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August 23, 2013

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On June 10, 2013, FEI filed the Application as referenced above. In accordance with Commission Order G-99-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1. Reference: Exhibit B-1, Page 1

> FEI's primary objectives for its PBR Plan are:
>
> 1. To enforce FEI's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
> 2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

1.1 Please discuss whether or not FEI establishes accountability for its "productivity improvement culture" such that efficiency gain plans must be documented before undertaking them and the finished implemented productivity improvement must be documented to establish objective post implementation evidence of efficiency improvement.

Response:

The question asks about the use of "efficiency gain plans" and post implementation documentation of these plans. FEI uses other effective mechanisms, described in the Application, to encourage a productivity improvement culture that focusses on delivering cost-effective service. FEI provides a recap of its position on the subject of Productivity here to set the context to address a number of related questions contained in the CEC's Information Request number one.

As indicated in Section 3.1 Productivity Focus in Exhibit B-1, a priority for FEI and its employees is to improve productivity and realize efficiencies to more effectively manage rates for our customers while maintaining a customer service focus. Employees are encouraged to assess work and ensure that it is being performed as efficiently and productively as possible. When evaluating productivity opportunities, maintaining a customer focus remains a priority, helping strike a balance between lower costs while providing the appropriate level of service and quality.

As indicated on page 21 of Exhibit B-1 Section 5 Organizational Performance and Monitoring, FEI's view is that the inclusion of a productivity improvement factor in FEI's PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. Departments have a requirement to maintain or increase their outputs and activity levels while keeping cost increases below inflation on a per customer basis, which will result in a measured improvement in productivity.

To help ensure this, departments are accountable for achieving productivity improvements. Departments identify and reflect achievable productivity opportunities in their budget requirements when preparing the detailed budgets for the year. Sustainable savings are reflected in future budget requirements. Proposed departmental budgets are validated by comparing to both the approved level of funding and to the most recent year's spending. Additionally, productivity improvement objectives are embedded into personal performance plans of managers throughout the organization to ensure accountability for a productivity improvement culture. This process helps to ensure a continued focus on productivity over the long term and that rates are being managed effectively for our customers.

And as noted in Exhibit B-1, the result of this focus is evident and discussed in the departmental results and forecasts included in Section C3 of Exhibit B-1 and in the Productivity Focus and Organizational Performance discussion that contains many actual examples of productivity achievements in the past. For the reasons outlined, departments are not expected to formally document and quantify all productivity initiatives and related savings except in ad-hoc situations or situations where a capital investment is required (i.e. IT capital investment). As indicated in the response to CEC IR 1.11.5, business technology capital requests related to productivity improvements and enhanced customer service will only be funded provided they are supported by a benefits case in accordance with the IT Benefits Management practice as detailed in Exhibit B-1-1 Appendix C4.

Also, FEI's view is that the focus should not be necessarily on minimizing costs for our customers, but instead it is about optimizing costs for the expected activity and service levels.

1.2 Please describe how FEI establishes internally whether or not real productivity gains have been achieved and whether or not they can be sustained over the long term.

Response:

Please refer to the response to CEC IR 1.1.1.

As outlined in that response, business areas identify and reflect achievable productivity opportunities in their budget requirements when preparing the detailed budgets for the year. Sustainable savings are reflected in future budget requirements. Additionally, productivity improvement objectives are embedded into personal performance plans of managers throughout the organization to ensure accountability for a productivity improvement culture.

This process helps to ensure a continued focus on productivity over the long term.

1.3 Please describe how FEI assures itself that its management of business priorities is better than it would have done has it not had the PBR process, other than with some global statistic on operating expenditures and capital expenditures (2014 to 2018 plan versus actual).

Response:

Regardless of whether there is a PBR agreement or not, the regulatory framework in this province is that the regulator establishes rates based on a global budget for the corporation for operating expenditures and capital expenditures in order to provide FEI with a reasonable opportunity to recover prudently incurred costs and earn its allowed return. The utility manages within that overall corporate budget. So, the "global statistic on operating expenditures and capital expenditures" referred to in the question is an important measure of productivity that is directly related to how utilities are regulated.

Under either PBR or cost of service, FEI utilizes a comprehensive planning process to assure itself that it appropriately sets and manages the business priorities of the Company. The fundamental difference under PBR relates to the opportunity to invest in efficiency programs that would not otherwise be in the mutual best interests of customers and shareholders because the Company would not be able to achieve an ROI before rebasing occurs. This point has been discussed at length in responding to questions related to the five year PBR period and the proposed ECM.

An integral part of the planning process is the preparation of operating and capital budgets which reflect the priorities of the business. The balanced scorecard is reviewed and adjusted to deliver on a number of key success measures critical to achieving the business priorities set. Additionally, managers' performance plans are aligned to reflect the organization's priorities. Lastly, the results of the balanced scorecard are communicated to all employees on a quarterly basis to provide a status update on how well the company is performing in achieving its business priorities. The scorecard is a valuable communication tool used to describe in clear and objective terms success measures for the Company.

PBR brings with it additional efficiency incentives like the ones summarized on p.29 of the Application, and FEI can be expected to respond to those incentives as it has in the past. Additionally, with the proposed PBR formula, a measurable level of discipline is added over the term of the PBR Plan. Annual increases to O&M and Capital funding are limited to measurable inflation and customer growth factors. Most importantly, the proposed PBR Plan incorporates a productivity factor of 0.5% that represents a minimum level of efficiency benefits that flow to customers.

1.4 Please explain how FEI determines that it is minimizing costs for customers other than basing it on a Commission approved plan for 2014 to 2018 as the benchmark.

<u>Response:</u>

Cost effectiveness, rather than minimizing costs, should be the objective, irrespective of whether a utility is operating under cost of service regulation or PBR. Please refer to the response to CEC IR 1.1.1.

1.5 In the workshops FEI stated that it did not plan to have any detailed accountability for its efficiency improvements but expected to rely simply improving on the adjusted overview formula for 2014 to 2018 as the benchmark for productivity improvement. Please confirm that this remains the FEI position.

<u>Response:</u>

The regulatory framework in this province, whether under cost of service or PBR, is for the Commission to set rates based on forecasts, and for a utility to manage its own affairs within its budgets. FEI's approach is consistent with that fundamental framework. As outlined in the response to CEC IR 1.32.4, this is consistent with the purpose of PBR which is to provide market like incentives and leave the management of the Company to make decisions.

Please refer also to the response to CEC IR 1.1.1.

2. Reference: Exhibit B-1, Page 1

> FEI's proposed PBR Plan builds on the successful components of the PBR plan that was approved for FEI for 2004-2007 and extended for 2008-2009 (the 2004 Plan), with improvements to a number of elements. Similar to the 2004 Plan, the proposed PBR Plan establishes incentives for those elements of cost of service over which the Company has the greatest control: operating and maintenance (O&M) and capital expenditures. The formula results in targeted levels of spending in these areas that are lower than FEI's forecast of O&M and capital costs over the five year period as set out in Section C. This provides the Company with an incentive to invest in new efficiencies to meet the targets under the formulas. In addition, the PBR Plan includes a sharing mechanism that provides an opportunity for customers to share in the benefit to the extent that FEI exceeds the formula-based targets. For those items over which FEI has limited or no control, the PBR Plan maintains the same regulatory treatment as was used in the 2004 Plan through the use of flowthroughs and Annual Reviews. The PBR Plan provides "off-ramps" should financial results or performance fall outside a band of reasonableness.

2.1 Please confirm that in the past when FEI has not been satisfied with the regime it is operating under that it has been able to go to the Provincial Government and ask for and receive support, including legislative and regulation support for improvements, which will benefits its customers.

<u>Response:</u>

Yes, FEI has been able, in a limited number of circumstances, to obtain government support for its initiatives in the form of special directions and/or regulations which provide benefits to its customers. These circumstances have been limited to instances where FEI has received a decision that it believed was contrary to the interests of its customers and inconsistent with government policy, and where government has agreed that the public interest would be served with such support. The *Greenhouse Gas Reduction (Clean Energy) Regulation*, passed in May 2012, which enables public utilities to make certain investments to promote natural gas for transportation is a recent example.

2.2 Please explain why an FEI forecast of O&M and capital costs represents the appropriate benchmark for the company to be held to when determining whether or not new efficiencies have been achieved.

Response:

The FEI forecast of O&M and capital costs does not represent the appropriate benchmark for the company to be held to when determining whether or not new efficiencies have been achieved. The 2014 through 2018 O&M and capital forecasts included in the Application are for reference purposes only. They represent a high level forecast of future trends, challenges and capital priorities over the upcoming five years.

Under the proposed PBR plan, each year the component of rates designed to recover O&M and capital expenses will adjust the previous year's amount by the PBR formula which includes a productivity factor. Since the PBR formula provides the Company with an incentive to invest in new efficiencies to meet the targets under the formula, it is this amount prescribed under the PBR formula that serves as the benchmark that indicates whether or not new efficiencies with respect to cost reductions have been achieved.

2.3 Please confirm that when FEI "invests in new efficiencies" its shareholder does not put in risk capital contingent on the success of the productivity improvement, but rather is able to invest both capital and operating resources, which it is able to recover from its customers and these resources are the investments which achieve the new efficiencies.

Response:

New efficiencies may be found in a number of ways. In some cases the efficiencies will be found through discovery of better ways of doing the work with little or no incremental expenditure involved. In other cases, where incremental expenditures are required to achieve the new efficiencies the incremental costs may be either a capital or an O&M expenditure. In cases that involve a capital expenditure to achieve new efficiencies, the capital will be considered a normal rate base addition that will be recoverable in rates as capital additions are under conventional cost-of-service ratemaking. O&M expenditures to produce efficiency savings will also be recoverable, as they are under conventional cost-of-service ratemaking. The PBR changes the manner in which rates are determined (i.e. using formulas) in order to incent the Company to pursue efficiencies but the actual expenditures that are made will be recorded as utility expenditures in the normal fashion.

A key selling feature of PBR is that it extends the period before rebasing, which allows the utility to invest in measures and obtain a payback of the investment in circumstances where rebasing after a typical test period of one or two years would otherwise preclude the utility from recovering that investment. In short, it opens new possibilities for the utility to achieve efficiencies to the benefit of both the utility and customers.

2.4 Please confirm that if FEI exceeds the formula based targets without incentives that 100% of the benefits would be realized by the FEI customers and that it is the case that the sharing mechanism provides an opportunity for the FEI shareholder to benefit by sharing in the determined gains.

Response:

Not confirmed. The scenario posed in the question of exceeding the formula-based targets without incentives is the same as what occurs under conventional cost of service ratemaking. If FEI (or another utility) spends less than the approved levels of O&M or capital under conventional cost of service ratemaking the shareholder would normally keep 100% of the benefits until the next rate case, at which time it would be expected that the benefits would be rebased in the allowed O&M spending levels and rate base going forward.

2.5 Please confirm that those items identified as flow through items, to the extent they change from plans or forecasts, will not have a sharing mechanism applied to the differences and will not result in any benefit to the FEI shareholder.

Response:

The treatment of flow-through items is conceptually identical to the treatment of flow-through items in the 2004 PBR Plan. The cost-of-service items subject to flow-through are substantially the same as in the 2004 Plan however there have been some accounting changes (such as the adoption of US GAAP) and changes in the deferral accounts that affect the flow-through treatment of some items.

Most of the flow-through items are covered by deferral accounts and therefore any variances (positive or negative) between forecast and actual costs or revenues will be refunded or charged in rates in a subsequent period. In other words rates will ultimately recover only the actual costs (after deferral account balances are amortized). Key flow-through cost items covered by deferral accounts are property taxes and interest costs, pensions, OPEBs and insurance. The revenue side can be divided into commodity related and delivery-related revenue streams. The commodity- related portion, consisting of commodity cost recovery and midstream cost recovery, is fully covered by deferral accounts (CCRA and MCRA). With respect to delivery-related revenues, the RSAM mechanism covers residential and commercial sales and transportation delivery revenues, which comprise over 90% of the non-bypass delivery revenues.

A small portion of the total delivery costs and revenues are subject to flow-through treatment (through annual reforecasting) but are not covered by deferral account treatment. These items include industrial revenues and Other Revenue on the revenue side and rate base working capital on the cost side. Variances in these items from forecast will give rise to 50/50 earnings sharing (which may be positive or negative) in the year that the variance occurs only. These items will be reforecast for the following year so variances will not be sustained from one year to the next.

3. Reference: Exhibit B-1, Page 1, Table A1-1

Table A1-1: Summary of 2014 PBR Plan Proposal

Element	PBR Plan
Term	A five-year term from 2014-2018 is proposed.
Inflation Factor (I-Factor)	A weighted average of BC Average Weekly Earnings (AWE) for labour costs and BC-CPI for other O&M costs will be used to determine the I-factor, which will be reforecast annually.
Productivity Improvement Factor (X-Factor)	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M is proposed. 2013 approved O&M expenditures (with adjustments) are adopted as the base O&M The O&M formula will adjust the prior year's formula O&M by forecast customer growth and (I-X). O&M will not be rebased during the PBR term but will be subject to true-up for actual customer growth.
Controllable Expenses – Capital	A formula based approach for Capital is proposed using 2013 approved capital expenditures (with adjustments) as the base. Two formulas will be applied. Growth Capital is tied to forecast service line additions and other regular capital is tied to forecast growth in average customers. The (I-X) escalation factor is also applied to both formulas. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%. Formula amounts will be subject to true-up for actual cost driver results (i.e. service line additions or average customers).
Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and Commission decisions will be flowed through in rates.
Earnings Sharing Mechanism	The PBR includes a 50/50 earnings sharing mechanism for returns above or below the approved return on equity
Efficiency Carry-Over Mechanism	An expanded Efficiency Carry-over Mechanism is proposed based on a rolling 5-year benefit calculation derived from O&M and capital efficiencies achieved each year.
Service Quality Indicators	10 SQIs (7 SQIs with a target benchmark and 3 informational measures) are proposed that deal with emergency response, customer service (telephone service, billing), employee safety and meter exchanges.
Mid-Term Review and Off Ramps	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	Annual reviews are also proposed for this PBR.

3.1 Please provide a description in the form of this table for the 2004 to 2007 PBR plan and its continuation extensions to 2008 – 2009.

Response:

The description of the 2004-2007 PBR and 2008-2009 extension in the form of Table A1-1 is provided in Table B6-10 on pages 80 and 81 of the Application. Table B6-10 also sets the provisions of the proposed 2014 PBR side by side with the corresponding provisions of the 2004 PBR Plan for ease of comparison.

3.2 The PBR plan does not provide for revenue generation being an aspect of the PBR plan, except as a flow through. Please confirm that revenue requirements determining customer rates are affected by both revenues and costs.

Response:

Confirmed, subject to a slight refinement. Strictly speaking the revenue requirement is determined by the utility's costs. Customer rates, and in particular rate increases (from revenue deficiencies) or decreases (from revenue surpluses), are affected by both revenues and costs. Under the PBR, revenues are reforecast annually and flowed through. FEI will continue to consider any incremental revenue generation opportunities during the term of the PBR and these will be included in the revenue forecasts as appropriate.

4. Reference: Exhibit B-1, Page 3

> Overall, FEI believes that the proposed PBR Plan is an appropriate model that will encourage FEI to seek efficiencies in its operations over the term of the PBR plan for the benefit of both customers and the Company, while maintaining safe, reliable and customer-oriented utility service. B&V, who have provided input in the preparation of both the PBR Plan and Section B of the Application, endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate productivity factor as being approximately zero, based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package. Section B of the Application provides a review of PBR in general, a review of PBR regimes approved in other jurisdictions and more detailed discussion of the proposed PBR Plan.

4.1 Please confirm that B&V are hired by FEI and are not expected to be neutral experts for advising the Commission.

<u>Response:</u>

B&V were hired to assist FEI in developing the PBR plan and to respond to the Commission's April 18, 2013 PBR letter which states:

> *"The Commission requires FEU and FortisBC to describe its productivity improvement culture by an examination of PBR methodologies in its next Revenue Requirements Applications. This examination is to evaluate the most recent PBR methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada. FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture."*

B&V conducted its TFP studies independently, but otherwise B&V's role has required that it have significant interaction with FEI, to co-operate, and develop and exchange ideas regarding the appropriate PBR Plan for FEI.

At the outset, Fasken Martineau DuMoulin LLP, who retained B&V on behalf of FEI, specifically confirmed with B&V that B&V were being retained for the purpose of providing expert advice, and not as advocates for a position developed by FEI. The distinction between expert and advocate is fundamentally important and has been maintained throughout. (As an indication of this, although B&V generally endorses the Plan it has declined to endorse the productivity factor proposed by FEI – a key element of FEI's proposed PBR Plan - because B&V believe it is higher than is warranted based on its own assessment.)

In short, FEI and B&V are well aware that B&V's ability to provide meaningful input of assistance to the Commission is dependent on their ability to maintain their own views and professional integrity.

4.2 If the TPF based "stretch" productivity factor is determined by the Commission to be greater than the B&V based research and greater than the FEI comfort zone, will FEI be agreeable to such a PBR or will it reject the PBR approach altogether and revert to filing RRAs instead?

Response:

FEI believes that it has proposed a "stretch" productivity factor that, in combination with the other PBR Plan components, will enable the Company to pursue efficiencies for the benefit of customers and the Company over the PBR term and beyond. It is already an aggressive target, which was proposed to provide for a significant consumer dividend for customers. If the Commission determined a more aggressive "stretch" productivity factor, FEI would reassess its plans on how to proceed but it is difficult to identify any particular response in the abstract. FEI would not consider the stretch productivity factor in isolation but rather would base its reassessment on the combined effect of the Commission determinations on all PBR Plan elements to determine whether or not the overall impact allowed the utility an opportunity to earn its fair return consistent with regulatory and legal principles.

4.3 Please discuss what the FEI responsibility is to achieve an efficient operating and capital regime and where the boundary is between this responsibility and the proposed sharing in "stretch" benefits.

Response:

FEI operates efficiently with respect to its O&M and capital programs in the context of its regulatory construct. In RRAs involving test periods of one or two years efficiency programs with longer term paybacks may not be pursued because neither payback nor a return on investment may be achieved. The regulatory compact is premised on the utility being able to earn a payback on its investments (i.e. a fair return), so this type of economic cost/benefit analysis by the utility is to be expected. It is inherent in the regulatory compact. Hence, regulators and utilities have looked for ways to improve the prospects for utilities to obtain a return on investment in efficiencies so as to provide a framework to drive greater efficiencies. A longer term regulatory control period such as the proposed five-year PBR term expands the array of efficiency opportunities that may pursued.

Please see also the response to CEC IR 1.23.1 for related discussion on this topic.

5. Reference: Exhibit B-1, Page 3

> FEI has provided forecasts of demand, revenue, O&M, and capital for the full 2014-2018 term (the PBR Period) in Section C of the Application. The 2014 through 2018 forecasts are included for reference purposes and represent a high level forecast of future trends and upcoming challenges for FEI. As FEI's proposed rates are based on the PBR Plan, FEI's cost of service forecasts should not be the focus of this proceeding. FEI has also provided an historical review of O&M expenditures since 2010. This historical review demonstrates that FEI has implemented a renewed focus on productivity which has resulted in efficiencies and sustainable savings. These sustainable savings have been incorporated into the 2013 Base O&M to which the O&M formula in the PBR Plan will be applied.

5.1 Please confirm that any efficiency savings achieved by FEI between 2009 and 2013 will have been realized 100% by the FEI customers because there has been no PBR or sharing mechanism.

Response:

Not confirmed

In 2009, FEI was under PBR. This means that, to the extent that savings realized were achieved as part of the productivity improvement factor, they were realized 100% by customers. To the extent the savings were in addition to the savings embedded in rates, they were shared equally between customers and the shareholder for that year only. Starting in 2010, FEI went back into cost of service regulation and the 2009 savings were rebased into the opening O&M and capital amounts.

From 2010 through 2013, any savings that FEI achieved in excess of the amounts that were included in rates were retained 100% by the shareholder, but only until rates were next reset. For example, savings achieved in 2011 were only realized by the shareholder for that year, because after that, rates were reset and these savings were embedded in the delivery margin and flowed back to customers.

Under FEI's PBR proposal, similar to 2009, rates will be set to provide 100% of savings from the productivity factor to customers. To the extent the savings are in addition to the savings embedded in rates, they will be shared equally between customers and the shareholder for the term of the PBR.

6 Reference: Exhibit B-1, Page 4

> Section E provides the financial schedules filed in support of the 2014 delivery rates proposed in this Application. The proposed 2014 non-bypass delivery rates are approximately 1.7 percent lower than the existing 2013 interim rates. This decrease is due to two factors. The first is the impact of the Generic Cost of Capital Phase 1 Decision (GCOC Decision) which decreases delivery rates by approximately 2.4 percent.[2] The second is a delivery rate increase of approximately 0.7 percent that results from the PBR Plan and demonstrates the continuing benefits of the Company's productivity and customer focus.

6.1 Please explain how a delivery rate of .7 % resulting from the PBR plan demonstrates the continuing benefit of the Company's productivity and customer focus, as it increases rates in opposition to the direction of the GCOC which decreased rates.

Response:

The reference provided in the preamble was from Exhibit B-1. On July 16, 2013 FEI provided an Evidentiary Update (Exhibit B-1-3) which replaced the above paragraph with the following:

> Section E provides the financial schedules filed in support of the 2014 delivery rates proposed in this Application. The proposed 2014 non-bypass delivery rates are approximately 1.0 percent higher than the existing 2013 delivery rates. This delivery rate increase demonstrates the continuing benefits of the Company's productivity and customer focus.

It is this 1% delivery rate increase that FEI references in this response.

In summary, it isn't the fact that the rates are increasing that shows the focus on customers and productivity, but rather the fact that the increase is only 1% given the overall circumstances. The 1% increase is the result of a number of influences affecting FEI's costs and revenues, but important among them are the controllable expenditures (O&M and capital). The base level of O&M in particular (including the proposed adjustment for sustainable savings) helps to keep the increase to 1%, which is less than half of the 2.31%[1] composite inflation for 2014.

[1] See Lines 6 and 7 of Page 48 of the Application (Exhibit B-1)

7. Reference: Exhibit B-1, Page 6

> **Deferral Accounts**
>
> 4. Approval pursuant to sections 59 to 61 of the Act of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI as set out in Section D4 and Appendices F4 and F5 of the Application and summarized in the following table.

7.1 Please provide a list of the deferral accounts established by FEI during the intervening period between the last PBR and the proposed start of this PBR.

Response:

The deferral accounts listed below were created between the last PBR and the proposed start of this PBR. These deferrals were primarily created to address changing energy policy and new service offerings, and changes in accounting policies and related classifications.

RATE BASE

Margin Related

Interest on Gas in Storage

Energy Policy Related

Energy Efficiency & Conservation ("EEC")

Emissions Regulations

Biomethane Program Costs

NGT Incentives

Fuelling Stations Variance Account

Rate Schedule 16 Cost & Recoveries

Non-Controllable

Customer Service Variances

US GAAP Pension & OPEB Funded Status

Application Costs

NGV for Transportation Application

Long Term Resource Plan Application

AES Inquiry

Rate Schedule 16 Application

<u>Other</u>

2010-2011 Customer Service O&M and COS

Gas Assets Records Project

BC OneCall Project

Gains and Losses on Asset Disposition

Negative Salvage Provision/Cost

Residual Deferrals

Depreciation Variance

BFI Costs and Recoveries

CNG and LNG Recoveries

2011 CNG and LNG Service Costs and Recoveries

IFRS Transitional Costs

2010-2011 Revenue Requirement Application

2012-2013 Revenue Requirement Application

CCE CPCN Application

Deferred Removal Costs

US GAAP Conversion Costs

US GAAP Transitional Costs

Overhead and Marketing Recoveries from NGT Class of Service

Residual Delivery Rate Riders

<u>NON-RATE BASE</u>

Thermal Energy Services Deferral Account ("TESDA")

Biomethane Variance Account ("BVA")

EEC Incentives

EEC Incentives for AES/TES

KORP Feasibility Costs

On-Bill Financing Pilot Program

7.2 Please confirm that FEI will continue to propose deferral accounts during the term of this PBR and that it will be possible for these deferral accounts to affect the proposed costs and revenues that would determine rates for the period 2014 to 2018.

<u>Response:</u>

FEI will continue to propose deferral accounts during the term of this PBR if required and as appropriate. The actual and forecasted balances for existing and new accounts will be adjusted each year during the Annual Review process while setting rates for the following year. These balances will affect the cost of service for rate setting purposes throughout the PBR period.

8. Reference: Exhibit B-1, Page 11

> **3.1 *PRODUCTIVITY FOCUS***
>
> A priority for FEI and its employees is to improve productivity and realize efficiencies to more effectively manage rates for our customers while maintaining a customer service focus. Employees are encouraged to assess work and ensure that it is being performed as efficiently and productively as possible. When evaluating productivity opportunities, maintaining a customer focus remains a priority, helping strike a balance between lower costs while providing the appropriate level of service and quality.

8.1 Please provide a list of the other priority focuses of the Company, in addition to productivity and describe how these may or may not help to manage rates for customers.

<u>Response:</u>

As stated in Exhibit B-1, the overall priority for FEI and its employees is to improve productivity and realize efficiencies to manage rates effectively for our customers while maintaining a customer service focus.

The priority focuses of the company are reflected in its balanced scorecard. As indicated in Exhibit B-1, FEI uses a balanced scorecard approach to deliver on a number of key success measures critical to the business. The scorecard is currently comprised of four categories of measures, with six measures in total, that describe and guide the company's overall performance in meeting the targets. The four categories of measures include Financial, Safety, Customer and Regulatory. These categories reflect the priorities of the company.

Of the four categories on the scorecard, the Financial category best incorporates the productivity focus of the company. Savings resulting from productivity initiatives will ultimately be reflected in the financial component and eventually to help manage rates for customers.

The Regulatory performance category highlights the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. Depending on the issue, this may or may not help to manage rates for customers.

The remaining two categories on the scorecard, Safety and Customer, are focused on ensuring the company is able to deliver a safe and reliable service while maintaining a customer service focus.

The Safety category helps to ensure focus on achieving employee safety through lost time and vehicle accidents. Creating a safe working environment for employees will support the delivery of a safe and reliable service to customers. Additionally, it may result in lower lost time injuries and vehicle accidents which may lead to reduced costs. The Customer category captures customers' satisfaction with the company's performance in certain aspects of the business and public safety awareness. This category helps to maintain a customer service focus in the organization.

8.2 Please describe the trade-off issues that may be involved between different Company focuses and the likely benefit for managing customer rates.

Response:

Please refer to the response to CEC IR 1.8.1 for discussion of the different company focuses including Customer, Safety, Regulatory, and Financial.

Recognizing the need to balance the interests of customers, the regulator and shareholder, the primary trade-off issue (i.e. the performance in one area may impact other areas positively/negatively) is between the customer and financial focuses. The competing objectives are for the company to perform at an acceptable level of customer service/satisfaction (i.e. how well we do things, how fast we respond) while meeting the obligations to provide safe and reliable utility service cost-effectively for the benefit of customers and earning a reasonable return.

FEI believes a PBR Plan that ensures an appropriate trade-off between the Customer and Financial objectives addressing the challenge noted (i.e. acceptable service level, financial incentive to lower costs) is beneficial to customers as it places continued emphasis to manage rates effectively for customers. This balance is a key issue of PBR Plan design and one that FEI believes is appropriately captured in the proposed 2014 PBR Plan. The proposed PBR Plan incents the utility to pursue efficiencies for immediate sharing and the longer term benefit of customers while maintaining service quality as measured by the proposed SQIs.

8.3 Please describe any analysis FEI may have done to determine which priorities would have the greatest potential payoff for customers and how the Company has determined the basis of its allocation of management time and effort to implement each of its priority focuses.

Response:

Please refer to the response to CEC IR 1.1.3 for a discussion of the planning and monitoring process used to set and manage the business priorities of the company.

The priorities as set out on the company's scorecard are determined by the Executive Leadership Team and presented to the Board of Directors annually for approval.

8.4 How will FEIs productivity focus be different under PBR than it has been for the period 2009 to 2013?

Response:

As indicated in Exhibit B-1 Section A3.1 Productivity Focus, FEI has already been pursuing a number of productivity initiatives and opportunities in recent years. Going forward, the Company expects to continue to evaluate opportunities depending on the circumstances and potential benefits to customers. The fundamental difference under PBR relates to the opportunity to invest in incremental efficiency programs that may not seem to be in the best interests of both customers and shareholder under cost of service regulation. Another way of looking at the effect of PBR is that, rather than fundamentally changing the way the Company approaches productivity initiatives, PBR creates new opportunities because it changes the cost benefit analysis for incremental initiatives that might not otherwise be practical under cost of service.

8.5 If there is to be an increase in productivity focus for 2014 to 2018, please explain why the 2009 to 2013 period did not have an equivalent level of focus on productivity?

Response:

Please refer to the response to CEC IR 1.8.4.

9. Reference: Exhibit B-1, Page 11

> In 2012, the Company was able to achieve a number of efficiency successes. These included significant annual savings of approximately $9 million related to implementing a new manual meter reading contract. Starting in 2013, the new arrangement provides improved meter reading service at a lower cost than the previous arrangement.

9.1 Please describe the base line for the determination of savings in this example in quantitative terms and if the base was an assumption of a continuation of the prior contract please explain the assumptions used.

Response:

The baseline assumed a continuation of services through 2012 utilizing the existing meter reading service provider and continuing to participate in joint meter reading with BC Hydro for as long as that synergy was available. These costs were applied for, tested and approved through the 2012-2013 RRA process based on the agreement in place at that time.

The $ 9 million in savings will be achieved in 2013 based on the costs projected from the prior contract. The cost impact is as follows:

2013 Approved	$19.696 million
2013 YE Forecast	$11.068 million
2013 O&M Savings	$ 8.828 million

9.2 Please provide the expiry date of the last contract and confirm that it would have been business as usual to acquire this service and to negotiate a new contract.

Response:

Refer to the response to BCUC IR 1.90.2.

9.3 Please confirm that FEI does not believe that it could have achieved better terms under a PBR than without a PBR as was done in 2012.

Response:

Specifically related to the outsourcing of meter reading services FEI does not believe that is could have achieved better results under a PBR than without a PBR. FEI's focus in providing services to customers is to achieve the highest quality of service at the lowest possible cost regardless of the regulatory mechanism.

9.4 Please provide a list of significant contracts which may come due during the PBR period and may require reacquisition of the service with an opportunity to negotiate new terms and please provide for each the annual expenditure magnitude.

Response:

For the purpose of defining a significant contract, FEI chose the threshold of contracts issued for one (1) million dollars annually. Most significant contracts have an initial term with an optional contract renewal period~~.~~. With respect to annual expenditure magnitudes FEI relies on historical values. Contractual values are estimates and may come in under one (1) million dollars in any given year based on operational demand. Please see the table below.

Type of Service	Number of Contracts	Expiry Periods	Value Range*
Construction Services			
Mains and Services	3	expiry December 2014 with 1 option to renew for 24 months	$3.6 - $15.3 million
Paving	2	annual and May 2014 with 1 one year renewal option	$700K - $2.3 million
Flagging	1	expiry June 2015 with 3 one year renewal options	$848K
Inline Inspection	1	expiry November 2013 with 1 three year renewal option	$800K
Software & Maintenance Agreements	2	annually and May 2014 with 1 one year renewal option	$1.3-$2.1 million

Type of Service	Number of Contracts	Expiry Periods	Value Range*
Engineering Services	2	expiry December 2013 with 3 one year renewal options	$1 - $1.1 million
Leak Hazard Detection	1	expiry December 2014 with 2 one year renewal options	$764K
Telecommunications	3	expiry September 2013 with 1 one year renewal option and December 2017	$1.1 - $4.5 million
Meter reading**	1	expiry December 2015 with 2 one year renewal options	$11 million
Advertising	1	annually	$2.4 million
Vegetation Management	1	expiry December 2014	$650K
Fleet Maintenance	1	expiry 2017 with 1 one year renewal option	$8.4 million
* estimated expenditure based on 2012 annual spend			
** new contract starting in 2013			

10. Reference: Exhibit B-1, Page 11

> Streamlining and enhancement of processes contributed to increased productivity and provided increased service to customers. FEI reduced the customer wait time for installation of a new gas service not requiring a permit by implementing process changes. An on-line self-help Home Energy Calculator was introduced allowing residential customers the ability to compare energy costs of operating home appliances at the customers' convenience while reducing the amount of support required from customer service staff. The meter exchange process was improved using live-agent calls, in addition to letters, which led to increased customer satisfaction with the process as well as increased efficiency. Process enhancements in the GIS area have enabled faster drawing production in support of distribution main expansions and alterations and more efficient use of resources. Simplification of various physical processes within Materials Services contributed to reduced cycle times.

10.1 Please quantify the savings related to the changes described above as was done for the new manual meter reading contract.

<u>Response:</u>

The following are further details of the changes and quantification of the related savings where possible. As discussed in the different sections, not all of the savings related to the initiatives are quantifiable as the resources freed up are reassigned to support other activities. Additionally, some of the benefits of these initiatives are more focused on improving service levels and increasing capacity than reducing costs from the bottom-line.

<u>Customer wait time for installation of a new gas service</u>

Reducing the wait time for applications that do not require a permit improves customer service and positively impacts the productivity of the various departments involved in processing the applications. The reduced wait time leads to a decrease in the number of applications that need to be monitored and updated, with the freed up time reassigned to process other service applications. Additionally, the reduced wait time for customers may also result in customers connecting to the system earlier than otherwise, resulting in more revenues.

The savings from this initiative are difficult to quantify given that it is focused more on improving customer wait time than reducing costs. As discussed, the freed up resources are reassigned to help with processing other applications and therefore do not translate into bottom-line savings.

<u>On-line self-help Home Energy Calculator</u>

By providing the calculator online, customers are now able to translate their individual appliance choices and associated energy portfolio into quantifiable monetary impacts through the energy cost savings output of the calculator. Customers benefit from having more tools available to analyze and assess energy options. By providing customers the ability to assess the potential impacts of their future energy choices, customers will be better able to choose “the right fuel for the right use at the right time.”

<u>Meter Exchange process</u>

The increased efficiency with this process change was in two main areas. First, there is cost savings associated with a reduced volume of letters being sent to customers as they were replaced by a live agent phone call. The cost savings associated with this is approximately $40,000 annually. The second area was in call volumes being shifted from peak times to low volume times. This reduction occurred because instead of customers calling in response to the letter, the Contact Center was able to make an outbound call during slower times of the day. Because these savings were not a reduction in calls, but instead a shift in the timing of those calls, the actual cost savings cannot be quantified.

In general, the meter exchange process changes were aimed at improving the customer experience by reducing customer effort and increasing first contact resolution. The cost savings, although not an initial goal of the changes, were an added benefit for customers.

<u>GIS process enhancements</u>

The faster drawing production time is the result of a number of improvement initiatives including training of staff, standardization of notes and forms used, automation of some routine processes, and improved drawing management. All of these changes have led to enhanced customer service by enabling a reduction in the drawing turnaround time, from four weeks to two weeks, and allowing for a reduction in the amount of rush work required. This translates into approximate savings of $10,000 per year.

<u>Simplification of physical processes with Materials Services</u>

Savings have been achieved by re-evaluating all work functions. This re-evaluation resulted in certain work functions being spread throughout the group resulting in a more balanced distribution of work. Additionally, certain procurement functions were automated which resulted in less manual intervention when processing purchase orders for inventoried materials. When requests exceed Supply Chain Services’ ability, third party suppliers are utilized instead of hiring more staff.

These business improvements resulted in a reduction of approximately $200,000 in annual O&M.

Since these savings have already been achieved, they are embedded in the 2013 Projections included in the Application that form the basis for rate setting for the PBR Period.

10.2 If the savings have not been quantified please explain why and whether or not they could be quantified.

Response:

Please refer to the response to CEC IR 1.10.1.

10.3 Does FEI have a view as to whether or not these savings were material or trivial and if so please explain how FEI knows?

Response:

Please refer to the response to CEC IR 1.10.1. As stated in the Application as quoted in the preamble to the IR, the examples were of streamlining and enhancement of processes, rather than dollar savings. The examples cover different areas of the Company and highlight the importance to FEI of improving productivity and realizing efficiencies while maintaining a customer service focus. Productivity is more than just reducing costs, but is also about improving customer service and options (i.e. energy calculator example refer to above) and growing revenues, using the same amount of resources available. In addition, these examples provide insight to the inherent challenges (i.e. not easily quantifiable, more focused on improving service) in tracking and reporting on individual productivity initiatives, as indicated in the response to CEC IR 1.1.1.

11. Reference: Exhibit B-1, Page 11

> Productivity gains from leveraging technology include enhancements in support of the BC One Call process which resulted in significant productivity gains and provides the Company the ability to respond faster to customer inquiries. In the supply chain services, business processes were simplified using automation.

11.1 Please describe how the savings in the BC One Call and Supply Chain Services processes were achieved.

Response:

For the BC One Call processes, the savings are achieved through the reduction in ticket processing time required. The technology stream enhanced and integrated FEI technologies, and therefore enabled automation for some of the routine and time consuming processes/steps required in assembling the underground utility information packages required by the information requestors through BC One Call.

One way that FEI simplified its supply chain processes was by automating the issuance of purchase orders for contracts with fixed prices, terms and conditions to reduce manual intervention. In addition, supply chain automated the workflow for contractors completing capital projects to reduce manual paperwork and simplify the process for approvals and payment. Finally, a reduction of data entry was achieved by linking different IT solutions used by Operations employees to order materials.

11.2 Please quantify the savings achieved by leveraging technology in this BC One Call process.

Response:

As indicated on page 175 of Exhibit B-1 Section C3.9.3 Engineering Services and Project Management Review, the total savings is estimated at $600 thousand per year.

11.3 Please advise whether or not there was a commitment of capital expenditure to a project to achieve these savings.

Response:

Yes.

11.4 Please advise whether or not the Company has a list of significant proposed opportunities to leverage technology to improve productivity and service and for each please describe their proposed implementation dates during the 2014 to 2018 time period.

Response:

As discussed in Exhibit B-1, Application, Section C4.6.4.2, the Company intends on leveraging technology to improve productivity and service in a variety of ways for several key business areas throughout the PBR time period. It intends on driving this change through the list of Business Technology Transformation programs (the current list of programs has been provided in Exhibit B-1-1, Appendix C4). FEI will measure the expected benefits of these changes through the newly introduced Benefits Management practice as discussed in Exhibit B-1-1, Appendix C4.

11.5 Please confirm that in addition to any list FEI has that it will continue to identify opportunities for leveraging technology during the PBR period.

Response:

This is correct. FEI will continue to identify opportunities to leverage technology coupled with business process change and training in order to support productivity improvements and enhanced customer service. However, these Business Technology capital requests will be funded provided that they are supported by a benefits case in accordance with the IT Benefits Management practice as detailed in Exhibit B-1-1 Appendix C4. These requests will be assessed as candidates for execution based on priority within the Business Technology Portfolio.

12. Reference: Exhibit B-1, Pages 11 & 12

> Integration with the electric business enabled certain efficiencies to be achieved. Integration driven opportunities involved a common management team, common processes and sharing of resources. Additionally, integration driven efficiencies were not only focused on lowering costs
>
> but also on increasing the capacity of both the gas and electric businesses and providing employee growth and development opportunities.

12.1 Please quantify the savings benefits of the integration with the electric business.

Response:

As discussed in Section C3.2 Historical O&M by Department in Exhibit B-1, FEI has achieved a number of sustainable productivity improvements in recent years of which integration is a contributor amongst others drivers. In addition, each department has included a discussion of the savings achieved. However, given FEI's approach to ensuring accountability for productivity improvement as described in the response to CEC IR 1.1.1, it has not required departments to specifically track savings benefits for each of the drivers including that due to integration. As a result, FEI does not have a comprehensive list of savings benefits due to integration with the electric business.

12.2 When did the integration with the electric business begin?

Response:

The integration efforts of the FortisBC gas and electric businesses started in mid-2010 with the announcement of a common President and CEO and a common Board of Directors for all of the FortisBC companies.

12.3 Please confirm that FEI is under no obligation to achieve savings through integration with the electric business and that the Commission could not order such integration between independent utilities or if the Commission could order this please explain the Commission jurisdiction to do so.

Response:

Confirmed.

12.4 Is the full extent of the savings from integration with the electric business captured now or will there be further opportunities in the 2014 to 2018 period to achieve additional savings?

Response:

There may be further opportunities in the 2014 – 2018 period to achieve additional savings. However, as indicated on page 13 of Exhibit B-1, Section A3-3 Productivity Focus - 2013 and Onward, future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome some challenges.

Following is an excerpt from page 13 of Exhibit B-1.

> Further opportunities may emerge and will be evaluated depending on the circumstances and potential benefits to customers. Future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome some challenges. These challenges include concerns raised by unions representing gas and electric employees around shifting of unionized work from one entity to another, and the need to transition to common IT platforms before more harmonization of business processes can occur. Differences in the nature of the gas and electric operations also pose challenges and limit the breadth of opportunities available. While the Company will continue its efforts to investigate productivity opportunities, future progress is expected to be considerably slower given the highlighted challenges, and may require an upfront investment in IT systems or other initiatives to achieve significant and sustainable savings.

13. Reference: Exhibit B-1, Page 12

> Integration driven opportunities in 2012 include the Human Resources (HR) department where the employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated and aligned between gas and electric utilities. Roles were redesigned and automated technology was implemented. The Communications and External Relations groups were also able to realize productivity improvements through sharing of resources across the two companies. In the Environmental Health and Safety department, many processes, programs, operating standards and roles have been aligned between the gas and electric utilities, contributing to the efficiencies realized.

13.1 Please quantify the productivity improvements in HR and break them out between those that were based on the automated technology implementation and those that were not.

Response:

Productivity improvements in HR in 2012 are listed in Table 13.1 below.

Table 13.1: Productivity Improvements in HR

Productivity Improvement	Associated Savings	Systems / Non-systems
Employee Express (automated time-entry technology)	$152,000 based on reduction of two FTEs (plus additional savings recognized through cost avoidance of an additional time administrator)	Systems
Integration and redefining of roles in employee services, employee relations and employee development	$561,000 based on reduction of four FTEs	Non-systems

It should also be noted that the HR department has been able to perform additional activities without increasing its costs. For example, the employee development group has been able to absorb the associated costs of providing training support to the Customer Service group by bringing additional knowledge and learning facilitators into the group. In addition, FEI has been able to provide additional eLearning and talent sourcing support without adding additional staff.

13.2 Please confirm that the automated technology implementation required a capital investment in the technology project to help achieve the savings.

Response:

Capital from the Business Technology Transformation budget was invested in support of automated technology for HR. Please refer to the response to CEC IR 1.13.1 for more information about Employee Express.

A breakdown of the investment is found in Table 13.2 below.

Table 13.2: Summary of FEI's Investment into Employee Express

		FEI	FEVI	TOTAL
Q-355 EMPLOYEE & MANAGER SELF SERVE	CAPEX	637,675.93	71,667.00	709,342.93
	OPEX	20,524.68		20,524.68
	TOTAL	658,200.61	71,667.00	729,867.61
Q-384 / IO 682972 Employee Express Analysis Ph2	CAPEX	480.72	53.00	533.72
	OPEX	26,421.95		26,421.95
	TOTAL	26,902.67	53.00	26,955.67

FEI will have realized the benefits of this investment by 2014. If Employee Express had not been implemented, FEI would have had to incur annual costs from 2011 and beyond for labour and administrative costs.

13.3 Please advise as to whether or not there is a list of potential productivity improvement opportunities in the HR department awaiting future implementation in the 2014 to 2018 time period and please advise whether or not there is an assigned estimate of potential savings and if so please provide the quantified estimates.

Response:

No, at this time, there are no productivity improvement opportunities within the HR department that are ready to be implemented. However, the HR department at FEI is continually looking for opportunities to improve productivity, while continuing to meet service requirements, at the lowest reasonable cost. Process improvements at FEI follow an internal review and evaluation process prior to implementation to ensure the improvement makes prudent business sense.

13.4 Please confirm that FEI will continue to look for such productivity savings as it has achieved in the HR department in the future 2014 to 2018 period for both the HR department and other departments.

Response:

FEI will continue to look for such productivity savings as it has achieved in the HR department in the future 2014 to 2018.

