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September 20, 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 Inc. (FBC)

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

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

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-109-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

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

1. Exhibit B-1, page 1

> FBC's primary objectives for its PBR Plan are:
>
> 1. To reinforce FBC'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 explain why the FBC culture for productivity improvement needs reinforcing.

Response:

Please refer to the response to BCMEU IR 1.2.0.

1.2 Please provide examples of the failures of the FBC productivity improvement customer that would need reinforcing.

Response:

Please refer to the response to BCMEU IR 1.2.0.

1.3. Please provide documentation of the other approaches to productivity improvement FBC has considered as potentially cost effective and or has used without PBR in place.

Response:

FBC has not considered other approaches to productivity such as reengineering which focuses on the redesign of the organization, as it believes the focus on ongoing improvement is more appropriate. Reinforcing a productivity focus in the organization's culture and encouraging actions to review embedded practices and rethink work with the view to improve efficiency and effectiveness is cost effective and appropriate for its business.

1.4. Please provide a quantitative baseline analysis of efficiency for the regulatory process, with all appropriate metrics defined, and provide the FBC expectation for a more efficient regulatory process in quantitative terms consistent with the baseline analysis.

Response:

FBC believes an efficient regulatory process is one that is "reasonable, transparent, and responsive to new opportunities while rendering decisions in a timely manner". These are desired characteristics which must be assessed and balanced against each other to arrive at a solution that meets the different needs.

For example, with new legislation regarding energy policy, clear interpretation or direction is imperative to enable regulators and companies to act quickly in response to new opportunities. Governments, business and regulators must work together to ensure a common understanding of the legislation's intent as well as implement a timely and efficient regulatory process. This will facilitate innovation and better enable B.C. to leverage the full potential of the economy to the benefit of taxpayers, energy consumers and investors.

Additionally, an efficient regulatory process recognizes the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. Of importance is the company's success in achieving reasonable regulatory decisions from the BCUC on the company's regulatory applications while maintaining constructive relationships with stakeholders.

Given the circumstances, FBC believes measurement of the efficiency of the regulatory process is best done subjectively. However, if FBC's proposal is accepted, there are two broad categories of efficiencies that will likely accrue to customers. They are:

1. Savings of incremental costs associated with avoided annual or bi-annual rate hearings. These could save customers approximately $0.5 million to $2.0 million annually. In total over the proposed five year term of the PBR, this would equate to approximately $2.5 million to $10.0 million. These incremental costs associated with lawyers, consultants, experts, Commission, intervener and hearing venue costs are deferred and amortized into customer rates as hearing costs; and

2. There are indirect costs associated with the amount of effort within the Company directed to managing the regulatory process, rather than being able to focus on managing the Company. Many dozens of people within the Company are affected by the regulatory process, performing that work in addition to their main work. Allowing

these employees to focus more attention on operating the business will assist the Company with identifying efficiencies and with achieving other improvements in operations without incurring additional costs for additional resources.

2. Exhibit B-1, Page 1

> capital costs over the five year period as set out in Section B. 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 FBC achieves greater efficiencies than represented by the formula-based targets. For those items over which FBC has limited or no control, the PBR Plan utilizes

2.1. Please confirm that FBC's 'investing' in new efficiencies, in the sense of providing capital will only be done with capital which would be fully paid for by the FBC customers or in the sense of providing management, employee and consultant time and effort will only be done with operating expenditures fully paid for by the FBC customers.

Response:

FBC agrees that the traditional regulatory compact would suggest that net benefits of capital projects and O&M initiatives that produce O&M savings would be reflected in customer rates upon rebasing, while the Company earns a fair return on its invested capital.

This fundamental relationship is true whether under cost of service regulation or under PBR. O&M and capital are rebased at the conclusion of a PBR to ensure the long term benefits of the savings go to customers. Customers achieve greater benefits in the long term under PBR than under traditional cost of service regulation because the PBR effectively delays rebasing to incent the utility to invest more to achieve new cost savings, efficiencies and/or new revenues. In the meantime, customers receive benefits through earnings sharing.

There is some risk to the Company regarding an incremental efficiency investment under PBR since, even with sharing of costs and benefits, the expected savings must materialize in order for there to be a payback and return before rebasing occurs.

2.2. Please confirm that to the extent FBC achieves efficiencies now, without a PBR process, they are 100% to the benefits of customers after a RRA period provided that the efficiencies are maintained.

Response:

Correct, since rebasing occurs after a specific test period. It should be noted, however, that the rebasing at the end of a test period has the effect of making some incremental investments in efficiencies uneconomic for the Company because payback cannot be achieved before rebasing occurs. Thus, the economics of efficiencies based on the management's responsibility to

shareholders will be different from the efficiencies achieved under PBR. This is one of the main factors for using PBR rather than the cost of service with regular RRA periods.

2.3. Please confirm that if FBC achieves efficiencies now, without a PBR, to the extent expenditures are below those approved for rate setting FBC's shareholder is the net beneficiary of 100% of expenditures below the approved levels for rate setting made by the Commission.

Response:

Conceptually, it is correct that the Company, and not customers, has the potential to benefit to the extent that expenditures are below those approved for rate setting in traditional cost of service ratemaking. However, the statement as written cannot be confirmed for two reasons. First, cost savings without the revenues equal to the approved revenues do not necessarily lead to earnings even equal to the allowed return hence the benefit to shareholders as related to earned ROE may not even be achieved. Second, ignoring for the moment the allowed ROE, the benefit to shareholders is less than 100% of the lower expenditures because of the tax effect.

3. Exhibit B-1, pages 1 and 2

> FBC's proposed PBR Plan builds on the successful components of its most recent PBR plan, which was approved for 2007 – 2008 and extended for 2009 – 2011 (the 2007 Plan), with improvements to a number of elements. The proposed PBR Plan establishes incentive for operating and maintenance (O&M) expense, similar to the 2007 Plan, and introduces a formula-based determination and incentive for capital expenditures. These are the two elements of cost of service over which the Company has the greatest control. The formula results in targeted levels of spending in these areas that are lower than FBC's combined forecast of O&M and capital costs over the five year period as set out in Section B. This provides the Company with

Element	PBR Plan
Term	A five-year term from 2014 to 2018 is proposed.

3.1. Why did FBC select a five year term as opposed to a two year term, possibly with extension as was done for 2007?

Response:

FBC believes that its 2007 - 2011 Plan was a success which resulted in further benefits for customers and the Company over what would have been the case under normal COS regulation. By building on its experience and success with PBR within this jurisdiction, FBC has proposed 5 year term that will reduce regulatory burden and make it economical for the Company to seek out incremental efficiencies before rebasing occurs. Shorter terms do not provide the same incentives and do not mirror the type of incentives from competitive markets to the same degree as longer term PBR Plans do. For example, in this regard a two year PBR Plan would be no different than cost of service based RRA on a biennial cycle.

3.2. How accurate does FBC consider its forecast of O&M over a five year period? Please provide evidence with examples from previous years with explanations as to why the forecasts were over or under.

Response:

FortisBC considers its forecast of O&M over the five year period of 2014-2018 to be a high level view that is reasonably indicative.

Past variances are not a result of inaccurate forecasts, but as a result of the Company having achieved greater cost savings as the PBR had incented it to do. The impact of savings on earnings was shared with customers pursuant to the 50/50 earnings sharing mechanism.

The average percent variance between approved and actual O&M during the period 2007-2011 is within a nominal variance of -1.5% as indicated in the Table below.

O&M Parameters	2007	2008	2009	2010	2011
Approved Gross O&M	43,093	45,310	46,573	47,645	53,885
Actual Gross O&M	43,001	44,725	46,017	46,148	53,076
Variance $	(92)	(585)	(556)	(1,497)	(809)
Variance %	-0.2%	-1.3%	-1.2%	-3.1%	-1.5%
Average Variance %	**-1.5%**				

3.3. How accurate does FBC consider its forecast of capital costs over a five year period? Please provide evidence with examples from previous years with explanations as to why the forecasts were over or under.

Response:

FBC's forecast of capital cost is based on the AACE International Recommended Practice No. 18R-97 with AACE Class 3 estimates provided for 2014 - 2015 projects and programs and AACE Class 4 estimates for 2016 – 2018 projects and programs.

The table below provides variance and variance explanation between actual and budgeted capital expenditure during 2007-2012 period. The variances primarily arose from factors not controllable by the Company. These factors and may be generally classified as:

1. Market related variance not previously anticipated;
2. Lower than anticipated customer activity; and
3. Project re-scheduling due to the timing of BCUC Decisions.

Years	Gross Loaded Expenditure (Without COR)		Variance Over / (Under)	Remarks
	Budget	Actual		
2007	133,660	143,742	10,082	Primarily due to the Kettle Valley Project escalation ($9M)
2008	124,934	111,579	(13,355)	Primarily delayed CPCN Approvals (OTR-$10M, Benvoulin - $5M)
2009	129,465	112,723	(16,742)	Primarily low customer activity ($8M) & Market driven savings in OTR Project ($9M)
2010	167,416	142,038	(25,378)	Primarily low customer activity ($3M) & Market driven savings in OTR ($19M) & Benvouline ($2M) Projects
2011	93,507	88,365	(5,142)	Primarily low customer activity ($5M)
2012	87,368	64,680	(22,688)	Rescheduled of projects mainly due to delayed BCUC decision, scope optimization and lower customer activity

The majority of these variances are related to capital projects that were approved pursuant to CPCN Applications. In the past, these CPCN capital project forecasts were included in Revenue Requirements. Going forward, beginning with this PBR Application, CPCN project forecasts have been excluded from Revenue Requirements until such time as the CPCNs are approved. Had this new treatment been in place historically, the majority of the above variances would not have occurred other than the market escalations experienced with the Kettle Valley Project and market savings experienced with the OTR project, as both of these projects were primarily price (as opposed to timing) variances.

4. Exhibit B-1, Page 3

> Overall, FBC believes that the proposed PBR Plan is an appropriate model that will encourage FBC 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, which has 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 FBC, with the exception that it regards the "stretch" productivity factor as being more aggressive than is warranted. B&V regards the appropriate productivity factor as being
>
> favourable to customers than B&V would recommend. FBC is nonetheless willing to incorporate a stretch factor and to attempt to achieve the 0.5 percent productivity factor proposed as part of an overall package. Section B of the Application provides a review of PBR in general, a review

4.1. Please confirm that FBC has only examined PBR plans as an approach to improving efficiency.

Response:

Not confirmed. There are other reasons that FBC proposes PBR unrelated to improving efficiency such as reducing regulatory processes and promoting an entrepreneurial culture for its employees that recognizes innovation.

4.2. Please confirm that the B&V mandate only included examination of PBR plans and did not allow for consideration of other approaches to achieving efficiency improvement.

Response:

Confirmed. The Company had considered PBR as the best possibility for achieving further efficiencies over and above its standard focus on productivity and past experience with PBR. The Commission's April 18, 2013 '2014 Revenue Requirements Application-Performance Based Rate Setting Environment' letter also placed focus on PBR. It requested FBC 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."*

4.3. Please explain why FBC is willing to incorporate .5% productivity factor as part of an overall package when it has not been recommended by B&V.

Response:

B&V made its recommendation for consideration as part of the assessment of PBR. Since B&V was not hired to be an advocate of the Companies' proposed X-Factor but rather to provide an independent review of PBR Plans and to develop estimates of TFP to provide guidance for FBC's proposal, FBC was not obligated to accept or reject B&V's recommendation. FBC was willing to take the additional risk of providing immediate benefits for customers through a positive X-Factor even though that exceeded the value that B&V felt to be appropriate. FBC views the B&V recommendation as a balanced risk and reward approach rather than the significant stretch that FBC proposes to undertake.

4.4. Does FBC find the B&V advice and recommendation inadequate such that FBC needs to upgrade the overall package?

Response:

No. FBC considers the B&V recommendation to be practically and theoretically sound and appropriate. Absent management's two-fold desire to stretch Company performance and provide initial up-front benefits for customers, the B&V recommendation would have been accepted. This is a case where a policy goal provided the impetus for a final decision. Please refer to the response to CEC IR 1.4.3.

Despite the positive X-Factor, B&V finds the PBR Plan as a whole to be reasonable, albeit not risk symmetric for reasonable policy reasons, and meets the goals FBC has articulated for the Plan.

4.5. Has FBC conducted an efficiency potential review examining all of its functions?

1

2 **Response:**

3 No. FBC relied on B&V's industry review of TFP.

4

5. Exhibit B-1, page 4 and Exhibit B-1-1 Appendix H-1, page 3

> As set out in Appendix H, FBC seeks acceptance of a Demand Side Management (DSM) portfolio over a five year term. The DSM expenditures under FBC's DSM Plan (Attachment H1) are lower than the expenditure levels approved for 2012 and 2013. This reduction is driven by a marked decrease in the Long Run Marginal Cost (LRMC), which is used in the evaluation of DSM measures and programs pursuant to regulation. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation. FBC is also seeking approval for a change in the amortization period of existing and future DSM expenditures from 10 years to 15 years, as set out in Appendix H.
>
> The 2014-18 DSM Plan is a modified extension of the 2012-13 DSM Plan, which received approval via Commission Order G-110-12. The 2014-18 DSM Plan programs, and expenditures, are reduced commensurate with the advent of the lower Long Run Marginal Cost (LRMC) of $56.61/MWh. The LRMC affects the Total Resource Cost test by reducing the benefit of power purchase reductions, which in turn makes fewer demand-side management programs and measures economic as prescribed by the Demand-Side Measures Regulation (DSM Regulation).

5.1. Please explain which demand side measures and programs are no longer considered cost effective/economic and how their costs relate to the LRMC.

Response:

Please refer to the response to BCSEA IR 1.20.2.1.

5.2. At what point (LRMC) does FortisBC believe that DSM programs are not cost effective?

Response:

FBC has not modelled the specific LRMC at which "all" program fall below a Benefit/Cost ratio (BCR) of unity. Individual measures and programs drop out as the LRMC declines, depending on how robust the BCR was to start with. Adequacy provisions and portfolio level costs (including Planning & Evaluation, and Supporting Initiatives such as Customer Education and Outreach) are to various degrees mandatory per the DSM regulation.

5.3. Is it FortisBC's view that those programs which remain cost effective have reached the maximum achievable savings annually?

Response:

Program savings are market driven and thus customer response is dependent on a host of market barriers or factors including customer awareness, measure availability, installer capacity, the incentive offer and the customers' financial capacity and hurdle rate.

The economic achievable potential, identified by Conservation Potential Reports, is achieved over the long-run, typically a 20-year timespan. To some degree this ramp-rate can be accelerated, but at a higher cost to the utility and its ratepayers.

5.3.1. If not, please explain why FortisBC would not choose to transfer DSM expenditures from less cost effective programs to more cost effective programs rather than reducing expenditures overall.

Response:

The first DSM guiding principle listed in Section 5.4 of Appendix H addresses the equity issue of having a broad offering available to all customers:

1. The DSM Plan will be customer focused by offering a range of measure choices within programs that address the key end-uses of the principal customer rate classes.

The most cost-effective programs for the utility are also often highly cost effective for customers, meaning that they require a lower incentive to encourage customers to participate.

6. Exhibit B-1-1 Appendix H page 1 and Appendix H1-1 page 3

> 2012 PowerSense programs, many of which FBC is proposing to continue. In sum, FBC's evidence in this Application demonstrates that the proposed DSM expenditures are cost effective and in the public interest.
>
> The 2014-2018 DSM expenditure filing reflects a marked reduction in the Long Run Marginal Cost (LRMC) (see Section 2.3), which is used in the Total Resource Cost (TRC) Benefit/Cost evaluation of DSM measures and programs. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation[1] (the DSM Regulation). The result is a reduced DSM expenditure request for the 2014-2018 filing period as compared to the 2012-13 approved Plan. The lower program expenditure level will result in lower average customer rates over the test period by between 0.3 percent and 0.5 percent annually, and approximately 1.6 percent over the 2014 – 2018 PBR period, compared to continuing at the approximate level of expenditures previously approved.
>
> Planned DSM expenditures are $3.0 million in 2014 with modest escalation in the subsequent years 2015-18 inclusive. The 2013 approved DSM expenditure was $7.8 million nominal (before tax effect). All figures in the DSM Plan are nominal..

6.1. Please confirm that FortisBC is planning to reduce its DSM expenditure by more than 50% from the 2012-2013 planned expenditures despite the prior levels of DSM expenditure being found to be cost effective and in the public interest.

Response:

At the time the Commission made its earlier findings, it did find the prior levels of DSM expenditure to be cost effective and in the public interest. FortisBC confirms that it plans to reduce its DSM expenditure by more than 50% from the 2012-2013 planned expenditures given the matters explained in its Application.

6.2. Please provide all relevant information to describe when FBC determined that its LRMC would drop.

Response:

As explained in the response to BCSEA IR 1.12.3, FBC's previous LRMC was based on FBC's BC Wholesale Market Energy price curve described in the FBC 2012 Long-Term Resource Plan. This curve was in turn on BC Hydro's 'mid-gas/mid carbon' price scenario described in the BC Hydro's IRP Technical Advisory Committee 2011 reports and presentations. Since the development of the 2012 Resource Plan, FBC has recognized that the impacts of shale gas developments across North America have continue to unfold causing market prices for natural

gas to remain lower than expected. At the same time, the momentum behind carbon regulation or legislation in various federal and state jurisdictions has slowed. In early 2012 FBC also became aware that BC Hydro was reviewing the appropriateness of its "mid-price" base case developed by Black & Veatch in 2011. The results of the BC Hydro internal review were reflected publically in BC Hydro's 2012 Draft IRP which states:

> *"It can be concluded from the updated Market Scenario weighting factors that there is a shift of the most likely scenario from Scenario B (a mid-market scenario) to Scenario C (a low market scenario). This shift underscores the dynamic nature of natural gas prices and GHG policy at present and in particular, this reflects the panelists' opinions that low GHG and natural gas prices are likely to continue for the near to mid-term."*[1]

As a result of these developments, in April 2013, FortisBC decided an independent price forecast updated was needed, and requested Midgard to update the British Columbia Wholesale Market Energy Curve, directing them to use the January 2013 GLJ gas price forecast to be consistent with the assumptions used by FortisBC Energy Inc. Midgard provided its results on April 19, 2013, followed up with internal Memo dated May 2, 2013 describing the methodology, and a second memo for external distribution dated June 15, 2013. (Please also refer to the response to BCUC IR 1. 239.1.)

FBC notes that in BC Hydro's Draft 2013 IRP, BC Hydro has re-adopted a mid-gas price/mid carbon price scenario as its "most likely" scenario[2]. Even with that, BC Hydro's most likely scenario creates an electric price forecast which for most years is lower than Midgard's Mid-C energy price forecast it developed as part of its 2013 BC Wholesale Market Energy Curve update. (Please also refer to the response to BCSEA IR 1.13.4.)

6.3. Please provide all relevant studies, internal or external, which FBC has with regard to determining how to determine the appropriate level of DSM given FBCs future resource requirements.

Response:

FBC interprets "the appropriate level of DSM" to mean the DSM Plan energy savings targets and expenditure schedule. As such FBC is not aware of any studies on "how to determine the appropriate level of DSM". Also the governing legislation (UCA, DSM Regulation), having

[1] BC Hydro 2012 Draft IRP, Chapter 4, Section 4.72, page 4-41, lines 1-6.
[2] BC Hydro 2013 Draft IRP, Chapter 5, Section 5.7.2, page 5-38, lines 10-11.

stated that a utility should pursue all cost-effective DSM, is silent in terms of specifying the "appropriate level of DSM".

The Company believes it has submitted an appropriate level of DSM for the reasons set out in its Application and other IR responses.

6.4. Please provide the estimated GWhs that FortisBC predicts would have been saved had FortisBC elected to continue with the DSM as in the 2012-2013 approved plan.

Response:

The energy savings, for an annual DSM expenditure portfolio of $7 million, are estimated to be as follows:

2014	2015	2016	2017	2018
25.6	25.8	26.0	25.7	25.9

7. Exhibit B-1-1, Appendix H page 8, Table 8-3

For historical reference, Table H-3 shows the planned and actual DSM expenditures since 2008, the year in which the Commission granted the Company approval to increase DSM activity. The 2012 Semi-Annual DSM Report provided in Attachment H2 shows (as do prior annual reports) that DSM spending in each of these years has been cost effective.

Table H-3: Plan and Actual DSM Expenditures Since 2008

DSM Expenditures since 2008

2008		2009		2010		2011		2012	
Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
2,355	2,683	3,667	3,464	3,952	3,712	7,842	5,907	7,731	7,300

7.1. Please explain why DSM expenditures have been consistently lower than planned since 2009.

Response:

Below is Table H-3 with an additional column showing the percentage of plan spent.

Year	Plan	Actual	Per Cent
2008	$ 2,355	$ 2,683	114%
2009	$ 3,667	$ 3,464	94%
2010	$ 3,952	$ 3,712	94%
2011	$ 7,842	$ 5,907	75%
2012	$ 7,731	$ 7,300	94%
Total	**25,548**	**23,066**	**90%**

On average FBC has spent 90% of Plan over the period shown. Participation and take-up in the DSM programs are primarily market driven in response to the PowerSense offers. The Company manages the DSM budget prudently to stay within the approved plan, but does not arbitrarily limit customer participation. The 2008 overspending was such an exception due to robust customer participation, and the Company increased its Plan in the 2009/10 filing in response. The 2011 underspending was partially due to the step change in the budget and the ramp-up time necessary to build capacity and launch new programs.

7.2. Please describe whether or not rates in each of the above years were set based on the planned expenditures.

Response:

Yes, rates in each year were set based on the forecast expenditures as identified in the applicable Revenue Requirements application.

7.3. Please describe whether or not the FBC shareholder benefits when FBC under spends with respect to its DSM plans.

Response:

The Deferred Charges component of Rate Base, which includes DSM expenditures, will be reforecast annually as part of the Annual Review process. Thus over time only actual expenditures will be recovered in rates and the shareholder does not benefit.

Small variances in the equity cost of financing DSM expenditures could occur during the forecast year, if actual DSM spending is less than or is greater than forecast. In subsequent years, no variances occur as Rate Base includes only actual expenditures.

8. Exhibit B-1-1, Appendix H2, page 1 and page 6

> **OVERVIEW OF RESULTS FOR THE YEAR ENDED DECEMBER 31, 2012**
>
> Energy efficiency savings for the year ended December 31, 2012 were 31.6 GWh, or 99 percent of the 32.0 GWh Plan. The commercial sector led performance, achieving more than 17 GWh of savings. Company costs incurred were $7,300,000 or 94 percent of the $7,731,000 Plan. Adding customer costs to the Company's program costs yields a Total Resource Cost (TRC) of $12,833,000 with an overall TRC benefit/cost ratio of 1.6. The method used to determine benefits is provided in the Financial Results section.

