utility could not mitigate.

The Company claims that its proposal makes "enhancements...to the Z-factor description and criteria" which "...will make the identification and evaluation of potential Z-factors requests more clear and consistent."[21] EGD claims that, in the previous IR plan, confusion about what costs qualify for Z-factor treatment arose in three ways:[22]

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[21] EB-2012-0459, Exhibit AW, Tab 4, Schedule 1, p. 1.

[22] EB-2012-0459, Exhibit AW, Tab 4, Schedule 1, p. 4-5.

1. The reference to a discrete event in the 2008-2012 IR plan was too restrictive because it is difficult to pinpoint one item or event that leads to changes in costs.

2. The requirement that the cost be beyond management control was unreasonable because most costs incurred by utilities are at least partly within management's control. EGD believes the key issue to be examined in relation to management control is whether management could have entirely prevented the costs.

3. The requirement that the cost not be "a risk in respect of which a prudent utility would take risk mitigation steps" was difficult to understand and interpret.

There is some merit in EGD's second and third points. Requiring that a cost not be "a risk in respect of which a prudent utility would take risk mitigation steps" is not entirely clear and can be interpreted in numerous ways. Many utility costs are also at least partly within management control, but the magnitudes of these costs can be impacted by exogenous events.

PEG believes these concerns can be addressed by changing criterion ii) in the Z factor language of the 2008-2012 IR plan from:

ii. the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps

To the following:

ii. the cost must be beyond what Company management could reasonably control or prevent through the exercise of due diligence

However, PEG does not agree with EGD's first concern. In our opinion, the 2008-2012 Z factor language that an "event must be causally related to an increase/decrease in cost" is far more clear than EGD's proposal that "the cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause." "Events" are discrete, concrete and readily identifiable. "Causes" are often subtle, complex and difficult to identify. Changing the impetus for Z-factor filings from "events" to "unexpected, non-routine causes" would shift the focus of Z investigations into broader and murkier territory. This, in turn, is likely to lead to more frequent, contentious and costly Z factor proceedings.

These concerns are heightened by the potential interaction between EGD's proposed Z factor language and the customized IR form of its proposal. EGD's Customized IR plan is designed to recover EGD's projected costs in 2014, 2015 and 2016 (and, after a subsequent application, in 2017-18). The projected costs in the Customized IR proposal reflect (with some adjustments) the Company's expected costs in the respective years.

EGD's proposed Z-factor language would allow rate adjustments for cost increases or decreases demonstrably linked to an unexpected, non-routine cause. This "unexpected cause" language could plausibly be interpreted to mean *any* cost change that is not reflected in Company's cost forecasts, since the forecasts themselves presumably reflect the expected causes.[23] The Company could thereby file Z factor applications whenever a "cause" arises that it did not anticipate when preparing the cost projections included in the EGD proposal. This would clearly be an overly broad application of the Z factor that is incompatible with the Board finding in the NGF that Z factors be applied "in limited, well-defined and well-justified cases only."[24] While PEG is not claiming that EGD actually intends to use the Z factor in this manner, we do believe that the interaction between EGD's proposed Z factor language and the form of the proposed Customized IR plan would greatly, and unnecessarily, expand the scope for Z applications compared with the Company's 2008-2012 IR plan.

2.5 AU Factor and Variance Accounts

In addition to the Z factor, ESM and off-ramp, EGD's proposal contains other features that mitigate risks under the plan. One of these provisions is the Average Use ("AU") Factor, which adjusts rates for the difference between forecast gas usage per customer and the weather normalized actual gas use per customer. This difference would be computed annually and captured in a variance account. The form of the AU factor and the Average Use True Up Variance Account are both identical to what the Board approved in EGD's 2008-2012 IR plan.

The Company's proposal also contains new variance and deferral accounts. The most substantive of these accounts is the Greater Toronto Area Project Variance Account ("GTAPVA"). The GTAPVA will true-up customer rates to collect EGD's entire cost of the project designed to reinforce gas delivery infrastructure in the Greater Toronto area. The Company projects that capital expenditures for this project will total $556.8 million in 2014-15.

[23] The Company would still have to demonstrate that the cost change that was experienced was still 'non-routine,' however.

[24] Ontario Energy Board, *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, Report on the Ontario Energy Board Natural Gas Forum, March 20, 2005 (RP-2004-0213), p. 31.

PEG does not oppose the AU factor or the use of variance accounts in EGD's IR proposal. It must be noted, however, that these provisions protect EGD shareholders against some of the most important risks the Company will face over the term of its IR plan. The AU factor largely eliminates the risks associated with declining natural gas usage per customer on EGD's revenues. The GTAPVA would ensure that EGD collects the entire cost of the largest capital investment project it will undertake over the 2014-18 period. These features of the proposal further shift the risk-reward balance under the plan towards protecting EGD shareholders against adverse financial outcomes. It should also be recognized that if the proposed AU factor, GTAPVA and other deferral mechanisms were elements of an IR plan that included an "inflation minus X" rate adjustment rather than a Custom IR approach, the plan would continue to offer substantial protection against risk to EGD shareholders.

2.6 Sustainable Efficiency Incentives

2.6.1 Sustainable Efficiency Incentive Mechanism

EGD's IR proposal also includes what it calls a Sustainable Efficiency Incentive Mechanism ("SEIM"). The SEIM would be implemented via an annual application made with the Company's ESM application. The SEIM application would include information on a number of productivity-boosting initiatives the Company may pursue. The application would present details of the proposed qualifying projects as well as estimates of the proposed long-term, multi-year benefits expected from each project. The SEIM would allow EGD to collect an upfront incentive payment equal to 20% of the net present value of the portfolio of qualifying projects, calculated as the present value of the estimated value of the projects (discounted by 10% forecast error) net of costs. This incentive payment would be incremental to other EGD earnings and not included in the ESM calculation.

PEG believes EGD's SEIM proposal is contrary to incentive regulation theory and regulatory practice. If the objective is to motivate productive behavior through rewards, the rewards must come *after* the desired behavior has taken place and is observed, not before. Rewarding an individual or firm up-front will actually *reduce* performance incentives since there's nothing to be gained, only the downside of expending effort, if financial rewards are reaped without having to take any action.[25] A carrot will only be effective in moving a horse forward if it is dangled in front of his nose, not if you feed it to him before the ride.[26]

The SEIM also differs greatly from the various "efficiency carry over mechanisms" ("ECMs") that have been approved.[27] Those plans allow utilities to retain the benefits of efficiency gains *that have been achieved* beyond the terms of the respective IR plans; they do not reward companies up-front for prospective or promised efficiency gains. In a Concept Paper prepared as part of the RRFE, PEG discussed the details of some of these ECMs:

> "A different, innovative approach towards rate updates has been applied in some UK and Australian plans. In some cases, regulators have created 'efficiency carryover mechanisms' that allowed estimated efficiency gains achieved in an incentive regulation plan to be distributed to customers in increments over the term of the successor plan. This is done by computing company-specific cost benchmarks for operating and capital costs for each year in a five year indexing plan, before that plan takes effect. These operating and capital cost benchmarks are determined as part of the same regulatory review that establishes allowed rate changes for the successor incentive regulation plan. While the plan is in effect, the regulator then monitors the network's actual operating and capital expenditures and computes the difference between actual and benchmark costs. For each cost category, the difference between the actual and benchmark cost is the measured 'efficiency,' which is then distributed to customers as rate reductions in five equal increments over the next five years. For example, efficiencies in year one of a plan are phased out in years two through five of the current plan, and year one of the next plan. Efficiencies in year two of a plan are phased out in years three through five of the current plan, and years one and two of the next plan. This mechanism enables the efficiencies associated with cost savings to be retained by the network for exactly five years, regardless of the year those efficiencies were realized (footnote suppressed)." [28]

In that same report, PEG also describes the potential value of such mechanisms in creating long-term, sustainable efficiency incentives:

[25] This assumes that the rewards will not be taken back after the fact, as in EGD's proposed SEIM. This example also assumes that all financial rewards are reaped immediately, which is not true of EGD's proposed SEIM. Nevertheless, the basic principle and conclusion still applies to the SEIM: rewarding firms up-front reduces performance incentives, it does not enhance them.

[26] The SEIM is unlike upfront "bonuses" that are paid to top executives, sports stars or other highly desired personnel, because in those instances the bonuses are part of a bidding process necessary to attract and hire the individual in the first place. Such up-front bonuses are not characterized as "incentives." Incentive provisions in these types of contracts include payments that are tied to performance after the person has assumed the job, and may be linked to indicators such as the corporation's stock price or whether an athlete wins the Most Valuable Player award in his league.