14. Reference: Exhibit B-1, Page 13

> FEI will evaluate the feasibility of introducing a Shared Services cost allocation approach during the PBR Period similar to that used between FEI and FEVI/FEW. The ability to implement such an approach depends on the nature of future integration opportunities and having the necessary conditions in place for shared services such as common management, common IT platforms and common policies and processes. The introduction of a cost allocation model would provide a representative approach to allocate costs and efficiencies between gas and electric, while minimizing the administrative efforts associated with the timesheet allocation approach.

14.1 Please provide any estimate, along with appropriate caveats for the estimating approach, FEI has with respect to the potential savings opportunity the Shared Services approach may provide in the 2014 to 2018 period.

<u>Response:</u>

Please note the reference to introduction of a Shared Services cost allocation approach is only in regards to the choice of the cost allocation approach (i.e. timesheet allocation approach vs. shared services cost allocation approach based on use of selected cost drivers) . Therefore, any potential savings opportunity regarding the implementation of the Shared Services agreement would be limited to only the administrative and accounting costs associated with administering the agreement, which would be immaterial (i.e. less than $10 thousand for labour to administer the agreements).

If the question is referring specifically to potential savings from future integration efforts between gas and electric, please refer to the response to CEC IR 1.12.4.

15. Reference: Exhibit B-1, Page 14

> Recent customer focused enhancement initiatives included the successful completion of the Customer Care Enhancement Project (CCE Project). The FEU successfully completed the stabilization phase of the CCE Project in the second quarter of 2012. The CCE Project was delivered on-time and under budget and successfully transitioned to an internally-delivered customer service operation, going live as planned on January 1, 2012. Final project costs were $109 million as compared to a budget of $115 million, a significant savings achieved while still meeting the timeline and project deliverables.

15.1 Please explain the nature of the $6 million in savings on the CCE project and quantify each of the significant reasons for the savings.

Response:

In a project of this complexity spanning a two year implementation window it is not unusual for the actual costs to be allocated to different cost categories as project needs change. The savings cannot be described in detail at a component level. The most significant areas of savings for the project related to internal labour and general consulting costs. These were achieved by identifying and retaining key resources throughout the project, which improved productivity and limited staff turnover. The project was implemented successfully with less staff than originally budgeted.

15.2 In explaining the nature of the savings please provide an assessment as to whether or not any of the reduced expenditure compared to the budget related to deferred implementation of CCE features and functions, which may be developed or added at a later date but were not needed for the go live date of the successful completion of the project.

Response:

None of the savings in the CCE project were the result of the deferral of features and functions to be developed or added at a later date. The project delivered all of the functions and features expected in the initial project scope.

16. Reference: Exhibit B-1, Pages 14 and 15

> During the first year of operations, the FEU were able to deliver on customer service level commitments and make improvements to services while achieving cost savings over and above what was committed to in the FEU's 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (2012-2013 RRA). These cost efficiencies have been built into the Customer Service department O&M and therefore will be sustained for the benefit of customers into the

> future. The operational efficiencies gained and the solid performance during the first year of operations sets the foundation for further improvements over the next several years.

16.1 Please explain what the impact is on customers and on the shareholder is when FEI has rates approved based on one assumption with respect to savings achieved from implementing a capital project such as the CCE project and then is able to achieve savings at a greater rate than was committed to in the rates determination process.

<u>Response:</u>

In general, the impact of operational efficiencies on customers and the shareholder would depend on what regulatory mechanisms are in place.

Specifically for the operational efficiencies (O&M savings) that are referred to in the preamble for the CCE Project, the O&M savings in 2012 and 2013 are being returned 100% to customers, and the shareholder does not benefit.

Under the PBR Proposal, and similar to the 2004 PBR Plan, rates will be set to provide 100% of the productivity savings to customers. To the extent the savings are in addition to the savings embedded in rates, they will be shared equally between customers and the shareholder for the term of the PBR. Under a cost of service regime, and absent any deferral mechanism, these savings would benefit the shareholder until O&M is next rebased.

16.2 In setting a foundation for the future over several years, please provide a list of the significant further improvement potential and quantify the estimated savings possibilities for each item, with appropriate caveats for the estimates and please provide a likely implementation date for the potential improvements.

Response:

Specifically for the Customer Service department, over the term of the PBR, FEI will be evaluating new initiatives to determine the cost-benefit of each. Two examples of initiatives being considered are enhancements to the Company's customer portal and changes to the contact center hours of operation. At this time, the estimated savings and implementation dates for these initiatives have not been finalized.

17. Reference: Exhibit B-1, Page 15

> The Company is also continuing its efforts to add more customers to the system by working directly with key influencers like builders and developers, architects and engineers and promoting the benefits of using natural gas more broadly in the marketplace. Recently, there are encouraging signs of the success of these activities as the declining customer growth trend may be flattening. For new housing construction, the Company's overall capture rate (i.e. new homes with natural gas) appears to have stabilized. At the end of 2012, the Company's capture rate was 67 percent of new housing completions, up from 61 percent in 2011.

17.1 Please explain whether or not the new housing construction capture rate is the only component of the flattening of the declining customer growth trend and if not please identify any other factors.

Response:

For clarity, the capture rate is an after-the fact comparison of gas customer growth against a larger measure, in this case new housing construction, and in itself does not affect customer growth. The flattening of the declining customer growth could be due to many factors such as government policies, building codes and standards, energy and equipment costs, or FEI's continued promotion of the benefits of natural gas. While FEI is encouraged with the recent improvement, it is too soon to tell whether there is indeed a reversal of the declining customer growth trend that will persist in the coming years.

In general, there is greater uptake of natural gas as the preferred fuel choice in single family dwellings compared to multi-family homes as single family home owners may have more input deciding the kind of appliances installed in their homes. In contrast, appliances installed in multi-family units are often determined by the builder or developer who is more concerned with maximizing profits and therefore installs less expensive electric heating infrastructure and appliances in the units. This is despite the fact that natural gas appliances and equipment for space heat and hot water currently offer operating cost savings relative to electric appliances, and would help to lower home energy bills. If further densification of city centers continues to take place, and more multi-family units are built than single family homes, then FEI will have a continuing challenge in capturing new customers.

17.2 Please quantify the approximate cost of this marketing effort for new housing construction and quantify the benefits for all customers of the achievement of a 67% capture rate versus a 61% capture rate over the potential life of the customer appliances involved.

Response:

All marketing costs related to improving capture rates in new construction are within the approved O&M budgets for the referenced years. No additional expense was incurred. The impact on the capture rate numbers was achieved by focusing existing sales and marketing resources on the builder community and demonstrating the features and benefits of natural gas over competing forms of energy for space and water heating.

While the overall increase represents a relatively small increase in added customers compared to the overall customer base, the existing customers do benefit from additional throughput and improved utilization of the natural gas system. For example, the increase of capture rate from 61% to 67% in 2011 and 2012 respectively represents an increase of 344 new customers. This will add new volumes to the system and over time will allow fixed costs to be spread over a larger volume, all else equal.

17.3 If there are other factors involved in explaining the declining customer growth trend please quantify those similarly to the quantification requested in the question above.

Response:

Please refer to the response to CEC IRs 1.17.1 and 1.17.2. In addition, FEI provides further elaboration on the factors that contributed to the declining customer growth as below.

Over the past decade there has been a significant increase in the construction of multi-family dwellings and a corresponding decrease in single family construction. While natural gas equipment installations in new single family homes have become more challenging due to less expensive electric equipment, and a general lack of understanding by the home buying public of the current operating cost advantage natural gas has over electricity, the situation in multifamily construction is even more acute. Developers have tended to favour electricity for space and water heating due to lower equipment and installation costs, and space constraints. FEI needs to continue to adapt to trends of this nature. The advent of newer technologies and smaller appliances such as, for example, instantaneous water heaters, is helping as has customer demand for natural gas cooking appliances. However, FEI will need to create market demand for natural gas appliances and educate the new home buying customers on the benefits of natural gas, if we are to expect the builders to include natural gas in their plans.

The new home buyer is often unaware of the current operating cost advantage of natural gas over electricity, and as such this differential is often not a part of the home buying decision. Since the new home buyer is not actively asking about natural gas equipment, the builder has the opportunity to install much less expensive electrical equipment without challenge. FEI must continue to work closely with the builder developer community to install gas appliances while also educating the home buying public on the value of natural gas equipment in terms of comfort, efficiency and operational cost savings.

17.4 Please explain whether or not changes and improvements such as these and the related benefits to all customers would be part of the PBR benefits to be shared.

Response:

Yes, changes and improvements such as those mentioned in the quote would be among the PBR benefits to be shared. Since revenues are reforecast annually (and residential/commercial deliveries use rates are subject to the RSAM) the revenue benefits will, in effect, be flowed through with the net benefits accruing to ratepayers.

17.5 Please explain whether or not there are additional benefits to be obtained for all customers through further marketing efforts and or improved performance of the existing marketing efforts or both.

Response:

There are additional benefits to be garnered from both further marketing efforts and the ongoing adjustments to existing marketing efforts. Additional marketing efforts through the forecasted period are outlined on pages 160 -161 of the Application. Benefits from these efforts would be an increase in natural gas throughput and conceivably customers' average use rates.

Any increases in throughput as compared to the prior year would result in lower rates for all customers, all else equal. Within a year, any increases in throughput that result from increases in use per customer as compared to the forecasted use per customer for residential and commercial customers will be captured in the RSAM and will flow to customers by way of a rate rider. All other increases in throughput as compared to forecast within a year will result in higher revenues that will be shared with customers through the Earnings Sharing Mechanism.

18. Reference: Exhibit B-1, Page 15

> In addition to new housing, there is renewed interest from residential and small commercial customers to convert from oil and propane to natural gas. As a result of the Company's campaign to identify and market to homes using oil and propane, conversions were 4 percent higher in 2012 compared to 2011.

> For industrial customers, the Energy Solutions team is working with large volume customers to understand and find solutions to meet their energy needs. With a stabilizing economy and low natural gas prices, load growth is being experienced from industrial customers in the mining, lumber, greenhouse and manufacturing sectors. From 2011 to 2012, total industrial volumes increased from approximately 58 petajoules to 60 petajoules. Similar to customer growth, adding more economic industrial load to the system will help to maintain the competitiveness of rates for customers.

> To meet customers' growing demand for alternate uses of natural gas, the Company has been developing the natural gas for transportation (NGT) and liquefied natural gas (LNG) markets and also supporting customer demand for renewable natural gas (RNG). Added load from these markets will help maintain the competitiveness of rates by increasing throughput on the gas delivery system. Similarly, on the industrial front, FEI has received interest in the development of new major industrial facilities that use natural gas as a feedstock. The Company is engaging these customers to explore the opportunities and benefits that could be achieved for the benefit of ratepayers if we were to deliver natural gas for them.

18.1 Please provide a quantification analysis of the benefits for customers from each of the described opportunities and provide the appropriate caveats for the estimations for the ones already achieved and a separate estimate for the potential to be achieved in the future with appropriate qualifications for the uncertainty with respect to whether or not they may actually happen.

<u>Response:</u>

While it is possible to quantify historical results for the referenced initiatives, it is difficult to do the same for future benefits and would involve making many assumptions. However, the purpose of the initiatives are all similar, to increase the throughput of natural gas on the FEI system. The cost structure of FEI's distribution system and other rate base components consists predominantly of fixed costs with small marginal costs attributable to load additions. Those fixed costs are spread over all of the gas that flows through the system. For incremental GJs of gas that FEI is able to bring onto the system, the fixed costs are spread over more and more volume and, all else being equal, will result in lower delivery rates.

FEI's 2014 Cost of Service is forecast at $616 million[2] with a forecast volume of 212 PJ[3]. Assuming nearly all of FEI's cost of service is fixed, dividing $616 by 212 PJ produces an overall cost of service rate of $2.906 per GJ. If the initiatives referenced increase volume by 5% the overall impact would be a reduction in this average rate of 4.8% [(2.906 – (616/(212 x 1.05)))/ 2.906][4]. However, if the load growth occurs in the large commercial and industrial classes which have lower delivery rates, the rate reduction for the other rate classes would be lower.

Therefore, based on the nature of FEI's system costs, average total cost will decline as volume is increased and the costs are spread over these larger volumes. Consequently, these initiatives are focused on increasing system volume to the benefit of rate payers.

18.2 Please comment on whether or not these sorts of benefits for customers would be included in the PBR benefits being shared with the Company.

Response:

Since revenues are reforecast each year, the revenue benefits from new loads added to the system will flow 100% to customers, as the new loads come on stream and are incorporated into the demand forecast.

[2] Section E, Schedule 4, Line 22, Column 5

[3] Section E, Schedule 4, Line 4, Column 5

[4] It is a simplifying assumption that the fixed costs will not increase with added load. While in general there is available capacity on the system, large new loads in a particular location on the system may require system upgrades to meet their demand.

19. Reference: Exhibit B-1, Page 17

> The Company is faced with slow customer addition growth and a decline in average use per customer despite low gas commodity rates in recent years. Although the decline in gas commodity rates has improved the price competitiveness of natural gas against electricity on an operating cost basis, this decline has been offset by increases in carbon tax along with higher capital and installation costs for natural gas equipment versus those of electric equipment. Additionally, residential customers do not generally understand the price differentials between differing fuel sources. Furthermore, the role of natural gas in its traditional use of space and water heating, which makes up over 80 per cent of residential natural gas throughput, continues to be challenged by changing environmental policies, energy policies and regulations. These declining trends negatively impact throughput and load growth. Steps need to be taken to mitigate these pressures.

19.1 Please describe the steps that need to be taken to mitigate these pressures and discuss whether or not they will be taken during the 2014 to 2018 period.

Response:

Our existing customers along with potential customers may be unaware of the operating cost advantage natural gas currently has. Marketing efforts need to be put in place to increase the awareness of this price advantage as it is critical in offsetting the capital cost of installing new natural gas equipment compared to electric equipment and justifying the expense with a reasonable ROI for the customer.

Also, since the cost of installation compared to electric is so dramatic, on certain equipment such as natural gas water heaters and heating equipment where natural gas equipment can be three times the cost of comparable electric equipment, marketing initiatives including incentives need to be created and distributed to those customers willing to convert their equipment to natural gas as well as builders who would consider natural gas equipment but can't currently justify the installation cost differential.

These marketing and incentive measures will be taken in the 2014-18 period.

19.2 Please advise whether or not the related customer benefits of achieving further mitigation will be part of the PBR benefits to be shared with the Company.

Response:

Refer to the response to CEC IR 1.17.5.

20. Reference: Exhibit B-1, Page 18

> Customer growth will continue to be facilitated through enhancement of FEI's high carbon fuel switching program which provides incentives to customers to switch from higher carbon to lower carbon-emitting fuels, through the installation of high efficient ENERGY STAR® heating systems. The program adds value to new and existing customers by reducing their fuel costs, increasing natural gas throughput, minimizing environmental hazards associated with oil storage tanks, decreasing the need to import propane and heating oil fuel from other provinces, and improving air quality.

20.1 Please advise as to whether or not FEI has a quantification of the market potential for the high carbon fuel switching and if so please provide an estimate of the customer benefit from achieving each 10% of the potential and provide an estimate as to when this may be done.

Response:

FEI has undertaken a preliminary attempt at quantification of the market potential for high carbon fuel switching. FEI has determined that there are approximately 50,000 dwellings within 100 meters of a gas main who are not yet natural gas customers. Of these, approximately 15% or 7500 dwellings are estimated to be using oil or propane.

20.2 Please advise as to whether or not the PBR will include sharing of these potential benefits.

Response:

The revenue benefits from the forecast of new customers attaching due to the high carbon fuel switching program will accrue entirely to ratepayers. Since FEI has been required by the Commission to treat the incentive and non-incentive program expenditures for high carbon fuel switching as O&M, these expenses will be included in rates to the extent they are included in the 2013 O&M base to which the formula is applied. Similar to the previous 2004 PBR Plan, rates will be set to provide 100% of the productivity savings to customers. To the extent the savings are in addition to the savings embedded in rates, they will be shared equally between customers and the shareholder for the term of the PBR. Similarly the capital costs to attach these customers, such as service lines and meters, are part of the Growth Capital category of formula-based expenditures. These costs will attract the same treatment under the PBR as other Growth Capital (i.e. 50/50 Earnings Sharing of the revenue requirement differences).

21. Reference: Exhibit B1, page 19

> Starting in 2012, changes to the FEU's scorecard were made to standardize the scorecard categories between the Gas and Electric businesses. The number of measures was reduced from 10 to six with two new measures added: All Injury Frequency Rate and Public Contacts with Pipelines.

21.1 What measures were deleted from the original scorecard and why?

Response:

In the 2012 review of the scorecard measures, four measures were retained including Customer Satisfaction, Regulatory Performance, Net Earnings and Recordable Vehicle Incidents. Two new measures, All Injury Frequency Rate (AIFR) and Public Contacts with Pipelines were added replacing the previous measures of Recordable Injuries and Public Safety. The new AIFR measure represented a more comprehensive safety performance indicator by comparing total medical aids and lost time injuries relative to hours worked (i.e. per 200,000 hours worked), whereas the previous measure Recordable Injuries reported just the number of injuries. The new Public Contacts with Pipelines measure focused on a key aspect of public safety, public contact with buried pipelines. The previous Public Safety measure was assessed dependent on the safety related SQIs. Three of the previous measures, Base Capital, Credit and Collections and Wellness were removed from the corporate scorecard and are instead now managed at the departmental level. The remaining measure O&M per customer is now incorporated into the Net Earnings measure.

Please also refer to the response to BCUC IR 1.19,1 for further discussion of the changes to the scorecard measures.

22. Reference: Exhibit B-1, Page 21

> The inclusion of a productivity improvement factor in FEI's PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. Departments have a requirement to maintain or increase their outputs and activity levels while keeping cost increases below inflation on a per customer basis, which will result in a measured improvement in productivity. The result of this focus is evident and discussed in the departmental results and forecasts included in Section C3 of this Application and in the Productivity Focus and Organizational Performance discussion above that contains many actual examples of productivity achievements. FEI will continue to discuss productivity measures taken during the PBR Period at its Annual Reviews.

22.1 Please confirm that the FEI concept for comprehensive productivity measurement is an aggregate difference between actual expenditures versus approved expenditures for FEI's rates, such as the Table C3-1 contained in section C3 and including the discussion thereafter identifying sustainable savings and temporary savings.

Response:

Not confirmed.

Under FEI's PBR proposal, productivity is measured by the proposed productivity factor of 0.5% per year **and** any savings realized in addition to the proposed productivity factor. Similar to the previous 2004 PBR Plan, any savings achieved to reach the productivity factor embedded in rates will be realized 100% by customers. To the extent the savings are in addition to the savings embedded in rates, they will be shared equally between customers and the shareholder for the term of the PBR.

Please also refer to the response to CEC IR 1.1.1 for discussion on how accountability for productivity is achieved at the departmental level.

22.2 Please confirm that while FEI requires departments to maintain or increase outputs and activity levels while keeping cost increases below inflation on a per customer basis that FEI chooses not to have measures of cost per unit of outputs or activities for its departments.

Response:

Confirmed.

As discussed on page 21 of Exhibit B-1, FEI's proposed productivity improvement factor serves to provide a comprehensive productivity measurement and ensures a continuous productivity focus in the organization over the term of the proposed PBR Plan. As discussed on page 21 of Exhibit B-1, FEI's use of productivity metrics is consistent with that of other utilities.

Please also refer to the response to CEC IR 1.1.1 for discussion on how accountability for productivity is achieved at the departmental level for FEI.

22.3 Please confirm that FEI does not intend to add productivity improvement to its Scorecard and intends to stick with the Score Card it has developed to date.

Response:

FEI does not intend to explicitly add a Productivity Improvement measure to its scorecard. As discussed in the response to CEC IR 1.8.1, FEI believes the Financial category on the existing scorecard incorporates a productivity focus and that the requirement to meet its Productivity Improvement Factor in its O&M and capital spending will result in a strong focus on productivity improvement.

FEI currently has no plans to change the existing scorecard. However, the scorecard may be changed over the period of the PBR to reflect the priorities of the company.

23. Reference: Exhibit B-1, Page 29

> **2.1 *PBR BENEFITS***
>
> The two most commonly cited benefits of a PBR plan are its effectiveness in incenting the utility to capture efficiencies, and regulatory efficiency.

23.1 Please explain why utilities should need an extra incentive to perform efficiently, when they are recovering their prudently incurred costs of service and earning a fair return on their invested capital (ROE).

Response:

B&V provides the following response.

Efficiencies with longer term economic paybacks are not economic for shareholders when the payback extends beyond the expected rate case cycle. Management must exercise its fiduciary responsibility to shareholders. If an investment in productivity cannot create a full return of and on the investment between rate cases, management would cause a loss in earnings from the investment if it were undertaken. It is this disincentive to invest in longer term efficiencies that is overcome under the FEI PBR Plan. Further, the return granted by the regulatory authority may not equal the actual market cost of capital. In that case, there is also no incentive to invest in efficiencies when system requirements for safety and reliability compete for capital dollars. Under PBR, effective strategies permit the utility to adjust operations to actually earn the required market based cost of capital.

23.2 Please explain whether or not FEI expects to have an incentive share of the regulatory efficiency provided through adoption of the PBR by the Commission.

Response:

Regulatory efficiency is an inherent benefit of a PBR plan which helps the utility staff to shift their focus from time and resource-consuming regulatory proceedings to focusing on providing service to customers and on finding productivity opportunities that may eventually benefit the company and its customers. In other words the incentive share of regulatory efficiency is not separable from other PBR incentives and is embedded in the PBR overall incentives. FEI's proposed earnings sharing mechanism shares all the PBR incentives among FEI and rate payers on an equal basis.

Another smaller component of regulatory efficiency pertains to lower costs for hearings, including Commission hearing costs and intervener funding allowances. These costs are normally collected in deferral accounts and recovered in rates. Savings during the PBR in this category will flow 100% to customers through lower amounts being recorded in deferral accounts.

24. Reference: Exhibit B-1, Page 29

> **2.2 POTENTIAL PBR CHALLENGES**
>
> The arguments typically raised in opposition to PBR relate to the potential for "windfall" profits or losses for the regulated utility or customers, service issues, and challenges relating to the timing of capital expenditures. These challenges are discussed below. B&V concurs that the challenges can be managed through the design of a PBR Plan, and that there are provisions in FEI's proposed PBR Plan that appropriately address these challenges.

24.1 Is there also a challenge that the utility may focus on cost efficiency issues and under focus on achieving revenue benefits for customers?

Response:

The incentives under PBR to generate revenues are similar to what they are under Cost of Service regulation. Revenues are being reforecast annually under the PBR and treated as a flow-through component of the Plan. FEI will retain revenue decoupling via the RSAM for residential and commercial customers. In addition, the provincial focus on promoting energy efficiency and conservation in BC (via policy and legislation) is also an element that tends to promote reductions in gas use. With that as background, PBR is focused on improving the incentives for cost efficiency.

Irrespective of the form of regulation, FEI is pursuing revenue growth opportunities in the natural gas for transportation sector, as well in the commercial and industrial sectors. These opportunities have a potential to produce increased throughput that will provide benefits for existing customers, however the success in these areas is not within FEI's control. As a non-controllable item FEI does not believe incentivizing revenues is appropriate in the PBR framework.

24.2 Do B&V have anything to say about the interaction between PBR and revenue type benefits for customers, given that PBR is specifically designed to disconnect costs from revenues and focus on cost efficiency?

Response:

Please refer to the response to CEC IR 1.24.1. While B&V believes that revenue type benefits can be valuable under a PBR Plan, the specific circumstances of the utility need to be taken into consideration in PBR plan design. In the context of FEI's revenue decoupling mechanism and other extenuating circumstances with respect to revenues the approach taken is reasonable.

24.3 Is there also a challenge with regard to setting a formula which produces a forecast for future rates that is inappropriately high creating easy opportunities for the utility to appear to perform?

Response:

B&V provides the following response.

While setting the elements of the fomulas at appropriate levels is the goal of any PBR Plan, in the context of the FEI filing, which uses an aggressive positive X-Factor for costs, it is difficult to imagine how the formula is creating a forecast of future rates that is too high in light of the industry trend for negative TFP. Negative TFP would result in even higher rates than those proposed by FEI.

24.4 Is there also a challenge in setting the test year the PBR is based from too high again inappropriately creating easy opportunities for the utility to appear to perform?

Response:

B&V provides the following response.

Setting the base year appropriately for the PBR formulas to operate from is an important consideration, among numerous others, in PBR Plan development, In the context of FEI's filing, since the test year is set on the basis of cost of service that is subject to detailed review by all parties to the rate case, it is unlikely that parties would not thoroughly review the cost of service basis for the initial Base PBR year.

25. Reference: Exhibit B-1, Page 30

> *"The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level. Customers actually benefit even in the absence of an earnings sharing mechanism by a reset of the cost basis of rates at the start of a new regulatory control period as the efficiency gains become entrenched in the utility's revenue requirements on a going forward basis."*

25.1 Please provide an explanation as to why B&V believe the industry average efficiency should be considered the appropriate benchmark for setting productivity targets and enable the utility to earn above its allowed rate of return if the utility performs above average.

<u>Response:</u>

B&V provides the following response.

B&V has addressed this issue, in part, in the responses to BCUC IRs 1.5.1, 1.21.2 and 1.21.3. Also, earning above the allowed return with performance above the industry average may or may not occur since the formula I-X only reflects the cost side of the earnings equation.

25.2 Please provide a definition of the industry average efficiency and the relevant metrics B&V were contemplating when they wrote this quoted section.

<u>Response:</u>

B&V provides the following response.

The quoted section assumes that the industry average TFP is measuring the performance of costs and that FEI finds efficiencies that allow the Company to be more productive than the industry average. It further assumes that the elements of the PBR Plan taken as a whole provide FEI with a reasonable opportunity to earn the allowed return throughout the regulatory control period. It further assumes that the costs associated with the operation of the plan are within the budgeted costs for the regulatory process (i.e. no extraordinary litigation costs or compliance costs associated with the regulatory reporting and monitoring of the Plan). It also assumes timely resolution for exogenous cost changes such that FEI is not required to absorb major cost changes for long periods during the pendency of the Plan. In general, the statement requires a positive and productive regulatory process that addresses all of the elements of the Plan in a consistent fashion with prior practice and without adjusting Plan elements in ways that create an unworkable Plan with unintended consequences that effectively prevent the reasonable opportunity to earn the allowed return.

26. Reference: Exhibit B-1, Page 33

> PBR design is an exercise in balancing utility flexibility to seek out efficiencies and the need for a regulatory review process that ensures just and reasonable rates and the safe and reliable provision of services to customers. B&V's view is that there is no single "correct" type of PBR design, and pure revenue and price cap PBR designs are unlikely to be practical. FEI's proposed PBR plan, discussed later in this chapter, is a building block model within the revenue cap category. It has been designed with reference to past experience and the particular context relevant to the utility. B&V endorses the proposed PBR Plan, with the caveat regarding the proposed productivity factor should be closer to zero rather than FEI's more challenging and aggressive proposal of 0.5 percent.

26.1 Please confirm that a zero percent productivity factor would mean that utility managements in the ordinary course of business would produce no efficiency gains and if not please explain what the zero productivity factor proposed by B&V represents as managements going in capability to perform in the context of a PBR.

<u>Response:</u>

B&V cannot confirm that a zero percent productivity factor means no productivity gains. TFP does not measure efficiency. Having a TFP equal to zero means that the change in output equals the change in input. Management may actually be very efficient in the context of a PBR if the X-Factor is zero when TFP for the industry is negative. As discussed in the evidence, utilities may be efficient and yet may be below the industry TFP because of factors unique to the operating environment.

27. Reference: Exhibit B-1, Pages 34 and 38

> and the break-even point on this restructuring "investment" was achieved by the fourth year. In addition to a focus on pursuing operating and maintenance cost efficiencies, the 1998-2001 PBR plan included a limited capital incentive mechanism and a series of SQIs that were tracked to confirm that service quality was being maintained throughout the term.

> During the 2004 PBR, FEI's actual base capital expenditures for the six-year period were $490.2 million. This was $80.1 million, or about 14 percent on average, below the formula-allowed capital expenditures of $570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI's actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately $1 million above the formula-based amount.

27.1 Please discuss the 'limited capital incentive mechanism' that was employed in the 1998-2001 PBR and compare and contrast the capital incentive mechanisms that were employed in later PBR structures.

Response:

In the 1998-2001 PBR Plan the base (i.e. non-CPCN) capital expenditures were divided into three categories[5] as follows:

Category A – Mains, Services and Measurement equipment (i.e. meters and regulators)[6]

Category B – System Integrity and Reliability (All transmission capital and Integrity-related distribution capital)

Category C – All other capital – e.g. buildings, IT hardware/software and other general capital.

All three categories were escalated using I-X formulas and there were incentives attached to Categories A and C, but not to Category B. The Category A incentives were unit cost-based, based on established target costs ($/metre of main installed, $ per service line and $ per meter for measurement). The incentive for Category C was based on spending less than an overall lump sum allowance.

[5] The 1998-2001 PBR Plan was approved by BCUC Order G-85-97. The negotiated settlement contains much more detail on which types of capital fell into Categories A, B and C.

[6] Category A is not fully synonymous with the current Growth capital category. The key difference is that the current Growth capital category includes only the meters and regulators pertaining to customer growth while Category A included all measurement–related capital, including both growth and meter/regulator replacement capital.

The Category A and C incentives were symmetrical in that beating the targets generated a benefit for the Company while going over the targets created a cost or disincentive for Company. The annual incentive or disincentive in each year resulted in a notional rate base increase or decrease that was phased out over three years[7]. In general FEI missed the unit cost targets in Category A, although there was more difficulty in meeting the mains and service lines unit costs while meeting the unit cost for measurement capital was achieved. FEI was able to come in under the lump sum Category C target cost in some years but overall there was a capital disincentive in each of the four years of the 1998-2001 PBR.

FEI believes there were several concerns with the capital incentive mechanism in the 1998 PBR that were improved or rectified in the 2004 PBR and this continues to be the case with the 2014 PBR.

- The capital incentive in the 1998 PBR was limited and the Plan focused more heavily on O&M productivity. The result was that the 1998 PBR produced positive benefits in terms of O&M efficiencies but the same success was not achieved in regard to capital. The 2004 PBR Plan had a better balance between the O&M and capital incentives and FEI responded by pursuing efficiencies and savings in both areas.
- The differing incentive treatment of Categories A, B and C had some inherent difficulties.
    - The unit cost approach for Category A did not function well based on some unanticipated changes in the actual results. The initial unit costs were based on a particular mix of urban versus rural and interior versus Lower Mainland activity which had different underlying costs. As growth activity shifted during the PBR, the unit costs were negatively affected which led to FEI having to bear a rate base penalty due to uncontrollable changes in capital requirements.
    - Having Categories A and C incentivized but not Category B gave conflicting signals about the need to pursue capital efficiencies.

In addition to having a stronger capital incentive than the 1998 PBR, the 2004 PBR also presented a similar incentive to find efficiencies in all areas of base capital spending.

[7] The impact of the notional rate base addition/deduction was a return on rate base only. It did not give rise to any amortization expense.

27.2 Please provide the total actual base capital expenditures for the years 1990 to 2012 (inclusive) and the equivalent base capital approvals for every year in which PBR was in effect.

Response:

Please find the actual base capital expenditures and approvals for the years 1997 through 2012. Of these years, PBR was in effect for 1998 through 2001 and 2004 through 2009. FEI is unable to provide data prior to 1997.

HISTORICAL FEI CAPITAL EXPENDITURES ($ THOUSANDS)

	1997 Actual	1997 Approved	1998 Actual	1998 Approved	1999 Actual	1999 Approved	2000 Actual	2000 Approved
Total Gross Base Capital Expenditures	80,368	71,564	73,213	87,017	82,593	79,500	88,428	87,343

	2001 Actual	2001 Approved	2002 Actual	2002 Approved	2003 Actual	2003 Approved	2004 Actual	2004 Approved
Total Gross Base Capital Expenditures	72,778	76,017	72,671	N/A	81,186	87,528	91,644	85,378

	2005 Actual	2005 Approved	2006 Actual	2006 Approved	2007 Actual	2007 Approved	2008 Actual	2008 Approved
Total Gross Base Capital Expenditures	95,409	90,611	83,591	97,985	73,158	101,570	89,998	99,660

	2009 Actual	2009 Approved	2010 Actual	2010 Approved	2011 Actual	2011 Approved	2012 Actual	2012 Approved
Total Gross Base Capital Expenditures	90,968	94,208	86,287	93,511	103,610	93,597	108,421	116,408

Notes:

1. N/A - FEI withdrew the 2002 RRA Application, therefore approved base capital expenditures are not applicable for that year.
2. Base capital expenditures are not available for the years 1994 to 1996.
3. Base Capital Expenditures exclude CPCNs, retirements & CIAC.
4. 2010-2012 Approved figures have been provided for informational purposes only as PBR was not in effect for this period.

28. Reference: Exhibit B-1, Page 36

> The variance between the allowed and actual return on equity was shared equally between customers and shareholders. Over the term of the PBR, customers and shareholders each received a benefit of $67.5 million, indicating that the PBR successfully reduced costs and resulted in material savings.

28.1 Does FEI consider the capital savings variance which it shares with customers to be costs that are permanently eliminated from FEI's rate structure?

Response:

The savings during the PBR Period are expected to come from permanent reductions, as opposed to deferrals. This is consistent with the past experience of PBR.

Appendix D4 to the Application summarized the evidence with respect to deferral of expenditures during the last PBR period. The evidence showed that FEI could not identify any instances of a deferral of capital spending during that time period. On this basis, FEI concludes that capital savings achieved during the past PBR period was sustained, and that the same experience is expected during the PBR period.

28.2 If not, does FEI consider "material savings" to be a have a time factor in terms of for how long the capital expense must be avoided in order to be considered a permanent saving rather than a delayed cost?

Response:

As stated in the response to CEC IR 1.28.1, the savings during the PBR Period are expected to come from permanent reductions, as opposed to deferrals. This is consistent with the past experience of PBR.

Considering the response to CEC IR 1.28.1 and the information provided in Appendix D4 with respect to benefits to customers of deferring capital expenditures, FEI does not see significant value in developing a guideline around the time period that would move a capital item from being a "deferral" to a "permanent savings" item. Benefits are generally provided to ratepayers in either case.

28.3 If so, please explain for how long FEI would require a capital expense to be avoided in order to be considered a permanent saving.

Response:

Please refer to the response to CEC IR 1.28.2.

28.4 Would FEI value a delay in capital expenditures on the basis of a net present value calculation comparing a later investment to a present day investment? If no, please provide an example of how FEI would calculate the value of a delay in capital expenditure.

Response:

This analysis has been provided in Appendix D4, page 2. The analysis provided in Appendix D4 assumed an earnings sharing throughout the hypothetical PBR Period. The analysis did not, however, incorporate an Efficiency Carryover Mechanism.

28.5 Is FEI able to determine if any given saving is a permanent saving or a deferred saving? Please explain how FEI determines the longevity of any saving.

Response:

Please refer to the responses to CEC IRs 1.28.1 through 1.28.4.

28.6 How would FEI recommend that a given saving be tracked as to whether or not it may be considered permanently eliminated? Please provide examples.

Response:

If required to do so, FEI is able to calculate the extent to which ratepayers are benefitting from a specific capital savings. However, since capital savings at a minimum provide benefits due to the present value benefit, there should be no requirement to provide this information. Please refer to Appendix D4 where FEI has provided an example of how the analysis would be completed.

Detailed tracking of individual projects, while possible, is contrary to the intent of developing a PBR Plan in the first place. A key purpose of PBR is to reduce the burden of regulatory oversight and to structure formulas and incentive mechanisms in a fashion that aligns the customer and utility interests.

29. Reference: Exhibit B-1, Application, Page 36

> *Service Quality Indicators*
>
> FEI established a number of SQIs to ensure that the Company continued to maintain a high level of service quality, and that cost reductions did not come at the expense of service and system standards. Each year, FEI's SQI results were compared to the established benchmarks and presented at the Annual Review. FEI consistently performed within the range for the SQIs.

29.1 Did the SQI benchmarks remain static over the PBR period or did they change from year to year?

Response:

The seven SQIs with benchmarks established for 2004-2009 PBR Plan were set at the beginning of the term and remained unchanged over the PBR period.

29.2 If changing, did FEI pre-establish annual benchmarks or have another mechanism in place to adjust the benchmarks to the current situation? Please explain.

Response:

Please refer to the response to CEC IR 1.29.1.

30. Reference: Exhibit B-1, Page 35 and Page 47

Inflation Rate

An average annual forecast inflation rate was determined based on the following sources for BC Consumer Price Index (CPI):

- Conference Board of Canada
- BC Ministry of Finance
- RBC Financial Group
- Toronto-Dominion Bank

Consistent with the methodology employed in FEI's previous PBRs, FEI has calculated an average BC-CPI forecast from the sources listed in the following table[16]:

Table B6-2: BC-CPI Forecasts for the PBR Period[17]

BC CPI Forecast	2014	2015	2016	2017	2018
Toronto Dominion Bank	2.00%				
Royal Bank of Canada	1.60%				
Bank of Montreal	1.70%	2.00%	2.00%	2.00%	2.00%
Canadian Imperial Bank of Commerce	1.80%				
Conference Board of Canada	1.90%	2.10%	2.00%	2.10%	2.10%
BC Ministy Of Finance	2.00%	2.10%	2.10%	2.10%	
AVERAGE	1.83%	2.07%	2.03%	2.07%	2.05%

30.1 Why did FEI include the Canadian Bank of Commerce and the Bank of Montreal as sources of CPI forecast in 2014 when it did not do so in other years?

Response:

CIBC and BMO are both Canadian Chartered Banks that provide economic forecasts, specifically in this case, of the BC CPI. FEI evaluates its forecasting methodologies each year and adjusts them if it is determined that an improvement can be made. Since the goal of the forecast is to obtain the best possible estimate of the BC CPI, then adding more credible data points to the analysis is an improvement to the estimation process.

30.2 Did FEI consider any forecasts other than the banks, the Conference Board of Canada and the BC Ministry of Finance in calculating the non-labour related CPI Forecast?

Response:

No, Table B6-2 includes all forecasts contemplated in calculating the forecast BC CPI.

31. Reference: Exhibit B-1, Page 39

> merits of other PBR plans. In this section, FEI summarizes the elements of PBR plans employed in other Canadian jurisdictions. B&V's report, which is included in Appendix D1 to this section, contains further analysis. FEI's proposed PBR Plan shares many common features with other plans, with the overall package tailored to fit the circumstances of a BC utility with past experience in PBR.

31.1 Does FEI believe that the PBR plan structures used by Canadian Utilities represent the best available methodologies for assessing productivity improvement?

Response:

The best available PBR structure is one that fits the unique circumstances of the utility and its regulatory environment. As noted in the response to BCUC IR 1.6.1, the Canadian plans reflect different circumstances and different processes. By selecting elements for the PBR Plan considering structures used by other Canadian utilities, as well as from FEI's own prior successful PBR Plans, FEI is able to customize a plan that is consistent with its operating and regulatory environment and builds on prior successes.

31.2 Do either FEI or B&V believe that there can be improvements to the methodologies proposed by FEI for this proposed PBR mechanism?

Response:

B&V provides the following response.

PBR Plans by their nature involve forecasts and the one thing we know for certain is that forecasts will be wrong. The question then becomes not whether the Plan could be improved but whether the Plan is the best Plan available given the state of the art and the necessary assumptions that underlie the Plan methodologies. In that case, the Plan could not be improved as it represents the best available information and analysis. Given the prior FEI and BCUC experience with successful PBR Plans, it seems reasonable to conclude that the changes from prior plans represent positive improvements for this Plan and continue the portions of prior Plans that resulted in successful outcomes.

31.3 Is FEI familiar with the detailed benchmarking studies available in the utility industry in general and in the natural gas distribution utility industry in specific?

Response:

Generally speaking, FEI and B&V have reviewed the economic literature and have also studied the reports prepared by other consultancy firms for the purpose of the preparation of this PBR plan. Therefore it is fair to say that we are relatively familiar with the studies that are conducted in other major Canadian jurisdictions (particularly Ontario and Alberta).

31.4 Has FEI participated in any natural gas detailed benchmarking studies with other natural gas utilities and if so could those benchmark comparisons be provided?

Response:

Although FEI does participate from time to time in surveys with other natural gas utilities, FEI is not aware of those surveys being used as part of a PBR related natural gas detailed benchmarking study.

31.5 Does FEI believe that detailed benchmarking studies are useful for its management of its various functions involved in delivering service to its customers?

Response:

B&V provides the following response.

Benchmarking studies may be useful for certain functions that are homogeneous across the industry but one should be cautious in drawing conclusions from them. Unfortunately these studies are of little value in addressing many of the operating and maintenance issues related to delivery service. This is the case because of a variety of factors that make it difficult to find comparable companies for a benchmark study. A few examples illustrate this issue.

First, the mix of urban and suburban customers impacts the cost of maintaining facilities. In urban areas, gas facilities are usually in the street whereas suburban facilities are likely to be in unpaved easements. For the urban area the facilities are co-located with a variety of other services such as water, sewer, telephone, electric and cable. It is often the case that repairs require hand digging in urban areas. Thus urban areas are more costly to operate.

Second, individual companies may face a variety of local restrictions related to opening the streets such as requirements for clean fill meeting certain specifications before repaving the street while others may make no such requirements. These restrictions may also include traffic control, limitations on non-emergency repairs as to hours when streets may be opened and so forth.

Third, for some utilities all of the transmission related costs are included in gas cost while for others the cost is in the delivery service because there is no direct pipeline access in the service area. Others may have service areas that are so large as to require looping transmission facilities to maintain adequate capacity for reliability.

Fourth, some utilities may require compression on the delivery system.

Fifth, the prevalence of economies of scale and scope impact the costs of delivery service as well.

Finally there are issues related to the age of the system, system density, customer mix, the size distribution of industrial customers and more.

Taken together these issues impact cost benchmarks in ways that provide little useful information for assessing relative performance. Again a simple example will illustrate this point. For larger customers, meters are customized for each installation and the costs may run into hundreds of thousands of dollars. If one was studying the cost of industrial meters two utilities could have the same number of customers and very different meter costs because of the size of the customers that impacts the cost. It is also true that other factors such as labor rates can significantly impact costs across companies and regions.

There are so many considerations that it is difficult to develop sufficient controls for a benchmark study with a large enough sample to be valid.

32. Reference: Exhibit B-1, Page 43

> The guiding principles are, in no particular order:
>
> **Principle 1:** The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.
>
> **Principle 2:** The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.
>
> **Principle 4:** The PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.
>
> **Principle 5:** The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Principle #1:

32.1 Please define the FEI view as to what the customer interests are?

Response:

FEI believes customer interests include receiving innovative, efficient, safe and reliable and cost effective service from a utility that operates in an environmentally and socially responsible manner.

32.2 Please define what the utility interests are?

Response:

The regulatory compact would define the utility's interest as being provided with an opportunity to earn a fair return on and of its invested capital. FEI would in practical terms, however, define its interest more broadly as achieving that financial objective, as well as accounting for the interests of other stakeholders that are key to a successful business. FEI would phrase its interest as follows.

FEI's interest and vision is to create value for our customers, employees and shareholders through leadership in the generation, transmission and delivery of energy, safety, reliability at the best cost. To achieve this, FEI focuses on:

1. Exceeding customer expectations through the delivery of innovative, efficient, reliable service, at the lowest reasonable cost;
2. Providing employees with a safe and healthy workplace that fosters personal growth and rewards initiative, action and productivity;
3. Operating in an environmentally and socially responsible manner; and
4. Optimizing allowed shareholder return.

32.3 Please discuss whether or not FEI believes that sharing of the benefits of PBR is a principle on its own or is derived from its views as to the alignment of customer and utility interests.

Response:

FEI has expressly included the concept of sharing benefits in Principle 1 as it is closely interrelated with the alignment of interests (the other aspect of of Princple 1).

FEI believes that there are two types of customer benefits associated with PBR. First, there is the benefit of changing the long term cost trajectory for utility operations. Second, there is the short term benefit of sharing efficiency gains with customers through provisions in the PBR Plan. FEI believes that by sharing the short term benefits of PBR we are in effect aligning the interests of the customer and the utility. This is the benefit that is tangible for customers and demonstrates that the innovative, efficient, safe and reliable service provided is done so at the lowest reasonable cost. In this respect, the sharing of benefits is associated with the alignment of interests. The long term benefit of a lower cost trajectory is just as real but is not tangible for customers who cannot view the results on the changes caused by the continuous improvement culture.