Table 3 - Energy Savings by Sector

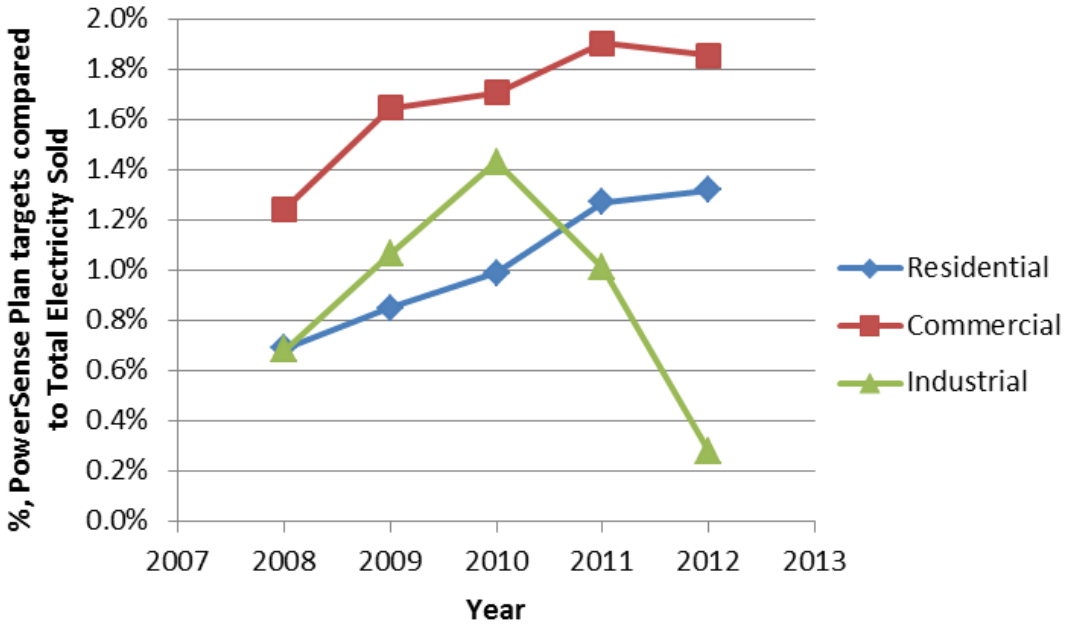
SECTOR	Plan	Actual	% of Plan Achieved
	GWh		
Residential	16.1	12.8	79%
Commercial	13.4	17.9	134%
Industrial	2.5	0.9	38%
Total Savings (GWh)	**32.0**	**31.6**	99%

Note: Minor differences due to rounding.

8.1. Please provide the plan targets as a percentage of total consumption for each sector for each of the years 2008-2012 inclusive.

Response:

The following figure shows the PowerSense plan targets compared to electricity sold per sector over the 2008 to 2012 period.


2.0%
1.8%
1.6%
1.4%
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
%, PowerSense Plan targets compared to Total Electricity Sold
2007
2008
2009
2010
2011
2012
2013
Year
Residential
Commercial
Industrial

1

2

9. Exhibit B1-1 Appendix H page 9

> **5.1 *FUNDING REQUEST BY PROGRAM AREA***
>
> FBC's 2012 Actual, 2013 Approved and the 2014 Plan expenditures in each of the Sectors or Program Areas are outlined in the table below:
>
> **Table H-4: FBC DSM Expenditures - 2012 Actual, 2013 Approved and 2014 Plan**

Program Area	2012 Actual		2013 Approved		2014 Plan		TRC	TRC incl mTRC
	Savings	Cost	Savings	Cost	Savings	Cost		
Programs by Sector	MWh	$(000s)	MWh	$(000s)	MWh	$(000s)	B/C ratio	
Residential	12,757	2,564	16,946	3,944	5,800	1,037	1.2	1.3
General Service	17,892	3,020	11,980	2,085	6,200	1,134	1.4	1.7
Industrial	937	173	2,580	364	800	148	2.8	2.8
Sub-total Programs:	**31,586**	**5,757**	**31,506**	**6,393**	**12,800**	**2,319**	**1.4**	**1.5**
Supporting Initiatives		816		725		190		
Planning & Evaluation		728		760		492		
Total (incl. Portfolio spend):		7,300		7,878		3,001	**1.2**	**1.4**

> The 2015 through 2018 plan years are patterned on the 2014 Plan. Details for the years 2014–2018 are found in the DSM Plan.

9.1. Given that the Total Resource Cost (benefit/cost ratio) for is 1.2 overall; exceeds 1 in every sector, and is 1.4 excluding portfolio expenditures, please explain why FortisBC is intending to reduce expenditures in 2014 by almost 60%.

Response:

The TRC Benefit/Cost ratio is the prescribed indicator to determine whether a measure, program or portfolio is cost-effective, or not. It does not determine DSM incentive levels. FortisBC has kept incentive levels for the remaining economic programs generally consistent with previous years to ensure market consistency and in recognition of the higher rate impact associated with higher incentive levels.

9.2. Does FortisBC expect the Total Resource Cost test to remain above 1 during the PBR period?

Response:

Yes. The TRC Benefit/Cost ratios are shown only for the year 2014, but apply to the entire 2014-18 PBR period.

9.2.1. Please provide any TRC and Modified Total Resource Cost Test forecasts that FortisBC may have with respect to DSM over the PBR period.

Response:

Please refer to the response to CEC IR 1.9.2.

> FBC seeks approval to increase its DSM amortization period from ten to fifteen years to follow suit with BC Hydro. A longer amortization period results in steady and manageable rate increases for customers and provides FBC with the opportunity to continue requesting DSM funding envelopes that adequately support customer energy efficiency needs.

> 2012 PowerSense programs, many of which FBC is proposing to continue. In sum, FBC's evidence in this Application demonstrates that the proposed DSM expenditures are cost effective and in the public interest.
>
> The 2014-2018 DSM expenditure filing reflects a marked reduction in the Long Run Marginal Cost (LRMC) (see Section 2.3), which is used in the Total Resource Cost (TRC) Benefit/Cost evaluation of DSM measures and programs. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation[1] (the DSM Regulation). The result is a reduced DSM expenditure request for the 2014-2018 filing period as compared to the 2012-13 approved Plan. The lower program expenditure level will result in lower average customer rates over the test period by between 0.3 percent and 0.5 percent annually, and approximately 1.6 percent over the 2014 – 2018 PBR period, compared to continuing at the approximate level of expenditures previously approved.

9.3. Please provide the rate impacts that are associated with a longer amortization period.

Response:

The cumulative rate impact associated with a longer amortization period is approximately 0.4 percent.

9.4. Do the lower average customer rates over the test period (1.6%) attributed to the lower program expenditure include the results of the increased amortization period?

Response:

The impact of the lower program expenditures is a reduction to rates of approximately 2.2 percent over the 2014-2018 period, not 1.6 percent as stated. The impact of the increased amortization period is not included.

9.4.1. If not, please provide a calculation including the increased amortization period.

Response:

The cumulative rate difference between the higher DSM expenditure level amortized over ten year and the lower expenditure level amortized over 15 years is approximately 2.5 percent.

10. Exhibit B1-1 Appendix H page 19

11. Exhibit B1-1 Appendix H page 19

> ### 8.2 *REQUEST FOR CHANGE IN DSM REPORTING PERIOD*
>
> FBC currently files semi-annual reports on its DSM activities, a reporting schedule which is inconsistent with the reporting requirements for other BC utilities, including the FEU and BC Hydro, and which is administratively burdensome. FBC therefore proposes to submit DSM reports on an annual, year-end, basis, consistent with the FEU and BC Hydro.

11.1 Please provide the original rationale that was applied in establishing a semi-annual reporting period for DSM activities.

Response:

The Commission ordered FBC (at the time West Kootenay Power Ltd.) to begin semi-annual reporting in its Decision and Order G-109-90 on the Company's general rate application filed on November 30, 1989 and amended on September 7, 1990. At the time, with WKP's PowerSense program being quite new, the Commission noted a number of challenges that needed addressing and ordered WKP to begin 6 month reporting of its DSM activities. Given that FortisBC's DSM program, and the province's experience with DSM has matured, the Company is now proposing to report on an annual basis consistent with the frequency of the other BC utilities.

12. Exhibit B-1, pages 5 and 6

> ***1.1.1.3 Advanced Metering Infrastructure***
>
> On July 26, 2012, FBC filed an application for a CPCN to develop and deploy its Advanced Metering Infrastructure (AMI) Project[5], which is a key element in improving the ability of both the utility and its customers to manage the cost of electricity. Following a written and limited oral public hearing which concluded in May 2013, the Company anticipates approval of the AMI Project shortly.

12.1. Please confirm that the AMI CPCN has recently been approved with a capital budget of $50.898 million including approved development costs and contingency as a control budget.

Response:

Confirmed.

12.2. Please provide a list of the unquantified benefits that FortisBC anticipates will be associated with the AMI project.

Response:

As discussed in Sections 3.2.5 and 6.0 of the Company's AMI CPCN application, potential future and non-quantified benefits arising from the Company's AMI project include:

- Distribution loss reduction;
- Power grid voltage optimization;
- Outage management;
- Customer pre-pay tariff;
- Future conservation rate structures;
- In-home displays; and
- Customer information portal.

13. Exhibit B-1, Page 12

> During 2012 and 2013, employees were asked to consider embedded practices and rethink work while maintaining appropriate service levels. As a result, efficiencies were realized from streamlining processes, leveraging technology and optimizing opportunities for integration with FEI.

13.1. Please provide a list of all efficiencies realized and or planned along with any documentation evaluating the efficiency improvements.

Response:

Please refer to section C4 Department O&M and section A3 Productivity Focus of Exhibit B-1 for actual examples of productivity achievements in recent past. The response to BCUC IR 1.96.2 identifies the factors contributing to the net sustainable savings of $0.452 million which is embedded in the 2013 Base O&M Expense and will persist throughout the PBR Period.

To ensure accountability for achieving productivity improvements, departments are required to 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. As a result of this budget preparation process, FBC's departments are not expected to formally document and quantify all productivity (efficiency) initiatives and related savings except in ad-hoc situations or situations where a capital investment is required (i.e. IT capital investment). Please also refer to the response to CEC IR 1.18.2.

FBC's view is that productivity is best measured at an overall company level such as that being proposed in the PBR Plan with the inclusion of a productivity improvement factor that will require each department to consider continuous improvement, which is preferred to measurement of individual activity.

With regards to future efficiency opportunities, FBC does not have a list of planned efficiency opportunities. As indicated Section A3 3.3 Productivity Focus – 2013 and onwards, FBC will continue to engage in efficiency review activities and to pursue productivity gains with the emphasis on managing costs. Further opportunities may emerge and will be evaluated depending on the circumstances and potential benefits to customers.

In addition to the $0.452 million of sustainable savings, the proposed productivity factor of 0.5 percent reflects the minimum level of productivity that the Company will attempt to achieve.

The regulatory framework in BC, 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. FBC's

approach is consistent with that fundamental framework and with the purpose of PBR which is to provide market like incentives and leave the management of the Company to make decisions.

13.2. Please provide a list of all efficiency improvements identified in the 2012 and 2013 period and where implementation has been started but not completed to realization and those where implementation is expected to be completed to realization in the future PBR period.

Response:

FBC does not have the list requested.

Please refer to the response to CEC IR 1.13.1.

14. Exhibit B-1, Page 14

> FBC will continue to engage in efficiency review activities and to pursue productivity gains as it has during its two previous PBR plans and during 2012 and 2013, with the emphasis on managing costs.

14.1. Please describe the efficiency review activities and FBC conducts and provide documentation of these reviews for 2012 and 2013.

Response:

FBC does not have a list of efficiency review activities conducted in 2012 and 2013. FBC's departments are not expected to formally document and quantify all productivity (efficiency) initiatives.

Please refer to the response to CEC IR 1.13.1.

15. Exhibit B-1, Page 14

> In providing value for FBC's customers while delivering safe and reliable service at the most reasonable cost, a productivity focus is a requirement and is engrained into the Company. The implementation of the PBR Plan proposed in this Application will result in a continuation of this focus through the PBR Period, and in an equal sharing with customers of any resulting incremental savings above the productivity factor built into customer rates.

15.1. Please explain why the sharing should be equal between FBCs customers and the FBC shareholder.

Response:

Including the proposed 50/50 ESM in the PBR Plan shares the benefits from efficiencies achieved equally between customers and the Company, rather than the savings accruing to the Company until rebasing occurs as would be the case absent the ESM. It should be noted that rates will be set each year with 100% of the X-factor (i.e. 0.5%) benefiting customers. Customers will also receive back 50% of any savings beyond this target through earnings sharing.

Based on the success of FBC's prior PBR Plan which included the same ESM (along with similar other PBR Plan elements), FBC believes that inclusion of the same 50/50 ESM in the 2014 PBR Plan is appropriate and will provide the Company with a consistent business case metric for pursuing additional efficiencies at all levels of ROE achievement (short of reaching the off-ramp). In addition, in comparison with other ESM designs, the symmetrical ESM better conforms to FBC's PBR principles. The Company believes it does a better job of aligning the interests of customers and the Utility than other ESM approaches, such as no earnings sharing or earnings sharing above or below a dead band, which are employed in other jurisdictions (see pages 36 and 37 of the Application). FBC's customers are sharing in efficiencies gained at all levels whereas this is not the case with these other PBRs. In other words FBC's customers will benefit from efficiencies as they are achieved rather than having to wait until the end of the term or until a certain ROE threshold has been exceeded.

15.2. Please confirm that significant IT investments required to support efficiency improvement would be capital expenditures on which FBC would be expecting to recover a return on investment as well as a recovery of the investment from the customers.

Response:

Confirmed.

15.3. Please describe how shared achievement of benefits from efficiency improvements would be factored into the company's cost benefit analysis for capital project implementations intended to achieve efficiency gains.

Response:

The cost benefit analysis of 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, whether capital or O&M, and the benefits, such as O&M savings, of the efficiency project or expenditure will be subject to sharing. The cost/benefit analysis for an efficiency based capital project will yield the same decision on whether to proceed with the project or not, regardless of whether the project is evaluated on a pre-sharing basis or a post-sharing basis.

15.4. Please confirm that if ½ of the efficiency benefits from a project supported by capital investment are not creditable to the project because they have been paid as an incentive that many capital projects, which would have been cost-effective, without the incentive payments, could become not cost effective, because of the incentive payment.

Response:

Not confirmed. Please refer to the response to CEC IR 1.15.3.

16. Exhibit B-1, Page 15

> Strengthening customer focus remains a high priority for the Company in serving customers and responding to their new and evolving requirements and concerns, while controlling costs and maintaining system reliability and safety. Recently, despite the fact that customer service has been maintained at a high level, FBC's customer satisfaction survey has reflected the effect of customers' perceptions of and reactions to the recently implemented two-tiered Residential Conservation Rate (RCR) and the proposed AMI Project.

16.1. Please provide the customer satisfaction survey results for the last 10 years.

Response:

The current customer satisfaction survey (Customer Satisfaction Index or CSI) was implemented in 2005. Since 2005, the CSI has been conducted quarterly. Results have remained high and relatively stable across all categories. CSI Survey methodology is described in FBC 2014-2018 PBR Plan Application – Volume 2 – Appendices, Appendix D6, Service Quality Indicators, pages 10-11.

Figure 1: Annual CSI Result (2005 through Q3 2013)

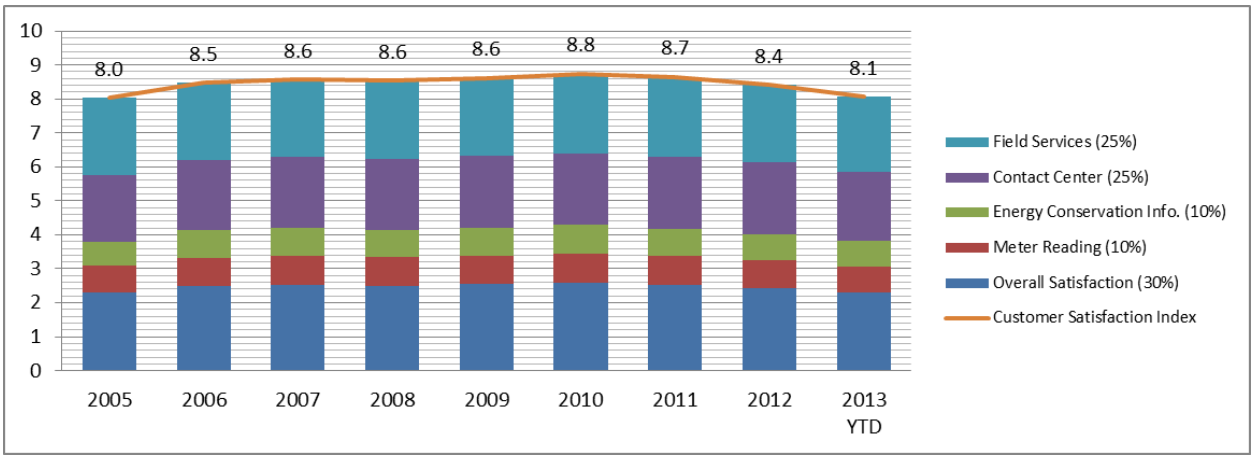


Table1: Annual CSI result by Service Attribute Score (2005 through Q3 2013)

Service Attribute	2005	2006	2007	2008	2009	2010	2011	2012	2013 YTD
Overall Satisfaction (30%)	7.7	8.3	8.4	8.4	8.5	8.7	8.5	8.1	7.6
Meter Reading (10%)	7.7	8.2	8.4	8.3	8.5	8.6	8.3	8.2	7.8
Energy Conservation Info. (10%)	7.2	8.1	8.2	8.1	8.2	8.4	8.1	7.7	7.5
Contact Center (25%)	7.8	8.2	8.4	8.4	8.4	8.5	8.5	8.5	8.1
Field Services (25%)	9.1	9.1	9.1	9.2	9.2	9.4	9.4	9.1	8.9
Customer Satisfaction Index	8.0	8.5	8.6	8.6	8.6	8.8	8.7	8.4	8.1

The declining 2012 and 2013 sub-index scores in the meter reading, energy conservation, contact centre and field services have occurred despite the fact that meter reading targets continue to be met or exceeded, contact centre and field services have been consistently maintained and DSM expenditures and customer outreach programs are at record levels. This supports FBC's view that CSI results, while useful directional indicators, are subject to variability outside of FortisBC's direct control and are therefore not appropriate as a Service Quality Indicator.

The CSI methodology for 2003 and 2004 was an average of scores for five service attributes as shown in Table 2, below. Although not identical, the types of questions asked in 2003 and 2004 were similar to those in the existing survey. The scores from those years were also inflated relative to the current methodology through the use of "top box" scoring. The CSI approach was again different in 2002 when the Company reported a year-end CSI result of 89.2%.

Table 2: Customer Satisfaction Index Results (2003-2004)

Service Attribute	2003	2004
Reliability of Electric Service	89.0%	87.0%
Speed of Service Restoration	89.0%	88.0%
Quality of Service Contact	76.0%	77.5%
Helping Customers Conserve Energy	80.0%	74.0%
Price	67.0%	65.6%
Total CSI Score	80.2%	78.4%

16.2. Please indicate whether or not the company believes that customer satisfaction is an important measure of whether or not the company is providing quality customer service.

Response:

Yes, FBC believes customer satisfaction is an important measure of customer service. For this reason, the Company conducts surveys that evaluate satisfaction with specific transactions (i.e., transactional satisfaction), as well as the Customer Satisfaction Index (CSI) that endeavors to capture customer sentiment about all their previous experience with FBC (i.e., cumulative satisfaction). The Company synthesizes operational data and survey feedback from both transactional and cumulative studies to help identify and correct service problems and prioritize improvement opportunities.

The CSI describes the influence that various service attributes such as billing, customer care, field services, communications and price have on overall or cumulative customer satisfaction. However, external influences can also affect these scores. Regional economic disparity,

regulatory requirements like the Residential Conservation Rate, consumer price tolerance and media coverage may also influence cumulative satisfaction scores up or down. Accordingly, FBC is of the opinion that overall satisfaction scores should be considered directional. Results are important, but should be evaluated in light of the current operating environment, transactional survey findings and various key operating measures.

17. Exhibit B-1, Page 16

> FBC will deliver on this goal in part by continuing to provide new lower-cost optional services to customers. One example is eBilling, which has been voluntarily adopted by nearly 19 percent of customers. These customers find this billing option better suits their needs than paper billing, while at the same time it is less costly for FBC and therefore all customers.

17.1. Please provide the progression of adoption since inception of the service to the current 19% and please provide a projection for the 2014 to 2018 period for expected adoption.

Response:

The average sign up for e-bills for FBC is 310 per month with the average for the City of Kelowna at 80 per month for a total of 390.

We have assumed the same uptake of e-bills for the period 2013 – 2018 with an average increase in customer count of 1% per year or 100/month.

17.2. Please provide the estimated savings per bill as a result of being able to provide ebilling.

Response:

The total saving for each e-bill is approximately $0.85.

17.3. Please provide the number of ebillings as of the point of adoption being 19%.

Response:

In April 2013 FBC reached 19.16% e-bill adoption. For the month of April this represented a total of 12,966 e-bills sent to customers.

18. Exhibit B-1, Page 18

> FBC uses a Balanced Scorecard approach to deliver on a number of key success measures critical to the business. The performance assessment is integral for management in evaluating performance and in determining cost-effective service levels for customers going forward.

18.1. Please confirm that productivity and efficiency are not currently key success measures critical to the business and being measured in the Balanced Scorecard.

Response:

FBC believes the Financial category on the existing scorecard incorporates a productivity focus as savings from productivity initiatives will ultimately be reflected in the financial component. This productivity focus on the scorecard along with the requirement for FBC to meet the Productivity Improvement Factor in its O&M and capital spending will result in a strong focus on productivity improvement.

18.2. Please confirm that the company does not have any measurement or tracking of its efficiency improvement initiatives.

Response:

FBC's departments are not expected to formally document and quantify all productivity (efficiency) initiatives and related savings except in particular situations or situations where a capital investment is required (i.e. IT capital investment). For IT investments, the Company requires business cases for projects including identification of costs and benefits. This process is continually evolving and being adapted to recognize changes in business requirements.

FBC's view is that productivity is best measured at an overall company level such as that being proposed in the PBR Plan with the inclusion of a productivity improvement factor that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. The result of this focus is evident and discussed in the departmental results and forecasts included in Section C4 of Exhibit B-1 and in Section A3 Productivity Focus that contain many actual examples of productivity achievements in the past.

The regulatory framework in BC, 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. FBC's approach is consistent with that fundamental framework and with the purpose of PBR which is to provide market like incentives and leave the management of the Company to make decisions.

19. Exhibit B-1, Page 23

> FBC has had two PBR plans in the past (1996-2004 and 2007-2011) and both were successful, further aligning the interests of customers and the Company. FEI, in addition, has also set rates

19.1. Please explain what FBC believes are the customer interests and what are the Company interests.

Response:

FBC believes the customer interests are essentially FBC's mandate – to provide safe, reliable and cost effective service. FBC considers the Company's interests, apart from its mandate above, to include earning a fair return on and of capital and providing meaningful employment for its employees. Please also refer to the response to CEC IR 1.19.2.

19.2. Please confirm that customer interests and the company's shareholder interests are fundamentally different and that the history of regulatory proceedings regularly involves the Commission in settling the balance between these competing interests.

Response:

It is an overstatement to say that the interests are fundamentally different. While it is true that with respect to certain interests there may be the appearance of conflicts based on different perspectives of customer interests, their interests are aligned in many respects. For example, both customers and shareholders benefit from a financially sound and stable Company. They may have different views of what is required for the utility to be financially sound but failure to provide a reasonable opportunity to earn a fair return actually raises cost for all customers in the long-run. Costs increase and reliability decreases when a utility is not financially sound.

Further, the pendulum for interests changes over time due to circumstances and can severely impact utility performance both financially and operationally. For example, some parties may argue for increasing the vegetation management cycle in order to reduce revenue requirements. There may be no immediate consequences from this delay until the next major storm when more customers lose service and restoration costs are higher as a result. At that point, revenue requirements increase because of new restoration capital and returning to the original vegetation management schedule. This is the kind of impact that hurts both customers and shareholders when the balance swings to reducing revenue requirements without fully understanding the consequences of missing the balance.