[27] These types of mechanisms are discussed in the LEI report on pp. 19- 21.

[28] Kaufmann, L., *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper,* Report to the Ontario Energy Board, April 2011, p. 76.

"Indeed, if regulation is designed to encourage greater focus on long-term outcomes, then the rules governing how rates are set when multi-year plans expire become even more critical. Utilities will not invest in initiatives with payback periods (*i.e.* the time it takes for the present value of future financial benefits to exceed the upfront cost of the initiative) that exceed the term of the incentive regulation plan unless there are regulatory assurances that they will be allowed to retain future benefits. In practice, this means that utility time horizons on some investments are naturally limited by the term of the multi-year plan. Efficiency carry-over mechanisms or partial true-ups can extend companies' effective time horizons and may thereby be effective in promoting longer-term thinking and long-term 'value for the money.'"[29]

It is clear from this discussion that the design of approved ECMs is very different from EGD's proposed SEIM. Approved ECMs reward companies *ex post* after they have achieved efficiency gains by allowing them to retain the benefits of those gains for a period of time that extends beyond the term of the IR plan. The SEIM proposes to reward EGD upfront because it has presented an application that promises efficiency gains.

Approved ECMs are also focused on behavior at the end of an IR plan and are designed to create strong performance incentives in every year of the plan. True ECMs therefore promote the Board's objective of generating sustainable, multi-year incentives. The SEIM, on the other hand, is focused on *ex ante* forecasting behavior detailed in an application.

It should also be noted that the LEI report cites several ECMs that were approved in Alberta, but it does not mention the one ECM proposed in Alberta that bears any resemblance to the SEIM and which was the only ECM proposal rejected outright by the Alberta Utilities Commission ("AUC"). The AUC describes the purpose and rationale of an ECM as follows:

> 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.[30]

ATCO Electric proposed what it called a K factor efficiency incentive ("KFEI"). The AUC summarized how this KFEI proposal would operate:

> 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

[29] Kaufmann, L., *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, Report to the Ontario Energy Board, April 2011, p. 77.

[30] Alberta Utilities Commission, *Rate Regulation Initiative: Distribution Performance-Based Regulation*, September 12, 2012, p. 165.

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. 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. (footnotes suppressed)[31]

The AUC rejected this proposal, finding 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.[32]

Like the SEIM, the calculation of rewards under the KFEI would depend on forecast costs. The AUC found that an ECM based on forecast capital costs will create perverse incentives to inflate cost projections and rejected it. Unlike the SEIM, the proposed KFEI did not award the Company up-front based on its cost forecasts, but if it had the KFEI proposal would have generated even worse incentives. Every ECM that was approved by the AUC was designed to allow utilities to retain realized efficiencies (as reflected in earnings in excess of allowed ROE) beyond the term of the IR plan, as previously described in PEG's Concept Paper. None of the ECMs in Alberta reward a utility up-front based on its forecast efficiency gains.

In summary, EGD's SEIM is not only inconsistent with well-designed ECMs, it inverts the design and rationale of appropriate ECMs. The SEIM would accordingly weaken, and not strengthen, performance incentives. It also creates a new risk (*e.g.* the risk that promised efficiency gains will not be realized) and shifts that risk to customers, since customer rates would be raised to pay for the SEIM rewards regardless of whether the initiatives are successful. PEG has always supported well-designed ECMs, but the SEIM proposal is plainly incompatible with effective incentive regulation and the Board's objectives, and it should be rejected.

[31] Alberta Utilities Commission, *Rate Regulation Initiative: Distribution Performance-Based Regulation*, September 12, 2012, p. 166.

[32] Alberta Utilities Commission, *Rate Regulation Initiative: Distribution Performance-Based Regulation*, September 12, 2012, p. 166.

2.6.2 Plan Term and Incentives for Sustainable Efficiencies

The term of the IR plan is also important for creating long-run, sustainable efficiencies. All else equal, incentives are stronger for plans with longer terms. ECMs that allow utilities to retain the benefits of efficiency gains into a succeeding IR plan also strengthen performance incentives.

EGD claims that its Customized IR plan has a five-year term, but the proposal includes a new revenue requirement application after the third year. In most IR plans, presenting a new revenue requirement (*e.g.* resetting the revenue requirements for 2017 and 2018) application effectively signals the end of the incentive-based plan. PEG believes this is also the case with EGD's Customized IR, since it will be difficult for the Company to sustain any multi-year performance initiatives at the same time it is adjudicating new revenue requirements with the Board. Because the outcome of the latter task is inherently uncertain, it runs counter to the regulatory certainty that supports effective incentive regulation and long-term projects.

PEG therefore concludes that EGD's IR proposal is more akin to a three-year IR than a five-year IR plan. In the NGF, the Board found that three years is the minimum term that is expected to give rise to productivity incentives, and its preference is for IR plans of five years. The relatively short duration of the Company's IR proposal will have a negative impact on EGD's ability to implement sustainable efficiency initiatives.

2.7 Assessment of Incentive Properties of EGD's IR Proposal

PEG's assessment of EGD's Customized IR proposal leads us to conclude that the Company's plan is flawed. The Company's proposal has some similarities to its first generation, targeted IR plan which the Board found in the NGF Report did not work effectively. EGD's proposal exacerbates the disparate treatment of capital and OM&A costs and thereby tends to create unbalanced incentives similar to those identified by the Board in the NGF.

EGD's IR proposal is based on a three-year forecast of the Company's costs, which falls short of the Board's "minimum term of five years." EGD says it cannot present a five year cost forecast because of the uncertainty of forecasting its 2017-18 investment needs. EGD plans to adjudicate revenue requirements for these years within the term of its proposed Customized IR proposal, which is incompatible with the Board's expectations and objectives for an IR framework. Re-setting revenue requirements in the middle of an IR plan is also inconsistent with the rationale for incentive regulation, which is designed to be an alternative to COSR that creates stronger performance incentives by extending the period between cost-based rate reviews. Because re-setting rates within the term of a multi-year IR plan will impose monetary and opportunity costs on the Company, the Board and intervenors, this provision of EGD's IR proposal is not consistent with the Board's objective of creating incentives that promote sustainable efficiency improvements.

EGD says its Customized IR proposal is an example of building block regulation, but it is a version of building blocks that Ofgem abandoned nearly a decade ago because of its poor incentive properties. The EGD Customized IR proposal creates the same perverse *ex ante* incentives to inflate capital cost projections as the early UK building block plans. Because the Company's capital expenditure *forecasts* are not supported by independent and external benchmarking evidence, the inherent incentive to inflate capital expenditure forecasts under EGD's Customized IR proposal can generate unreasonably high prices and shift risks to customers.

PEG disagrees with EGD's claim that its proposed ESM provides assurance to the Board that its cost forecasts are reasonable. The ESM does not provide any independent verification that the *ex ante* cost forecasts reflected in rates are reasonable. The Customized IR proposal can also create incentives for EGD to act inefficiently in order to avoid triggering the off-ramp and a review of the Company's cost projections. PEG also does not believe the ESM would protect customers. In fact, PEG concludes that under a Custom IR proposal where rates depend on company cost projections, the Board can only be assured that customers are not paying for excess cost forecasts if there is objective, external evidence that supports the efficiency of the cost *projections* themselves.

EGD's proposed Z-factor language is also problematic. The Company's amended Z factor would allow rate adjustments for cost increases or decreases demonstrably linked to an unexpected, non-routine cause. This "unexpected cause" language could plausibly be interpreted to mean *any* cost change that is not reflected in Company's cost forecasts, since the forecasts themselves presumably reflect the expected causes. This has the potential to expand the frequency, contentiousness, and cost of Z factor proceedings.

EGD's proposal includes an AU factor and several new variance and deferral accounts, which PEG does not oppose. We note, however, that these provisions protect EGD shareholders against some of the most important risks the Company will face over the term of its IR plan. These features of the proposal further shift the risk-reward balance under the plan towards protecting EGD shareholders. It should also be recognized that if these mechanisms were part of an IR plan that included an "inflation minus X" rate adjustment rather than a Custom IR approach, the plan would continue to offer substantial risk protection to EGD shareholders.

EGD's SEIM is incompatible with the Board's objectives for incentive regulation. It inverts the design and rationale of appropriate ECMs. The SEIM would weaken, not strengthen, performance incentives. It also creates a new risk and shifts that risk to customers. As currently designed, the SEIM should be rejected.

PEG also concludes that EGD's IR proposal is more akin to a three-year IR than a five-year IR plan. In the NGF, the Board found that three years is the minimum term that is expected to give rise to productivity incentives, and its preference is for IR plans of five years. The relatively shorter duration of the Company's IR proposal will have a negative impact on EGD's ability to implement sustainable efficiency initiatives.

