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BY E-MAIL

January 16, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2017-2021 Payment Amounts
Ontario Energy Board File Number EB-2016-0152

Please find attached a revised response to Exh M2-11.1-OPG-2. The interrogatory relates to the report prepared by Pacific Economics Group Research LLC entitled "IRM Design for Ontario Power Generation".

OPG and all intervenors have been copied on this filing.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

Ontario Power Generation (OPG) Interrogatory #2

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 section 5

Please provide the results of PEG's study and revised versions of Tables 3, 4, 5, and 6 in Exhibit M2, assuming one-hoss shay depreciation for the periods 1975-2014, 1996-2014, and 2003-2014.

Response (Revised):

The response is provided by PEG in Attachments M2-11.1-OPG 2A and 2B.

Attachment M2-11.1-OPG 2A

1. Introduction

Considerable work has been required for PEG to estimate hydroelectric generation productivity trends using a one hoss shay ("OHS") methodology. The work, which involved development of a new capital treatment, additional data collection, and mathematical analysis, cannot be considered just a simple modification of the PEG work described in Exhibit M2, but is rather a new study. We provide here a thorough discussion of the methodology, data, and calculations.

The first part of our discussion will review the traditional monetary approach to capital quantity measurement and then explain how this methodology is implemented in multifactor productivity ("MFP") research using the geometric decay ("GD") and OHS assumptions. We then discuss our empirical work to implement the OHS method. We conclude with a critique of the OHS method that reflects lessons learned.

2. The Monetary Approach to Capital Quantity Measurement

The monetary approach to capital quantity measurement decomposes capital cost ("*CK*") into a consistent capital quantity index ("*XK*") and capital service price index ("*WKS*") such that

$$CK = WKS \bullet XK \quad [1]$$

[1]

[1] The *growth rate* of capital cost is thus the sum of the growth rates of the capital price and quantity indexes.

The cost of capital includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

In MFP research it is customary to assume that a capital good provides a stream of valuable services over a period of time that is called the service life of the asset. The capital service price index measures the trend in price of the stream of services provided by one unit of capital. The product of the capital service price index and the capital quantity index is the annual cost of using the flow of services.

A capital service price index is sometimes called a *rental* price index since, in markets for rentals of assets (e.g., automobiles and apartments), there are observable prices per unit of service from assets. Suppose, for example, that landlords own 1,000 identical houses and that these assets are each valued at a price established in the real estate market. They rent out each house at a price per month of use that is set in the market for housing rentals. The monthly cost to tenants of using the houses is the sum of their monthly rental payments. The trend in the user cost of housing rentals is the sum of the trends in rental rates and the number of houses.

Well-developed markets do not exist for the rental of most assets that utilities own. However, capital service prices can be imputed for these assets that permit an imputation of the user cost of capital. These prices are founded on the assumption that the ("stock") value of a capital asset is the expected discounted value of the stream of services that the asset provides. There is then an equation linking the price of a unit of a capital asset ("WKA") to future prices of capital services. Manipulation of this equation makes it possible to express the capital service price in a given year as a function of capital asset prices and the rate of return on capital. This function also depends on the assumed pattern of decay in the flow of services from assets.

Various assumptions have been used in empirical research regarding the decay in the flow of services from capital assets. The pattern of asset decay over time is sometimes called the age-efficiency profile.

In most of our utility cost and productivity research for the OEB and other clients, including our work for Board Staff in this proceeding, PEG has assumed that a GD pattern of decay applies to assets in the aggregate. LEI has, in its direct evidence in this proceeding and its supplementary memo last December, stated that an OHS pattern is more appropriate for hydroelectric generation.[2] Alternative decay patterns have also been used in capital cost and productivity research. These include linear and hyperbolic (gradually increasing) decay.

Capital cost and the capital service price formula should be consistent with the decay specification. The characterization of the flow of benefits in the equation linking the asset price to capital service prices should therefore properly reflect the decay assumption.

Decay in the flow of services from an asset over time causes its unit price to decline in real terms. In the case of geometric decay, this decline is due to the gradual drop in the expected flow of services. In the case of OHS, the decline is due to the falling number of years during which the constant level of the service flow is expected to continue.

Depreciation is the decline in the value of an asset due to wear and tear, obsolescence, accidental damage, and aging. "Economic" depreciation is depreciation that properly reflects the diminishing expected net present value of productive services.

[2] LEI, *LEI Memo Responding to Pacific Economics Group's "IRM Design for Ontario Power Generation"*, December 2016.

The *pattern* of decline in the price of used assets over time due to depreciation is sometimes called the age-price profile. Each decay specification has its own age-price profile. Data on trends in the prices of assets as they age can then be used to infer the age-efficiency profiles of real-world assets

Under certain simplifying assumptions, an *OHS* age-efficiency profile produces a *linear* age-price profile because a used asset, while still producing the same service flow each year as younger assets, declines in value by a constant amount each period as the year of its retirement approaches.[3] The *rate* of depreciation under OHS decay increases as the asset ages. Hyperbolic, straight line, and geometric decay give rise to nonlinear age-price profiles that are convex to the origin.[4] With all of these alternative decay assumptions, the rate of depreciation is *faster* in the early years of an asset's service life than the rate for OHS decay but is *similar* in the middle years and *slower* in the later years.

3. Geometric Decay Application

Capital Quantity Index

Under the geometric decay assumption, the flow of services from each asset declines at a constant rate ("*d*") over time. For each asset type *j* that is separately considered, the quantity of capital at the end of each period *t* ("$XK_{j,t}$") is related to the quantity at the end of

[3] Baldwin, Liu, and Tanguay (2015) state that "the depreciation curve corresponding to a one-hoss shay efficiency profile will not be linear if (1) the duration of the service life is not known with certainty, or (2) the value of the asset's productive capacity is discounted in future periods."
[4] Please note that a straight line age-*efficiency* profile does not produce a straight-line age-*price* profile but instead a profile that can be similar to that from geometric decay.

last period and the quantity of new plant additions (“$XKA_{j,t}$”) by the following “perpetual inventory” equation.

$$XK_{j,t} = XK_{j,t-1} \bullet (1\text{-}d) + XKA_{j,t-1}\,. \qquad [2]$$

The quantity of capital added each year can be measured by dividing the value of plant additions by the contemporaneous value of a suitable asset price index. In research on the productivity of US utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose. The total quantity of type and capital assets can be estimated by adding to an estimate of the capital quantity in a certain benchmark year estimates of the quantities of plant added in subsequent years and subtracting each year’s decay. The estimation of the capital quantity in the benchmark year is sometimes called the benchmark year adjustment.

<u>Capital Price Index</u>

Recall that a service price index is derived from the equation linking the value of a unit of capital to the value of the stream of services that it provides. Assuming perfect foresight, and in the absence of taxes, an equation corresponding to the GD assumption is

$$WKA_t = \sum_{s=0}^{\infty} \left(\frac{1}{1+r}\right)^{s+1} \bullet WKS_{t+s+1} \bullet (1-d)^s. \qquad [3]$$

To derive a GD capital service price from this equation, consider that the (unit) value of an asset in year 0 is

$$WKA_0 = \left(\frac{1}{1+r}\right) \bullet WKS_1 + \left(\frac{1}{1+r}\right)^2 \bullet WKS_2 \bullet (1-d) + \left(\frac{1}{1+r}\right)^3 \bullet WKS_3 \bullet (1-d)^2 + \ \ldots\ .$$

Then

$$(1+r) \bullet WKA_0 = WKS_1 + \left(\frac{1}{1+r}\right) \bullet WKS_2 \bullet (1-d) + \left(\frac{1}{1+r}\right)^2 \bullet WKS_3 \bullet (1-d)^2 +$$

$$= WKS_1 + WKA_1 \bullet (1-d).$$

The key development here is that, if one adjustment is made, the (unit) value of an asset in year 1 anticipates the value of the stream of services provided by an asset acquired in year 0 after its first year of use. Solving for WKS_1, we find that the capital service price in year 1 is a function of the (unit) prices of capital assets, the rate of return, and the depreciation rate.

$$WKS_1 = (1+r) \bullet WKA_0 - (1-d) \bullet WKA_1$$

$$= WKA_0 + r \bullet WKA_0 - WKA_1 + d \bullet WKA_1$$

$$= r \bullet WKA_0 + d \bullet WKA_1 - (WKA_1 - WKA_0).$$

The *general* formula for a GD capital service price is

$$WKS_t = r \bullet WKA_{t-1} + d \bullet WKA_t - (WKA_t - WKA_{t-1}). \qquad [4a]$$

The three terms correspond to the return on capital, depreciation, and capital gains. The last term in this formula can be restated as

$$\left(\frac{WKA_t - WKA_{t-1}}{WKA_{t-1}}\right) r \bullet WKA_{t-1} = i \bullet WKA_{t-1}$$

where *i* is the asset price inflation rate in year 1. The general GD capital service price formula can then be restated as

$$WKS_t = (r - i) \bullet WKA_{t-1} + d \bullet WKA_t. \qquad [4b]$$

where *r-i* is the real interest rate.

4. One Hoss Shay Application

<u>Capital Quantity Index</u>

Under the one hoss shay assumption the flow of services from a capital asset is constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. For each asset type *j*, the formula for the OHS capital quantity index in a given year *t* is

$$XK_{jt} = XK_{j,t-1} + XKA_{j,t} - XKR_{j,t}. \quad [5]$$

Here $XKR_{j,t}$ is the quantity of plant *retirements*.

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the assets retired were added. The total quantity of type *j* capital in year *t* can then be calculated by adding to the estimated quantity of capital in the benchmark year the estimated quantities of all plant additions since that year and subtracting the estimated quantities of all plant requirements.

Capital Service Price Index

Assuming perfect foresight, and in the absence of taxes, the value of a unit of a capital asset under the OHS assumption equals the expected net present value of the corresponding capital service prices over the years of its service life.[5]

$$WKA_t = \sum_{s=0}^{N} \left(\frac{1}{1+r}\right)^{s=1} WKS_{t+s+1}. \quad [6]$$

The unit value of such an asset in year zero is then

[5] For an alternative derivation of a OHS service price index see Merrile Sing, "The Cost Structure of the Gas Distribution and Electricity Industries," University of Wisconsin PhD thesis (1984), pp. 143-145.

$$WKA_0=\left(\frac{1}{1+r}\right)\bullet WKS_1+\left(\frac{1}{1+r}\right)^2\bullet WKS_2+\ldots+\left(\frac{1}{1+r}\right)^N\bullet WKS_N.$$

so that

$$(1+r)\bullet WKA_0=WKS_1+\left(\frac{1}{1+r}\right)\bullet WKS_2+\ldots+\left(\frac{1}{1+r}\right)^{N-1}\bullet WKS_N$$

$$=WKS_1+\ WKA_1-\left(\frac{1}{1+r}\right)^N\bullet WKS_{N+1}.$$

Once again, with one adjustment the unit price of a new capital asset in year 1 reflects the value of the future flow of services from an asset acquired in year 0 after one year of use.

Rearranging terms and supposing for simplicity that *i* is the annual inflation in *WKS* between year 1 and year N+1 and *r* is the interest rate in this interval we find that

$$r\bullet WKA_0-(WKA_1-WKA_0)=WKS_1-\left(\frac{1+i}{1+r}\right)^N\bullet WKS_1.$$

Then

$$WKS_1=\frac{r\bullet WKA_0}{1-\left(\frac{1+i}{1+r}\right)^N}-\frac{WKA_1-WK_0}{1-\left(\frac{1+i}{1+r}\right)^N}.$$

The OHS price in year 1 is a function of the unit prices of capital assets and the rate of return on capital.

The general formula for an OHS capital service price then is expressed as

$$WKS_t=\frac{r\bullet WKA_{t-1}}{1-\left(\frac{1+i}{1+r}\right)^N}-\frac{WKA_t-WK_{t-1}}{1-\left(\frac{1+i}{1+r}\right)^N}. \qquad [7a]$$

There are terms corresponding to the return on capital and capital gains. This may be expressed equivalently as

$$WKS_t = \frac{r \bullet WKA_{t-1} + \left(\frac{WKA_t - WKA_{t-1}}{WKA_{t-1}}\right) \bullet WKA_{t-1}}{1 - \left(\frac{1+i}{1+r}\right)^N}$$

Assuming for simplicity that the same *i* applies to asset price inflation between years 0 and 1, it follows that

$$WKS_t = \frac{(r-i) \bullet WKA_{t-1}}{1-\left(\frac{1+i}{1+r}\right)^N}. \qquad [7b]$$

5. Implementing the One-Hoss Shay Method for Hydroelectric Power Generation

As discussed above, the one-hoss shay formula for the perpetual inventory equation has some similarities to the geometric decay formula. Both require an estimate of the quantity of plant in a benchmark year and update the quantity of capital by deflating plant additions by the contemporaneous value of an asset price index. The difference in the methods is that, in each year, the GD method reduces the beginning-of-year capital quantity by a fixed percentage each year whereas the OHS method reduces the quantity of capital only for asset retirements. In addition to data already gathered to perform GD calculations, OHS thus requires data on the value of retired hydroelectric plant and decisions on when assets retired were added in the past. We discuss each step in turn.

Data on the value of retired plant are available on FERC Form 1 on pages 204-207 as part of the plant in service accounts. This is the same place on the form where data on the values of plant additions are found. PEG was able to gather these data electronically for the years 1995-2014. For prior years, the only publicly available source of data on the value of additions and retirements is the series of US Energy Information Administration publications entitled *Financial Statistics of Major U.S. Investor-Owned Electric Utilities* (and predecessor publications). We obtained these volumes and entered hydroelectric retirement data for the period 1964-1994 manually and then performed various adjustments to the data for mergers and acquisitions.

The reported retirement values for each company typically pertain to a mix of assets that were acquired by construction or purchase in different years. The years in which these assets were added is not reported. Thus, the appropriate year of an asset price index for converting the value of retirements into a quantity is uncertain. In contrast, the date of plant *additions* are known with certainty. Thus, there is a major source of uncertainty with OHS capital quantity calculations that is not present with GD calculations.

A sensible first step in calculating capital quantities using the OHS method is to assume that the retired assets had the estimated average service life of *all* hydroelectric assets. This approach can make sense if the service lives of the bulk of assets lie in a fairly narrow range. However, the major categories of hydroelectric assets can have typical service lives that vary between fifty and one hundred years. Furthermore, our featured sample period (1996-2014) was one in which retirements frequently did not involve dams and other large civil structures. Use of an average service life could then frequently overstate the quantity of retirements. This makes decisions on the vintages of retired assets very important.