32.4 Please comment on whether or not a key principle for the utility and the customer sharing a benefit could or should be that the utility demonstrably earn any benefit it receives from a PBR.

Response:

B&V states that as a practical matter, the purpose of PBR is to provide market like incentives and leave the management of the Company to make decisions that lead to benefits measured by enhanced bottom line earnings. It is not the purpose to impose the type of additional regulatory review implied by the need for the utility to demonstrate how the benefits were earned. In fact, using this as a standard would effectively reduce the benefits through added regulatory oversight and thus contradict a fundamental purpose of PBR.

Principle #2:

32.5 Please define FEI's view with respect to what is a reasonable opportunity to recover its prudently incurred costs.

Response:

In FEI's view a reasonable opportunity to recover prudently incurred costs includes setting rates for service at levels which produce revenues that cover all of its approved operating costs plus allows for the return of (depreciation expense and negative salvage) and on its entire allowed rate base (rate of return). The return on rate base would be based on the weighted average cost of capital for an economically efficient and financially sound capital structure recovering the embedded cost of debt and a market based return on equity.

32.6 Please comment on whether or not a key principle for the utility and the customers sharing a benefit could or should be that the utility be significantly challenged to achieve productivity gains beyond normal expectations for utility management without a PBR.

Response:

The elements of the PBR plan should be designed in a way that the utility is best incentivized to achieve the highest amount of efficiency possible and bring the highest amount of benefit to its customers through lower long term costs, but equally recognizing that a fundamental obligation under the regulatory compact is to provide the utility with an opportunity to earn a fair return.

In terms of articulating a key principle relating to productivity, the key principle developed by FEI relating to efficiency (set out in principle 4) is preferable to a principle that the utility be significantly challenged to achieve productivity gains beyond normal expectations for utility management under cost of service regulation. A utility's ability to achieve productivity gains under PBR depends on how efficiently it had been operating historically. It is also important to recognize that as PBR Plans continue over time, the law of diminishing returns sets in and there are fewer economic opportunities to increase efficiency absent major technological changes. In general, if the utility was operating efficiently, then the utility would be challenged to achieve further productivity gains and vice versa.

Given the obligation to provide an opportunity to earn a fair return, any principle developed to deal with efficiency or productivity must be read in context of Principle #2 as well.

Principle #3:

32.7 Please define FEI's view with respect to what constitutes unique circumstances of the utility that are relevant.

Response:

At any time unique circumstances may vary for the utility itself. The response to CEC IR 1.31.5 identifies some of the circumstances that matter for a utility as they relate to a PBR Plan related to O&M related costs. That list is not exhaustive but provides a flavor of the kinds of issues that may impact the elements of a PBR Plan. The OEB identified three different sets of circumstances for electric distribution providers in its Fourth Generation IR decision. See page 12 and following of Appendix D-1 for a description of the three options. B&V's assessment is that, by proposing a complete and comprehensive PBR Plan, FEI has addressed the circumstances it faces that are relevant for its operation.

32.8 Please comment on whether or not a key principle for the utility and customers sharing a benefit could or should be whether or not the utility achieves a significant portion of its unique productivity improvement potential.

Response:

Such a principle is not required. Under the comprehensive PBR plan proposed, which addresses the circumstances FEI faces that are relevant for its operation, FEI is incented to achieve its productivity improvement potential consistent with the analysis of costs and benefits for each option implemented by FEI. At that point, Principle #1 comes in to play; by design, the benefits achieved under the proposed PBR Plan flow to both customers and shareholders.

Principle #4:

32.9 Please provide FEI's views on whether or not the safe and reliable service and customer service are the only key metrics to maintain while pursuing efficiency improvement.

Response:

In general, providing safe and reliable service and customer service are two key metrics to maintain while pursuing efficiency improvements under PBR. In particular, the Service Quality Indicators outlined in Section B6.6 of the Application represent the specific key metrics to maintain, and their respective annual targets to be reviewed at the PBR Annual Review, while pursuing efficiency improvements under PBR.

Principle #5:

32.10 Please define what FEI means by a PBR that is easy to understand, implement and administer.

Response:

The simplicity principle refers to a PBR plan that is not overly complicated, that should reduce the regulatory burden over time and incentivize the utility to achieve productivity improvements. The Plan itself should not be overly complex that the administration of the Plan creates additional regulatory burden to undermine the sought-after regulatory efficiencies. The potential to achieve regulatory efficiencies is a benefit of PBR over cost of service regulation when coupled with the potential for productivity improvements and a lower rate trajectory.

There is some inherent complexity in any PBR plan or rate case. However, the proposed PBR plan should be relatively easy to understand, implement and administer compared to other possible PBR models as it builds on FEI's successful 2004-2009 plans, which stakeholders are familiar with, and focuses the performance incentives on the main areas of controllable costs, operating and maintenance expenses and capital expenditures, consistent with the 2004 PBR Plan.

32.11 Please comment on whether or not a key principle of a PBR plan is that it should be designed to optimize the achievement of benefits for customers at reasonable costs (earnings for the utility) and should not be shaped by simplicity at the expense of optimizing the achievement of benefits.

Response:

Adding such a principle is unnecessary. Principles relating to efficiency and ease of understanding are already included in the list. The elements of the proposed PBR plan inherently incentivize FEI to achieve its productivity improvement potential to the extent that it is based on sound economic principles of efficiency and are not shaped by simplicity at the expense of optimizing the achievement of benefits.

33. Reference: Exhibit B-1, Page 45

> FEI proposes a five-year term for the PBR, effective 2014 to 2018. Five years is a commonly adopted PBR term in North America, and similar in term to previous plans in BC. The proposed term is one year less than FEI's 2004 PBR Plan, which became six years in duration after an approved two-year extension was added to the initial four-year term. There are two key advantages to the proposed term, relative to a shorter term.

33.1 Please comment on why a term is needed and why a PBR plan cannot be designed as an annually rolling forward mechanism with the opportunity to continuously improve the design.

Response:

B&V provides the following response.

There are a number of reasons for setting a plan term including:

1. Reducing regulatory costs and regulatory uncertainty.
2. Providing a plan long enough for the utility to implement cost effective efficiency improvements without adjusting those benefits away as would occur under an annual mechanism.
3. Providing a more market like price trajectory than typically results from annual reviews.
4. Periodic rebasing of O&M and capital at the end of a fixed PBR term would provide benefits for customers, as compared to a rolling term that did not involve rebasing.

Changing the design annually increases the risk for all parties and decreases the incentive powers of the PBR plan since it would limit the expected return on capital previously invested during the PBR period to achieve efficiencies over time.

34. Reference: Exhibit B-1, Page 46

> The use of an inflation or I-factor in a PBR plan is to provide recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. This is one area where FEI is proposing a change from the 2004 PBR Plan. FEI's previous PBRs calculated an average inflation rate for British Columbia using a combination of sources for CPI forecasts. These forecasts were collectively referred to as the BC-CPI. FEI proposes to use instead a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to BC All Weekly Earnings (BC-AWE) and non-labour indexed to BC-CPI. FEI believes it is more appropriate to use a composite labour and non-labour inflation index in determining the I-Factor since this is more reflective of Company costs, which consist of both labour and non-labour components, than an economy-wide inflation measure such as CPI.

34.1 Please comment on whether or not accepting that inflationary pressure is a key feature of a PBR plan effectively relieves the utility of dealing with more difficult productivity and efficiency challenges such as comparing its costs including wages with least cost benchmarks for performing similar functions or jobs.

Response:

FEI disagrees with the premise of the question. Including inflationary measures allows the company to ensure its cost structure reflects economic conditions that are beyond the control of FEI and that affect businesses generally. The AUC correctly acknowledges this issue in its AUC Decision 2012-237 that the "changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors"[8]. Therefore there is no contradiction between pursuing the efficient improvements and minimizing the costs that are within the control of the Company and adjustment of costs for changes in input prices that are outside of its control.

It is very common, if not universal, to refer to PBR formulas as I-X formulas. This recognizes that inflation is a central concept in PBR. In addition, it is cost effectiveness in the utilities' particular circumstances and not "least cost benchmarks" that should be the focus of the efficiency improvement projects as least cost benchmarks may not even be accessible for a utility because of the varying local economic, regulatory and legislative conditions specific to each utility. By removing inflation, the Company not only is challenged to become more productive through the X-factor, but without the ability to address the increase in input costs, the Company may be forced to find cost savings that are beyond efficiency.

[8] AUC Decision 2012-237, paragraph 154, page 33.

34.2 Please comment with respect to how much of the FEI labour cost is locked in to union agreements and whether or not there are productivity improvement opportunities to be achieved with the Company's unions.

Response:

This response is being filed confidentially, as it contains information about future collective bargaining strategy, and should not be disclosed publicly or to representatives of FEI's bargaining units as it will impact FEI in future negotiations.

34.3 Please provide the facts with respect to the FEI union contracts and when they expire and are open for renegotiation.

Response:

FEI is party to three different union contracts, which are effective as follows:

- COPE Customer Service (January 1, 2011 to March 31, 2014)
- IBEW 213 (April 1, 2011 to March 31, 2015)
- COPE (April 1, 2012 to March 31, 2015)

None of these collective agreements are currently open for renegotiation. Under the current provincial labour legislation, notice to commence collective bargaining may be given anytime within the four months prior to a collective agreement expiring.

35. Reference: Multiyear Performance Based Rate-Making Mechanism, Exhibit B-1, Application, Part B, Section 6.2.2.1, Inflation Factor (I Factor) Proposal, Pages 46 to 48

FEI has proposed as an inflation factor a weighted average of the growth rates of the BC Average Weekly Earnings ("AWE") index and the BC-CPI. Weights are based on the share of labor in the Company's O&M expenses.

35.1 Why is this index more appropriate for capital expenditures than an index based on the Electric Utility Construction Price Index?

Response:

B&V provides the following response.

There would be no reason to use the Electric Utility Construction Price Index for capital expenditures for gas since the two industries have very different capital profiles. Using the measure of inflation proposed by FEI represents a reasonable measure from a set of reasonable measures that are determined transparently by independent sources.

As stated on the Statistics Canada website[9], the Electric Utility Construction Price Index (EUCPI) measures the price change for constructing two types of plants, distribution systems and transmission lines systems, representing electric utility capital expenditure construction projects.

The EUCPI is geared towards electric utilities, and therefore was not considered as an index for FEI's proposed PBR. Generally, a firm's inflation rate is compared to that of the broader economy. This is consistent with the selection of the BC-CPI, which is a measure of inflation for the overall BC economy. However, EUCPI has a narrow focus on electric utilities, which is in contrast to how a firm should be evaluated.

In addition, the selection of AWE is consistent with that of the Alberta Utilities Commission recent decision to use AWE as a measure of labor inflation in their PBR implementation.

[9] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ144d-eng.htm

36. Reference: Exhibit B-1, Page 48

Table B6-3: BC AWE Forecasts for the PBR Period[18]

BC Average Weekly Earnings Forecast	2014	2015	2016	2017	2018
AVERAGE	2.70%	2.70%	2.60%	2.60%	2.50%

Based on these tables, the 2014 BC-CPI and BC-AWE rates are forecasted to be 1.83 percent and 2.70 percent respectively. As such, FEI proposes to use an I-Factor of 2.31 percent (calculated as (45% x 1.83%) + (55% x 2.70%)) for 2014.

36.1 Did FEI consider other measures than the BC AWE Forecast for determining labour related inflation?

Response:

FEI investigated the possibility of using alternative sources of labor-related inflation other than the BC AWE. However, an alternative source that represented BC's economy-wide labor inflation is not available, and the BC AWE remains the most appropriate measure of BC labor-related inflation.

36.2 If so, why did FEI decide to use the BC AWE Forecasts?

Response:

Please refer to the response to CEC IR 1.36.1.

36.3 Please identify any other labour related Forecasts that could be reasonably considered as relevant and provide the forecasts for the PBR period.

Response:

Although not considered relevant for this PBR for the reasons listed in response to CEC IR 1.35.1, the percent changes related to the Electric Utility Construction Price Index for the period 2008 – 2012 are summarized in the table below:

Construction price indexes[10]
(Electric utility)

	2008	2009	2010	2011	2012
	Electric utility				
	1992=100				
Distribution systems	150.3	151.1	155.1	160.1	161.6
Transmission line systems	148.8	149.7	150.5	154.0	154.3
	% change				
Distribution systems	1.0	0.5	2.6	3.2	0.9
Transmission line systems	4.3	0.6	0.5	2.3	0.2

Source: Statistics Canada, CANSIM, table 327-0011 and Catalogue no. 62-007-X.
Last modified: 2013-04-04.

[10] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ144d-eng.htm

37. Reference: Multiyear Performance Based Rate-Making Mechanism, Exhibit B-1, Application, Part B, Section 6.2.2.2, X-Factor Estimation, Pages 48 to 53

37.1 On page 50 FEI states that "In some cases, the subjective stretch factors are much greater than the measured TFP". Please provide all examples of this outcome that you know of.

Response:

The table below provides examples of cases in which the subjective stretch factor is significantly greater than the measured TFP.

State	Utility	Time	Case Reference	TFP	Stretch factor
MA	Berkshire Gas	2004-11	Docket D.T.E. 01-56	0%	1%
MA	NSTAR	2006-12	Docket D.T.E. 05-85	0%	0.5 to 0.75%
ME	Bangor Gas	2000-12	Docket 970795	0%	Up to 0.5%
Ontario	Union Gas	2001-2003	RP-1999-0017	1.10%	1.40%
Ontario*	OEB's 4th Generation IR	2014-2019	EB-2010-0379, PEG Report	0.07% to 0.1%	Up to 0.6%

* Proposed by the Board's consultant

37.2 On page 51 FEI states that "the downward trend in TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output". Please provide a full and complete substantiation for this contention. Make sure to explain why this factor was more important than other factors such as rising DSM expenses and the recession that commenced in 2008.

Response:

B&V provides the following response.

Please refer to the responses to BCUC IRs 1.36.1, 1.37.1 and 1.40.2 for explanations. The recession has no impact on the measure of output used in the TFP study (capacity and customers) as it would when using throughput. Rising DSM expenses have less weight in the analysis because they are small relative to the total dollars of operating expense and represent smaller amounts for gas utilities in the study in general.

37.3 On page 51 FEI states that "This declining trend can also be seen as a pattern in individual jurisdictions. For example, Ontario's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study 19 conducted by the OEB‟s consultant was estimated at 0.72 per cent, while the most recent study 20 prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative 21 TFP growth of -0.05 to -0.03 per cent." Please confirm that FEI is not relying upon the most recent version of this study and that these numbers have since been adjusted above zero. Please also confirm that one possible cause of this decline in TFP is a change in the data source from US electric utility data to Ontario electric utility data.

Response:

FEI confirms that a new version of the mentioned report was published by OEB's consultant on Friday May 31st, 2013. The computed TFP values in the new version were increase from -0.05 and -0.03 % to 0.07 and 0.1%. This increase has no impact on the logic of the statement made on page 51. The new values are still significantly lower than the 0.72% TFP value approved for OEB's 3rd Generation IR. Therefore, FEI's position regarding the declining trend of TFP values since the year 2000 is still supported by the new version of the report.

FEI cannot confirm the claim that one possible cause of this decline in TFP values is a change of data source from US data to Ontario data (this is not to say that a change of data source does not have any impact, positive or negative, on the measured TFP). The declining TFP values are not specific to Ontario or Canada as demonstrated by B&V's TFP study which is completely based on US data.

38. Reference: Exhibit B-1, Page 51

> This declining trend can also be seen as a pattern in individual jurisdictions. For example, Ontario's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study conducted by the OEB's consultant was estimated at 0.72 per cent, while the most recent study prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative TFP growth of -0.05 to -0.03 per cent. B&V concludes that the downward trend of TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output. B&V expects that this trend will continue during FEI's proposed five year PBR term.

38.1 Please comment on whether or not this means that an appropriate X factor is highly dependent on the way capital is managed in the PRB and that if the capital is disconnected from the operating much higher X factors should be expected.

Response:

B&V assumes that the question is one of what an X-Factor would be if all capital is treated outside of the PBR Plan. While B&V believes the X-Factor would be less negative than found in the TFP study, we have not prepared any analysis of the level of that factor. Operating costs include labor and labor related costs, materials and supplies and rents. While B&V generally believes that current labor costs would reflect market conditions and would have positive productivity, the movement from pay as you go for post retirement benefits to accrual accounting along with amortizing the prior period liabilities may cause the overall non-capital related costs to be zero or slightly negative, albeit much less than the TFP values. The question is however hypothetical because it does not represent the FEI proposal, which includes capital as part of the Plan.

39. Reference: Exhibit B-1, Page 53

> The 2014 PBR Plan applies only to the delivery portion of customers' rates. The commodity and midstream components of customer rates are set through separate flow-through regulatory processes. Delivery costs include the costs incurred to build, maintain, finance and operate the infrastructure necessary to deliver natural gas and provide service to customers.

39.1 Does this mean that there is nothing FEI can do to improve the cost effectiveness of the midstream costs customers must pay?

Response:

Please refer to the response to CEC IR 1.39.3.

39.2 Does this mean that there is nothing FEI can do to improve the cost of the commodity customers must pay for?

Response:

Please refer to the response to CEC IR 1.39.3.

39.3 Please explain in some detail what FEI currently does to optimize midstream costs and control commodity costs for customers.

Response:

FEI actively manages midstream and commodity requirements on an ongoing basis in order to ensure an appropriate balance of cost minimization, security, diversity and reliability of supply in order to meet core customer design peak day and annual demand requirements. The Commission has established processes to review FEI's gas portfolio, and the gas cost deferral account balances and gas cost forecasts that are used to determine future commodity and midstream rates that are separate from the review of FEI's delivery rates. These separate review processes are important because the gas portfolio reviews and the quarterly gas cost report reviews are conducted on a more frequent basis than a revenue requirement to set delivery rates, which may only occur once over a multi-year period. The midstream and commodity costs are generally market based, or, as is the case with contracted transportation capacity, based on the cost of service of the service provider.

The management of midstream and commodity costs focuses on four broad groups of activities.

First, the Annual Contracting Plan (ACP) develops a gas portfolio that includes a balanced mix of daily and monthly priced commodity supply supported by a range of storage and transportation options. This mix is important to be able to effectively mitigate adverse price movements and to provide resource flexibility that is needed to reliably serve customers across a large, geographically diverse footprint. The ACP is reviewed by the Commission on an annual basis to ensure it meets its stated objectives, which include cost effectiveness.

Second, FEI contracts for a range of storage and third party transportation capacity options that are needed to ensure the availability of supply and its movement to FEI's system. FEI attempts to negotiate favourable terms for storage contracting and the good relationships FEI has with regional storage operators helps in this regard. Transportation costs are managed by contracting for longer terms in order to take advantage of discounted rates.

Third, FEI actively manages variations in daily demand and mitigates costs for customers by optimizing transportation, storage, and off-system sales when these resources are not needed by core customers. FEI optimizes these resources by performing trading activities around the contracted pipeline and storage assets. These trading or mitigation activities generate revenue that offset overall costs and have contributed significantly to the reduction of gas costs to the benefit of customers.

Fourth, FEI actively monitors and often participates in regional regulatory and market developments to help minimize any potential adverse cost impact for customers.

40. Reference: Exhibit B-1, Page 54

> 1. An adjustment to recognize the sustainable savings that were realized in 2012 that should be carried forward to future years;
> 2. Adjustments to include actual incurred 2013 "non-controllable" O&M that is held in deferral accounts in 2013; and
> 3. Accounting changes that reclassify items from O&M to capital.

40.1 Please explain why there would not be a forecast of sustainable savings achieved in 2013 that should carry forward to future years.

Response:

Table B6-4, page 55, identifies sustainable savings in the amount of $14.670 million. These savings were actually generated in the 2012-2013 timeframe.

The reference to sustainable savings on page 54 inadvertently omitted reference to 2013 savings. FEI will update this page in its next Evidentiary Update.

For an analysis of sustainable savings generated in 2012 please refer to the response to BCUC IR 1.82.1.

For an analysis of sustainable savings generated in 2013 please refer to the response to BCUC IR 1.83.1.

40.2 If FEI achieved sustainable savings in 2012 is there an expectation within FEI that there will be sustainable savings in 2013?

Response:

Please refer to the response to CEC IR 1.40.1.

41. Reference: Exhibit B-1, Page 56

> The 2013 Base O&M is then escalated using the formula approach. Excluded from the O&M formula approach are pensions and OPEBs, insurance and also the O&M related to Rate Schedule 16[27]. The pensions, OPEBs and insurance were also excluded from the formula in the last PBR and were considered "flow through" items in recognition of their uncontrollable nature. The Rate Schedule 16 O&M has been excluded because these costs are directly tied to incremental revenue that is not part of the formula approach.

41.1 Please identify any other areas (other than Rate 16 O&M) of the Company's operations that are specifically oriented to generating incremental revenue.

Response:

Of the Company's operations, the ES&ER department is oriented towards generating incremental revenue. While there are other departments in the Company's operations that have revenues embedded in their O&M, for these groups, revenues are primarily related to "cost recovery" activities. The ES&ER department focuses on identifying and implementing new service offerings which bring in incremental revenue. These include RNG, NGT, the development of new markets for LNG and CNG, such as remote communities the development of applications for use of LNG and CNG, as well as increases in natural gas throughput from new large industrial customers. Furthermore, FEI is proposing to introduce an incentive program in the forecasted period in order to encourage customers to switch to natural gas.

Any incremental revenue generated by the ES&ER department will be captured in delivery revenue or in other revenue. Such revenue items will be re-forecasted each year, and thereby customers will receive the benefits of the department's efforts in this regard in the following year.

Furthermore, as described on pages 78-79 of the Application, through the Annual Review process FEI has proposed that FEI will bring forward any proposals for the funding of incremental resources in support of load growth initiatives identified during the course of the PBR period.

42. Reference: Exhibit B-1, Page 56

> As in the 2004 PBR Plan, the PBR formula FEI proposes to apply to the O&M is tied to the average number of customers. FEI will reforecast the average number of customers for the upcoming year in the Annual Review. The following formula illustrates the formula applied to O&M:

42.1 Please provide data with respect to the various O&M categories of costs to demonstrate which O&M costs are directly and linearly connected to the customer count and which O&M costs are or can be more fixed and result in reduced costs per customer as the customer count grows.

<u>Response:</u>

Customer additions and design day demand forecasts are the key drivers of the O&M and capital costs incurred by FEI in serving its customers. As existing customers' peak load requirements change along with new customer additions the timing for when new capacity is needed may be impacted and for when incremental operations and maintenance would be required.

Costs for billing and meter reading are directly correlated to customer count and will increase as customer count grows. Costs for transmission and distribution operations and maintenance are indirectly related to customer count and will incrementally increase as customer and customer capacity requirements grow. The additions of pipeline and system capacity are lumpy investments that are required as existing capacity is fully utilized or as the existing gas plant reaches its end of life and must be replaced.

Please refer to the response to CEC IR 1.42.2 below for a discussion of revenue requirement impacts overall. It is important to recognize that when customers are added there are both direct and indirect costs added to the system. If the prices and technology for providing service to added customers were the same as the average embedded costs in rates it would be reasonable to talk about fixed costs that decline with added output. They are not because embedded costs are a function of prior period prices and technology. Costs are added at today's prices and technology that exceed the costs in rates whether it is O&M or capital. New customers impact cost at the marginal cost for today not the embedded cost in rates as implicitly assumed in the question. If marginal nominal cost exceeds the embedded costs, O&M costs increase by the nominal marginal cost. As FEI notes, customer count is a proxy for both capacity and customers. This is appropriate for the O&M adjustment because the largest part of growth in output is related to small customers who can be served with the smallest size of pipe and the associated costs.

Administrative costs for Finance, Human Resources, Governance and Corporate Administration are temporarily fixed and average cost would decline with increasing number of customers. But these costs will increase with general inflation from year to year.

The only cost that increases with throughput is odourant which is an extremely small component of the total O&M. Own-use gas for compressors and line heaters will increase but only to support system capacity requirements when needed (in the non-heating season most line heaters and compressors are shut down). Own-use gas is a very small portion of the total revenue requirement. For 2014 the forecast O&M for own-use gas (compressor fuel and line heater) is $1.5 million which is only 0.1% of the total revenue requirement.

Please also refer to the response to BCPSO IR 1.18.1 for a discussion of cost drivers for various O&M activities/functions.

42.2 Please provide an explanation of the economic cost structure concepts of economies of the scale of operation and indicate how they may apply to the Company when considering O&M per customer concepts.

<u>Response:</u>

B&V provides the following response.

Economies of scale may be defined as declining long-run average cost curves under the assumptions of fixed technology and input prices. Cost curves relate costs to units of output typically measured as throughput. As we have shown, throughput is not a relevant measure of output for delivery service. Instead, the measure of output is capacity and customers. Thus, under the economic definition of economies of scale, cost would decline as the number of customers and capacity increased for fixed technology and input prices. Since we are measuring utility costs over periods when both input prices and technology have changed the result is an upward shift in the long-run cost curve as the result of adding customers and capacity even in the presence of economies of scale. This is always a confusing issue because the utility industry does benefit from economies of scale in the sense that increasing capacity of a pipeline from 2-inch to four-inch results in dramatically lower costs per unit of capacity (the scale economies concept). However, the revenue requirement would increase overall because both the first year revenue requirement and the nominal cost of the pipe would likely exceed the embedded cost of capacity reflected in current rates.

42.3 Please confirm that in a system where there is a decline in average use per customer and flat customer growth rates there are a number of capacity issues in the system that will not be related to customer growth versus a system with increasing rates of customer growth and flat to increasing use per customer.

Response:

The question cannot be confirmed or denied. Given that systems do not experience uniform load increases or decreases, capacity constraints will move around based on the location on the system where these changes take effect. This occurs because even where there is a general load decrease driven by a decline in use per customer and flat customer growth, this will not occur equally everywhere on the system. Additionally, sections of the system still face significant local growth, like Surrey. As a result, it is true that a system facing these two scenarios would have different costs. It is also true that a system facing these two scenarios may need to continue to manage issues not related to customer growth. Further, it is true that use per customer has no impact on system costs in either case. The issues for the system costs are defined by customers and capacity on a design day.

Other factors that can lead to capacity constraints not related to customer growth (e.g. increases in demand) can include:

- reduction in pipeline Maximum Operating Pressure (MOP) due to class location change;
- relocation of loads within systems without increases in demand (e.g. smaller loads being replaced by a single larger load);
- changes in gas demand profiles; for example, steady loads changing to more intermittent higher demands (e.g. peakier); and
- changes in observed minimum pressures at feed points to laterals.

All of these factors apply to both decreasing and increasing annual consumption on the gas system.

42.4 Please describe how the customer count reflects multi-family units connected to the system and explicitly deal with whether the unit is considered one customer or whether each family unit is considered a customer.

Response:

Customer count is based on active contracts. If each unit of a multi-family dwelling has a separate meter and a customer has contracted for service at each unit, each contract is counted as an active customer. A building that is centrally metered would have one contract and be counted as one customer. For a more complete discussion of customer count methodology refer to Appendix E4 of the Application.

43. Reference: Exhibit B-1, Page 59

> Capital expenditures include both regular capital expenditures and projects approved as CPCNs. FEI proposes the same treatment in the 2014 PBR Plan for regular capital expenditures and CPCN expenditures as was approved in the 2004 PBR Plan. Regular capital expenditures will be determined by formula and CPCN expenditures will be excluded from the formula and will continue to be subject to the minimum $5 million cost threshold. CPCN expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service. B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It is akin to the adoption of a
>
> "capital tracker", which is incorporated in PBR plans elsewhere. B&V describe the purpose of such mechanisms as follows in the PBR Report:

43.1 Does FEI typically provide P90 or P50 estimates of capital expenditures in its CPCN applications for approval and which level of estimate is used for capital planning that would be used for the PBR?

<u>Response:</u>

For clarity, "P90" and "P50" refer to the development of probabilistic cost estimates. All estimates inherently incorporate a degree of uncertainty; probabilistic estimating attempts to quantify this uncertainty by applying analytical techniques to compute – based on known and assumed project risks – the likeliest project cost for a given level of probability. In general, this estimating method is fairly complex and is more suitable for larger, "one-off" projects.

FEI has provided P90 or P50 estimates with some of its CPCN applications. The South Arm Fraser River Crossing Project is an example where a Monte Carlo analysis was completed providing a P90 and P50 estimate of the capital cost. All cost estimates for CPCN applications are completed in accordance with Order G-50-10 "2010 Certificate of Public Convenience and Necessity Application Guidelines" and to a Class 3 degree of accuracy as defined in AACE International Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009).

For most ongoing projects, FEI does not employ probabilistic estimating techniques due to the higher costs that would be incurred (with little offsetting benefit). Instead, project costs are typically single-value estimates with a contingency. This estimating method is straightforward to apply and relies on professional judgement and historical costs from similar completed projects. Since the vast majority of FEI capital projects are recurring in nature, this is a cost-effective method of developing project estimates. The estimates used for capital planning are either to AACE Class 5 or 4 degree of accuracy depending on the nature and timing of the project.

Regardless, the delivery rates for the PBR Period will be set using the capital formula, and not the capital estimates that have been provided in this Application.

44. Reference: Exhibit B-1, Page 61

> For capital, there is no need to adjust the 2013 Approved for savings realized in 2012. This is because amounts that were not spent in 2012 are not considered sustainable, since they have been carried forward to the 2013 Projection. As described in Section C4 on Capital

44.1 Please confirm that it will continue to be the case in 2013 that amounts not spent will not necessarily represent efficiency or productivity gains but may simply reflect the fact that expenditures planned were not undertaken and will simply be undertaken at a later time period.

<u>Response:</u>

In any given year, there are often variations between actual and forecast levels of capital activity.

These variations could be due to a variety of reasons. Some, due to timing, are considered temporary in nature, while others such as efficiency gains could be considered permanent in nature. To the extent that any variation is temporary in nature, it will typically be offset in the following year.

In 2012, FEI experienced a shortfall in capital expenditure due to timing. Conversely, FEI is projecting to catch up for this in 2013.

As stated in the response to CEC IR 1.28.1, at the very least, the prudent deferral of capital spending from one year to the next creates a present value benefit for customers.

44.2 Please confirm that inefficiency in the capital expenditure implementation processes of the company could lead to less capital expenditures being undertaken.

<u>Response:</u>

FEI is unable to confirm *that 'inefficiency in the capital expenditure implementation process of the company could lead to less capital expenditures being undertaken'.* Inefficiency can lead to either more or less capital being spent in any given year.

Typically FEI attempts to define levels of capital activity to allow conformity with various commitments. These commitments arise from several sources:

- The General Terms and Conditions set down FEI's obligation to attach new customers and serve existing customers.
- Various codes and regulations obligate FEI to maintain gas assets to prescribed integrity standards.
- FEI's commitment to customer and employee safety drives ongoing levels of capital spending.

FEI's base capital expenditures reflect these levels of capital activity. Consider the following examples:

1. If the capital program is poorly planned, this may lead to inadequate resources to complete the required work. This will result in re-planning of work and re-scheduling of resources. In the short term this may result in work not being completed. But recognizing that the work still needs to be done, any shortfall in a given year is usually completed in the following year. In this example, poor planning will lead to higher capital spending.
2. If the capital program is poorly planned and an inadequate process is in place, this may:
    a. Establish the need for overtime to remain on schedule
    b. Result in inefficient use of contactors
    c. Result in errors being made, that have later to be corrected

What FEI can confirm is that, if FEI is successful in implementing process improvements and achieving productivity gains, *"**efficiency** in the capital expenditure implementation processes of the company could lead to **less** capital expenditures being undertaken".*

44.3 Please describe all of the types of Sustaining Capital projects the Company would be expecting to undertake in any given year.

Response:

The following types of work fall within sustaining capital projects.

Meter Recall / Exchanges

- Replacement of time expired or inaccurate meters

- Replacement of obsolete regulators

Transmission System Reinforcements

- Replacement or alteration of transmission pipelines
- Installation of additional equipment (e.g. valves, pigging barrels)
- Upgrades to pipeline valves
- Installation of protection of transmission pipelines from natural hazards
- Internal inspection and assessment of transmission pipelines
- Improvements to cathodic protection systems
- Acquisition of additional land rights
- Upgrades to compressor, pressure control or measurement stations
- Upgrades to the LNG plant
- Upgrades to the SCADA system

Distribution System Reinforcements

- Improvements to the cathodic protection systems
- Upgrades to pressure control or measurements stations
- Installation of system improvements to maintain system tail end pressures (i.e. ensure adequate capacity)
- Upgrades to the SCADA system

Distribution Mains and Service Renewals

- Alterations and replacements of mains and services either due to third party requests or direction
- Replacement or addition of valves to facilitate operations and emergency response
- Mitigation of hazards affecting service lines or meter sets
- Replacements of mains and services as a result of company initiated renewal to manage safety and reliability risk

- Installation of new pressure control stations
- Acquisition of additional land rights (e.g. to correct trespass issues)

44.4 Please identify for Sustaining Capital any metrics (such as meters of pipe replaced) that would demonstrate a homogeneous project type included in the Sustaining Capital amounts or clarify that Sustaining Capital projects are each unique one from another and have no common metrics.

Response:

Referring to the list of activities provided in the response to CEC IR 1.44.3:

Meter Recall / Exchanges

- The work undertaken in this activity is of a repetitive nature and a cost per meter or regulator replacement could be established.

Transmission System Reinforcements

- Only for the replacement or alteration of transmission pipelines could one expect to derive a common metric such as a cost per metre which could be used to estimate the cost of future work or to review the costs of similar work. However this is complicated by the fact that FEI operates transmission pipelines of various diameters and in recent history has not undertaken this work in a significant amount. Most replacements have been of very short length. During the next 5 years FEI will be undertaking a number of replacements of significant length which will be useful in the future for deriving a metric such as the cost per metre to do such work.
- The other activities within this category are generally non-routine and the scope and complexity varies from site to site. The variance would be due to such things as the number of pieces of equipment touched while a station upgrade was being undertaken. Or in the case of pipeline valve upgrades the size of the pipeline and the location.

Distribution System Reinforcements

- Within this category only from the activity of installing system improvements, could a metric be derived for the installation cost per meter. FEI generally does use a cost per meter derived from past work to estimate the cost of future projects, however it is necessary to consider a range of figures due to the geographic location of the work and the site conditions.

Distribution Mains and Service Renewals

- This is the same as the previous category.

45. Reference: Exhibit B-1, Page 62

> In determining the Growth Capital allowed under PBR, a Average Growth Capital Cost[29] per Service Line Addition is calculated by dividing the current year's total Growth Capital by the current years' service line additions. This Average Growth Capital Cost per Service Line Addition is then escalated by the I-X mechanism and then multiplied by the forecasted level of service line additions for the upcoming year. FEI will recalculate the Average Growth Capital

45.1 Please identify in the cost structure for the cost per service line showing the components of the costs incorporated in the cost structure.

Response:

The Average Growth Capital per Service Line (Table B6-7) for the 2013 Base is $2,739 and is broken down into the following three cost components:

Category	Cost Structure ($ per Service Line Addition)	%
Mains	$ 828	30%
Services	$ 1,643	60%
Meters	$ 268	10%
Total	$ 2,739	100%

45.2 Please identify those components of the cost structure which are fixed or partially fixed as opposed to directly variable with the service line addition.

Response:

Virtually all of the components of the growth capital cost structure are variable, and are a function of service line additions, which are dependent on gross customer additions. If there is no growth in gross customer additions, there are no new mains, no new services and no new meters.

45.3 Please provide a historical experience quantitative analysis to show how much of the cost per service line is for the service line and how much is related to distribution system extension or additions.

Response:

This answer responds to CEC IRs 1.45.3 and 1.45.4

The following table consists of three sections:

1. A summary of historical Growth Capital costs and service line additions from 2010-2012;
2. A summary of historical Growth Capital costs on a per service line dollar basis; and
3. A summary of historical Growth Capital costs with the dollars expressed on a percentage basis.

Historical Cost Structure per Service Line Additions (2010-2012 and 2013 Base)

Growth Capital Category	2010 Actuals ($000s)	2011 Actuals ($000s)	2012 Actuals ($000s)	2013 Base ($000s)	2013 Base Less Insurance &OPEB ($000s)
Mains	$ 4,538	$ 4,510	$ 5,374	$ 6,783	$ 6,615
Services	$ 13,874	$ 14,423	$ 17,423	$ 13,471	$ 13,126
Meters	$ 1,905	$ 1,699	$ 1,403	$ 2,197	$ 2,141
Total	$ 20,317	$ 20,632	$ 24,200	$ 22,451	$ 21,882
Service Line Additions	*9,382*	*7,958*	*7,898*	*7,989*	*7,989*
Growth Capital Category	**2010 Actuals ($/service)**	**2011 Actuals ($/service)**	**2012 Actuals ($/service)**	**2013 Base ($/service)**	**2013 Base Less insurance & OPEB ($/service)**
Mains	$ 484	$ 567	$ 680	$ 849	$ 828
Services	$ 1,479	$ 1,812	$ 2,206	$ 1,686	$ 1,643
Meters	$ 203	$ 213	$ 178	$ 275	$ 268
Total	$ 2,166	$ 2,593	$ 3,064	$ 2,810	$ 2,739
Growth Capital Category	**2010 Actuals (%/service)**	**2011 Actuals (%/service)**	**2012 Actuals (%/service)**	**2013 Base (%/service)**	**2013 Base Less insurance & OPEB (%/service)**
Mains	22%	22%	22%	30%	30%
Services	68%	70%	72%	60%	60%
Meters	9%	8%	6%	10%	10%
Total	100%	100%	100%	100%	100%

45.4 Please provide historical data to show the range of variation

Response:

Please refer to the response to CEC 1.45.3 for the historical data.

46. Reference: Exhibit B-1, Page 68

> A brief summary of the flow-through revenue and expense items is provided below.

46.1 Please describe for each of the flow through items what the Company does or can do from time to time to control each of these costs or revenues as they may impact customer rates.

Response:

FEI notes that for the flow through items discussed below, there are often components that are controllable and others that aren't. In most cases, it is the rate component of the expense that results in the item being deemed uncontrollable, and FEI employs deferral accounts to ensure the impacts of these rate changes, whether favourable or unfavourable, are appropriately included in customers' rates.

Each of the flow through items are listed below along with a description of what the Company does to control each of these items to minimize their impact on customer rates.

Interest Expense

FEI has no control over the underlying interest rates that form the basis for its borrowing rates. FEI regularly meets with and speaks to Debt Capital Markets and Corporate Banking groups of the Canadian Chartered Banks to discuss the current state of the debt markets relative to FEI's future borrowing needs. FEI prudently manages its cash flow through its daily treasury activities, investing excess cash or issuing commercial paper (backed stopped by its term credit agreement) to meet short-term funding needs.

Return on Equity

FEI's cost of capital goes through a separate periodic review by the BCUC, and the rate of return is set through that process. Most recently, the BCUC issued its Stage 1 Generic Cost of Capital Decision on May 10, 2013 and set FEI's ROE at 8.75% for 2013 and made it subject to an Automatic Adjustment Mechanism in 2014 and 2015.

Property Taxes

FEI cannot control the property tax rates that are set by the taxing authorities. Property Taxes are generally driven by:

1. assessment and taxation legislation;
2. changes real estate markets; and

3. changes in commodity and construction prices used to establish rates for most taxable improvements of utilities.

Measures taken to control costs include:

1. a detailed annual review all property assessments to ensure accuracy. Negotiate reductions whenever possible and undertake appeals when warranted;
2. active participation in annual updates to ensure costs are appropriate and market conditions are accurately reflected in cost manuals and legislated rates;
3. reviewing all tax notices before payment to ensure assessments are reflected accurately and taxes are appropriate; and
4. Staying abreast of legislative changes and appeal case decisions to ensure compliance.

Income Taxes

FEI cannot control the income tax rates that are set by the provincial and federal government. As far as the amount of tax, the Company's overall goal from a tax perspective is to pay the minimum amount of tax as required by law. Tax laws are subject to reasonable but different interpretations by taxpayers and tax authorities and the Company seeks to ensure it is not only in compliance with the letter of the tax law but also with the object and spirit of the tax law.

Experienced tax professionals prepare/review the Company's tax calculations. This ensures beneficial changes to tax laws or administrative policies that may be applicable to the Company are considered and built into its tax estimates. The Company's tax professionals attend tax seminars and presentations and regularly review (daily) tax updates issued by public accounting firms, law firms and tax service providers to keep up to date on changes to tax laws and CRA administration policies and on changes to GAAP as they may impact taxes.

The Company's tax department employees are kept informed about Company activities and projects through regular meetings to discuss operating and capital spending. The Company's tax department is consulted directly by the operating groups to review the tax impacts of business plans and initiatives. In addition, the tax department seeks to maximize deductibility through reviewing the timing of when expenditures are deductible for tax purposes, requests income tax rulings where appropriate, consults with external tax advisors on complex or unusual issues, and reviews all proposed adjustments that result from tax audits before agreeing to any reassessments. The company will appeal any reassessments it believes are incorrect in law or not in accordance with the object and spirit of the law.

Pension and OPEB Expenses

The net benefit pension and OPEB expense is determined by a number of assumptions, many of which (like the rates) the company has limited or no control over. The assumptions, which are reviewed on an annual basis, include the discount rate (which is based on Corporate AA bond yields), the expected return of pension plan assets, the rate of inflation, the rate of increase in pensionable earnings, the rate of increase in extended health care costs for retired employees, the rate of increase of MSP premiums, rates of mortality and rates of termination of employment. Most of these are outside the control of the company and are either based on individual employee's decisions (like the rates of retirement), based on market conditions (like the discount rate), and some based on experiences of plan members, like the morality rates of plan members. The biggest driver of expense increases in recent years has been discount rates. Although FEI works with its unions and employees to review and mitigate impacts to the extent possible and review its investment returns against other indices, this has a small impact on the overall expense and as a result, the vast majority of the costs of the defined benefit pension plans and other post-employment benefits are outside its control.

Insurance Costs

FEI, as part of the Fortis Inc. Group of Companies, participates in the Corporate insurance program. The insurance groups at Fortis Inc. and FEI are very experienced and work together to place the insurance program on a yearly basis with a renewal date of July 1 each year. The Fortis insurance group works with its brokerage firm Aon Reed Stenhouse Inc. each year to provide professional insurance services to the Fortis Group of Companies. As part of the process, each year Fortis and Aon assess the insurance market to determine the best course of action to provide Fortis the broadest coverage at the most competitive rates. This is accomplished by continual contact with underwriters capable of insuring the Fortis Group of Companies' risk profile. Annually, Fortis and Aon provide underwriters with updated underwriting information (Statement of Values, Loss Control reports etc.) for renewal purposes. We also attend in person visits with the majority of the markets, in particular, the lead or key markets on the Fortis program to present the Fortis risk and answer any questions underwriters may have concerning Fortis. The Fortis Insurance group meets annually with peer organizations and Aon to benchmark the Fortis insurance program. FEI is therefore comfortable that its current levels of coverage are in line with both its peer group and property and liability exposure faced by it. Regardless of these efforts, insurance costs are very difficult to control as the majority of the impacts to rates are beyond the control of the Fortis Group of Companies.

Depreciation and Amortization

As stated on Page 69 of Exhibit B-1, "Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include the formula-based capital expenditures as plant additions." Therefore, depreciation rates are already predetermined, but depreciation expense will be controlled through the inclusion of the capital expenditures in the formula which includes a productivity factor.

47. Reference: Exhibit B-1, Page 70 and Page 75

> Further, for O&M expenditures, the total efficiency gains are measured as the variance between actual expenditures and formula-based forecasts on a year-to-year incremental basis to avoid rolling forward of temporary savings. Capital expenditure savings however tend to be more discrete between the years and savings in one year implies a reduction in the costs of financing and other carrying costs rather than a permanent reduction in future capital spending. Therefore only a specific percentage of capital savings representing the avoided capital financing and carrying costs should be included in the ECM model. Similar to the 2004 PBR Plan, this percentage is identified as the "rate base benefit factor" in FEI's ECM model and is applied to the capital savings to account for average avoided financing and carrying costs (cost of capital, taxes and depreciation) in annual revenue requirements associated with the cost of service incurred by plant additions added to rate base.