3. Analysis of Empirical Support for IR Plan

This Chapter addresses the empirical research that CEA and, to a lesser extent, the Company has presented in support of EGD's Customized IR proposal. PEG's analysis is necessarily limited to the information provided in the Company's IR application. PEG reserves the right to provide further comments after we have had a chance to review CEA's workpapers and other details of its empirical research.

We begin by examining how CEA has applied the empirical results it developed. The following three sections evaluate the merits of CEA's proposed benchmarking evidence, estimates of industry total factor productivity (TFP) growth, and proposed inflation factor, respectively.[33] We then briefly consider EGD's proposed expenditure forecasts before providing an overall assessment of the empirical research presented in support of IR.

3.1 Application of Empirical Evidence

CEA applies its empirical analysis in an unusual manner to EGD's IR application. In most IR proposals, input price, TFP and benchmarking evidence is used directly to calibrate the terms of the plan's rate adjustment formula. This is not the case for EGD's IR proposal. Instead, CEA uses its empirical research to examine whether alternate rate adjustment formulas utilizing this research would generate sufficient revenues to recover EGD's forecast costs. In CEA's words, the input price and X factor (*i.e.* productivity plus stretch factor) evidence it develops is used "to evaluate the reasonableness of the Allowed Revenue Amounts included in EGD's Customized IR plan."[34]

PEG believes this statement does not accurately describe the focus of CEA's evaluation. CEA does evaluate several rate adjustment mechanisms calibrated with its research and finds the revenues generated under these IR plans are below EGD's projected costs. In every instance, however, it does not conclude that EGD's projected costs are too high, which would seem to be the logical conclusion if the analysis is designed "to evaluate the reasonableness of the Allowed

[33] It is somewhat atypical for PEG to consider empirical IR topics in this order, but this is the order in which these issues are addressed in the CEA report, and some of CEA's TFP results flow directly from decisions it makes for its benchmarking analysis. It is therefore logical to assess CEA's benchmarking analysis first, then its productivity analysis, and finally its proposed inflation factor.

[34] Concentric Energy Advisors, *Incentive Ratemaking Report Prepared for Enbridge Gas Distribution*, p. 3.

Revenue amounts included in EGD's Customized IR plan." Rather, CEA concludes that the rate adjustment mechanisms generate revenues for EGD that are too low.

A more accurate description of CEA's analysis is that it uses EGD's projected costs as *standards* or *benchmarks* to evaluate the reasonableness of conventional IR rate adjustment formulas. Whenever CEA finds revenues under a potential rate adjustment formula are below EGD's costs, it concludes that the rate adjustment formula is inappropriate, not the cost levels reflected in the Customized IR proposal. CEA is therefore using the Company's cost proposals to judge the reasonableness of IR rate adjustment formulas, not the other way around.

There are two important implications from CEA's approach. First, it provides no evidence to support the efficiency of EGD's projected costs or the reasonableness of the Customized IR proposal itself. Second, it is not consistent with the Board's description of the role that empirical research – and in particular, productivity research – plays in incentive regulation applications.

On the first point, CEA's approach clearly takes the reasonableness of EGD's cost forecasts as given. The focus of CEA's exercise is simply whether alternate rate adjustment formulas calibrated with its empirical research would allow EGD to recover these projected costs. It is difficult to see how this approach could ever lead to the conclusion that the Company's cost forecasts are excessive. In any event, CEA plainly directs its analysis towards assessing the revenues generated by different IR formulas, not EGD's cost projections.

CEA has therefore not developed any independent evidence that can be used to confirm, reject or otherwise test the reasonableness of EGD's forecast costs over the term of its Customized IR proposal. The reasonableness of EGD's Customized IR application depends on the reasonableness of its cost projections. Since CEA's empirical analysis provides no evidence on the latter issue, it does not affirm the reasonableness of EGD's Customized IR proposal.[35]

On the second point, CEA effectively uses Company costs to benchmark the adequacy of rate adjustment formulas that include inflation and productivity factors. This is not consistent with how the Board has described the role of productivity evidence in IR plans. In its report on 3rd Generation Incentive Regulation for electricity distributors, the Board described the productivity factor component of IR rate adjustment formulas as follows:

[35] Another way to state this is that CEA's conclusion that EGD's Customized IR proposal is reasonable is conditional on the reasonableness of the Company's cost projections, and CEA does not provide or develop any evidence to support this condition.

> The productivity (factor) component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable.[36]

In CEA's comparative analysis, the productivity factor it estimates (which PEG addresses in Section 3.3) is not "an external benchmark which all distributors are expected to achieve." If that was the case, CEA would expect EGD to reduce its costs to "achieve" cost levels that are no greater than the revenues generated by rate adjustment formulas with external inflation and productivity targets. CEA's analysis does not use industry productivity factors as external, objective benchmarks to assess the reasonableness of Company costs; it uses Company costs to assess the reasonableness of productivity factors. This approach is not consistent with the Board's description of the role that empirical productivity research should play in IR.

3.2 Benchmarking

3.2.1 CEA's Benchmarking Approach

While CEA has not benchmarked the efficiency of EGD's projected costs (which would be necessary to assess the reasonableness of the Customized IR proposal itself), it has undertaken benchmarking analyses of EGD's historical costs. In these analyses, CEA's benchmarking metrics are partial unit costs; that is, they take partial measures of EGD's 2011 costs (such as its OM&A costs) and divide them by a single output measure (either customer numbers served or delivery volumes) to construct partial unit cost measures. CEA computes several partial unit cost measures for EGD, but it does not attempt to aggregate them into more comprehensive unit cost indices, nor does it consider potential tradeoffs among the partial indices (*e.g.* whether higher net plant value per customer is associated with lower OM&A costs per customer).

CEA compares each partial unit cost measure for EGD to analogous partial unit cost measures for a designated peer group of gas distributors, which CEA calls the "Industry Study Group." CEA says that it used four criteria to determine which North American gas distributors were included in the peer group. These criteria are:

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[36] Ontario Energy Board. EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors.* July 14, 2008. p. 12. The Board cited this same language in its October 2012 RRFE Report.

1. Similarity of operations to EGD: peer companies had to be natural gas distributors, or the gas distribution operations of a combination utility if data for gas distribution operations were available separately from electricity operations;
2. Similarity of weather conditions: the companies in the industry study group were either (a) located in the northern half of the continental US and had State heating degree days within +/- 45% of EGD service territory; or b) Canadian gas distributors;
3. Similarity of size to EGD: the companies in the study group had to have at least 500,000 customers within a single State or at least 150,000 customers within a Province; for many of the 'companies' in the group, EGD actually added up the customer numbers of different utilities within a State that had a common corporate owner.
4. Data availability: the necessary data for the companies in the industry study group had to be available in either published or subscription service reports or databases.

There were 34 gas distributors in EGD's peer group. Twenty eight of these companies were from the US, and six were from Canada. For the US distributors, 13 of the 28 'companies' were actually constructed by CEA by adding up data from different gas distribution utilities (with a common corporate owner) within a single US State.

PEG has several concerns with CEA's benchmarking methodology and results. Our main concerns pertain to: 1) the peer group benchmarking approach; 2) the criteria used to select companies for the peer group; 3) the lack of statistical controls for differences in scale economies among distributors; and 4) the lack of assessments of comprehensive or overall cost efficiency. We deal with these concerns in turn below.

3.2.2 Peer Group Benchmarking

CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency. Gas distributors operate under a wide variety of disparate business conditions that can impact their OM&A and capital costs. It is very difficult to capture all the differences in these conditions within a designated peer group, or have every distributor comparable to every other distributor in the group across the entire array of relevant business conditions. Comparing partial unit costs across utilities deemed to be 'peers' is therefore a blunt and imprecise exercise that can lead to misleading and/or incorrect inferences on a utility's cost efficiency, unless the peer group comparisons are supplemented with other comparative cost information.

The Board has also found that it does not have confidence in peer group benchmarking methods. In 4th Generation Incentive Regulation ("4th Gen IR") for electricity distributors (EB-2010-0379), the Board compared the merits of peer group benchmarking with other, more sophisticated benchmarking techniques. A substantial amount of benchmarking evidence was put forward and examined in the 4th Gen IR initiative. In assessing this evidence and stakeholder comments on different benchmarking approaches, the Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors (the "Draft Board Report") said that "the Board finds the lack of support over the use of peer groups in benchmarking compelling. Stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations."[37] The peer group studies that the Board considered, and rejected, in 4th Gen IR were also far more rigorous than the simple partial unit cost comparisons developed by CEA. Given the Board's views in its Draft Board Report, PEG believes that CEA's peer group benchmarking approach is not consistent with the Board's policies for appropriate benchmarking evidence in IR applications. [38]

3.2.3 Selection of Peer Group

CEA selects its peer group of 34 gas distributors based on four criteria: 1) they must be gas distributors; 2) they must have at least 500,000 customers in a State or 150,000 customers in a Province; 3) their service territories must have weather similar to EGD; and 4) they must have available data. PEG believes the first and fourth of these criteria are obvious and obviously non-controversial. The second criterion (similarity in size) is important, and we address this issue in the following sub-section.