Assume, for example, that Alabama Power retired $1,000,000 of plant in 2014. If this unknown group of assets were all civil structures constructed in 1915 then the value of the asset price index appropriate for deflation of the retirements would be only 1.60. If they were generators installed in 1955 then a price index value of 8.63 would apply. The assets could even be shorter-lived equipment that were installed in 1995 when the value of the price index was 56.38. The quantity of plant removed from the perpetual inventory equation for Alabama Power can thus differ radically with the assumed vintage. In the case of a generator vs. civil structure, there is over a 500% difference in the quantity retired.

Starting with the most straightforward method, an average service life assumption was nonetheless attempted to calculate the quantity of retirements. PEG's calculations using the GD methodology assumed a 73-year weighted average life for hydroelectric plant, based on OPG data. Using this 73-year average life for *all* retired assets for all companies resulted in 12 of the 20 companies in the sample having a negative capital quantity in at least one year. Evidently, a 73-year service life assumption for retirements was far from reality in some years. This matters because only one negative capital quantity is required to cause an inability to calculate MFP results. Therefore, additional work was required to find more appropriate vintage assumptions.

Since the ages of different kinds of hydroelectric assets can vary greatly, it would clearly be useful to construct capital quantity indexes using data on plant additions and retirements which are itemized by type of asset. The growth in the capital quantity index could in principle be a weighted average of the growth rates of quantity subindexes for each asset category. The data available electronically since 1994 are itemized by asset type but the data available before 1994 are not and PEG does not have these itemizations. Our capital quantity index starts in 1964 to reduce the sensitivity of results to the calculation of the quantity in the benchmark year. Thus, we must rely on data that are not itemized for the lengthy 1964-1993 period.

Here is the itemization of the aggregate gross value of hydroelectric plant in service owned by major US investor-owned electric utilities ("IOUs") in 1996.[6]

[6] U.S. Energy Information Administration, *Financial Statistics of Major US Investor-Owned Electric Utilities 1996*, U.S. Department of Energy, 1997.

	US IOU Gross Value 1996 (million USD)	Share of Total
Hydraulic Production Plant		
Land and Land Rights	544	4.3
Structures and Improvements	2,001	15.8
Reservoirs, Dams and Waterways	6,261	49.6
Water Wheels, Turbines, and Generators	2,661	21.1
Accessory Electric Equipment	759	6.0
Miscellaneous Power Plant Equipment	242	1.9
Roads, Railroads, and Bridges	162	1.3
Total	**12,631**	**100.0**

It can be seen that structures and improvements, reservoirs, dams, and waterways, and waterwheels, turbines, and generators were the “big ticket” items accounting for most of the gross plant value.

The table below provides a breakdown of the itemized aggregate annual retirement data, over the 1995-2014 period, for all US hydroelectric generators for which we have gathered data. A few observations are noteworthy:

- Dams and reservoirs accounted for 43% of value of retirements on average over the sample period. Other assets with longer service lives such as other structures and improvements and roads, railroads, and bridges accounted for another 11%.
- Generators accounted for 31% of retirements.
- Shorter-lived accessory electric equipment and miscellaneous plant accounted for just 12% of plant retirements.
- We assigned average asset service lives to each of FERC’s hydroelectric plant accounts. These lives were informed by information obtained from OPG as part of

OPG EB-2013-0321 Ex F5-3-1. We then calculated a weighted average of the service lives excluding the reservoirs dams, and waterways account. This weighted average service life was 52.7 years. The average service life of *all* retired assets based on these shares was about 72.9 years.

- Similar results are obtained if just the companies in PEG's large sample are used.

Hydroelectric Retirements by Type of Plant

	Accessory Electric Equipment	Dams and Reservoirs	Generators	Land	Misc.	Retirement Obligations	Road, Rails, Bridges	Other Structures
1995	15%	21%	38%	6%	7%	0%	0%	12%
1996	7%	49%	23%	1%	2%	0%	1%	17%
1997	14%	33%	25%	5%	5%	0%	2%	15%
1998	15%	24%	30%	5%	6%	0%	5%	16%
1999	6%	57%	19%	4%	2%	0%	1%	11%
2000	19%	35%	29%	4%	2%	0%	0%	12%
2001	33%	22%	18%	2%	15%	0%	0%	11%
2002	8%	43%	31%	4%	1%	0%	2%	10%
2003	17%	11%	66%	0%	2%	0%	0%	4%
2004	6%	46%	35%	6%	1%	0%	1%	6%
2005	10%	24%	58%	1%	3%	0%	1%	3%
2006	7%	12%	62%	7%	4%	0%	0%	7%
2007	2%	38%	30%	2%	3%	2%	0%	22%
2008	13%	29%	43%	2%	3%	6%	1%	4%
2009	15%	20%	49%	1%	10%	0%	2%	4%
2010	11%	41%	22%	1%	5%	10%	1%	9%
2011	20%	25%	34%	0%	4%	12%	1%	6%
2012	8%	28%	52%	1%	3%	1%	1%	5%
2013	8%	32%	50%	0%	3%	0%	1%	6%
2014	8%	49%	29%	0%	2%	0%	2%	10%
Total	9%	43%	31%	3%	3%	1%	1%	10%
Assumed Life	**30**	**100**	**50**	**100**	**30**	**30**	**75**	**75**

Weighted Average Life	**72.85**
Weighted Average Life Without Dams and Reservoirs	**52.74**

The share of civil structures in the total value of retirements is surprisingly large considering that the oldest structures would have a much lower book value to retire than equipment added much later at a much higher price. In addition, one would not normally expect the concrete structure of a dam to be fully replaced. It seems likely that a sizable share of the value of retirements reflects capex made many years after the facilities were first acquired.

We therefore examined the company by company retirement data for dams and reservoirs and found that a sizable share of the retirement value was attributable to companies that physically removed dams or otherwise removed generating units from service. Units are removed from service when they will not produce power for the company in the future. This can be due to the sale of the unit or to suspension of generation at the dam complex.

We found more than twenty cases in which generating units were removed from service. Years in which these retirements took place were often years in which large values for civil structure retirements were observed. Retirements of civil structures are ongoing and important, but are nevertheless fairly rare. Therefore, although structures accounted for 43% of the total value of retirements, it is not proper to assume that 43% of the total value of retirements of every utility in every year is due to the retirement of the dam and reservoir assets.

Based on this analysis, we made a distinction in our treatment of retirements between cases in which a generating unit was retired and more typical ongoing retirement of plant and equipment, which we believe mainly involved assets other than civil structures.

The method we used to assign a vintage to each observed value of retirements involved a default age and a custom age. Our default assumption was that retired plant was 50 years old on average. The value of 50 years was chosen because it is a round number consistent with the analysis and did not require an amendment to our asset price index to add values for years prior to 1915. The year 1915 is the first year for which the Handy

Whitman hydroelectric construction cost index that we use as the asset price index is available. The default price assigned to retirements was thus our asset price index lagged by 50 years.

In cases in which there was evidence that a unit was removed from service, a custom calculation was considered. The evidence for unit retirements took two forms. The first is a listing of retired hydroelectric units tracked by the EIA using form EIA-860. This revealed 21 units owned by companies in the sample which have been taken out of service. We also looked for large retirements in the company data which would cause the value of the capital quantity index to turn negative. There were 6 instances of this happening, a few of which involved a unit that had been sold or removed from service which was not on the EIA's list.

The following table contains a list of companies, plants, and years in which unit retirements occurred so that a custom calculation was considered. Since the list contains generating *units* that are retired, it is possible that other units at the site were still operational during the sample period.

Facilities with Retired Units Considered for Price Adjustment

Utility Name	Facility Name	Year(s) in Service	Retirement Year(s)	Resolution
Avista Corp	Nine Mile	1908, 1910	2005, 2012	Default
Georgia Power Co	Goat Rock	1912	2001	Default
New York State Elec & Gas Corp	Keuka	1928	2006	Custom
PacifiCorp	Powerdale	1923	2007	Custom
PacifiCorp	Condit	1913	2011	Custom
PacifiCorp	Cline Falls	1943	2010	Custom
PacifiCorp	Cove	1917	2006	Custom
Pacific Gas & Electric Co	Kerckhoff	1920	2013	Custom
Pacific Gas & Electric Co	Coal Canyon	1907	2013	Custom
Pacific Gas & Electric Co	Alta Powerhouse	1902	2013	Custom
Puget Sound	Snoqualmie (Rebuild)	1890	2010	Default
Southern California Edison Co	San Gorgonio 1	1923	2001	Custom
Georgia Power Co	Barnett Shoals	1910	2010	Default
NYSEG	Collier	1939	1966	Custom
Portland General	Bull Run Hydro	1912, 1922	2008	Custom
Portland General	Pelton	1958	2002	Custom
Public Service Co of Colorado	Tacoma	1949	2007	Default
Puget Sound Energy	White River	1911	2004	Custom
Puget Sound Energy	Electron	1901	2014	Custom
VEPCO	Park	1940	1965	Custom
VEPCO	Balcony falls / Embrey	1915	1969	Custom

Each unit thus identified was evaluated to determine the circumstances of the retirement. In 5 cases the nature of the retirement was not related to the civil structures. In these cases, the default 50-year vintage assumption was retained. For the remaining units, civil structures *were* retired and a custom calculation was performed. The custom calculation took the following general form:

- For the few retirements in which there were less than 60 years between the date when the unit was acquired and the date when it was retired, the price assigned was that for the year of acquisition.

- For retirements with a greater than 60-year gap between acquisition and retirement, it is assumed that half of the original quantity of the plant was replaced 50 years prior to retirement. The price assigned to retirements is in this case a weighted average of the price at the acquisition date and a 50-year lagged price. The weights were calculated as follows:
    - Let Po = Price index at first in service date, P[-50] = Price index 50 years prior to retirement, and Qo = the quantity of plant at first in service date
    - Original Cost = Po x Qo
    - Cost at retirement = 0.5 x (Po x Qo) + 0.5 x (P[-50] x Qo)
    - % of cost priced at Po = Po / (Po + P[-50])
    - % of cost priced at P[-50] = P[-50] / (Po + P[-50])
- For retirements of units constructed/acquired before 1915, a 1915 price is assumed for the civil structures.
- In cases where the dam was physically removed or re-licencing costs were incurred, we assigned a portion of retired cost to environmental and regulatory costs that were assumed to have been incurred at the prices prevailing at the time of retirement.
- There were cases in which the retired hydroelectric facility did not have a dam and reservoir. In one case, the water was delivered via a flume made of wood that was replaced by one of steel at times that are known. In this case, the original in service date was not appropriate to use in the asset price formula. In another case the retirement was part of a rebuild and the civil structures were not retired. This was an underground unit in which the tunnel structure was not affected and a fifty-year lagged price was an appropriate match for the retired plant.

In choosing each treatment, our motive was to obtain a reasonable vintage associated with the value of the retired assets. In several of these cases, the use of a vintage informed by other information avoided the possibility of negative capital quantities being obtained.

Once the required data and prices were obtained, the one hoss shay capital quantity index was calculated. The starting point is the calculation of the capital quantity in the benchmark year (1964). Since OHS involves the calculation of stocks *gross* of depreciation rather than *net* of depreciation, in the benchmark year a weighted average of historical prices which did not account for depreciation was used to convert the value of gross plant to a quantity. As was done in the original PEG study, information on the historical pattern of capacity additions was used to provide weights. Because the price of gross plant was desired, it was not necessary to "depreciate" the capacity before calculating the percent of remaining plant in 1964.

For each year after the benchmark year, the OHS version of the perpetual inventory equation set forth in equation [5] was used to calculate the capital quantity. An OHS capital service price index was calculated using a variant of equation [7b] and multiplied by the capital quantity to calculate each company's capital cost. The real rate of return (r - i) and the r and the I used in the bracketed term in equation 7b were all three-year moving averages of results for the current and previous two years. The remainder of the work (including the treatment of taxes) was done in the same manner as in the original PEG study.

Results were calculated for OPG using the same methodology. A custom vintage calculation was not required for OPG. Data on the value of plant retirements were missing for the same 1989-1999 period as was the case for plant *additions* data. We imputed these data using methods consistent with our imputations for the plant addition calculations.

6. Results of the One-Hoss Shay Study

PEG recalculated the partial factor productivity and multifactor productivity indexes based on a one-hoss shay method using the methodology just described. Results for PEG's featured large sample of US hydroelectric power generators can be found in Table 3A. Here are some highlights.

- The average annual growth in the capital quantity was **2.26%** for the full 1975-2014 period using the OHS methodology. Using the GD methodology, the trend was only 0.15%. This sizable difference reflects the fact that the 1975-1995 period featured the large capacity additions and low plant retirements that are typical of an industry if assets are generally young. During the 1996-2014 period that we feature in our study, the average annual growth in the capital quantity using the OHS methodology *fell* by an average of **0.19%** per year. This was much more similar to the -0.48% trend in the capital quantity for the same period using GD.
- The resulting MFP trends using OHS and capacity as the output variable were **-0.93%** for the full sample period and -**0.15%** for the featured 1996-2014 period. The analogous trends using GD were 0.94% for the full sample period and 0.29% for the featured 1996-2014 period. Note also that the OHS results for LEI's featured sample period are quite different than those LEI obtained using its own capital quantity treatment.
- The MFP trends for the *common* sample using OHS and capacity as the output variable were **0.12%** for the featured 1996-2014 period and **-0.80%** for the longer period. Using geometric decay, the analogous results were 0.29% for the featured 1996-2014 period and 0.94% for the full sample period.
- Evidently, MFP growth using OHS is unusually sensitive to the portion of the replacement cycle that the sample period covers. MFP growth using the OHS specification can accelerate markedly as a utility's assets mature. This is an important finding since the assets under study are mature assets.
- The implementation of the OHS methodology produces different results for other variables (e.g. capacity) as well. This is because the reported trends are *cost-weighted averages* of individual company results and the OHS methodology affects costs.

Results for OPG are shown on Table 6A. The Company had an unusually large plant addition for the Niagara Tunnel project in 2013 which shows up in 2014 data. This slows the MFP growth trend substantially. The one-hoss shay MFP trend for OPG through 2013 was **+0.26%**. The trend through 2014 was **-0.24%**.

While MFP results have not been computed for 2015, OPG made a large *retirement* in 2014. This will materially affect the estimated MFP trend through 2015. The OHS capital quantity index grew by +6.5% 2013-2014 but fell by 4.1% 2014-2015. The upturn in MFP growth in 2014 using one hoss shay would substantially offset the big downturn in 2014.