> The rate base benefit factor is representative of the avoided revenue requirements from reduced capital expenditures, which on average equal approximately 15 percent of the amount of the capital cost saving. The components that make up the avoided revenue requirements are the return on rate base, depreciation expense and associated taxes, sometimes referred to as rate base carrying costs. The calculations supporting the proposed 15 percent rate base benefit factor as well as an illustrative example of the proposed rolling ECM are provided in Appendix D6.

47.1 Please confirm that in FEI's view, the total capital expenditure savings should be rewarded during the term of the PBR but that only the rate base benefit factor should be considered in the ECM following the PBR.

Response:

Not confirmed. Both during the term of the PBR and as a consideration in the ECM, it is the revenue requirement impact of the reduced capital expenditure that results in savings to be shared between the utility and its customers (the ROE that is achieved during the PBR term will reflect the reduced revenue requirement for capital savings).

During the term of the PBR plan, the actual revenue requirement impact (depreciation, taxes and financing costs) of the capital expenditure savings relative to the formula-allowed expenditure levels is the source of the capital-related benefit, while after the five-year term under the ECM, a fixed percentage (rate base benefit factor) which is representative of the avoided revenue requirements from the reduced capital expenditures is the source of the benefit.

In both cases the benefit to customers and FEI's amount are each 50% of the total benefit calculated.

47.2 Would FEI accept that the 'rate base benefit factor' is the actual benefit that is derived from the bulk of capital expenditure savings throughout the term of the PBR as well as in the Efficiency Carry Over Mechanism?

Response:

The rate base benefit factor is an approximation of the benefit that is derived from capital expenditure savings. Although the actual benefit from capital expenditures savings will depend on the type of avoided capital expenditure, FEI has analyzed several types of capital expenditures to determine a reasonable average rate base benefit factor of 15%. Therefore the rate base benefit factor may be appropriately considered to be the approximate benefit, not the actual benefit that is derived from savings in capital expenditures. It should be noted that the actual benefits from capital expenditure savings during the PBR term and the amounts carried forward in the ECM through the rate base benefit factor of 15% are both subject to 50/50 sharing through the Earnings Sharing Mechanism.

48. Reference: Exhibit B-1, Page 72

> Based on the feedback received from various stakeholders and the positive experience with the previous earnings sharing mechanism, FEI believes that an earnings sharing mechanism continues to be beneficial and proposes an ESM similar to the 2004 PBR Plan with a 50:50 basis sharing between customers and the Company for earnings above and below the allowed ROE established for each year by the Commission.

48.1 Please explain whether or not the Company believes that it should share 50% of the benefits in all circumstances and explain why.

Response:

The Company believes it should share 50% of the variances with customers. According to FEI's proposed PBR plan, variances from the allowed earnings will be shared between FEI and ratepayers on equal terms. As discussed in Exhibit B-1, Section B-6.4 of the Application, a symmetric sharing mechanism is a fair approach for sharing the risks and benefits of the PBR plan. B&V further articulates the rational for a symmetric earnings sharing mechanism:

> *"The FEI plan included an earnings sharing mechanism that provided symmetric protection for all stakeholders. As a matter of regulatory policy, this reduces the risk of unfavorable outcomes for both FEI and stakeholders. Particularly, the ESM provided customers with real time benefits if FEI earned above the authorized return and assured customers that FEI would not be permitted to deteriorate financially such that system service, safety and reliability would not be compromised."*

In addition please note that the approved sharing mechanism in 2004 PBR Plan, which received positive feedback from the stakeholders, was also designed on a 50:50 sharing basis.

48.2 Please comment on whether or not the contribution of investing capital to reduce operating and maintenance costs deserves some recognition as contributing to the benefit and therefore result in a different split of benefits say 75%:25%, when the cost of the capital will be paid for entirely by customers and the Company is rewarded with an ROE for the capital and the project is undertaken for the purpose of achieving the reduced operating costs.

Response:

FEI believes its proposed treatment of capital and O&M spending variances from the levels allowed by the PBR formulas and the symmetrical 50/50 ESM mechanism provide a balanced approach that will encourage FEI to pursue efficiencies that are in the long-term interest of customers. Under the PBR, capital expenditures that produce O&M savings must be assessed for their impact on the earnings results and the ESM for both the capital expenditure and the O&M savings. An incremental capital expenditure at the margin will also affect the ROE and be subject to earnings sharing. Thus it is not correct to say that customers will pay 100% of the capital costs in rates.

FEI believes there are other concerns with adopting an ESM that is asymmetric or gives different treatment to different costs. Asymmetric sharing mechanisms are unfair and may distort or lessen the incentive power of the PBR plan. Adopting an approach such as the example suggested in the question would lead to definitional concerns about whether or not a particular capital project is undertaken for the purpose of reducing O&M. In addition, it would be hard to distinguish between O&M savings that are caused by capital investments included in the PBR plan (and not by CPCNs for example) and O&M savings that have resulted from other actions. Therefore due to the practical reasons and also based on diminishing effects of such a proposal on PBR incentives, FEI is of the opinion that its proposed symmetric 50/50 ESM is more beneficial to success of the PBR plan.

48.3 Please discuss whether or not the ESM should be considered a bonus for increased levels of productivity gain and should vary in proportion to the level of increased efficiency.

Response:

Characterizing the ESM as a “bonus” for the utility appears to be premised on the assumption that, absent ESM, the productivity gain would flow to customers and that ESM is providing something to the shareholder that it would not otherwise receive. In fact, the opposite is true. Until rebasing occurs, all productivity gains beyond those included in rates would flow to the shareholder in the absence of an ESM. The ESM is something that increases the benefits flowing to the customer, not vice versa. The corresponding benefit to the shareholder is that it reduces downside risk.

In addition to the symmetrical 50/50 earnings sharing approach proposed by FEI, various other approaches have been proposed and adopted for ESM elsewhere such as no earnings sharing, asymmetric earnings sharing, earnings sharing outside of a dead-band, increasing percentages of earnings sharing at prescribed ROE levels relative to a benchmark and decreasing percentages of earnings sharing at prescribed ROE levels relative to a benchmark, to name some. The last alternative mentioned is similar to the one mentioned in the question. In that approach to an ESM, smaller percentages of the gains are shared with customers at higher ROEs above the threshold. This is predicated on the assumption that efficiencies become successively harder and harder to achieve so the rewards for the utility should be greater for attaining those harder-to-get efficiencies.

While there may be merits to the various alternative ESM approaches in particular circumstances FEI believes its proposed approach is appropriate as an element of the 2014 PBR Plan. The 50/50 symmetrical earnings sharing model has been successfully employed in FEI's two previous PBR plans. FEI's ESM provides a consistent business case metric for pursuing additional efficiencies at all levels of ROE achievement (short of reaching the off-ramp). FEI's ESM will generate less controversy and regulatory process around the calculation of earnings sharing than with dead bands or where sharing percentages change at certain ROE levels.

49. Reference: Exhibit B-1, Page 73

> does this by ensuring that the benefits of the efficiency gains are retained for a reasonable period after the PBR term. The benefit to customers of an ECM is that the greater efficiencies achieved throughout the PBR term become incorporated into rates going forward. A well-designed ECM decouples the link between the timing of efficiency gains and the PBR incentives and ensures that the stream of savings resulting from an investment in efficiencies will be allocated to help repay the investment regardless of how close the investment is to the end of the term of the PBR plan.

49.1 Please describe the investment in efficiencies and which party, the shareholder or the customer pays for any investment made in obtaining efficiencies.

<u>Response:</u>

Investment in new efficiencies may involve either O&M or capital expenditures that can increase the productivity through technological, operational and managerial improvements in FEI's activities. For instance, as indicated in section C3.14.3 of the Application, the HR department was able to offset the need for increased HR services due to the insourcing of the customer care function through the use of Employee Self-Serve and Manager Self-Serve (ESS/MSS) programs by investing in self-serve technology in SAP. The total impact of efficiency improvement projects such as ESS/MSS will bring benefits to FEI's customers over the long-term period. For further information please refer to the response to CEC IR 1.2.3.

Whether under Cost of Service or PBR, FEI pays for the costs of these efficiency projects and recovers the costs over time in rates. Whether under Cost of Service regulation or PBR, the utility will only make unforecast investments in efficiency if it can reasonably achieve payback of its investment before rebasing occurs. Under Cost of Service, the period in which payback must be achieved is limited to the test period, usually one or two years. Under the PBR Plan FEI must achieve payback on these unforecast investments in efficiency, whether O&M or capital, within the term of the plan, inclusive of any ECM period. For further information regarding sharing of costs please refer to the response to BCPSO IR 1.25.1.

49.2 Please discuss the relationship between efficiency projects with varying lengths of economic payback times and the concept of sharing 50% of reduced costs for achieving a benefit, including providing and analysis of the tradeoff point at which sharing a benefit can make a project unprofitable to undertake at all.

Response:

The payback period in a particular efficiency project will not be affected by the 50/50 sharing of the efficiency benefits captured. Since the 50/50 earnings sharing mechanism is symmetrical, the revenue requirement impact of both the costs and the benefits of the efficiency project or expenditure will be subject to sharing. The payback period will be the same whether the project is assessed on a gross basis or after-sharing basis.

50. Reference: Exhibit B-1, Page 75

> Service Quality Indicators (SQIs) are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality. B&V's discussion of SQIs appears at p.11 of its PBR Report (Appendix D1). SQIs were a key component of the 2004 PBR and FEI proposes to continue with this feature, with appropriate updates to the SQIs themselves.

50.1 Please discuss for each SQI the percentage of the costs that the company is proposing to have under PBR which directly affect the SQI measure.

<u>Response:</u>

The following table summarizes the different proposed SQIs and the costs directly related to the SQIs. Of the SQIs proposed, only the direct costs for the emergency response and meter exchange appointment SQIs are currently tracked and reported in a comparable manner.

For the Customer Service related SQIs which include telephone service factor (emergency and non-emergency), first contact resolution, billing index and meter reading accuracy, these metrics collectively represent approximately $45 million of customer service O&M costs. However, assignment of costs to the individual SQI measures is difficult to determine as most of the customer service related metrics also depend on other areas and departments as well.

Performance Measure	Indicator	Annual Costs	% of Total Annual Costs
Emergency response time	Percent of calls responded to within one hour	~$4 million (O&M)	1%
Meter exchange appointment	Percent of appointments met for meter exchanges	~$28 million (O&M and Capital)	8%
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	n/a	n/a
Telephone service factor (Non Emergency)	Percent of non-emergency calls answered within 30 seconds or less	n/a	n/a
First contact resolution	Percent of customers who achieved call resolution in one call	n/a	n/a
Billing index	Measure of customer bills produced meeting performance criteria	n/a	n/a

Performance Measure	Indicator	Annual Costs	% of Total Annual Costs
Meter reading accuracy	Number of scheduled meters that were read	n/a	n/a
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	n/a	n/a
Public contact with pipelines	Informational indicator – 3 year rolling average of number of line damages per 1,000 BC One Calls received	See emergency response SQI	See emergency response SQI
Customer satisfaction index	Informational indicator	n/a	n/a

* The definition of total costs include O&M and Capital which totals to approximately $345 million based on 2013 Projection.

FEI does not believe it is valid to evaluate the appropriateness and comprehensiveness of the proposed suite of SQIs based on the percentage of total costs that they represent. As indicated in Exhibit B-1, the purpose of the SQIs is to ensure that service quality to our customers is maintained at acceptable levels throughout the terms of the PBR Period while the company is encouraged to pursue efficiencies. The percentage of total costs that the SQIs represent has no correlation to the importance and determination of the appropriate SQIs to adopt. Instead, the proposed SQIs have been selected primarily based on their importance in ensuring a safe and reliable service while maintaining a customer focus. For instance, although the emergency response time indicator comprises only a small fraction of the overall operational and capital expenditure, its importance with regard to customer and employee safety has much greater magnitude.

51. Reference: Exhibit B-1, Page 76

Table B6-9: Proposed 2014 PBR Improved SQIs

Performance measure	Indicator	Benchmark
Emergency response time	Percent of calls responded to within one hour	95%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%
Telephone service factor (Non Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%
First contact resolution	Percent of customers who achieved call resolution in one call	78%
Billing index	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%
All injury frequency rate	Informational indicator - 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	---
Public contact with pipelines	Informational indicator - 3 year rolling average of number of line damages per 1,000 BC One Calls received	---
Customer satisfaction index	Informational indicator	---

FEI will report to the Commission and stakeholders at the Annual Review to allow a comparison of the performance of the Company against the targets set for each of the SQIs. A full discussion of the improved SQIs is included in Appendix D7 to this Application.

51.1 Please provide FEI's current results with respect to the SQI.

Response:

FEI's results to June 2013 are provided in the table below.

Performance Measure	Indicator	Benchmark	June 2013 YTD
Emergency response time	Percent of calls responded to within one hour	95%	97.5%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%	96.9%
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	95%
Telephone service factor (Non Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	70.5%

Performance Measure	Indicator	Benchmark	June 2013 YTD
Emergency response time	Percent of calls responded to within one hour	95%	97.5%
First contact resolution	Percent of customers who achieved call resolution in one call	78%	81%
Billing index	Measure of customer bills produced meeting performance criteria	5	1.92
Meter reading accuracy	Number of scheduled meters that were read	95%	89%
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked		2.89
Public contact with pipelines	Informational indicator – 3 year rolling average of number of line damages per 1,000 BC One Calls received		9
Customer satisfaction index	Informational indicator		8.3

51.2 Please confirm that FEI's proposed SQI would be considered as a minimum threshold to achieve, but do not reward FEI for making improvements nor penalize FEI if the threshold is not met.

<u>Response:</u>

As outlined in Appendix D-7 Service Quality Indicators, Section 2.2 Choice of Benchmarks, the proposed benchmarks are not to be considered as a minimum threshold to achieve and instead are reference points against which levels of service quality can be compared.

Please refer to the response to COPE IR 1.7.8 for details of the proposed review process concerning SQI performance.

FEI also confirms that it is proposing that no reward or penalties be attached to the performance of the SQIs as part of its proposed PBR plan. This is consistent with the approach applied to natural gas and electric utilities in Alberta and Ontario, the two Canadian jurisdictions most active in PBR (reference: Table B5-1 Jurisdictional Comparison).

51.3 Would FEI expect to improve service in the absence of PBR? Please explain why or why not.

Response:

In the absence of a PBR agreement, FEI would still look to improve the performance of the service quality indicators within the agreed acceptable level of overall cost to our customers as becoming more customer focused is a key business objective for the Company.

52. Reference: Exhibit B-1, Page 76 and Page 78

> 1. If any one (or more) particular element of the PBR Plan appears to be inducing unintended outcomes or results in continuous material changes to service quality, then stakeholders will work to identify a change that can address that element and put it forward to the Commission.

> Plan during the mid-term assessment review. Failure to meet one (or more) SQI benchmarks does not necessarily constitute unacceptable performance. Reasons provided by the Company as to why certain service quality indicator benchmarks were not met will be taken into account, recognizing that variances in performance may occur due to random events or events beyond the full control of FEI. Triggering of the off-ramp provision would be warranted only if there is sustained serious degradation of the SQIs.

52.1 How will a 'continuous material change to service quality' or 'sustained serious degradation of the SQIs' be defined and over what period of time would it need to occur?

Response:

FEI does not believe that "sustained serious degradation" can be defined in a manner that would foresee all circumstances. For example, a fire or other unexpected event might lead to a short term degradation of certain SQIs. Such a circumstance might not be considered as a sustained serious degradation while a lesser but persistent long-term degradation of the same SQIs might be regarded as a sustained serious degradation.

Please refer to the response to CEC IR 1.52.2 for the proposed process to handle a potential sustained serious degradation of the SQIs.

52.2 Please confirm that in the event an unintended outcome or continuous material change in service quality was identified it would be up to 'stakeholders' to prepare a proposal and advance this to the commission to remediate the situation?

Response:

As indicated in the response to COPE IR 1.7.8, as part of the proposed annual and mid-term assessment review process, the Commission and interveners will have the opportunity to review and comment on the SQI results. If there is a material change to service quality identified by stakeholders, stakeholders will work to identify a change that can address that element and put it forward to the Commission. FEI will work co-operatively to ensure compliance with requirements.

52.3 Please provide an example of how a long term drop is an SQI such as Meter Reading Accuracy might be resolved and remediated. Please include how a drop in the service factor would be identified as continuous and material and by whom, how it would be determined if it required remediation, who would develop the remediation plan, and who would pay for any remediation plans.

Response:

Through trending analysis, if the number of out-of-tolerance transactions increased significantly over time, FEI would raise the issue with the meter reading service provider and require that action be taken to resolve the service performance issue.

Any service issues that were the responsibility of the service provider would be addressed through the performance standards in the agreement we have in place. There are also legal provisions of the agreement which would compel the provider to perform the services in a professional manner and the provider would be required to develop a remediation plan to resolve the accuracy issue at their expense.

52.3.1 Would FEI have adjustments to the financial achievements acquired under the PBR in during the period in which the meter reading accuracy did not meet the SQI threshold?

Response:

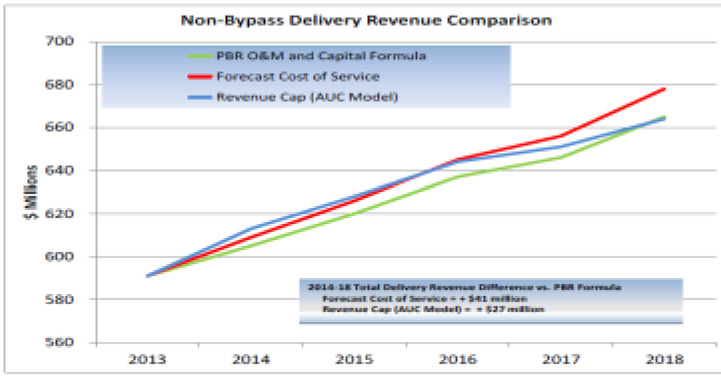
No. FEI is not contemplating adjustments to the financial elements of the PBR Plan as the result of the performance of one (or more) SQIs (i.e. meter reading accuracy) not meeting the established benchmarks.

Please also refer to the response to COPE IR 1.7.8.

If it is determined there is a sustained serious degradation of the SQIs, a triggering of the off-ramp provision may be warranted but would still not result in an adjustment to the financial achievements achieved.

53. Reference: Exhibit B-1, Page 82

Figure B-5: Non-Bypass Delivery Margin Comparison



53.1 Please provide an analysis of the Commission decisions with respect to the Company's previously filled Revenue Requirement Applications and specifically identify whether the Commission approved the Company's proposed expenditures for operating and capital expenses as proposed by the Company or whether the Commission ordered reductions from the levels proposed by the Company.

<u>Response:</u>

FEI has recently filed Revenue Requirement Applications (RRAs) for 2010-2011 and for 2012-2013. Prior to that (2004 to 2009), FEI operated under PBR.

FEI's 2010-2011 RRA was determined through a negotiated settlement, including an O&M reduction of $3.1 million in 2010 and $4.5 million in 2011 (before overheads capitalized) and a capital reduction of $3 million in each of 2010 and 2011 (not including adjustments for the CPCN threshold).

While the O&M reductions result in direct reductions to the FEI revenue requirements in those respective years, the capital reductions served to reduce the total FEI revenue requirement by approximately $100 thousand in 2010 and by approximately $300 thousand in 2011.

In the 2012-2013 RRA, the Commission ordered reductions of approximately $3.2 million in 2012 and $5.2 million in 2013 related to the FEU's operating expenses (before overheads capitalized), of which FEI's portion was close to 100%, directly reducing the FEI revenue requirements in those respective years.

In regards to FEI capital reductions from the 2012-2013 RRA, $2.9 million of net plant in service was disallowed for the Olympic Cauldron and a further $400 thousand was disallowed for a mobile refueling station. However, factoring in one-time tax impacts in 2012, the total revenue requirement impact was negligible for that year. In 2013, these capital reductions served to reduce the total FEI revenue requirement by approximately $400 thousand.

53.2 Please identify the percentage reduction adjustment ordered by the Commission in each case.

Response:

For the FEI 2010-2011 Revenue Requirement operating expense reductions discussed in the response to CEC IR 1.53.1, the average of the two years gross O&M reductions was approximately $3.8 million. The average gross approved O&M for FEI in 2010-2011 was approximately $211 million, meaning the FEI gross O&M request was reduced an average of about 1.8 percent due to the NSP. However, the graph above shows the total delivery revenue request and not the total O&M request. The average total approved delivery revenue for FEI in 2010-2011 was $547 million, meaning only approximately 0.7 percent of the non-bypass delivery revenue was related to the gross O&M reduction.

For the FEI 2010-2011 Revenue Requirement capital reduction discussed in the response to CEC IR 1.53.1, the average of the two years reduction to FEI revenue requirements is approximately $200 thousand. Based on the same average delivery revenue of $547 million calculated above, this would equate to a 0.04 percent reduction of the non-bypass delivery revenues.

Using the same logic and calculations for the FEI 2012-2013 Revenue Requirement operating expense reductions discussed in the response to CEC IR 1.53.1, the average of the two years gross O&M reductions were approximately $4.2 million. The average gross O&M for FEI in 2012-2013 was approximately $231 million, meaning approximately 1.8 percent of the FEI gross O&M request was disallowed. To re-iterate however, the graph above shows the total delivery revenue request and not the total O&M request. The average total delivery revenue for FEI in 2012-2013 was approximately $598 million, meaning only approximately 0.7 percent of the non-bypass delivery revenue was reduced by gross O&M disallowed.

For the FEI 2012-2013 Revenue Requirement capital reductions discussed in the response to CEC IR 1.53.1, the average of the two years reductions to FEI revenue requirements is approximately $200 thousand. Based on the same average delivery revenue of $598 million calculated above for 2012-2013, this would equate to a 0.03 percent reduction of the non-bypass delivery revenues.

53.3 Please prepare a version of the graph in B-5 with a line adjusted every two years by the average % reduction approved by the Commission in their decisions on the Revenue Requirement Applications.

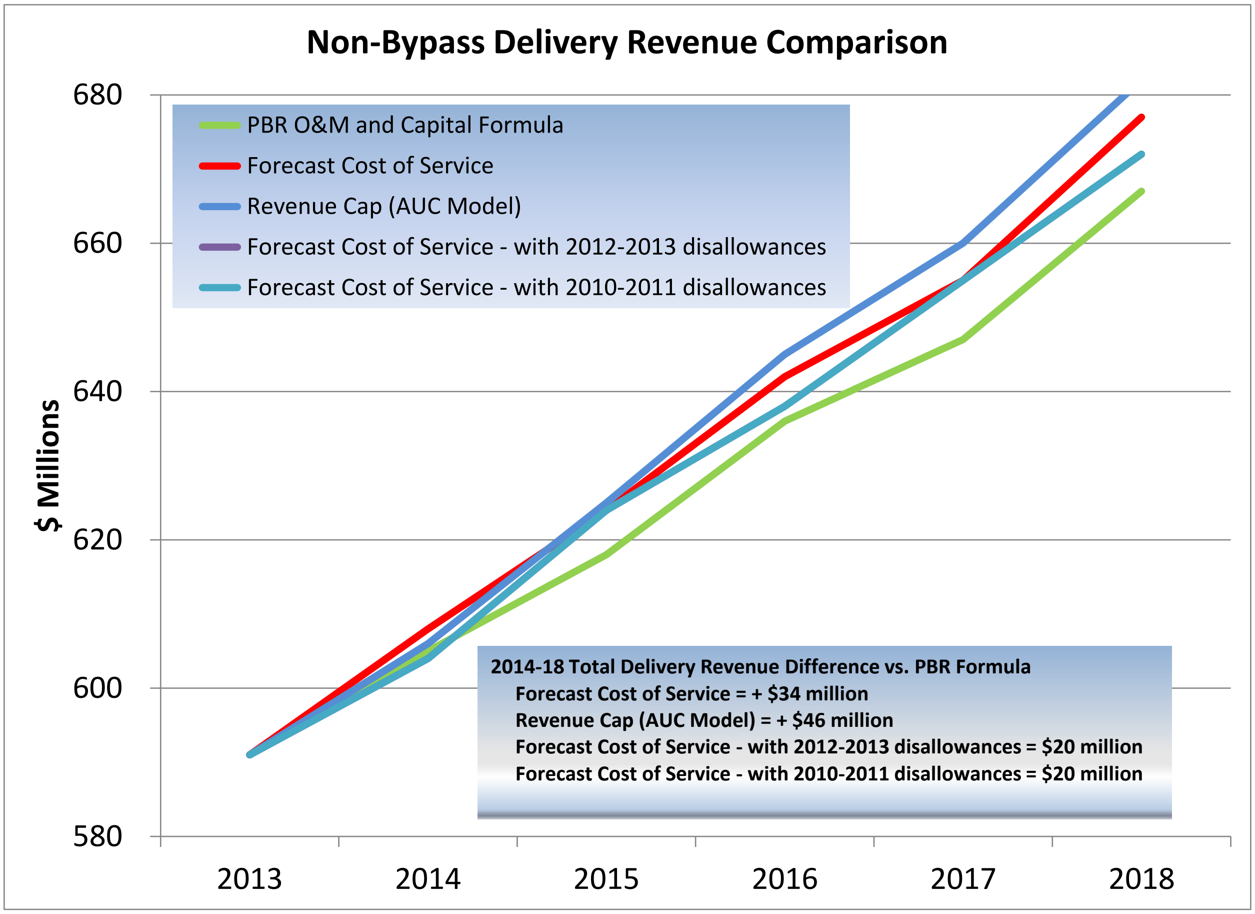
Response:

FEI disagrees with the implicit assumption that the appropriate comparison is to take FEI's high-level forecast cost of service provided in the Application reduced by an assumed percentage disallowance. FEI's forecast included in the Application is a reasonable high-level forecast, assumes productivity improvements and, more importantly, cannot reasonably forecast cost pressures over a five year period. The O&M and capital included in the delivery rates under FEI's proposal are calculated using the 2012-2013 Approved amounts as a starting point, which already include the % reductions described in CEC IR 1.53.2 as well as additional productivity reductions in the case of O&M.

Nonetheless, FEI has provided the requested graph to be responsive to the question.

FEI has provided an updated graph which shows the "Forecast Cost of Service" line adjusted in 2014, 2016 and 2018 to show the 0.73 percent total delivery revenue reduction related to both O&M and capital disallowances calculated in response to CEC IR 1.53.2 for 2012-2013, and an additional line to show the 0.74 percent total delivery revenue reduction related to both O&M and capital disallowances calculated in response to CEC IR 1.53.2 for 2010-2011. Since the two lines overlap, only one is visible.

The "PBR O&M and Capital Formula" and "Forecast Cost of Service" lines represent the amount embedded in the July 16, 2013 Evidentiary Update. The "Revenue Cap (AUC Model)" has been updated to reflect the amounts provided in response to BCUC IR 1.29.1.



Non-Bypass Delivery Revenue Comparison
680
660
640
620
600
580
$ Millions
PBR O&M and Capital Formula
Forecast Cost of Service
Revenue Cap (AUC Model)
Forecast Cost of Service - with 2012-2013 disallowances
Forecast Cost of Service - with 2010-2011 disallowances
2014-18 Total Delivery Revenue Difference vs. PBR Formula
Forecast Cost of Service = + $34 million
Revenue Cap (AUC Model) = + $46 million
Forecast Cost of Service - with 2012-2013 disallowances = $20 million
Forecast Cost of Service - with 2010-2011 disallowances = $20 million
2013
2014
2015
2016
2017
2018

54. Reference: Exhibit B-1, Page 88

> The slight increase in total throughput has a positive impact in reducing delivery rates, all else equal, for 2014 through 2018.

54.1 Please confirm that the reason there is a positive impact is because the system has costs that are fixed relative to the factors that can result in increased throughput.

<u>Response:</u>

Confirmed.

55. Reference: Exhibit B-1, Page 88

Table C1-2: Net Customer Additions

	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential	4,822	6,824	4,994	4,475	4,316	4,594	4,955	5,085	4,972	4,806
Commercial	299	141	417	272	315	388	373	358	372	367
Industrial & Transportation	-31	-96	-67	-4	0	0	0	0	0	0
Total Net Additions	**5,090**	**6,869**	**5,344**	**4,743**	**4,631**	**4,982**	**5,328**	**5,443**	**5,344**	**5,173**

55.1 Please explain why if the industrial category has seen reductions in numbers of customers for the last four years that this would not be expected to continue into the 2014 to 2018 period.

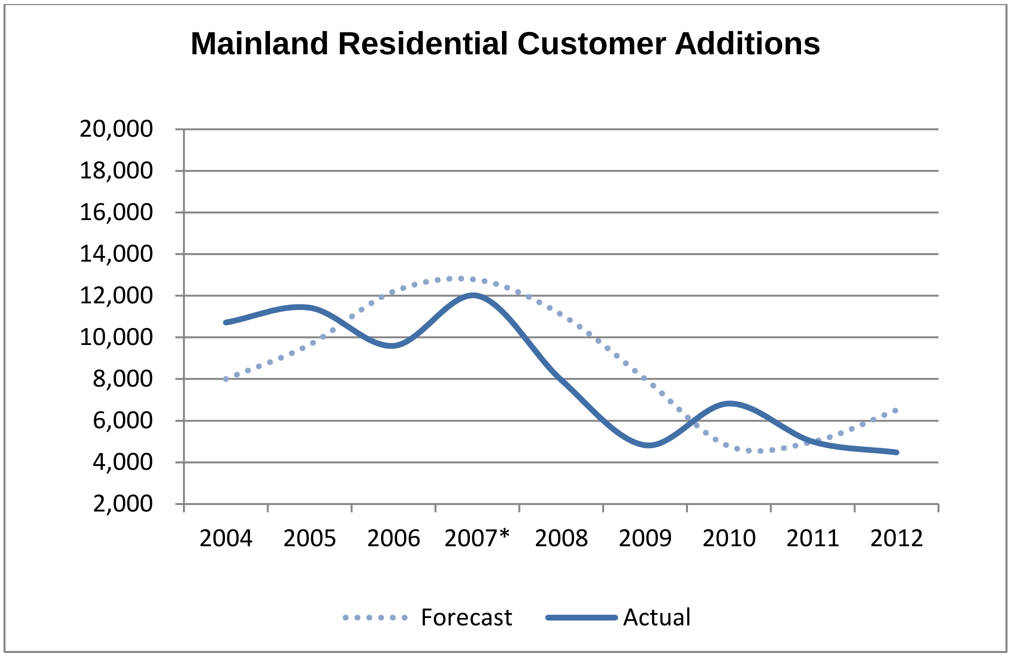
Response:

Unlike the residential and commercial forecasts, the industrial forecast is not the product of average UPC and accounts so the actual net industrial additions (whether positive or negative) are not material to the forecast. The fact that no net additions or reductions are shown in the forecast is a reflection of the survey methodology. Each current customer is surveyed and is expected to remain a customer for the duration of the forecast.

55.2 Please describe what happens to customer additions when the BC economy becomes enmeshed in a recessionary period and provide the quantitative and graphic history for this related to the previous recession experiences.

Response:

The recent recession experienced in 2008-2009 resulted in lower than expected customer additions in both 2008 and 2009 followed by a modest recovery in 2010. Customer additions continue to be very modest in 2012, at approximately 50% of the pre-recession level.



55.3 Please describe what will happen with the PBR mechanism if there is a recession in the 2014 to 2018 period and a similar impact to past experience is felt with respect to customer additions, including how the PBR forecast will change dynamically or not as the case may be.

Response:

With respect to customer additions, the PBR mechanism will not be affected if there is a recession in the 2014 to 2018 period. The demand forecast (based on updated customer addition forecasts) for all rate groups will be recalculated annually at the annual review, with prior forecasts adjusted to reflect actual experience so any changes such as a future recession will be picked up in a timely manner. Both the accounts and UPC forecasts are based on the actuals experienced in the previous year so both positive and negative changes to the economy are captured quickly.

56. Reference: Exhibit B-1, Page 93

> From the figure above we can see that there is a clear and consistent downward trend in use per customer irrespective of annual weather. The exception is in 2012 when the conversion to the new CIS had the impact of increasing the reported UPC. In rate schedules where a consistent trend is not identifiable a three year average is used.

56.1 Please provide the Percentage shift in UPC caused by the new CIS in 2012.

Response:

The normalized UPC without the CIS adjustment for the Lower Mainland (as per Exhibit B-1, Page 93) would have been 97.4 in 2012 which is approximately 1% less than 2012 normalized actual of 98.6 GJ after the adjustment.

56.2 Would it be fair to say that the percentage shift cause by the new CIS affected the whole year in 2012 and therefore would be a proxy for adjusting prior data to make it consistent with the current methodology for counting customers?

Response:

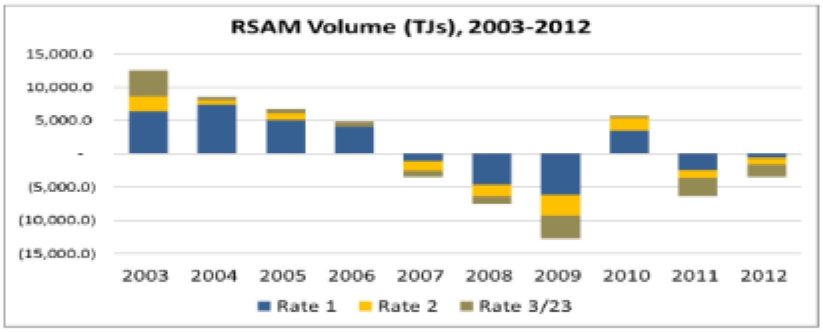
No. If a percentage were added to historical UPC values then customer totals would also need to be adjusted, which would then not correlate to the true recorded actuals.

Rather than make multiple changes to actual historical data, FEI maintained actual measurable data without any requirement for restating historical data.

Furthermore, as this onetime adjustment increased UPC artificially in 2012, trending analysis only included data prior to 2012 to prevent the 2012 UPC from adversely affecting the true trend in UPC.

57. Reference: Exhibit B-1, Page 99

Figure C1-10: RSAM Volumes Since 2003



57.1 Please describe how the rate rider for the RSAM works and specifically address the period of time over which the variances are recovered from RSAM customers.

<u>Response:</u>

The rate rider for the RSAM currently recovers the forecasted ending RSAM balance for the current year over the following three years. Specifically, the ending balance of the RSAM and RSAM interest account are forecasted for the current year. The calculation then takes one-third of this balance and grosses the amount up for tax purposes, considering the amount is recovered through a rate rider and the recovery will be net-of-taxed. The pre-tax amount that has been calculated is then divided by the forecasted Rate 1, 2, 3 and 23 volumes for the following year to arrive at an amount per GJ that must be recovered from or returned to customers.

In this Application, FEI has included the request to change the RSAM recovery period to two years beginning in 2014. This request can be found in the Application Section D4.2.2. Additionally, for a numerical example of the 2014 RSAM rider calculation, please see Section E, Schedule 63 of the Application.

58. Reference: Exhibit B-1, Page 111 and Page 114

Table C1-6: Forecast Sales Revenue for NGT at Existing Rates[41]

Revenue ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16	10.8	14.8	18.8	22.7	23.3
Rate 25	0.3	0.4	0.4	0.5	0.5
Total	11.1	15.2	19.3	23.2	23.8

Table C1-9: Forecast Gross Margin for NGT at Existing Rates[45]

Margin ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16	5.5	7.3	9.0	10.5	10.5
Rate 25	0.3	0.4	0.4	0.5	0.5
Total	5.8	7.7	9.4	11.0	11.0

58.1 Please provide a description of what the impact on customer rates could be if the Company and the government could increase the use of NGT by double the current projected levels.

Response:

For reference, the two tables provided in the IR response were revised in FEI's Evidentiary Update, dated July 16, 2013, marked as Exhibit B-1-3. However, this response uses the tables provided above as the reference points.

Doubling the projected levels of NGT sales would nearly double the gross margin collected through those gas sales. For rate schedule 16, FEI has estimated that the additional throughput attracts $0.94 per GJ in incremental costs, therefore the net margin collected for each GJ sold would be $3.18[11]. For simplicity, FEI has assumed no incremental costs for rate schedules 25. At a high level, each dollar FEI collects from an NGT Customer is a dollar that FEI would not have to collect from non-bypass customers. The table below shows the approximate annual and cumulative rate impact if FEI were able to double NGT related volumes for the term of the PBR.

[11] $3.18 = $4.12 – $0.94, where $4.12 was the Approved Rate Schedule 16 Delivery Rate at the time of filing FEI's Application on June 10 2012, and $0.94 is FEI's average incremental costs to produce 1 GJ of LNG at Tilbury derived from FEI's "Application for Approval to Amend Rate Schedule 16 on a Permanent Basis" filed with the BCUC on September 12, 2012.

Line	Particulars	Reference	2014	2015	2016	2017	2018	Total
1	Rate 25 Volume supporting Table C1-9 (GJ)	Appendix H, Table H-13	400,103	483,734	558,869	633,015	633,015	2,708,735
2	Rate 16 Volume supporting Table C1-9 (GJ)	Appendix H, Table H-14	1,341,319	1,778,349	2,187,326	2,555,744	2,555,744	10,418,481
3								
4	***Assuming FEI doubles NGT related volumes***							
5	Rate 25 Volume incremental to Table C1-9 (GJ)	Line 1	400,103	483,734	558,869	633,015	633,015	2,708,735
6	Rate 25 Delivery Rate ($/GJ)	Pre G-75-13, Approved Rate	0.731	0.731	0.731	0.731	0.731	
7	Rate 25 Incremental Margin ($000)	Line 5 x Line 6 / 1,000	292	354	409	463	463	1,980
8								
9	Rate 16 Volume incremental to Table C1-9 (GJ)	Line 2	1,341,319	1,778,349	2,187,326	2,555,744	2,555,744	10,418,481
10	Rate 16 Delivery Rate ($/GJ)	Pre G-75-13, Approved Rate	4.12	4.12	4.12	4.12	4.12	
11	Rate 16 Incremental Costs		0.94	0.94	0.94	0.94	0.94	
12	Rate 16 Incremental Margin ($000)	Line 9 x (Line 10 - Line 11) / 1,000	4,265	5,655	6,956	8,127	8,127	33,131
13								
14	Total Incremental Margin ($000)	Line 7 + Line 12	4,558	6,009	7,364	8,590	8,590	35,111
15	Gross Margin at Existing Rates ($000)	Section E and Appendix G1	609,962	632,386	637,227	641,945	645,067	
16	Incremental Rate Decrease from doubling NGT Volumes	Line 14 / Line 15	0.7%	1.0%	1.2%	1.3%	1.3%	5.5%
17								
18	Note: 5.5% represents the cumulative rate decrease over the term of the PBR if FEI were able to double NGT related volumes							

58.2 Please provide a description of what would be required to do achieve increased use moving to double the 2018 projected level.

Response:

To achieve large increases in delivery margin, the greatest opportunity for growth exists in Rate Schedule 16 volumes. New customers may include trucking, marine and other offroad applications. To realistically achieve double the 2018 forecast levels, FEI would first require the approvals as sought in FEI's Application for Amendments to Rate Schedule 16, rather than the approvals granted in BCUC Order G-88-13. FEI believes there are significant impediments to LNG adoption that result from Order G-88-13 including a delivery charge of $6.50/GJ. If adoption occurs at a higher pace, FEI will also require new sources of LNG supply incremental to the liquefaction capacity available from the Tilbury and Mt. Hayes facilities.

Market growth from the CNG trucking sector (Rate Schedule 6P and Rate Schedule 25) could increase marginally but not to the same degree as LNG due to a lower consumption per unit demand profile.

58.3 Please confirm the net contribution to customers from the NGT service under the current rate 16 are as shown in C1-9 and provide the margins that would have occurred under the rate 16 proposal for which the Company applied for approval.

Response:

Not confirmed. Please refer to the response to BCSEA IR 1.20.2.

59. Reference: Exhibit B-1, Page 117

Table C2-1: 2013 and 2014 Other Revenue Components

Other Operating Revenue, ($ thousands)	Approved 2013	Projected 2013	Forecast 2014
Late Payment Charge	$ 2,333	$ 2,134	$ 2,114
Connection Charge	2,685	2,622	2,636
NSF Returned Cheque Charges	79	79	79
Other Recoveries	126	284	284
FEVI Wheeling Charge	3,464	3,464	3,365
SCP Third Party Revenue	14,827	14,773	14,773
NGT Overhead and Marketing Recovery	-	-	490
Burnaby & Surrey Operations Pump Charges	-	(55)	(55)
Biomethane Other Revenue	(29)	(97)	(70)
CNG & LNG Service Revenues	1,304	-	-
Total Other Operating Revenue	**$ 24,789**	**$ 23,204**	**$ 23,616**

59.1 Please provide a description of what FEI is doing and could be doing to increase the contribution from these other revenue sources.

Response:

Many of the 2013 and 2014 Other Revenue Components listed in Table C2-1 are recoveries to offset business costs / charges associated with each item (i.e. Late Payment Charge, Connection Charge, and NSF Returned Cheque Charges). These Other Revenue Components primarily go toward recovery of the processing, servicing and/or implementation costs of these items. For a positive balance of recoveries versus cost, FEI reviews processes and procedures associated with these items on a regular basis to ensure guidelines for appropriate application and collection of these Other Revenue Components.

Some of the Other Revenue Components such as the FEVI Wheeling Charge and the SCP Third Party Revenue are revenue sources that FEI receives for the contracting of wheeling capacity services across the FEI transmission pipeline systems.

The SCP Third Party Revenues, as described within the Application, consist of the revenues from the firm service capacity held by three parties. The forecast comprises the Northwest Natural Gas Co. (NWN) contract that is in effect until October 2020, the firm service capacity held by the FEI MCRA that the Company is seeking to continue for the duration of the PBR period, and the Spectra firm service capacity associated with the T-South Enhanced Service that is anticipated to be extended throughout the PBR period (please also refer to the response to BCUC IR 1.72.1).

The FEVI Wheeling Charge is an intercompany agreement for the capacity that FEVI has contracted from FEI to wheel gas across the FEI coastal transmission system from Huntingdon to the start of the FEVI system at the V1 compressor station at Eagle Mountain. Increases in

FEVI Wheeling Charge revenue would come from customer growth opportunities that FEVI is undertaking on their system and FEVI's need to expand their capacity requirements under the Wheeling Agreement in place between FEI and FEVI.

59.2 Please provide a description of any other potential revenue sources that FEI might be able to pursue for the benefit of its customers.

<u>Response:</u>

While the Company remains committed to pursuing other sources of revenue for the benefit of customers, at this time, the Company is not able provide any new opportunities for other revenues.

60. Reference: Exhibit B-1, Page 123

Table C3-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Operations	54,444	55,756	59,806	58,599	63,509	63,189
Customer Service [1]	53,278	56,575	40,737	49,115	41,825	52,452
Energy Solutions & External Relations	14,636	15,456	18,075	17,509	19,215	18,181
Energy Supply & Resource Dev	2,075	3,409	3,488	3,664	4,000	3,738
Information Technology	17,320	18,654	23,442	24,553	24,217	25,379
Engineering Services & PM	13,566	14,329	13,599	16,705	15,456	16,956
Operations Support	10,916	10,580	11,038	12,132	11,867	12,990
Facilities	7,329	6,835	9,563	9,509	9,249	9,259
Environment Health & Safety	2,427	2,445	2,481	2,749	2,681	2,999
Finance & Regulatory Services	12,177	12,064	12,149	13,129	13,279	14,184
Human Resources	8,823	8,170	8,610	8,983	8,458	8,511
Governance	7,368	7,895	7,366	7,602	7,935	7,935
Corporate	2,158	1,439	1,915	2,743	(358)	230
	206,518	213,606	212,269	226,993	221,333	236,003

1 Excludes deferred Customer Service O&M for 2012 Actual and 2013 Projection

60.1 Please describe for each department that increased cost above the average for the Company from 2010 to 2013 what significant values were added for customers, if any.

Response:

As stated in the response to other IRs, the appropriate basis of comparison for the 2013 Projected O&M is the 2013 Approved O&M. The 2013 Approved O&M was subject to a full hearing and the costs that were included in that figure are at an appropriate level to compare the 2013 Projections (and 2013 Base) that form the basis for the 2014 delivery rates. The 2010 Actual O&M reflects a different set of accounting classifications between O&M and capital, and a different set of circumstances than 2013, including some organizational changes that FEI was not able to restate to be fully comparable.