[37] Ontario Energy Board, EB-2010-0379, *Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors*, September 6, 2013, p. 27.

[38] PEG made use of peer group benchmarking in Third and Fourth Generation IR, but only in conjunction with and as a supplement to econometric benchmarking evidence. We believed it was particularly important to have two benchmarking "tests" in Third Generation IR because: 1) this was the first time benchmarking had been used directly to assign stretch factors in IR; and 2) the only available benchmarking studies at the time applied to OM&A costs, and OM&A benchmarking studies are typically less robust than total cost benchmarking studies. PEG did not rely exclusively on peer group, partial unit cost studies to make inferences on utility efficiency, as CEA has done.

The third criterion (similarity in weather) is problematic. Heating degree days will certainly have an impact on gas consumption, but this is irrelevant in a study that (like CEA's) compares unit OM&A costs per customer across utilities. Gas distributors incur little, or no, incremental OM&A cost when gas consumption increases.

Heating degree days also has little or no impact on other gas distribution costs. PEG has been benchmarking gas distribution costs for nearly two decades, and we cannot recall a single PEG study finding a statistically significant relationship between a gas distributor's costs and heating degree days in its territory. CEA does not present any evidence to support the similarity in weather criterion, or even a rationale for why weather is a reasonable basis for selecting a peer group in a gas distribution cost benchmarking study. This criterion cannot simply be accepted on its face; similarity in heating degree days would be a persuasive criterion for selecting peers only if CEA can provide rigorous, empirical evidence of a significant relationship between heating degree days and gas distribution costs.

The similar-weather criterion is also having a substantial impact on CEA's benchmarking results. CEA explicitly excludes gas distributors in the southern half of the United States from its potential benchmarking (and productivity) sample. This decision excludes nearly all the rapidly-growing US gas distributors from the universe of potential EGD peers, since the regions experiencing rapid growth in the US are the Southeast, the Southwest and the Northwest. Of the US peer distributors selected by CEA, only three (at most) come from a region experiencing rapid growth: Puget Sound Energy, Northwest Natural Gas and (arguably) Questar Gas.

Excluding gas distributors serving rapidly-growing territories from the peer group materially impacts CEA's benchmarking comparisons, because EGD serves a territory that has experienced (and continues to experience) rapid customer growth. Customer growth clearly impacts a distributor's OM&A and capital costs. If the distributors selected for a peer group study have substantially slower customer growth than EGD, this can lead to material differences in unit costs for EGD and other distributors in the study group.

Figure 11 of the CEA Report (p. 28) vividly illustrates the divergence in customer growth between EGD and the US gas distributors that CEA selects as peers. Only three US gas distributors (the three from the rapidly growing Northwest referenced earlier) have customer growth rates that are similar to EGD's. The other 22 distributors on this figure have markedly slower customer growth.

Other business conditions indirectly related to the weather criterion will also impact unit cost comparisons between EGD and its peers. One such condition concerns the materials used to construct the gas delivery network. Older gas delivery systems have a much higher composition of cast iron or bare steel main than newer systems. Cast iron and (especially) bare steel main is more prone to gas leaks than polyethylene main, and remediating gas leaks is a significant driver of OM&A and capital replacement costs for distributors with extensive cast iron and bare steel delivery systems. In the US, older systems constructed with cast iron or bare steel are disproportionately (indeed, almost exclusively) in the northern half of the country.

If we confine our attention to the seven gas distributors in the northeast quadrant of Figure 11 (which CEA (p. 28) calls the "sub-group that is more representative of EGD and of sufficient size to provide meaningful results"), PEG's data show that 14.4% of gas distribution main for these seven distributors is constructed using cast iron or bare steel materials. In contrast, only 0.7% of EGD's gas distribution main is constructed using cast iron or bare steel. CEA's analysis takes no account of this important difference between EGD and its selected peers.

PEG believes the similar-weather criterion has materially distorted CEA's benchmarking sample. This criterion tilts the peer group towards US "rust belt" distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks. The unit costs of operating and maintaining such a network are substantially higher than those associated with a nearly 100% polyethylene network, much of which was recently installed to serve a newly-connected customer base. Nearly all the US gas distributors that (like EGD) operate the latter type of network are in the southern half of the country and excluded from CEA's sample because of the similar-weather criterion. Because CEA compares EGD almost exclusively to slow-growth, high-unit cost distributors in America's rust belt rather than firms operating under similar growth and system conditions, PEG believes that CEA's selected peer group leads to inappropriate and misleading benchmarking inferences.

3.2.4 Controls for Scale Economies

CEA's attempt to control for differences in size, and hence the extent to which distributors have realized scale economies that reduce their unit costs, is also unsatisfactory. CEA selects only distributors that serve 500,000 or more customers in a single US State or 150,000 or more customers in a Canadian Province. While this criterion does implicitly acknowledge the importance of size and economies of scale on unit cost comparisons, it does not adequately control for size differences among distributors.

One reason is that it cannot be assumed that scale economies are exhausted when a distributor's customer base reaches 500,000 customers. Gas distributors can experience scale economies beyond this point. Whenever this is the case, it is not reasonable to compare the unit costs of all distributors in a peer group serving more than 500,000 customers because those simple unit cost comparisons do not control for the incremental scale economies that larger gas distributors in the group have achieved and which tend to reduce their unit costs. These unit cost reductions cannot be attributed to "efficiency" gains achieved by management, but this is the conclusion that would be drawn from simple unit cost comparisons that did not control for the incremental scale economies inherent in larger gas delivery systems.

CEA's benchmarking methodology simply compares partial unit costs and therefore does not control for these differences in economies of scale among distributors. All else equal, the lack of controls for economies of scale will bias benchmarking comparisons towards larger distributors in CEA's sample like EGD. The reason is that CEA's methodology will incorrectly interpret unit cost reductions arising from economies of scale as evidence of "efficiency." Smaller distributors will tend to be unfairly disadvantaged by the lack of controls for differences in scale economies.

It is critical to control for differences in scale economies in benchmarking research. Economies of scale are inherent in gas delivery networks; indeed, the existence of scale economies is an important reason gas distribution is a "natural monopoly" industry where service is provided by regulated utilities rather than through competitive markets. CEA specifies a minimum size that companies must attain to be included in the peer group but makes no controls for differences in scale economies beyond this minimum size criterion.[39] Proper controls for scale economies can only be implemented through statistical methods and not through the simple, partial unit cost comparisons undertaken by CEA. Since CEA's benchmarking methodology does not include appropriate controls for economies of scale, it is likely to be biased in favor of relatively larger gas distributors like EGD.

[39] There are actually two minimum size cut-offs in the CEA study: 500,000 customers for US gas distributors and 150,000 customers for Canadian gas distributors.

3.2.5 Comprehensive Benchmarking Evaluations

CEA's analysis finds that EGD is one of the most efficient distributors in its peer group, but this conclusion depends exclusively on the Company's OM&A costs. A gas distributor's comprehensive cost performance depends on how efficiently it manages both OM&A and capital costs. Since capital accounts for the largest share of gas distribution costs, focusing only on OM&A costs will provide an incomplete, and potentially misleading, assessment of a utility's overall cost efficiency.

Indeed, if we take the CEA benchmarking results at face value and assess their implications for EGD's total cost performance, an objective observer can draw a different conclusion than CEA regarding the Company's efficiency.[40] Consider Figure 9 and Figure 10 in the CEA report, both presented on page 25. Figure 9 shows OM&A per customer for CEA and the study group (the 28 US gas distributors). Although this is a figure and it does not present actual numbers for OM&A per customer, it appears that this value is approximately $185 for EGD and $265 for the study group in 2011. Hence, EGD's OM&A expenses per customer in 2011 is about 30% below the average OM&A per customer for the study group (*i.e.* ((185-265)/265 = -30%). This figure in isolation supports CEA's conclusion that EGD is an efficient cost performer.