Updated versions of Tables 4 and 5 from our direct evidence are also provided as Tables 4A and 5A. Table 4A contains additional results for the US sample that is common to LEI and PEG and shows higher MFP growth trends for this sample. Table 5A takes OHS results for OPG and the US and inserts them into a reconciliation of LEI and PEG results as an additional step.

Table 3A

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(Larger Sample, one-hoss-shay method)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1996	-1.36%	0.70%	4.94%	6.11%	5.91%	-7.26%	-5.20%
1997	1.27%	-0.81%	-8.75%	-4.04%	-8.23%	9.50%	7.42%
1998	0.19%	7.50%	1.05%	-4.68%	-0.07%	0.26%	7.57%
1999	-0.56%	-17.10%	-0.25%	7.63%	1.14%	-1.71%	-18.25%
2000	0.11%	-10.37%	-4.85%	-13.96%	-3.11%	3.22%	-7.27%
2001	0.52%	-8.76%	-0.37%	8.28%	-0.16%	0.68%	-8.60%
2002	-0.60%	8.90%	-0.77%	-0.67%	-1.03%	0.44%	9.93%
2003	0.11%	20.33%	-3.74%	3.74%	-1.74%	1.85%	22.07%
2004	-0.07%	-10.79%	-0.79%	6.11%	0.40%	-0.47%	-11.19%
2005	0.38%	5.59%	-5.01%	2.06%	-2.43%	2.81%	8.02%
2006	0.16%	-1.78%	1.91%	-5.90%	0.35%	-0.20%	-2.13%
2007	1.46%	-32.14%	0.00%	10.69%	2.95%	-1.49%	-35.09%
2008	-0.07%	4.13%	-2.43%	1.35%	0.44%	-0.51%	3.70%
2009	0.09%	25.14%	-0.58%	4.14%	1.20%	-1.11%	23.93%
2010	-0.02%	-4.57%	1.41%	5.25%	1.95%	-1.96%	-6.52%
2011	0.14%	1.26%	2.36%	0.11%	2.09%	-1.95%	-0.83%
2012	-0.08%	-20.97%	2.01%	-0.24%	1.45%	-1.53%	-22.42%
2013	2.04%	12.33%	5.03%	0.35%	2.95%	-0.90%	9.38%
2014	0.48%	-14.51%	5.23%	0.84%	2.93%	-2.45%	-17.43%
Averages:							
1975-2014	**1.51%**	**-0.28%**	**2.26%**	**1.98%**	**2.43%**	**-0.93%**	**-2.72%**
1975-1995	**2.67%**	**1.17%**	**4.47%**	**2.48%**	**4.30%**	**-1.63%**	**-3.13%**
1996-2014	**0.22%**	**-1.89%**	**-0.19%**	**1.43%**	**0.37%**	**-0.15%**	**-2.26%**
2003-2014	**0.39%**	**-1.33%**	**0.45%**	**2.38%**	**1.04%**	**-0.66%**	**-2.38%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

Table 4A

Summary of US Hydroelectric Productivity Growth Trends

	Outputs		Inputs			Multifactor Productivity		Partial Factor Productivities[1]	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume	O&M	Capital
Common Sample[2]									
1975-1995	1.52%	-0.32%	2.09%	1.97%	2.32%	-0.80%	-2.64%	-0.45%	-0.57%
1975-2014	2.67%	1.17%	4.47%	2.48%	4.30%	-1.63%	-3.13%	0.19%	-1.80%
1996-2014	0.25%	-1.97%	-0.54%	1.40%	0.13%	0.12%	-2.10%	-1.15%	0.79%
2003-2014	0.41%	-1.45%	0.00%	2.28%	0.73%	-0.32%	-2.18%	-1.86%	0.42%
Larger Sample									
1975-1995	2.67%	1.17%	4.47%	2.48%	4.30%	-1.63%	-3.13%	0.19%	-1.80%
1975-2014	1.51%	-0.28%	2.26%	1.98%	2.43%	-0.93%	-2.72%	-0.48%	-0.75%
1996-2014	0.22%	-1.89%	-0.19%	1.43%	0.37%	-0.15%	-2.26%	-1.21%	0.41%
2003-2014	0.39%	-1.33%	0.45%	2.38%	1.04%	-0.66%	-2.38%	-1.99%	-0.06%

[1] PFP results use capacity as the output measure.

[2] Sample of US utilities used by both LEI and PEG.

Table 5A

Reconciling LEI and PEG Productivity Results

	Average Annual Growth	
	MFP	Output Quantity
LEI methodology (2003-2014)		
As stated (capacity used as capital input)	-1.01%	-0.64%
With common US sample	-1.38%	-0.99%
Add estimated impact from using PEG Form 1 MWh data (+0.05%)	-1.33%	-0.94%
With capacity used as both output and capital input	-0.19%	0.19%
PEG methodology including a one-hoss shay (1HS) capital quantity index and capacity as output		
With a common sample	-0.32%	0.41%
With an expanded sample	-0.66%	0.39%
PEG methodology including a geometric decay (GD) capital quantity index		
With volume as output (2003-2014)	-1.70%	-1.64%
With capacity as output (2003-2014)	0.33%	0.39%
With a longer time periods and capacity as output index		
1996-2014	0.47%	0.22%
1975-2014	1.06%	1.49%
With an expanded sample of US IOUs and capacity as output index		
2003-2014	0.05%	0.38%
1996-2014	0.29%	0.20%
1975-2014	0.94%	1.40%
OPG productivity trends		
Calculated from LEI workpapers	-0.49%	-0.87%
With a one-hoss shay capital quantity index and capacity as output	-0.24%	0.06%
WIth capacity as output and a GD capital quantity index	0.28%	0.06%
1996-2014 trend	1.07%	0.51%
1985-2014 trend	1.24%	0.34%

Table 6A

OPG's Productivity Growth Using Capacity as Output and a One-Hoss Shay Capital Quantity Index[1]

	Generation Capacity (MW)	O&M Cost	O&M Price	Input Quantities O&M	Input Quantities Capital	PFP O&M Index	PFP O&M Growth	PFP Capital Index	PFP Capital Growth	Weights O&M	Weights Capital	MFP Growth
2002	6,384	109,088	1.000	109,088	35,103,778	1.000		1.000		6%	94%	
2003	6,409	120,945	1.022	118,382	35,037,849	0.925	-7.8%	1.006	0.6%	6%	94%	0.1%
2004	6,439	122,341	1.046	116,908	34,485,436	0.941	1.7%	1.027	2.1%	7%	93%	2.0%
2005	6,407	131,759	1.079	122,146	34,567,137	0.896	-4.9%	1.019	-0.7%	8%	92%	-1.0%
2006	6,451	144,915	1.099	131,830	33,975,362	0.836	-6.9%	1.044	2.4%	11%	89%	1.5%
2007	6,450	152,640	1.135	134,431	34,025,768	0.820	-2.0%	1.042	-0.2%	12%	88%	-0.4%
2008	6,477	171,873	1.163	147,807	33,978,568	0.749	-9.1%	1.048	0.5%	11%	89%	-0.6%
2009	6,390	171,279	1.177	145,469	33,766,724	0.751	0.2%	1.041	-0.7%	14%	86%	-0.6%
2010	6,390	170,905	1.210	141,195	33,543,808	0.773	3.0%	1.048	0.7%	16%	84%	1.0%
2011	6,422	174,611	1.232	141,787	33,511,074	0.774	0.1%	1.054	0.6%	16%	84%	0.5%
2012	6,422	178,134	1.250	142,489	33,562,454	0.770	-0.5%	1.052	-0.2%	19%	81%	-0.2%
2013	6,433	182,584	1.270	143,719	33,395,313	0.765	-0.7%	1.059	0.7%	16%	84%	0.4%
2014	6,433	188,020	1.296	145,026	35,639,377	0.758	-0.9%	0.993	-6.5%	14%	86%	-5.6%
2015					34,209,628							
Average Annual Growth Rates												
2003-2014	**0.06%**	**4.54%**	**2.16%**	**2.37%**	**0.13%**		**-2.31%**		**-0.06%**	**13%**	**87%**	**-0.24%**
2003-2013	**0.07%**	**4.68%**	**2.18%**	**2.51%**	**-0.45%**		**-2.44%**		**0.52%**	**12%**	**88%**	**0.26%**

[1] Growth rates are calculated logarithmically.

7. One Hoss Shay Pros and Cons

The OHS assumption is sometimes argued to better fit the age-efficiency profile of individual assets. LEI, for example, has argued in its direct evidence and its response memo that it better fits the pattern of hydroelectric generation assets. OHS has been used in a few productivity studies filed in proceedings to determine X factors.

Other evidence suggests that the OHS assumption is disadvantageous.

- We explained in Section 6 that implementation of OHS requires estimates of the vintages of assets that are retired. MFP results using one hoss shay are quite sensitive to the vintage estimates. Seemingly reasonable estimates can produce negative capital quantities. Under geometric decay, in contrast, only plant *additions* must be deflated and the year in which they occur is known with certainty.
- This problem can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Itemization is especially desirable in studies of hydroelectric generation productivity because roughly half of all assets by value have unusually long service lives, while the average lives of most other assets are much shorter. Unfortunately, itemizations of FERC Form 1 plant additions and retirements are not publicly available before 1994, while our methodology uses addition and retirement data back to 1964.
- In recent power distribution productivity research for the Consumers Coalition of Alberta we have found OHS results to be much more sensitive to the assumed average service

life of assets than those using geometric decay.[7] This evidence is attached to our response as Attachment M2-11.1-OPG 2B.

- Numerous statistical studies of trends in used asset prices have revealed that they are generally not consistent with the OHS assumption.[8] Instead, *accelerated* depreciation appears to be the norm for machinery and is also generally the case for buildings.[9] One expert has concluded that "the empirical evidence is that a geometric depreciation pattern is a better approximation to reality than a straight line pattern [i.e., the pattern consistent with OHS decay], and is at least as good as any other pattern [bracketed remark from PEG]."[10]
- A common sign of the decline in the flow of services from an asset is a rise in the use of labor and materials to operate and maintain it. In this regard, it is noteworthy that LEI states in its December response memo that "hydroelectric generating assets, *if properly maintained*, continue to deliver the same productive capability in the long run [*italics added*]."[11] PEG and LEI both found substantial declines in the productivity of hydroelectric O&M inputs in their direct evidence. PEG, with its longer sample period, found that O&M productivity growth has worsened substantially since 1974. In contrast, negative O&M productivity trends are not typical of electric power distributors in our

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[7] See for example, Mark Newton Lowry and David Hovde, *PEG Reply Evidence*, Exhibit 468, AUC Proceeding 20414, revised June 22, 2016, p. 16.
[8] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts", *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.
[9] OECD, *Measuring Capital OECD Manual 2009,* p. 101.
[10] Fraumeni, op cit, p. 17.
[11] LEI, op cit, p. 5.

experience.[12] Figure 2 of this memo, which is reportedly drawn from a Hydro Equipment Association document, shows that, after holding steady for many years, the hydraulic flow and reliability of hydroelectric generation assets starts to decline while the quantity of O&M inputs rises. Since the hydroelectric generation assets in the PEG study were far from new during the featured 1996-2014 sample period, it is not at all clear that the sampled utilities were not typically operating in the period of declining capital service flows in LEI's figure.

- In real-world productivity studies, capital quantity trends are not calculated for individual assets. They are instead calculated using data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each *individual* asset in a cohort had an OHS age/efficiency profile, the age/efficiency profile of the *cohort* could be poorly approximated by OHS, for several reasons. Different kinds of assets could have different average service lives. Assets of the *same* kind could end up having different service lives. Alternative specifications such as GD can provide a better approximation of the service flow of a cohort of assets that individually have OHS patterns.
- The code for GD is intuitively appealing and easy to implement and review.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of

[12] For example, a 0.76% average annual growth rate in O&M productivity is reported for a large sample of US power distributors from 1997 to 2014 in Mark Newton Lowry and David Hovde, op cit., p. 38.

> assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age-efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the *Manual* is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, *i.e.* a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. The ***Manual therefore recommends the use of geometric patterns for depreciation*** because they tend to be empirically supported, conceptually correct and easy to implement.[13] [Emphasis in original]

The many disadvantageous of the OHS specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. For example, GD is used to calculate capital quantities in the National Income and Product Accounts of the US and Canada. GD has also been used in numerous productivity studies intended for X factor calibration in the energy and telecommunications industries, including many prepared for utilities. Statistics Canada uses GD in its multifactor productivity studies for sectors of the economy.[14] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand assume hyperbolic decay in their sectoral MFP studies.

In summary, there are many disadvantages to the use of the OHS specification in multifactor productivity research. The OHS approach seems *especially* disadvantageous in

[13] OECD, op cit., p. 12.
[14] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program", *Canadian Productivity* Review, Catalogue no. 15-206-XIE – No. 14. p. 41 and Statistics Canada, "The Statistics Canada Productivity Program: Concepts and Methods", Catalogue no. 15-204, January 2001.

an application to US hydroelectric generation productivity. The requisite plant data are insufficiently itemized for the OHS approach and generation assets do not in any event seem to conform to the OHS age efficiency profile. The GD approach is preferable based on the data and other information available at this time.

Conclusion

Although we were able to produce results using a one-hoss shay methodology, the uncertainty associated with assigning vintages to retired plant gives us concerns about the accuracy of results. When combined with our general reservations about the use of an OHS specification in the calibration of an X factor for hydroelectric generation, we cannot recommend these results as an alternative to the original PEG work using geometric decay as the basis for calibrating an X factor for OPG.

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Reply Evidence of Pacific Economics Group Research LLC
Filed in Alberta Utilities Commission Proceeding 201414
Exhibit 468, June 22, 2016

Referenced in Exhibit M2/11.1/OPG-002/Attachment A

PEG Reply Evidence

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1. Introduction

Please state your name and business address.

My name is Mark Newton Lowry. My business address is 44 East Mifflin, Suite 601, Madison Wisconsin USA 53703.

What are your credentials to provide testimony in this proceeding?

I am the President of Pacific Economics Group ("PEG") Research LLC, a consulting firm that is prominent in the field of utility regulation. Performance-based regulation ("PBR"), cost trackers, and other alternatives to the traditional North American approach to rate regulation are company specialties. We are also well known for our statistical research on productivity and other aspects of utility performance. PEG personnel have over 60 person-years of experience in these related fields. Our practice is international in scope and has included projects in Australia, Europe, Japan, and Latin America. We have been fortunate to play a major role in the advance of PBR in Canada.

My duties as company president include expert witness testimony and the supervision of research on PBR plan design and related empirical issues such as the productivity trends of energy utilities. I have supervised dozens of utility productivity studies over the years. In addition to Alberta, venues for my PBR testimony have included British Columbia, California, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Québec, Texas, and Vermont.