While FEI does not believe the information requested is helpful, FEI has provided it to be responsive to the question.

The average increase in costs from 2010 to 2013 is approximately 7% as shown below.

Average Increase in Costs from 2010 to 2013

	2010 Actual	2013 Projection	% Change
Operations	54,444	63,509	17%
Customer Service [1]	53,278	41,825	-21%
Energy Solutions & External Relations	14,636	19,215	31%
Energy Supply & Resource Dev	2,075	4,000	93%
Information Technology	17,320	24,217	40%
Engineering Services & PM	13,566	15,456	14%
Operations Support	10,916	11,867	9%
Facilities	7,329	9,249	26%
Environment Health & Safety	2,427	2,681	10%
Finance & Regulatory Services	12,177	13,279	9%
Human Resources	8,823	8,458	-4%
Governance	7,368	7,935	8%
Corporate	2,158	(358)	-117%
	206,518	221,333	7%

1 Excludes deferred Customer Service O&M for 2012 Actual and 2013 Projection

For Operations Support, Environment Health & Safety, Finance & Regulatory Services, and Governance, the increase in costs is attributed to normal inflation.

Above average increases within the Operations group (Distribution, Transmission and Plant Operations) were approved within prior Revenue Requirement applications and include:

- labour and benefit inflation, changing codes and regulations (i.e. right of way signage, security, competency assessments), responding to the demographic challenge within the workforce (i.e. peer training, succession planning, new manager development);
- enhancing service standards (i.e. enhancements to the estimating process, improving planner response time to homeowners, developers and municipalities) expansion of bridge crossing repairs and valve inspection programs, response to increased gas odour calls
- enhancing system sustainment and reliability (i.e. development of long term plans regarding replacement of assets)

The increase in costs for Energy Solutions & External Relations is discussed in response to BCUC IR 1.111.2.

The increase in costs for Energy Supply & Resource Development is discussed in Section C3.7 of the Application. Due to some organizational changes in 2011, the 2010 Actual O&M shown for Energy Supply & Resource Development is not comparable with the 2013 projected O&M. The 2010 to 2013 incremental O&M, excluding inflationary increases, shown for Energy Supply & Resource Development in the above table is primarily the result of inter-departmental O&M budget transfers that occurred in 2011, and which were discussed in the FEU 2012-2013 RRA. The restated O&M for Energy Supply & Resource Development would be approximately $1.2 million higher and the restated O&M for Operations would be approximately $1.2 million lower.

The increase in IT costs from 2010 to 2012 is mainly due to the CCE project. The additional IT operating costs were identified in the CPCN along with the overall benefits of the project.

Above average increases within the Engineering Services and Project Management are discussed in response to BCUC IR 1.135.4 and approved within prior RRAs. These costs were incurred for the maintenance and continuous improvement of engineering and other practices to:

- Meet changing regulatory requirements (i.e. Oil and Gas Activities Act and Gas Safety Regulation) and industry standards (i.e. Canadian Standards Association Z662) for natural gas pipeline and distribution system operators in the province of British Columbia.
- Enhance asset management practices including establishment and maintenance of the Long Term Sustainment Plan to ensure that assets continue to meet customer needs and are not replaced unnecessarily.

Facilities increases are above the average for the Company primarily due to the addition of the 78,000 square foot of office space for two new contact centres. The increased funding supports the costs for the lease and operating and maintenance of the two facilities.

61. Reference: Exhibit B-1, Page 133

Table C3-5: Departmental O&M Forecasts ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	69,016	71,062	73,298	75,084	77,253	79,648
Customer Service	44,398	45,353	46,323	47,873	49,068	50,956
Energy Solutions & External Relations	20,721	23,275	23,771	24,343	24,961	25,721
Energy Supply & Resource Dev	4,440	4,738	4,918	5,040	5,175	5,350
Information Technology	23,768	24,392	24,911	25,487	26,097	26,809
Engineering Services & PM	17,018	17,736	17,766	18,214	18,692	19,325
Operations Support	13,111	13,698	14,013	14,386	14,794	15,313
Facilities	9,504	9,959	10,170	10,469	10,705	11,065
Environment Health & Safety	2,872	2,934	2,997	3,069	3,147	3,242
Finance & Regulatory Services	15,079	15,401	15,728	16,101	16,502	16,987
Human Resources	9,192	9,399	9,601	9,841	10,102	10,431
Governance	8,028	8,371	8,742	9,135	9,544	9,974
Corporate	(6,161)	(6,385)	(6,478)	(6,600)	(6,726)	(6,914)
	230,985	239,933	245,761	252,443	259,315	267,907

61.1 Is there nothing strategic that can be achieved over the 2014 to 2018 period that would cause the kinds of cost structure impacts seen during the period 2009 to 2013?

Response

FEI is not clear on what kind of cost structure impacts CEC is referring to.

Over the period of 2009 through 2013, O&M cost increases averaged 3.7% per year. In comparison, from 2013 to 2018 under the PBR formula that will be used to set rates (refer to Table B6-5 in Exhibit B-1), the average increase is 2% per year.

Under the proposed PBR Plan, O&M annual percentage increases will in fact be lower than the 2009 – 2013 period for rate setting purposes. This provides evidence of FEI's plan to control costs for the benefit of customers.

62. Reference: Exhibit B-1, Page 151

Table C3-15: FEI Customer Service O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 2,085	$ 2,457	$ 18,198	$ 19,453	$ 19,577
Non-Labour	51,193	54,118	22,539	22,372	32,875
Total O&M	$ 53,278	$ 56,575	$ 40,737	$ 41,825	$ 52,452
Deferral-Labour			1,959		
Deferral-Non Labour			5,476	10,285	
Total Deferral			$ 7,435	$ 10,285	
Total O&M with Deferral	**$ 53,278**	**$ 56,575**	**$ 48,172**	**$ 52,110**	**$ 52,452**

62.1 Please describe the deferral labour and non-labour as it relates to customer service O&M.

Response:

The 2013 projected deferral amount of $10.285 million is described on page 151 of the Application.

Customer Service realized $7.4 million in O&M savings in 2012, which are deferred in the Customer Service Variance Deferral Account. For the 2012 actual deferral of $7.435 million, the labour portion amounts to $1.959 million and the non-labour portion amounts to $5.476 million.

As stated in the response to BCUC IR 1.96.3, these cost savings are as follows:

- $1.0 million – customer assistance
- $2.7 million – customer billing
- $3.7 million – meter reading

Cost savings for contact center and customer assistance were achieved due to being able to reduce temporary staff levels more quickly as staff became more proficient in handling customer inquiries. Cost savings from customer billing were mainly from lower print and mailing costs and temporary staffing was reduced faster than anticipated. Cost savings from meter reading in 2012 were possible due to the extension of shared meter reading costs between electric and gas meters resulting from delays of BC Hydro's smart meter program.

63. Reference: Exhibit B-1, Page 169

Table C3-21: Historical O&M for the IT Department ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 6,252	$ 7,096	$ 7,417	$ 7,704	$ 9,660
Non-Labour	11,069	11,559	16,025	16,513	15,719
Total O&M	$ 17,320	$ 18,654	$ 23,442	$ 24,217	$ 25,379

63.1 Please explain the increase in non-labour expense for the IT department and explain what benefits are expected to be achieved in the Company related to this increase.

Response:

Besides the normal inflation for ongoing support and maintenance costs, the increase in non-labour expense is primarily due to the software licensing and support costs for the technologies associated with the Customer Care Enhancement project. The benefits of this project were identified in the CPCN.

64. Reference: Exhibit B-1, Page 175

Table C3-24: Engineering Services and Project Management O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 12,769	$ 13,407	$ 13,696	$ 14,058	$ 14,449	$ 14,993
Non-Labour	4,249	4,329	4,070	4,156	4,243	4,332
Total O&M	$ 17,018	$ 17,736	$ 17,766	$ 18,214	$ 18,692	$ 19,325

64.1 Please explain why the non-labour expense is expected to be relatively flat through the period 2014 to 2018.

Response:

As stated on page 175 of Exhibit B-1, with respect to non-labour costs this business area is forecasting minor cost reductions resulting from the scheduled completion of the standardized locks and security devices upgrade described in the 2012-2013 RRA. Beyond this, non-labour cost pressures are expected to be offset by efficiency gains. This is further described on pages 175 through 177 of the Application.

65. Reference: Exhibit B-1, Page 180

Table C3-26: Operations Support O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 10,281	$ 10,690	$ 10,915	$ 11,199	$ 11,514	$ 11,939
Non-Labour	2,830	3,009	3,097	3,187	3,280	3,374
Total O&M	$ 13,111	$ 13,698	$ 14,013	$ 14,386	$ 14,794	$ 15,313

65.1 Please explain why the non-labour expense is expected to be relatively flat through the period 2014 to 2018.

Response:

Operations Support's O&M non-labour costs are driven by codes, regulations and system reliability requirements identified both internally and in support of maintenance activities of both the Operations department and Customer Service billing operations. As such, any change in regulatory requirements, industry standards or internal standards that significantly influences Operations Supports may have a direct impact on the funding required on non-labour costs.

The non-labour expenses are relatively flat from 2014-2018 since no changes in codes, regulations, and internal requirements have been identified at this time which would significantly impact Operations Support's non-labour costs beyond incremental network fees for AMR service to large commercial and industrial customers and inflationary pressures as identified on page 180 of the Application.

66. Reference: Exhibit B-1, Pages 182 and 183

Table C3-27: Facilities O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 1,510	$ 1,599	$ 1,532	$ 1,634	$ 1,649
Non-Labour	5,818	5,236	8,031	7,615	7,610
Total O&M	$ 7,329	$ 6,835	$ 9,563	$ 9,249	$ 9,259

Table C3-28: Facilities O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,848	$ 1,893	$ 1,934	$ 1,986	$ 2,043	$ 2,121
Non-Labour	7,656	8,067	8,236	8,484	8,662	8,944
Total O&M	$ 9,504	$ 9,959	$ 10,170	$ 10,469	$ 10,705	$ 11,065

66.1 The increase in non-labour costs in the period 2010 to 2013 was to provide for new contact centres and the level of expenditure in maintained and increase. Please explain whether or not the two new centres are leased and these are the ongoing lease costs or whether there is some other explanation.

Response:

Of the two new contact centres, the Prince George Contact Centre is owned and the Willingdon Contact Centre is leased. The increases in non-labour costs in 2012 are primarily driven by the addition of these two facilities. The costs for these facilities include the lease cost of the Willingdon Contact Centre and other costs to support the operations and maintenance of the two facilities such as janitorial, landscaping, security, snow removal, Heating/Ventilation/Air Conditioning maintenance, heat, light, natural gas, stationary, courier and postage.

67. Reference: Exhibit B-1, Page 186

Table C3-29: EH&S O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Labour	$ 984	$ 1,327	$ 1,344	$ 1,366	$ 1,574
Non-Labour	1,443	1,118	1,137	1,314	1,425
Total O&M	$ 2,427	$ 2,445	$ 2,481	$ 2,681	$ 2,999

67.1 Please explain why the non-labour costs were relatively flat from 2010 to 2013.

Response:

Workplans for the EH&S department are comprised of several ongoing areas of focus that attract non-labour costs. Changing or new regulatory requirements often require evaluation by external consultants with unique subject matter expertise; the subsequent operational integration of any new requirements must be ensured. As the scope of work has increased, the EH&S group, with increased expertise due to the integration of the utility divisions, has been able to efficiently manage scope increases as required, resulting in non-labour costs being relatively flat from 2010 to 2013.

68. Reference: Exhibit B-1, Page 192

Table C3-32: Finance and Regulatory O&M Forecast

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 7,657	$ 7,839	$ 8,007	$ 8,218	$ 8,453	$ 8,769
Non-Labour	7,422	7,563	7,722	7,884	8,049	8,218
Total O&M	$ 15,079	$ 15,401	$ 15,728	$ 16,101	$ 16,502	$ 16,987

68.1 Please explain why the non-labour component is relatively flat for 2014 to 2018.

Response:

For the non-labour component, the Finance and Regulatory department is not forecasting any major pressures except for general inflation.

69. Reference: Exhibit B-1, Page 198

Table C3-35: Governance O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Legal Services	$ 2,039	$ 2,280	$ 1,917	$ 2,282	$ 2,282
Insurance	4,410	4,631	4,397	4,617	4,617
Risk Managemer	334	332	357	281	281
Internal Audit	586	653	695	755	755
Total O&M	$ 7,368	$ 7,895	$ 7,366	$ 7,935	$ 7,935

69.1 Please explain how the Governance costs have managed to be held relatively flat over the 2010 to 2013 timeframe.

Response:

The Governance Department has been able to use existing resources to meet the functions as described in Section C3.15.1 of the Application.

70. Reference: Exhibit B-1, Page 209

Figure C4-1: 10 Year History of Estimated vs. Actual Cost-Per-Mile for US Natural Gas Pipeline Projects

70.1 Please provide the FEI actual cost per kilometer versus estimated.

<u>Response:</u>

FEI is not able to provide data that is comparable to the one presented in Figure C4-1, page 209 for the US Natural Gas Pipeline due to the following reasons:

- FEI operates transmission pipelines of various diameters and in recent history has not undertaken this work in a significant amount.
- Most of the transmission pipeline work consists of pipeline replacements that have been of very short length.
- Other activities such as pipeline valve assemblies and upgrades, and station upgrades are generally non-routine and the scope and complexity varies from site to site.

71. Reference: Exhibit B-1, Page 211

Table C4-5: Forecast Sustainment Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
System Integrity and Reliability Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,224	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains and Service Renewals/Alterations	22,556	25,815	24,433	28,245	34,059	34,304
	78,065	78,449	79,045	77,198	80,578	82,340

71.1 Please provide the number of meters recalled and exchanged for each of the forecast periods.

Response:

Please refer to the following table. This information was extracted from Table C4-9 from page 218 of the Application, Exhibit B1, where further details may be found relating to meter exchange quantities and costs. The meter exchange forecast was developed to support continued compliance to Measurement Canada compliance sampling standard S-S-06.

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Meter Recall Activity	71,815	75,315	79,815	79,815	79,815

71.2 Please provide the number of kilometers of transmission system to be reinforced for each period and explain the nature of the reinforcement.

Response:

The category of "transmission system reinforcements" is very general and the total budget does not represent and cannot be converted to a number of kilometres. The category includes the following activities:

- Upgrades to transmission pipelines in the form of pipe replacements, valve replacements and upgrades, and installation of erosion and damage prevention measures.
- Purchase of additional land rights.

- Upgrades to compressor station buildings, equipment and sites.
- Upgrades to pressure and flow control station buildings, equipment and sites.
- Upgrades to the Tilbury LNG Plant buildings, equipment and site.
- In-line inspection of segments of the transmission system.
- Upgrades to the cathodic protection system for buried piping.
- Upgrades to the SCADA system used for monitoring and controlling the facilities.

71.3 Please provide the number of kilometers of distribution system reinforcement for each period.

Response:

The category of "distribution system reinforcements" is very general and the total budget does not represent and cannot be converted to a number of kilometres. The category includes the following activities:

- Pressure regulating or odorant injection station upgrades to address equipment of inadequate capacity or obsolescence.
- System capacity improvements in the form of additional intermediate or distribution pressure mains.
- Additions to or replacements of cathodic protection equipment.
- SCADA system improvements to provide additional monitoring capability.

72. Reference: Exhibit B-1, page 254

> - The $75 million issue is the refinancing of FEI's Series A Purchase Money Mortgage, shown in the long term debt schedules as net proceeds of $74.250 million after reduction for issuance costs.
> - The $200 million issue is the refinancing of FEI's Series B Purchase Money Mortgage, shown in the long term debt schedules, of which approximately $166 million is allocated as regulated debt.

72.1 Please confirm or otherwise explain that of the $200 million issue in the Series B Purchase Money Mortgage, there is $34 million that would be considered as unregulated debt.

Response:

Confirmed.

72.2 Please explain how unregulated debt differs from regulated debt and the manner in which the difference impacts FEI's financing costs.

Response:

FEI's regulated debt funds the 61.5% debt component of FEI's rate base and its annual interest expense forms part of FEI's Cost of Service. Unregulated debt does not fund rate base and so its interest cost and related tax shield is excluded from FEI's Cost of Service. FEI has $34 million of unregulated debt, which forms part of the Series B Purchase Money Mortgages (PMM's) as noted in the reference. The unregulated debt does not impact the financing costs of FEI's regulated debt.

73. Reference: Exhibit B-1, Pages 255 and 255

> FEI obtains short term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the commercial paper by maintaining a $500 million committed credit facility that currently matures August 2014. On May 30, 2013, FEI applied for approval from the Commission to extend the maturity date to August 2015[62]. The credit facility provides FEI with required liquidity should there be constraints issuing commercial paper used to fund working capital and/or issuing long-term debt used to fund capital spending.

> FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian

73.1 Please confirm that Order G-78-12 approved the extension of the maturity date to August 2014 but did not approve renewal without commission approval.

<u>Response:</u>

Confirmed. The maturity date of the existing credit facility has since been extended to August 2015 pursuant to Order G-92-13.

73.2 Please provide the implications for FEI's borrowing rate in the event that commission approval is not forthcoming on an annual basis as requested by FEI during the term of the PBR.

<u>Response:</u>

FEI requires the operating credit facility to support its short term borrowing requirements that fund both the company's working capital and capital expenditures. The short term credit facility is extended on terms that reflect market conditions at the time of extension. The annual extension is undertaken to ensure that there is typically greater than a minimum of 12 months of term prior to maturity, to avoid situations where a credit facility maturity would occur in a period of market disruption that could result in a loss of liquidity. Therefore, FEI is not clear under what circumstances the approval for extension of the credit facility would not be forthcoming from the Commission, as the short term facility is necessary.

In theory, if the extension was not provided, there could be a lack of liquidity for FEI. With respect to implications, there may be an adverse ratings impact, due to the potential lack of liquidity, which may increase overall borrowing costs on long term debt.

If FEI believed that there was a concern regarding the Commission not approving future annual extensions of FEI's existing credit facility over the PBR period then FEI would need to find an alternative to address its short-term liquidity needs. The most reasonable course of action would be to enter into a longer-term credit facility, approved by the Commission.

FEI did not consider a situation where no extension of facility was approved as it is illogical to consider a situation where FEI has no short term credit facility.

73.3 Would a change in FEI's borrowing rate impact the efficacy of the PBR program? Please explain.

Response:

No, FEI's borrowing rate reflects the rate then available in the market. The efficacy of the PBR plan incentives is not related to the changes in borrowing rates. The difference between forecasted and actual borrowing rates is captured under the Interest Variance deferral account.

74. Reference: Exhibit B-1, Page 265

> *Capitalization of Annual Software Costs*
>
> FEI is proposing to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. The costs capitalized reflect estimates of the portion of these costs that relate to the upgrade capability versus the support and maintenance components. The costs allocated to capital using this methodology are to fund only the upgrade component of the annual costs which extend the life of the affected software assets. Annual software costs in regards to support and maintenance continue to be an operating expense. The impact of this capitalization methodology is the reduction of FEI 2013 Base O&M by $1.8 million and an increase of capital within the Application Sustainment sub-Portfolio by the same amount.

74.1 Please confirm that under PBR, FEI would create earnings based on reducing (capital) costs of software upgrades relating to extending its service life. If not, please explain why not.

Response:

FEI pays annual software costs that are related to both upgrade capability and support and maintenance. Under its proposal, FEI would allocate the annual cost between the capital and the O&M portion based on the percentages described in response to BCUC IR 1.165.5. These percentages would remain fixed over the PBR Period.

The realistic scenarios under which annual software costs could decrease would be a decrease in the number of licenses (less employees or less CPUs) or a change to the methodology under which the vendor calculates the annual fees. These decreases would be reflected in a lower annual cost and the resulting savings would be allocated proportionately to capital and O&M in accordance with the percentage allocations described in response to BCUC IR 1.165.5. As FEI proposes to maintain the same allocations between capital and O&M over the PBR Period, FEI does not foresee any situation where only capital savings would be achieved.

Under the proposed PBR Plan, any capital or O&M spending reduction relative to the PBR formula would generate earnings benefits during the PBR term that would be shared through the earnings sharing mechanism with customers.

75. Reference: Exhibit B-1, Pages 265 and 266

> FEI completed an analysis on its current fleet of vehicles, with the review intended to ascertain whether FEI should continue to lease its vehicle fleet or transition to an owned fleet. FEI's analysis indicates that FEI should transition the vehicle fleet to an owned status as the current leased vehicles are retired. This option has the lowest present value cost of service (approximately $3 million over a 20 year analysis period), and therefore a lower rate impact to customers. To facilitate the transition, as existing leased units are retired; they will be replaced by units that are purchased.
>
> FEI notes that this decision to purchase vehicles does not change the regulatory treatment. Since the existing vehicle lease is treated as a capital lease for financial and regulatory purposes, the change only results in what was previously shown as a capital addition now being

> shown as a capital expenditure (an actual cash outlay) in the financial schedules. The vehicles that are being purchased are estimated to have an average 8 year service life, resulting in a depreciation rate of 12.5 percent for this asset class (484).

75.1 Please provide the schedule under which the fleet vehicles are expected to retire and provide the number of vehicles in each year until the transition to ownership is complete.

<u>Response:</u>

Many factors are taken into consideration when an actual vehicle replacement decision is made. Factors such as ability to maintain adequate safety, age, condition, and compliance with regulations are reviewed when vehicles are near the end of their life cycle. Each replacement decision is evaluated on a unit-by-unit basis.

FEI utilizes a five year replacement model to determine which vehicles will need to be retired and replaced and is therefore only able to provide the information for five years; however the full transition from a leased to owned fleet will take 10 years to complete. The table below lists the number of vehicles that are scheduled for replacement over the next five years.

Planned vehicle replacements 2014-2018

Category	2014F	2015F	2016F	2017F	2018F
Number of Vehicles	45	48	45	47	43

75.2 Is the depreciation rate for this asset class accrue in straight line or declining balance?

Response:

The depreciation rate for asset class (484) accrues in straight line over an 8 year service life.

75.3 Please provide the current lease rates and the anticipated purchase price of new vehicles until the transition is complete.

Response:

The current lease rate as of June 2013 is 3.23%.

FEI depends upon a variety of specialized vehicles to perform its operations safely and reliably. As such, although the average vehicle cost is calculated to be approximately $54,500, the actual purchase price will vary widely depending on the functionality of the vehicle being acquired and the market conditions at the time of purchase.

76. Reference: Exhibit B-1, Page 267

> Also in this PBR Period, FEI proposes to return to the method of calculating depreciation expense that was approved as part of the 2004-2007 PBR (extended for 2008 and 2009), whereby depreciation expense commences at the beginning of the year following when the asset is placed into service (as compared to the current practice of depreciation commencing at the time the asset is placed into service). This will allow FEI to discontinue the use of the Depreciation deferral account, as described further in Section D4.

76.1 Please confirm or otherwise explain that prior to the PBR of 2004-2007 and extended for 2008 and 2009 depreciation commenced at the time the asset was placed into service.

Response:

Prior to 2010, which includes the 2004-2009 PBR period and the prior periods before that, depreciation commenced at the start of the year after the asset was placed into service. In 2010 through 2013, depreciation commenced the month after the asset was available for service (which for FEI is the same as when the asset is placed into service).

76.2 Please provide the rationale under which the FEI sought and received approval for the revision under the 2004-2007 PBR.

Response:

FEI did not seek nor receive approval for any change in the timing for the commencement of depreciation in the 2004-2007 PBR period, as that was already the policy.

The approval from the BCUC for the change in the timing of the commencement of depreciation began January 1, 2010 as part of FEI's (then Terasen Gas Inc.) 2010-2011 RRA. The reason for the change to have the depreciation commence when the asset was available for service was to comply with International Financial Reporting Standards (IFRS) as the Company was anticipating adopting IFRS at the time of submitting the application in 2009. Subsequently, the Commission granted approval for FEI to adopt US GAAP which does not require the change in depreciation method; therefore, FEI is now requesting to adopt the pre-2010 depreciation method and to discontinue the use of the Depreciation Variance deferral account.

76.3 Please provide the orders under which the current practice of depreciation commencing at the time the asset is placed into service was resumed.

Response:

The Order approving the current practice of depreciation commencing at the time the asset is placed into service is BCUC Order G-141-09 dated November 26, 2009 approving the Negotiated Settlement Agreement for the FEI 2010-2011 RRA. The change to this method was to achieve compliance with IFRS requirements. FEI is now under US GAAP.

Appendix A, Page 16, Item 30 (e) of Order G-141-09 states "All capital expenditures, including CPCN's, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Applicant Page 515 and 516, Item 11)."

77. Reference: Exhibit B-1, Page 271

Table D3-2: Historical Net Asset Losses / (Gains) by Asset Class ($ thousands)

Particulars (1)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
INTANGIBLE PLANT										
461-00 Transmission Land Rights	-	-	-	-	-	-	(17)	(35)	-	-
402-01 Application Software - 12.5%	-	-	-	-	-	-	(3,160)	-	-	-
402-02 Application Software - 20%	-	-	-	-	-	-	101	-	-	-
	-	-	-	-	-	-	(3,076)	(35)	-	-

77.1 Please provide the specifics of item 402-01 and to what the Application Software gains of $3,160,000, that occurred in 2009 related to.

Response:

In 2009 the $3,160,000 represents the reclassification of the unrecognized accumulated gains of prior years from General Plant (Computer Software 483-20) to Intangible Plant (402-01 Application Software) as part of adopting a whole life depreciation method for IFRS compliance. In 2010 this amount was transferred to the IFRS transitional deferral account approved by BCUC Order G-141-09.

78. Reference: Exhibit B-1, Pages 287 and 288

As part of the 2010-2011 NSA for FEI, pursuant to BCUC Order G-141-09, Page 15 of Appendix A, the Parties agreed to a change in the overheads capitalized rate to 14 percent of O&M for 2010 and 2011 which reflected the approximate actual overheads capitalized rate for 2009.

In the 2012-2013 RRA the Company proposed that the overheads capitalization rate remain at 14 percent of O&M during the 2012 and 2013, which was accepted by the Commission, but with the following directive found at page 78 of the 2012-2013 RRA Decision (Appendix A, page 4, directive 29):

> *"The Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application."*

The 2013 Study provides two estimates of a reasonable overheads capitalized rate based on 2013 approved O&M. The 2013 Study provides details of the two estimating methods - a Survey based methodology and a Mathematical based methodology. The Survey based approach suggests a 12 percent rate while the Mathematical based approach yielded an 11 percent rate.

The Company is of the opinion that there has been no material change in utility operations since the 2012-2013 RRA that would require a change to the overheads capitalized rate. Therefore, the Company is proposing that the overheads capitalization rate remain at 14 percent of O&M.

Also, as illustrated in Table D3-9 the Company is expecting forecast net capital expenditures for the period 2014 – 2018 to remain at levels that are higher than in the 2010 – 2013 period. Based on this summary, FEI also concludes that there is no basis to recommend a change in the overhead capitalization rate during the PBR Period, as the regular capital spending level is expected to remain relatively constant, and therefore the percentage of O&M that supports capital is expected to remain relatively constant. In addition the rate has been shown to be reasonable based on the two estimating methods employed.

78.1 Would FEI agree that the 2012-2013 RRA on which it is relying as the foundation for stating no material change is expected was based on information reflecting actual capitalized overheads from 2009.

Response:

The Overhead Capitalization Methodology Review prepared for the FEI 2010-2011 RRA was based on 2009 budget figures, as the 2010-2011 budget figures were not yet available at the time.

Subsequently, as part of the FEU 2012-2013 RRA (page 267), the FEU provided an opinion that there had been no material change in utility operations since the FEI 2010-2011 RRA that necessitated a further review of the overheads capitalized rate.

78.2 Would FEI agree that the Commission's directive to provide an independent third parties' opinion for the next RRA was indicative of a desire to update information for future decision-making. If not, please explain why not and why the estimates from an independent third party should not be incorporated into the capitalization rate in this application.

Response:

The Commission's directive was to update the capitalized overhead methodology ***using relevant accounting standards*** (emphasis added) in the next test period, 2014. In the Company's opinion the directive was issued in part because the previous overheads capitalized study issued by KPMG in 2009 was reflective of IFRS guidelines, not US GAAP.

For the reasons discussed in Section D.3.7 of the Application, the 14% overheads capitalized rate remains appropriate and should continue.

78.3 Does FEI not consider an increase of 2-3% above the 11- 12% recommendations from the 2013 study from independent third parties as being significantly higher? If not, please explain why not and further explain what objections FEI would have to utilizing either 11 or 12% as suggested by the independent third party.

Response:

FEI considers a 2-3 percent decrease from the current capitalization rate to be significantly lower as it would increase customer rates by approximately 0.8 to 1.2 percent.

Please also refer to the response to CEC IR 1.78.2.

79. Reference: Exhibit B1-1 Appendix I, Section 5.1, Page 17

Table I-4: FEU EEC Expenditures - 2012 Actual, 2013 Approved and 2014-2018 Proposed[7]

	Actual Expenditures ($000s)	Approved Expenditures ($000s)	Requested Expenditures ($000s)				
Program Area	2012	2013	2014	2015	2016	2017	2018
Residential	11,295	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	603	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	4,865	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	358	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	394	1,502	1,207	1,218	1,233	1,218	1,210
CEO	2,200	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities	4045*	n/a	4,515	5,015	4,420	4,425	4,365
Totals	19,715	35,574	34,353	36,537	35,839	35,388	35,874

* The value for Enabling Activities for 2012 is in fact for Portfolio-level activity

79.1 Please confirm that the "Enabling Activities" in the Actual Expenditures are over and above the $19,715 indicated in Table I-4, creating a Total Spent of $23,760,000 for the year 2012.

Response:

Yes, the 2012 actual expenditure listed for "Enabling Activities" was mistakenly excluded from the total calculation in Table I-4. The total actual expenditures for the year 2012 were $23,760,000. Note that figures in Table I-4 are rounded to the nearest thousand. FEI will update this page in its next Evidentiary Update.

79.2 Please provide examples of the types of portfolio activities included "Enabling Activities" including an estimate of costs for each of the activities identified.

Response:

For 2012, Portfolio Level Activities were defined as those activities for which the costs cannot be assigned to an individual Program Area. Examples of these activities with associated costs are listed in the table below:

Portfolio Level Activities	2012 Actual Expenditures ($000s)
Labour	3,447
DSMS Program Tracking Tool	19
Staff Training & Conferences	105
Portfolio Pilots and Partnerships	179
Miscellaneous Portfolio Admin	294
Total	**4,044**

Note that the total listed in table above varies slightly from that listed in Table I-4 due to rounding.

For 2014 to 2018, a complete list of Enabling Activities with estimated costs and descriptions can be found in Exhibit B-1-1, Appendix I, Attachment I-1, Section 9, p. 103 – 105.

80. Reference: Exhibit B-2, page 2 (not numbered) and B1-1 Appendix I, Section 5.1, Page 17

Program Area	Approved Expenditures ($000s) 2012	2013	Requested Expenditures ($000s) 2014	2015	2016	2017	2018
Residential	9,261	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	4,969	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	8,759	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	1,072	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	1,546	1,502	1,207	1,218	1,233	1,218	1,210
CEO	3,470	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities**	n/a	n/a	4,515	5,015	4,420	4,425	4,365
Totals	29,077	35,574	34,353	36,537	35,839	35,388	35,874

** included in Residential in 2012-2013

Table I-4: FEU EEC Expenditures - 2012 Actual, 2013 Approved and 2014-2018 Proposed[7]

Program Area	Actual Expenditures ($000s) 2012	Approved Expenditures ($000s) 2013	Requested Expenditures ($000s) 2014	2015	2016	2017	2018
Residential	11,295	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	603	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	4,865	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	358	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	394	1,502	1,207	1,218	1,233	1,218	1,210
CEO	2,200	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities	4045*	n/a	4,515	5,015	4,420	4,425	4,365
Totals	19,715	35,574	34,353	36,537	35,839	35,388	35,874

* The value for Enabling Activities for 2012 is in fact for Portfolio-level activity

80.1 Please provide an estimate of the projected 2013 spending by program area.

Response:

The table below provides an estimate of the projected 2013 spending by program area along with the expected variance compared to the 2013 approved expenditures. Reasons for each program area variance are listed below the table.

Program Area	Total 2013 Forecast Expenditures ($000s)	2013 Approved Expenditures ($000s)	Variance ($000s)
Residential	11,204	10,623	581
Low Income	1,100	4,969	(3,869)
Commercial	6,940	12,708	(5,768)
Industrial	900	1,756	(856)
Innovative Technologies	1,092	1,502	(410)
Conservation Education & Outreach	2,200	4,016	(1,816)
Enabling Activities	4,500	n/a	4,500
Total	**27,936**	**35,574**	**(7,638)**

Residential

The Residential program area is forecast to go slightly over its approved expenditures in 2013 due primarily to the EnerChoice Fireplace Program and Furnace Replacement Program.

Initially, the FEU expected the EnerChoice qualified efficiency rating to go up by 2013 but have since learned that this will not be raised until 2014. Therefore, expenditures were underestimated on this program.

For the Furnace Replacement Program there has been a large uptake on the pre-qualification process which has been reflected in the forecast. It should be noted, however, that the actual customer uptake rate is not yet known.

Low Income

The forecast underspend in the Low Income area is due to the Energy Conservation Assistance Program (ECAP). The original 2013 expenditure forecast included furnaces in the ECAP program. However, furnaces are currently not being included; therefore not as many incentive dollars are being distributed in 2013 as originally envisioned. The intention is still to incorporate furnaces into the ECAP program. The main reason they have not been included yet is because both program partners (FEU and BC Hydro) reached the end of their business case timeline recently and therefore have spent some time and resources re-visioning the overall delivery of the ECAP program. This has delayed the inclusion of furnaces into the program.

Note also that FEU now has a better understanding of what the appropriate budget amount should be for the Low Income program area and has therefore revised its expenditure request accordingly in its EEC Plan 2014-2018.

Commercial

The Commercial program area variance is largely attributable to two specific programs: The Commercial Custom Design Program and the Continuous Optimization program.

FEU had intended to bring the Commercial Custom Design Program to market as early as 2011, however due a number of competing priorities, and at certain points staffing constraints, this was not possible. While the New Construction version of the program was successfully launched in January of 2012 as a joint initiative with BC Hydro, the Retrofit program was not available until mid 2013. Projects in this program typically have long leads times as they must first perform detailed energy studies, and subsequently implement customized energy conservation measures. As such only limited expenditures are expected in this program in 2013.

The FEU's Continuous Optimization Program, launched in 2012 as a joint initiative with BC Hydro, will spend less than originally expected in 2013 largely due to a change in the Long Run Marginal Cost of electricity. This change has adversely affected the program's TRC score, leading BC Hydro to curtail new participation in the program and thereby significantly reducing forecasted expenditures in 2013 and in the coming years.

Industrial

The main source of variance comes from the Technology Retrofit Program. The incentive payment structure for this program was changed to reduce the FEU's risks in each project as it originally paid each participant of the Technology Retrofit Program a single incentive payment once the project was commissioned. The FEU decided instead to pay out incentives in four installments based on the performance of each energy efficiency upgrade and link payments to actual savings measured each year for the first three years. Therefore, the incentive paid out to the Technology Retrofit Program's participants in 2013 will be lower than what was originally forecast. In addition, the FEU have also managed to reduce the Technology Retrofit Program's administration and evaluation costs while maintaining the planned level of customer service, and evaluation, measurement and verification.

Innovative Technologies

The Innovative Technologies program area variance is primarily due to the process in this program area of 'filtering out' technologies that may pose a high risk or be deemed unfeasible. Also some pilot programs have encountered unforeseen challenges which has caused them to be delayed or to change form.

Conservation Education and Outreach

Several of the projects in this program area require consultation with program partners which has increased the development time. These partnerships have also lead to some cost efficiencies which has further reduced the expenditures required for Conservation Education and Outreach.

Note too that the FEU now have a better understanding of what the appropriate budget amount should be for this program area and has therefore revised its expenditure request accordingly in its EEC Plan 2014-2018.

Enabling Activities

The original overall EEC 2013 expenditure forecast did not include Enabling Activities and instead spread the Enabling Activities spend across all the program areas. FEU has since pulled out these types of expenditures into a separate category. Therefore, the forecast 2013 expenditures for all of the EEC program areas have been impacted accordingly.

80.2 Please provide the total spending to date for the year 2013 for each program area.

Response:

The table below lists the total spending from January 1, 2013 to June 30, 2013 for each program area.

Program Area	Total 2013 January 1 to June 30 Expenditures ($000s)
Residential	3,638
Low Income	588
Commercial	3,104
Industrial	204
Innovative Technologies	157
Conservation Education & Outreach	693
Enabling Activities	2,527
Total	**10,911**

80.3 Please confirm the following proportions of spending vs. approvals for the year 2012, or, if not confirmed, please revise the table accordingly.

Program Area for 2012	Approved Expenditures (000's) (A)	Actual Expenditures (000's) (B)	Difference Approved vs. Actual($) (A-B)	Actual Expenditures Proportion of Approved Expenditures (%) (B/A)*100	Program Area by % Approved Expenditures (% of A)	Program Area by % Actual Expenditures (% of B)
Residential	9,261	11,295	+2034	122	32	48
Low Income	4,969	603	(4366)	12.1	17	2.5
Commercial	8,759	4,865	(3894)	56	30	20
Industrial	1,072	358	(714)	33	3.6	1.5
Innovative Tech's.	1,546	394	(1152)	25	5.3	1.7
CEO	3,470	2,200	(1270)	63	12	9
Enabling Activities	N/A	4,045	+4045	N/A	N/A	17
Total	29,077	23,760	(5,317)	82	100	100

<u>Response:</u>

FEU confirms that the values in the table are correct.

81. Reference: Multiyear Performance Based Rate-Making Mechanism, Appendix D2, Productivity Reports from Black and Veatch

Black and Veatch ("B&V") has prepared a report for FEI on the productivity trends of US gas distributors.

81.1 Please provide working papers for the B&V study in electronic format. A Microsoft Excel version of schedules 1 and 2 containing the data and formulas intact should be included.

Response:

All of the data is provided in the schedules. There are no other work papers. B&V does not provide live Excel versions of models when all of the data and formulas are contained in the exhibits and when prohibited by the data provider. It should also be noted that the data in the analysis is not from a single source. The PHMSA data on miles of pipe by size and type is available from the US DOT. The SNL data has been audited by B&V by reviewing the original source documents from Commission filings and making corrections as necessary.

81.2 Please provide the names of the authors of the study and identity additional individuals who assisted in the research and their roles in B&V's work for FEI. Please also provide CV's for these individuals highlighting their training and experience with TFP studies and PBR.

Response:

H. Edwin Overcast and Russell A. Feingold assisted by Eric Franco. Mr. Franco extracted the data and ran the models. The CVs for Dr. Overcast and Mr. Feingold may be found in the filing (Exhibit B-1-1) in Appendix D-3.

81.3 Please detail the team's experience measuring total factor productivity ("TFP"). Please provide copies of previous productivity studies by the authors which are in the public domain. Please provide docket numbers for any productivity studies filed with a regulator.

Response:

The development of TFP studies relies on a combination of theoretical and practical tools involved in the estimation.

Dr. Overcast has a theoretical background through both his graduate education and teaching in both MBA and graduate programs related to applied microeconomic theory. Dr. Overcast has lectured on PBR and other incentive regulation at the AGA Rate Course at the University of Wisconsin. Dr. Overcast has also been a discussant of benchmark analysis in the context of productivity at a conference sponsored by Rutgers University.

The application of a microeconomic theory on TFP to the utility context requires an in-depth understanding about utility cost inputs and what drives costs for utilities (outputs), as they are not the same as for the manufacturing industry that is the basis for the academic paradigm. Dr. Overcast has extensive gas and electric utility planning, engineering and operating experience that provides a detailed understanding of the fundamental building blocks of TFP analysis. Dr. Overcast is also the author of the AGA Magazine article that developed the basis for understanding scale economies and the impact on cost of service and rate design. Dr. Overcast has experience with cost of service analysis for both electric and gas utilities having filed dozens of both embedded and marginal cost studies for utilities. In addition, Dr. Overcast taught electric cost of service analysis for the EEI Rate Fundamentals Course and the Advanced Rate Course at Indiana University.

Mr. Feingold is a nationally recognized expert in all elements of utility costing, pricing and regulatory requirements. He has participated in numerous projects for gas and electric utilities and has extensive experience in a broad range of utility ratemaking issues including: fully allocated and marginal cost studies; rate design, strategic and market-based pricing; service and rate unbundling; revenue sharing, weather normalization and other automatic adjustment mechanisms; incentive ratemaking and PBR, end-user bypass and energy regulation analysis. Mr. Feingold served as an organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, and University of Chicago – School of Business, 1985 – 2012. He has taught on a variety of issues related to cost of service and rate design. Mr. Feingold's industry expertise covers many of the issues critical to the development of TFP analysis related to inputs and outputs.

In terms of public regulatory filings, Dr. Overcast has filed direct and rebuttal testimony specifically on TFP in joint testimony with Dr. Mark Lowry in Docket No. 8390-U before the Georgia Public Service Commission as an employee of Atlanta Gas Light Company (AGL) in 1998. This was part of the unbundling proceeding for AGL. The testimony included a productivity study prepared by Dr. Lowry under the supervision of Dr. Overcast. In addition, the testimony included a recommended I- X-Factor price cap proposal. As an officer of AGL, Dr. Overcast provided the AGL policy testimony related to this issue and others. He analyzed productivity in the context of regulatory proceedings. The Georgia Commission did not act on the PBR proposal because of the complexity of the docket related to full unbundling.

Mr Feingold has testified many times regarding cost of service issues that are relevant to the selection of proper TFP inputs. He advised FEI (Terasen Gas Inc.) on the development of its previous PBR plan, which was resolved by negotiated settlement. He has also testified related to PBR Plans in Fitchburg Gas and Electric Light Company in Massachusetts, Docket Numbers MA-DTE 02-22 and MA-DTE 02-23 related to the 2002 application for approval of a PBR Plan.

The CV's of Dr. Overcast and Mr. Feingold are attached to the Application. It is the combination of their academic and practical experience that supports the development of a TFP analysis that reflects the proper measure of inputs and outputs which is critical to rigorous TFP study.

81.4 Please detail the team's experience in proposing PBR plans with indexing (I-X) components including docket numbers for any PBR proposals filed with regulators. Please provide copies of previous PBR testimony by the authors which are in the public domain. Please note if these PBR proposals were approved or rejected by regulators.

<u>Response:</u>

Please refer to the response to CEC IR 1.81.3.

81.5 Please provide the correspondence between Fortis and B&V that led to the engagement and include a copy of the contract and amounts invoiced to date. Please split these costs if possible between the PBR survey, the productivity study, and any other items that were billed to FEI. We specifically request information about the number of hours billed and the charges for services rendered.

<u>Response:</u>

Through its experience with consultant Russ Feingold during FEI's previous PBR preparation, B&V was chosen as the expert who would best be able to assist with the PBR development. FEI was also cognizant of the Commission's April 18th letter in which the Commission required as follows:

> *"The Commission requires FEU and FortisBC to describe its productivity improvement culture by an examination of PBR methodologies in its next Revenue Requirements Applications. This examination is to evaluate the most recent PBR methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada. FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture."*

B&V was retained through FortisBC's legal counsel Fasken Martineau DuMoulin LLP. Please refer to Attachment 81.5 for copies of the Commission's April 18, 2013 PBR letter, B&V's Consulting Services Agreement and correspondence.

The total amounts invoiced to date include time required for consultation on the PBR survey, preparation of the PBR survey report, preparation of the gas TFP study and preparation of the electric TFP study, preparation and presentation to stakeholders at the June 19, 2013 PBR workshop, and preparation of responses to some of FEI's round 1 PBR IRs. The costs to date total $191,912.94, and are split roughly equally between consultation and preparation of the PBR survey, consultation and preparation of the gas and electric TFP studies, participating in the stakeholders' PBR workshop, and responding to IRs.

For the work invoiced to date B&V have provided their expert PBR advice to both FEI and FBC. The current invoicing is allocated approximately 75% to FEI and 25% to FBC because FEI is farther along in its proceeding. The Companies expect that the costs will be approximately split equally between FEI and FBC once both proceedings are completed.