However, Figure 10 presents data on net plant per customer for EGD and the study group. This figure shows that EGD's net plant per customer in 2011 is approximately $1920, while the comparable figure for the study group is about $1480. EGD's net plant value per customer in 2011 is therefore about 30% higher than that of the study group (*i.e.* ((1920-1480)/1480 = +30%). All else equal, this would mean that EGD's capital costs are 30% higher than those of the study group.

If we conservatively estimate that capital is about 60% of costs for both EGD and the study group, Figures 9 and 10 would imply that EGD's total unit cost per customer is about 6% above that of the study group (*i.e.* (-30% * 0.4) + (30% * 0.6) = 6%). Thus, CEA's own Figures suggest that EGD's total costs per customer are actually greater than the total costs per customer for the study group. This more comprehensive cost assessment, which is the assessment that is

[40] Obviously, given the points discussed earlier in this section, PEG does not believe CEA's benchmarking results should be taken at face value, but this hypothetical exercise is undertaken here simply to consider what the results presented in CEA's study would suggest about EGD's overall cost performance if the CEA methodology was extended to consider OM&A and capital cost performance simultaneously.

ultimately relevant for customer rates and making an inference on EGD's overall cost efficiency, would imply that EGD is an inefficient cost performer, not an efficient one.

It should be emphasized that PEG is not contending that EGD is inefficient.[41] Our point is simply that assessments of utility cost efficiency cannot focus only on OM&A costs and ignore capital costs if capital cost data are available. CEA cannot reasonably conclude that EGD is efficient without considering the Company's capital cost performance.

3.2.6 Assessment

PEG believes that CEA's benchmarking results provide no persuasive evidence on EGD's cost efficiency for four primary reasons. First, CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency. Second, there is no justification for the similar-weather criterion CEA uses to select its peer group. This criterion tilts the peer group towards a high cost set of US rust belt distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks, rather than distributors like EGD operating and maintaining a nearly 100% PE network for a rapidly growing customer base. Third, CEA's benchmarking methodology does not control for differences in scale economies among the distributors that are selected for its peer group; all else equal, this will tend to bias benchmarking comparisons towards the larger distributors in the group, like EGD. Fourth, EGD does not attempt to undertake comprehensive cost comparisons even though such comparisons are feasible given its methodology. The partial, OM&A cost comparisons that EGD relies on provide an incomplete and potentially misleading measure of relative cost efficiencies. Given these deficiencies in CEA's benchmarking methodology, PEG believes that no conclusions can be drawn about EGD's cost efficiency from CEA's benchmarking results.

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[41] However, if CEA believes that simple unit cost comparisons of OM&A per customer are relevant for assessing OM&A cost performance, then it is not clear why their methodology cannot be extended straightforwardly to capital costs as well. If this is done, then the hypothetical exercise performed by PEG would be a valid benchmarking assessment under CEA's benchmarking approach. It should be noted, however, that PEG has only estimated the OM&A per customer and net plant per customer values used in our example since CEA did not provide the actual values for these metrics in Figures 9 or 10.

3.3 Productivity Growth and Productivity Factor

CEA also estimates productivity growth for EGD, the Industry Study Group, and the Seven Company industry Sub-Group for the 2000-2011 period. CEA finds that TFP grew at an average rate of -0.32% per annum for the Industry Study Group, -.01% per annum for the Seven Company sub-group, and -0.28% per annum for EGD over the 2000-2011 period. The comparable growth rates for OM&A partial factor productivity ("PFP") growth over the same period are -0.25%. -0.02%, and 0.50%, respectively.

Using this research, CEA recommends a productivity factor of zero to be used in its evaluation of alternate rate adjustment mechanisms for EGD. It also recommends an overall X factor of zero to be used in these evaluations. CEA did not include an explicit stretch factor in its recommended X factor because (a) EGD is not embarking on a first generation IR plan; (b) CEA concluded that EGD is a relatively efficient utility; (c) EGD's proposed ESM creates opportunities for customers to share benefits in place of a stretch factor; and (d) CEA's X factor recommendation can be viewed as having a built-in productivity challenge.

PEG cannot comment in detail on CEA's productivity research until we have had a chance to examine its workpapers. We note, however, that CEA's TFP estimates for EGD over the 2005-2010 period differ substantively from PEG's TFP estimates of EGD's TFP growth for the same period. PEG prepared these estimates as part of our assessment of the gas IR plans approved for Union Gas Limited ("Union Gas") and EGD for 2008-2012, using data provided to us by EGD for the purposes of TFP estimation.[42]

CEA's estimate of TFP growth for the US gas distribution industry also differs substantially from credible estimates presented in other regulatory proceedings. For example, in evidence presented in December 2011 on behalf of the Consumer Coalition of Alberta, PEG estimated that TFP for the US gas distribution industry grew at an average rate of 1.32% per annum over the 1996-2009 period.[43] TFP growth was even more rapid in regions experiencing more rapid economic growth.

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[42] In particular, see Table 15 of *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans*, April 2012.

[43] Lowry, M.N., D. Hovde, and J. Kalfayan, *PBR Energy Plans for Alberta Energy Distributors*, AUC ID 566 RRI, December 17, 2011, p. 2.

Although it is not clear why EGD has estimated markedly lower TFP growth for US gas distributors than PEG, a likely explanation (at least in part) is because its sample is tilted towards slow-growth rust belt utilities. Economic and output growth for these gas distributors will be below the industry norm. All else equal, slower output growth will be reflected in slower TFP growth.

PEG believes a TFP study that arbitrarily rules out half of the US gas distribution industry cannot yield a credible estimate of the industry's TFP trend. Such a trend is also not relevant for EGD, since the Company continues to experience rapid customer and output growth. PEG is likely to have further comments on CEA's TFP results after we have had an opportunity to review its work in detail.

PEG also believes that CEA's rationale for excluding a stretch factor is unwarranted. On CEA's first point, there is no persuasive evidence that EGD is actually an efficient cost performer. On the second, it is true that EGD has been subject to IR in the past, but the Board has rejected the view that stretch factors are appropriate only for distributors under a "first generation" IR plan in its findings for both 3rd Generation IR and 4th Generation IR for electricity distributors.[44] Regarding CEA's third point, PEG has described in Section 2.3 why the Board cannot be assured that EGD's proposed ESM will either protect customers or allow them to share in EGD efficiency gains under the Company's proposed Customized IR plan. On CEA's fourth point, PEG notes that CEA's TFP study conflicts with credible TFP evidence that has been presented elsewhere. A positive TFP trend for the gas distribution industry coupled with a recommended X factor of zero would render the "built-in productivity challenge" argument moot. While CEA's estimated TFP trends appear suspect, we will reserve judgment on this issue until we have had a chance to review the workpapers supporting CEA's estimate.

3.4 Inflation Factor

CEA also recommends a three-factor, industry-specific measure of input price inflation as the inflation factor used when assessing alternate rate adjustment mechanisms. CEA's proposed

[44] Contrary to CEA's claim in footnote 41 on p. 36 of their report, PEG has also never supported the view that stretch factors are appropriate only for first generation IR plans; in fact we recommended positive stretch factors for distributors that had been previously subject to IR in both 3rd and 4th Generation IR for electricity distributors.

industry-specific inflation factor is constructed as a weighted average of inflation in three indices: 1) Ontario Average Hourly Wages, to reflect inflation in labor prices; 2) Canada's GDP-IPI, to reflect inflation in non-labor, OM&A input prices; and 3) Canada's implicit price index for net gas distribution plant, to reflect inflation in capital prices.

CEA's proposed industry-specific inflation factor is unacceptable because it excludes the rate of return on a utility's capital stock, as well as depreciation of that capital stock. These are two large components of capital input prices, and no input price inflation measure that excludes them will be a credible measure of input prices for the gas distribution industry. If CEA's recommended inflation factor was implemented, CEA's cost calculations presented on pp. 55 -56 of its report would not be satisfied. CEA's recommended inflation factor would also not be consistent with the basic indexing logic that underpins the calibration of index-based incentive regulation.[45] The Board should reject this proposed inflation factor.[46]

3.5 Expenditure Forecasts

EGD discusses the process used to develop its forecasts for OM&A and capital expenditures. This discussion is particularly detailed for the capital budget process within the Company. EGD describes how that process whittled down initial capital expenditure proposals and produced a capital cost forecast that EGD believes is necessary to meet the growth, safety and operational needs of the Company for the 2014-2016 period. These capital projections are in turn reflected in the Customized IR proposal.

While the Company's testimony on these issues is interesting, and in some cases informative, it ultimately provides no assurance that the cost projections embedded in the Customized IR proposal is efficient. The reason is that there is no assurance that the capital cost

[45] The relevant part of the indexing logic that would not be satisfied by this proposal is that an index of industry cost C must be the product of an index of input prices for the industry W and an index of input quantities for the industry X , *i.e.* $C = W * X$. The cost of the gas distribution industry C must include the cost of capital and depreciation of capital stock; if these costs are not reflected in the input price index W, then cost will not equal the product of the input price and the input quantity indices.