19.3. Please describe the FBC view with respect to alignment of customer and company interests.

Response:

Please refer to the response to CEC IR 1.19.2.

20. Exhibit B-1, Page 28

> In practice, the majority of PBR models are of a hybrid form, reflecting elements of both PBR and cost of service and regulators use various policy tools to overcome the above mentioned challenges.

20.1. Please confirm that there is no way to absolutely overcome the challenges inherent in the PBR models and guarantee that such challenges as were referred to will not be present.

Response:

FBC considers that assessing either a cost of service or PBR regulatory model with reference to such absolutes is not productive, because there are pros and cons to each model. FBC believes that its proposed PBR plan is the best plan available given the state of the art and the necessary assumptions that underlie the Plan methodologies. Accordingly, FBC's PBR plan contains the necessary tools and mechanisms to overcome the challenges inherent in PBR plans to the greatest extent possible.

B&V's view is that the hybrid model is critical to an effective PBR because some costs are beyond the reasonable control of management. In the case of FBC, power costs represent a good example. The price for purchased power in BC is impacted by markets all over the west coast of the continent. Prices increase with unit outages and decrease with surplus energy. The availability of water impacts the price of purchased power and hydroelectric generation fluctuates with weather, seasonal obligations and a variety of other factors that management does not control. This means that power costs cannot reasonably be tracked under PBR and thus must continue under cost of service principles. The lumpy nature of capital investment also requires some cost of service type principles as is the case of the CPCN projects excluded from the PBR mechanism.

21. Exhibit B-1, Page 32

> **4.2.3 Capital Expenditures**
>
> As discussed previously, capital expenditures were not included in the 2007 PBR plan, and were instead to be approved as part of a separate annual filing or by way of applications for CPCNs for major projects.

21.1. Please explain why the capital expenditures were not included in the 2007 PBR plan.

Response:

The proposed PBR mechanism filed by FBC as part of the 2006 Revenue Requirements Application included a proposal for capital expenditures to be approved as part of a separate annual filing (a capital expenditure plan) or by way of a CPCN application. This proposal was made in response to the following:

- Stakeholder concern around a lack of transparency regarding the nature of capital expenditures during the previous PBR term;
- Concern that linking capital expenditures to a PBR mechanism could produce an incentive to reduce costs, potentially resulting in suboptimal reinvestment in new plant. It was recognized that capital expenditures needed to increase and that a PBR formula could actually incent the opposite behavior and cause the Company to decrease capital expenditures; and
- Concern that formula-driven capital expenditures under a PBR mechanism would not support the required levels of capital investment for the PBR period as indicated by FBC's 2005 – 2025 System Development Plan (2005 SDP). The 2005 SDP demonstrated that capital expenditures needed to be dramatically increased from historic levels in order to improve system capacity, reliability and safety.

FBC's proposal to exclude capital expenditures from the 2007 – 2011 PBR mechanism was ultimately accepted and approved by the Commission.

22. Exhibit B-1, Page 32

> The 2006 Negotiated Settlement Agreement (NSA) established PIFs of 2 percent for 2007, 2 percent for 2008, and 3 percent for 2009 (if the term of the PBR was extended). For the period 2009 – 2011, the Parties to the 2009 NSA agreed that some linking of the productivity factor to BC CPI would be beneficial. As such, the 2009 NSA established PIFs of 1.5 percent for 2010

22.1. Please explain why the PIFs were established at these levels.

Response:

The PIFs were established at the indicated levels as a result of negotiations, approved by the Commission, between the Company and parties to the 2006 Negotiated Settlement Agreement and to the 2009 NSA extension. The negotiations considered all aspects of the Company's last PBR proposals given the circumstances at the time.

22.2. Please explain why productivity factors are not set at similar levels to the 2010 levels.

Response:

The values were developed through a settlement and for only one year. The current values are more reflective of the evolution of the PBR through multiple plan periods. Essentially, TFP has declined as discussed in detail in Appendix D-1 and D-2. In fact, there is sound analysis to suggest that TFP has become negative on average for the electric utility industry. B&V has also shown that the trend for X- Factors has declined over time on a consistent basis. Setting the X-Factor at an unrealistic level would be confiscatory and fail to provide a reasonable opportunity to earn the allowed return.

23. Exhibit B-1, Page 33

> **4.2.7 Earnings Sharing Mechanism**
>
> The variance between the allowed and actual earnings (after being adjusted for certain revenue and cost variances), up to a 200 basis point collar around the approved ROE, were to be shared equally between customers and shareholders. The 200 basis point collar was not exceeded during the term of the PBR. Over the 2007 - 2011 term of the PBR, customers and shareholders each received a benefit of $7.6 million, indicating that the PBR successfully reduced costs and resulted in material savings, including an avoided rate increase of approximately 2.7 percent.

23.1. Please provide the Commission decision with respect to the FBC revenue requirements application for 2012 to 2013 and whether or not the Commission decreased the rate increase level requested by FBC and if so by how much, as a percentage of rates and dollar consequence.

Response:

In FBC's Evidentiary Update to its 2012-2013 Revenue Requirements Application, the Company requested rate increases of 1.5 percent in 2012 and 6.5 percent in 2013. Commission Order G-159-12 approved a final rate increase of 1.5 percent in 2012 and 4.2 percent in 2013. The reduction to revenue requirements for 2013 was $6.7 million, primarily related to lower approved Power Purchase Expense and reduced financing costs. Commission Orders G-110-12 and G-159-12 are available on the BCUC website at the following links.

Order	BCUC Website Link
G-110-12 and Decision	http://www.bcuc.com/Documents/Orders/2012/DOC_31458_G-110-12_FBC-2012-13RRA_Decision.pdf
G-159-12	http://www.bcuc.com/Documents/Orders/2012/DOC_32236_G-159-12_FBC-12-13RR-12ISP_Compliance-Rates.pdf

23.2. Please provide a breakdown of the $15.2 million in savings claimed by the specific departmental functions that were improved.

Response:

A breakdown of the total savings and the customer share (50%) has been provided in the table below. Please note that the cumulative savings was slightly higher at approximately $16.4 million than the $15.2 million referenced in the Application. These savings were equally shared between the customers and the Company.

Additionally, the referenced savings are a function of various operational factors, internal and external including flow-through adjustments, and may not solely be attributable to improved departmental functionalities. As the achieved savings are a result of all the combined components of the last PBR and management's ability under the PBR to implement efficiency measures, it is not possible to identify all individual savings items that comprise the benefit. Despite this, it is assumed the majority of the achieved savings required minimal or no capital investment, and relate primarily to power purchase savings and the reorganization of existing processes for improved efficiency. As such, the savings related to these efficiencies are permanently embedded in customer rates.

Year	Approved Earnings	Earnings Before Sharing	Variance (Shared between Customers & FBC)	Sharing %	Actual Customer / Company Share
2007	26,212	30,074	3,862	50%	1,931
2008	29,688	32,314	2,626	50%	1,313
2009	32,215	36,783	4,568	50%	2,284
2010	38,615	37,971	(644)	50%	(322)
2011	43,292	49,244	5,952	50%	2,976
Total Pre Sharing:			**16,364**	**Customer / Company Share**	**8,182**

23.3. For each of the specific savings identified above please provide a description as to whether or not there was a significant capital investment made to achieve the savings, whether the savings were derived from deferring expenditures, whether they we one time savings or whether processes were reorganized to be performed more efficiently.

Response:

Please refer to the response to CEC IR 1.23.2.

23.4. For each of the specific savings identified above please provide the timeline with respect to when it was realized and how long it lasted.

Response:

Please refer to the response to CEC IR 1.23.2.

23.5. For each of the savings identified please provide a description as to why the savings would not have occurred under cost-of-service regulation.

Response:

The preamble to this question references the total benefit each received by customers and shareholders over the term of the last PBR. Since this benefit is a result of all the combined components of the last PBR and management's ability under the PBR to implement efficiency measures, it is not possible to identify all individual savings items that comprised the benefit. Moreover, expecting FBC to have tracked savings associated with individual efficiency improvements like this would have gone against one of the benefits of PBR, which was to reduce the regulatory burden.

What can be said with certainty is (a) that the added incentive provided by PBR increases the likelihood of achievement of such savings, and (b) the PBR included a sharing mechanism, which ensured that benefits were shared immediately with customers, which might not otherwise have been the case under COS regulation.

24. Exhibit B-1, Page 38

> 5. There is no particular pattern with regard to the use of earnings sharing mechanism, stretch factors, off ramps, re-openers and efficiency carry-over mechanism. The use and design of these regulatory tools are mainly based on the overall design of the PBR and/or negotiations between the companies and interveners. In addition, the design of these items is inter-connected. For instance, the trigger point in an off-ramp provision may be higher for PBR plans without a sharing mechanism. Another example is the stretch factor. Stretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective.

24.1. Please explain in the jurisdiction where there is no earnings sharing why this is the case and what the experience in those jurisdictions is with efficiency improvement.

Response:

Ontario's electric utilities and Alberta's electric and gas utilities do not have an ESM in their PBR plans.

In the case of Ontario, the OEB's report for 3rd Generation IR acknowledged that the ratepayers advocate groups were strong supporters of the continuation of ESM however OEB decided that due to the concerns over the potential regulatory burdens of an ESM, the benefit of ESM as a "safety net" does not outweigh its disadvantages. B&V and FBC have not studied the performance of individual Ontarian power distributors under the PBR plan however it is logical to believe that the OEB is satisfied with its no ESM policy since it decided to continue with that policy in its new PBR framework for 4th generation IR.

In Alberta, the AUC decided not to use an ESM due to the concerns over regulatory burden, efficiency disincentives and earnings volatility issues. Since the AUC's PBR is just started it is not possible to comment on its experience with efficiency improvements during the PBR period.

The FBC's ESM experience indicates that the FBC's proposed ESM design does not involve heavy regulatory burdens and does not reduce Company's incentives for efficiency improvements.

24.2. Please explain in the jurisdiction where the customers receive 90% of excess earnings why this is the case and what the experience in that jurisdiction is with efficiency improvement.

Response:

As indicated in page 22 of Appendix D1, Union's initial ESM had a 200 bp dead-band above which the earnings were shared on 50:50 basis (until the 300 bp trigger point for off-ramp provision). In the first year of the Union gas PBR plan, the actual ROE exceeded the benchmark ROE by more than 300 bp which led to the triggering of the off-ramp provision. In the subsequent negotiated settlement between Union and interveners, it was decided that the off-ramp should be terminated and instead the ESM shall be modified to provide the same safety net effect as an off-ramp. Therefore the ESM was modified so that the earnings above 300 bp ROE dead-band were shared on 90:10 basis in favour of ratepayers.

24.3. Please explain why it is not part of the company's ongoing responsibility as the operator of the utility and therefore the responsibility of the management to identify efficiency improvement opportunities and realize them.

Response:

The question is based on an incorrect assumption regarding FBC's evidence. FBC should and does undertake steps to operate efficiently, irrespective of whether the utility is under PBR. The difficulty under normal cost of service regulation, which PBR is designed to address, is that some efficiency measures cannot be undertaken without extending the period before rebasing occurs, because otherwise there is insufficient time for the utility to recover its incremental investment in efficiency. A utility is not under a duty to invest with an expectation of losing money; rather a utility has the right to expect an opportunity to earn a fair return on its investment.

B&V adds that management has both a fiduciary responsibility to shareholders and an efficiency responsibility to customers. They exercise both with the former acting as a constraint of the latter. In addition, the expected earned return also acts as a constraint on efficiency improvements.

25. Exhibit B-1, Page 39

> 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 electrical 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.

25.1. Please comment on a 6th principle that "The PBR plan should require clear identification of the efficiency improvements implemented, the capital investment required to achieve the efficiency improvement, whether or not the efficiency improvement is permanent or one time, whether or not the expenditure reduction is a result of deferral of expenditure, whether or not the efficiency improvement involved a process change or redesign.

Response:

FBC does not believe that this is, in fact, a rational principle for evaluating a PBR Plan. One of the elements of PBR is the more market like application of efficiency principles within the operating context of the utility. It would be impossible to identify efficiency measures or their costs in the Plan as these are part of the competitive discovery process. Further, the environment under PBR must permit experimentation with new designs and processes in order to adequately understand both the costs and the benefits. This proposed principle would stifle innovation and entrepreneurial efforts and result in only those changes that meet financial metrics based on RRA reset periods. Further the "sixth principle" actually may undermine PBR and be more akin to cost of service regulation with respect to the extra regulatory administration this will require. The constrictive focus on predetermining a course of action and requirement to measure will remove flexibility and efficiency that the PBR is intended to provide.

26. Exhibit B-1, Page 40

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 reforecast annually.

26.1. Please explain why there would be a customer growth adjustment to all O&M expenditures versus only to those expenditures which are directly customer growth related.

Response:

Customer growth is a proxy for both customers and capacity in this context. As customer growth adds facilities that are both customer related and capacity related the system O&M costs increase. For example, there are more miles of conductor to inspect and maintain; more trees to trim; and more opportunities for system damage. Although these costs are not directly customer related they are classified and allocated on capacity. The use of customers is a reasonable proxy in this instance for measuring the impact on additional O&M.

26.2. Please provide a fixed and variable cost breakdown for each of the O&M expenditure categroies.

Response:

FBC does not categorize its O&M expenditures in terms of fixed and variable costs. Most costs could be categorized as either fixed or variable, depending on the context, the assumptions made with regard to cost causation, and the timeframe under consideration.

For the purpose of a Cost of Service Allocation Study, for example, O&M Expenses are classified on a Demand/Energy basis, which could be considered to be a fixed/variable analysis. However FBC does not understand how such an analysis would be relevant to this Application.

Without further clarification of this question, FBC is unable to provide a meaningful response.

27. Exhibit B-1, Page 40

Controllable Expenses - Capital	The same formula as O&M will be used. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.

27.1. Please explain whether or not FBC is proposing to have benefit sharing for reduced capital expenditures below the formula driven base each year and that FBC expects to be relieved of responsibility if the expenditures in any given year are more than 10% above the formula driven base.

Response:

There is no imbalance in the treatment of capital expenditures above or below the formula allowed spending levels as is implied in the question. The treatment of formula-based capital expenditures under the PBR is symmetrical both for spending variances above or below the formula and for the limited rebasing that will occur if capital expenditures are below 90% or above 110% of the formula-based amount for the year.

Thus, there will be sharing of the cost impact of regular capital spending between 100% and 110% of the formula amount just as there will be sharing of the benefits of regular capital spending between 90% and 100% of the formula amount for that year. Similarly, symmetrical treatment of the annual capital spending that falls outside of 90% to 110% of formula-based amounts means that capital spending below 90% of the formula-based amount in any year will lead to a reduction to opening rate base for ratemaking for the following year while capital spending above 110% of the formula-based amount in any year will lead to an increase in opening rate base for ratemaking for the following year.

28. Exhibit B-1, Page 40

Earnings Sharing Mechanism	The PBR Plan includes an equal earnings sharing between Customers and the Shareholder for returns above or below the approved return on equity.

28.1. Please confirm that this proposal involves customers giving up ½ the benefits achieved in any given year if the expenditures are below the formula driven base and paying for ½ the expenditures in any given year if they are above the formula driven base.

Response:

This cannot be confirmed. The earnings sharing is based on earnings not expense levels and revenue is a component of earnings. The sharing is symmetrical.

29. Exhibit B-1, Page 40

Efficiency Carry-Over Mechanism	An Efficiency Carry-over Mechanism is proposed based on a rolling 5-year benefit calculation derived from O&M and capital efficiencies achieved each year.

29.1. Please confirm that FBC would like to continue to share in benefits achieved for 5 years after the benefits are achieved.

Response:

The proposed ECM has an additional 4 years of sharing in the efficiency benefits after the year in which the efficiency benefit is first achieved (and also subject to 50/50 sharing). This opportunity is the one that exists for efficiency savings achieved in the first year of the 5-year PBR (even without the proposed ECM). The proposed rolling 5-year ECM extends that same relationship to efficiency savings achieved in years 2 through 5 of the PBR so that the motivation to pursue efficiencies will remain the same throughout the 5 year term. Customers will benefit by receiving 50% of the efficiency savings during the rolling ECM period and 100% of the savings after that.

29.2. Please explain whether or not this would be determined on the basis of incremental benefits achieved in a given year being accorded the carry over or whether it would be applied to the whole benefit achieved as of the end of the PBR period.

Response:

The incremental benefits achieved in each year are carried over for four additional years after the year in which the benefits were initially achieved. In other words, the incremental benefits achieved in the first year remain in place throughout the entire PBR term; incremental benefits achieved in the second year are carried for one year past the five-year PBR term; incremental benefits achieved in the third year are carried for two years past the PBR term, and so on. The ECM, the five-year rolling treatment of each year's incremental benefits and the 50/50 earnings sharing throughout is illustrated in Appendix D5, page 3.

29.3. Please describes what would happen if the benefits were lost in a subsequent period, would the carryover cease?

Response:

The ECM is symmetrical in its treatment of benefits and losses. If the benefits were lost in a subsequent year within the PBR term the effect of the loss would also be carried forward in the ECM for four additional years. There are two occurrences of this nature in the illustrative ECM example presented in Appendix D5, page 3. The first is where the hypothetical actual capital expenditures exceed the formula-allowed spending level in 2015 (see the 2015 column of line 12 of the table). The second case is in 2017 where the O&M savings vs. formula amount has lost ground relative to the cumulative savings that had been achieved in the prior year (see the 2017 column of line 7 of the table). Each of these two cases of missing the target has an implicit impact on the ECM that extends an additional four years beyond the initial year of occurrence.

30. Reference: MULTIYEAR PERFORMANCE BASED RATE-MAKING MECHANISM
Exhibit B-1, Application, Part B, Section 6.2.2.2, X-Factor Estimation, pp. 44-49

30.1. On p. 46 FBC 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.37.1. This response is identical to the FEI response to that IR.

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*

30.2. On p. 47 FBC 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.

This is a mathematical conclusion based on the formula for TFP. TFP is the change in output minus the change in input. If the change in output is zero (replacing existing facilities) the

added capital inputs represent an increase and zero minus anything is a negative TFP. DSM expenditures are small relative to the other operating expenses and have been included in costs for electric utilities since the 1980s in one form or another and thus have minimal impact on the TFP measure. The 2008 recession has little or no impact on TFP in the FBC report because output is measured on a more stable customer and capacity basis. If output is measured on a volumetric basis there would be a significant impact because it would result in a negative change in output over the period. Negative output minus any positive change in inputs results in a negative TFP.

30.3. On p. 47 FBC 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 FBC 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:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.37.3. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

FBC confirms that two new versions of the mentioned report were published by OEB's consultant on May and later on September 2013. The computed TFP values in the May 2013 version were increased from -0.05 and -0.03 % to 0.07 and 0.1% however the most recent version of this study (September 2013 version) which was updated with 2012 data is back into the negative values and indicates a negative TFP value of -0.33%. These changes (upward or downward) have no impact on the logic of the statement made on page 47. The values in all three versions are still significantly lower than the 0.72% TFP value approved for OEB's 3rd Generation IR. Therefore, FBC's position regarding the declining trend of TFP values since the year 2000 is still supported by PEG's reports.

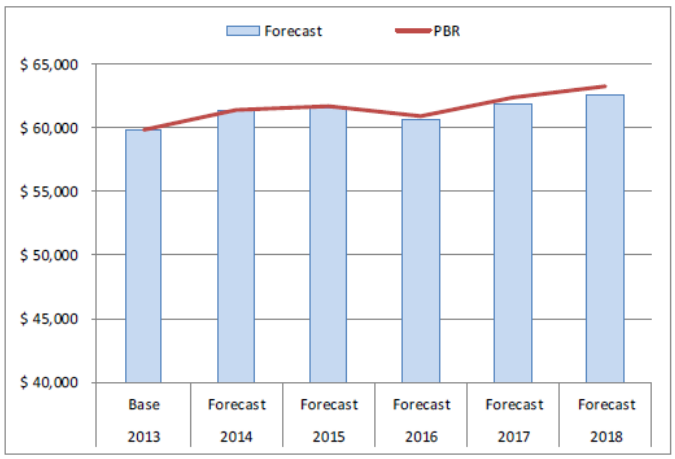
FBC cannot confirm the claim that one possible cause of this decline in TFP values is a change of data source from US data to Ontario data (this is not to say that a change of data source does not have any impact, positive or negative, on the measured TFP). The declining TFP

1 values are not specific to Ontario or Canada as demonstrated by B&V's TFP study which is
2 completely based on US data.

3

31. Exhibit B-1, Page 53

Figure B6-2: Comparison of PBR O&M vs. Forecast ($000s)



	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Forecast	$ 59,848	$ 61,375	$ 61,612	$ 60,608	$ 61,889	$ 62,634
PBR	$ 59,848	$ 61,386	$ 61,744	$ 60,960	$ 62,378	$ 63,302

31.1. Please confirm that the PBR number used in this comparison includes the .5% productivity factor per year.

Response:

Confirmed.

31.2. Given that the PBR number for O&M is equivalent to the forecast why would FBC expect this to be seen as a stretch?

Response:

Please see the response to ICG IR 1.8.1.

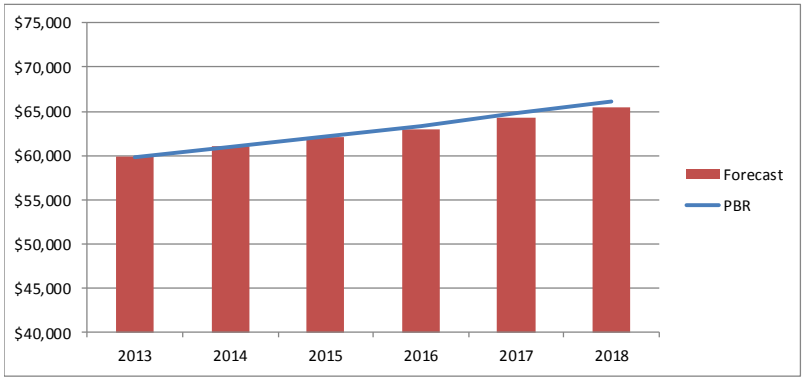
31.3. Please explain the dip in the forecast in 2016 and why there is a significant tail increase rate in 2017 and 2018.

Response:

The dip in the forecast for 2016 is primarily related to the increase in O&M savings related to the AMI project. These savings increase from a forecast of $0.4 million in 2015 to approximately $2.4 million in 2016. As well, there is a decrease in O&M related to pensions and OPEB in 2016 of approximately $0.5 million. There is no tail increase, but simply rather a return to the average annual increases once the 2016 savings related to AMI are taken into account.

When the AMI impact as noted on line 23 of Table B6-5 is excluded from 2014 – 2018, it is apparent that the annual increases are relatively linear and that there is neither a dip in 2016, nor a significant tail increase in 2017 and 2018. Please see the figure provided below which excludes the AMI impact as initially provided in Figure B6-2.