81.6 B&V states on page 1 of its report that "because of the growing importance of infrastructure replacement TFPs are more likely to be negative going forward". Please provide an empirical substantiation of this statement. Has the capital productivity growth of gas distributors declined substantially more than their O&M productivity growth in recent years? Did companies with negative productivity growth typically have negative capital productivity growth on average in the B&V sample?

Response:

B&V provides the following response.

The statement is not based on any empirical analysis. It is a logical conclusion based on the facts as explained in the testimony. B&V did not conduct a multifactor productivity analysis and therefore it is impossible to conclude anything about the relationship between capital and O&M productivity independently.

81.7 B&V states on page 1 of its report that "As adopted by Stephen Littlechild in the 1980s, the original formulaic version of PBR was simply a measure of inflation minus an adjustment for productivity and efficiency. In this simple model, TFP is the measure of productivity and efficiency and is a building block for the change in revenue or price under PBR." Please indicate where in Stephen Littlechild's work in the 1980s and provide the document(s) in which he specifically called for TFP studies to establish the X factor.

Response:

B&V provides the following response.

Littlechild did not call for TFP studies to support the X-Factor. This has been a later development of the fundamental model.

81.8 B&V states on page 1 of its report that "Care must be taken in using the results of any TFP study values because the underlying assumptions of the study may not match the implementation of a proposed plan. For example, the TFP calculated in this study includes an ex-post measure of capital that may differ from the capital treatment that separates a portion of capital such as CPCNs for treatment outside of the plan." Would CPCN exclusions tend to raise or lower the TFP growth target and why?

Response:

B&V provides the following response.

Excluding CPCNs from the capital component would reduce the costs while also reducing the capacity component of the system. Since both outputs and inputs change, it is impossible to know how TFP would be changed. To the extent that a CPCN project is largely related to infrastructure replacement the impact on cost would be greater than the impact on output. This would indicate that TFP would be less negative because the value of the input measure would be smaller and that change has a negative sign in the equation.

81.9 B&V states on page 2 of its report that "As a practical matter, TFP signals whether costs are rising faster or slower than the rate of cost inflation… a positive TFP means costs are changing slower than inflation." Please explain these statements. Since Divisia price and quantity indexes exist such that growth Cost = growth Input Prices + growth Input Quantities so that growth Cost - Inflation = growth Input Quantities, isn't B&V in fact enunciating the conditions for input quantity growth?

Response:

B&V provides the following response.

At a theoretical level, no Divisia index is used as part of this analysis. It was not necessary to measure input quantities using the indirect measure of inputs. This is a benefit of the Kahn method as it avoids all of the assumptions related to measuring those units. Specifically, the infrastructure replacement is exactly that- a growth in inputs but more importantly a growth in inputs that may not change output. The proper specification of the change in inputs as measured by the ex-post measure is illustrated by the following equation for labor:

$$((\Delta \boldsymbol{QL} + \Delta \boldsymbol{QualL}) * \boldsymbol{WAPL_{t=1}}) + (\boldsymbol{QL_{t=0}} * \boldsymbol{WAPL_{t=1}}) = \Delta \boldsymbol{Labor\ Input}$$

In fact, the measure of inputs is not a measure of input quantity growth as your equation hypothesizes. As can be seen from the labor sample, the change in labor such as full time equivalents (FTEs) could be zero but input costs would still increase based solely on the change in price. This is another advantage of the method used because there is no requirement to calculate specifically the impact of the change in the quantity or quality of labor and the impact of these changes on the prices for labor. They are included in the analysis. To evaluate labor costs solely on FTEs fails to take into account the various mix of labor quality on the average price of labor. This is important since increased labor cost that results from improved productivity is not related to inflation which is assumed by the equation in the question.

Finally, the issue of quality of labor has been an issue related to TFP studies in the economic literature. One common option for addressing this issue is to use salary distribution as the basis for assessing labor quality. As noted above the indirect measure of labor covers this issue as well as the quantity issue.

81.10 B&V states on page 6 of its report that "By excluding general plant from the capital component of costs, the AUC adopted study failed to include the investment in line trucks and other vehicles used to maintain the distribution system. The study also excluded all of the investment in equipment used to maintain the delivery system. This was an explicit assumption of the study to exclude these costs but an unrealistic assumption when estimating the productivity of delivery services. To then attempt to use this result to estimate the productivity of a gas distribution company where these costs are even more significant because of the underground nature of gas delivery is unrealistic". Since general plant constitutes only a small fraction of the base rate cost of energy delivery, please explain why the exclusion of general plant would substantially alter results. Please present any evidence that suggests that the productivity of vehicles and other equipment mentioned is substantially different from the productivity of other gas distribution inputs.

Response:

B&V provides the following response.

The question misses the point in the testimony. Labor without vehicles and equipment would be about as productive as Stone Age man. The key point is that by not including the capital necessary to make labor productive the analysis understates the cost of that productivity. It is simple to understand that wages reflect expected productivity based on the use of this equipment. It is poor economic analysis to exclude those factors of production. It does however make the analysis of TFP easier.

81.11 Please explain why 5 years is the best period of time to measure to measure long run industry productivity trends. What would be the arguments against the use of a ten year period? The authors note on page 6 that "In order to avoid the impacts of weather and external economic conditions, the use of volumetric outputs require significantly longer periods because of the inherent volatility of the output measure. Where a more correct specification of output based on customers and/or capacity is used, there is no need to use extraordinarily long periods as shorter periods will properly reflect the estimated TFP for more fixed inputs". Is the volatility of input quantities not also concern in choosing the duration for the sample period? Could input and output quantities alike have been affected by the recession that occurred during the chosen 2007-2011 sample period? If so, how? Please cite all productivity studies you are aware of that use a sample period as short as 5 years to measure the long run industry productivity trend. Please provide productivity results for the longest sample period for which B&V gathered the necessary data.

Response:

B&V provides the following response.

The use of a five year period has been explained in the responses to BCUC IR 1.8.1, 1.8.2 and 1.9.1. Further, when the proposed PBR Plan has a five year regulatory control period it is asymmetric to use a longer period to assess productivity. The theoretical foundation for defining long-run is not reasonable for gas LDCs in any event since the long-run in its purest since (all factors of production may be changed) could potentially be more than 50 years. In this context, the long run must necessarily refer to a period when some fixed factors of production can be changed. In that case five years is a long run period. With respect to the volatility of input factors of production, those factors change in every period. However, utilities' productivities are less affected by the economy because most of their costs are fixed and the response to an economic downturn is much slower. Further, infrastructure replacement is critical to assure that a system is safe and reliable. Replacing plant during a recessionary period is also more economic and thus one would expect to see utilities investing in infrastructure to the extent permitted by existing financial conditions. With respect to input quantities other than infrastructure replacement as noted above, growth capital may decline but would be made up for by replacement capital. Distribution labor would not change significantly because that cost is relatively fixed. A&G expenses may be reduced where they are discretionary.

The net result of a change in costs as a result of lower expenses would be to increase productivity. This is just basic math. If input costs are lower for the same or greater output TFP is either less negative or positive if cost changes are negative. Thus there is no bias in the selected period although cost and plant changes may be made up of different components, but that conclusion is also true for any period and for any length of time. Understanding the cost drivers for a gas LDC is critical to understanding TFP and correctly specifying the model as B&V has done in this case. B&V only collected data for the five year period because a longer period was not needed as discussed above.

81.12 Please defend your use of data from SNL Financial on utility operations. Has SNL Financial approved the publication of this data?

Response:

B&V provides the following response.

The use of the SNL data base is fully explained in the TFP study report. Please see page 8 of that report. The SNL data base has not been made public as we used only a few selected variables required for the analysis and we are not releasing the data base in electronic form.

81.13 On page 8 of its report B&V states that "We have included all net plant for natural gas LDCs as well as all costs including customer account costs and Administrative and General (A&G) overheads. It is important to include these costs because their exclusion would result in a substantial over-estimation of the productivity associated with gas delivery since the exclusion of many of the costs associated with plant maintenance and overhead costs associated with labor are included in the A&G cost category. Failure to include these costs under-estimates changes in the cost of inputs and, thus, overestimates productivity of the labor resource. Further, there are significant costs associated with customer and billing as well as general plant costs to support these activities." B&V emphasizes on page 10 that "The results represent a more comprehensive review of costs than that found in the AUC [productivity] analysis".

81.14 Please confirm that B&V has included the costs of demand-side management programs, pensions and other benefits, and uncollectible bills in its calculations. Weren't all of these costs prone to rise rapidly during the period in question?

Response:

B&V provides the following response.

These costs are included in operating expenses less gas cost. The cost for non-capital pensions and benefits is included in A&G costs as are the customer service expenses. With respect to the magnitude of these costs changes, the change in operating expense less gas cost averages approximately 5.1% per year for the utilities in the TFP Study. Over this same period inflation averaged about 2.2%. B&V considers that the 5.1% would be representative of what could be expected over the next 5 years.

81.15 Please demonstrate how and why the exclusion of A&G expenses from the B&V study would raise the TFP trend results.

Response:

B&V's statement is predicated on the theory that these costs in total represent a positive change in input costs over the period. If that is true the statement is theoretically correct.

81.16 Doesn't the inclusion of pension and benefit expenses increase the weight on the labor quantity and to that extent increase measured TFP growth given the slower growth of the labor quantity?

Response:

There is no weight on labor quantity in the TFP analysis. The input values of labor, materials and supplies and rent is a composite as calculated under the ex-post measurement. This is a benefit of the methodology because it is unnecessary to estimate shares which require any number of assumptions and potentially allocations that are not required under the B&V method. Having to make assumptions and allocations not only makes the analysis less transparent it makes the analysis less reliable to the extent that the assumptions are not adequate to address all of the issues. The impact on TFP cannot be measured under the B&V methodology because there is no basis for multi-factor analysis.

81.17 B&V state on page 9 of their report that "Each measure of output produces a different level of TFP" [italics added]. The "level" of TFP is also mentioned elsewhere in its report. Isn't the TFP index developed by B&V designed instead to measure the trend and not the level of TFP?

Response:

B&V provides the following response.

No. As measured the values are the level of TFP.

81.18 B&V discusses on page 10 of its report the "ex post" approach to capital cost measurement. Please provide a copy of the cited testimony by Alfred Kahn and mentions of this approach by the FCC and the Australian Energy Regulator. What method was used to measure the capital quantity trend in Dr. Kahn's testimony? Please confirm that the capital cost measured by this means is sensitive to volume fluctuations.

Response:

B&V provides the following response.

Capital is measured based on net plant times 1 minus the operating ratio. This is the equivalent of cost times quantity. This is the same method used by Dr. Kahn and others. B&V cannot confirm that the measure is sensitive to volume. By volume, B&V assumes that the reference is to throughput and its impact on operating revenues used to determine the operating ratio. There are a number of reasons that make it impossible to conclude that volume in this sense has any impact on the cost of capital as measured in the TFP study. First, a number of gas LDCs in the sample operate in jurisdictions with full decoupling. This includes both California and New York for example. Second, other utilities have specific provisions that adjust rates automatically for changes in return such as Alabama Gas that has the Rate Stabilization and Equalization (RSE) provision to adjust rates to the allowed return. Third, a number of the utilities use SFV rates that are not impacted by volume like Atlanta Gas Light. Fourth, many gas companies have Weather Normalization Adjustments that adjust revenues for volume associated with weather. Fifth, many of these utilities have adjustment mechanisms with true up provisions to recover a variety of different costs such as infrastructure replacement and other types of expenses. Finally, utilities in the sample have the ability to seek new revenues through rate cases as needed and B&V is aware that many of these utilities filed rate cases and received rate increases during this period (B&V consultants have provided testimony in some of those cases, and we regularly follow rate case reporting from AGA and other sources that report on the results of rate cases).

The testimony of Alfred Kahn is provided as Attachment 81.18.

81.19 B&V discusses on page 10 of its report the "ex post" approach to capital cost measurement. Please explain whether in its previous productivity work B&V has used or considered the use of other approaches to capital cost measurement, the reasons for adopting the "ex post" approach to capital cost measurement, and any empirical evidence comparing productivity results using varying forms of capital cost measurement. Please provide any productivity results calculated by B&V for FEI using any other approach to capital cost measurement.

Response:

B&V provides the following response.

B&V adopted the ex-post approach based on its review of methods used by other agencies that have previously adopted I- X revenue or price cap regulation. The method is more transparent, easier to understand. Further discussion on this point is provided in response to BCUC IR 1.31.2. For a further discussion of the ex-post measure of capital, please see The Total Factor Productivity Performance of Victoria's Gas Distribution Industry by Denis Lawrence and John Kain cited in response to BCUC IR 1.30.2. Please also see the Benchmarking Opex and Capex in Energy Networks prepared for the Australian Competition and Consumer Commission. The comparison of these two methods will likely produce different results based on the assumptions made for each method. However, there is no reason to believe that the overall results would be significantly different in terms of the magnitude and sign (i.e. negative or positive) of TFP if the proper measure of outputs and inputs were used.

B&V did not use any other methods for estimating TFP in its previous productivity work or for FEI.

81.20 On page 9 of its report B&V characterize their measure of "gas inputs" as the "change in weighted cost of capital and total expenses, excluding gas costs". FEI states, relatedly, on p. 50 of its PBR application that "the input measures represent the operating and capital costs associated with the utility delivery function". Can one conclude from this that B&V used the trend in cost to measure the trend in the input quantity? If so, and since growth Cost = growth Input Prices + growth Input Quantities, wouldn't the resultant trend in input quantity be upward biased by the pace of input price growth?

Response:

B&V provides the following response.

The measure of inputs is based on an ex-post measurement as described by B&V. This issue has been fully discussed in the responses to CEC IRs 1.81.8, 1.81.16 and 1.81.18.

The formula provided in the question is an incorrect measure. The TFP measures the change in inputs which may or may not be related to cost growth. If input quantity increased and costs decreased cost growth could be zero or negative. Since the ex-post measure of all other factors is weighted total dollars it reflects both price changes and quantity changes and importantly also the quality changes in inputs without the necessity of directly measuring these factors as part of a labor index.

81.21 Please provide a citation for the formula used to calculate the input quantity trend from a scholarly or other respected source such as Statistics Canada or the United State Bureau of Labor Statistics. Is this input measure the same as presented on schedule 2 column Y under the heading "Cost Change"?

Response:

B&V provides the following response.

The input quantity trend is calculated using the Kahn method as noted in the B&V Report on TFP Appendix D-2. Each of the late Dr. Kahn, the FERC and the FCC are respected sources.

81.22 On Schedule 2, the input measure appears to be in column Y and calculated as a cost-weighted average of the cost level of net plant and non-gas O&M expenses. The first two observations for Alabama Gas contain column Y values of 498,392 in 2007 and 517,627 in 2008 for a growth of 3.86%. The 2008 weights are 45% O&M (55% capital) from column J. Given that net plant (column D) grows by 3.94% (686,366 /660,339 - 1) and O&M (column I) by -0.48% (139,512/140,186 - 1), why is it reasonable that the growth in the combined measure is nearly identical to the growth in net plant and not closer to what would be obtained by taking a weighted average of the growth rates (1.95%)? What would be the average growth in TFP if column Z was calculated by weighting growth rates instead of the method used?

Response:

B&V provides the following response.

First, the calculation of the input change is not an index. The change is based on the quantity of capital as measured by net plant times the price of capital as reflected in the proxy for capital cost applied to net plant. Similarly for O&M the quantity is measured by the dollars multiplied by the composite proxy price as measured by the percent that O&M represents of revenue. It is easy to see that capital has a larger impact on productivity than does O&M ($26 million compared to $700,000). Simply put, the small savings in O&M translates into a cost impact of less than one million dollars while capital costs increase over six times as much. By using the weighted average of the two percentage changes, the estimate of TFP would not reflect the relative importance of each component of productivity.

81.23 Net plant is the total cost of plant and equipment, acquired over many decades at rising prices, less accumulated depreciation. Did the study make any adjustment to net plant to account for the price at which these assets were acquired such that it could be considered a measure of capital quantity?

Response:

No. The ex-post methodology used by B&V does not require adjustments of this nature, since it uses the net plant times the operating ratio as the total plant input.

81.24 Please explain why non-gas O&M expenses are a plausible proxy for the quantity of O&M if not adjusted for inflation.

Response:

B&V provides the following response.

The important point in the TFP analysis is that there is no need to estimate quantity or quality of labor when using the ex-post measure. The estimation of the quantity of labor required a number of assumptions in the NERA study for the AUC that were unnecessary in the TFP Report.

81.25 Please explain the rationale for the specific output index formula. The customer/density index in column AA of Schedule 2 is apparently equal to K/S. Column S appears to be (1/42) x (K / (L+M)). Is it correct to interpret the customer/density index as just 42 x the total line miles (L+M)? Is the factor exactly 42 or just the first value in column R that rounds to 42? Does the number of customers actually factor into the customer/density index in column AA? If so, how?

Response:

B&V provides the following response.

The density index equals the system density for each utility based on the 42 customer density observation for Alabama Gas Company. It is common to express indices in terms of a single observation within a data set. The interpretation is not correct mathematically. The density index can be rewritten as follows:

$$\boldsymbol{Density\ Index_t = (Customers_t/(Distribution\ Miles_t + Transmission\ Miles_t)/42}$$

The base value is 42 as the rounded value of the first system density value. The corrected equation shows how the number of customers is included in the index.

81.26 Please explain the formulas used to calculate the values in column U and V of Schedule 2.

Response:

B&V provides the following response.

The formulas used to calculate columns U and V are discussed in the TFP Report Appendix D-2 pages 9 and 10. Both formulas for distribution and transmission are available on the internet. The full calculation is explained in the text of the TFP Report.

81.27 In column AB of Schedule 2, an Output Measure is calculated as a weighted average of the customer/density index level and a capacity measure. The weights are based on the percentage of distribution pipe that has a diameter under 2". Please explain why physical quantities were used as the basis for the weights as opposed to other methods that would recognize the cost associated with serving the different outputs as is done in other productivity studies? Is omitting transmission miles from the calculation of the weights inconsistent with the use of transmission data in the calculation of total capacity (column W)?

Response:

B&V provides the following response.

The 2-inch pipe represents the minimum size of pipe installed and all of the capacity values are indexed on that basis so the two inch weighting is appropriate for determining the split between pipe related to customers and pipe related to design day capacity which are the two variables used to measure output. Outputs in this case are physical amounts not dollars. The transmission values are all related to capacity so omitting them from this weighting is logically correct.

81.28 Do the calculations that lead to the total capacity in column W result in a measure consistent in units with column AA? If not, how is it possible to take a weighted average of customer numbers and capacity and obtain a sensible result if they are not in the same units?

Response:

B&V provides the following response.

In this case the measure of output represents both customers and capacity. The measure is a final value that attributes a portion of the capacity to customer count and a portion to design day demand. It is important to recall that the capacity measure is not actual capacity but an index based on the capacity value of 2-inch main as the basis for the index. Thus the customer related capacity matches the two inch pipe and the resulting output value is the customer capacity and the design day capacity.

81.29 Please explain any disagreement you have with the following statement: The negative productivity trend obtained by Black and Veatch is due in large measure to its failure to deflate cost and its choice of an extraordinarily short sample period characterized by unusually slow system growth and brisk growth in O&M expenses.

Response:

B&V provides the following response.

The statement is incorrect. As explained in the TFP Report (Appendix D-2) and numerous IR responses, the negative TFP has nothing to do with slow system growth since growth is related to customers and capacity not throughput. It is throughput that grew slowly over the period. The costs used represent the actual costs of capital and all other costs. It is fair to say that the growth in costs represents the market based prices for the factors of production used to determine the TFP as approved by the utility regulators for each data point. Finally, the use of five years is an appropriate period when the use of the model is to forecast the TFP trend for five years as proposed in the plan. This has also been fully discussed in numerous IRs.

81.30 Please provide any recent studies of FEI's productivity that B&V or any other entity has conducted.

Response:

FEI has not conducted or commissioned any other TFP studies or other productivity studies pertaining to its own utility operations.

82. Reference: Multiyear Performance Based Rate-Making Mechanism, Appendix D1, PBR Jurisdictional Benchmarking Report from Black and Veatch

On page 44 of Appendix D1, B&V states that "The results of the IR Plans have been quite positive for the Ontario gas LDCs' stakeholders based on the PEG report cited above."

82.1 Please confirm that the referenced PEG report found TFP growth trends above 1% for both Enbridge and Union between 2005 and 2010.

Response:

B&V provides the following response.

The referenced PEG report was not used for the purpose of X-factor determination and was conducted for assessment of individual companies (Enbridge and Union) productivity performance during their PBR term. A TFP study requires a much larger sample size for the purpose of determining TFP for the gas distribution industry.

The PEG TFP results for the period are above 1% although only slightly for Enbridge. It is worth noting however that the cost basis for PEG over this period did not include all of the labor costs (pension expenses excluded), also excluded were costs for franchise fees, DSM expenses and uncollectible accounts expenses. (Please see page 75 of the report.) Further, the output measure used was customers and kilometers of pipe. While this is a more plausible measure of output than throughput, kilometers of pipe ignores the economies of scale associated with pipe costs that would be reflected in a capacity measure. We would also note that the study period for this analysis is five years. Finally, the X-Factor for Enbridge over the more comparable and later period of 2008-2010 is below 1% at 0.72%.

Attachment 81.5

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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BRITISH COLUMBIA UTILITIES COMMISSION

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VIA EMAIL

April 18, 2013

Ms. Diane Roy
Director, Regulatory Affairs – Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
(gas.regulatory.affairs@fortisbc.com)

Mr. Dennis Swanson
Director, Regulatory Affairs
FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC V1Y 7V7
(electricity.regulatory.affairs@fortisbc.com)

Dear Ms. Roy and Mr. Swanson:

Re: FortisBC Energy Inc.
and FortisBC Inc.
2014 Revenue Requirements Application
Productivity Improvements in a Performance Based Rate Setting Environment

The British Columbia Utilities Commission (Commission) writes to provide FortisBC Energy Utilities and FortisBC Inc. (together the Companies), with further direction regarding the inclusion of an evaluation of Performance Based Regulation (PBR) methodologies, utilized in Canada and a proposal for a PBR methodology in the Companies' next Revenue Requirements Applications (RRA).

Commission Decisions on the FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application (FEU 2012-2013 RRA) and the FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan (FortisBC 2012-2013 RRA and ISP) examined productivity improvements under a PBR setting.

The FEU 2012-2013 RRA Decision found there was sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements but also recognized that there are limitations to the PBR methodology. The FortisBC 2012-2013 RRA and ISP Decision had the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in a productivity improvement culture.

The Commission requires FEU and FortisBC to describe its productivity improvement culture by an examination of PBR methodologies in its next Revenue Requirements Applications. This examination is to evaluate the most recent PBR methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada. FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture.

Yours truly,

EHamilton

Erica Hamilton

PWN/yl

IP/April/FEI/04-18-2013_FEI-FBC_PBR 2014RRA

CONSULTING SERVICES AGREEMENT

This Agreement, effective March 14, 2013, is between Fasken Martineau DuMoulin LLP (Client) and BLACK & VEATCH CANADA COMPANY ("Consultant"). Consultant shall perform Services in accordance with written Requests for Services (Requests) issued by Client and agreed to by Consultant during the term of this Agreement, which shall be attached as separate Exhibits A. Consultant shall accept or decline a Request as promptly as practicable under the circumstances.

1. Consultant warrants that it shall perform the Services in accordance with the standards of care and diligence normally practiced by recognized consulting firms in performing services of a similar nature. If, during the ninety –day period following the earlier of completion or termination of the Services under the applicable Request for Service it is shown there is an error in the Services caused solely by Consultant's failure to meet such standards, and Client has promptly notified Consultant in writing of any such error within that period, Consultant shall perform, at Consultant's cost, such corrective consulting services within the original Request for Service as may be necessary to remedy such error. ***EXCEPT AS PROVIDED IN THIS ARTICLE, CONSULTANT MAKES NO OTHER WARRANTIES OR GUARANTEES, EXPRESS OR IMPLIED, RELATING TO CONSULTANT'S SERVICES AND CONSULTANT DISCLAIMS ANY IMPLIED WARRANTIES OR WARRANTIES IMPOSED BY LAW INCLUDING WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.*** This Article governs, modifies, and supersedes any other terms in this Agreement which may be construed to address warranties or guarantees or the quality of the Services. Consultant shall have no liability for defects in the Services attributable to Consultant's reliance upon or use of data, design criteria, drawings, specifications or other information furnished by the Client.

2. Reports and other documents which Consultant prepares and delivers to Client pursuant to this Agreement shall become the property of Client when Consultant has been compensated for Services rendered. Nothing contained in this Section shall be construed as limiting or depriving Consultant of its rights to use its basic knowledge and skills to design or carry out other projects or work for itself or others, whether or not such other projects or work are similar to the work to be performed pursuant to this Agreement. Consultant shall have the right to retain and use copies of drawings, documents, and other data furnished or to be furnished by Consultant and any non-confidential information contained therein. At all times, each party shall retain all of its rights in its drawing details, designs, specifications, models, databases, computer software, copyrights, trade and service marks, patents, trade secrets, and any other proprietary property. Rights to intellectual property developed, utilized, or modified in the performance of the Services shall remain the property of Consultant. Client shall not acquire any rights to any of Consultant's, its subcontractors' or vendors' proprietary computer software that may be used in connection with the Services except as expressly provided in the Request or as may be separately agreed. Files delivered in electronic medium may not work on systems and software different than those with which they were originally produced. Consultant makes no warranty as to the compatibility of these files with any other system or software. Because of the potential degradation of electronic medium over time, in the event of a conflict between any specifications, reports, or other documents and electronic files, the original will govern.

3. All documents, including, but not limited to, drawings, specifications, reports, electronic files, and computer software prepared by Consultant pursuant to this Agreement, are instruments of service in respect to the project. They are not intended or represented to be suitable for reuse by Client or others on extensions of the project or on any other project. Any reuse without prior written approval, and verification or adaptation by Consultant for the specific purpose intended will be without liability or legal exposure to Consultant. Any approval, and verification or adaptation of documents will entitle Consultant to additional compensation at rates customarily charged by Consultant for such services. Neither the report nor any information contained therein, or otherwise supplied by Consultant in connection with the Services, shall be released or used by Client in connection with any proxy, proxy statement, proxy soliciting material, prospectus, official statement, offering memorandum, Securities Registration Statement or similar document without the express written approval of Consultant, except as may be required by law. Client is hereby contracting for, and purchasing, a Report from Consultant, responses to information requests, any necessary rebuttal report, and testimony, which contain the sum total of Consultant's Services under this Agreement. Consultant may include its standard commercial third-party disclaimers in its Report and related materials and deliverables. Consultant acknowledges and agrees that the Report and related materials produced by Consultant are to be used in a public proceeding, and the tribunal has control over what documents prepared by the Consultant are tendered into evidence.

4. Consultant shall maintain in force, during the period that Services are performed, workers' compensation insurance in accordance with the laws of the states having jurisdiction over CONSULTANT'S employees (or its affiliates if applicable) who are engaged in the Services and employer's liability insurance with a limit of $100,000 each occurrence and in the aggregate. CONSULTANT also shall maintain commercial general liability insurance with a limit of $1,000,000 per occurrence and in the aggregate; automobile liability insurance with combined single limit of $1,000,000; and professional liability insurance with per occurrence and aggregate limits of $1,000,000.

6. In performance of the Services, it is understood that Consultant may be supplied with certain information and/or data by Client and/or others, and that Consultant will rely on such information. It is agreed that the accuracy of such information is not within Consultant's control and Consultant shall not be liable for its accuracy, nor for its verification unless otherwise provided in the Request.

7. Client may, with or without cause, terminate the Services at any time upon ten working days written notice to Consultant. In such case, Consultant shall be paid costs incurred and fees earned to the date of termination and through demobilization and neither party shall be entitled to any other compensation or damages from the other. At all times, each party shall retain all of its rights in its drawing details, designs, specifications, databases, computer software, copyrights, trade and service marks, patents, trade secrets, and any other proprietary property.

8. Client may audit and inspect Consultant's records and accounts covering reimbursable costs for a period of six months following the completion of Consultant's Services. The purpose of any such audit shall be only for verification of such costs. Consultant shall not be required to keep records of or provide access to those of its costs expressed as fixed rates, a lump sum, or as a percentage of other costs.

9. With specific reference to the subject matter of this retainer agreement, neither party shall be liable to the other party for loss of profits or revenue; loss of use; loss of opportunity; loss of goodwill; cost of substitute facilities, goods or services; cost of capital; cost of replacement power; governmental and regulatory sanctions; and claims of customers for such damages; or for any special, consequential, incidental, indirect or exemplary damages whether a claim for any such loss arises out of breach of contract, warranty, tort (including negligence), strict liability, indemnity, or another theory. Except for an obligation to make payments, neither party shall be in default to the extent any nonperformance is caused by a circumstance beyond such party's reasonable control. The warranties, obligations, liabilities and remedies of the parties, as provided herein, are exclusive and in lieu of any others available at law or in equity. The total aggregate liability of Consultant (and its related companies) under this Agreement shall not exceed the compensation received by Consultant under the applicable Request for Services. To the fullest extent allowed by law, releases from, and limitations of liability shall apply notwithstanding the breach of contract, tort including negligence, strict liability or other theory of legal liability of the party released or whose liability is limited. Consultant may subcontract portions of the Services to its related entities. The controlling language of this Agreement shall be English.

10. At all times during the term of this Agreement, and for a period of six months following any termination or expiration hereof, Client agrees that it will not, hire, or solicit any employee of Consultant who performed services hereunder, to become employees or independent contractors of Client or such other person or entity, excluding employees who are responding to a general solicitation for employment advertised by Client. In the event Client does hire a Consultant employee as prohibited herein, Client shall be liable to Consultant for 60% of such employee's first-year salary (including any signing bonuses or reimbursable relocation costs). Client shall be obligated to disclose such amounts to Consultant and Consultant shall immediately invoice Client for such amount to be paid by Client within 10 business days of receipt of Consultant's invoice. Failure to pay such amount when due shall be considered a breach of this Agreement by Client and entitle Consultant to any and all remedies available under this contract, at law or in equity.

11. Notwithstanding any other provision of this agreement, Consultant is under no obligation to submit any deliverable if any invoice is more than 45 days outstanding. Client understands that Consultant will not provide legal or tax advice or opinions, and Client will seek such advice and opinions from its attorneys and tax advisors.

This Agreement and the attached Exhibits constitute the entire Agreement. No other representations of any kind, oral or otherwise, shall have any effect. This Agreement shall be governed by the laws of Ontario, notwithstanding the operation of any conflict or choice of law statutes or decisional law to the contrary.

FASKEN MARTINEAU DUMOULIN LLP (Client)	**BLACK & VEATCH CANADA COMPANY (Consultant)**
By:	By:
By: MATTHEW GHIKAS (Printed)	By: Russell A. Feingold (Printed)
Title: PARTNER	Title: Attorney-In-Fact

Legal Approved OPR
Reviewed
Date March 18, 2013

PM Approved
Date

EXHIBIT A
REQUEST FOR SERVICES

CONSULTING SERVICES AGREEMENT

Between

Fasken Martineau DuMoulin LLP ("Client")

And

Black & Veatch Canada Company ("Consultant")

Pursuant to the terms and conditions of the Consulting Services Agreement executed and made effective as of the 14th day of March 2013, by and between Fasken Martineau DuMoulin LLP ("Client") and Black & Veatch Canada Company ("Consultant"), Client hereby requests Consultant to perform the following Services:

Effective Date: This Exhibit A will be effective on March 14, 2013.

A. Requested Services:
See Appendix A to this document.

B. Commencement Date:
March 14, 2013.

C. Estimated Cost of the Services:
This project is a time and materials project with an estimated cost of between $60,000 and $75,000 (in U.S. Dollars).

The compensation is exclusive of Goods and Services Tax (GST), sales tax and similar taxes which are or may be imposed in respect to the services to be provided. These taxes shall be charged in addition to the price and shall be separately identified as a discrete line item on all of Consultant's invoices. The Consultant will deduct all recovered Canadian Goods and Services Tax paid or payable from reimbursable expenses before adding Canadian Goods and Services Tax to amounts to be invoiced to the Client.

D. Estimated Completion Date:
December 31, 2013. This is subject to the regulatory requirements of the British Columbia Utilities Commission.

E. Monthly Billing:
Commencing on or about the first day of the calendar month following execution of this Agreement, and monthly thereafter, Consultant shall furnish Client with an invoice covering the Reimbursable Costs and Fee (in U.S. dollars) incurred during the previous month and any interest due under this Agreement. Invoices may be submitted electronically by email to cbystrom@fasken.com. In such event, the electronic copy of the invoice will be considered the official invoice and will not be followed by a hard copy invoice. Invoices are due upon receipt. All payments will be in U.S. dollars.

F. Method of Payment: Payments to be made to Consultant under this Agreement shall be electronically transferred by wire transfer to the bank account and in accordance with the bank instructions identified in Consultant's most recent invoice in immediately available funds no later than the payment due date. Invoice number and project name shall be referenced in the bank wire reference fields.

G. Disputes: In the event Client disputes any invoice item, Client shall give Consultant written notice of such disputed item within ten days after receipt of such invoice and shall pay to Consultant the undisputed portion of the invoice according to the provisions hereof. If Client fails to pay any invoiced amounts when due, interest will accrue on each unpaid amount at the rate of eighteen percent per annum, or the maximum amount allowed by law if less, from the date due until paid according to the provisions of this Agreement. Interest shall not be charged on any disputed invoice item which is finally resolved in Client's favor. Payment of interest shall not excuse or cure any default or delay in payment of amounts due. In the event Consultant refers this Agreement to a third party for collection or enforcement of its terms, Consultant shall be entitled to reimbursement for all costs and expenses incurred, including a reasonable attorneys' fee. In the event that Client has an unpaid invoice over 50 days past due, Consultant may, in addition to all other remedies available at law and equity, terminate this Request for Services.

This Request for Services and the above-referenced Agreement constitute the complete understanding of the parties with respect to the Services specified herein. Terms and conditions contained in purchase orders, work orders, or other documents issued by Client with respect to the Services shall be of no force and effect.

IN WITNESS WHEREOF, the parties have executed this Request for Services.

FASKEN MARTINEAU DUMOULIN LLP (CLIENT)	**BLACK & VEATCH CANADA COMPANY (Consultant)**
By: ______________	**By:** ______________
By: MATTHEW GHIKAS **(Printed)**	**By:** Russell A. Feingold **(Printed)**
Title: PARTNER.	**Title:** Attorney-In-Fact

Legal		PM	
Approved		Approved	
Reviewed		Date	
Date	March 18, 2013		

15 March 2013

APPENDIX A

Fasken Martineau DuMoulin LLP
Review and Development of PBR Plans for FortisBC Inc. and FortisBC Energy Inc.
Proposed Scope of Work

Task 1 – Assist the FortisBC Utilities in Preparing Their PBR Structure and Plans

Black & Veatch will assist in the review and evaluation of Performance-Based Regulation (PBR) concepts and the related regulatory mechanisms available to FortisBC Inc. (electric) and FortisBC Energy Inc. (gas) (together, the FortisBC Utilities). This Task will include the following activities:

- Provide a theoretical discussion of the role of PBR as a utility regulatory tool;
- Provide a practical discussion of the structure and performance of the various PBR mechanisms and other innovative ratemaking mechanisms that have been approved by utility regulators and implemented by gas and electric utilities in North America;
- Conduct a situational assessment of the operational and business characteristics of the FortisBC Utilities to identify and understand their financial, operational, and ratemaking objectives; and
- Conduct a high-level review and assessment of the PBR concepts and approach being considered by the FortisBC Utilities, and provide feedback on the specific elements of the PBR Plan(s) that are being considered.

As part of this Task, Black & Veatch staff will meet in the Vancouver, BC area with the FortisBC Utilities' team to discuss PBR-related issues and to address questions related to their PBR approach and proposed plans.

Task 2 – Assist in the Development of Evidence on the Conceptual and Operational Appropriateness of the Proposed PBR Approach of the FortisBC Utilities

Black & Veatch will assist in the development of evidence with respect to the proposed PBR plan(s) of the FortisBC Utilities for submission to the British Columbia Utilities Commission (the Commission). This may or may not include the preparation of a separate Black & Veatch report; this question will be revisited as the work proceeds.

The evidence that will require Black & Veach's substantive input is expected to include the following:

- A summary of the overall findings and recommendations related to the FortisBC Utilities' PBR approach and proposed plan(s):
- A discussion of the broader utility context of the issues faced by the FortisBC Utilities as they relate to the recent and current ratemaking and regulatory trends of gas and electric utilities in North America;
- A discussion of the specific elements of the FortisBC Utilities' proposed PBR plan(s) and how the elements are intended to function within the context of their proposed PBR mechanism(s);
- An assessment of the appropriateness of the FortisBC Utilities' proposed PBR approach and proposed plan(s) in consideration of the theoretical and practical objectives of PBR, and the specific jurisdictional circumstances that exist in British Columbia.

15 March 2013

Task 3 – Provide Post-Filing Support to the FortisBC Utilities

As required, Black & Veatch will provide the following post-filing services to the FortisBC Utilities in support of their PBR filing(s) before the Commission:

- Assist in preparing responses to data requests and other informational requests;
- Attend and participate in any technical sessions or workshops before the Commission;
- Review any written evidence submitted by other parties relative to the evidence in which Black & Veatch had substantive input and prepare rebuttal evidence, as required;
- Provide ongoing support as an expert witness during the FortisBC Utilities' PBR proceeding(s);
- Participate in any settlement discussions; and
- Provide support to legal counsel, if required, regarding the technical aspects of the PBR evidence.

Crocker, Stan

From:	Matthew Ghikas <mghikas@fasken.com>
Sent:	Monday, April 29, 2013 4:23 PM
To:	Feingold, Russell A. (FeingoldRA@bv.com)
Cc:	Crocker, Stan
Subject:	Budget for FortisBC work

Russ,

I can confirm that the budget for your work for FortisBC has increased by $60k to accommodate the studies for the gas and electric utilities that you have been discussing with FortisBC.

Matt

--
Matthew Ghikas | Partner (Matthew T. Ghikas Law Corporation)

T. +1 604 631 3191 | F. +1 604 632 3191
mghikas@fasken.com | www.fasken.com
2900 - 550 Burrard Street, Vancouver, British Columbia V6C 0A3

FASKEN MARTINEAU

VANCOUVER CALGARY TORONTO OTTAWA MONTRÉAL QUÉBEC CITY LONDON PARIS JOHANNESBURG

Crocker, Stan

From: Matthew Ghikas <mghikas@fasken.com>
Sent: Tuesday, June 25, 2013 4:11 PM
To: Overcast, Howard E. (Edwin); Crocker, Stan
Subject: RE: Tomorrow's call

Ed,

After corresponding with Stan, I can confirm that the budget for your work for FortisBC to accommodate the rest of the regulatory proceeding including IR responses for the gas and electric utilities will be on a time and materials basis.

Let me know if you require anything further.

Matt

From: Overcast, Howard E. (Edwin) [mailto:OvercastHE@bv.com]
Sent: June-25-13 9:08 AM
To: Crocker, Stan
Cc: Matthew Ghikas
Subject: RE: Tomorrow's call

Stan,
We will need an e-mail from Fasken confirming the change to T&M for the consulting agreement for our accounting records. Thanks for your help. I have copied Matt on this e-mail so you can confirm with him to send the e-mail to Russ and I. Thanks.

H. Edwin Overcast, Ph.D.
Director, Management Consulting Division
Black & Veatch Corporation
Phone- 678-344-6701
e-mail: overcasthe@bv.com

From: Crocker, Stan [mailto:Stan.Crocker@fortisbc.com]
Sent: Monday, June 24, 2013 12:25 PM
To: Overcast, Howard E. (Edwin)
Subject: RE: Tomorrow's call

Ed, further to our discussion last Tues, checked with Purchasing, and we should be good to go.
Regards,

Stan
Surrey Ops 3-312
Direct: (604) 592-7905 | **Mobile:** (360) 319-4731 | **Fax:** (604) 576-7670

From: Crocker, Stan
Sent: Monday, June 24, 2013 8:29 AM
To: 'Overcast, Howard E. (Edwin)'
Subject: RE: Tomorrow's call

Thanks Ed, talk tomorrow.

Stan
Surrey Ops 3-312
Direct: (604) 592-7905 | **Mobile:** (360) 319-4731 | **Fax:** (604) 576-7670

From: Overcast, Howard E. (Edwin) [mailto:OvercastHE@bv.com]
Sent: Monday, June 24, 2013 8:26 AM
To: Crocker, Stan
Subject: Tomorrow's call

Stan,
Thank you for the voice mail. I am fine with the schedule for a call tomorrow. I am also supposed to get some additional testimony today and we might want to include that as part of the call. I felt like the workshop was positive. Thank you for the positive feedback. Talk with you tomorrow.
Ed

H. Edwin Overcast, Ph.D.
Director, Management Consulting Division
Black & Veatch Corporation
Phone- 678-344-6701
e-mail: overcasthe@bv.com

Attachment 81.18

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions To Oil Pipeline Regulation Pursuant to the Energy Policy Act of 1992	)))	Docket No. RM93-11-000

COMMENTS OF CRYSEN REFINING INC., LION OIL COMPANY AND SINCLAIR OIL CORPORATION WITH RESPECT TO REVISION OF OIL PIPELINE REGULATIONS

WITH ATTACHED TESTIMONY OF ALFRED E. KAHN

Melvin Goldstein
Goldstein & Claxton
2300 M Street, N.W.
Suite 750
Washington, D.C. 20037

Attorneys for Crysen Refining, Inc., Lion Oil Company and Sinclair Oil Corporation

Dated: August 12, 1993

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FEDERAL ENERGY REGULATORY COMMISSION

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions To Oil Pipeline Regulation Pursuant to the Energy Policy Act of 1992	)))	Docket No. RM93-11-000

COMMENTS OF CRYSEN REFINING INC., LION OIL COMPANY AND SINCLAIR OIL CORPORATION WITH RESPECT TO REVISION OF OIL PIPELINE REGULATIONS

WITH ATTACHED TESTIMONY OF ALFRED E. KAHN

Melvin Goldstein
Goldstein & Claxton
2300 M Street, N.W.
Suite 750
Washington, D.C. 20037

Attorneys for Crysen Refining, Inc., Lion Oil Company and Sinclair Oil Corporation

Dated: August 12, 1993

FERC DOCKETED
AUG 12 1993

TABLE OF CONTENTS

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Revision To Oil Pipeline Regulations Pursuant To The Energy Policy Act of 1992	)))	Docket No. RM93-11-000

COMMENTS OF CRYSEN REFINING INC., LION OIL COMPANY AND SINCLAIR OIL CORPORATION

In the Energy Policy Act of 1992, the Congress underscored the requirements of the Interstate Commerce Act and directed the Commission to promulgate a simplified methodology to ensure "just and reasonable" rates in the oil pipeline industry. Unfortunately, the Notice of Proposed Rulemaking ("NOPR") which the Commission published on July 2, 1993 fails to do so. It departs from a cost-based rate structure in which pipelines are required to show that they have incurred cost increases before they are permitted to increase rates to shippers. Instead, the Commission has proposed an indexation scheme which improperly permits pipelines to increase their rates regardless of whether they have incurred cost increases.

Moreover, the particular index proposed by the Commission -- the Gross Domestic Product Deflator ("GDP") -- is grossly defective. It bears little direct relationship to actual cost increases experienced by crude oil pipelines and no relationship to cost increases experienced by product pipelines. In support of that position we submit the attached testimony of Dr. Alfred E. Kahn. Clearly, the use of the GDP would result in excessive returns to oil pipelines. In addition, the retention in the NOPR of the

Commission's "*Buckeye* procedures" as a way of achieving market based regulation of oil pipelines is contrary to the expectations of the Congress as expressed in the Energy Policy Act.

Accordingly, Crysen Refining Inc., ("Crysen"), Lion Oil Company ("Lion") and Sinclair Oil Corporation ("Sinclair") -- shippers on crude oil and product pipelines -- recommend that the Commission revise considerably the NOPR before adopting any final rule.

In these comments we first provide a summary of our recommendations for revising the NOPR. We then proceed to describe the way in which the NOPR substantially affects the operations and competitive viability of Crysen, Lion and Sinclair. Finally, we provide a detailed discussion of the changes which we recommend be made in the NOPR in order to achieve the objectives which the Commission itself espouses.