[46] PEG also notes that CEA apparently uses a different input price subindex for capital in its TFP analysis than it uses for the capital price subindex for its inflation factor. The "capital price" explanation on page B-13 of the CEA report says that the capital price used for CEA's TFP analysis includes cost of capital, depreciation and perhaps capital gains components, although it is not clear from CEA's discussion whether and capital gains were actually calculated. This capital price subindex is not consistent with the inflation measure used for capital in CEA's inflation factor; this creates an internal inconsistency in the Company's empirical work which may, in turn, be impacting CEA's measured TFP trends. This is one of the issues PEG will examine more closely after we have had a chance to review CEA's workpapers.

forecasts submitted at the outset of the budget process were not inflated. If they were, then it is possible that the capital cost projections produced at the end of the process will also be inflated.

The Company has clear incentives to err on the "high" side when forecasting capital expenditures for a Customized IR plan, as the early experience with building block regulation in the UK illustrates. These incentives exist both to protect the Company against capital investment risks while the plan is in effect and to lock in relatively high price trajectories that boost earnings. Given the inherent incentives to pad capital cost forecasts, PEG's believes that EGD must present compelling evidence to the Board which shows that its initial and final capital cost projections are efficient and will generate reasonable prices.

PEG believes that objective, external benchmarks can potentially be used to demonstrate the reasonableness of forward-looking cost projections in a Customized IR plan. For example, rigorous measures of PFP growth for OM&A and capital inputs can validate the reasonableness of forecast OM&A and capital expenditures, respectively. Statistical or engineering methods can also be used to develop forward-looking OM&A and/or capital expenditure benchmarks.

However, PEG concludes that EGD's application does not contain compelling evidence which shows that EGD's projected capital or OM&A expenditures are efficient. Neither EGD nor CEA has presented any external, objective evidence directly addressing the reasonableness of the Company's projected capital spending.[47] CEA has developed estimates of industry OM&A PFP growth but, as discussed, CEA's productivity evidence has been distorted by the choice of industry peers and perhaps other issues, which PEG will examine after we have had a chance to review CEA's workpapers. Moreover, capital expenditures account for the lion's share of EGD's projected cost growth over the term of its IR plan, and the Company has not put forward any external benchmarks that justify its projected capital spending. PEG therefore finds that the information presented in EGD's application regarding expenditure forecasts does not support the conclusion that these projected expenditures are efficient.

[47] EGD's budgeting process is "internal" to the Company, not an external, third-party measure that can be objectively examined and tested by outside experts or Board staff.

3.6 Assessment of Empirical Evidence Supporting EGD's IR Proposal

CEA's empirical analysis effectively uses EGD's projected costs as standards or benchmarks to evaluate the reasonableness of conventional IR rate adjustment formulas. Whenever CEA finds revenues under a potential rate adjustment formula are below EGD's costs, it concludes that the rate adjustment formula is inappropriate, not the cost levels reflected in the Customized IR proposal. CEA is therefore using the Company's cost proposals to judge the reasonableness of IR rate adjustment formulas, not the other way around.

This analysis provides no evidence to support the efficiency of EGD's projected costs or the reasonableness of the Customized IR proposal itself. CEA takes the reasonableness of EGD's cost forecasts as given and simply evaluates whether alternate rate adjustment formulas calibrated with its empirical research would allow EGD to recover these projected costs. Because CEA directs its analysis towards assessing the revenues generated by different IR formulas, and not EGD's cost projections, it has not developed any independent evidence that can be used to confirm, reject or otherwise test the reasonableness of EGD's forecast costs over the term of its Customized IR proposal. The reasonableness of EGD's Customized IR application depends on the reasonableness of its cost projections. Since CEA's empirical analysis provides no evidence on the latter issue, it does not affirm the reasonableness of EGD's Customized IR proposal.

CEA's empirical analysis is also not consistent with the Board's description of the role that productivity research should play in incentive regulation applications. The Board has described the productivity factor as an external benchmark that distributors are expected to achieve. CEA's analysis does not use industry productivity factors as external, objective benchmarks to assess the reasonableness of Company costs; it uses Company costs to assess the reasonableness of productivity factors.

While CEA has not benchmarked EGD's cost projections, it has benchmarked the Company's historical costs, but no conclusions can be drawn about EGD's cost efficiency from this analysis. CEA's benchmarking methodology provides no persuasive evidence on EGD's cost efficiency for four main reasons. First, CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency. Second, CEA does not justify the similar-weather criterion it uses to select its peer group. This criterion tilts the peer group towards a high cost set of US rust belt distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks. These distributors are not the most appropriate peers for EGD, which operates and maintains a nearly 100% polyethylene network for a rapidly growing customer base. Third, CEA's benchmarking methodology does not control for differences in scale economies among the distributors selected for its peer group; all else equal, this will tend to bias benchmarking comparisons towards larger distributors in the group, like EGD. Fourth, CEA does not attempt to undertake comprehensive cost comparisons even though such comparisons are feasible given its methodology. The partial, OM&A cost comparisons that EGD relies on provide an incomplete and potentially misleading measure of relative cost efficiencies.

CEA has also undertaken a productivity study for EGD and a group of US utilities. This study yields markedly lower estimates of total factor productivity (TFP) growth for the Company and the industry than credible TFP estimates of these trends that have been presented elsewhere. It is not clear why EGD has estimated lower TFP growth for US gas distributors, but a likely explanation (at least in part) is because its sample is tilted towards slow-growth rust belt utilities. Economic and output growth for these gas distributors will be below the industry norm. All else equal, slower output growth will be reflected in slower TFP growth.

A TFP study like CEA's that arbitrarily rules out half the US gas distribution industry cannot yield a credible estimate of the industry's TFP trend. Such a trend is also not relevant for EGD, which continues to experience rapid customer and output growth. PEG is likely to have further comments on CEA's TFP results after we have had an opportunity to review its work in detail.

CEA excludes a stretch factor from the empirical analyses it uses to evaluate alternate rate adjustment mechanisms, which PEG believes is unwarranted for four reasons: 1) there is no persuasive evidence that EGD is actually an efficient cost performer; 2) the Board has rejected the view that stretch factors are appropriate only for distributors under a "first generation" IR plan; 3) as previously discussed, the Board cannot be assured that EGD's proposed ESM will either protect customers or allow them to share in EGD efficiency gains under the Company's proposed Customized IR plan; and 4) CEA's TFP evidence conflicts with credible TFP evidence that has been presented elsewhere.

CEA's proposed industry-specific inflation factor is unacceptable because it excludes the rate of return on a utility's capital stock, as well as depreciation of that capital stock. These are two large components of capital input prices, and no input price inflation measure that excludes them will be a credible measure of input prices for the gas distribution industry. The Board should reject this proposal.

EGD discusses the process used to develop its forecasts for OM&A and capital expenditures. While the Company's testimony on these issues is interesting, it ultimately provides no assurance that the cost projections embedded in the Customized IR proposal are efficient. If the capital cost forecasts submitted at the outset of the budget process were inflated, the capital cost projections at the end of the process can also be inflated. Given the Company's incentives to err on the high side when forecasting capital expenditures for a Customized IR plan, PEG believes EGD must provide compelling evidence to the Board that its initial and final capital cost projections are efficient and will generate reasonable prices. PEG does not believe that EGD's application contains such evidence.

4. Conclusion

This report has analyzed EGD's Customized IR proposal. PEG believes that Enbridge's proposed IR plan as currently designed raises serious concerns. In particular, it has poor incentive properties that may generate unreasonable prices and shift risks to customers. The empirical analysis presented in support of the proposed plan is not compelling and does not allay PEG's fundamental concerns.

PEG notes that our analysis of the Company's previous IR plan indicated that this plan generated benefits for both shareholders and customers and was consistent with the Board's criteria for effective regulation.[48] We believe an IR plan for the 2014-18 period that is calibrated using objective measures of industry TFP growth, appropriate benchmarking studies, and well-designed benefit sharing provisions will also be effective. This plan can also contain Y factors that recover the costs of large capital projects. PEG believes the input price and TFP research for US gas distributors that was presented in Alberta can be used to assess the appropriateness of the elements of an IR plan for EGD.

[48] Kaufmann, L. *et al*, *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans,* April 2012.

Appendix: United Kingdom Building Block Experience

Utilities in the UK have been subject to incentive regulation since the early 1980s. Most British utilities were formerly public enterprises and were subject to privatization and formal regulation beginning in 1984 with British Telecom (BT). Since then, privatization has extended to the nation's electric, gas, water, airport and rail utilities.