Work for diverse clients has given my practice a reputation for objectivity and dedication to regulatory science. In Canada, for example, my clients have included the Association Québécoise de Consommateurs d'Electricité Industrielles, ATCO Electric, the Canadian Electricity Association, the Commercial Energy Consumers Association of British Columbia ("CEC"), Enbridge Gas Distribution, EPCOR, FortisAlberta, Hydro-Québec, the Ontario Energy Board, and Terasen Gas as well as my client in this proceeding, the Consumers' Coalition of Alberta ("CCA"). I have recently done productivity research and testimony for the CCA and CEC, as well as for Central Maine Power, Oshawa PUC Networks, Pepco, and Unitil.

Before joining PEG I worked for many years at Laurits R. Christensen Associates ("LRCA") in Madison, first as a Senior Economist and later as a Vice President. The key members of the team I led at LRCA have for many years worked for PEG. My career has also included work as an academic economist. I served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at l'École des Hautes Études Commerciales in Québec.

My academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. I have been a referee for several scholarly journals and have a lengthy record of professional publications and public appearances. I hold a doctorate degree in Applied Economics from the University of Wisconsin-Madison.

Please discuss the credentials of Mr. Hovde.

Dave Hovde is a Vice President of PEG. He undertook most of the productivity calculations in our work for CCA in this and the previous proceeding, along with those in dozens of other projects over two decades. Dave holds a master's degree in Economics from the University of Wisconsin-Madison.

What are the goals of your reply evidence?

My principal goal is to continue to abide by the AUC issues list and doing so to rebut evidence presented, in direct evidence and responses to information requests, by the utility expert witnesses: Dennis Weisman, Mark Meitzen of LRCA, and Paul Carpenter and Toby Brown of the Brattle Group. I find both their X factor research and recommendations problematic, as well as their discussions of other plan design issues. I will also remark on the evidence provided by the distributors.

2. X Factor Issues

2.1 Base Productivity Trend

Let's start with the research and evidence on the base productivity trend. Please provide an overview of the productivity research undertaken by utility witnesses.

Brattle and LRCA have based their X factor recommendations on studies that update the multifactor productivity ("MFP") indexes developed by National Economic Research Associates ("NERA") in Proceeding ID 566.[1] The MFP trend is the difference between the average annual growth rates of output and input quantity indexes. The trend in outputs is an average of trends in the volumes of services provided to four groups of customers. The trend in inputs is an average of the trends in subindexes measuring the use of capital and of labor and material and service ("M&S") inputs used in operation and maintenance ("O&M").

The sample period for the NERA study was 1973-2009. Brattle and LRCA updated the study, adding the five years from 2010 to 2014. Considerable attention is paid to MFP results for these years and whether estimates of long-term MFP trends are good predictors of results for these years.

NERA recommended calibrating the X factor using the MFP trend for the *full* sample period, and the AUC agreed with this recommendation in Decision 2012-237. To defend their research methods, Brattle and LRCA have noted repeatedly in their evidence that the AUC used the NERA results to set the base productivity trend.[2] However, Brattle and LRCA recommend basing X for next-generation PBR on the trends in their MFP indexes in later years of the sample period, when the values of their indexes fall after decades of growth.

Please summarize your concerns

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[1] I prefer the term *multifactor* productivity to *total factor* productivity since many costs incurred by the sampled utilities have been excluded from all of the studies filed in this proceeding.

[2] EDTI stated in response to EDTI-AUC-012, for example, that "Because his results are based on the same methodology approved and deemed reliable by the Commission in Decision 2012-237, Dr. Meitzen believes his results are reliable."

The NERA/Utilities methodologies for measuring productivity trends are flawed, and the flaws cause MFP to fall in the later years of the sample period when my own study found the MFP for a larger group of US power distributors to be rising on average. Some of the flaws take the form of obvious methodological and data errors. Others may be better described as substandard practices. Research that provides the basis for Alberta X factors should be free of major errors and use the best available methods. Brattle and LRCA effectively cherry picked results for a favorable sample period without undertaking a thorough review of the NERA methodology and making approximate corrections and upgrades. The NERA/Utilities methodology is a poor basis for setting X in this or future plans.

In what areas have serious errors have been made in your view?

The main problems are in three areas.

- There is an error (as well as substandard practices) in the calculation of the labor quantity trend.
- Some output data are egregiously flawed.
- Errors were made in the benchmark year calculations for the capital quantity index.
- I might also note that corrections were not made for several mergers and a restructuring, and data for two companies were confused.

Let's discuss one by one your concerns about errors, beginning with the labor quantity research.

Until 2002, US electric utilities reported on the FERC Form 1 the total number of their employees. For these years, NERA and the Utilities witnesses estimated the number of power distribution employees by multiplying the total number by the share of power distribution in total salaries and wages.

A means was required to extend these estimates of total labor quantities to the later years of the sample period. NERA endeavored to do this using estimates of labor quantity growth from 2002 onwards obtained using the “residual” approach I discussed on p. 42 of my testimony. The formula for this calculation is

$$\textit{trend Inputs}^{Labor} = \textit{trend Expenses}^{Labor} - \textit{trend Input Prices}^{Labor} \qquad [1]$$

In other words, the trend in the quantity of labor equals the trend in "deflated" or "real" labor expenses.

Recollecting that a share of the total labor quantity is, in a second stage of the NERA/Utilities methodology, allocated to distribution, *total* labor O&M expenses should be used in equation [1]. These expenses would shrink after 2001 for the many electric utilities in the sample that sold or spun off generation during this period, as many did in Alberta. Meanwhile, the distribution share of the total would rise. These offsetting trends would cause the estimated number of distribution employees to grow gradually for these companies. Unfortunately, NERA used the growth in *distribution* O&M expenses in equation [1]. This exaggerated labor quantity growth in the later years of the sample period and understated MFP growth.

How did the utility witnesses deal with this error?

Dr. Meitzen noted this error in his testimony and corrected for it. Brattle did not. In response to data request Brattle-AUC-007, however, Brattle acknowledged the error and provided a correction at the AUC’s request. They found that the correction *raised* their estimate of MFP growth by 5 basis points for the full sample period and by a substantial 14 basis points for the more recent 2000-2014 period.

Is this the only serious error NERA made with respect to the trend in the labor quantity?

Remarkably, no. I pointed out in my direct evidence for the CCA in Proceeding ID 566 that, when NERA initially tried to extend its estimates of total employees to the post-2001 period, it escalated the total using the growth in O&M expenses, neglecting to net off labor price growth as required by equation [1].[3] The prices of salaries and wages in the United States grew by around 3% annually on average from 2001 to 2006. Thus, NERA's initial work grossly overstated labor quantity growth in the later years of the sample period by virtue of another error. NERA acknowledged this error and corrected for it in their February 2012 update in Proceeding ID 566.[4]

Turning next to data problems, why do you consider some of the NERA/Utilities output data to be egregiously flawed?

NERA, Brattle, and LRCA employed as their output measure an index of service volume trends. They relied on the Federal Energy Regulatory Commission ("FERC") Form 1 for their volume data. As Dr. Meitzen acknowledged in response to Meitzen-CCA/PEG-010, volumes reported on FERC Form 1 are *sales* volumes, and these do not always equal *delivery* volumes. I disagree with Dr. Meitzen when he says in response to the same question that "the FERC Form 1 data are a reliable measure of output of the study period." These data can produce spurious trends for electric utilities which 1) were restructured to face retail power market competition and 2) thereafter lost substantial sales to competing merchants but did not experience corresponding declines in deliveries.

Restructuring of investor-owned electric utilities in the United States began in the late 1990s. Sales volumes of several distributors declined substantially, as independent merchants made inroads, but delivery volumes did not. The declines in sales volumes were particularly marked for *industrial* customers, and this matters since industrial sales volumes are assigned a sizable weight in the NERA/Utilities output index. Declines in sales volumes due to this problem were large enough to slow the measured output growth of the industry materially and are one reason for the negative MFP growth in the later years of the sample period that Brattle and LRCA highlight in their testimony.

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[3] AUC Proceeding 566, Exhibit 0307.01.CCA-566, *PEG Evidence in AUC RRI*, December 18, 2011, pp. 35-36.

[4] AUC Proceeding 566, Exhibit 0391.02.NERA-566, *Second Report of NERA*, February 22, 2012.

Is there a fix for this problem?

Yes. Data on *deliveries* of power by US distributors are readily available on the US Energy Information Administration's Form EIA 861 for years after 1990. PEG routinely uses these data in our studies when delivery volume data are needed. Using these data we found that there were marked differences between sales and delivery volumes for five companies in the NERA/Utilities sample. It would have been straightforward for NERA, Brattle, and LRCA to combine FERC Form 1 data for early years of the sample period with Form EIA 861 data for the later years but they all chose not to.

Have the utility witnesses acknowledged that this is a problem with their work?

No. Brattle conceded in their response to Brattle-AUC-009 (a) that delivery data would be *preferable*.

> Conceptually, the best measure of volume distributed would be the sum of bundled MWh and distribution MWh (since the utility is responsible for distributing bundled MWh and distribution-only MWh). It would be appropriate to refer to the sum of these quantities as the "delivered" MWh.

However, having not been asked by the AUC to provide a run that corrected for the use of sales data, they didn't provide one. Brattle did present sales and delivery data for *3 companies* that were roughly the same for the two sources. Ironically, their acceptance of the slight differences in the FERC Form 1 and Form EIA 861 data undermines an argument against combining these data in a sample for productivity research --- that there may be improper discrepancies between some of these data. In response to EDTI-AUC-13 (a), Dr. Meitzen stated that

> It is Dr. Meitzen's understanding that, for the most part, sales are equal to deliveries in the FERC Form 1 data, but there are some instances where this is not the case. Dr. Meitzen is also aware that NERA found that the EIA-861 data that was [sic] proposed as a "patch" contained some anomalies and that using it in conjunction with the FERC Form 1 data did not materially change the results of the NERA study. Given these factors, Dr. Meitzen believes the FERC Form 1 sales data are a reasonable measure of output. [footnote removed]

Neither NERA, Meitzen nor Brattle made a serious attempt to demonstrate that there were worrisome discontinuities between the FERC Form 1 and Form EIA 861 data that made use of the latter data inadvisable.

Table 1 and Figure 1 illustrate the magnitude of this issue. For most sampled companies, the two data sources are similar, if not identical. It is in the case of outliers that this problem matters. The table and figure show the 5 cases with the most extreme differences between the two data sources. For these five companies, more than half the volume is missing from the Form 1 reporting.

Let's turn now to problems with the *cost* data used in the NERA/Utilities indexes. Please provide an overview.

More than a dozen companies in the NERA/Utilities sample had mergers that were not corrected for. Some utilities transferred sizable costs from transmission to distribution (or vice versa). Some capital cost data for Mississippi Power and Mississippi Power and Light (now Entergy Mississippi) were intermixed. No account was taken of the separation of Gulf States Power into two companies serving Louisiana and Texas and the resultant itemization of their data.

Why do mergers and T&D transfers matter?

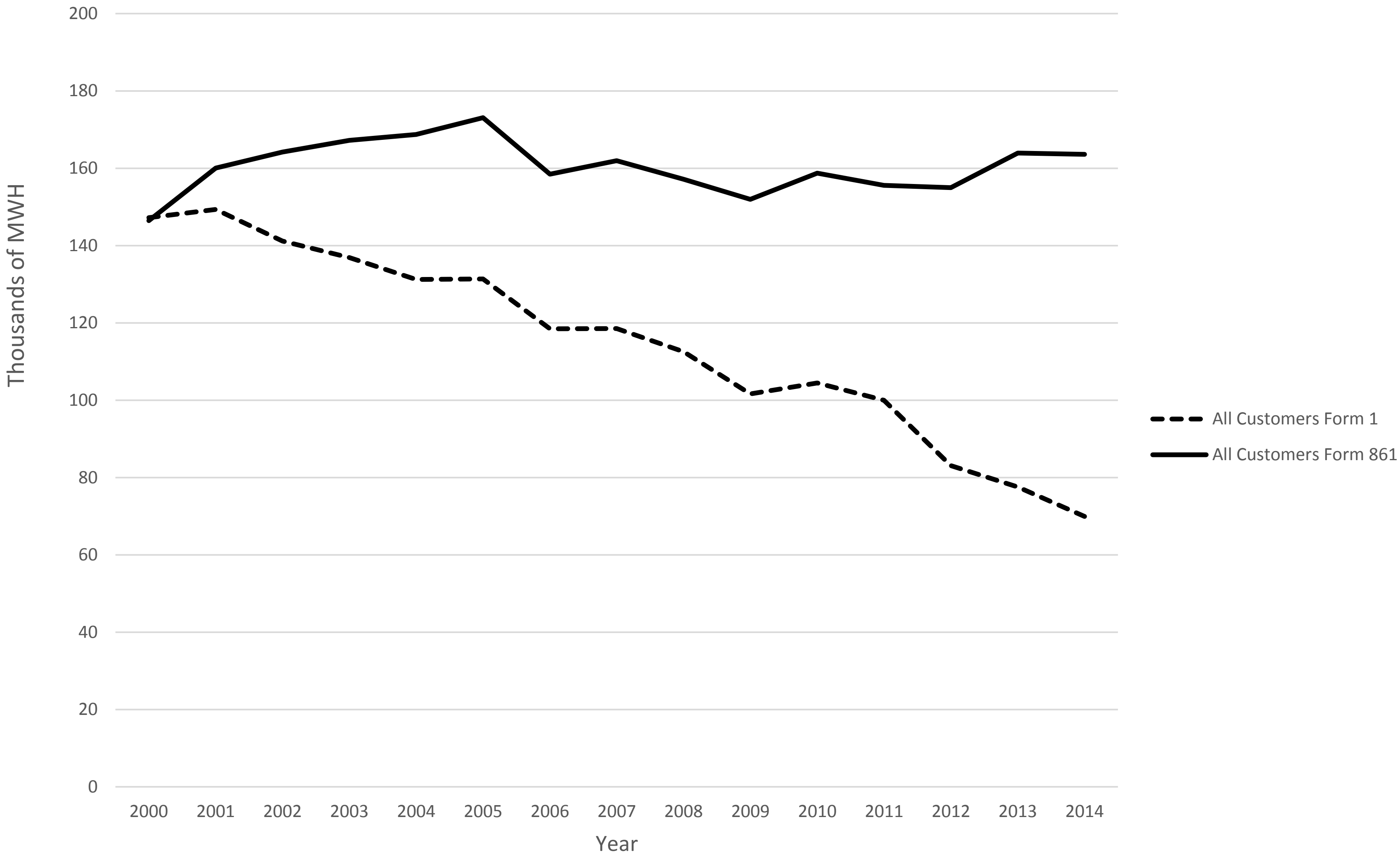
In common with PEG, NERA, Brattle, and LRCA used a "perpetual inventory" approach to construct their capital quantity indexes. Under this approach, the quantity of capital held in a given year is a function of the size of real plant additions made in previous years. Absent a cumbersome adjustment, if a merger or acquisition occurs or costs are moved from transmission to distribution, O&M expenses and plant additions will rise abruptly but the older capital quantity will not. Future MFP growth is then underestimated. Brattle implicitly acknowledged the problems mergers can cause when they excluded data for certain companies (e.g., Illinois Power and Central Illinois Public Service) which were involved in mergers during the update years.