SUMMARY OF RECOMMENDATIONS

(1) Cost-Based Rate Regulation -- We recommend that the Commission adopt a simplified cost-based rate regulation. With the resources available to it, the Commission can easily describe the type of data which pipelines should provide to shippers and to the Commission Staff to demonstrate that they have incurred increased costs. In fact, the Commission has already done so in natural gas cases. The Commission could then conduct expeditious rate cases to examine relevant cost data. This type of individual cost-based rate proceeding would satisfy the requirements of both the Interstate Commerce Act as well as the Energy Policy Act. It would achieve "just and reasonable" rates and would do so expeditiously and efficiently.

(2) Indexation -- If the Commission does adopt an index, the index chosen must reflect the actual cost experience of oil pipelines. A generalized inflation index that bears little relationship to the increased costs of the oil pipeline industry in particular is of little, if any, value. The data studied by Dr. Kahn demonstrates that the cost increases actually experienced by product pipelines are substantially below the GDP. They are also significantly below the Producer Price Index for Finished Goods ("PPI"). We therefore recommend that the index used for product pipelines be the PPI less 1 percent as originally recommended by the Staff in its March 18, 1993 proposal.

Insofar as crude oil pipelines are concerned, the aggregate data is so dispersed and the individual cost components of the pipelines involved raise such serious questions that no permanent index can properly be chosen at this time. We therefore recommend that the Commission study this matter further using the methodology recommended by Dr. Kahn. Until that study is completed we recommend that the PPI be used.

(3) Market Based Regulation -- The Commission's proposed regulations maintain the procedures it instituted in the *Buckeye Pipe Line Co.* [1] case. This is perhaps the single most objectionable feature of the NOPR. It was the inordinate expense and interminable proceedings of *Buckeye* which led the Congress to enact the Energy Policy Act directing the Commission to simplify its procedures. Yet those supposedly simplified procedures retain *Buckeye* intact. We recommend that the portion of the NOPR that permits a continuation of the *Buckeye* procedures be deleted as contradictory to both the Interstate Commerce Act as well as the Energy Policy Act.

1 *Buckeye Pipe Line Co.*, 13 FERC ¶ 61,267 (Dec. 24, 1990).

(4) Procedural Requirements -- We also recommend changes in several procedural requirements of the NOPR. First, pipelines should be required to provide all current shippers with at least 60 days advance notice of any rate increase. At that time, they should provide a detailed specification of the basis for the rate increase. The information provided to shippers in oil pipeline cases should be the same type of information which natural gas pipelines presently provide to their customers. Shippers should be permitted to file a protest 20 days prior to the effective date of the tariff.

The present proposal also places substantial impediments on participation in pipeline rate proceedings by consumers and producers. Those obstacles should be eliminated. Shippers often will not have sufficient resources to initiate and prosecute a rate case. Yet the rates proposed could nonetheless be unlawful and adversely affect both producers of crude oil and consumers of refined petroleum products. Both groups should be permitted to intervene in a rate case without undue restrictions.

EFFECT OF THE NOPR ON THE BUSINESS OPERATIONS OF CRYSEN, LION AND SINCLAIR

Crysen Refining Inc.

Crysen is a small and independent refiner in the Salt Lake City, Utah area. It operates one refinery whose rated capacity is 12,500 barrels a day. A major portion of the crude oil which Crysen uses in its refinery operations is transported by common carrier pipelines. In addition, Crysen uses common carrier pipelines to distribute the petroleum products which it produces. For a small refiner such as Crysen, the price of transporting crude oil to its refinery and petroleum product to its customers plays a major role in its overall operation. It can often make the difference between profitable and unprofitable sales.

Lion Oil Company

Lion refines approximately 50,000 barrels of crude oil a day at a refinery in El Dorado, Arkansas. Lion receives approximately 70% of its crude oil supplies through common carrier pipelines and distributes approximately 85% of the products it produces through common carrier product lines. These products are distributed primarily to rural users in Arkansas, Illinois, Kansas, Louisiana, Mississippi, Missouri, Ohio, Oklahoma, and Tennessee. In view of its substantial dependence on common carrier pipelines, Lion and the rural customers that it serves have a strong interest in the Commission's rate methodology in this proceeding

Sinclair Oil Corporation

Sinclair is also an independent oil refiner. It operates three refineries in the Midwest and Rocky Mountain sections of the United States, each of which is dependent on common carrier crude oil pipelines for its supplies. Sinclair also operates eight product terminals which are dependent on common carrier pipelines for their source of supply. Consequently, the regulation of interstate oil pipelines by the Commission is of critical importance to Sinclair's entire business enterprise.

DISCUSSION OF SPECIFIC RECOMMENDATIONS

I. COST BASED RATE REGULATION SHOULD BE THE PRINCIPAL METHOD OF CONTROLLING EXCESSIVE RATE INCREASES BY OIL PIPELINES

A. History of Rate Regulation in the Oil Pipeline Industry.

Any effort to revise the methodology of rate regulation must begin with the decision of the Court of Appeals in *Farmers Union II* [2]. Reversing an earlier attempt at generic regulation of the oil pipeline industry,[3] the Court of Appeals told the Commission that it could not freely abandon a cost-based rate system without substantial factual justification:

> . . . Because the relevant costs, including the cost of capital, often offer the principal points of reference for whether the resulting rate is "less than compensatory" or "excessive," the most useful and reliable starting point for rate regulation is an inquiry into costs. *See, e.g., Mobil Oil Corp. v. FPC*, 417 U.S. at 305-06, 316, 94 S.Ct. at 2344-45, 2349; *FPC v. Hope Natural Gas Co.*, 320 U.S. at 602-03, 64 S.Ct. at 287-88. At the same time, non-cost factors may legitimate a departure from a rigid cost-based approach. *See, e.g., Pennzoil Products*, 439 U.S. at 518, 99 S.Ct. at 771; *Mobil Oil*, 417 U.S. at 308, 94 S.Ct. at 2345. The mere invocation of a non-cost factor, however, does not alleviate a reviewing court of its duty to assure itself that the Commission has given reasoned consideration to each of the pertinent factors. On the contrary, "each deviation from cost-based pricing [must be] found not to be unreasonable and to be

---

2 *Farmers Union Cent. Exchange v. FERC*, 734 F.2d 1486 (D.C. Cir. 1984).

3 The determination of the Court of Appeals involved a review of a decision of the Commission in an adjudication, *Williams Pipe Line Co.*, 21 FERC ¶ 61,260 (1982). However, even though it occurred in the context of an adjudication, the Commission effectively established a rule that governed rate methodology for the entire oil pipeline industry.

> consistent with the Commission's [statutory] responsibility." *Mobil Oil*, 417 U.S. at 308, 94 S.Ct. at 2346; see *Pennzoil Products*, 439 U.S. at 518, 99 S.Ct. at 772. *Thus, when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates.*[4]

The court also emphasized the nature of the detailed factual findings that must be made to justify a departure from the use of a cost-based rate methodology:

> . . .[W]e find FERC's largely undocumented reliance on market forces as the principal means of rate regulation to be similarly misplaced.
>
> * * *
>
> Judicial review in such circumstances demands that the agency set out the basis in the record for its critical findings.
>
> * * *
>
> Departures from cost-based rates must be made, if at all, only when the non-cost factors are clearly identified and the substitute or supplemental ratemaking methods ensure that the resulting rate levels are justified by those factors.[5]

It is within the context of these determinations that the propriety of the Commission's efforts to substitute an indexation scheme for cost-based regulation must be judged.

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4 Farmers Union II. at 1502 (emphasis added).

5 Farmers Union II. at 1508, 1508 n. 50 and 1530.

B. Adequacy of Justification Offered By the Commission for Abandoning a Cost-Based Rate Methodology

The Commission apparently views the Energy Policy Act as legislative permission to abandon cost-based rate regulation. However, that is clearly not the case. In proceedings leading to the Energy Policy Act, the Congress expressed its exasperation with the seemingly interminable proceedings the Commission had been conducting in rate cases. At the same time, however, the Congress directed the Commission to continue to ensure just and reasonable rates under the Interstate Commerce Act. As the previous section of these comments indicates, the Court of Appeals has interpreted the Interstate Commerce Act as mandating a cost-based rate methodology, unless specific contrary factors can be demonstrated. The Congress was, of course, well aware of the *Farmers Union II* case, and did not in any way disturb it in the Energy Policy Act.

There is a simple way to reconcile the requirements of the Interstate Commerce Act, the Energy Policy Act and the *Farmers Union II* case. The long delays that have occurred recently in oil pipeline rate cases have *not* resulted from the effort to develop a cost-based methodology. Rather they have resulted from the Commission's decision in *Buckeye*. Under *Buckeye*, before a cost-based rate analysis is even begun, the Commission conducts what amounts to an antitrust trial. Whenever a pipeline requests *Buckeye* treatment, the geographic confines of markets are determined, the number of participants in the market are ascertained, a determination is made of whether other potential market entries exist, the nature of those potential entries is examined and the potential extent of their market share is determined. After that is done -- which in and of itself consumes literally years of administrative litigation -- a determination is made as to how to apply the data in order to ascertain whether the pipeline has market power. That determination -- *i.e.*, what market power means under the circumstances presented in a particular case and whether the pipeline involved in the case possesses it -- requires additional years. And, under *Buckeye*, all this is done before the pipeline produces *any* data with respect to the costs which it claims justifies a rate increase.

We believe that the exasperation of the Congress was directed to the antitrust trials which the Commission decided to conduct and not to the use of cost-based regulation. This view is supported by the fact that the Congress underscored the continuing applicability of Section 1(5) of the Interstate Commerce Act, which requires the establishment of just and reasonable rates, and at the same time left intact the decision of the Court of Appeals in *Farmers Union II*, which states that cost-based rate regulation is the principal way to achieve just and reasonable rates. The way in which the Commission can now comply with the Energy Policy Act is by abandoning *Buckeye* proceedings, and developing a streamlined format for deciding individual rate cases.

This simplified methodology would expand the data required on the present Form 6 to include the allocation of costs between interstate and intrastate services, the allocation of costs between crude oil and product services, and a schedule that shows the allocation of shared costs among the different operating systems which the pipeline maintains. All of this material could of course be developed into a spreadsheet which would then be combined with the type of information the Commission envisioned in the Appendix to the NOPR. In fact, a spreadsheet which the Staff developed on April 16, 1993 in a model for the "ABC Pipeline Company" is a good start in formulating a simplified cost based format. The development of a formula for the cost allocations described above would be the next step.

If pipelines are required to think through the basis of their rate increases before they file them and justify them in advance by providing the Commission and shippers with the type of data discussed above, the Commission will be able to conduct streamlined rate cases that comply with both the Energy Policy Act and the Interstate Commerce Act. It will then have no need to use either indexation or *Buckeye* procedures.

II. THE PARTICULAR INDEX SELECTED BY THE COMMISSION IS SERIOUSLY DEFECTIVE.

A. The Only Reasonable Index For Product Pipelines Is The PPI Less 1 Per Cent

In the NOPR, the Commission proposes to use the GDP deflator as the index which would lead to automatic annual increases in the rates of crude oil and product pipelines. We will discuss below the use of that index with respect to crude oil pipelines. Insofar as product pipelines are concerned, the empirical data developed by Dr. Alfred Kahn clearly demonstrates that the GDP deflator would provide pipelines with price increases that are far in excess of the costs they have experienced. In fact even the PPI, which reflects a lower inflation rate than the GDP deflator, provides excessive benefits.

The following table indicates the *actual* cost increases which Dr. Kahn found product pipelines have incurred over the past ten years:

Table 1
CRUDE OIL PIPELINES COMPARISON OF ANNUAL RATE OF CHANGE OF OPERATING EXPENSES AND NET PLANT PER BARREL-MILE WITH PPI AND GDP DEFLATOR

	1982-87	1987-92	1982-92
Operating expenses and net plant			
Weighted Average	0.82%	2.49%	1.24%
Unweighted average	0.11%	1.27%	1.54%
Median	-0.26%	0.45%	0.85%
Composite	0.22%	1.40%	1.21%
Producer price index	1.06%	3.17%	2.11%
Difference from composite	0.84%	1.77%	0.90%
Gross domestic product deflator	3.60%	3.87%	3.73%
Difference from composite	3.38%	2.47%	2.52%

Notes

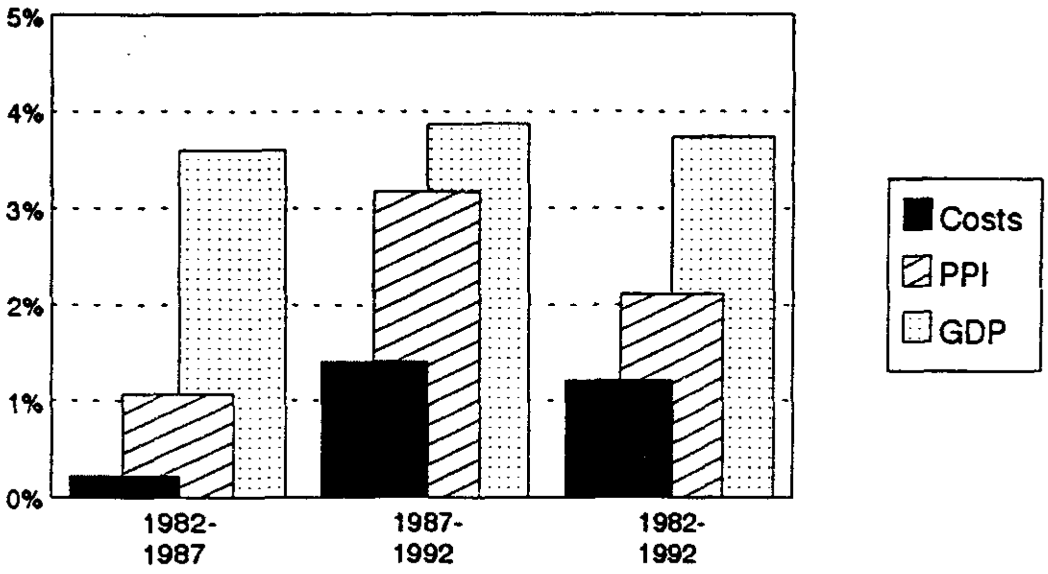
1. Based on the middle 50 percent of product pipelines that (i) have no crude operations and (ii) for which a 1982 Form 6 report is available.

2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982-1992 rate of change is not an average of the rates of change over the two five-year periods.

3. The "composite" is an average of the other three measures.

The data in the table can be viewed graphically in the following manner:

Product Pipelines
Comparison of Annual Rate of Change of Costs Per BBL-Mile With PPI And GDP Deflator



* Rate of change in costs is composite of median and weighted and unweighted average of rate of change for individual pipelines.

According to the data, the average cost increases experienced by product pipelines during the period 1982[6] to 1987 was 0.22%[7]. The GDP deflator during that period was 3.60%. If the Commission's indexation proposal had been in effect during the 1982 to 1987 period, product pipelines would have been permitted to increase their rates by more than 15 times their actual cost increases. In fact, even if indexation on the basis of the PPI had been in effect, product pipelines would still have been permitted to increase their rates by amounts that considerably exceeded their costs.

6 Actual cost data for pipelines is not available for the period prior to 1982 since the relevant Form 6's have been discarded by the Commission.

7 In this discussion, the GDP and PPI are compared with a composite rate of change. The composite consists of an average of the median and weighted and unweighted average rate of change for individual product pipelines. Any of these measures would lead to the same conclusions, since all of them are lower than both the GDP and PPI.

The PPI during the 1982 to 1987 period was 1.06%, *i.e.*, almost five times the actual cost increases experienced by product pipelines.

The situation is the same for the 1987 to 1992 period. The average price increase experienced by product pipelines in 1987 to 1992 was 1.40%. During that same period of time, the GDP deflator averaged 3.87%, or nearly three times the actual cost increases experienced by product pipelines. The PPI averaged 3.17%, or more than twice the actual cost increases of product pipelines. If the original staff proposal of PPI less 1% had been in effect during the 1987 to 1992, period product pipeline rates would still have been more than 50% higher than actual costs.

The results for the full 1982 to 1992 period are same. The use of the GDP deflator as an index would have produced product pipeline rate increases that were more than three times the increase in actual costs. The use of the PPI would have produced product pipeline rate increases that were almost twice as high as the actual cost increases. The index that would have come closest to replicating actual costs was the original staff proposal of PPI less 1%. That index would have deviated from actual costs by only 0.10%.

If the Commission ultimately decides to regulate oil pipeline rates through an index of inflation, the index chosen must be a rational one. In view of *Farmers Union II*, the only type of index that can be considered to be rational is one that replicates the costs that pipelines have actually experienced. Using this standard, the Commission cannot use the GDP deflator as a proper inflation index. The data which Dr. Kahn has analyzed clearly demonstrates that the GDP deflator is unrelated to cost increases experienced by product pipelines and is therefore irrational. Moreover, even the PPI fails to properly reflect actual cost experience. The only index that comes close is the one originally recommended by the Staff, - *i.e.*, PPI less 1%.

B. The PPI Should Be Used On An Interim Basis For Crude Oil Pipelines

The Government began measuring the rate increase of crude oil pipelines in 1986 as part of its calculation of an overall Producer Price Index. According to that data, between 1986 and 1993, the PPI index for crude oil pipelines, excluding the Trans-Alaska Pipeline System, increased by a total of only 2.3 percent, or an average of only about 0.3 percent annually. Thus, in the real world, the representative crude oil pipelines included in the PPI actually increased their rates by an average of only three-tenths of one per cent for each year of the past seven years. Similarly, the weighted average rate per barrel-mile of a broad sample of crude oil pipelines which we examined for these comments increased at an annual rate of only 0.59 percent between 1987 and 1992.[8]

These very low rates of increase in the rates actually charged by crude oil pipelines can be contrasted with the rate of increase that would have been permitted if the GDP index has been in effect during that period, as the Commission is presently proposing. During the 1987-1992 period, the GDP increased at an annual average rate of 3.87 percent. That rate of increase is more than ten times the actual rate of increase of crude oil pipelines according to the PPI and more than six times the actual rate of increase for the group of pipelines which we examined.

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8 The sample consisted of the middle 50 percent of all crude oil pipelines for which a 1982 Form 6 was available. The middle 50 percent was used to avoid the effect of apparent data entry error with respect to barrel-miles.

This difference between the rate at which crude oil pipeline prices in fact increased and the rate at which they would have been allowed to increase under the Commission's proposal is relevant for two reasons. First, it demonstrates that the proposal to use a GDP index can in no sense be considered merely a procedural resolution of oil pipeline rate cases. The evident purpose of the Energy Policy Act was to expedite the resolution of oil pipeline rate cases; it clearly was not designed to permit either crude oil or product pipelines to implement rate increases that were *ten times higher* than the rate increases achieved under cost based regulations.

The history of actual rate increases in the crude oil pipeline industry also calls into question the underlying justification for using a GDP index as a basis for future rate changes. In the attached report, Dr. Kahn discusses the reported cost experience of crude oil pipelines. He first points out that the reported rate of increase for operating expenses alone of crude oil pipelines (excluding the plant account) was *lower* than the GDP for the 1982 to 1987 period. Although the rate of increase for the operating account of crude oil pipelines was above the GDP for the 1987 to 1992 period, the rates of change of individual pipelines during that period were very widely dispersed. For example, even for the middle 50 percent of crude oil pipelines, the annual rate of change ranged from 0.11 percent to 14.42 percent.[9] For the total group of pipelines, the range was of course much greater.

Although we have not yet completed our full analysis of the reasons for the wide dispersion, our preliminary review indicates that the specific components of the operating expense account of a number of crude oil

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9 The full extent of the dispersion can be observed in the Table attached to these comments as Exhibit A.

pipelines would raise serious questions in a rate adjudication. Equally serious questions are presented in a rulemaking that seeks to find a substitute for rate case adjudication. For example, approximately one-third of the total amount of reported increases in operating expenses of crude oil pipelines between 1987 and 1992 was due to increases in expenses for "outside services," which increased at a compound annual rate of 22.5 percent.

Under the circumstances, there is no overall basis for using the GDP as the governing regulation for crude oil pipeline price increases. We recommend that if an index is used at all to regulate price increases of crude oil pipelines, the PPI be used pending the completion of a full study by the Commission. However, during that interim period, crude oil pipelines should be permitted to seek additional rate increases on the basis of actual costs experienced. This methodology will ensure that crude oil pipelines do not receive excessive rates at the expense of shippers. At the same time, pipelines will be ensured of receiving an inadequate return during the period of time in which an appropriate index is being studied.

III. WITH THE ADOPTION OF EITHER SIMPLIFIED COST-BASED REGULATIONS OR AN INDUSTRY-WIDE INDEX, THERE IS NO REASON FOR THE COMMISSION TO CONTINUE TO CONDUCT *BUCKEYE* PROCEEDINGS

The Commission is to be commended for revising recommendations in the original Staff proposal that would have effectively deregulated pipelines through a supposed market power analysis. But the present rulemaking still contains a proposal that would permit a market power analysis to be conducted in individual rate cases. We believe that any such approach is fundamentally wrong.

As past experience with rate proceedings under *Buckeye* has demonstrated, the original concept was ill-conceived and has produced exasperating and expensive administrative proceedings. *Buckeye* cases have developed into miniature antitrust trials and have taken years to unwind. The result has been wholly unsatisfactory from the point of view of shippers and pipelines. The fact of the matter is that the Commission and its administrative law judges are simply not equipped to act as surrogates for the Antitrust Division of the Department of Justice or the Bureau of Competition of the Federal Trade Commission. Moreover, it is exasperation with the Commission's efforts to conduct antitrust trials in the context of pipeline rate proceedings that led the Congress to direct it to formulate simplified rules.

With the adoption of either a simplified basis for analyzing the costs of individual companies or industry-wide indexation, there is no reason to subject either shippers or pipelines to the flawed *Buckeye* methodology. It should be deleted in its entirety from any final rule.

IV. THE PROCEDURES SPECIFIED IN THE NOPR SHOULD BE REVISED IN ORDER TO ACHIEVE EFFICIENT AND EFFECTIVE ADMINISTRATIVE PROCEEDINGS.

A. Pipelines Should Be Required To Furnish A Detailed Explanation Of The Underlying Basis Of Their Rate Changes

Regardless of the rate change methodology the Commission chooses, substantial changes should be made in the process used by pipelines and shippers to effectuate tariff increases. At the present time, shippers are flying blind. All a pipeline is required to do to effectuate a rate change is announce it. The pipeline is not presently required to provide any information at the time it files its tariff about the underlying basis of the rate change. That procedure should be changed.

At least 60 days prior to instituting any rate change, pipelines should be required to file with the Commission and serve on their shippers a detailed explanation of the basis of the rate increase. To the extent the increase is based on a cost-based rate methodology, the pipeline should be required to provide the information we have described in a previous section of these Comments. (See pp. 9-10). Oil pipelines would therefore be required to file the same type of information natural gas pipelines now file with their tariff sheets. At a minimum, the pipeline should be required to furnish the information set forth in the Staff's April 16, 1993 ABC Pipeline Co. model along with information about the allocation of costs.

B. Shippers Should Be Afforded At Least Twenty Days Before The Effective Date Of A Tariff To File A Protest

The NOPR proposes that shippers be given only ten days after notice of a rate increase to file a protest. Moreover, that protest must make a prima facie showing that the rate increase proposed by the pipeline is improper. Furthermore, shippers must make this showing without knowing the underlying basis of the pipeline's actions. In addition to being fundamentally unfair, the proposed methodology violates due process requirements. It is virtually certain to be overturned in the courts. The Commission should revise its proposal. As recommended above, pipelines should be required to provide shippers with detailed information explaining the underlying basis of any rate change. Shippers should have sufficient time to analyze that data and should be required to file any Protest at least 20 days before the tariff becomes effective.

C. Summary Disposition

At the present time, considerable time is wasted by prolonging administrative proceedings even when it is clear that there is no proper basis for a tariff increase. For example in a recent oil pipeline case, the administrative law judge ruled that even if the underlying rationale of a price increase is "unlawful," the case must still proceed to full discovery and a full evidentiary hearing because somewhere along the way, the pipeline might discover a legitimate basis for a tariff increase.[10] The waste of time and resources in this type of proceeding is enormous.

We therefore recommend that the Commission expand the use of summary disposition in the present rulemaking. The regulations should require the presiding judge in any proceeding to hold a hearing shortly after the issues are joined. The rule should encourage administrative law judges to dismiss rate proceedings where there is no supporting basis for the increase, either as a matter of law or Commission policy. An interlocutory appeal to the Commission should also be afforded as a matter of right to any shipper whose request for summary disposition has been denied.

CONCLUSION

The regulations which the Commission is presently considering for the oil pipeline industry are of major economic importance to the country. As the convulsions that accompanied the Arab Oil Embargo in the 1970's

[10] *Koch Pipe Line Co.*, FERC Docket No. IS 93-32-000. Decision of Presiding Judge dated July 28, 1993.

demonstrated, the petroleum industry is at the heart of the country's economy. It is equally clear that the petroleum industry cannot operate efficiently or effectively without a sound pipeline transportation system that serves the country's independent producers, refiners and marketers. The major integrated oil companies that control the majority of the country's pipeline transportation system simply cannot serve all of the country's petroleum requirements. It is therefore essential that the oil pipeline rate regulations under consideration by the Commission treat independent refiner/shippers fairly. Unfortunately, the present proposal does not do so.

The indexation system which the Commission proposes permits excessive returns by any standard. It bears no relationship to either the costs product pipelines have actually experienced in the past five years or to the price behavior of crude oil pipelines. In addition, the proposal continues in effect the discredited *Buckeye* antitrust trials. It does so despite the fact that the interminable procedures and ineffective results of *Buckeye* led the Congress to direct the Commission to adopt simplified procedures.

It would indeed be unfortunate if the Commission's current efforts to establish a rate methodology structure for the oil pipeline industry met the same fate as the Commission's last efforts in Opinion 154 -- *i.e.*, court challenges, reversal and regulatory stagnation.

In order to avoid that result, we, as independent refiners who have a vital stake in the health of the petroleum industry, recommend that the Commission:

(1) Use a simplified cost-based structure to consider and approve rate increases in individual cases. Formats for accomplishing this objective already exist. However, the Commission could certainly apply its expertise in the natural gas field to improve on them.

(2) If an indexation structure is to be used, the index applied to product pipelines should be the Producer Price Index for Finished Goods less 1 per cent. The index applied to crude oil pipelines on an interim basis should be the Producer Price Index for Finished Goods. The Commission should undertake a comprehensive study of the nature and extent of cost increases experienced by crude oil pipelines in order to determine whether a different index would be more appropriate. While that study is being conducted, any crude oil pipeline should be permitted to seek rate increases on the basis of increased costs. A simplified cost-based procedure should be used for this purpose.

(3) The provisions of the proposed regulations that continue to provide for *Buckeye* proceedings should be deleted. A simplified cost-based system or an indexation system should eliminate any need for shippers or pipelines to conduct complex antitrust trials before the Commission.

A new rate methodology for the oil pipelines can enhance the economic health of the entire petroleum industry. On the other hand, it can also frustrate competition and effective participation in the industry by independent refiners, producers and marketers. We urge the Commission to strike an appropriate balance between the competing economic interests in order to accomplish the underlying objectives of the Energy Policy Act. We respectfully suggest that our recommendations for modifying the current proposal will do so.

Dated: August 12, 1993

Respectfully submitted,

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Exhibit A

3230 0000

Crude Oil Pipelines
Reported Annual Rate of Change
In Operating Expenses Per Barrel–Mile
1987–1992

Top 25%

SHE10	335.44%
POG10	87.73%
PEN10	37.75%
SHA10	28.52%
AME20	23.65%
WHI20	23.12%
COO10	22.13%
MES10	22.02%
KER10	15.15%
WIL10	14.76%

Middle 50%

MOB30	14.42%
NOR10	13.72%
CHE10	12.44%
FOU10	11.35%
AMO10	10.50%
MID30	9.76%
WES30	8.14%
POR10	7.83%
TRA20	6.44%
ASH10	5.76%
PHI20	5.69%
MIN10	5.10%
PLA20	5.03%
FAR10	4.68%
SOU10	3.57%
JAY10	3.43%
MAR10	2.66%
MOB20	2.57%
MID10	1.54%
PAL10	1.27%
SON10	0.11%

Bottom 25%

CRO10	0.05%
CIN10	−1.29%
LOC10	−2.37%
KEN10	−2.40%
POR20	−4.64%
HES10	−5.08%
SUN10	−9.93%
TOT10	−11.55%
CHI10	−11.56%
KIA10	−56.23%

Notes:

1. Sample consists of crude oil pipelines for which form 6 reports are available for 1982. Two pipelines were excluded from the sample for this purpose because they did not report both operating expenses and barrel–miles for 1987 and 1982.

2. Extreme values are assumed to be due to data entry errors with respect to barrel–miles of throughput.

Testimony of
Alfred F. Kahn

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Revision to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992	)))	Docket No. RM93-11-000

TESTIMONY OF ALFRED E. KAHN
ON BEHALF OF A GROUP OF INDEPENDENT REFINER/SHIPPERS

I. INTRODUCTION AND SUMMARY

My name is Alfred E. Kahn, my business address is 308 North Cayuga Street, Ithaca, New York 14850. I am the Robert Julius Thorne Professor of Political Economy, Emeritus, at Cornell University and a Special Consultant with National Economic Research Associates, Inc.

The experiences of mine most relevant to this proceeding are that, in addition to having been a professor of Economics at Cornell University since 1947, I was Chairman of the New York State Public Service Commission between 1974 and 1977 and of the Civil Aeronautics Board between 1977 and 1978; and I am the author of the two-volume The Economics of Regulation, published originally by John Wiley & Sons in 1970 and 1971 and reprinted by MIT Press in 1988. I have published extensively in professional journals in the area of regulatory policy, and have testified in more than 45 regulatory proceedings, before state and federal regulatory commissions. I attach a copy of my full resume as an appendix to this testimony.

The purpose of this comment on the Commission's Notice of Proposed Rulemaking on Oil Pipeline Regulation is the limited one of evaluating its proposed use of the GDP deflator as the basis for indexing oil pipeline rates henceforward. The experience of product pipelines over the last ten years supports the judgment of the Commission Staff that the Producer Price Index for finished goods is likely to be the better index; indeed, even that index appears to err on the side of generosity.

The much more erratic behavior of the costs of crude oil pipelines might be taken as casting doubt on the applicability of any indexation formula. If the Commission decides nevertheless to proceed with indexation of their rates as well, it appears upon an investigation less intensive and less complete than I have conducted in the case of the product lines that, on average--and probably fortuitously--the GDP deflator might be the better choice. The evidence clearly does not justify its selection except on an interim basis only, and subject to the Commission subjecting its choice to the further tests such as I applied to the cost experience of product pipelines and summarize in this testimony.

II. THE LOGIC OF THE COMMISSION'S PROPOSALS

The Commission's proposed rules have three major components: effective deregulation ("market-based rates") of pipelines that lack market power; the availability of a cost-of-service--i.e., a rate base/rate of return--test in extraordinary circumstances; and indexed averages of rate maxima. Of these, it conceives the third as the method of most general applicability.

Since I support this proposal, it would be superfluous for me to explain my reasons for doing so; that would in effect involve telling the Commission things it already knows. I confine my exposition of the underlying logic to what is necessary only to emphasize the importance of the specific indexation formula adopted and lay the basis for my criticisms of the proposed use of the GDP implicit deflator, at least for product pipelines.

The importance of the indexation formula

As the Commission is fully aware, the ideal indexation formula would be one that, beginning with rates that Congress has, with minor exceptions, declared to be just and reasonable, tracked as closely as possible the actual average costs of the pipeline industry. I would modify that statement only to incorporate the notion that the changes in cost to be measured by the index and applied to the present rate ceilings are the changes that might reasonably be expected to be achieved by an efficient operator. The pertinent question, then, is whether the GDP deflator is the most reasonable among the possible conveniently available proxies for the actual course of pipeline industry-specific input prices. If it is not, the proposed regulatory scheme will fail.

This is so for two interrelated reasons that are worth emphasizing. The first is that if it is not, the Commission will not realize its intention of relying primarily on indexation to fulfill its regulatory functions. That is to say, only if the indexation formula reasonably closely reflects what would be the course of competitive prices will the Commission be able to rely on it in most or all cases, and so avoid the difficult exercises of determining, company by company, whether the pipeline does or does not possess market power or, by a cost-of-service determination, whether it has been deprived of the opportunity to earn a reasonable return on its investment. If the indexation formula that the Commission adopts seems likely to depart substantially from the course of pipeline costs (as always, the costs achievable by a reasonably efficient operator), it can not realize that hope: it will inescapably find itself drawn into investigations of the presence or absence of market power and/or of the actual cost of service of individual pipeline companies, with a frequency directly related to the degree of imperfection of the indexation formula--either by complaining shippers, if the formula proves excessively generous, or by pipelines, if it proves excessively constricting.

By the same reasoning, a defective indexation formula will quickly frustrate expectations of the benefits--expected by the Commission and equally expected by me--of a shift from rate base/rate of return to indexed price cap regulation. The essential anticipated superiority of this new method of regulation is that it offers superior incentives for improved efficiency and innovation by the regulated companies, as compared with a system that in effect bases permissible rates on the costs of the individual company.

If the course of a company's prices is in effect fixed for some considerable period of time--that is to say, either remains unchanged or varies according to some index of costs for the industry as a whole rather than of the individual company--the company will retain the full benefits of improvements in its relative efficiency and suffer the consequences of either deterioration or deficiencies relative to the average or expected average on the basis of which the index is set.

To achieve this purpose alone, the indexation formula could indeed be totally arbitrary. I have at times in the past suggested, only partially facetiously, that the formula might well relate the change in permissible prices over time to a random table of numbers: all that is required from the standpoint of maximizing efficiency incentives is that those prices be divorced from the costs of the individual company.

Such a system would be unsustainable, however, because it would quickly eventuate in quixotically unacceptable rates of return--either unacceptably high, from the standpoint of consumers, or intolerably low, from the standpoint of suppliers--and therefore require early regulatory intervention to relate prices more closely to actual costs. It would therefore quickly make untenable the central respect in which indexation would improve the regulatory process--the lengthening of the intervals of time during which the course of prices is fixed and not subject to regulatory corrections on the basis of actual costs. All of this the Commission clearly recognizes.

The Commission's choice

If one is to judge the Commission's decision to use the GDP Implicit Price Deflator rather than the Staff's proposed PPI for finished goods purely on the basis of its own explanation of that decision, one is forced to the conclusion that its choice was irrational.

- First, it points to the benefit of "linking rates to a general price index"--the benefit of simplicity. (p. 22) In addition, it points out

  > General inflation indices would not be subject to concern over potential manipulation, and their use would not require Commission resources.... (p. 23)

  These would be advantages equally of the Staff's proposed PPI-PG and the GDP deflator, and therefore provide no basis for choosing the latter over the former.

- The Commission recognizes that any general measure of economy-wide inflation has the

  > disadvantage...that it will not precisely track cost changes in the oil pipeline industry.

It was for this reason, specifically, that the Staff recommended choice of the PPI over the GDP deflator:

> the CPI and the GDP Implicit Price Deflator have been significantly influenced in recent years by rapidly escalating health-care costs. The PPI for Finished Goods, however, does not include service industries such as health care....the Staff believes that the PPI for Finished Goods is the general inflation index that best tracks changes in oil pipeline costs. (p. 21)

and, once again, in referring to its recommended choice:

> unlike the...GDP Implicit Price Deflator, it [the PPI] does not include service industries, such as health care, that have experienced extraordinary inflation in recent years. (p. 24)

o In explaining its decision, in the face of this contrary recommendation, to use the GDP Deflator, the Commission offers only the reason that

> the GDP deflator is the best indicator of inflation in the overall economy,

to which it attaches the footnote explanation,

> the Commission believes the GDP Implicit Price Deflator would be a better measure of inflation in the overall economy, since the PPI-FG reflects only a fraction of the economy (FERC NPRM, p. 26, footnote 41)

and, it goes on to support its choice on the ground that:

> since it covers the broadest range of goods and services, the GDP deflator is the least volatile of general inflation indexes. (p. 26)

But it nowhere justifies that basis for its choice--namely, that it is looking for the best measure of inflation economy-wide--rather than what it has itself recognized is the more logical criterion: the measure of economy-wide inflation that best "track[s] cost changes in the oil pipeline industry." (p. 22)

o It then goes on to offer additional reasons for its choice--namely, that the deflator

> is totally independent of the behavior of any pipeline,

and that its use

> will free the Commission from the difficulties associated with the construction of an oil pipeline industry cost index. (p. 26)

But of course these are advantages equally of using the PPI-FG.

- So, the Commission goes on immediately to conclude:

> Finally, the Commission believes that no other general inflation index is better than the GDP deflator in predicting future costs in the oil pipeline industry.

Yet it offers absolutely no support for that conclusion other than the ones I have already summarized and therefore nowhere explicitly confronts, let alone explains its reasons for rejecting, the reasoning of the Staff that the GDP deflator, precisely because "it covers the broadest range of goods and services" and particularly because it includes consumer services, the inflation of whose prices has by general recognition been greater in recent decades than for the rest of the economy and because those services do not enter into the costs of the pipeline industry, is for these very reasons inferior to the PPI-FG.

In short, the Commission's decision is irrational on its face and completely fails to confront the Staff's explicit reason for proposing use of the PPI-FG rather than the GDP deflator.[1] It remains, therefore, only for me to examine to what extent the GDP deflator is indeed superior to the PPI-FG as well as an acceptably close proxy for the kind of index that, considerations of practicality and administrability apart, the Commission itself recognizes would be theoretically preferable--sufficiently close to promise that the proposed shift from rate base/rate of return to indexed price regulation will in fact prove sustainable.

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[1] The Commission also rejected the Staff's proposal that the index be reduced each year by 1 percent, as an "offset for productivity," on the ground that

> The Commission sees little justification for the productivity offset...." (p. 26, footnote 42)

The analysis of product pipelines discussed in this testimony suggests, however, that even the PPI-FG errs on the side of generosity, and that a negative offset such as the staff recommended would cause it to track their cost experience more closely.

III. TESTS OF THE PROPOSED INDEXATION FORMULA

The only way of testing a formula proposed as a basis for indexation of rates in the future is to see what kind of results it would have produced had it been applied in the past, while taking into account to the extent feasible the possibility that the factors influencing the behavior of costs in the future period, to which the proposed formula would apply, may be expected to differ from those in the past. The attached Appendix provides a fuller description than appears here of the available data and the tests we conducted.

The available data

The first and simplest test that suggests itself would be the behavior of pipeline rates over the recent past--preferably, one would hope, for more than a decade, in order to be able to contrast the period of high inflation with the more stable macro-economic situation of the last decade. The point would be to compare the actual behavior of rates with how they would have changed had they had applied to them the two alternative indexes, on the assumptions--presumably supported by the Congressional finding that present rates must essentially be taken as just and reasonable--that any substantial divergence between what actually happened and what would have happened under these formulas casts serious doubt on their applicability or, at least, suggests that one would have been a better predictor than the other. Unfortunately, the only source of these rates with which I am familiar is the crude and pipeline rate components of the PPI itself, and these have been available only since 1986.

The other source of data, on which we perform the preponderant share of our calculations and comparisons, is the annual Form 6 reports that the interstate pipelines are required to file with the Commission. These are superior for our purposes to the PPI for two reasons: first, they permit comparisons over a slightly longer time period--although totally unavailable before 1982, they do permit comparisons over the last ten years, for a substantial number of pipelines; and second, among other things, they provide direct information about costs, company-by-company, as I explain more fully in an attached appendix. Our inability to test the hypothetical application of the PPI-PG and GDP indexes against Form 6 costs before 1982, which embraced a period of double-digit inflation, is probably not a significant shortcoming, in consideration of the general view that we are unlikely to see a recurrence of such high rates of inflation during the next decade. The data are, however, subject also to other limitations and infirmities, requiring the exercise of judgment, particularly with respect to the sample of companies surveyed and--particularly in view of the somewhat erratic behavior of the information, both from year to year and company to company-- the best possible measures of central tendency--which choices I describe in the attached appendix.

An overview of the analysis

Our tests of the Commission's indexation proposal consisted, first, in a comparison of the changes, separately, in the BLS PPI's of the rates of product and crude oil pipeline between 1986 and 1992, and then of their costs over the 1982-1992 period, as reflected in their Form 6 reports, with the two economy-wide indexes considered by the Commission. In the case of the product pipelines we used the data for all of the pipelines for which Form 6 reports are available for the entire period, examining the annual rates of change in both operating expenses per barrel-mile and net plant per barrel-mile. We were unable to perform a similar analysis for the crude oil pipelines, because of the limited time available, and had therefore to confine our study of them to the operating expenses per barrel mile of the companies for which Form 6 reports are available over the 1982-92 period. For this reason, and also because the crude oil pipeline cost figures behave much more erratically than the product lines, our conclusions with respect to them are both more limited and more tentative than with respect to the product lines.

As I have already observed, the unit cost figures--cost per barrel mile--seem to vary erratically from year to year, and many times more erratically from one company to the next. Individual companies will show annual changes in unit costs, both up and down, in double-digit ranges--annual rates of increase, for example, of more than 100 percent or decreases of more than 90 percent, at least some of which seem clearly attributable to errors in the entry of the information on the Form 6's.

Since, whatever indexation formula is applied, the ceilings it produces are to apply uniformly to all companies, across the board, the apparently wide dispersion among individual company experiences raises questions about the validity of this proposed method of regulation--questions that are not the subject of this testimony. It is not relevant, however, to the choice between the PPI-FP and GDP deflator; both suffer this same infirmity--to the extent it is an infirmity.[2]

In any event, because of this wide dispersion we based our analysis on the middle 50 percent of the pipelines in our groupings. For that middle 50 percent, we calculated four alternative measures of central tendency for the annual rates of change: the median, unweighted mean or average, the weighted mean and a composite rate or average of the first three. We used all four measures because, even with the exclusion of the upper and lower 25 percent of the companies, the results for individual pipelines were still widely dispersed, as the differences among the first three measures suggests. Each of the three, however, captures a significant aspect of the composite results from an industry perspective; the fourth measure represents a pragmatic effort to provide a single reflection of the behavior of "industry" costs for comparison with the changes in the PPI-FG and GDP deflator.

The results: prices

The results of the comparisons with the PPI pipeline price indexes can be very quickly summarized: between June of 1986 and February of 1993 the PPI index for crude oil pipelines excluding Trans-Alaskan rose a total of only 2.3 percent; the comparable figure for refined petroleum lines was 1.2 percent. Over roughly the same period (1986 to February 1993) the increase in the PPI-FG index was 20.6 percent and the GDP deflator (1986 to the first quarter of 1993) 26.8 percent.

[2] The mere fact that changes in a particular price or cost index, intended to be applied to all companies across-the-board, diverges substantially from changes in the costs of individual companies is not necessarily an infirmity: the same is true in competitive markets, just as the competitive market price at any given time will typically allow some companies to make very high profits and others to suffer losses. Since I have no criticism to offer in this submission of the Commission's proposed recourse to indexation, I do not propose to consider whether the variability of company-by-company profitability that would be produced by the use of either price index suggests that indexation should not be employed as a method of regulating this industry.

We have been unable, in the time available, to discover the reason or reasons for this extraordinary discrepancy, which suggests that a zero rate of indexation over the last almost seven year period would have come far closer to the proper rate than application of either of the two suggested indexes.

The average rates of increase in <u>prices</u> per barrel mile derived from the Form 6 reports compare much more plausibly with the overall inflation indexes. Over the period 1982 to '92, the weighted average compounded annual rates of price increase per barrel-mile for all the product pipelines for which we have Form 6 information over the entire decade was 1.84 percent per year, the unweighted average, 1.94 percent. Comparison of these rates with the respective average annual (as always compounded) rates of increase in the PPI-PG of 2.11 percent and of the GDP deflator of 3.73 percent over this same decade provides--setting aside the PPI pipeline indexes--the first and most general suggestion of the superiority of the former over latter index as the basis for future indexation of these rates.

<u>The results--Form 6 costs--product pipelines</u>

For product pipelines, the results of the analysis of the Form 6 data likewise point unambiguously to the conclusion that the PPI-FP is the preferable index: indeed, they too suggest that some offset against increases in the PPI-FP (a positive X factor in the familiar RPI or GNP-PI minus X formulation) would track pipeline costs even more closely. Table 1 compares the annual rates of change in the PPI-FP and the GDP deflator with operating costs and net investment per barrel mile for three periods: 1982-1987, 1987-1992, and 1982-1992.