The decision to use rate indexing in British utility regulation was strongly influenced by the recommendations of Stephen Littlechild of the University of Birmingham, in a report released in 1983.[49] He proposed to adjust BT's rates using an index with an "RPI-X" formula. The RPI term is the inflation in the Retail Price Index (RPI). A specific value for X was not recommended, nor was there significant discussion in Littlechild's paper of the appropriate framework to be used to determine X. Rather, the value for X was described vaguely as "a number to be negotiated."

Following its application to BT in 1984, RPI-X regulation was first applied to the gas industry in 1986 and to the electric utility industry in 1990. The electricity industry in England and Wales was unbundled into a separate power transmission firm (National Grid) and twelve distribution network operators (DNOs) when industry restructuring was completed in 1990. The two DNOs serving Scotland were originally part of vertically-integrated firms. The gas utility industry was initially served by a single regulated firm, British Gas, which also had gas production and other interests. In the mid 1990s, the gas transmission and distribution operations of British Gas were functionally unbundled into a firm called Transco. UK gas distribution operations were later formally unbundled into eight separate local gas distributors, four of which were retained by the original entity (which had since merged with National Grid) and four of which became stand-alone utilities. The first price review for the UK's unbundled gas distributors was recently completed in 2007.

RPI-X regulation for UK energy distributors has employed a "building block" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated firm over the term of the price controls. The earliest energy price reviews were rather opaque and did not provide much detail on the regulators' specific determinations on

[49] Stephen Littlechild, *Regulation of British Telecommunications' Profitability: Report to the Secretary of State*, February 1983.

particular "building block" elements. Over time, however, UK regulatory reviews have become more transparent and followed a more clearly defined and organized process.

The first fully articulated statement of the British approach towards price cap regulation is contained in the 1997 price cap plan for Transco. To determine the price controls for Transco, the regulator took as a "starting point" a long term net present value (NPV) calculation.[50] This calculation determined "a level of revenue which, when set against expected expenditure (over the term of the controls) and discounted at the company's cost of capital, would produce a net present value (NPV) of zero".[51] In other words, price controls were based on a projected forward-looking revenue requirement that just recovers the sum of opex and capital costs (return on and depreciation of existing assets plus costs of new capital expenditures) for the price cap period. More specifically, the basic components of the basic building method are:

1. Defining the regulatory asset base (RAB). The approach that ultimately developed was based essentially on the (conventional) historic cost of assets.
2. Estimating depreciation of the RAB
3. Assessing future capital expenditure (capex) and its depreciation
4. Estimating the weighted average cost of capital (WACC).
5. Determining a reasonable level of future operating expenditure (opex)

New price controls are almost always affected via two price adjustments: an initial price (P_0) change in the first year of the plan; and an X factor that applies during the subsequent plan years, when index-based price changes take effect. The building block approach used in the UK can lead to any number of initial price adjustment-X factor combinations for a company that are consistent with that company's allowed revenue adjustment over the term of the controls. Any revenue neutral reallocation between initial price adjustments and X factors (*i.e.* any change between the P_0 and X factor that does not affect the NPV of the company's expected revenues over the term of the price control) is consistent with the regulator's building block computations.

The UK incentive regulation experience is extremely rich and diverse, but the most relevant precedents in the context of 3rd Generation IRM in Ontario are the plans that have been approved for the UK power distribution industry. Five-year price cap plans were instituted for

[50] There were separate regulators of the gas and electricity industries until 1999, when the regulatory agencies were merged to form the Office of Gas and Electricity Markets (Ofgem).
[51] Office of Gas Supply, *Price Control Review, British Gas' Transportation and Storage: A Consultation Document*, June 1995, p. 22.

the DNOs upon their privatization in 1990. Initial rates were set at the levels charged by the companies just before privatization, even though these rates presumably reflected inefficiencies under state ownership. Different X-factors were established for each DNO, ranging from 0 to -2.5% with an average value of -1.3%. Therefore, DNOs' distribution prices were allowed to *increase* by an average of 1.3% per annum in real terms during the five years of the first price cap plan. The reasons for allowing real price increases were not made explicit. However, the companies were being sold to private investors. The terms of the indexing plans were likely set, in part, to spur investor interest and extend share ownership.

DNO price controls were first reviewed in 1994. This review focused on four considerations when re-setting allowed revenues over the upcoming price control term: operating expenses, planned capital expenditures, the valuation of the capital stock used in power distribution, and the allowed return on that capital stock. The Office of Electricity Regulation (Offer) reviewed these factors by analyzing the DNOs' cost and sales data and by soliciting independent evaluations of REC operations. For example, consultants provided opinions on "best practice" for different distribution functions, and outside analysts estimated the costs of network expansions given projected changes in the number and location of customers. Statistical benchmarking studies were undertaken to estimate the efficient levels of operating costs for individual DNOs given various factors beyond management control. These included the number of customers served, volumes distributed at low and high voltage, and customer density within the territory served. The results of these benchmarking studies were not made public, nor did the regulator detail how the benchmarking results specifically affected the final X factors.

The outcome of this review was an initial price cut for each of the DNOs and a common X-factor of 2%. Distribution rates were cut either 11%, 14%, or 17% in the initial year of the new plan, depending on what the benchmarking and other analyses indicated were efficient cost levels for the company. Revenue reductions were divided between an initial rate cut and a higher X because it was believed that both customers and utilities preferred this approach.

The new price cap plan took effect in April 1995 and was widely viewed as too generous for the Companies. Public dissatisfaction was heightened when outside investor groups responded to the new price controls with takeover bids for several DNOs, allegedly because the new price controls offered the opportunity for unexpected profits. Only one month after the distribution price cap plan went into effect, the Director General (DG) re-opened the plan, which led to an additional, up-front price cut of 9% and an increase in the X factor to 3%.

The DNOs distribution price control was updated again in 2000. This led to another initial price cut that varied between 19%, and 33% between companies. The X factor in the other four years remained at 3%. The methods used to update the control were similar to those used in 1995.

The 2005 update of DNOs distribution prices included an initial price increase that averaged about 1% per company and an X factor of 0 for the remaining four years of the control. Unlike the earlier power distribution price reviews, prices did not decline in real terms as a result of this review. The main reason was that Ofgem allowed substantial increases in capital spending for many of the distributors.

Over time, benchmarking has played an increasingly important role in the regulation of opex in UK RPI-X plans. Ofgem has primarily relied on econometric benchmarking in its price reviews. Its econometric benchmarking approach is a variant of corrected ordinary least squares (COLS). For price controls taking effect in both 2000 and 2005, Ofgem regressed a "normalized" measure of opex on what it called a "comprehensive scale variable" (CSV). Distributors' opex data were normalized by ensuring that these data were defined and collected comparably across all DNOs. The CSV was based on each DNO's number of customers served, kWh distributed, and network length. The weights applied to these variables in developing each DNO's CSV were 25%, 25%, and 50%, respectively. These weights differed from those used in the 1999 COLS study, which were 50% for customers served, 25% for kWh and 25% for network length. These weights were considered roughly proportional to the impact of each scale measure as a "driver" of distribution opex.

In two dimensional space, COLS is normally applied by running an OLS regression and shifting the intercept of that regression until the line passes through the minimum observation. Any gap between a DNO's opex and this COLS line would therefore reflect that DNO's inefficiency, or the excess of its opex costs over the observed minimum regression line. For the 2000 review, however, Ofgem's COLS benchmarking was done by shifting the *slope* of the estimated function and not the intercept. The slope was shifted until the line passed through the *second* lowest observation. This approach was taken because Ofgem believed a conventional COLS application would have led to implausible results. That is, the intercept from a regression of (normalized) opex on the CSV could be interpreted as the fixed operating costs of a DNO, independent of the size of its operations. In the 2000 review, Ofgem believed that if the intercept was shifted as in a typical COLS procedure, it would have produced a fixed opex cost estimate that was implausibly low from an engineering perspective, so Ofgem shifted the slope as an alternative.

For the 2005 review, Ofgem did shift the intercept in its COLS application as is typically the case. However, the intercept was shifted so that the line passed through the upper quartile opex performance rather than minimum performance. Upper quartile performance was effectively determined as the midpoint between the third and fourth lowest opex cost observation of the 14 DNOs.