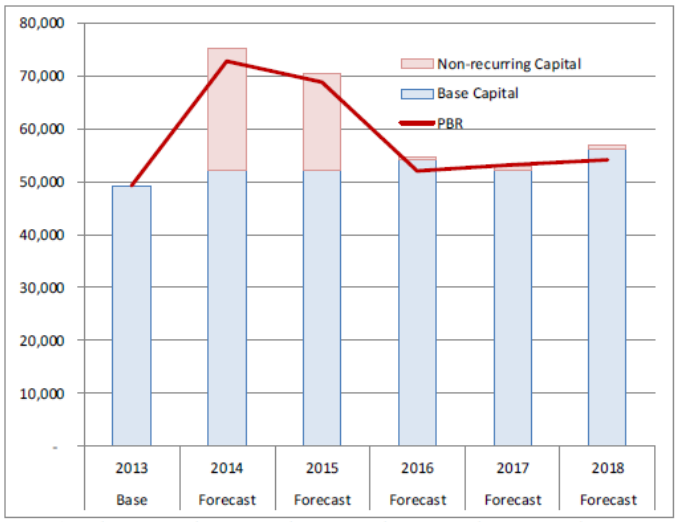
Comparison of PBR O&M vs. Forecast – Excluding AMI Impact ($000s)



	2013	2014	2015	2016	2017	2018
Forecast	59,848	61,375	61,612	60,608	61,889	62,634
PBR	59,848	61,386	61,744	60,960	62,378	63,302

32. Exhibit B-1, Page 59

Figure B6-3: Comparison of PBR Capital vs. Capital Forecast



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Forecast	$ 49,180	$ 75,176	$ 70,435	$ 54,681	$ 53,028	$ 56,960
PBR	$ 49,180	$ 72,758	$ 68,950	$ 52,103	$ 53,183	$ 54,060

32.1. Please confirm that the PBR number includes the .05% productivity reduction per year.

Response:

Figure B6-3 as shown in the preamble includes a 0.5% productivity improvement factor not a 0.05% productivity improvement factor.

32.2. Given that the PBR number is approximately equivalent to the forecast is the primary reason that this is a stretch because the company plans to absorb the City of Kelowna capital expenditures within its overall formula capital expenditures.

Response:

The PBR formula yields approximately $9.2 million less in capital expenditures as compared to the forecast, a portion of which ($6.3 million) is related to the absorption of future capital expenditures driven by the addition of the utility assets formerly owned by the City of Kelowna.

32.3. Please explain what happens under the PBR process if FBC simply does not carry out as much capital expenditure activity as it has forecast or projected by PBR formula, because it chooses to defer or delay making certain of the capital expenditures. Is this treated as a savings and would the company and customers share ½ of the reduced expenditures?

Response:

Under the PBR plan, rates are set based on the formula, irrespective of actual spending. Should spending levels fall below the allowed amount under the PBR formula for a given year, the revenue requirement impact of that difference would be treated as a savings, of which customers would share 50%. The Plan includes, however, a 10% deadband for capital expenditures as discussed in the response to BCPSO IR 1.11.1.

Under the PBR process the Company intends to continue carry out its capital expenditures as planned in order to properly maintain its system and infrastructure to continue to provide customers with safe reliable service at the lowest reasonable cost.

32.4. Why has FBC included the AMI project when it is planning to exclude all other CPCN approved projects?

Response:

FBC included the AMI project in revenue requirements for this Application because of the expected timing of the CPCN approval. In fact, the AMI project was approved on July 23, 2013, slightly more than two weeks after the filing of the Application. Had the AMI project not been included in the revenue requirements, it would have been necessary to prepare an evidentiary update to the Application.

On a go-forward basis, FBC will continue to include CPCN projects, once approved, in revenue requirements.

33. Exhibit B-1, Page 59

> ***6.2.5.3 Total O&M and Capital Under PBR***
>
> When the O&M and capital allowed under the PBR formula are examined together, the total is lower than what has been forecast by FBC in every year of the PBR term, with the exception of 2017. In other words, customers will benefit under the proposed PBR Plan since the resulting costs for customers under PBR are less than what FBC is forecasting they would likely be if rates were set under an indicative Cost of Service model using the O&M and capital forecast in Sections C4 and C5 (see Section 7 below for further discussion on rate forecasts under PBR). Figure B6-4 provides a comparison of the total capital and O&M allowed under the PBR formula and the total O&M and capital forecasts over the PBR term.

33.1. Please provide the historic Commission decisions for any FBC revenue requirement applications comparing the requested rate increased versus the approved rate increases.

Response:

The following table sets out the historic Commission decisions for FBC's Revenue Requirements Applications back to 2005. A link to each Order has been included in the table.

Year Effective	Requested Rate Increase	Approved Rate Increase	Order
January 1, 2005	3.6%	3.4%	G-52-05
January 1, 2006	5.8%	5.9%	G-58-06
January 1, 2007	2.1%	1.2% and 2.1%	G-162-06/G-20-07
January 1, 2008	3.4%	2.9%	G-147-07
January 1, 2009	5.6%	4.6%	G-193-08
January 1, 2010	4.0%	6.0%	G-162-09/G-158-09
January 1, 2011	6.2%	6.6%	G-184-10/G-195-10
January 1, 2012 and January 1, 2013	1.5% 6.5%	1.5% 4.1%	G-110-12/G-159-12

33.2. Please confirm that if the period 2014 to 2018 were to be managed under a cost of service approach that there would be no certainty that the approved rates would be based on the company's forecasts and there is 100% certainty that rates would be based on Commission decisions with respect to the company's forecasts.

1
2 **Response:**

3 Confirmed.

4

34. Exhibit B-1, Page 61

> ***Interest Expense***
>
> At the Annual Reviews a forecast of interest expense for the following year will be provided, and customers' rates for that following year will be determined on the basis of the forecast. A deferral account will record variances in long-term and short-term interest costs in accordance with the method approved by the Commission for FEI. Projected deferral account balances and forecasts of short term and long term interest rates and costs will be provided each year during the Annual Review process.

34.1. Please describe all of the variables which go into determining the interest expense for any given year.

Response:

Since the preamble to this question is discussing the forecasting of interest expense, the response is assuming that "determining the interest expense" is equivalent to forecasting interest expense. As discussed on page 234 and 235 of Section D1, under D1.1.2.1 Forecast of long-term interest rates, D1.1.2.2 Forecast of Short-Term Interest Rates and D1.1.3 Interest Expense Forecast, of the PBR Application, variables that go into forecasting interest expense include forecasted mid-year rate base, the timing and volume of issuing long-term debt (weighted average balance), underlying Government of Canada bond Yields, long-term debt indicative spreads, term of the long-term debt issuance, Bankers' Acceptances (or the Canadian Dealer Offered Rate or CDOR), spread to CDOR, acceptance fee rate on Bankers' Acceptances, term of the Bankers' Acceptances, prime rate, primate rate margin, term of prime rate loan, standby fee rate, balances undrawn on the credit facility, overdraft charges, banking agreement renewal fees, annual lender and agency fees, interest due to customers on outstanding security deposits and other minor interest charges.

34.2. Please identify those variables affecting interest expense which are a function of company policy and practice.

Response:

Of the interest expense variables identified in the response to CEC IR 1.34.1, there will be certain situations where the Company's practice could influence the terms of Bankers' Acceptances and prime rate loans, however, it should be noted that that these terms will have very little impact on the overall interest expense. In addition, the Company can have influence over the term of long-term debt issuances, but this influence could be lessened in times of uncontrollable and adverse economic conditions which could lead to supply and demand

imbalances in the market or a higher interest rate environment. In such situations, FBC would attempt to balance the market demand for the Company's debt term while considering the expected useful life of the assets being financed, the frequency of market exposure, the estimated coupon rate at the time of issuance compared to historical and the frequency of incurring issue costs. Overall, the Company has very limited control over the variables that affect interest expense.

35. Exhibit B-1, Page 62

> ***Taxes***
>
> FBC proposes that variances in property tax expenses, income tax rates, and other tax items be captured in deferral accounts. Projected deferral account balances and forecasts of tax expenses will be provided each year during the Annual Review process.

35.1. Please describe the variables which go into determining the property tax expense for any given year.

Response:

To determine property tax expense FBC begins with the most recent actual assessment values and taxes paid for each property folio, then calculates average general, school and other tax rates for each property tax folio. Revenues earned within each municipality are taken from the most recent reporting or data available.

Each property tax folio is classified based on the general valuation methodology used to determine its value. The general categories are generation facilities, distribution lines, transmission lines, substations, offices and other.

Update factors are then estimated based on discussions with BC Assessment, historical and market trends, or any other information that may be relevant in determining future changes to:

1. land values;
2. improvement values for each category (including annual additions to distribution and transmission lines, additions or changes to substations;
3. average tax rates. When estimating tax rates we generate separate estimates for First Nations, General Municipal, General Rural and School and Other taxes because they may all be impacted differently; and
4. revenues. Due to the 2 year time lag we often are able to use actual revenues, otherwise changes are based on forecast changes to corporate sales of electricity.

Once FBC is satisfied that base assessment and taxation rates are reasonable, estimated additions are applied to each tax folio, as well as appropriate update factors to land, improvements and tax rates. Finally each tax bill is recalculated. The sum of these tax bills becomes the property tax estimate.

Once actual taxes are received, actual taxes levied on each folio are compared with the projected amount for that folio. Analyses of the variances are used to improve future procedures and estimates.

35.2. Please identify those variables affecting property tax expense which are a function of company policy and practice.

Response:

Property tax expense is generally comprised of 3 major components.

First is the assessment or property value. The determination of which properties are taxable and the methodology under which they will be valued is set out in Provincial or Federal legislation. More specifically, the Assessment Act, or in the case of First Nations under assessment bylaws approved by the First Nations Tax Commission.

Second is tax rates. Taxing authority is established in either Provincial or Federal legislation. First Nations tax bylaws are approved by the First Nations Tax Commission. Municipalities, the Surveyor of Taxes and other taxation authorities receive their authority from either the Community Charter, Local Government Act, the Taxation (Rural Area) Act or from the Act that governs operation (for example the Regional District Act or Hospital District Act, Assessment Authority Act) based on:

a) their budget requirements; and

b) the total assessment or property value they have access to.

Third is revenues. FBC is required under the Local Government Act to pay to municipalities 1% of revenues from electricity consumed within their boundary in lieu of general municipal property taxes that would otherwise be payable.

Except for revenues, and then only to the extent that FBC has control of revenues earned within municipalities, and ensuring compliance with legislation there are no factors that company policy or practice has any meaningful impact on the determination of property tax expense.

36. Exhibit B-1, Page 62

> ***Pension and OPEB Expenses and Insurance Costs***
>
> These items are subject to deferral account treatment. Pension and OPEB expenses, and insurance expenses will be re-forecast at each Annual Review based on the most recent information provided by actuaries and FBC's insurance provider. Projected year-end deferral account balances will also be provided at the Annual Reviews.

36.1. Please describe the variables which go into determining the insurance expense for any given year.

Response:

The preamble to the question is referring specifically to the insurance expense that is subject to deferral. To clarify, the Insurance Expense Variance deferral account will include only the variance on insurance premiums as noted on page 263 in Section D4, item 4.3.4 of the 2014-2018 PBR Application which states "therefore a deferral account to capture the difference between actual and forecast costs of insurance premium is appropriate."

Insurance premiums are affected by a number of conditions, which may include the following:

- Increase in asset values for which premiums are adjusted by insurers. The addition of assets by acquisition (e.g. City of Kelowna) or capital projects (e.g. OTR) will increase premiums.
- Claims history, both for FortisBC directly and the insurance industry overall. In particular, rates will be impacted if losses accumulate within the utility industry sector.
- Insurance market conditions including loss history, investment returns and re-insurance rates.

36.2. Please identify those variables affecting insurance expense which are a function of company policy and practice.

Response:

The only variables affecting insurance expense which are a function of company policy and practice would be insurance limits, deductibles, and whether the Company obtains insurance or elects to self-insure. As part of the Fortis Inc. Group of Companies, FBC renews its insurance program on a yearly basis. FBC works with Fortis Inc. and Aon Reed Stenhouse Inc. (Aon), a leading broker of insurance in the industry. The process includes assessing the insurance

market to determine the best course of action to provide the most prudentcoverage at the most competitive rates. FBC meets annually with peer organizations to benchmark its insurance program. FBC also secures input from Aon on coverage limits and deductibles as they represent a number of Canadian utility clients. FBC, therefore, feels comfortable that its current levels of coverage are in line with both its peer group and the exposure faced by the Company.

36.3. Please describe the variables which go into determining the OPEB expense for any given year.

Response:

The OPEB expense is calculated using actuarial methods and actuarial assumptions in accordance with the requirements of generally accepted accounting practices. The primary components of the annual expense include service cost, which represents the value of benefits being accrued by active employees over the fiscal year; interest cost on the accrued liability; and amortization of actuarial gains and losses and prior service costs. Also included in OPEB expense for the term of the PBR period is the amortization of the 2005 CICA OPEB liability and US GAAP OPEB Transitional Obligation approved pursuant to BCUC Order G-110-12. The actuarial assumptions included in the determination of OPEB expense include the following:

- The discount rate, which is used to discount projected future benefits to present values. As required by the applicable accounting standards, the discount rate is based on the yield of an hypothetical portfolio of high quality corporate bonds;
- The health care cost trend rate, which is the rate at which health care costs under the OPEB plans are assumed to increase each year. Health care costs include prescription drugs and other medical costs not covered by the Provincial Medical Services Plan; and
- Rates of retirement of active employees and rates of mortality of retired employees.

36.4. Please identify those variables affecting OPEB expense which are a function of company policy and practice.

Response:

Of the OPEB expense variables identified in the response to CEC IR 1.36.3, which included discount rates, health care cost trend rates and rates of retirement of active employees and

1 rates of mortality of retired employees, none of these are a function of FBC's policy and
2 practice.

3

37. Exhibit B-1, Page 62

> ***Power Purchase Expense***
>
> Variances in Power Purchase Expense from amounts included in rates arise from factors outside of FBC's control, including load variances due to variances in customer growth, usage, or weather; unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates and other contracts whose prices are tied to BC Hydro rates) not known at the time of application; and factors related to the operation of the Canal Plant Agreement governing FBC's generation plants, which affect the Company's usage or timing of entitlements. FBC also flows through the benefits of its ability to displace BC Hydro purchases with lower-cost market purchases. All such variances are deferred and returned or recovered in future rates as approved by Order G-110-12.
>
> Power Purchase Expense will be forecast each year at the Annual Review and included in the determination of the revenue requirement and rates for the forecast year.

37.1. Please describe the variables which go into determining the power purchase expense for any given year.

Response:

In general the power purchase expense for any given year will be largely determined by two main variables, load and resources. Long-term load is driven by economic factors and population growth as described in the Application at Section C, pages 77 to 94, but for any given year, the largest variable in actual load will be the weather. Except as influenced by rate design, load is independent of any Company policy or practice.

The Company's resources to meet load are described in the Application as part of the discussion explaining Power Purchase Expense at Section C, pages 96 to 107. The main factor influencing costs to meet load is Company owned generation. If this generation remains available to meet load, then actual Power Purchase Expense will most likely reflect the assumptions in the forecast. If Company owned generation is not available for any reason, then costs can be significantly higher depending on the amount of and the length of time generation is not available. It is the Company's practice to plan to meet firm load with firm resources, either Company owned or under contract.

A full description of both the load forecast and power purchase expense can be found in the referenced sections.

37.2. Please identify those variables affecting power purchase expense which are a function of company policy and practice.

1 **Response:**

2 Please refer to the response to CEC IR 1.37.1.

3

38. Exhibit B-1, Page 62

> ***Revenues***
>
> Revenues include amounts received from customers for the sale electricity, and various other sources of revenue which are detailed in Sections C1 and C3. The majority of variances in sales revenue are attributable to weather-related load variances, customer usage rate variances and customer count load variances which are not under the control of FBC. FBC's Revenue Variance Deferral Account was approved by Order G-110-12.
>
> Revenues will be forecast each year at the Annual Review and these revenues will be included in the determination of the revenue requirement and rates for the forecast year.

38.1. Please describe the variables which go into determining the revenues for any given year.

Response:

The referenced statement contains an error. It is meant to refer only to revenue from sales of electricity and should not refer to other sources of revenue contained in Section C3. This statement has been corrected in Errata No. 2.

Revenue from sales is derived from billing determinants as set out in the Load Forecast (Section C1) and the Company's approved Tariff rates.

38.2. Please identify those variables affecting revenue which are a function of company policy and practice.

Response:

The Company's load forecasting methodology may be described as a function of Company "practice". Both the load forecast and the Tariff rates are approved by the Commission; except as influenced by rate design, neither would be characterized as a function of Company "policy".

39. Exhibit B-1, Page 62 & 63

> ***Depreciation and Amortization***
>
> As discussed in section B6.2.5, the 2014 Plan proposes to derive the annual regular capital expenditures by means of formulas. The formula-based capital expenditures are carried forward in the rate base throughout the PBR term without adjusting the amounts to the actual spending levels (unless total capital expenditure spending deviates in any year by more than 10 percent from the formula amounts). Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include plant additions consistent with the formula-based capital expenditures. The incentive power of the formula-based capital elements of the PBR Plan relates to finding ways to be more efficient in capital activities so that actual spending is less than the formula-derived amount. The accumulating differences between formula and actual spending give rise to variations in rate base carrying costs (i.e., return on rate base, depreciation expense and taxes).
>
> Amortization of deferrals will be re-forecast at each Annual Review and actual amortization expense each year will equal the approved amount.

39.1. Please describe the variables which go into determining the depreciation and amortization for any given year.

Response:

Under the proposed PBR formula-based capital expenditures, which is discussed further in Section B6, Part 6.2.5 of the 2014-2018 PBR Application, the variables that affect depreciation and amortization in any given year are explained below.

Depreciation on capital assets (excluding deferral accounts)

- Opening plant account balances, which is based on forecast capital rate base (excluding major projects, which are generally approved by way of CPCN applications). This will be dependent on forecast regular capital expenditures consistent with the capital formula, non-recurring major project expenditures, and additions to plant in service as illustrated in Section E, Table 1-A-1;

- Inputs used for calculating regular capital expenditures under the capital formula, which includes number of average customers, including the year to year change; composite I-Factor value, as discussed in Section B6, Part 6.2.2.1; and Productivity X-Factor, which has been proposed at 0.5% for the term of the PBR in Section B6, Part 6.2.2.2, page 49; and

- BCUC approved depreciation rates for the different asset classes, which may change during the term of the proposed PBR if an updated depreciation study with updated depreciation rates is accepted by the Commission.

Depreciation expense will be adjusted accordingly when major projects outside the capital formula, which are normally related to CPCN applications, are included in rate base after receiving approval from the Commission and being placed into service.

Amortization on deferral accounts

- BCUC direction on approved expenditures to include in the deferral accounts; and
- BCUC approved amortization expense for the different deferral accounts, which is based on approved forecast expenditures included in the deferral accounts.

As discussed in Section B6, Part 6.8 of the 2014-2018 PBR Application, there will be an annual review in each year of the proposed PBR term which allows for FBC to present the current year's projections and the upcoming year's forecasts for, among other things, capital expenditures (as determined by the PBR formula), plant balances, and deferral account balances. Based on all of these variables, depreciation and amortization is also reforecast each year as part of the annual review.

39.2. Please identify those variables affecting depreciation and amortization which are a function of company policy and practice.

Response:

In the response to CEC IR 1.39.1, for the variables identified as affecting depreciation on capital assets, the additions to plant in service will be somewhat influenced by the Company's asset management practices. The remaining variables listed are elements of the Company's PBR proposal.

Amortization of deferral accounts will be forecast at each annual review and actual amortization expense each year will equal the BCUC approved amount.

39.3. Please confirm that if FBC were to lease assets instead of owning them it would potentially increase operating and maintenance costs and possibly reduce financial expense and also confirm that the opposite is true that owning an asset which was previously rented or leased would increase financial expenses and reduce operating and maintenance costs.

Response:

Not confirmed, as the cost of service difference between leasing assets and including those assets in rate base on customer rates will depend on many factors, including, but not limited to, the nature of the asset, the interest rate implicit in the asset being leased, FBC's weighted average cost of capital at that time and the undepreciated capital tax pools for which the assets will be eligible.

Further, there could be different accounting treatment required depending on whether a lease is classified as capital or operating. If classified as an operating lease, the lease payments are recognized as an O&M expense. If classified as a capital lease, an asset and offsetting lease obligation are recognized and the items recorded as an expense are depreciation expense on the asset and interest expense on the lease obligation. While different classifications of leases currently exist, another factor to consider is that there is movement by accounting standard setters towards a single model for accounting for leases whereby all lease arrangements would be recognized on the balance sheet as a capital lease. Currently, Exposure Drafts on revisions to lease accounting guidance are open for public comment with roundtable meetings by the Financial Accounting Standards Board set to occur in the fourth quarter of 2013. Based on this Exposure Draft, if an asset is leased, there is no increase to O&M because depreciation and interest would be recognized as an expense, instead of the lease payment itself. While the timing of amounts recorded as expense are different, once the lease expires the total amount paid under the agreement would equal the total amount expensed as interest and depreciation.

40. Exhibit B-1, Page 63

> ***Rate Base other than Plant in Service (from Capital Expenditures)***
>
> Section B6.2.5 explains that the use of formula-based calculations will be limited to the regular capital expenditures. Larger projects which will be the subject of CPCN applications in addition to any other large projects that the Company may ask for approval as part of the Annual Review will be added into rate base after they are approved and complete.
>
> There are several other smaller components of rate base such as working capital and deferred charge balances other than those described above that are proposed to be forecast each year in the Annual Review process. These items, including deferral account balances, cannot be reliably reduced to a formula, therefore FBC proposes to re-forecast the rate base balances each year in the Annual Review process.

40.1. Please describe the variables which go into determining the rate base related expenditure items for any given year.

Response:

To clarify, the preamble to the question is referring only to those items outside of the capital expenditure formula and therefore is specifically referring to rate base items such as the deferred charges and working capital. However, FBC has interpreted the question more broadly as requesting a description of variables for all rate base related expenditures. There are numerous variables that go into determining the rate base related expenditure items, many of which have been previously described throughout the 2014-2018 PBR Application and include, but are not limited to:

- Variables that affect the capital expenditure formula are explained in item B6.2.5.2 – 2014-2018 Capital formula on pages 56-57 of Section B6 of the 2014-2018 PBR Application. These include the inputs for the capital expenditure formula, as well as non-recurring capital projects during the PBR period such as the substation portion of the PCB Environmental Compliance and AMI.

- A description of the many variables that drive the additions to the various deferred charge accounts included in rate base begins under item D4.2 Rate Base Deferral Accounts on pages 258 to 271 in Section D4 of the 2014-2018 PBR Application.

- The allowance for working capital is also included in rate base to recognize the lag between revenue is earned and when the funds are received for that revenue, offset by when expenses are incurred and when the funds are released to pay for the expenses. Working capital is influenced by the timing differences between the provision of services or use of goods, and the exchange of funds between FBC and the customer or vendor. Additionally, working capital also includes working capital funds that are unavailable for

use, and excludes working capital funds that are available for use. The cumulative impact of these timing differences is added to the average value of inventory and other current assets to arrive at the working capital balance in rate base.

- An Adjustment for Capital Additions is applied so that the weighted average of when capital expenditures qualify as Plant in Service is used to determine the Utility Rate Base.
- Depreciation and amortization described in the response to CEC IR 1.39.1
- Contributions in Aid of Construction (CIAC) are entirely driven customer driven and result from new services to be installed in excess of a specified level of investment to avoid other customers from subsidizing the cost of the extension.

40.2. Please identify those variables affecting rate base expenditure related items which are a function of company policy and practice.

Response:

Based on the variables that affect rate base expenditure related items identified in the response to CEC IR 1.40.1, the following are variables that are potentially affected by company policy or practice.