Table 1
Form 1 and Form 861 Retail Service Volumes for Selected Companies

	Dayton Power and Light			Central Hudson Gas & Electric			Niagara Mohawk Power		
	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861
2000	27,783,546	27,783,191	100%	9,053,748	9,053,748	100%	60,387,259	60,387,259	100%
2001	27,559,389	27,559,389	100%	9,598,877	9,617,125	100%	59,755,400	66,543,642	90%
2002	28,372,290	28,372,290	100%	9,237,804	10,014,527	92%	56,652,151	67,851,557	83%
2003	27,608,521	29,013,339	95%	8,521,261	10,759,408	79%	52,523,850	68,275,800	77%
2004	28,027,844	29,427,563	95%	8,347,417	10,984,308	76%	49,469,132	68,838,406	72%
2005	28,942,390	30,372,874	95%	8,151,043	11,477,786	71%	46,769,036	70,724,647	66%
2006	28,106,248	29,528,142	95%	7,761,531	10,998,824	71%	43,038,777	58,995,909	73%
2007	29,000,360	30,463,304	95%	9,133,053	11,263,122	81%	41,862,854	59,995,868	70%
2008	28,410,290	29,859,366	95%	7,058,940	10,843,130	65%	39,351,536	58,293,030	68%
2009	25,687,098	27,069,828	95%	6,320,306	10,348,616	61%	36,486,972	57,529,928	63%
2010	27,122,087	28,552,852	95%	6,189,767	10,429,470	59%	37,540,308	59,026,327	64%
2011	24,937,180	28,042,697	89%	5,918,817	10,368,848	57%	35,988,363	59,168,976	61%
2012	11,149,047	27,995,958	40%	5,312,833	10,146,974	52%	35,051,423	59,200,432	59%
2013	8,564,854	27,751,214	31%	5,199,613	10,217,306	51%	31,601,536	67,914,766	47%
2014	7,581,841	28,008,530	27%	4,945,171	10,041,508	49%	26,221,001	68,676,832	38%

	Massachusetts Electric			Narragansett Electric			Total		
	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861
2000	36,413,741	36,325,075	100%	13,589,575	12,893,355	105%	147,227,869	146,442,628	101%
2001	38,686,548	41,692,951	93%	13,744,779	14,608,190	94%	149,344,993	160,021,297	93%
2002	33,779,592	43,024,540	79%	13,141,963	14,922,213	88%	141,183,800	164,185,127	86%
2003	34,268,563	43,675,711	78%	13,983,557	15,470,656	90%	136,905,752	167,194,914	82%
2004	31,456,226	43,835,932	72%	13,936,512	15,651,016	89%	131,237,131	168,737,225	78%
2005	33,314,004	44,531,961	75%	14,176,125	15,970,824	89%	131,352,598	173,078,092	76%
2006	26,166,270	43,489,169	60%	13,428,016	15,472,968	87%	118,500,842	158,485,012	75%
2007	25,064,361	44,324,744	57%	13,465,718	15,900,522	85%	118,526,346	161,947,560	73%
2008	24,318,744	42,621,584	57%	13,441,583	15,513,494	87%	112,581,093	157,130,604	72%
2009	21,929,528	41,905,032	52%	11,221,218	15,112,600	74%	101,645,122	151,966,004	67%
2010	22,954,183	45,269,846	51%	10,619,705	15,442,341	69%	104,426,050	158,720,836	66%
2011	22,769,189	42,662,927	53%	10,394,015	15,309,200	68%	100,007,564	155,552,648	64%
2012	21,663,887	42,355,707	51%	9,892,747	15,262,099	65%	83,069,937	154,961,170	54%
2013	21,931,169	42,629,454	51%	10,247,431	15,398,278	67%	77,544,603	163,911,018	47%
2014	21,185,570	41,767,210	51%	10,002,855	15,123,218	66%	69,936,438	163,617,298	43%

Figure 1
Comparison of Form 1 and Form 861 Service Volumes for Selected Companies



Were appropriate data corrections made for all utilities involved in mergers and restructurings in the NERA/Utilities sample?

No. We examined the data for earlier years of the sample period closely and found that the data had not been corrected for several mergers or for the Gulf States Power separation. We asked LRCA about these problems in Meitzen-CCA/PEG-007. When we (deliberately) asked about a *single* merger between New Jersey Power & Light and Jersey Central Power & Light, EDTI responded that "Dr. Meitzen does not know if the NERA/Brattle study takes into account the assets of New Jersey Power & Light." EDTI further commented that "Dr. Meitzen concluded that NERA did not take measures to account for the separation of Entergy Gulf States" and "did not independently evaluate the data for transfers of assets between transmission and distribution." In response to EDTI-AUC-009, Dr. Meitzen acknowledged that he had included Central Illinois Light, Columbus Southern Power, Central Vermont Public Service, and Illinois Power in his sample even though they ceased filing Form 1s late in the sample period, leading to an unbalanced panel.

As for Brattle, the following responses were made to Brattle-CCA/PEG-010.

Requests:

Please respond to the following questions regarding the continuity of data used in the study.

a) What other years from 1964-2014 did you check besides 2009-2010 for data discontinuities?

b) Can you confirm that the data for other years are free from large discontinuities?

c) Please explain what measures, if any, were taken to adjust the data for Entergy Gulf States to account for the separation of the company into Entergy Gulf States Louisiana and Entergy Texas.

d) For companies included in the analysis, what steps if any were taken to account for transfers of assets between transmission and distribution during the sample period?

e) Attached below is a copy of the 1964 version of the "Statistics of Electric Utilities in the United States" which contains published data for Jersey Central Power and Light and New Jersey Power & Light. These companies merged operations and the assets of New Jersey Power & Light are now part of the current Jersey Central P&L.

i. The working papers provided show a value of 125,883,373 in cell E40 of the Initial Capital Stock worksheet. This matches our records for Jersey Central but does not include the corresponding dollars of plant for New Jersey Power and Light. Does the NERA/Brattle study take into account the assets of New Jersey Power and Light?

ii. Would the exclusion of the assets of acquired companies have an impact on the trend in the capital quantity of Jersey Central using the one-hoss shay method?

iii. Please describe any steps taken to ensure the accuracy of Jersey Central's capital quantity trend in light of merger activity since 1964.

Response:

a) The written evidence of Dr. Brown and Dr. Carpenter contains new results for 2010 through 2014. The TFP recommendation is based on combining the new TFP results with the TFP results for earlier years already put forward by NERA in Proceeding 566 and relied on by the AUC in that proceeding. Dr. Brown and Dr. Carpenter examined the new data for 2010 through 2014 as well as for 2009 (as described in the cited portion of evidence).

b) No. The results for earlier years were taken from NERA's TFP study in Proceeding 566.

c) None. The new data added to the TFP study includes data for Entergy Gulf States Louisiana only.

d) None. The FERC form 1 data was used without adjustment.

e) See response to b).

Did some witnesses acknowledge the importance of the T&D transfer issue?

Yes. Brattle stated in response to Brattle-CCA/PEG-003 (d) that "if there are changes in cost allocation of the type hypothesized in the request, then the measured TFP trend might not be reliable.

Please restate your concerns about the benchmark year calculations.

Let me begin by noting that all of the studies in this proceeding use capital quantity indexes that are, basically, measures of the growth in total plant value adjusted for inflation in the unit cost of construction. The total plant value used in these calculations may, in principle, be gross or net plant value.

NERA and the utilities used the “one-hoss shay” method to calculate the capital cost and quantity. As I discussed on p. 51 of my direct testimony in this proceeding, under this method the quantity of an asset is assumed not to decline gradually due to depreciation but instead to fall abruptly to zero when it is retired and removed from gross plant value. In other words, the capital quantity index is an index of the quantity associated with gross plant value. Dr. W. Erwin Diewert stated in this regard that “we consider the one hoss shay model of depreciation which assumes that the efficiency and hence rental price of each vintage of the capital good is constant over time (until the good is discarded as completely worn out after *N* periods). This model is sometimes known as the *gross capital stock* model.”[5] PEG, in contrast, used two approaches to measuring capital cost (geometric decay ["GD"] and cost of service ["COS"]) in its research for this proceeding which attempt to measure the trend in quantity consistent with *net* plant value.

[5] Diewert, W.E., and Lawrence, D.A. (2000), “Progress in Measuring the Price and Quantity of Capital”, *Econometrics, Volume 2, Econometrics and the Cost of Capital*, edited by Lawrence J. Lau, 2000, MIT Press, Cambridge, Massachusetts, p. 274-275.

Using any of these methodologies, the capital quantity index starts in a certain "benchmark" year in which the total quantity of plant owned by the utility must be estimated.[6] Total plant value in any year is the sum of assets of different vintages. The quantity of plant in the benchmark year is for this reason estimated by taking the ratio of total plant value to an index of past values of an electric utility construction cost index. NERA and the utilities, like PEG, used the *net* plant value in their benchmark year adjustment.[7] However, the *gross* plant value is consistent with the NERA/Utilities' calculation of capital cost using the one hoss shay specification.

Another problem with the NERA/Utilities benchmark year adjustments is the inconsistency between the 33-year service life assumed for distribution assets before their retirement and the 20-year average of past values of the construction cost index employed in the benchmark year adjustment. A 33-year average would be more consistent.

What are the implications of these problems for the calculated MFP trend?

The use of net plant additions causes the capital quantity to be underestimated in the benchmark year. So does including too few years in the average of construction cost index values used in the benchmark year adjustment, because this increases the denominator of the adjustment. Understatement of the initial capital quantity makes the capital quantity index unduly sensitive to plant additions. Capital quantity growth is *over*stated while MFP growth is *under*stated.

Have Brattle or Meitzen acknowledged problems with the benchmark year adjustment?

No. EDTI stated rather evasively in response to Meitzen-CCA/PEG-011 that "because the benchmark is an approximation, it is reasonable to use net plant with a one hoss shay

[6] PEG uses a slightly different method in its alternative COS approach to measuring capital cost.

[7] Note, however, that net plant value had to be imputed because NERA relied on electronic data.

approach." When asked for his *own* views of whether the use of gross or net plant value in the benchmark year adjustment was theoretically consistent with one hoss shay, Dr. Meitzen answered that there was no clear resolution of this issue *in the literature*. In their response to Brattle-AUC-007, Brattle states with respect to the gross vs. net plant value issue that

> these are the sort of technical detail which should not have an important influence on the results of the study if the study is robust. There is unlikely to be a "correct answer" to the determination of a capital quantity index….policy decisions (such as the choice of X-factor) should not be determined by such technical details. As such it would be reasonable to adopt either of the approaches suggested.

At the AUC's request, Brattle nonetheless recalculated the results using gross plant value for the benchmark year adjustment, and reports in their response that MFP growth is 8 basis points more rapid over the full sample period and 8 points more rapid over their featured 1999-2014 period.

What evidence can you present that these problems with the NERA/Utilities study are quantitatively important?

We recalculated the NERA/Brattle index after correcting sequentially for these problems. Results for the full sample of these and other steps we have taken to reconcile results of the PEG and Utilities work are presented in Table 2. Please note the following.

- Our correction for the problem in the labor quantity work which Dr. Meitzen identified raised the MFP growth trends by 5 basis points for the full 1973-2014 sample period, by 12 points for the 1997-2014 period that we featured in our evidence, and by 15 points for the five most recent years of the sample period (2010-2014).[8]

[8] Due to other differences between the Brattle and LRCA studies such as the sample and capital price, our results will differ from those of the final LRCA trends.

Table 2

Summary of Corrections and Modifications to NERA/Brattle/LRCA Productivity Calculations

	MFP Trend (volume weighted averages, Brattle sample)		
	1973-2014	1997-2014	2010-2014
As Reported by Brattle	0.71%	-0.71%	-1.25%
Corrections			
Salary Escalation Correction (Meitzen)	0.76%	-0.59%	-1.10%
Correct Output Quantity Data	0.86%	-0.43%	-0.86%
Use Gross Plant Benchmark with 20 year life	0.99%	-0.28%	-0.71%
Use Gross Plant Benchmark with 33 year life	1.10%	-0.17%	-0.61%
Exclude companies not included in PEG work	1.15%	-0.12%	-0.62%
Methodological Upgrades (Major)			
Use One-Hoss Shay with a 37 year service life and a gross plant benchmark	1.62%	0.49%	0.02%
Use Geometric Decay and a 33 year service life	1.31%	0.14%	0.13%
Use Geometric Decay and a 37 year service life	1.23%	0.09%	0.07%
Correct Data for Mergers and Mismatch	1.28%	0.15%	0.12%
Use total customers	NA	0.18%	0.17%
Variations on the PEG Work (all simple averages)			
PEG using only distribution, 37 year life, GDPPI, and a common sample	NA	0.25%	0.22%
PEG using only distribution, 37 year life and GDPPI	NA	0.21%	0.13%
PEG with 37 year life and GDPPI	NA	0.37%	0.32%
PEG with 37 year Service Life [Revised Testimony]	NA	0.43%	0.31%
PEG Testimony [Original]	NA	0.48%	0.39%

Correcting for the problems caused by using FERC Form 1 volume data raised the MFP trend by another 10 basis points for the full sample period, 16 points for the 1997-2014 period, and by 24 points for the five most recent years.

- Using gross rather than net plant in the benchmark year calculation raised the MFP trend by another 13 to 15 basis points.
- Using a 33-year average of past construction cost index values in the benchmark year calculation raised MFP growth by another 10-11 basis points. Excluding companies not included in the PEG sample due to T&D transfers and other problems raised the MFP trend by 5 basis points for the full sample period and 1997-2014 period but decreased it by one point for the five most recent years.

When all of these errors are corrected, please note that the MFP trend for the 1997-2014 period is -0.12%, still negative but much closer to zero than the trend Brattle reported for a similar sample period.