In the 2000 review, Ofgem set opex targets by assuming that companies would catch-up to the opex target determined by the COLS procedure by closing 75% of the gap between their (normalized) operating cost and the normalized opex of the second most efficient firm in the UK by the second year of the price review.[52] In the 2005 review, each REC's allowed opex is based on an upper quartile benchmark within the UK. Ofgem's rationale for this decision is that an "upper quartile benchmark…provides a more robust and sustainable benchmark than a frontier based on one company."[53] The 2005 review also undertook some data envelope analysis (DEA) as a "cross check" on the econometric results. However, Ofgem concluded that the DEA results "are not plausible so it (DEA) has not been incorporated directly."[54]

The regulation of capex has also changed considerably since the initial RPI-X controls but has evolved in a different direction. In the 2005 price review, Ofgem applied a sliding scale mechanism to the UK distribution companies' capital expenditures. A similar type of mechanism was applied in the most recent energy price control review for the gas distributors but was called an "information quality incentive." These mechanisms were motivated by Ofgem's view that the distributors have incentives to inflate their forecast capex during the next price control period but then "underspend" once an allowed capex is used to set the value of X.

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[52] Office of Gas and Electricity Markets, *Electricity Distribution Price Control Review: Initial Proposals*, June 2004, p. 66. "Normalized" cost here refers to costs that are adjusted for scale of output and other factors that are quantified through econometric benchmarking.

[53] Ofgem, *op cit*, p.67.

[54] Office of Gas and Electricity Markets, *Electricity Distribution Price Control Review: Final Proposals*, November 2004, p. 70.

Ofgem believes some utilities have actually behaved in this way, although others have not. The aims of the sliding scale mechanism are to:

- retain incentives for efficient capital spending during all years of the control
- reduce the emphasis on Ofgem's or its consultant's view of the appropriate level of capex
- reduce the perceived risk that the price control causes under-investment
- allow but not encourage expenditure in excess of the allowance
- reduce the possibility that companies submitting high capex projections will make very high returns from underspending
- reward companies making "low" capex forecasts
- avoid incentives to underspend in ways that reduce service quality or create service quality problems in subsequent years

The sliding scale mechanism essentially gives companies a choice between:

- a lower allowance for capex reflected in the controls, but with a higher- powered incentive that allows them to retain a greater share of "underspend" relative to the allowance and collect a greater share of "overspend"; or
- a higher allowance for capex in the controls, but with a lower-powered incentive that lets companies keep a lower share of "underspend" and collect a lower share of "overspend."

Companies also get an additional reward if they do choose the lower allowed capex option, but do not receive this reward if they select higher allowed capex. If the sliding scale mechanism is designed correctly, it is "incentive compatible" and removes incentives for the company to inflate its projected capex. The mechanics of Ofgem's proposed sliding scale mechanism are as follows:

- Ofgem determines a benchmark level of projected capex over the price control period for each DNO; in the 2005 distribution price review, these benchmarks were determined by the engineering consulting firm PB Power
- Each REC presents its actual capex projections over the price control period
- Ofgem determines a capex *allowance rate*, *additional income* and a capex *incentive rate* depending on the relationship between benchmark and forecast capex. The allowance rate is the total amount of capex that will be allowed in the controls; this

number is specified as a multiple over the benchmark level. The additional income term is an addition to the distributor's allowed revenue. The incentive rate is equal to the portion of capital "underspend" the company is allowed to retain. The allowance rate, additional income and incentive rate each increase as the company's forecast gets closer to the benchmark level, and vice versa. This approach therefore rewards companies for keeping their capex forecasts low.

For example, if a company's projects its capex to be 140% of the PB Power benchmark, their capex allowance rate is 115% of the PB Power forecast value. If they over- or underspend relative to this forecast, they get to keep or bear 20% of the difference *i.e.* the marginal incentive rate is 20%. Alternatively, for companies whose capex forecasts are equal to or less than the PB Power benchmarks, their allowance is set at 105% of the PB Power capex forecast. Companies keep or bear 40% of any over- or under-spend relative to the allowed capex level, so their marginal incentive rate is 40%.

Ofgem established the sliding scale mechanism as a matrix which displays the values of the key parameters and how they vary with the forecast/benchmark relationship. The table below captures the main features of the sliding scale matrix.

Forecast (F)/ Bench (B)	Δ	Allowance Rate (AR)	Δ	Incentive Rate (IR)	Δ	Additional Income (AI)	Δ
100		105		0.4		2.5	
105	5	106.25	1.25	0.38	-0.02	2.1	-0.4
110	5	107.5	1.25	0.35	-0.03	1.6	-0.5
115	5	108.75	1.25	0.33	-0.02	1.1	-0.5
120	5	110	1.25	0.3	-0.03	0.6	-0.5
125	5	111.25	1.25	0.28	-0.02	-0.1	-0.7
130	5	112.5	1.25	0.25	-0.03	-0.8	-0.7
135	5	113.75	1.25	0.23	-0.02	-1.6	-0.8
140	5	115	1.25	0.2	-0.03	-2.4	-0.8

The first column shows the ratio between forecast and benchmark capex (in percentage terms). The second column (the "delta") presents the change in the forecast/benchmark ratio from the row above. The third column presents the allowance rate (AR, also in percentage terms) associated with a given forecast/benchmark ratio; this allowance rate is multiplied by the benchmark capex value, and the product determines allowed capex. The fourth column presents the change in the AR from the row above. The fifth column presents the incentive rate (IR) for a given forecast/benchmark ratio; this incentive rate is multiplied by the difference between allowed and actual capex value. The sixth column presents the change in the IR from the row above. The seventh column presents the additional income (AI) associated with a given forecast/benchmark ratio. The eighth column presents the change in the AI from the row above.

In some ways, the UK approach to incentive regulation must be seen as a success. It is indisputable that price cap regulation in the UK has delivered considerable benefits to British consumers. There have been substantial declines in prices for all regulated utility services in Britain (except water, where there has been substantial new investment to comply with EU water quality standards) since RPI-X controls took effect. The British "building block approach" to price cap regulation can create some incentives for firms to pursue efficiency gains and, over time, these efficiency gains have been distributed to customers in the form of price reductions.

Other aspects of the British approach are also appealing. The sliding scale mechanism that is being applied to capex should help to diminish the incentives to game capex forecasts. Developments regarding the actual operation of this scheme merit attention.

The econometric approach to benchmarking opex has also worked reasonably well, although the econometric models and methods have been extremely simple because of the regulator's decision to rely only on data from the limited sample of UK DNOs. Richer econometric specifications (for both opex and total distribution cost) can be estimated using the much more ample data from North America. The upper quartile benchmarking standard that was applied in the 2005 distribution price review is also appealing and generally consistent with a competitive market paradigm. It is not reasonable for regulators to expect all firms in their industry to be performing at frontier levels, or to set the terms of price controls so that firms earn their cost of capital only by achieving frontier performance standards. In competitive markets, firms that are on the frontier earn above average returns. If regulation is designed to emulate the operation of competitive markets, then the appropriate performance standards must also be set at less than the frontier. Equivalently, firms must have "room" to outperform the standards reflected in the price controls for them to have incentives to boost their efficiency and thereby earn more than their weighted average cost of capital. The upper quartile standard chosen by Ofgem is ultimately based on judgment, but it is generally consistent with this competitive market paradigm.

There are also disadvantages associated with UK, building block regulation. One is that the building block model is susceptible to gaming on the part of companies. Prices are based on a company's projected costs. Companies therefore clearly have incentives to game the estimates of their projected costs that they present at the outset of the regulatory process. Regulators must attempt to "de-game" these forecasts and ascertain the "truth" about how much costs are actually expected to increase over the term of the controls. This is an inherently imprecise exercise which necessarily exposes regulators to the well-known "information asymmetry" problem, since regulators will know far less about the company's actual and projected costs than the companies themselves. Ironically, economists have long believed that information asymmetries are at the heart of problems with cost of service regulation. Incentive regulation is therefore designed to create regulatory institutions that encourage companies to use their superior information in a socially beneficial manner; it should not allow companies to profit by gaming this information through other channels. The UK has created elaborate sliding scale or information quality incentive mechanisms to counter this problem, but developing and implementing such mechanisms is likely to be difficult and costly in Ontario, particularly since separate capex benchmarks would need to be developed for more than 80 distributors.

This reflects a more fundamental concern, which is the information-intensiveness and regulatory burdens of the building block approach. Building block regulation requires detailed cost information, on both a historical and prospective basis, for each regulated company. Implementing this approach for a large number of regulated energy networks could place considerable burdens on the regulatory process and increase the cost and complexity of regulation for all parties involved (companies, regulatory staff and intervenors). The costs of a UK-type approach to incentive regulation are therefore considerably higher than a North American-style approach, and these incremental administrative and regulatory costs would likely outweigh the incremental benefits of implementing a full, building block methodology in Ontario.

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