- A portion of the working capital amount included in rate base will be influenced by the Company's practice of paying invoices net 30 and implementing collection efforts on overdue accounts.
- The Company's depreciation and amortization policies, which are approved by the BCUC, are discussed in the response to CEC IR 1.39.1 would affect rate base.
- The Company's execution of its capital expenditures could affect the timing of when capital expenditures are placed into Plant in Service which in turn drives the Adjustment for Capital Additions.

41. Exhibit B-1, Page 75

> FBC's proposed PBR Plan offers both regulatory efficiencies and the opportunity for lower rates for customers through the ESM as compared to the indicative Cost of Service approach. The RSDM not only reduces rate variability but lowers the overall rate impact over the 2014-2018 period.

41.1. Please confirm that the RDSM could be proposed in a cost-of-service context as well as in a PBR context and that it is not dependent on either and would represent a separate regulatory rate setting decision.

Response:

Yes, since the RSDM could be proposed in a cost-of-service context as well as a PBR context it is accurate to say that it is not dependent on either. FBC does not understand the statement "would represent a separate regulatory rate-setting decision." A decision on the RSDM would necessarily be made as part of the decision on revenue requirements associated with either a cost-of-service or PBR-based application.

42. Exhibit B-1, Page 76

> B&V and FBC regard FBC's proposed PBR Plan as capturing the best elements of the past plans, while improving upon some of the aspects that could work better. B&V's conclusion in its PBR Report sums up this view:

42.1. In making improvements to the PBR plan did the company and or B&V interview customer groups with respect to their views and concerns with respect to the PBR plan and its success or lack thereof and if so please provide copies of the feedback received.

Response:

FEI had a meeting with customer groups BCPSO and CEC on May 9, 2013 in which the PBR proposals for both FEI and FBC were discussed generally, and the customer groups did provide some feedback at that time. On May 10, 2013, FEI also discussed its PBR proposal on the phone with customer group BCSEA. FBC presented its PBR proposal at the Commission workshops with customer groups, first at a high level on June 19, 2013 at the Joint FEI - FBC Workshop in the Commission's Vancouver hearing room, and then again in more depth on July 25, 2013 in Kelowna.

The Company has negotiated with customers regarding PBR in prior proceedings and is fully aware of the positions stakeholders have taken in those discussions. In developing its proposal the Company considered IRs and comments received during the evidentiary phase of its 2012 – 2013 RRA which included an oral hearing.

42.2. In making improvements to the PBR plan did the company and or B&V interview any of the Commission staff to determine if they have perceived issues or concerns with respect to the plan and if so please provide copies of the feedback received.

Response:

FBC and/or FEI had meetings with Commission Staff on January 15, 2013, February 5, 2013 (FEI only), March 11, 2013 and May 14, 2013. During the meetings the Companies discussed with staff the structure of the Application as well as, various aspects of the proposed PBR Plans. No written feedback was received. Staff did not comment specifically on the proposed PBR structure, but did provide some feedback regarding information to be included in the application. On April 18, 2013 Commission Staff issued to FBC and FEI its "Productivity Improvements in a Performance Based Rate Setting Environment" letter, which provided the Companies with

formal input. A copy of the April 18th letter is contained in Attachment CEC 74.5, provided in response to CEC IR 1.74.5. FBC presented its PBR proposal at Commission workshops, first at a high level on June 19, 2013 at the Joint FEI - FBC Workshop in the Commission's Vancouver hearing room, and then again in more depth on July 25, 2013 in Kelowna.

43. Exhibit B-1, Page 78

> FBC's allocation of weather-normalized gross energy load for the years 2011, 2012 and the 2013 to 2018 after-savings forecast is shown in Figure C1-2. The after-savings forecast includes not only DSM savings but also other savings which consist of the Residential Conservation Rate (RCR), the future Consumer Information Portal program (CIP), the Advanced Metering Infrastructure (AMI) program and rate-driven impacts. These other savings are further explained in Section 3 - Demand Side Management and Other Savings.

43.1. Please confirm that the company's DSM savings do not include the impacts of provincial codes and standards implementations.

Response:

Confirmed.

43.2. Please confirm that the company's load forecasting is not and end use forecasting methodology.

Response:

Confirmed.

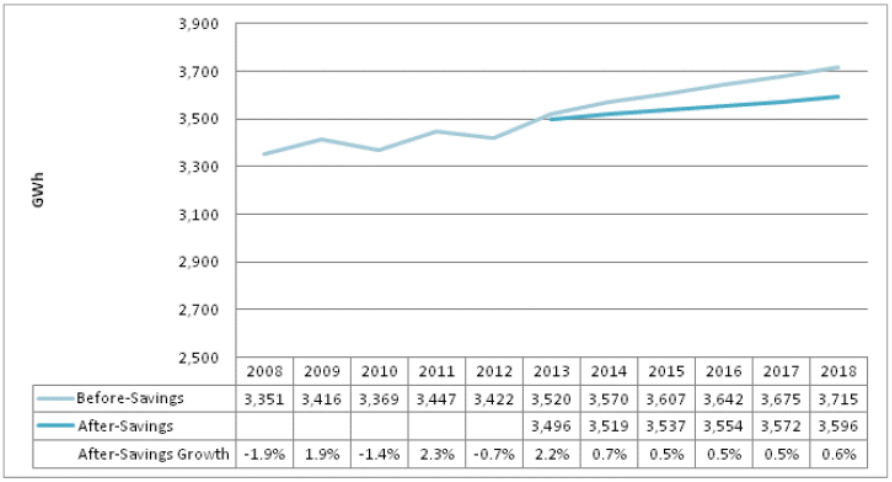
43.3. Please describe the load forecasting methodology for the gross forecast and indicate whether or not the forecast is adjusted for either provincial codes and standards implementations and or for changes in the assumed background rate of energy use intensity.

Response:

The gross load is forecast by adding together the residential, commercial, wholesale, irrigation and lighting loads plus system losses. For details regarding how each of these load classes are forecast, please refer to Exhibit B-1-1, Appendix E2, Section 3.1 to 3.6. The load forecast is not adjusted for provincial codes and standards implementation, but indirectly adjusts for changes in the assumed background rate of residential energy use intensity by using a three year rolling average for the residential UPC.

44. Exhibit B-1, Page 80

Figure C1-3: Normalized and Forecast Gross Load Energy Consumption (GWh)

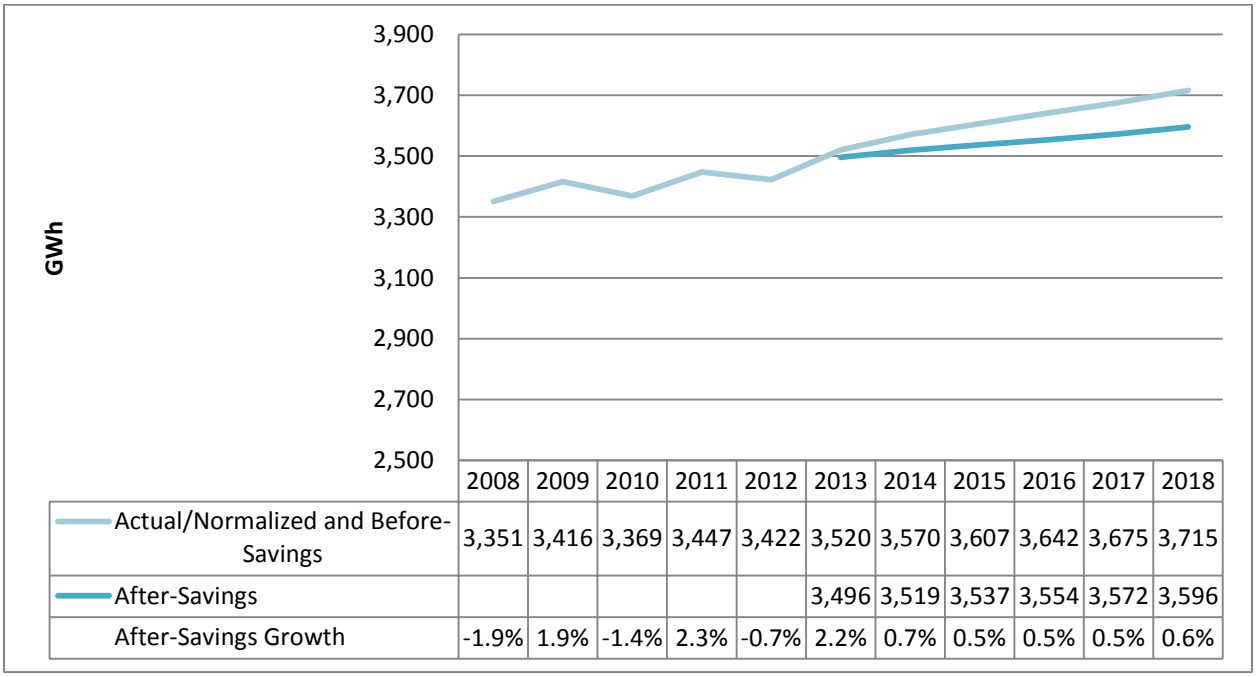


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings						3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

44.1. Please confirm that the normalized load from 2008 to 2012 is actual load normalized and is not load before savings as labeled.

Response:

Confirmed, Figure C1-2, has been updated below.



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Normalized and Before-Savings	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings						3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

45. Exhibit B-1, Page 81

> Rate-driven savings due to price elasticity are also taken into account and deducted from the before-saving loads. This is independent of the RCR mentioned above and applied to all rate classes. In the absence of specific information with regards to price elasticity, FBC has applied the assumption of -0.05 elasticity made by BC Hydro[36], which is considered to be reasonable given its geographic proximity and similarities in terms of customer mix and behaviours.

45.1. Please explain whether or not the term independent of RCR means that FBC takes its projected rate increases and factors the elasticity impact of those into its forecast but does not include a specific elasticity impact for the RCR implementation.

Response:

Please refer to the response to BCUC IR 1.73.3.

46. Exhibit B-1, Page 82

> Due to the unavailability of sufficient historical load information prior to the transaction, it is not possible to ensure that the same forecast methods applied to the existing FBC load classes would also be reasonable to apply to the CoK load classes. Therefore the CoK load is forecast as a whole, and then allocated to the three load classes according in the proportions identified above. CoK before-savings load is forecast at the growth rate of 0.5%. This, together with the savings, gave a growth rate consistent with that which was provided during the application for the acquisition of the CoK utility assets. All forecast values in this report have taken the CoK integration into account unless explicitly stated otherwise.

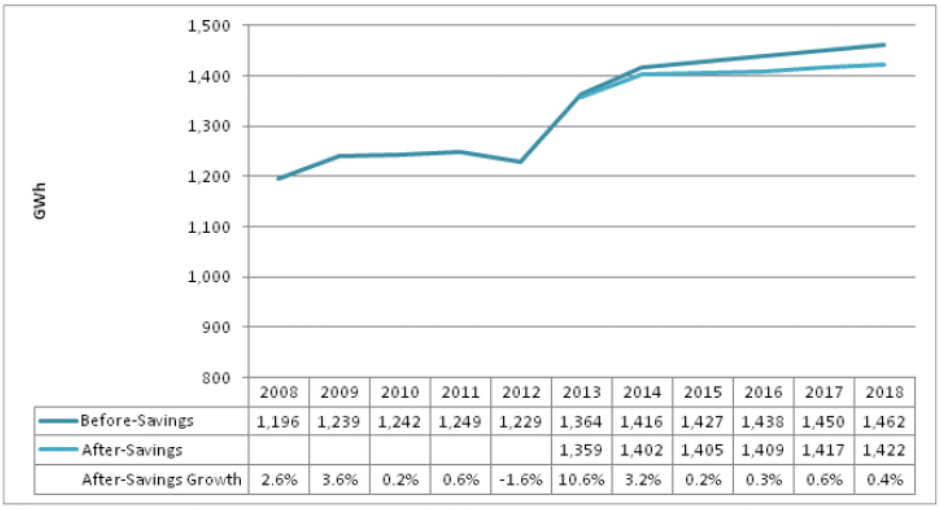
46.1. Please explain whether or not the company's DSM programs have been adjusted to anticipate application to the CoK loads and explain how much this has been provided for.

Response:

No adjustment was necessary since the PowerSense programs were already offered to City of Kelowna customers on an equal footing to FBC direct customers.

47. Exhibit B-1, Page 84

Figure C1-6: Normalized and Forecast Residential Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	1,196	1,239	1,242	1,249	1,229	1,364	1,416	1,427	1,438	1,450	1,462
After-Savings						1,359	1,402	1,405	1,409	1,417	1,422
After-Savings Growth	2.6%	3.6%	0.2%	0.6%	-1.6%	10.6%	3.2%	0.2%	0.3%	0.6%	0.4%

47.1. Please confirm that the increase in load in 2013 is due to the addition of the CoK load residential component.

Response:

Confirmed. The load increase in 2013 is due to the addition of the CoK load residential component, effective March 31st 2013.

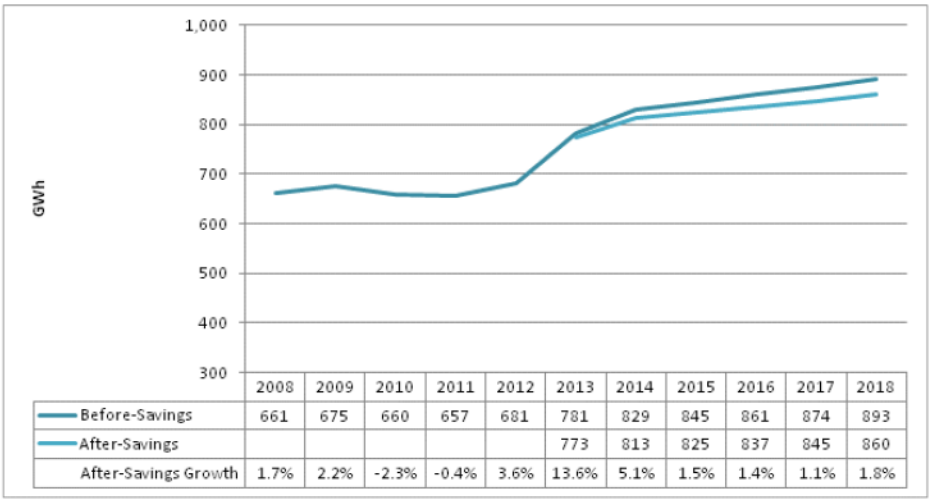
47.2. Please confirm that the further growth in load in 2014 is due to the fact that this would be the first full year with the CoK residential load, because the acquisition transaction took place in the first quarter of 2013.

Response:

Confirmed.

48. Exhibit B-1, Page 85

Figure C1-7: Actual and Forecast Commercial Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	661	675	660	657	681	781	829	845	861	874	893
After-Savings						773	813	825	837	845	860
After-Savings Growth	1.7%	2.2%	-2.3%	-0.4%	3.6%	13.6%	5.1%	1.5%	1.4%	1.1%	1.8%

48.1. Please confirm that the growth in 2013 (3/4 year) and 2014 (full year) is primarily related to the acquisition of the CoK commercial customers.

Response:

Confirmed.

48.2. Please explain why the commercial growth in the FBC service territory would be expected to grow continuously in excess of the residential load growth.

Response:

The forecast commercial growth is different from the forecast residential growth because both the methods and underlying data that support the two forecasts are different and the expected growth in each of the sectors is driven by different factors. Residential load growth tends to be tied to population growth, whereas commercial growth tends to be tied more closely to overall economic growth.

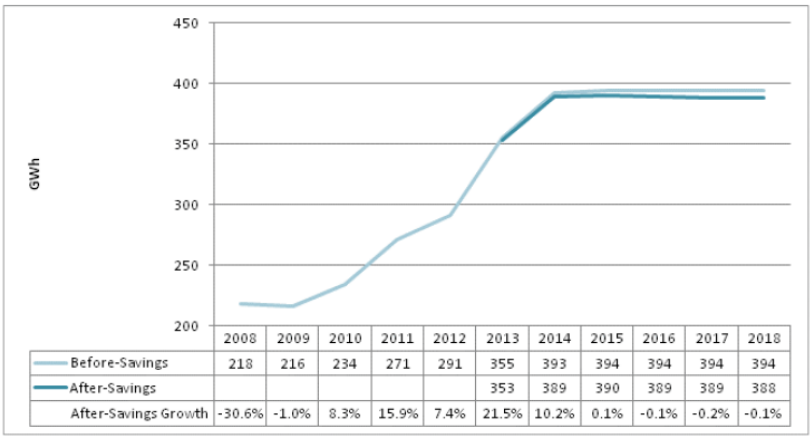
The FBC commercial forecast is based on a regression using Provincial GDP data from the Conference Board of Canada (CBOC) (see Exhibit B-1-1, Appendix E2, Section 3.2).

Conversely, the residential load forecast is calculated by multiplying the residential UPC forecast by the customer count forecast. The residential UPC forecast is determined from a

regression of historic actual data while the customer count forecast is based on population statistics for the FBC service area from BC Stats. The residential forecast does not use GDP as an input, just as the commercial forecast does not use a population forecast and as a result it is reasonable for the two forecasts to grow at different rates.

49. Exhibit B-1, Page 86

Figure C1-8: Actual and Forecast Industrial Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	218	216	234	271	291	355	393	394	394	394	394
After-Savings						353	389	390	389	389	388
After-Savings Growth	-30.6%	-1.0%	8.3%	15.9%	7.4%	21.5%	10.2%	0.1%	-0.1%	-0.2%	-0.1%

49.1. Please provide any information FBC has with respect to whether or not the industrial capacity in the FBC service territory has reached maximum utilization and or whether or not the capacity is underutilized at the projected levels.

Response:

The annual industrial survey sent to each customer asks for a forecast of their upcoming demand requirements. The individual capacity of each customer and their forecast use of that capacity is assumed to be intrinsic in the individual responses. The survey does not ask for the available capacity or the customer's potential use of that capacity. For competitive reasons it is unlikely that customers would provide that information. Additionally the remaining industrial capacity is not an input into the forecast model and no changes are anticipated to the model. Collecting this information, even if it were provided by customers, would not be incorporated into the forecast model. At this time FBC does not have information with respect to whether or not the industrial capacity in the FBC service territory has reached maximum utilization and whether or not the capacity is underutilized.

49.2. Please provide any information FBC has with respect to the international markets to which the industrial production and electricity usage is exposed.

Response:

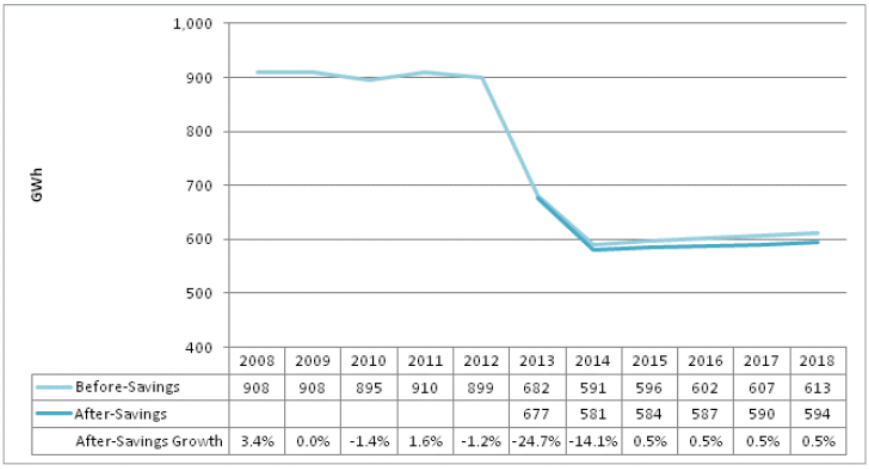
FBC does not gather information on international (or other) markets that our industrial customers might participate in. The Industrial Survey process assumes our customers are the

1 best ones to forecast their future demand and by implication that each of them have taken into
2 account the pressures and opportunities in the markets where they sell their products.

3

50. Exhibit B-1, Page 87

Figure C1-9: Normalized and Forecast Wholesale Energy Consumption (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	908	908	895	910	899	682	591	596	602	607	613
After-Savings						677	581	584	587	590	594
After-Savings Growth	3.4%	0.0%	-1.4%	1.6%	-1.2%	-24.7%	-14.1%	0.5%	0.5%	0.5%	0.5%

50.1. Please confirm that the drop in the wholesale consumption is related to the CoK loads now transferred to residential, commercial and industrial categories.

Response:

Confirmed.

50.2. Please provide the history for the CoK wholesale load compared to the load for the other wholesale load, such that the relative growth of each can be shown.

Response:

Please refer to Exhibit B-1-1, Appendix E2, Section 3.3, Table E2-11, p. 16.

50.3. Please comment on whether or not the CoK growth would be expected to be in excess of the other wholesale customer growth.

Response:

The CoK load growth is not expected to be in excess of the other wholesalers' forecasted growth. The wholesale forecast is derived from survey information provided by wholesale customers. FBC believes that each wholesale customer has the best knowledge of their service

territory's load with respect to their customer mix, load behaviors, development projects with associated energy requirements. For the actual forecast growth of each individual wholesaler please refer to Exhibit B-1-1, Appendix E2, Section 3.3, Table E2-11. The before-savings expected load growth for each of the individual wholesalers and the CoK are presented in the table below.

Before-saving Wholesale and CoK Load Growth Rate (%)

	2014	2015	2016	2017	2018
BCH Lardeau	0.4%	0.4%	0.4%	0.4%	0.4%
BCH Kingsgate	0.9%	0.9%	0.9%	0.9%	0.9%
City of Grand Forks	0.7%	0.7%	0.7%	0.7%	0.7%
City of Nelson	1.0%	1.0%	1.0%	1.0%	1.0%
City of Penticton	0.9%	0.9%	0.9%	0.9%	0.9%
District of Summerland	1.0%	1.0%	1.0%	1.0%	1.0%
City of Kelowna	0.5%	0.5%	0.5%	0.5%	0.5%

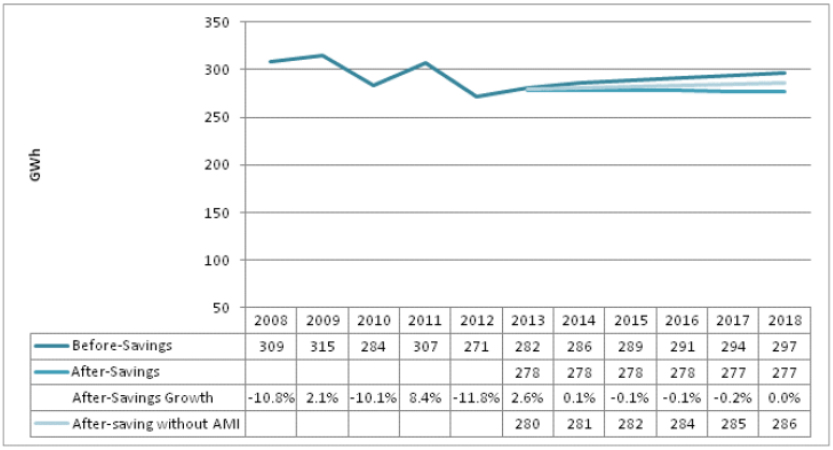
50.4. Please confirm that the .5% growth in the wholesale load is in excess of the average load growth from 2009 to 2012, which in the graphic above looks completely flat.

Response:

The Wholesale load growth of 0.5% during 2015 to 2018 is based on survey information received from all the FBC wholesale customers. FBC believes that its wholesale customers have the best knowledge of their service territory's loads with respect to their customer mix, load behaviors, development projects with associated development projects. Note that for the purpose of this application, rates are only being set for 2014. For rates beyond 2014, a survey of industrial customers will be conducted and a forecast produced for each year. Further information with regards to the wholesale load can be found in Exhibit B-1-1, Appendix A2, Section 3.3.