Let's turn now to your concerns about aspects of the NERA/utilities methodology that are not in your view clearly erroneous but are instead "suboptimal". What are your main concerns?

The most notable areas of substandard practice are as follows:

- The one hoss shay approach to calculating capital cost is very sensitive to the assumption made concerning the average service life of capital. This matters because the 33-year average service life assumed in the NERA/Utilities methodology is too low.
- The geometric decay and COS approaches to capital costing are more appropriate.
- The number of customers is a better output measure than the volumetric index that the utilities use.
- The NERA/Utilities methodology excludes meter reading and administrative and general expenses.

- GDPPI is not an ideal measure of M&S input price inflation.

Let's discuss these issues one by one, starting with the service life issue.

The NERA study assumes a 33-year service life for power distributor assets. Based on our extensive experience in the field of energy utility productivity measurement, we believe that this is lower than the norm for US power distribution assets and is likely also lower than the norm in Alberta. Lacking evidence on average service lives in Alberta, the MFP index we used to prepare our direct evidence for CCA in this proceeding assumed a 44-average service life based on an estimate we obtained from a recent client, Central Maine Power.

We asked Brattle and LRCA in information requests to provide data that would permit us to calculate average service lives for Alberta power distributors. Both refused, arguing in part that they didn't know the answer. However, in response to information request EDTI-UCA-014, EDTI submitted data that permit us to calculate a *37*-year average service life for the distribution assets of this company.[9] We believe that, absent better data, this the most reasonable number available in this proceeding for use in productivity research to calibrate X factors for Alberta energy distributors.

What is your concern about the one hoss shay methodology for calculating the capital cost and quantity?

The one hoss shay methodology involves an assumption about asset decay that is very different from the assumption (typically straight-line depreciation) used in North American regulatory accounting. The geometric decay approach that PEG has featured in its testimony for the CCA is much more similar, yet mathematically elegant and easy for other parties to the proceeding to review. Another advantage of the GD approach is that it is more robust than one hoss shay with respect to the choice of an average service life for the capital quantity index.

[9] See Attachment G-1, EDTI Service Life Review.

The GD approach is also much more widely used than the one hoss shay approach. GD would thus facilitate involvement of expert witnesses in future proceedings on distributor productivity trends in Alberta. For example, EDTI noted in response to Meitzen-CCA/PEG-011 that "Dr. Meitzen has used geometric depreciation in each of the studies he has co-authored and has not used the one hoss shay method." In recent work for the Ontario Energy Board, PEG used the geometric decay approach to measure the productivity trends of Ontario power distributors. This research was used to set the X factors currently used in the PBR plans of most Ontario distributors.

What about the output specification?

I have a number of additional concerns about the NERA/Utilities treatment of power distributor output. Consider first that, as Dr. Meitzen acknowledged in response to question Meitzen-CCA/PEG-010 and Brattle acknowledged in response to Brattle-CCA/PEG-008, the NERA/Utilities methodology assigns a weight to the sales volume of each customer class based on its share of the revenue for *all* services provided and not just *distribution* services. This often includes a sizable charge for energy supplied. NERA reported that this approach produced a 20.5% weight for industrial sales volumes on average during their 1972-2009 sample period. A 20.5% share for the industrial volume is far above the typical share of industrial customers in power distribution *base* rate revenues because these customers tend to have high load factors and, as Brattle acknowledged in response to Brattle-CCA/PEG-008, some take delivery of power directly from the transmission grid, as they do in Alberta.[10]

Most of my concerns about the NERA/Utilities output treatment, however, involve the fact that it is an index of *volume* trends. Utility sales (and delivery) volumes tend to be volatile. Business cycle and weather conditions are important causes of this volatility. It is generally considered desirable to include the most recently available data in productivity research to

[10] Dr. Meitzen stated in response to Meitzen-CCA/PEG-010 that "Dr. Meitzen is not aware of how often bypass occurs for large industrial customers in the United States."

calibrate X factors. With a volume-based output index, however, the trend for the entire sample period is then sensitive to unusual business conditions in the most recent year. This was a problem with NERA's study in Proceeding ID 566, which ended in 2009 at the bottom of the Great Recession, and was probably one reason why NERA used such a long sample period.[11] Volumetric output indexes can be smoothed by various means, but this adds a new level of complexity to the study and is sometimes opposed by parties to the proceeding.

The relevance of recent US volume trends is, in any event, questionable in the calibration of X factors for Alberta energy distributors.

- I explain on pp. 47-50 of my direct testimony that the output index in productivity research to calibrate the X factor for a *revenue* cap index should be consistent with the scale variable in the revenue cap formula. The AUC acknowledged this logic in Proceeding ID 566.[12] Alberta *gas* distributors operate under revenue caps escalated by customer growth. Accordingly, numbers of customers served are the appropriate output metrics for productivity research to calibrate their X factors.
- One reason that the number of customers is typically used as the scale escalator in revenue cap indexes is that it is a good measure of the trends in demand that drive up the cost of base rate inputs. The number of customers is an important cost driver in its own right and is also highly correlated with peak demand. Extensive econometric cost research by PEG over the years has revealed that the number of customers served is the single most important scale-related driver of the costs of energy distributors. Our econometric research on this topic is detailed in our response to CCA-Utilities-073.

[11] 2015 would, similarly, be an inconvenient year to end a study of Alberta productivity trends were a volumetric index used.

[12] AUC Proceeding 566, Decision 2012-237, p. 82.

- The number of customers has the added advantage of being much more stable than volumes. This reduces the need to have a long sample period in productivity studies.

- Since I left LRCA with my research team, LRCA has prepared just one stand-alone study of power distributor productivity trends to my knowledge. In that study, for Kansas City Power and Light, the trend in output was measured as an average of customer and peak demand trends. There was no volume variable.[13]

- I explain on pp. 46-47 of my direct testimony that productivity research to calibrate the X factor for a *price* cap index should consider by some means a revenue-weighted average of the trends in billing determinants. The structure (aka design) of rates is thus an important consideration in designing a research plan for X factor calibration. I have used revenue-weighted output indexes several times in productivity research and in testimony for clients proposing price cap indexes.[14]

- In the United States, base (non-energy) revenue from residential and small business customers is typically collected chiefly through volumetric charges, while the rest of the revenue from these customers is gathered through fixed charges. Revenue from customers with larger loads is drawn chiefly from demand charges. In designing a price cap index for a *US* power distributor, volume trends therefore matter greatly, but so can trends in the number of customers and peak demand. The trends in delivery volumes and peak demand matter less to the extent that a high percentage

[13] Meitzen states otherwise in response to a data request but is referencing the measure of TFP for *integrated* services in the KCP&L study. LRCA's *distribution* TFP output measure was constructed from peak MW and the number of customers. Please see AUC Proceeding 566, Exhibit 0244.06.AUI-566, CCA-AUI-AUI-CA Energy Consulting 1b, Technical Discussion Paper, p. 1.

[14] Please see Dr. Lowry's testimonies for Gaz Metro in 2011 and 2012, OEB in 2007, and Direct Testimony for Central Maine Power in 2013.

of base rate revenue is drawn from fixed charges and large industrial customers make little use of distribution services.

- The choice between revenue-weighted and customer-based output indexes matters little in productivity research for X factor calibration if their trends are similar. Since residential and commercial ("R&C") *volumes* typically have heavy weights in *revenue*-weighted output indexes, the trends in revenue-weighted and customer-based indexes differ chiefly to the extent that trends in R&C customers and volumes differ. The difference between the volume and customer trends is sometimes referred to as the trend in "average use."

- Table 3 presents data on trends in the average use of power by R&C customers of US electric utilities. It can be seen that these trends have slowed substantially since the Great Recession and are now zero or negative. This is one reason for the slowdown in MFP growth that occurs over the lengthy NERA sample period. The MFP numbers before 2008 were accelerated by growth in R&C average use.

What are the implications of your analysis for Alberta?

Alberta power distributors currently operate under price caps, but some have fixed charges that are high by US standards. This is shown in Table 4, where we compare the residential fixed charges of the Alberta power distributors to those of a sample of US utilities. It can be seen that those of ENMAX and EDTI are fairly similar to those of US utilities whereas those of Fortis and (particularly) ATCO Electric are considerably higher.

Table 3

AVERAGE ANNUAL ELECTRICITY USE PER RESIDENTIAL & COMMERCIAL CUSTOMER 1927-2014

	Residential		Commercial	
	U.S.		U.S.	
	Level	Growth Rate	Level	Growth Rate
Multiyear Averages				
1927-1930	478	7.06%	3,659	6.67%
1931-1940	723	5.45%	4,048	2.00%
1941-1950	1,304	6.48%	6,485	5.08%
1951-1960	2,836	7.53%	12,062	6.29%
1961-1970	5,235	6.13%	28,893	9.51%
1971-1980	8,205	2.45%	49,045	3.07%
1981-1990	9,062	0.63%	56,571	1.40%
1991-2000	10,061	1.15%	67,006	1.68%
2001-2007	10,941	0.73%	74,224	0.64%
2008-2014	11,059	-0.38%	75,311	-0.22%

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

Table 4

Comparison of Residential Fixed Charges Between Alberta and US Electric Utilities

	Number of Utilities	Average Monthly Fixed Charge (CAD)	Median Monthly Fixed Charge (CAD)
Alberta			
ATCO Electric	1	$36.50	$36.50
FortisAlberta	1	$21.25	$21.25
EDTI	1	$17.18	$17.18
ENMAX	1	$13.01	$13.01
Total	**4**	**$21.99**	**$19.22**
United States			
IOUs	70	$13.66	$13.11
Non-IOUs	20	$18.33	$14.94
Total	**90**	**$14.70**	**$13.29**

Data for the Alberta utilities were obtained from their current tariff sheets.

The U.S. data were obtained from three recent reports: A) Caught in a Fix: The Problem with Fixed Charges for Electricity (Synapse Energy Economics, February 2016, pp. 43-45); B) The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report (NC Clean Energy Technology Center, February 2016, pp. 57-73); and C) The 50 States of Solar: Q1 2016 Quarterly Report, April 2016, pp. 33-38). Where the information from these three reports differed, data from the more recent report were used. Data were thus included in the following order of preference: the "approved" charge listed in (C), the "existing" charge listed in (C), the "approved" charge listed in (B), the "approved" charge listed in (A), and the "existing" charge listed in (A) (the table in [C] includes a footnote stating "Research as of December 1, 2015"; since [B] extends through the end of 2015, its data were considered more recent than the data from [C]). No verification was performed that cases listed as "pending" are still pending at this time.

Tables 5a-5d present trends in the average use of power by R&C customers of the four Alberta power distributors in this proceeding. Over the 2005-2014 (non-recession) years for which data are available for all four companies, the average use of residential customers averaged 0.35% growth while the average use of commercial customers averaged 1.12% growth.

None of the average use data I have presented have been normalized for weather or the business cycle. However, they nonetheless seem to suggest that the average use trends of R&C customers of power distributors in the United States and Alberta have since 2007 been quite

Table 5a

Demand Trends of Alberta Energy Distributors: ATCO Electric

	Demand Drivers		Residential						Commercial						Total	
			Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
Year	Edmonton Cooling Degree Days[1]	Alberta Population Growth Rate[2]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2002[5]	76.5		110,376		797,536		7.23		23,096		1,480,759		64.11		172,720	
2003[5]	73.6	1.73%	113,606	2.88%	806,369	1.10%	7.10	-1.78%	23,317	0.95%	1,489,756	0.61%	63.89	-0.35%	177,070	2.49%
2004	37.0	1.73%	118,020	3.81%	826,614	2.48%	7.00	-1.33%	23,954	2.70%	1,531,276	2.75%	63.93	0.05%	182,068	2.78%
2005	16.5	2.54%	121,325	2.76%	850,612	2.86%	7.01	0.10%	24,492	2.22%	1,567,342	2.33%	63.99	0.11%	186,134	2.21%
2006	65.5	2.96%	125,562	3.43%	900,244	5.67%	7.17	2.24%	25,040	2.21%	1,667,735	6.21%	66.60	4.00%	191,132	2.65%
2007	68.8	2.67%	130,885	4.15%	966,966	7.15%	7.39	3.00%	25,570	2.09%	1,749,215	4.77%	68.41	2.68%	197,354	3.20%
2008	52.2	2.30%	135,377	3.37%	997,982	3.16%	7.37	-0.22%	26,118	2.12%	1,808,790	3.35%	69.25	1.23%	202,824	2.73%
2009	56.5	2.29%	138,838	2.52%	1,037,896	3.92%	7.48	1.40%	26,579	1.75%	1,865,909	3.11%	70.20	1.36%	206,980	2.03%
2010	25.8	1.44%	141,967	2.23%	1,040,448	0.25%	7.33	-1.98%	26,873	1.10%	1,885,712	1.06%	70.17	-0.04%	210,630	1.75%
2011	37.6	1.53%	143,957	1.39%	1,072,984	3.08%	7.45	1.69%	27,089	0.80%	1,958,721	3.80%	72.31	3.00%	213,022	1.13%
2012	63.6	2.56%	146,242	1.57%	1,069,358	-0.34%	7.31	-1.91%	27,482	1.44%	2,069,234	5.49%	75.29	4.05%	215,964	1.37%
2013	53.7	3.00%	149,409	2.14%	1,120,871	4.70%	7.50	2.56%	28,021	1.94%	2,113,725	2.13%	75.43	0.19%	219,951	1.83%
2014	69.8	2.82%	152,243	1.88%	1,160,263	3.45%	7.62	1.58%	28,535	1.82%	2,217,404	4.79%	77.71	2.97%	223,259	1.49%
2015	94.6	1.94%	155,418	2.06%	1,126,254	-2.97%	7.25	-5.04%	29,076	1.88%	2,186,342	-1.41%	75.19	-3.29%	226,886	1.61%
2016		1.64%	158,566	2.01%					29,410	1.14%					230,248	1.47%
2017		1.64%	161,778	2.01%					29,749	1.14%					233,661	1.47%
2018		1.80%	165,313	2.16%					30,138	1.30%					237,494	1.63%
2019		1.88%	169,057	2.24%					30,557	1.38%					241,580	1.71%
2020		1.83%	172,809	2.19%					30,967	1.33%					245,625	1.66%
2021		1.74%	176,472	2.10%					31,352	1.24%					249,495	1.56%
2022		1.67%	180,094	2.03%					31,721	1.17%					253,259	1.50%
2023		1.65%	183,751	2.01%					32,088	1.15%					257,025	1.48%
Average Annual Growth Rates:																
2003-2015		**2.27%**		**2.63%**		**2.65%**		**0.02%**		**1.77%**		**3.00%**		**1.23%**		**2.10%**
2005-2014		**2.41%**		**2.55%**		**3.39%**		**0.84%**		**1.75%**		**3.70%**		**1.95%**		**2.04%**
2006-2015		**2.35%**		**2.48%**		**2.81%**		**0.33%**		**1.72%**		**3.33%**		**1.61%**		**1.98%**
2018-2023		**1.76%**		**2.12%**		**N/A**		**N/A**		**1.26%**		**N/A**		**N/A**		**1.59%**

[1] Data are from http://edmonton.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for Alberta, released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Alberta population is calculated for 2003-2015. Second, the projected Alberta population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecast number of customers for each year.