As the table demonstrates, the PPI-FP follows the product pipelines' cost experience much more closely than the GDP deflator, which exceeds that experience by margins of 1.47 to 3.38 points for the three periods. (As I have already suggested, in contrast with the other three measures of central tendency the "composite" figure is, in a sense, an artificial construct, with no particular scientific basis for its equal weighting of the other three measures. If, however, we look to the first three measures of central tendency, of which it is a simple average, we see that in every single one of the nine observations--three each for the three time periods--increases in the product pipeline

Table 1
PRODUCT PIPELINES
COMPARISON OF ANNUAL RATE OF CHANGE
OF OPERATING EXPENSES AND NET PLANT PER BARREL-MILE
WITH PPI AND GDP DEFLATOR

	1982-87	1987-92	1982-92
Operating expenses and net plant			
Weighted Average	0.82%	2.49%	1.24%
Unweighted average	0.11%	1.27%	1.54%
Median	-0.26%	0.45%	0.85%
Composite	0.22%	1.40%	1.21%
Producer price index	1.06%	3.17%	2.11%
Difference from composite	0.84%	1.77%	0.90%
Gross domestic product deflator	3.60%	3.87%	3.73%
Difference from composite	3.38%	2.47%	2.52%

Notes:

1. Based on the middle 50 percent of product pipelines that (i) have no crude operations and (ii) for which a 1982 Form 6 report is available.

2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982-1992 rate of change is *not* an average of the rates of change over the two five-year periods.

3. The "composite" is an average of the other three measures.

costs are in all cases markedly smaller than the increases in the PPI, and, again in every single case, even more markedly smaller than the increases in the GNP deflator.) Even the PPI-FP exceeds the rate of change in product pipelines' costs, regardless of the period over which the change is measured or the measure of central tendency used to summarize them.

The evidence seems therefore also to support the conclusion that the Commission should consider using as its index the PPI-FP minus 0.5 percent to 1.0 percent. This "X factor" would not necessarily be justified by an assumption that continuing increases in productivity are achievable in the use of variable inputs. Indeed the evidence suggests that the slower rate of increase in product pipeline costs than in the PPI is attributable, instead, to the slow rate of growth in the capital inputs. In any event, the reduction would be based on the actual behavior of product pipeline costs over the past decade and on the desirability of the index tracking that cost behavior as closely as possible.

The cost experience summarized in Table 1 reflects the combined effects of changes in operating expenses and net plant, both on a per barrel-mile basis. As Table 2 shows, the rate of change in operating expenses alone is higher than of the two combined. For the 1982-1992 decade as a whole, that higher rate of change is attributable in large part to an exceptionally high rate of increase from 1988 to 1991. This is illustrated in Figure 1, which presents the year-to-year changes in weighted average operating expenses per barrel-mile for 1987-1992, along with the five-year average for 1982-1987 and the two five-year averages also of the PPI and GDP deflator.

As that figure also shows, the increase in expenses appears to have decelerated sharply in 1991-1992: conceivably the acceleration from 1988 to 1991 was a transitory phenomenon. In any event, the PPI would have permitted full recovery, on average, of the increases even in unit operating expenses alone over the 1987-92 period: as the Table and Figure suggest, it was in the first five years, 1982-87, that the PPI would have provided inadequate recovery so far as operating expenses alone were concerned.

The proposed index would be applied, however, to the entire rate, not merely to the portion representing operating expenses. Any test therefore of whether the index would track total product pipeline costs with reasonable accuracy must take account also of the other element of those

Table 2
PRODUCT PIPELINES
COMPARISON OF ANNUAL RATE OF CHANGE
OF OPERATING EXPENSES PER BARREL–MILE
WITH PPI AND GDP DEFLATOR

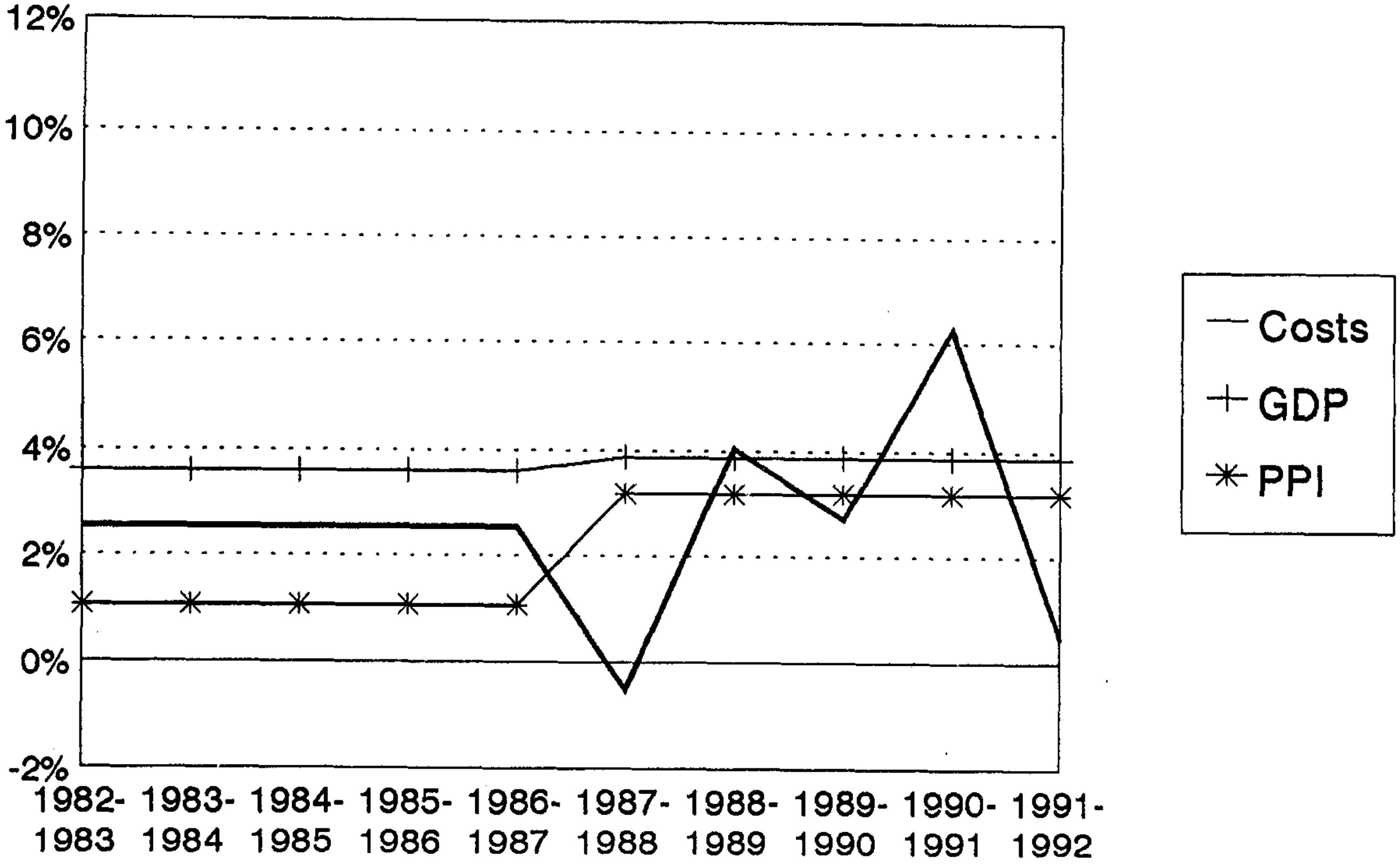
	1982–87	1987–92	1982–92
Operating expenses per barrel mile			
Weighted Average	3.22%	4.79%	3.82%
Unweighted average	2.15%	4.04%	3.11%
Median	2.20%	3.35%	3.37%
Composite	2.52%	4.06%	3.43%
Producer price index	1.06%	3.17%	2.11%
Difference from composite	–1.46%	–0.89%	–1.32%
Gross domestic product deflator	3.60%	3.87%	3.73%
Difference from composite	1.08%	–0.19%	0.30%

Notes:

1. Based on the middle 50 percent of crude oil pipelines for which a 1982 Form 6 report is available (the expanded sample).
2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982–1992 rate of change is not an average of the rates of change over the two five–year periods.
3. The "composite" is an average of the other three measures.

Product Pipelines

Year-to-Year Change in Operating Expenses Per BBL-Miles
Composite of Median and Weighted and Unweighted Average



costs: the return on their investment and the income taxes associated with that return--a large element of costs for so capital-intensive an industry as this one.

To take account of these capital costs--the changes in return and income taxes per barrel-mile--we have calculated the changes in net plant--that is, investment in plant less accumulated depreciation--for the same companies. Changes in net plant differ from the changes in the return and income tax components of company costs because the latter vary also with allowable rates of return (or, roughly, the cost of capital) and income tax rates. During the period from 1982 to 1992, both of these declined; if we had taken those declines into account, it would have further reduced our calculated rates of increase in pipeline costs per barrel-mile and further supported our recommendation of the PPI less an X factor. Since what is at issue, however, is the choice of an index for application from 1992 onward, and we have no basis for estimating future changes in either of these two factors, I suggest that our exclusion of them from our analysis of the past and recommendations for the future is proper.[3]

The incorporation of changes in net plant per barrel mile would have no effect on the conclusions drawn from operating costs alone if the two had increased at the same rate. In the case of product pipelines they did not. On the contrary, net plant generally declined over the decade, as new investments fell short of the combined effect of depreciation and abandonment of existing facilities. Moreover, since barrel-miles increased over the period, the decline in net plant per barrel-mile was even greater, as Table 3 shows.

There remains the task of combining the average annual changes in these two elements of unit costs--unit operating expenses and unit return on investment, as represented by changes in net plant per barrel-mile. We did so on the basis of the ratio of the pipelines' operating expenses to

[3] We now know, as of this writing, that the corporate income tax has been increased marginally. To the extent the result is an increase in cost, presumably that increase will be reflected in the PPI as well, except for the fact that it is likely to bulk larger for a capital-intensive industry like pipelines than on average in the economy at large. To the extent that the Commission regards this change--more significantly, the difference between its effect on pipelines and on the PPI--as sufficient to justify its doing so, it can of course adjust its formula on an ad hoc basis to take it into account, just as most indexation formulas make explicit provision for such truly exogenous changes in costs.

Table 3
PRODUCT PIPELINES
COMPARISON OF ANNUAL RATE OF CHANGE
OF NET PLANT PER BARREL-MILE
WITH PPI AND GDP DEFLATOR

	1982-87	1987-92	1982-92
Operating expenses and net plant			
Weighted Average	-1.02%	0.41%	-1.52%
Unweighted average	-3.63%	-0.47%	-2.13%
Median	-2.03%	-2.65%	-3.84%
Composite	-2.23%	-0.90%	-2.50%
Producer price index	1.06%	3.17%	2.11%
Difference from composite	1.96%	5.67%	2.11%
Gross domestic product deflator	3.60%	3.87%	3.73%
Difference from composite	4.50%	6.37%	3.73%

Notes:

1. Based on the middle 50 percent of product pipelines that (i) have no crude operations and (ii) for which a 1982 Form 6 report is available.
2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982-1992 rate of change is not an average of the rates of change over the two five-year periods.
3. The "composite" is an average of the other three measures.

operating revenues, with the residuum representing total return on investment before tax. The results are the ones shown earlier in Table 1--a rate of increase in total unit costs consistently lower than in the PPI-FP, and much lower than in the GDP deflator.

Crude oil pipelines

Our analysis of crude oil pipelines was limited to their operating expenses; we were unable within the time available to us to take into account changes in their net investment. Since these expenses comprised only about 68 percent of the operating revenues of a broad sample of crude oil pipelines in 1992[4] and since incorporation of capital costs substantially affected the results in the case of the product lines, this omission means that whatever conclusions about selection of the best index for the crude oil pipelines may flow from the operating expenses experience alone must be regarded as highly tentative.

The limited evidence we have been able to compile so far suggests use of the GDP deflator, but only because the clear superiority of the PPI during the five-year period 1982-1987 (when, however, it "erred" on the low side) is outweighed during the next five years, in comparison with the GDP deflator, by the apparent sharp increase in the average annual inflation of pipeline expenses. At most, however, this showing would justify adoption of the deflator as an interim measure only, and only pending further study.

The first reason additional investigation is necessary is the one I have already mentioned: our inability thus far to have taken into account the return on investment component of total costs. The other reason is the erratic behavior of the operating expenses figures themselves. These appear in Table 4 and Figure 2.

Probably the most striking feature of that experience is the dramatic contrast between the 1982-1987 and 1987-1992 periods. During the former, the average rate of annual increase in expenses per barrel-mile was 1.46 percent, as measured by our composite of the median and

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[4] For this calculation, the sample consisted of the 43 crude oil pipelines for which a *Form 6* report was available, but eliminating pipelines that did not report both operating expenses and operating revenues for that year. The latter exclusion produced a total sample of 39 companies.

Table 4
CRUDE OIL PIPELINES
COMPARISON OF ANNUAL RATE OF CHANGE
OF OPERATING EXPENSES PER BARREL–MILE
WITH PPI AND GDP DEFLATOR

	1982–87	1987–92	1982–92
Operating expenses per barrel–mile			
Weighted Average	1.93%	8.14%	5.50%
Unweighted average	0.95%	6.48%	4.46%
Median	1.46%	5.69%	5.48%
Composite	1.45%	6.77%	5.15%
Producer price index	1.06%	3.17%	2.11%
Difference	0.39%	3.60%	3.04%
Gross domestic product deflator	3.60%	3.87%	3.73%
Difference	–2.15%	2.90%	1.42%

Notes:

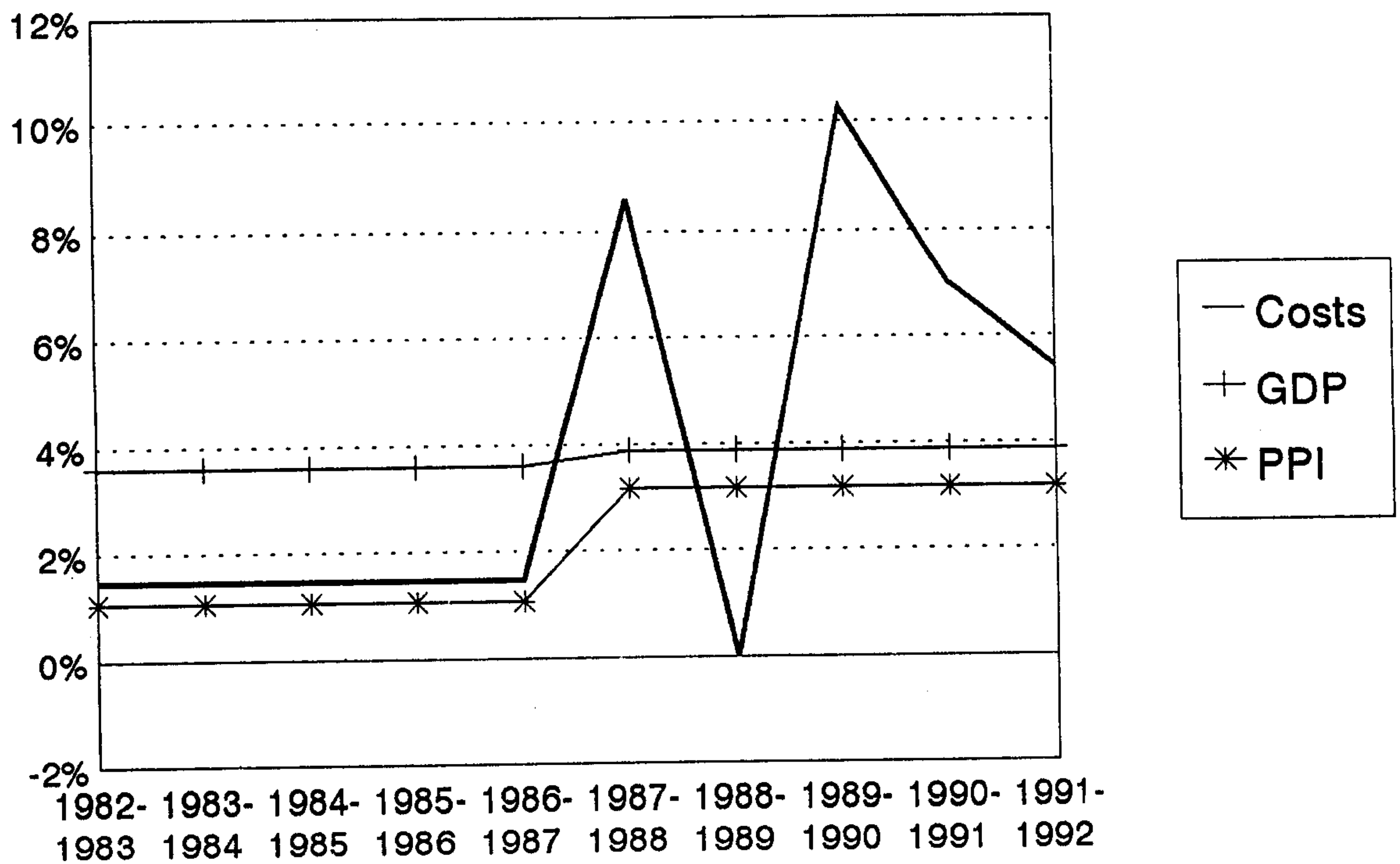
1. Based on the middle 50 percent of crude oil pipelines for which a 1982 Form 6 report is available (the expanded sample).

2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982–1992 rate of change is not an average of the rates of change over the two five–year periods.

3. The "composite" is an average of the other three measures.

Crude Oil Pipelines

Change in Operating Expenses Per BBL-Miles
Composite of Median and Weighted and Unweighted Average



weighted and unweighted averages, and by all the measures the rate of change was significantly closer to the PPI-FP than to the GDP. Between 1987 and 1992, in contrast, unit operating expenses increased at an average annual rate of 6.77 percent (according to the composite measure). The volatility of the year-to-year changes during the later period (for which alone we have calculated them[5]) is also greater for the crude oil than the product lines, as a comparison of Figures 1 and 2 will show.

The rapid increase in reported unit operating expenses for the 1987-1992 period, on average, is puzzling because of its contrast not only with the previous five years but also with the contemporaneous behavior of crude oil pipeline rates, as the latter are reflected in the pipelines component of the PPI. Under the Interstate Commerce Act, the maximum period of time for which a rate increase proposed by a pipeline can be suspended before going into effect subject to refund is seven months, and the Commission's practice has been to do so for only one day. One would therefore expect cost increases of the magnitude shown by the Form 6 data to have been accompanied, after a brief delay at most, by similar increases in rates. As I have already observed, however, the PPI index for crude oil pipelines excluding Trans-Alaska increased by only 2.3 percent over the entire six years between 1986 and 1992.

A closer analysis of the behavior of total crude oil pipeline costs than we have been able to perform is clearly necessary. One reason is the contrast between the increases in operating expenses over the decade and the apparently much more modest rate increases. A second reason is the extraordinary increase in reported unit operating costs over the last five years. The ultimate question, after all, is how total costs (including the important element of gross returns on investment, which we have not been able to incorporate in our analysis) are likely to behave in the next five years. Only then should it be possible to make an informed judgment about which economy-wide price index is likely to track those costs more closely.

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[5] The computer data base that we used to analyze the 1987-1992 period includes the information for each year. For the 1982-1987 comparisons we had to compile the information from the individual Form 6 reports, and were unable to make the year-to-year comparisons within that period in the time available to us.

APPENDIX
DATA AND METHODOLOGY

This appendix discusses in more detail the data and methods of analysis used in this testimony.

DATA

For the period since 1986, the changes in crude and product pipeline rates can be tracked through their respective components of the PPI. With that exception, the necessary data must be taken from the annual Form 6 reports that interstate oil pipelines are required to file with the Commission. These report pipeline revenues, throughput in barrels and barrel-miles, operating expenses and plant in service. In principle, therefore, they permit the calculation of annual rates of change in unit revenues, expenses and in gross and net investment. They are, however, subject to limitations of both availability and quality.

Availability

These limitations are of two kinds. One has to do with the availability of the Form 6 reports themselves. For the 1987-1992 period, one can obtain a complete set in a computer data base.[1] For the period before 1987, however, it is necessary to rely on the reports at the Commission. The Commission has apparently retained none of them for the period before 1982. For 1982 through 1986 period, there are reports for approximately two-thirds of all the pipelines.

As I observe in the text of this testimony, it might have been useful to test the application of the alternative price indexes during a period of rapid economy-wide inflation such as 1977-1982, when the GDP deflator rose almost exactly 50 percent, as well as for 1982-1987 and 1987-1992, when it rose by 19 percent and 21 percent respectively. Our inability to do so is not a significant

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[1] 1993 The Petroleum Pipeline Encyclopedia, Diskette Version, Oil Pipeline Research Institute, Inc.

shortcoming, however, in view of the unlikelihood of such a high rate of inflation recurring during the next decade.

In addition, the Form 6 reports of companies with both crude and product pipeline operations do not consistently report their total plant in service separately for the two. This creates no problems in the analysis of operating expenses, but it means the analyses of--or that make use of--net plant in service had to exclude all companies that operate both crude and product pipeline systems.[2]

The combined effect of these two limitations on the number of pipelines for which usable data are available is summarized in Table 1.

Table 1
Pipelines for Which
Data are Available

	Product	Crude
Pipelines with operations in both 1987 and 1992	54	64
Pipelines for which 1982 Form 6 reports also are available	37	43
Of these, pipelines with only crude or products operations	25	NA

<u>Quality of the Form 6 data</u>

Form 6 reports are typical of the annual reports that utility commissions commonly require from the companies subject to their jurisdiction. Although they are certified to be correct, they inevitably reflect errors in the entry or transcription of the underlying data. The most readily identifiable of these are the result of inconsistent reporting of throughput: in a number of cases, the

[2] Pipelines do in general distinguish between crude and product <u>depreciable</u> plant. Within the time available, it was not possible to determine whether that disaggregation is consistently available for the 1982-1992 period and, if so, whether it would have been sensible to use those figures as a substitute for total plant.

reported numbers strongly suggest that the units have changed between two reporting periods--for example, from barrel-miles to thousands of barrel-miles. Such a change will of course have a dramatic (and entirely illusory) effect on reported unit costs, causing them to increase or decrease at an extraordinary rate from one year to the next. It is impossible to identify data entry errors such as these directly or to distinguish them from actual sudden and dramatic changes in operations, except in the context of a rate case or similar proceeding.

To avoid the distorting effect of the more significant errors--as well as of extreme erratic and atypical changes in actual operations--we have in all our analyses of Form 6 information confined our attention to statistics for the middle 50% of the pipelines--that is to say, that exclude the highest and lowest 25 per cent, as I describe more fully below.

METHODOLOGY

Selection of the sample

Our original plan was to base our analysis on a stratified sample drawn from the set of pipelines that were in operation during the 1987-1992 period and for which a Form 6 report was available also for 1982--43 crude oil and 37 product lines, in total. That *original sample* consisted of 17 crude oil and 17 product pipelines.[3]

It soon became apparent that it would be necessary to exclude results at the two ends of the scale, in order to eliminate the effect of apparent data entry errors (and of erratic, extreme fluctuations in actual costs). To this end, we decided to base our analyses on the middle 50 percent of the sample, ranked in each case with respect to the variable being analyzed--for example, rate of increase in costs per barrel-mile. This means that the middle 50 percent we selected consisted of

[3] We selected separate samples for crude and product pipelines. For each of those categories, the sample consisted of (i) the three pipelines with the largest 1992 throughput, measured in barrel-miles, (ii) a random sample of approximately one-half of the remaining pipelines with a 1992 throughput of at least 1,000 million barrel-miles, and (iii) two randomly selected from pipelines with an 1992 throughput of less than 1,000 million barrel-miles. For purposes of both this sample and the expanded one, the crude and product operations of pipeline companies with both types of operation were treated as separate pipelines.

a group of companies the composition of which changed from one set of interyear comparisons to another, because we identified them independently for each variable and for each time period over which we measured its rate of change. Whenever we combined one set of comparisons with another, however, we of course used *the same set of companies, whose results fell in the middle 50 percent for that particular comparison:* we did not commit the error of mixing apples and oranges.

When applied to the original sample, the exclusion of the upper and lower 25 percent of the pipelines limited consideration to only eight or nine of them. We therefore expanded the sample to include all pipelines that were in operation during the 1987–1992 period for which a Form 6 report was available for 1982--43 crude oil and 37 product pipelines before exclusion of the upper and lower 25 percent: these made up our *expanded sample*. Because, however, of the failure of combination companies consistently to disaggregate their crude oil and property accounts, as I have already pointed out, we had to use a sub-set of the expanded sample (*expanded sample II*) for analyzing changes in carrier plant.

<u>Variables measured</u>

The samples were used primarily to analyze rates of change in three measures of pipeline costs: operating expenses per barrel-mile, net investment per barrel-mile, and a weighted average of the two. The basis for the relative weighting of the first two in calculating the third was the ratio of operating expenses to operating revenues for the individual pipeline or group of pipelines.[4]

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[4] The ratio we used was the average of the operating expense/operating revenue ratios for the beginning and end years of the period over which we were calculating the rate of change. In a few cases, a pipeline failed to report operating revenues for one of those years, even though it did operate in that year. In those cases, we used the ratio for the year for which operating revenues were reported.

For the composite group of pipelines, the ultimate calculation of the weighted average change in total costs (operating expenses plus capital costs) was based on the rates of change in the weighted average operating expenses and weighted average net investment per barrel mile. We combined these two components with respective weights derived from the ratio of the total operating expenses to total operating revenues for the group of pipelines.

(Mechanically, we used that specific ratio directly to weight the rate of change in operating expenses per barrel-mile, and weighted the rate of change in net investment per barrel-mile by its residual: one minus operating expenses/operating revenues.)

It is probably desirable to explain two of our specific measures of cost. One was our use of barrel-miles rather than barrels as the denominator. The reason is that most pipeline costs--return, depreciation, fuel and some other operating expenses increase with distance as well as volume.

The other has to do with our use of changes in net plant as a measure of changes in return and income taxes. I discuss in the text of my testimony the implications of the fact that these costs vary also with the rates of return and of income taxes.

Dispersion of results and its implications for the choice of a measure of central tendency

Even after exclusion of the upper and lower 25 percent, there remained a relatively wide dispersion among pipelines in the changes in their unit costs. For example, the average annual rate of increase in operating expenses per barrel mile for the middle 50 percent of product pipelines over the 1987 to 1992 period ranged from -0.1 percent to 6.45 percent.

Because of the dispersion, there is no single measure of the changes in "industry" costs clearly superior to the others. For this reason, the analysis in this testimony presents four measures of central tendency--the median, the unweighted average, the weighted average,[5] and an average of the other three measures. Fortunately, all of them support the same conclusion, as far as product pipelines are concerned.

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[5] The weighted average used for the analysis is the annual rate of change of the weighted average operating expenses or net plant per barrel-mile. This measure is equivalent to treating the middle 50 percent of the pipelines--the same pipelines at the beginning and terminal date of each separate time period studied--as a single consolidated entity.

n/e/r/a

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Professor Kahn was appointed by President Carter to serve as Advisor to the President on Inflation and as Chairman of the Council on Wage and Price Stability.

At the time of his appointment, Professor Kahn was serving as Chairman of the Civil Aeronautics Board. He previously served as Chairman of the New York Public Service Commission.

Professor Kahn received his Bachelor's and Master's degrees from New York University and a Doctorate in Economics from Yale University. Following service in the Army, he served as Chairman of the Department of Economics at Ripon College, Wisconsin. He moved to the Department of Economics at Cornell University, where he remained until he took leave to assume the Chairmanship of the New York Public Service Commission. During his tenure at Cornell, Professor Kahn served as Chairman of the Department of Economics, Robert Julius Thorne Professor of Political Economy, member of the Board of Trustees of the University and Dean of the College of Arts and Sciences.

Throughout his career, Professor Kahn has served on a variety of public and private boards and commissions including: the Attorney General's National Committee to Study the Antitrust Laws; the senior staff of the President's Council of Economic Advisors; the Economic Advisory Council of American Telephone & Telegraph Company; the National Academy of Sciences Advisory Review Committee on Sulfur Dioxide Emissions; the Environmental Advisory Committee of the Federal Energy Administration; the Public Advisory Board of the Electric Power Research Institute; the Board of Directors of the New York State Energy Research and Development Authority; the Executive Committee of the National Association of Regulatory Utility Commissioners; the National Commission for Review of Antitrust Laws and Procedures; the New York State Council on Fiscal and Economic Priorities; the Governor of New York's Fact-Finding Panel on Long Island Lighting Company's Nuclear Power Plant at Shoreham, L.I.; the Governor of New York's Advisory Committee on Public Power for Long Island; the National Governing Board of Common Cause; and, in 1990, as Chairman of the International Institute for Applied Systems Analysis Advisory Committee on Price Reform and Competition in the USSR. He served as Advisor to New York Governor Carey on communications policy and was Vice President of the American Economic Association.

He has received L.L.D. honorary degrees from Colby College, Ripon College, Northwestern University, the University of Massachusetts and Colgate University, and an honorary D.H.L. from the State University of New York, Albany; he also received the

Distinguished Transportation Research Award of the Transportation Board Forum, The Alumni Achievement Award of New York University, the award of the American Economic Association's Transportation and Public Utilities Group for Outstanding Contributions to Scholarship, The Henry Edward Salzberg Honorary Award from Syracuse University for Outstanding Achievement in the Field of Transportation, and the Burton Gordon Feldman Award for Distinguished Public Service from Brandeis University; and was elected to membership in the American Academy of Arts and Sciences. He is a regular commentator on PBS's "The Nightly Business Report."

He has testified before many U.S. Senate and House Committees, the Federal Power Commission, the Federal Energy Regulatory Commission and numerous state regulatory bodies.

Professor Kahn's publications include *Great Britain in the World Economy; Fair Competition: The Law and Economics of Antitrust Policy* (co-authored); *Integration and Competition in the Petroleum Industry* (co-authored); and *The Economics of Regulation*. He has written numerous articles which have appeared in *The American Economic Review, The Quarterly Journal of Economics, The Journal of Political Economy, Harvard Law Review, Yale Journal on Regulation, Yale Law Journal, Fortune, The Antitrust Bulletin* and *The Economist*, among others.

EDUCATION:

YALE UNIVERSITY
Ph.D., Economics, 1942

UNIVERSITY OF MISSOURI
Graduate Study, 1937-1938

NEW YORK UNIVERSITY
M.A., Economics, 1937
A.B. (summa cum laude), Economics, 1936

EMPLOYMENT:

1961-1974 1980-	NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC. Special Consultant
1947-1989	CORNELL UNIVERSITY Assistant Professor; Associate Professor; Robert Julius Thorne Professor of Economics; Robert Julius Thorne Professor of Political Economy, Emeritus, 1989-; Chairman, Department of Economics; Dean, College of Arts and Sciences; on leave 1974-80.
Spring 1989	NEW YORK UNIVERSITY SCHOOL OF LAW Visiting Meyer Professor of Law

	UNITED STATES GOVERNMENT
1978-1980	Advisor on Inflation to President Carter
1978-1980	Chairman, Council on Wage and Price Stability
1977-1978	Chairman, Civil Aeronautics Board
1955-1957	Senior Staff, Council of Economic Advisors to the President
1943	U.S. Army, Private
1943	War Production Board
1942	Associate Economist, International Economics Unit, Bureau of Foreign and Domestic Commerce, Department of Commerce
1941-1942	Associate Economist, Antitrust Division, U.S. Department of Justice
	NEW YORK STATE PUBLIC SERVICE COMMISSION
1974-1977	Chairman
	BROOKINGS INSTITUTION
1940, 1950-1951	Staff Economist
	RIPON COLLEGE
1945-1947	Assistant Professor, Chairman, Department of Economics
	TWENTIETH CENTURY FUND
1944-1945	Research Economist
	COMMISSION ON PALESTINE SURVEYS
1943-1944	Economist
	UNIVERSITY OF MISSOURI
1937-1938	Teaching Assistant

CONSULTANCIES AND PROFESSIONAL ACTIVITIES:

1992	New Zealand Telecom on the progress of competition in New Zealand telecommunications
1992	Rochester Telephone Company on corporate restructuring and deregulation
1992	Russian Government on economic reform
1991	British Mercury on terms of competition with British Telecom
1989	City of Denver on charging and financing of Stapleton Airport
1988-1990	Attorneys General, New York and Pennsylvania, on airline mergers
1985	Attorney General, State of Illinois, on Illinois Bell rates
1981-1984	City of Long Beach, California, the Coca-Cola Company and American Airlines on antitrust litigation
1981-	Economic commentary, Nightly Business Report (PBS)
1980-1982	Advisor to Governor Carey on Telecommunications Policy
1968	Ford Foundation
1966	National Commission on Food Marketing
1965,1974	Federal Trade Commission
1963-1964	Antitrust Division, Department of Justice
1960-1961	U.S. Department of Agriculture
1957-1961	Boni Watkins, Jason & Co.

See also the list of testimony below.

MEMBERSHIPS:

1992-	Member, New York State Telecommunications Exchange
1992-	Member, Ohio Blue Ribbon Panel on Telecommunications Regulation
1991-	Board of Editors, *Review of Industrial Organization*
1990-91	Chairman, International Institute for Applied Systems Analysis Advisory Committee on Price Reform and Competition in the USSR
1986	Governor Cuomo's Advisory Panel on public power for Long Island
1983-89	Governor Cuomo's Fact-finding Panel on Long Island Lighting Company's Nuclear Power Plant at Shoreham, L.I.
1983-90	New York State Council on Fiscal and Economic Priorities
1982-	*The American Heritage Dictionary* Usage Panel
1982-1985	Governing Board, Common Cause
1980-1986	Director, New York Airlines
1978-1979	National Commission for the Review of Antitrust Laws and Procedures
1975-1977	Project Committee, Electric Utility Rate Design Study, Electric Power Research Institute
1974-1975	National Academy of Science Review Commission on Sulfer Oxide Emissions
1974-1977	Public Advisory Board, Electric Power Research Institute
1974-1977	Environmental Advisory Committee, Federal Energy Administration
1974-1977	Executive Committee, National Association of Regulatory Utility Commissioners, and Chairman, Committee on Electric Energy
1968-1974	Economic Advisory Board, American Telephone & Telegraph Corporation
1965-1967	Economic Advisory Committee, U.S. Chamber of Commerce
1967-1969	Chairman, Tompkins County Economic Opportunity Corporation
1964-1969	Board of Trustees, Cornell University
1961-1964	Board of Editors, *American Economic Review*
1953-1955	Attorney General's National Committee to Study the Antitrust Laws

HONORS AND AWARDS:

Mar 1989	Burton Gordon Feldman Award for Distinguished Public Service, Gordon Public Policy Center, Brandeis University
Feb 1989	Distinguished Service Award, Public Utility Research Center, University of Florida
Nov 1988	International Film and TV Festival of New York, Bronze Medal presented to The Nightly Business Report/WPBT2 for Editorial/Opinion Series written by Alfred E. Kahn
Apr 1986	Harry E. Salzberg 1986 Honorary Medallion for outstanding achievement in the field of transportation
Oct 1984	Distinguished Transporation Research Award of the Transportation Research Forum
1981-1982	Vice President, American Economic Association
1978	Richard T. Ely lecturer, American Economic Association, 1978
1978	Rejection Scroll, International Association of Professional Bureaucrats
May 1985	State University of New York (Albany), DHL (Hon.)
May 1983	Colgate University, LL.D. (Hon.)
June 1982	Northwestern University, LL.D. (Hon.)
May 1980	Ripon College, LL.D. (Hon.)
May 1979	University of Massachusetts, LL.D. (Hon.)
May 1978	Colby College, LL.D. (Hon.)
1977-	Fellow of the American Academy of Arts and Sciences
1976	Distinguished Alumni Award, New York University

1976	American Economic Association, Section on Public Utilities and Transportation, citation for distinguished contributions
1954-1955	Fulbright Fellowship, Italy
1935-	Phi Beta Kappa
1939-1940	Yale-Brookings Fellow

BOOKS:

The Economics of Regulation, 2 volumes, John Wiley, 1970 and 1971. Reprinted by The MIT Press, 1988, with a new "Introduction: A Postscript, Seventeen Years After," pp. xv-xxxvii.

Integration and Competition in the Petroleum Industry, (with Melvin G. DeChazeau), Petroleum Monograph Series, Volume 3 (Yale University Press, 1959). Reprinted in 1971.

Fair Competition: The Law and Economics of Antitrust Policy (with Joel B. Dirlam) (Cornell University Press, 1954). Reprinted by Greenwood Press, 1970.

Great Britain in the World Economy (Columbia University Press, 1946). Reprinted in 1968.

MAJOR ARTICLES:

"The Competition Consequences of Hub Dominance: A Case Study," in *Review of Industrial Organization*, Vol. 8, 1993, pp. 381-405.

"Pricing of Telecommunications Services: A Comment," in *Review of Industrial Organization*, Vol. 8, 1993, pp. 39-41.

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Verified Statement before the Interstate Commerce Commission in Coal Trading Corporation, et al. v. Baltimore & Ohio Railroad Company, et al. (Docket No. 38301S) on the computation of rail stand-alone costs, April 1988.

Testimony on behalf of Public Service Electric & Gas Company, New Jersey on the used and useful doctrine in the context of utility performance standards, April 1988.

Testimony on behalf of the U.S. Postal Service on the pricing of Express Mail, March 28, 1988.

Testimony on behalf of Kentucky Industrial Utility Customers Case No. 9934 on the criteria for deciding whether a nuclear plant should be completed, February 8, 1988.

Testimony and Rebuttal Testimony before the Iowa State Utilities Board Department of Commerce on behalf of Northwestern Bell on the regulatory treatment of depreciation reserve deficiencies, October 1987 and November 1987.

Testimony before the State of Connecticut Department of Public Utility Control on behalf of the Connecticut Cable Television Association on regulating cable television rates, November 13, 1987.

Testimony before the Federal Communications Commission on behalf of Bell South In the Matter of Policy and Rules Concerning Rates for Dominant Carriers (CC Docket 87-313) October 1987 and Reply Testimony, November 1987.

Reply Verified Statement before the Interstate Commerce Commission on behalf of McCarty Farms et. al. and Montana Department of Commerce, on the stand-alone cost constraint on railroad rates to captive shippers, October 2, 1987.

Testimony before the New York State Public Service Commission on behalf of New York Telephone Company on assessing the competitiveness of telecommunications markets, April 1987.

Testimony before the New Jersey Senate Energy and Environment Committee on behalf of Public Service Electric and Gas Company on draft bill, No. 2801, the "Electricity Market Pricing Act of 1986," January 26, 1987.

Testimony before Federal Energy Regulatory Commission on behalf of Interstate Natural Gas Association of America on "Competitive Implications of Natural Gas Pipeline Marketing Affiliates," December 29, 1986.

Testimony before the New York State Public Service Commission on behalf of the Owners Committee on Electric Rates, Inc., on rent-inclusion and submetering, November 19, 1986.

Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company on standard for deciding whether Braidwood Unit 2 should be cancelled, August 4, 1986.

Verified Statement on Standards for Railroad Revenue Adequacy, on Interstate Commerce Commission's Ex Parte No. 393, Sub-No.1, July 1986.

Supplemental Verified Statement before the Interstate Commerce Commission, Docket No. 38783, Omaha Public Power District v. Burlington Northern Railroad Company on behalf of Omaha Public Power District, April 1986.

Statement to Federal Communications Commission on New England Telephone Company's Proposed Interstate Access Tariff Restructure, January 30, 1986.

Testimony before the Public Utilities Commission of the State of Oregon on inverted rate structures on behalf of the Pacific Power & Light company, January 1986.

Rebuttal Testimony before the California Public Utilities Commission on San Onofre nuclear plants on behalf of Southern California Edison Company, January 1986 and En Banc Proceeding, February 1986.

Testimony and rebuttal testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company on economic and regulatory principles applicable to entry of nuclear plants into rate base, December 1985, March 1986, December 1986 and March 1987.

Testimony before the Corporation Commission of the State of Oklahoma on economic principles applicable to access charges, Cause No. 29321 on behalf of Southwestern Bell Telephone Company, September 1985.

Testimony before the California Public Utilities Commission on regulatory principles applicable to prudence determinations on behalf of Southern California Edison Company, August 1985.

Testimony before the Corporation Commission of the State of Oklahoma on development of intrastate access charges, Cause No. 28309 on behalf of Southwestern Bell Telephone Company, May 1985.

Verified Statement before the Interstate Commerce Commission, Docket No. 38783 on behalf of Omaha Public Power District, on the grouping of captive shippers for purposes of applying a stand-alone cost test of contested rail rates, November 1984.

Testimony before the House Public Policy and Veterans Affairs Committee of the Indiana General Assembly on behalf of the Indiana Telephone Association, October 25, 1984.

Testimony before the Iowa State Commerce Commission, Docket No. INU-84-6, Investigation into competition in communications services and facilities, October 18, 1984.

Testimony and rebuttal testimony on current cash support for construction and the reorientation of regulatory policy before the Maine Public Utilities Commission, in the matter of Central Maine Power Company's proposed increase in rates, Docket No. 84-120, August 1984 and February 1985.

Testimony and rebuttal testimony for Illinois Power Company on rate base treatment of construction work in progress, before Illinois Commerce Commission, Docket No. 84-0480, August 1984 and April 1985.

Verified Statement before the Interstate Commerce Commission, Docket No. 39687, on behalf of Platte River Power Authority, on the proper definition of the cost of capital for purposes of applying a stand-alone cost test of contested rail rates, July 1984.

Verified Statement and Surrebuttal Verified Statement Before the Interstate Commerce Commission, Finance Docket No. 30300 on behalf of the Water Transport Association, in opposition to the application of CSX Corporation to acquire American Commercial Barge Lines, Inc., February 14, 1984 and April 19, 1984.

Direct and rebuttal testimony, Federal Energy Regulatory Commission, Trans Alaska Pipeline System, Dockets Nos. OR 78-1-014 and OR 78-1-016 (Phase I Remand) November 1, 1983 and December 23, 1983.

Verified Statement, Interstate Commerce Commission, on the stand alone test for rail rates to captive shippers, on behalf of Utility Fuels, Inc., Docket No. 39002, October 3, 1983.

Testimony on telephone rate structures before the Colorado Public Utilities Commission for Mountain States Telephone & Telegraph Company, May 27, 1983; the California Public Utilities Commission, for Pacific Telephone & Telegraph Company, August 18, 1983; the Missouri Public Service Commission, September 8, 1983; and Texas Public Service Commission, September 19, 1983, for Southwestern Bell Company.

Testimony before the Utility Diversification Committee of the Legislature of the State of New Mexico, September 2, 1982.

Testimony before the Ad Hoc Committee on Utility Diversification, National Association of Regulatory Utility Commissioners, May 6, 1982.

Testimony before Motor Carrier Ratemaking Study Commission, Orlando, Florida, April 2, 1982.

Testimony before the State of Connecticut Department of Public Utility Control on methods of regulating rates for basic television cable service, March 9, 1982.

Testimony before the Committee of Energy and Public Utilities, The General Assembly of the State of Connecticut on regulation of cable television, March 1, 1982.

Testimony before the Public Utilities Commission of the State of California, for Pacific Power & Light Company on methods of allocating aggregate revenue requirements, September 24, 1981.

Verified Statement, Interstate Commerce Commission, Ex Parte No. 347 (Sub-No. 1), "Coal Rate Guidelines-Nationwide," September 1981.

Testimony for the Department of Justice in the U.S. v. Standard Oil Co. (Indiana) et al. Civil Suit 40212, filed July 28, 1964.

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REGULATORY COMMISSION

August 12, 1993

BY HAND

The Honorable Lois D. Cashell
Secretary
Federal Energy Regulatory Commission
Room 3110
825 North Capitol Street, N.E.
Washington, D.C. 20426

Re: Notice of Proposed Rulemaking in FERC Docket No. RM93-11-000

Dear Secretary Cashell:

Enclosed for filing are the original and fourteen copies of the Comments of ARCO Pipe Line Company and Four Corners Pipe Line Company on the Notice of Proposed Rulemaking in the above-captioned matter. I would appreciate it if you would date-stamp the additional copy and return it to the messenger for our files. Thank you for your assistance.

Sincerely,

Steven Reed

Steven Reed

Enclosures

FERC DOCKETED

AUG 12 1993

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