51. Exhibit B-1, Page 90

Figure C1-12: Normalized and Forecast Energy Losses (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	309	315	284	307	271	282	286	289	291	294	297
After-Savings						278	278	278	278	277	277
After-Savings Growth	-10.8%	2.1%	-10.1%	8.4%	-11.8%	2.6%	0.1%	-0.1%	-0.1%	-0.2%	0.0%
After-saving without AMI						280	281	282	284	285	286

51.1. Please provide the average loss rate for the period 2008 to 2012.

Response:

The average loss rate for the 2008-2012 period is estimated at 8.7%.

51.2. Please explain why the loss rate in 2013 and 2014 are increasing.

Response:

The loss rate of 8 percent is constant for the forecast period and is not increasing.

Losses (GWh) are increasing slightly because the gross load is increasing. Losses are forecast at 8 percent of gross load, therefore if the gross load increases so do the before-saving losses.

51.3. Please explain why the loss rate average from 2015 to 2018 is negative and why it is not expected to be similar to the rate from 2008 to 2012.

Response:

The loss rate is forecast to be 8 percent of the gross load for the forecast period, which is estimated based on a detailed analysis of billing reports of individual accounts from 2011 and

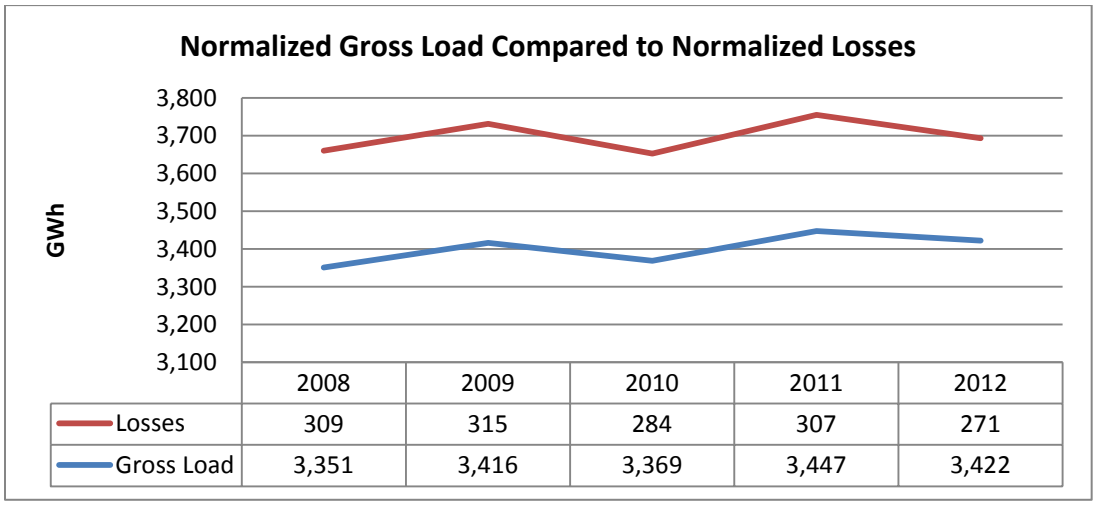
2012, Exhibit B-1, Section C1, 1.4.7. The after-savings growth shown in Figure C1-12 is the year over year after-savings loss growth percentage, not the loss rate.

The after-savings growth shown in Figure C1-12 is negative from 2015 through 2018 due to reduced theft as a result of the implementation of the AMI system.

51.4. Please explain the oscillation in losses for the period from 2008 to 2012 and why they appear to change more significantly that the actual loads.

Response:

The reason for the fluctuation of the losses is that losses increase as load increases and decrease as the load decreases. For example, in the years 2009 and 2011 the gross load saw positive growth, which increased losses while in the years 2008, 2010 and 2012 there was a decline in growth and therefore losses decreased. The stacked line graph below shows the fluctuation of the normalized gross load compared to the normalized losses from 2008 to 2012. The primary reason for the overall change in losses from the years 2008 to 2012 is due to effects of the Okanagan Transmission Reinforcement Project (OTR).



	2008	2009	2010	2011	2012
Losses	309	315	284	307	271
Gross Load	3,351	3,416	3,369	3,447	3,422

52. Exhibit B-1, Page 95

Table C1-4: Forecast Sales Revenue at Existing Rates ($ millions)

	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential	160.2	165.4	165.9	166.4	167.5	168.3
Commercial	69.2	75.7	76.7	77.7	78.4	79.6
Industrial	25.0	29.9	29.9	29.8	29.6	29.6
Wholesale	50.5	41.9	42.2	42.4	42.7	42.9
Total	**304.9**	**312.9**	**314.6**	**316.3**	**318.2**	**320.4**

Note: Commercial includes Lighting and Irrigation classes.

52.1. Please provide the calculation basis for the above table in terms of the price and energy quantities assumed.

Response:

Please refer to Attachment 52.1 containing a functioning spreadsheet. Projected 2013 includes actual sales up to April 2013. Please note that approved 2013 rates have been used for all years.

52.2. Please confirm that the 2014 increase in revenue is primarily associated with the CoK acquisition impacts on revenue.

Response:

The increase in 2014 revenue in Table C1-4 is primarily associated with the City of Kelowna acquisition impacts on revenue and forecast load growth of approximately 1.6 percent.

53. Exhibit B-1, Page 101

Table C2-5: 2014 Forecast vs. 2013 Year End Forecast ($ thousands)

		2013 Projection	2014 forecast	Difference
1	Brilliant	36,781	35,764	(1,017)
2	BC Hydro	31,021	37,201	6,180
3	Independent Power Producers	229	162	(67)
4	Market Purchases	16,094	15,281	(813)
5	Surplus Revenues	(308)	(594)	(286)
6	Special and Accounting Adjustments	14	-	(14)
7	Balancing Pool	435	-	(435)
8	TOTAL	84,266	87,814	3,548
11	Gross Load (GWh)	3,461	3,519	58

53.1. Please provide an estimation for BC Hydro costs based on a 10% rate increased for BC Hydro for 2014.

Response:

If BC Hydro rates increased by 10% on April 1, 2014, the forecast for BC Hydro expenditure would be $39.9 million in 2014 and the total power purchase expense would be $90.5 million.

For illustrative purposes, if the rate increase were to occur on January 1, 2014, the forecast for BC Hydro expenditure would be $41.1 million, and total power purchase expense would be $91.7 million.

53.2. Please discuss whether or not purchases of energy from the Mid-C market would be more economic and attractive than purchases from BC Hydro for 2014.

Response:

BC Hydro supply is a flexible and cost effective firm capacity and energy resource that adds significant value to the FBC resource stack and FBC expects to continue to make significant use of BC Hydro supply for the foreseeable future. Given the requirements of system operation and the variable nature of customer load, although FBC is able to displace a portion of BC Hydro supply, it does not mean that all BC Hydro supply can be displaced operationally or economically.

However, the flexibility of FBC overall power supply resource portfolio, including the BC Hydro supply, does allow for some displacement of PPA energy while still having the supply reliability

and security of a firm resource. The purchase of energy from the Mid-C market can be more economical than purchases from BC Hydro from time to time, depending on the season and the time of day. Given current market conditions, FBC has entered into term contracts to lock in a portion of this value for 2014. These contracts and resulting BC Hydro displacements have been included in the 2014 forecast as part of this Application.

54. Exhibit B-1, Page 106

Table C2-9: 2015 to 2018 Power Purchase Expense Forecast ($ thousands)

		2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Brilliant	38,336	39,151	39,983	40,835
2	BC Hydro	40,660	48,315	51,287	55,712
3	Waneta Expansion	25,864	41,960	42,594	43,597
4	Independent Power Producers	165	169	172	176
5	Market and Contracted Purchases	11,822	5,060	3,125	414
6	Surplus Sales Revenues	(467)	(451)	(446)	(411)
7	Special and Accounting Adjustments	-	-	-	-
8	Balancing Pool	-	-	-	-
9	TOTAL	116,380	134,204	136,716	140,322
10	Gross Load (GWh)	3,537	3,554	3,572	3,596

54.1. Please provide the above table with the 2012, 2013 and 2014 comparative data.

Response:

Please refer to the following table.

		2012 Actual	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Brilliant	35,591	36,781	35,764	38,336	39,151	39,983	40,835
2	BC Hydro	26,037	31,021	37,201	40,660	48,315	51,287	55,712
3	Waneta Expansion	0	0	0	25,864	41,960	42,594	43,597
4	Independent Power Producers	180	229	162	165	169	172	176
5	Market and Contracted Purchases	14,366	16,094	15,281	11,822	5,060	3,125	414
6	Surplus Sales Revenues	0	-308	-594	-467	-451	-446	-411
7	Special and Accounting Adjustments	-162	14	0	0	0	0	0
8	Balancing Pool	-13	435	0	0	0	0	0
9	**TOTAL**	75,999	84,266	87,814	116,380	134,204	136,716	140,322
10	Gross Load	3,413	3,461	3,519	3,537	3,554	3,572	3,596

54.2. Please provide costing of the BC Hydro purchases at 10% per year in an alternate table to the one above.

Response:

The table below shows Table C2-9 with an assumed 10% BC Hydro rate increase on April 1 of each year between 2014 and 2018 and no other changes.

		Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Brilliant	38,336	39,151	39,983	40,835
2	BC Hydro	48,168	62,461	72,729	86,849
3	Waneta Expansion	25,349	40,772	40,892	41,328
4	Independent Power Producers	165	169	172	176
5	Market and Contracted Purchases	11,822	5,060	3,125	414
6	Surplus Sales Revenues	-467	-451	-446	-411
7	Special and Accounting Adjustments	0	0	0	0
8	Balancing Pool	0	0	0	0
9	**TOTAL**	123,372	147,161	156,455	169,192
10	Gross Load	3,537	3,554	3,572	3,596

54.3. Please explain whether or not the assumptions behind this table would change significantly if the BC Hydro rates increase at 10% per year.

Response:

If BC Hydro rates increased at 10% per year, the assumptions behind this table would not change significantly in the short-term because FBC cannot replace the PPA with an equivalent resource without sufficient lead time. FBC's power purchase expense would increase but the Company's firm available resources will not change. FBC may have more opportunity to displace some PPA purchases with market purchases, if the market purchases are be more cost effective compared to the PPA. However, an equivalent market purchase does not exist, since no market purchase can replace the PPA with similar reliability, ability to shape deliveries and ability to meet FBC's remote loads.

In the long-term, continued large increases to BC Hydro rates may significantly affect FBC's resource planning process. It may accelerate the need to bring on new generation resources, if they were to become more cost effective compared to the PPA.

54.4. Please explain why the market and contracted purchases are expected to decline so dramatically and why the BC Hydro purchases are projected to increase so significantly.

Response:

The increase in BC Hydro purchases and decline in Market and Contracted purchases is mainly due to the forecast market price increase, and FBC anticipating an increased use of PPA energy and capacity through 2018. It also takes into account the expiry of FBC's current short term market supply contracts. The following table shows the volumes of BC Hydro energy purchases and the volume of Market and Contracted Purchases from 2015 to 2018.

Energy Purchases (GWh)	2015	2016	2017	2018
BC Hydro	771	916	981	1,068
Market and Contracted Purchases	251	123	75	9

However, each year prior to the June 30th deadline for the Annual Energy Nomination under the New PPA, FBC will analyze forward market prices and the BC Hydro rates, and either lock in market purchases at a lower cost to BC Hydro where possible taking into account both cost and operational considerations, or nominate the BC Hydro energy purchases to meet forecast load. By that time each year, FBC will have more certainty with BC Hydro rates for the coming year, and can make decisions to mitigate power purchase expense with market purchases over a shorter time frame, when possible to do so. Any changes will be incorporated into the power purchase forecast at the annual review as part of the annual rate setting process.

54.5. Please provide the calculations behind this table for 2015 to 2018 and include the calculations for additional columns for 2014, 2013 and 2012 requested in earlier questions.

Response:

This response is being filed confidentially under separate cover as it contains commercially sensitive information.

55. Exhibit B-1, Page 110

Table C3-2: 2015 to 2018 Other Income ($ thousands)

	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1 Other Income	7,360	7,781	7,755	7,819

55.1. Please provide this table with the 2012, 2013 and 2014 comparative data included as well as with the complete breakdown provided in table C3-1

Response:

Please refer to the following table.

		Actual 2012	Approved 2013	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
					($000s)				
1	Apparatus and Facilities Rental	5,018	3,478	4,184	4,156	4,242	4,330	4,420	4,431
2	Contract Revenue	1,943	1,315	1,709	1,385	1,329	1,382	1,263	1,285
3	Miscellaneous Revenue	728	1,203	717	738	744	750	758	764
4	Transmission Access Revenue	1,454	1,071	1,247	1,224	1,248	1,273	1,299	1,325
5	Investment Income	104	98	90	78	67	46	15	15
6	Total	9,247	7,165	7,947	7,582	7,630	7,781	7,755	7,819

56. Exhibit B-1, Page 112

Table C4-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Generation	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	$ 827	893	986	1,069	1,124	1,124
Information Technology	$ 2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 727	867	894	925	953	953
Finance & Regulatory	$ 3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-		-	-
Total O&M	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**

56.1. Please provide this table with 2013 adjusted numbers and also the 2014 to 2018 numbers on a comparative basis.

Response:

The table below has been extended to include the 2013 Base and 2014-2018 Forecasts.

The department view of 2014-2018 O&M described in the Table below is a high level forecast of future trends and upcoming challenges for FBC that was prepared by department. The O&M in Appendix G, Page 1 has been calculated through the PBR formula which is discussed in Tab B and does not rely on the departmental O&M forecasts in Tab C. The two streams of O&M are independent of each other.

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Generation	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492	$ 3,046	$ 3,130	$ 3,217	$ 3,307	$ 3,398	$ 3,493
Operations	$ 14,892	18,604	19,730	19,920	20,938	20,816	21,760	22,571	23,046	23,609	24,184	24,775
Customer Service	$ 5,975	6,398	6,766	6,624	7,510	7,541	7,858	7,576	7,788	8,003	8,220	8,444
External Relations	$ 1,639	1,469	1,244	1,431	1,440	1,469	1,490	1,525	1,561	1,598	1,636	1,674
Energy Supply	$ 827	893	986	1,069	1,124	1,124	1,178	1,283	1,393	1,430	1,469	1,509
Information Technology	$ 2,929	2,903	2,925	2,841	2,988	2,974	3,149	3,231	3,315	3,400	3,489	3,580
Engineering	$ 1,242	2,363	2,615	2,701	2,822	2,791	3,867	3,973	4,084	4,197	4,313	4,433
Operations Support	$ 993	1,315	1,240	1,223	1,205	1,252	1,258	1,291	1,325	1,360	1,396	1,431
Facilities	$ 3,700	3,720	3,596	3,685	3,389	3,466	2,526	2,683	2,690	2,748	2,808	2,869
Environment, Health & Safety	$ 727	867	894	925	953	953	1,013	1,043	1,072	1,104	1,135	1,168
Finance & Regulatory	$ 3,576	3,882	3,823	4,392	4,080	4,271	4,288	4,403	4,522	4,646	4,771	4,899
Human Resources	$ 1,638	1,747	1,816	1,840	1,874	1,874	1,958	2,009	2,062	2,116	2,172	2,228
Governance	$ 2,284	2,031	2,134	1,792	2,490	2,373	2,531	2,691	2,783	2,875	3,032	3,069
Corporate	$ 3,510	4,484	3,444	4,118	3,800	4,225	3,926	3,605	3,173	2,637	2,245	1,863
Advanced Metering Infrastructure	$ -	-	-		-	-	-	368	(439)	(2,411)	(2,369)	(2,794)
Total O&M	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**	**$ 59,848**	**$ 61,382**	**$ 61,592**	**$ 60,619**	**$ 61,899**	**$ 62,641**

Note: *Minor variations due to rounding*

57. Exhibit B-1, Page 113

The reconciliation of the 2013 Base O&M to the 2013 Approved O&M by department is shown below in Table C4-2.

Table C4-2: Determination of Base O&M by Department ($ thousands)

	2013 Approved	Productivity (Sustainable Savings)	2013 Projection	2013 Deferrals			Incremental O&M	2013 Base
				PST	Pension	MRS		
Generation	2,492	64	2,556	3	137		350	3,046
Operations	20,816	122	20,938	53	769			21,760
Customer Service	7,541	(31)	7,510	15	333			7,858
Communications & External Relations	1,469	(29)	1,440	14	35			1,489
Energy Supply	1,124	-	1,124	2	52			1,178
Information Technology	2,974	14	2,988	36	124			3,148
Engineering and Project Management	2,791	31	2,822	5	141	900		3,868
Operations Support	1,252	(47)	1,205	2	51			1,258
Facilities	3,466	(77)	3,389	16	30		(909)	2,526
Environment, Health & Safety	953	-	953	1	59			1,013
Finance & Regulatory	4,271	(191)	4,080	6	201			4,287
Human Resources	1,874	-	1,874	4	80			1,958
Governance	2,373	117	2,490	10	31			2,531
Corporate	4,225	(425)	3,800	11	115			3,926
Total O&M	**57,621**	**(452)**	**57,169**	**180**	**2,158**	**900**	**(559)**	**59,848**

57.1. Please explain the Pension amount and the MRS amount in detail with respect to its quantitative calculation and determination, particularly because they appear to be onetime adjustments.

Response:

The determination of 2013 Base O&M in Table C4-2 starts with approved 2013 O&M, which did not include the incremental MRS expenses and included pension/OPEB costs originally estimated in 2011 by the Company's third party external actuary. Therefore it is necessary to increase the 2013 Base O&M by $900 thousand, to reflect the current expenses of MRS in 2013, and $2,158 thousand, to reflect the current cost of pensions and OPEBs in 2013.

The explanation of the ongoing MRS O&M expense increase on prospective basis is discussed under C4.10.3 Engineering Services and Project Management Review on pages 144 to 148 of Section C4 of the 2014-2018 PBR Application.

The qualitative calculation and determination of the ongoing pension/OPEB O&M expense increase on a prospective basis is provided in the responses to BCUC IRs 1.212.1 and 1.212.1.1. The $2,158 thousand increase in O&M to establish 2013 Base O&M is based on the explanation provided in Section 4.3.3.4.2 – Benefit Inflation on page 117 of the PBR Application which stated "for 2013, the actuarial estimate that was recently completed is approximately 70 percent higher than the actuarial estimate that was completed in 2011 to establish the 2012-2013 RRA forecasts and approved amounts. This increase is primarily due to the low interest rate environment and poorer than expected returns on pension plan assets."

Both Pension/OPEB and MRS increases to 2013 Base O&M shown in Table C4-2 are not one-time adjustments but rather are incremental O&M expenses that will occur during each year of the PBR term. In addition, pension and OPEB expenses are outside of the PBR O&M formula and will be reforecast each year as part of the Annual Review. The MRS increase in costs are treated differently than the pension and OPEB expenses on a prospective basis as the MRS costs will be embedded in the O&M formula and will continue to be part of the PBR O&M formula for the term of the PBR.

57.2. Please comment upon whether or not FBC believes that the Commission could smooth the impact of the Pension and MRS adjustments into the rates over the five year PBR period.

Response:

FBC does not understand the mechanism that is intended by this question. The Pension, MRS and generation costs are not one-time costs to be smoothed, but rather recurring O&M costs on a prospective basis during the term of the PBR. The Pension and MRS adjustments, as is the Generation adjustment, are necessary expenditures in every year of the PBR period beginning in 2014 (subject to annual pension adjustments as set out in Section B6) and must be included in O&M Expense at the full amount required to adequately perform the associated activities.

58. Exhibit B-1, Page 123

Table C4-4: Generation O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,600	$ 1,703	$ 1,854	$ 1,887	$ 1,916	$ 2,357
Non-Labour	617	696	477	605	640	689
Total O&M	**$ 2,217**	**$ 2,399**	**$ 2,331**	**$ 2,492**	**$ 2,556**	**$ 3,046**

Table C4-5: Generation O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 2,427	$ 2,500	$ 2,575	$ 2,652	$ 2,732
Non-Labour	703	717	732	746	761
Total O&M	**$ 3,130**	**$ 3,217**	**$ 3,307**	**$ 3,398**	**$ 3,493**

58.1. Please provide the inflation and growth rates for 2010 to 2013.

Response:

The inflation rates for 2010 to 2013 are provided in Appendix E1 to the 2014-2018 PBR Application (Exhibit B-1-1) and have been reproduced in the table below for convenience. Customer growth rates for 2010 through 2013 are provided in the table below.

	2010 Actual	2011 Actual	2012 Actual	2013 Projected
BC Inflation (CPI)	1.40%	2.30%	1.10%	0.93%
AWE Labour Inflation	2.80%	1.50%	2.30%	2.30%
Customer Growth	1.15%	1.08%	0.74%	13.39%[1]

Note:

[1] Large customer growth for 2013 Projected is attributable to FBC's purchase of the utility assets of the City of Kelowna. As of March 31, 2013, the approximately 15,000 customers of the City of Kelowna became direct customers of FBC.

58.2. Please provide the inflation and growth assumptions for 2014 to 2018.

Response:

The inflation and customer growth rate assumptions for 2014 to 2018 are provided in Appendix E1 to the 2014-2018 PBR Application (Exhibit B-1-1), and have been reproduced below for convenience.

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
BC Inflation (CPI)	1.83%	2.07%	2.03%	2.07%	2.05%
AWE Labour Inflation	2.70%	2.70%	2.60%	2.60%	2.50%
Customer Growth	0.76%	0.89%	0.93%	0.94%	0.98%

58.3. Please provide the fixed and variable cost structure components for the Generation function.

Response:

Please refer to the response to CEC IR 1.26.2.

59. Exhibit B-1, Page 128

Table C4-7: Operations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 8,668	$ 9,532	$ 10,060	$ 10,812	$ 10,794	$ 11,564
Non-Labour	6,223	9,072	9,670	10,004	10,144	10,196
Total O&M	**$ 14,892**	**$ 18,604**	**$ 19,730**	**$ 20,816**	**$ 20,938**	**$ 21,760**

Table C4-8: Operations O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 12,028	$ 12,388	$ 12,760	$ 13,143	$ 13,537
Non-Labour	10,543	10,658	10,849	11,041	11,238
Total O&M	**$ 22,571**	**$ 23,046**	**$ 23,609**	**$ 24,184**	**$ 24,775**

59.1. Please provide a detailed explanation of the Commission decision to require FBC to expense items it previously capitalized.

Response:

In its decision regarding the 2011 Capital Plan, the Commission determined that certain items which had been approved as capital expenditures in previous years' revenue requirements should, going forward, be more appropriately classed as routine operating and maintenance expense. The programs affected included:

- Transmission and Distribution Pine Beetle Kill Hazard Tree Removal;
- Transmission and Distribution Right-of-Way Reclamation; and
- Hot Tap Connector Replacement Program.

With respect to the Pine Beetle Hazard Tree Removal program, the Commission disagreed with FBC's justification for capitalization of the program (extraordinary event, long term benefit), and directed instead that expenditures under this program should addressed as routine operating and maintenance expense.

With respect to the Right-of-Way Reclamation program, the Commission expressed concern with the capitalization of the clearing of an existing right-of-way more than once, particularly if cyclical brushing was not routinely completed which could lead to an increase in the expenditures under this program. As such, the Commission directed that expenditures under this program should be addressed as routine operating and maintenance expense.

With respect to the Hot Tap Connector Replacement Program, the Commission determined that the program related to an on-going issue with respect to FBC's legacy system, and directed the Company to instead address the required expenditures as a part of routine operating and maintenance expense.