[4] Total customers includes all of the utility's customers except for lighting customers (which are not reported on the company's Rule 005 filings).

[5] 2002 and 2003 values from CCA AE 1(a) Attachment 1, from 2013 PBR capital tracker applications (proceeding ID 2131).

Table 5b

Demand Trends of Alberta Energy Distributors: FortisAlberta

	Demand Drivers		Residential						General Service						Total	
Year	Calgary Cooling Degree Days[1]	Alberta Population Growth Rate[2]	Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	37.0		284,308		2,111,485		7.43		48,972		6,679,529		136.39		396,780	
2005	16.5	2.54%	295,230	3.77%	2,190,968	3.70%	7.42	-0.07%	49,776	1.63%	6,941,360	3.85%	139.45	2.22%	433,734	8.90%
2006	65.5	2.96%	306,631	3.79%	2,322,664	5.84%	7.57	2.05%	51,025	2.48%	7,300,516	5.04%	143.08	2.57%	446,969	3.01%
2007	68.8	2.67%	320,641	4.47%	2,485,272	6.77%	7.75	2.30%	52,863	3.54%	7,557,021	3.45%	142.95	-0.09%	463,914	3.72%
2008	52.2	2.30%	333,633	3.97%	2,586,733	4.00%	7.75	0.03%	54,687	3.39%	7,760,476	2.66%	141.91	-0.74%	480,100	3.43%
2009	56.5	2.29%	343,006	2.77%	2,691,700	3.98%	7.85	1.21%	55,995	2.36%	7,805,224	0.57%	139.39	-1.79%	500,832	4.23%
2010	25.8	1.44%	351,395	2.42%	2,732,204	1.49%	7.78	-0.92%	57,110	1.97%	7,897,864	1.18%	138.29	-0.79%	511,608	2.13%
2011	37.6	1.53%	359,075	2.16%	2,777,057	1.63%	7.73	-0.53%	58,098	1.72%	8,071,356	2.17%	138.93	0.46%	521,032	1.83%
2012	63.6	2.56%	366,422	2.03%	2,799,511	0.81%	7.64	-1.22%	59,226	1.92%	8,313,449	2.96%	140.37	1.03%	529,721	1.65%
2013	53.7	3.00%	374,579	2.20%	2,872,740	2.58%	7.67	0.38%	60,467	2.07%	8,393,967	0.96%	138.82	-1.11%	539,703	1.87%
2014	69.8	2.82%	383,792	2.43%	2,979,104	3.64%	7.76	1.21%	61,722	2.05%	8,383,229	-0.13%	135.82	-2.18%	550,857	2.05%
2015	94.6	1.94%	393,709	2.55%	2,989,285	0.34%	7.59	-2.21%	62,999	2.05%	8,108,212	-3.34%	128.70	-5.38%	562,135	2.03%
2016		1.64%	402,596	2.23%					63,980	1.55%					576,438	2.51%
2017		1.64%	411,685	2.23%					64,977	1.55%					591,108	2.51%
2018		1.80%	421,635	2.39%					66,092	1.70%					607,095	2.67%
2019		1.88%	432,165	2.47%					67,279	1.78%					624,005	2.75%
2020		1.83%	442,759	2.42%					68,457	1.74%					641,097	2.70%
2021		1.74%	453,172	2.32%					69,588	1.64%					658,018	2.61%
2022		1.67%	463,522	2.26%					70,690	1.57%					674,937	2.54%
2023		1.65%	474,008	2.24%					71,795	1.55%					692,145	2.52%
Average Annual Growth Rates:																
2005-2014		**2.41%**		**3.00%**		**3.44%**		**0.44%**		**2.31%**		**2.27%**		**-0.04%**		**3.28%**
2006-2015		**2.35%**		**2.88%**		**3.11%**		**0.23%**		**2.36%**		**1.55%**		**-0.80%**		**2.59%**
2018-2023		**1.76%**		**2.35%**		**N/A**		**N/A**		**1.66%**		**N/A**		**N/A**		**2.63%**

[1] Data are from http://calgary.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for Alberta, released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 residential and general service customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Alberta population is calculated for 2005-2015. Second, the projected Alberta population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecast number of customers for each year.

[4] Total includes all of the utility's customers.

Table 5c

Demand Trends of Alberta Energy Distributors: EDTI

Year	Demand Drivers: Edmonton Cooling Degree Days[1]	Demand Drivers: Edmonton Population Growth Rate[2]	Residential Customers[3] Level	Residential Customers[3] Growth Rate	Residential MWh Level	Residential MWh Growth Rate	Residential MWh/Customer Level	Residential MWh/Customer Growth Rate
2004	67.0		264,739		1,633,388		6.17	
2005	45.5	2.38%	272,092	2.74%	1,653,030	1.20%	6.08	-1.54%
2006	143.4	3.03%	280,795	3.15%	1,730,470	4.58%	6.16	1.43%
2007	139.4	2.71%	288,803	2.81%	1,812,794	4.65%	6.28	1.84%
2008	115.0	2.42%	294,627	2.00%	1,848,929	1.97%	6.28	-0.02%
2009	111.5	2.60%	298,533	1.32%	1,890,054	2.20%	6.33	0.88%
2010	61.2	1.75%	303,447	1.63%	1,905,023	0.79%	6.28	-0.84%
2011	55.8	1.84%	308,689	1.71%	1,925,708	1.08%	6.24	-0.63%
2012	120.8	2.73%	315,210	2.09%	1,960,505	1.79%	6.22	-0.30%
2013	83.0	3.36%	323,613	2.63%	2,014,497	2.72%	6.23	0.09%
2014	126.4	3.13%	332,484	2.70%	2,076,522	3.03%	6.25	0.33%
2015	151.8	2.09%	342,910	3.09%	2,084,920	0.40%	6.08	-2.68%
2016		1.81%	348,088	1.50%				
2017		1.83%	353,383	1.51%				
2018		1.99%	359,336	1.67%				
2019		2.03%	365,548	1.71%				
2020		2.01%	371,795	1.69%				
2021		1.91%	377,784	1.60%				
2022		1.85%	383,615	1.53%				
2023		1.83%	389,450	1.51%				
Average Annual Growth Rates:								
2005-2014		**2.59%**		**2.28%**		**2.40%**		**0.12%**
2006-2015		**2.57%**		**2.31%**		**2.32%**		**0.01%**
2018-2023		**1.94%**		**1.62%**		**N/A**		**N/A**

Year	Small Commercial Customers[3] Level	Small Commercial Customers[3] Growth Rate	Small Commercial MWh Level	Small Commercial MWh Growth Rate	Small Commercial MWh/Customer Level	Small Commercial MWh/Customer Growth Rate	Medium Commercial Customers[3] Level	Medium Commercial Customers[3] Growth Rate	Medium Commercial MWh Level	Medium Commercial MWh Growth Rate	Medium Commercial MWh/Customer Level	Medium Commercial MWh/Customer Growth Rate
2004	26,095		704,896		27.01		2,369		561,189		236.89	
2005	26,185	0.34%	718,107	1.86%	27.42	1.5%	2,442	3.03%	580,733	3.42%	237.81	0.39%
2006	26,464	1.06%	732,225	1.95%	27.67	0.9%	2,620	7.04%	643,846	10.32%	245.74	3.28%
2007	26,649	0.70%	748,287	2.17%	28.08	1.5%	2,769	5.53%	659,934	2.47%	238.33	-3.06%
2008	26,833	0.69%	753,028	0.63%	28.06	-0.1%	3,098	11.23%	691,049	4.61%	223.06	-6.62%
2009	27,024	0.71%	742,889	-1.36%	27.49	-2.1%	3,348	7.76%	689,473	-0.23%	205.94	-7.99%
2010	27,251	0.84%	740,439	-0.33%	27.17	-1.2%	3,510	4.73%	709,849	2.91%	202.24	-1.81%
2011	27,390	0.51%	745,899	0.73%	27.23	0.2%	3,672	4.51%	736,882	3.74%	200.68	-0.77%
2012	27,621	0.84%	755,211	1.24%	27.34	0.4%	3,928	6.74%	769,605	4.34%	195.93	-2.39%
2013	27,828	0.75%	753,886	-0.18%	27.09	-0.9%	4,280	8.58%	818,231	6.13%	191.18	-2.46%
2014	27,973	0.52%	756,936	0.40%	27.06	-0.1%	4,532	5.72%	853,729	4.25%	188.38	-1.47%
2015	28,096	0.44%	734,195	-3.05%	26.13	-3.5%	4,833	6.43%	870,253	1.92%	180.06	-4.51%
2016	28,072	-0.08%					5,117	5.71%				
2017	28,052	-0.07%					5,418	5.72%				
2018	28,076	0.09%					5,746	5.88%				
2019	28,113	0.13%					6,097	5.92%				
2020	28,144	0.11%					6,467	5.90%				
2021	28,148	0.01%					6,854	5.81%				
2022	28,133	-0.05%					7,259	5.74%				
2023	28,112	-0.07%					7,686	5.72%				
Average Annual Growth Rates:												
2005-2014		**0.69%**		**0.71%**		**0.02%**		**6.49%**		**4.20%**		**-2.29%**
2006-2015		**0.70%**		**0.22%**		**-0.48%**		**6.83%**		**4.04%**		**-2.78%**
2018-2023		**0.04%**		**N/A**		**N/A**		**5.83%**		**N/A**		**N/A**

Year	Small + Medium Commercial Customers[3] Level	Small + Medium Commercial Customers[3] Growth Rate	Small + Medium Commercial MWh Level	Small + Medium Commercial MWh Growth Rate	Small + Medium Commercial MWh/Customer Level	Small + Medium Commercial MWh/Customer Growth Rate	Total Customers[3,4] Level	Total Customers[3,4] Growth Rate
2004	28,464		1,266,085		44.48		296,961	
2005	28,627	0.57%	1,298,840	2.55%	45.37	1.98%	304,454	2.49%
2006	29,084	1.58%	1,376,071	5.78%	47.31	4.19%	313,502	2.93%
2007	29,418	1.14%	1,408,221	2.31%	47.87	1.17%	321,830	2.62%
2008	29,931	1.73%	1,444,077	2.51%	48.25	0.79%	328,168	1.95%
2009	30,372	1.46%	1,432,362	-0.81%	47.16	-2.28%	332,566	1.33%
2010	30,761	1.27%	1,450,288	1.24%	47.15	-0.03%	337,861	1.58%
2011	31,062	0.97%	1,482,781	2.22%	47.74	1.24%	343,396	1.62%
2012	31,549	1.56%	1,524,816	2.80%	48.33	1.24%	350,349	2.00%
2013	32,108	1.76%	1,572,117	3.05%	48.96	1.30%	359,192	2.49%
2014	32,505	1.23%	1,610,665	2.42%	49.55	1.19%	368,446	2.54%
2015	32,929	1.30%	1,604,448	-0.39%	48.72	-1.68%	379,294	2.90%
2016	33,189	0.79%					384,553	1.38%
2017	33,469	0.84%					389,930	1.39%
2018	33,822	1.05%					396,017	1.55%
2019	34,209	1.14%					402,373	1.59%
2020	34,611	1.17%					408,752	1.57%
2021	35,002	1.12%					414,832	1.48%
2022	35,392	1.11%					420,723	1.41%
2023	35,799	1.14%					426,604	1.39%
Average Annual Growth Rates:								
2005-2014		**1.33%**		**2.41%**		**1.08%**		**2.16%**
2006-2015		**1.40%**		**2.11%**		**0.71%**		**2.20%**
2018-2023		**1.12%**		**N/A**		**N/A**		**1.50%**

[1] Data are from http://edmonton.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for census division 11 (Edmonton), released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Edmonton population is calculated for 2005-2015. Second, the projected Edmonton population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecasted number of customers for each year.

[4] For the small + medium commercial customer category, customer number forecasts are the sum of the rate class-specific customer forecasts.

[5] Total includes all of the utility's customers.

Table 5d

Demand Trends of Alberta Energy Distributors: ENMAX

	Demand Drivers		Residential (& Farm)						Commercial (& Industrial)						Total	
Year	Calgary Cooling Degree Days[1]	Calgary Population Growth Rate[2]	Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	37.0		343,600		2,359,053		6.87		35,024		5,596,132		159.78		378,624	
2005	16.5	3.28%	352,385	2.52%	2,406,165	1.98%	6.83	-0.55%	35,506	1.37%	5,787,254	3.36%	162.99	1.99%	387,891	2.42%
2006	65.5	3.32%	363,856	3.20%	2,490,381	3.44%	6.84	0.24%	35,319	-0.53%	6,014,019	3.84%	170.28	4.37%	399,175	2.87%
2007	68.8	2.73%	376,767	3.49%	2,634,137	5.61%	6.99	2.13%	31,082	-12.78%	6,105,847	1.52%	196.44	14.29%	407,849	2.15%
2008	52.2	2.77%	385,031	2.17%	2,691,101	2.14%	6.99	-0.03%	32,282	3.79%	6,209,525	1.68%	192.35	-2.10%	417,313	2.29%
2009	56.5	2.84%	390,774	1.48%	2,745,805	2.01%	7.03	0.53%	32,814	1.63%	6,164,116	-0.73%	187.85	-2.37%	423,588	1.49%
2010	25.8	1.82%	397,761	1.77%	2,756,791	0.40%	6.93	-1.37%	33,370	1.68%	6,256,824	1.49%	187.50	-0.19%	431,131	1.77%
2011	37.6	1.89%	403,199	1.36%	2,821,254	2.31%	7.00	0.95%	33,936	1.68%	6,385,752	2.04%	188.17	0.36%	437,135	1.38%
2012	63.6	3.26%	410,179	1.72%	2,830,473	0.33%	6.90	-1.39%	34,437	1.47%	6,506,354	1.87%	188.93	0.41%	444,616	1.70%
2013	53.7	3.63%	419,199	2.18%	2,903,992	2.56%	6.93	0.39%	34,937	1.44%	6,466,483	-0.61%	185.09	-2.06%	454,136	2.12%
2014	69.8	3.43%	428,326	2.15%	2,936,869	1.13%	6.86	-1.03%	35,343	1.16%	6,561,393	1.46%	185.65	0.30%	463,669	2.08%
2015	94.6	2.39%	435,644	1.69%					35,195	-0.42%					470,753	1.52%
2016		2.06%	441,650	1.37%					34,934	-0.74%					476,395	1.19%
2017		2.00%	447,464	1.31%					34,654	-0.81%					481,809	1.13%
2018		2.16%	454,099	1.47%					34,432	-0.64%					488,085	1.29%
2019		2.24%	461,157	1.54%					34,236	-0.57%					494,791	1.36%
2020		2.13%	467,828	1.44%					34,005	-0.68%					501,057	1.26%
2021		2.00%	473,965	1.30%					33,731	-0.81%					506,729	1.13%
2022		1.92%	479,822	1.23%					33,433	-0.89%					512,078	1.05%
2023		1.89%	485,591	1.20%					33,128	-0.92%					517,315	1.02%
Average Annual Growth Rates:																
2005-2014		**2.90%**		**2.20%**		**2.19%**		**-0.01%**		**0.09%**		**1.59%**		**1.50%**		**2.03%**
2006-2015		**2.81%**		**2.12%**		**N/A**		**N/A**		**-0.09%**		**N/A**		**N/A**		**1.94%**
2018-2023		**2.06%**		**1.36%**		**N/A**		**N/A**		**-0.75%**		**N/A**		**N/A**		**1.19%**

[1] Data are from http://calgary.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for census division 6 (Calgary), released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2015-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Calgary population is calculated for 2005-2014. Second, the projected Calgary population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecasted number of customers for each year.