59.2. Please provide an explanation as to whether or not these items are repeating expenditures every year and explain why.

Response:

Please refer to Section C4.5.1 of the application which describes the activities associated with Operation O&M, all of which are recurring activities necessary for the safe and reliable operation of the utility.

59.3. Please provide the fixed and variable cost structure components for Operations O&M.

Response:

Please refer to the response to CEC IR 1.26.2.

Exhibit B-1, Page 132

Table C4-9: Customer Service O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 4,329	$ 4,725	$ 4,716	$ 4,830	$ 4,669	$ 5,002
Non-Labour	1,646	1,673	2,050	2,711	2,841	2,856
Total O&M	**$ 5,975**	**$ 6,398**	**$ 6,766**	**$ 7,541**	**$ 7,510**	**$ 7,858**

Normalizing the total 2013 forecast expenditures to $6,475 thousand by excluding revenue protection and City of Kelowna costs of $1,035 thousand results in a compound annual increase of 2.7 percent since 2010.

Table C4-10: Customer Service O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 5,399	$ 5,561	$ 5,727	$ 5,898	$ 6,075
Non-Labour	2,177	2,227	2,276	2,322	2,369
Total O&M	**$ 7,576**	**$ 7,788**	**$ 8,003**	**$ 8,220**	**$ 8,444**

59.4. Please provide the inflation rates for 2010, 2011, 2012 and 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

59.5. Please provide the customer growth rates for 2010, 2011, 2012 and 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

59.6. Please provide the inflation rates assumed for 2014 to 2018 by year.

Response:

Please refer to the response to CEC IR 1.58.2.

59.7. Please provide the customer growth rates assumed for 2014 to 2018 by year.

Response:

Please refer to the response to CEC IR 1.58.2.

59.8. Please provide the fixed and variable components of the cost structure for Customer Service O&M.

Response:

Please refer to the response to CEC IR 1.26.2.

Exhibit B-1, Page 135

Table C4-11: Communications and External Relations O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 556	$ 543	$ 493	$ 544	$ 496	$ 531
Non-Labour	1,083	926	751	925	944	959
Total O&M	**$ 1,639**	**$ 1,469**	**$ 1,244**	**$ 1,469**	**$ 1,440**	**$ 1,490**

Table C4-12: Communications and External Relations O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 547	$ 564	$ 581	$ 598	$ 616
Non-Labour	978	997	1,017	1,038	1,058
Total O&M	**$ 1,525**	**$ 1,561**	**$ 1,598**	**$ 1,636**	**$ 1,674**

The forecast expenditures over the 2014-2018 period is expected to remain steady from the 2013 base level with only annual inflationary increases over this period.

59.9. Please explain why the External Relations O&M has been maintained at level of decreased levels through the 2010 to 2013 period.

Response:

A combination of unique circumstances and the reclassification of expenditure resulted in a lower level of spend in the 2010 to 2012 period.

In 2011, the lower expenditure was due to higher cross charges to the gas operations to backfill a temporary employee leave. In 2012, the lower spend was attributable to a vacant Communications Advisor position, the reclassification of expenditure to non-regulated expense, a vacant manager position and higher cross charges to the gas operations. The department intentionally delayed filling the Communication Advisor role until 2013, in order to determine if the workload of the group could be managed without this position but realized that this was not a sustainable solution. As per the 2012/2013 RRA and Order G-1101-12, FBC was directed to allocate 50 percent of its community investment and 100% of political donations to the shareholder. As such, the 2012 actual and the 2013 projected expenditure does not include $93 thousand and $80 thousand respectively, of community investment and political donations

as these expenses are borne by the shareholder. The role and responsibilities of the vacant manager position have since been addressed through the shared gas and electric management responsibility reflecting the integrated nature of the department. Additionally, in 2012 the lower expenditure was attributable to higher cross charges to the gas operations by electric employees, to backfill the work of gas employees working on capital projects during that year.

In 2011 and 2012 the department experienced temporary circumstances contributing to a temporary and unsustainable period of underspend, and thereby 2013 forecasted expenditure is more reflective of the appropriate base from which to develop a forecast the next five year period in order to sustain ongoing operations for the department. This will enable the department to meet customer and stakeholder expectations along with the increasing demands on communications and external relations for such initiatives as AMI, RCR and customer education on rates, billing and energy usage.

59.10. Please explain why the costs for External Relations grow significantly from 2014 to 2018.

Response:

To clarify, FBC is not seeking approval for the O&M Expenses set out in Table C4-12, or for the aggregate of the costs in section C4. O&M Expense during the term of the PBR Plan will be set at the corporate level according to the formula set out in Section B6.

The Communications and External Relations groups do not expect to increase costs significantly over the 2014 to 2018 period. Rather, only annual inflationary increases, with annual increases of just over 2 percent from 2013 base, are forecasted over this period, as noted in the footnotes to the above tables.

59.11. Please provide the inflation and growth assumptions used to derive these numbers from 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

59.12. Please provide the fixed and variable cost structure components for O&M.

Response:

Please refer to the response to CEC IR 1.26.2.

60. Exhibit B-1, Page 138 & 139

Table C4-13: Energy Supply O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 629	$ 631	$ 709	$ 772	$ 732	$ 784
Non-Labour	198	262	277	352	392	394
Total O&M	**$ 827**	**$ 893**	**$ 986**	**$ 1,124**	**$ 1,124**	**$ 1,178**

Table C4-14: Energy Supply O&M Forecast ($thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 881	$ 983	$ 1,012	$ 1,042	$ 1,074
Non-Labour	402	410	418	427	435
Total O&M	**$ 1,283**	**$ 1,393**	**$ 1,430**	**$ 1,469**	**$ 1,509**

60.1. Please provide the inflation rates and growth rates for 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

60.2. Please provide the inflation and growth assumptions from 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

60.3. Please provide the fixed and variable components of the cost structure for Energy Supply.

Response:

Please refer to the response to CEC IR 1.26.2.

61. Exhibit B-1, Page 142

Table C4-15: IS O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,801	$ 1,731	$ 1,689	$ 1,755	$ 1,746	$ 1,871
Non-Labour	1,128	1,172	1,236	1,219	1,242	1,278
Total O&M	**$ 2,929**	**$ 2,903**	**$ 2,925**	**$ 2,974**	**$ 2,988**	**$ 3,149**

Table C4-16: IS O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,927	$ 1,984	$ 2,044	$ 2,105	$ 2,168
Non-Labour	1,304	1,331	1,356	1,384	1,412
Total O&M	**$ 3,231**	**$ 3,315**	**$ 3,400**	**$ 3,489**	**$ 3,580**

61.1. Please provide the inflation and growth rates for 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

61.2. Please provide the inflation and growth assumptions for 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

61.3. Please provide the fixed and variable cost structure components for the IS O&M function.

Response:

Please refer to the response to CEC IR 1.26.2.

62. Exhibit B-1, Page 145 & 147

Table C4-17: Engineering Services and Project Management O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 928	$ 1,789	$ 1,951	$ 2,127	$ 1,974	$ 2,964
Non-Labour	314	574	664	664	848	903
Total O&M	**$ 1,242**	**$ 2,363**	**$ 2,615**	**$ 2,791**	**$ 2,822**	**$ 3,867**

Table C4-18: Mandatory Reliability Standards O&M Review ($ thousands)
(Including Deferred O&M Expense)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ 856	$ 1,328	$ 914	$ 1,709	$ 1,770
Non-Labour	-	160	171	273	379	380
Total O&M	**$ -**	**$ 1,016**	**$ 1,499**	**$ 1,187**	**$ 2,088**	**$ 2,150**

Table C4-19: Engineering Services and Project Management O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,053	$ 3,145	$ 3,239	$ 3,336	$ 3,437
Non-Labour	920	939	958	977	996
Total O&M	**$ 3,973**	**$ 4,084**	**$ 4,197**	**$ 4,313**	**$ 4,433**

Table C4-20: Mandatory Reliability Standards O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,823	$ 1,878	$ 1,934	$ 1,992	$ 2,052
Non-Labour	387	395	403	411	419
Total O&M	**$ 2,210**	**$ 2,273**	**$ 2,337**	**$ 2,403**	**$ 2,471**

62.1. Please provide the inflation and growth rates for 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

62.2. Please provide the inflation and growth assumptions for 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

62.3. Please provide the fixed and variable cost components of the Engineering and Project management function as well as for the MRS function.

Response:

Please refer to the response to CEC IR 1.26.2.

63. Exhibit B-1, Page 149 & 150

Table C4-21: Operations Support O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 3,475	$ 3,510	$ 3,354	$ 3,510	$ 3,425	$ 3,669
Non-Labour	3,152	2,992	2,754	3,829	3,027	3,042
Recoveries	(5,633)	(5,186)	(4,868)	(6,087)	(5,247)	(5,453)
Total O&M	**$ 993**	**$ 1,315**	**$ 1,240**	**$ 1,252**	**$ 1,205**	**$ 1,258**

Table C4-22: Operations Support O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,779	$ 3,892	$ 4,009	$ 4,130	$ 4,253
Non-Labour	3,103	3,166	3,229	3,294	3,359
Recoveries	(5,591)	(5,733)	(5,878)	(6,028)	(6,181)
Total O&M	**$ 1,291**	**$ 1,325**	**$ 1,360**	**$ 1,396**	**$ 1,431**

63.1. Please provide the inflation and growth rates for the 2010 to 2013 period.

Response:

Please refer to the response to CEC IR 1.58.1.

63.2. Please provide the inflation and growth assumptions for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

63.3. Please provide the fixed and variable cost structure components for the Operations support function.

Response:

Please refer to the response to CEC IR 1.26.2.

64. Exhibit B-1, Page 152

Table C4-23: Facilities O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 578	$ 501	$ 386	$ 499	$ 422	$ 452
Non-Labour	3,122	3,219	3,210	2,967	2,967	2,074
Total O&M	**$ 3,700**	**$ 3,720**	**$ 3,596**	**$ 3,466**	**$ 3,389**	**$ 2,526**

Table C4-24: Facilities O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 517	$ 480	$ 494	$ 509	$ 524
Non-Labour	2,166	2,210	2,254	2,299	2,345
Total O&M	**$ 2,683**	**$ 2,690**	**$ 2,748**	**$ 2,808**	**$ 2,869**

64.1. Please explain why the Facilities O&M costs have been maintained and reduced slightly from 2010 to 2013.

Response:

The trend for O&M costs incurred by Facilities between the years 2010 to 2013 is a reflection of several factors including the fixed lease costs observed throughout the period and the downward fluctuation of long period work that is scheduled as part of the normal maintenance cycle. In addition, the Facilities Department combined two FTE positions within FBC and FEI into a single FTE position residing within FEI and cross charging to FBC.

64.2. Please provide the inflation and growth rates for 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

64.3. Please provide the inflation and growth rate assumptions for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

64.4. Please provide the fixed and variable cost structure components of the facilities function.

Response:

Please refer to the response to CEC IR 1.26.2.

65. Exhibit B-1, Page 156 & 157

Table C4-25: EH&S O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 586	$ 689	$ 714	$ 760	$ 830	$ 889
Non-Labour	141	178	180	193	123	124
Total O&M	**$ 727**	**$ 867**	**$ 894**	**$ 953**	**$ 953**	**$ 1,013**

Table C4-26: EH&S O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 916	$ 943	$ 972	$ 1,001	$ 1,031
Non-Labour	127	129	132	134	137
Total O&M	**$ 1,043**	**$ 1,072**	**$ 1,104**	**$ 1,135**	**$ 1,168**

65.1. Please provide the inflation and growth rates for the 2010 to 2013 period.

Response:

Please refer to the response to CEC IR 1.58.1.

65.2. Please provide the inflation and growth assumptions for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

65.3. Please provide the fixed and variable cost structure components for the EH&S function.

Response:

Please refer to the response to CEC IR 1.26.2.

66. Exhibit B-1, Page 159 & 160

Table C4-27: Finance and Regulatory O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,659	$ 2,887	$ 2,649	$ 3,067	$ 2,815	$ 3,016
Non-Labour	917	995	1,174	1,204	1,265	1,272
Total O&M	**$ 3,576**	**$ 3,882**	**$ 3,823**	**$ 4,271**	**$ 4,080**	**$ 4,288**

Table C4-28: Finance and Regulatory O&M Forecast ($thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 3,106	$ 3,200	$ 3,296	$ 3,394	$ 3,496
Non-Labour	1,297	1,322	1,350	1,377	1,403
Total O&M	**$ 4,403**	**$ 4,522**	**$ 4,646**	**$ 4,771**	**$ 4,899**

66.1. Please provide the growth and inflation rates for the period 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

66.2. Please provide the growth and inflation assumptions for the period 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

66.3. Please provide the fixed and variable cost structure for the finance and regulatory function.

Response:

Please refer to the response to CEC IR 1.26.2.

67. Exhibit B-1, Page 163 & 164

Table C4-29: Human Resources O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,309	$ 1,217	$ 1,047	$ 1,370	$ 1,128	$ 1,208
Non-Labour	329	530	769	504	746	750
Total O&M	**$ 1,638**	**$ 1,747**	**$ 1,816**	**$ 1,874**	**$ 1,874**	**$ 1,958**

Table C4-30: Human Resources O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,244	$ 1,282	$ 1,320	$ 1,360	$ 1,400
Non-Labour	765	780	796	812	828
Total O&M	**$ 2,009**	**$ 2,062**	**$ 2,116**	**$ 2,172**	**$ 2,228**

67.1. Please provide the inflation and growth rates for the 2010 to 2013 period.

Response:

Please refer to the response to CEC IR 1.58.1.

67.2. Please provide the inflation and growth assumptions for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

67.3. Please provide the fixed and variable cost structure components for the Human Resources function.

Response:

Please refer to the response to CEC IR 1.26.2.

68. Exhibit B-1, Page 166

Table C4-31: Governance O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 284	$ 215	$ 313	$ 428	$ 428	$ 459
Non-Labour	2,000	1,816	1,821	1,945	2,062	$ 2,072
Total O&M	**$ 2,284**	**$ 2,031**	**$ 2,134**	**$ 2,373**	**$ 2,490**	**$ 2,531**

Table C4-32: Governance O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 472	$ 486	$ 501	$ 517	$ 532
Non-Labour	$ 2,219	$ 2,297	$ 2,374	$ 2,515	$ 2,537
Total O&M	**$ 2,691**	**$ 2,783**	**$ 2,875**	**$ 3,032**	**$ 3,069**

68.1. Please provide the growth and inflation rates for 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

68.2. Please provide the assumed inflation and growth rates for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

68.3. Please provide the fixed and variable cost components for the governance function.

Response:

Please refer to the response to CEC IR 1.26.2.

69. Exhibit B-1, Page 170, 171 & 172

Table C4-33: Corporate O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,329	$ 2,049	$ 1,459	$ 1,995	$ 1,607	$ 1,722
Non-Labour	1,181	2,435	1,985	2,230	2,193	2,204
Total O&M	**$ 3,510**	**$ 4,484**	**$ 3,444**	**$ 4,225**	**$ 3,800**	**$ 3,926**

Table C4-35: Board of Directors O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
	$ 289	$ 268	$ 241	$ 275	$ 245	246
Total O&M	**$ 289**	**$ 268**	**$ 241**	**$ 275**	**$ 245**	**$ 246**

Table C4-36: Executive O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 2,329	$ 2,049	$ 1,459	$ 1,995	$ 1,607	$ 1,722
Non-Labour	185	245	163	370	223	233
Total O&M	**$ 2,514**	**$ 2,294**	**$ 1,622**	**$ 2,365**	**$ 1,830**	**$ 1,955**

Table C4-37: Corporate Other O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
	(576)	310	(287)	-	-	$ -
Total O&M	**$ (576)**	**$ 310**	**$ (287)**	**$ -**	**$ -**	**$ -**

Table C4-38: Corporate O&M Forecast ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 1,773	$ 1,826	$ 1,881	$ 1,938	$ 1,996
Non-Labour	2,337	2,454	2,471	2,572	2,625
Pension	(505)	(1,107)	(1,715)	(2,265)	(2,758)
Total O&M	**$ 3,605**	**$ 3,173**	**$ 2,637**	**$ 2,245**	**$ 1,863**

Table C4-39: Corporate O&M Forecast by Business Driver ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Fortis Inc. Costs	$ 1,848	$ 1,955	$ 1,963	$ 2,054	$ 2,096
Board Costs	251	256	261	266	272
Executive	2,011	2,069	2,128	2,190	2,253
Corporate Other	-	-	-	-	-
Pension	(505)	(1,107)	(1,715)	(2,265)	(2,758)
	$ 3,605	**$ 3,173**	**$ 2,637**	**$ 2,245**	**$ 1,863**

69.1. Please provide the growth rates and inflation rates for the period 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.58.1.

69.2. Please provide the growth and inflation rate assumptions for the period 2014 to 2018.

Response:

Please refer to the response to CEC IR 1.58.2.

69.3. Please provide the fixed and variable cost structures for the Corporate O&M functions.

Response:

Please refer to the response to CEC IR 1.26.2.

70. Exhibit B-1, Page 174 to 176

Table C4-40: AMI O&M Impact – Information Systems ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ 289	$ 623	$ 634	$ 654	$ 665
Non-Labour	477	587	597	607	618
Total O&M	**$ 766**	**$ 1,210**	**$ 1,231**	**$ 1,261**	**$ 1,283**

Table C4-43: AMI O&M Impact – Operations Support ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ -	$ -	$ -	$ -	$ -
Non-Labour	-	(176)	(443)	(450)	(477)
Total O&M	**$ -**	**$ (176)**	**$ (443)**	**$ (450)**	**$ (477)**

Table C4-44: Total AMI O&M Forecast Impact ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	$ (71)	$ (667)	$ (2,248)	$ (2,201)	$ (2,594)
Non-Labour	439	229	(163)	(168)	(200)
Total O&M	**$ 368**	**$ (439)**	**$ (2,411)**	**$ (2,369)**	**$ (2,794)**

70.1. Please provide the growth and inflation assumptions for the 2014 to 2018 period.

Response:

Please refer to the response to CEC IR 1.58.2.

70.2. Please confirm the savings in other functions associated with the addition of the AMI function costs are all of the savings firmly identified in the AMI CPCN application but none of the unquantified or future benefits are included.

Response:

Confirmed.

70.3. Please provide the fixed and variable cost structures for the AMI function.

Response:

AMI essentially will have no variable costs associated with it once the project is implemented. Please also refer to the response to CEC IR 1.26.2.

71. Exhibit B-1, Page 182

Table C5-3: Forecast FBC Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Generation	2,468	3,155	2,940	2,944	3,010	2,847
Transmission, Station & Telecommunications	8,359	16,171	9,821	9,480	11,073	11,520
Distribution	9,220	11,827	12,092	14,164	14,248	14,503
Total Sustainment Capital	20,047	31,153	24,854	26,587	28,331	28,869
Growth Capital						
Transmission, Station & Telecommunications	332	3,187	3,190	-	293	2,928
Distribution	20,306	15,102	14,732	15,589	15,764	16,916
Total Growth Capital	20,638	18,289	17,922	15,589	16,057	19,844
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,783	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	16,765	18,233	583	741	604
Total Other Capital	8,495	26,078	28,449	13,738	10,247	10,162
Pension Adjusments	-	(345)	(789)	(1,233)	(1,608)	(1,915)
Total Gross Capital Expenditures	49,180	75,176	70,435	54,681	53,028	56,960

71.1. Please prepare the above table without CPCN related projects and without one time major expenditure projects.

Response:

The requested table is provided below. The projects that have been eliminated (highlighted in the table below) are as follows:

- Advanced Metering Infrastructure (CPCN project)
- PCB Project (One time Major Expenditure Project)
- Okanagan Long Term Solution (One time Major Expenditure Project)

Please note that only the CPCN expenditures for the Advanced Metering Infrastructure have been excluded in the table, and not the incremental sustaining expenditures (non-CPCN expenditures) which are driven by the AMI project

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Generation	2,468	3,155	2,940	2,944	3,010	2,847
Transmission, Station & Telecommunications	8,359	16,171	9,821	9,480	11,073	11,520
Less PCB Project		(6,062)	-	-	-	-
Distribution	9,220	11,827	12,092	14,164	14,248	14,503
Total Sustainment Capital	20,047	25,091	24,854	26,587	28,331	28,869
Growth Capital						
Transmission, Station & Telecommunications	332	3,187	3,190	-	293	2,928
Distribution	20,306	15,102	14,732	15,589	15,764	16,916
Total Growth Capital	20,638	18,289	17,922	15,589	16,057	19,844
Other Capital						
Information Systems	4,271	5,290	6,134	5,791	5,747	5,721
Vehicles	2,360	1,948	1,783	1,749	1,907	1,945
Meters Changes	369	-	71	109	114	118
Telecommunications	166	156	159	162	166	169
Buildings	803	1,044	912	942	961	980
Furniture & Fixtures	110	260	531	87	88	90
Tools	416	494	504	514	524	535
Okanagan Long Term Solution	-	120	122	3,800	-	-
Advanced Metering Infrastructure	-	16,765	18,233	583	741	604
Less Okanagan Long Term Solution		(120)	(122)	(3,800)	-	-
Less Advanced Metering Infrastructure		(16,468)	(17,660)	-	-	-
Total Other Capital	8,495	9,490	10,666	9,938	10,247	10,162
Pension Adjusments	-	(345)	(789)	(1,233)	(1,608)	(1,915)
Total Gross Capital Expenditures	**49,180**	**52,525**	**52,652**	**50,881**	**53,028**	**56,960**

71.2. Please explain how it would be possible to know whether or not FBC has implemented the capital expenditures planned and forecast as opposed to knowing just how much capital expenditure dollars have been spent.

Response:

Please refer to the response to BCUC IR 1.152.1.

71.3. Please provide for each capital expenditure category a metric that provides a measure of how much capital investment functionality is being implemented in each year.

Response:

FBC considers the most appropriate measure for any given project or project category would be an evaluation of the total expenditures as compared to the original estimate, schedule and scope (normalized for any non-controllable factors). In other words, a desirable outcome is that projects are completed on the needed timeline and fully implement the originally defined project scope, but at an equal or lower cost than the detailed project estimate. FBC submits that due to the large number of external factors which can influence project schedules (such as permitting requirements or interaction with external stakeholders) normalizing for uncontrollable factors that impact project costs, scope or schedules must be considered.

FBC considers that the 2014 PBR application inherently incorporates such a capital expenditures incentive mechanism in that the capital allowed under the PBR formula is lower than that derived from totaling the individual project forecasts. Hence, FBC is challenged to complete an identified portfolio of projects at a lower cost than forecast by finding design, procurement and construction efficiencies. On that basis a metric for each capital category is inappropriate under a PBR arrangement.

71.4. Please describe how FBC will know whether it is being more efficient or whether it only knows if it has spent more or less than planned for each category listed.

Response:

Please refer to the response to CEC IR 1.71.3.

72. Exhibit B-1, Page 261

> FBC is proposing to create new deferral accounts to capture the costs of regulatory proceedings, revenue impacts of BCUC decisions, and other non-controllable items, as detailed in this section. The establishment of deferral accounts for the non-controllable items in this section will result in a consistent treatment, including amortization periods, of those similar items deferred by its affiliates that are also regulated by the BCUC.

72.1. Please provide a list of all of the items excluded from the PBR and provide the matching deferral account requested to flow through actuals.

Response:

Section D4.8 and Table D4-4, on page 274 of the Application provides a Summary of Approvals Sought regarding Deferral Accounts as well as cross references to the relevant Section of the Application where relevant.

Items excluded from the PBR O&M formula include:

1. The O&M portion of Pension/OPEB (see Section D4.4.40. The Company is proposing to defer variances to Pension/OPEB expense and change from a 3 year amortization period to a 11 year amortization period based on EARSL beginning January 1, 2014.

2. Insurance (see Section D4.3.4). FBC has requested that differences in Insurance premiums from forecast will be deferred and amortized in the following year.

3. Advanced Metering Infrastructure (AMI) Project. Incremental costs and savings resulting from the AMI project will be tracked and presented outside of the PBR O&M formula.

72.2. Please explain why there is not a deferral account for variances with any items excluded from the PRB which do not have deferral accounts.

Response:

FBC assumes this question is referring to Advanced Metering Infrastructure (AMI) Project costs excluded from the O&M and capital formula and the PCB Compliance – Substations costs excluded from the capital formula.

FBC has not requested deferral accounts to capture variances from forecasts for these items as the forecasts will be updated annually during the Annual Review process, thereby leaving both FBC and customers at risk for only one year of forecasts. Additionally, FBC has attempted to reduce the amount of deferral accounts it currently uses as is evidenced by Section D4.8 of the

Application where the utility has requested nine new accounts compared to the 23 deferral accounts it has requested for discontinuance. However, FBC would be amenable to creating deferral accounts to capture variances from forecast for both the AMI Project and PCB Compliance – Substations should the Commission determine it appropriate.

72.3. Please explain how the excluded capital project variances will be handled during the PBR period.

Response:

Please refer to the responses to BCUC IR 1.58.1, and BCPSO IRs 1.25.1 and 1.25.2.

73. Exhibit B-1, Page 277 & Page 106

REVENUE REQUIREMENTS OVERVIEW

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Sales Volume (GWh)	3,240	3,258	3,276	3,295	3,318
2	Rate Base	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
3	Return on Rate Base	7.13%	6.98%	7.01%	7.01%	7.02%
4						
5	**REVENUE DEFICIENCY**			($000s)		
6						
7	**POWER SUPPLY**					
8	Power Purchases	87,814	116,380	134,204	136,716	140,322
9	Water Fees	10,057	10,532	10,479	10,688	10,902
10		97,871	126,913	144,683	147,404	151,224
11	**OPERATING**					
12	O&M Expense	61,386	61,744	60,960	62,378	63,302
13	Capitalized Overhead	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)
14	Wheeling	5,224	4,856	4,952	5,050	5,208
15	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
16		46,751	46,621	45,939	47,198	48,030
17	**TAXES**					
18	Property Taxes	15,903	16,329	16,612	16,975	17,290
19	Income Taxes	9,241	4,738	3,896	6,818	9,544
20		25,144	21,067	20,508	23,793	26,834
21	**FINANCING**					
22	Cost of Debt	42,607	41,742	42,925	43,545	43,861
23	Cost of Equity	44,899	46,010	46,942	47,529	47,839
24	Depreciation and Amortization	57,773	56,067	58,217	60,557	62,877
25		145,279	143,819	148,085	151,631	154,576
26						
28	Flow Through Adjustments	(14,207)	-	-	-	-
29	Rate Stabilization	22,567	(2,430)	(10,112)	(7,100)	(2,925)
30		8,360	(2,430)	(10,112)	(7,100)	(2,925)
31						
32	**TOTAL REVENUE REQUIREMENT**	323,405	335,990	349,102	362,926	377,740
33						
34	**LESS: REVENUE AT APPROVED RATES**	312,923	325,111	337,798	351,194	365,502
35	**REVENUE DEFICIENCY FOR RATE SETTING**	10,482	10,879	11,304	11,732	12,237
36						
37	**RATE INCREASE**	**3.30%**	**3.30%**	**3.30%**	**3.30%**	**3.30%**

73.1. Please calculate the portion of the rate increases expected that are being driven by assumed BC Hydro increased volume for power purchases.

Response:

The table below calculates at a high level the portion of the rate increases that are driven by BC Hydro increased volume for power purchases. There are no forecasted BC Hydro rate increases in 2014 forward so the difference in cost is due to volume.

Power Purchase Cost Parameters - BC Hydro		2013	2014	2015	2016	2017	2018
BC Hydro Energy & Capacity Costs		**31,021**	**37,201**	**40,660**	**48,315**	**51,287**	**55,712**
BC HydroCost Increases			6,180	3,459	7,655	2,972	4,425
Base Revenue			**323,405**	**335,990**	**349,102**	**362,926**	**377,740**
BC Hydro Increases as a % of Base Revenue			**1.9%**	**1.0%**	**2.2%**	**0.8%**	**1.2%**

73.2. Please confirm that the BC Hydro rates are assumed to be their April 1, 2013 rates and that no rate increases are factored into the estimates.

Response:

Confirmed.

73.3. Please confirm that the increase in power purchase costs is driven by a decrease in market purchases causing a transfer to purchases from BC Hydro.

Response:

Not confirmed. Please refer to Section C, page 106 of the application for a discussion of the increase in power purchase expense from 2014 to 2018. A greater reliance on BC Hydro energy and capacity is only a part of the reason for the increase.

73.4. Please provide an explanation as to whether or not FBC will continue purchasing from the market if the prices for energy are lower than the costs of power from BC Hydro.

Response:

Yes, FBC will continue to make market purchases to displace BC Hydro PPA power where it is operationally feasible and economical to do so. A discussion of the approach and methodology used in the application is found in Section C, page 101 to 103 in sub-section 2.5. A similar approach will be applied every year to determine the appropriate BC Hydro PPA nomination.

73.5. Please calculate the portion of the rate increases expected that are being driven by the addition of the Waneta Expansion.

Response:

The cumulative Rate increases during 2015-2018 increases expected as a result of the Waneta Expansion is approximately 11.8%.

Table C2-9: 2015 to 2018 Power Purchase Expense Forecast ($ thousands)

		2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Brilliant	38,336	39,151	39,983	40,835
2	BC Hydro	40,660	48,315	51,287	55,712
3	Waneta Expansion	25,864	41,960	42,594	43,597
4	Independent Power Producers	165	169	172	176
5	Market and Contracted Purchases	11,822	5,060	3,125	414
6	Surplus Sales Revenues	(467)	(451)	(446)	(411)
7	Special and Accounting Adjustments	-	-	-	-
8	Balancing Pool	-	-	-	-
9	TOTAL	116,380	134,204	136,716	140,322
10	Gross Load (GWh)	3,537	3,554	3,572	3,596

73.6. Please confirm that BC Hydro rate increases would be proposed to flow through to customer rates.

Response:

Confirmed. Please see the response to BCMEU IR 1.4.1.

73.7. Please describe the timing for recognizing the BC Hydro rate increases in the costs for customers of FBC, will it be upon application and interim rate approval or will it await a finalization decision?

Response:

Please see the response to BCMEU IR 1.4.1..

73.8. Please describe the flow through mechanism, will the impacts of BC Hydro rate increases be captured in a deferral account and flowed through to customers in a following year after an annual PBR review?

Response:

Please see the response to BCMEU IR 1.4.1.

74. 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.

74.1. 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:

B&V provides the following response.

All of the data is provided in the schedules. There are no other workpapers. 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. Rather, the Ventyx Velocity data has been audited by B&V by reviewing the original source documents from Commission filings and making corrections as necessary.

74.2. 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 or confirm that all the relevant CVs are in Appendix D3.

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.18.2. This response is identical to the FEI response to that IR.

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.

74.3. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.3. This response is identical to the FEI response to that IR.

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.

74.4. 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.

Response:

Please refer to the response to CEC IR 1.74.3.

74.5. 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 FBC. We specifically request

information about the number of hours billed and the charges for services rendered.

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.5. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

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. FBC 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 74.5 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 its 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.

74.6. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.18.6. This response is identical to the FEI response to that IR.

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.

74.7. B&V states on p. 1 of its report that "As adapted 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.7. This response is identical to the FEI response to that IR.

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.

74.8. B&V states on p. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.8. This response is identical to the FEI response to that IR.

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.

74.9. B&V states on p. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.9. This response is identical to the FEI response to that IR.

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:

$$((\Delta \boldsymbol{QL} + \Delta \boldsymbol{QuallL}) * \boldsymbol{WAPL_{t=1}}) + (\boldsymbol{QL_{t=0}} * \boldsymbol{WAPL_{t=1}}) = \Delta \boldsymbol{Labor\ Input}$$

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.

74.10. B&V states on p. 6 of its report that 'By excluding general plant from the capital component of costs, the AUC adopted NERA 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.' 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 distribution inputs.

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.10. This response is identical to the FEI response to that IR.

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.

74.11. 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 p. 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 a 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.11. The question asks about FEI not FBC, but we have assumed it was intended to apply to FBC.

B&V provides the following response.

The use of a five year period has been explained in the responses to BCUC IR 1.17.1, 1.17.2 and 1.18.1. 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 electric utilities 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 an electric utility 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.

74.12. Please defend your use of data from SNL Financial on utility operations. Has SNL Financial approved the publication of this data?

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.12. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V provides the following response.

The FBC TFP Study in Appendix 2 used the Ventex Velocity database. The use of the Ventex Velocity data base is fully explained in the TFP study report. Please see page 8 of that report. The Ventex Velocity 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.

74.13. On p. 8 of its report B&V states that "We have included all net plant for electric utilities 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 electric 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 p. 11 that "The results represent a more comprehensive review of costs than that found in the AUC [productivity] analysis".

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?

Please demonstrate how and why the exclusion of A&G expenses from the B&V study would raise the TFP trend results.

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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IRs 1.81.14, 1.81.15, and 1.81.16. This response is similar to the FEI responses to those IRs but has been changed to be appropriate for the electric utility.

Part 1:

B&V provides the following response to the question of whether "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?"

These costs are included in operating expenses. 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 fuel and purchased power averages approximately 5.3% per year for the utilities in the TFP Study. Over this same period inflation averaged about 2.2%. B&V considers that the 5.3% would be representative of what could be expected over the next 5 years.

Part 2:

B&V provides the following response to the question "Please demonstrate how and why the exclusion of A&G expenses from the B&V study would raise the TFP trend results."

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.

Part 3:

B&V provides the following response to the question "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?"

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.

74.14. B&V discusses on p. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.18. The response has been changed to be applicable to the electric utility context.

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 electric utilities in the sample operate in jurisdictions with full decoupling. This includes both California and New York for example. Second, 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 FortisBC and other sources that report on the results of rate cases).

The testimony of Alfred Kahn is provided as Attachment 74.14.

74.15. B&V discusses on p. 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:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.81.19. This response is identical to the FEI response to that IR with the exception of the name change to FBC and minor modifications to properly refer to other IR responses.

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 1.46.2. 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 1.45.2. 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 FBC.

74.16. On p. 9 of its report B&V characterize their measure of "electric inputs" as the "change in weighted cost of capital and total expenses". FBC states, relatedly, on p. 46 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.20. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

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 1.74.8, 1.81.13 and 1.81.14.

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.

74.17. 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 AB under the heading "Cost Change"?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.81.21. This response is identical to the FEI response to that IR.

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.

74.18. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.23. This response is identical to the FEI response to that IR.

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.

74.19. Please explain why O&M expenses are a plausible proxy for the quantity of O&M if not adjusted for inflation.

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.24. This response is identical to the FEI response to that IR.

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.

74.20. Please explain the formulas used to calculate the values in column X and AF of Schedule 2.

Response:

The formulas used to calculate columns X and AF are discussed in the TFP Report Appendix D-2 pages 9 and 10 and shown on Schedule 2 above the column. The full calculation is explained in the text of the TFP Report.

74.21. 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:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.29. This response is identical to the FEI response to that IR.

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.

74.22. Please provide any recent studies of FEI's productivity that B&V or any other entity has conducted.

Response:

This question is identical to FEI's 2014-2018 PBR Application, CEC IR 1.81.30. FBC assumes that this question to FEI was intended to refer to FBC, not FEI. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC has not conducted or commissioned any other TFP studies or other productivity studies pertaining to its own utility operations.

75. 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."

75.1. Please confirm that the referenced PEG report found TFP growth trends above 1% for both Enbridge and Union between 2005 and 2010.

Response:

Confirmed. Note that Enbridge and Union are gas distribution utilities. B&V observes that growth trends for gas LDC TFP are fundamentally different than electric utilities. This point is discussed in Appendix D-1 relative to the application of electric TFP to gas LDCs. Also note the response to BCUC 1.15.1 where the PEG results for Ontario electric studies suggests the proposed X-Factor is above the value for electric distribution companies. Also note the response to BCUC IR 1.15.1 where the PEG results for Ontario electric studies suggests the proposed X-Factor is above the value for electric distribution companies.

Attachment 52.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 74.5

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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,

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)

By: _____

By: MATTHEW GHIKAS
(Printed)

Title: PARTNER

BLACK & VEATCH CANADA COMPANY (Consultant)

By: _____

By: Russell A. Feingold
(Printed)

Title: Attorney-In-Fact

Legal Approved _____
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)

By: _____

By: MATTHEW GHIKAS
(Printed)

Title: PARTNER.

BLACK & VEATCH CANADA COMPANY (Consultant)

By: _____

By: Russell A. Feingold
(Printed)

Title: Attorney-In-Fact

Legal
Approved _____
Reviewed _____
Date March 18, 2013

PM
Approved _____
Date _____

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
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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

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Dated: August 12, 1993

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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.

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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

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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

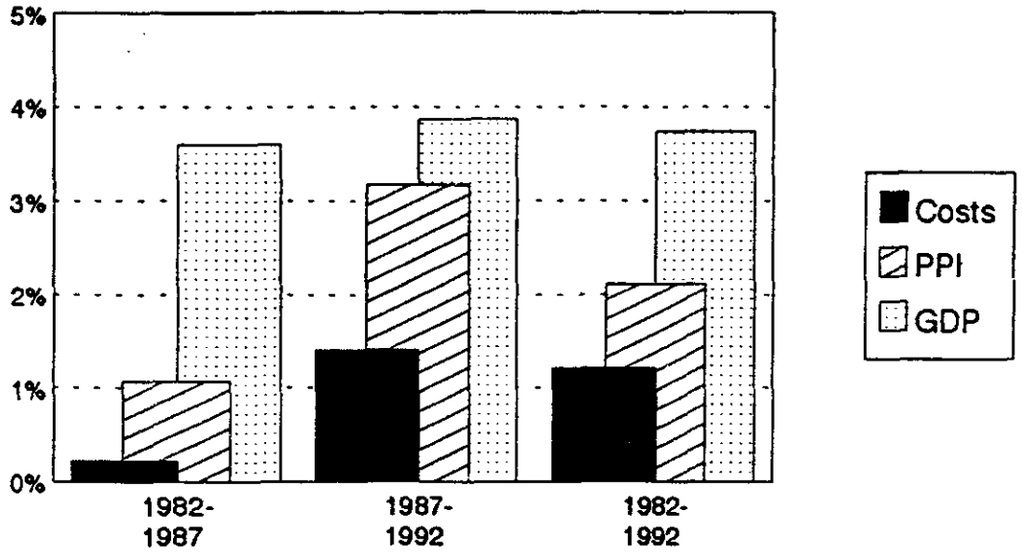
1. Based on the middle 50 percent of product pipelines that (i) have no crude operations and (ii) for which a 1982 Form 6 report is available.

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.

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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

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 .

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)

- 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)

- 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.

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[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 prices 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.

The results--Form 6 costs--product pipelines

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:

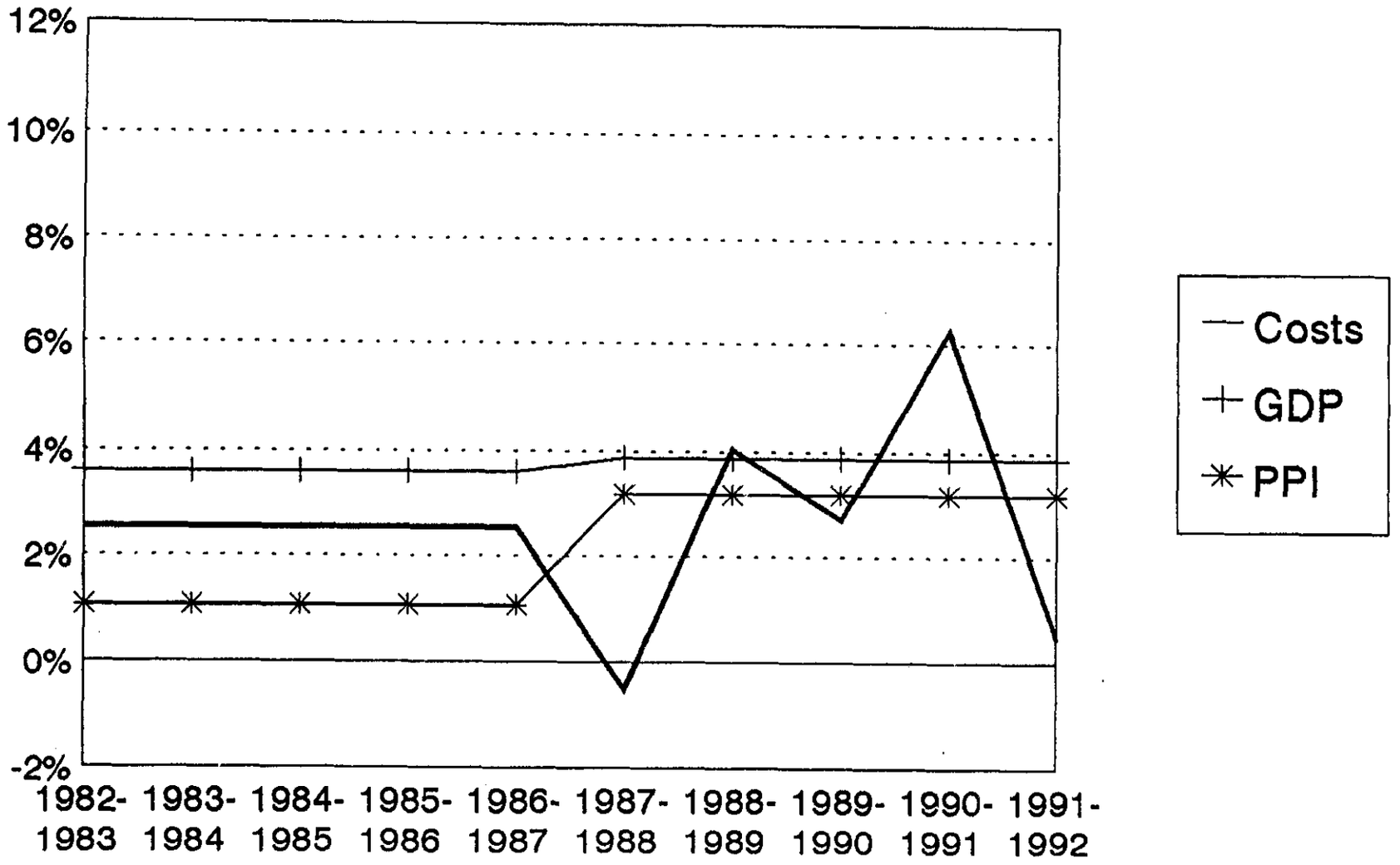
1. Based on the middle 50 percent of crude oil pipelines for which a 1982 Form 6 report is available (the expanded sample).

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

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[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).

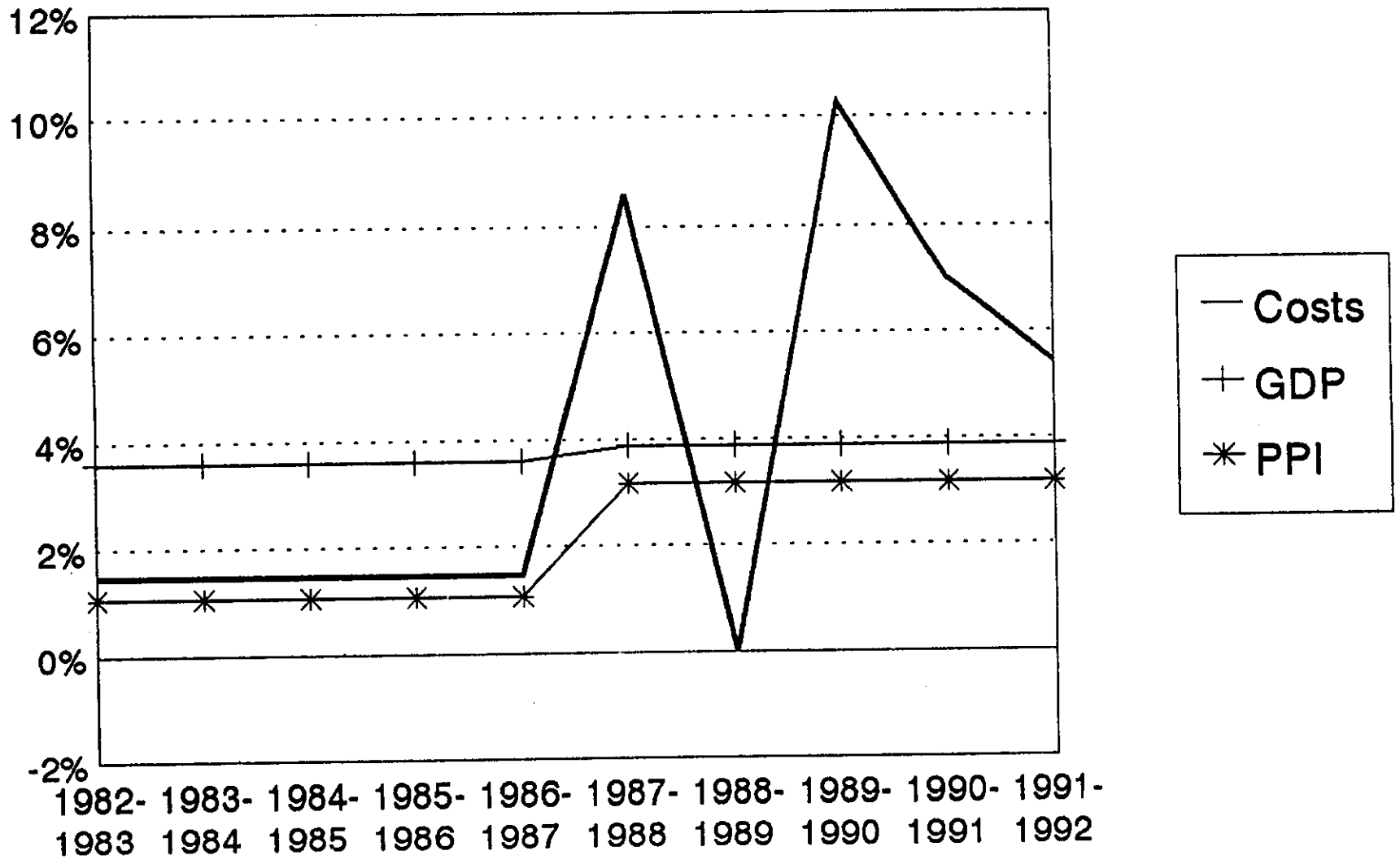
2. Because the middle 50 percent was determined separately for each of the three periods, the composition of that group differs between periods, and the 1982–1992 rate of change is not an average of the rates of change over the two five–year periods.

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

Quality of the Form 6 data

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 depreciable 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

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[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.

Variables measured

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.

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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.)
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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.

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MAJOR ARTICLES:

"The Competition Consequences of Hub Dominance: A Case Study," in *Review of Industrial Organization*, Vol. 8, 1993, pp. 381-405.

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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

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