[4] Total customers includes all of the utility's customers except for lighting customers (which are not reported on the company's Rule 005 filings).

different. Brattle and LRCA are therefore advocating basing the X factor for Alberta power distributors on the recent trend in an MFP index that is particularly sensitive to declining R&C average use trends in the US. Meanwhile, R&C average use trends in Alberta may very well rise prospectively.

How might considerations of volume trends be included in the X factor calibration procedure?

I showed on pp. 45-46 of my direct testimony that the trend in an MFP index constructed using a revenue-weighted output index can be decomposed into the trend in a cost efficiency index (i.e., a productivity index using the number of customers to measure output) and an output differential. It is then possible to base X factors for Alberta power distributors on the trends in MFP of US power distributors that use the number of customers to measure output and an Alberta-specific output differential. I have used this methodology in work for several clients, including several utilities. Our evidence suggests that if such an adjustment were undertaken for the Alberta utilities it would, if anything, *raise* the X factors by a modest amount.

Consideration of volume trends can be sidestepped by using *revenue* cap indexes for the power distributors in Alberta, as is done for the gas distributors. This facilitates the additional step of instituting revenue decoupling sometime during next generation PBR or in later years. The combination of revenue caps and revenue decoupling is used for electric utilities in a number of American states, including California, Idaho, Massachusetts, Maryland, Minnesota, New York, and Washington. A central appeal of this combination is its ability to remove the disincentive utilities have to aggressively promote demand-side management.

What is your concern about administrative, general, and meter reading costs?

Administrative, general, and meter reading expenses are an important part of the O&M expenses addressed by the I-X escalator in Alberta. These expenses should, accordingly, be included in the study if a sensible means can be found to allocate the A&G expenses. PEG has developed a sensible allocation method that is based on the share of distribution services in the sum of O&M expenses allocated to the various utility functions. The sensitivity of results to the method for allocating costs diminishes as the era of restructuring recedes in the rear view mirror. It is therefore preferable to include these additional expenses in the MFP study.

What is your concern about the use of the GDPPI as an inflation measure for M&S inputs?

NERA, Brattle, LRCA, and PEG all use the residual approach to measure trends in M&S inputs. The general formula used is

$$\textit{trend Inputs}^{M\&S} = \textit{trend Expenses}^{M\&S} - \textit{trend Price Index.} \qquad [2]$$

The accuracy of the approach depends on the accuracy of the price index employed as a measure of M&S input price trends. In its gas productivity study for the CCA in ID 566, PEG used a sophisticated M&S price index constructed from detailed price indexes for utility M&S inputs purchased (or, more accurately rented) from the *Power Planner* service of Global Insight. However, the AUC indicated a preference in Decision 2012-237 for the use of publicly available data in productivity studies. In this proceeding, PEG has therefore used a custom M&S price index it constructed from producer price indexes. The design is similar to that of the Global Insight price indexes we previously used.

NERA, Brattle, and LRCA have instead used the GDPPI to deflate M&S expenses. This is the federal government's featured measure of inflation in the prices of the economy's final goods and services. Its use is problematic in this application for several reasons.

- The GDPPI places much larger weights on products like food, gasoline, and capital goods than are appropriate for the M&S product basket.
- As a measure of output prices, the GDPPI also reflects the oftentimes substantial growth in the MFP of the US economy. It therefore tends to underestimate the trend in the economy's *input* prices.
- Over PEG's full 1997-2014 sample period, the average annual growth rate of our custom M&S input price index exceeded that of the GDPPI by 23 basis points. Thus, the use of the GDPPI as the deflator for M&S expenses would tend to *over*state M&S quantity growth and *under*state MFP growth.

What evidence can you present that the methodological upgrades you propose are quantitatively important?

We started with the corrected NERA/Utilities methodology and then added methodological upgrades in the areas I have discussed. These results are also presented in Table 2. Please note the following.

- Raising the average service life to 37 years raised MFP growth by a remarkable 47 basis points for the full sample period, 61 basis points for the 1997-2014 period, and 64 basis points for the five most recent years. Even if the AUC for some reason prefers a 33-year service life, it should be concerned about how sensitive the results from the one hoss shay approach are to the service life assumption.

- Switching next to geometric decay with a 37-year service life *slowed* MFP growth modestly. Growth was down 39 basis points for the full sample period and 40 basis points for the 1997-2014 sample period but was up 5 basis points for the last five years. It is also important to note that when GD is assigned a 33-year service life, the MFP trends change little and are far above the results obtained using one hoss shay and a 33-year service life. Thus, a decision to EITHER adopt the geometric decay approach that Dr. Meitzen routinely uses OR extend the average service life (or do BOTH) has a major impact on the estimated MFP trend and produces a trend for recent years that is positive (though close to zero) in recent years.

- At this point in our sequence it is possible to correct for the mergers and the "Mississippi mismatch" I discussed above. Correcting for these data problems had a small 5 to 6 basis point effect on the MFP trends.

- For NERA's lengthy full sample period, we unfortunately do not know the impact of replacing the volumetric index (with corrected volume data) with the total number of customers as the output index, since customer data have not been gathered (apparently by any consultant) for the earlier years of NERA sample period. We would expect the MFP trend to fall, since R&C average use rose between 1974 and 1996. For the 1997-

2014 period, using the total number of customers accelerates MFP growth by only 3 basis points. For the five most recent years, however, it accelerates MFP growth by 5 basis points. Thus, for the most recent years a switch from the uncorrected volume index used by NERA and the Utilities to the number of customers raises the MFP trend by a substantial 29 basis points. (24 + 5 = 29)

Since use of the number of customers rather than the corrected volumetric index has little impact over the 1997-2014 sample period, why is its use nonetheless preferable?

In a nutshell, modestly *positive* growth in R&C average use before 2008 was offset by modestly *negative* growth after 2008. For this reason the number of customers and corrected volumetric index yield similar results and there is no real harm in using the number of customers for this sample period. However, when a corrected volumetric index is used, it will reflect modest *growth* in R&C average use before 2008 and a modest *decline* in average use going forward. This will incentivize utility witnesses in future proceedings to focus on the latest MFP results, and discourage a focus on results for earlier years. Note also that results for the full sample period reflect the many years of modest growth in average use that occurred before 2008. Due to their use of revenue per customer caps, this is irrelevant to the calculation of gas distributor X factors.

When all of these data corrections and upgrades are made, how do the results compare with those from your own research?

To make this comparison, I first calculated results using PEG's code and the sample of common companies with good data. To enhance comparability, I also chose a 37-year service life for distribution plant, excluded general costs and meter reading expenses, and used GDPPI as the M&S price index rather than our own custom index. With these changes, MFP growth averages 25 basis points for the 1997-2014 period and 22 basis points for the last five years of the sample. This is similar to the 18 basis points for the 1997-2014 period and the 17 basis point average for the final five years using the corrected and upgraded NERA/Utilities methodology. Results still differ due to the combined effect of several additional small upgrades in our methodology.

What is the impact of adding general costs and meter reading expenses, expanding the sample, and using the custom M&S price index?

The MFP growth trend for the full sample rises by 18 basis points for the 1997-2014 sample period to 0.43%. The MFP growth trend for the final five years rises from 22 basis points to 0.31%. Note there is no slowdown in the final five years.

The Commission could use the results you have provided for the upgraded NERA/Utilities methodology rather than the results from your own research. What are the advantages of PEG's research as the basis for X factors in next-generation Alberta PBR?

There are, first of all, the advantages to using our considerably larger sample, the custom M&S price index, and general cost and meter reading expenses. There are a number of small additional advantages.

- Regionalized labor price indexes are used to calculate labor quantity trends.
- The residual approach is used to calculate the labor quantity trend throughout the sample period.
- Since the four Alberta power distributors are small by US standards, a simple average of the productivity trends of sampled US power distributors is more relevant than a size-weighted average.

The combined effect of all of these upgrades on the MFP growth trend is appreciable. Using our approach will also liberate the Commission from continuing to base X factors on a methodology with many flaws.

You mentioned above that the NERA/Utilities method for calculating the labor quantity index is substandard even when corrected. Please explain.

It is suboptimal to calculate the *distribution* labor quantity in the early years of the full sample period as a share of the *total* labor quantity, for several reasons.

- The NERA/Utilities method essentially estimates the trend in the *total* number of employees rather than the trend in distribution *O&M* employees, which is what we care about. The total number of employees includes construction employees, which are counted implicitly in the capital quantity index.

- The trend in the *total* number of employees does not take account of changes in the *composition* of employees over time.

- The NERA/Utilities method uses the share of distribution salaries and wages in *total* salaries and wages.[15] Total salaries and wages includes an allocation to clearing accounts. In other words, the denominator includes expenses that have not been allocated to a utility function (generation, transmission, etc.). The distribution share is thus understated.

All of these problems can be sidestepped by using the residual approach set forth in equation [1] in *all* years of the sample period, as PEG did in its research for the CCA. I should also note that in our application of the residual method we regionalize the labor price trend.

Some of the productivity research methods you propose for X factor calibration seem tailored to the circumstances of Alberta utilities. Do you often customize your productivity research methods to be relevant to the utilities to which they apply?

Yes. For example, I tend to consider *revenue*-weighted output indexes that include volumes by *some* means when utilities will likely be subject to *price* caps, and the number of customers when they are likely to be subject to *revenue* caps. In work for utilities in the northeast United States, I have throughout my career tended to use northeast utility peer groups.

[15] They could instead have used the share of distribution salaries and wages in the sum of all salaries and wages *assigned directly to utility functions*.

I have in recent years featured the COS approach to measuring capital cost in my US research and testimony. This reflects the fact that US utilities often propose *macroeconomic* inflation measures such as the GDPPI in the rate (or revenue) cap escalator. This raises the issue of how well these measures track input price trends of utilities. The COS approach to measuring capital cost sheds more light on this issue than the GD or one hoss shay approaches. In this proceeding, I have instead featured the GD approach because a more customized measure is more likely to be used for inflation in next generation PBR, and the GD approach is simpler and easier for other parties to review. In future proceedings, MFP calculations using GD can be presented on a spreadsheet if parties so desire.[16]

Are there other reasons why your methodology may change from time to time?

Yes. My opinions concerning best practices in X factor calibration have naturally evolved over the years. For example, I now use a custom M&S price index rather than the GDPPI when calculating the M&S quantity trend. I have greater appreciation for the usefulness of the GD approach to capital costing in Canadian proceedings.

This Commission ruled in paragraph 337 of Decision 2012-237 that "the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta." Why then have you tried to customize your approach to X factor calibration in this proceeding?

My reading of this paragraph is that the Commission felt that business conditions that were different in Alberta but affected the *level* of costs rather than their *trends* were not grounds for X factor customization, and I generally agree. However, some business conditions may be unusual in Alberta that affect productivity *trends*. Or, as in the case of the

[16] We did not do this in this proceeding because the COS approach to capital costing is also used and is more difficult to place on a spreadsheet.

NERA/Utilities assumption of a 33-year service life, a methodology may for some reason fail to account for the fact that Alberta business conditions are *normal.* In that event, customization is appropriate if it is not unduly complicated.

The Commission stated in the very next paragraph of D. 2012-237 that "The relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities but ... whether the US industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies." The Commission goes on to say in paragraph 342 that the productivity trend of the US power distribution industry is a reasonable "*starting point*" for setting an Alberta X factor [italics added]. I should also note that Principle 4 on the Commission's list for PBR plan design is "A PBR plan should recognize the unique circumstances of each regulated Company that are relevant to a PBR design."

What positions have the other expert witnesses in this proceeding taken on the customization issue?

Their positions have varied considerably. Dr. Meitzen has strongly asserted that the X factor should reflect the *industry* productivity trend. He stated in response to Meitzen-CCA/PEG-004, for example, that "The X factor should represent industry trends, irrespective of particular company circumstances." On the other hand, Brattle stated in response to question Brattle-CCA/PEG 3 (c) that, “If the industry itself is changing in the US in a way that it is not changing in Alberta, then a trend measured in the US may be irrelevant to Alberta.” Brattle stated in response to Brattle-CCA/PEG-006 that "the X factor should reflect the utility's prospects for the plan term so that the revenues delivered by the plan are consistent with the utility's expected costs."

Dr. Weisman also argued in favor of a customized X factor. He stated in response to Weisman-CCA/PEG-015 (b) that "the X factor applied to a regulated firm should be based on a representative peer group of firms. To the extent that the unique circumstances of the regulated firm are expected to lead to changes in productivity growth it would be necessary to take these into account." He stated in response to Weisman-CCA/PEG-016 that "The X factor for Alberta utilities should be based on a representative peer group. If it is not, then the X factor would not provide the proper 'competitive benchmark' called for in AUC PBR Principle 1."

Are there other arguments in favor of customized X factors?

Yes. One is that customization has been quite common in PBR. X factors based on productivity trends in the Northeast United States have been favored by utilities and regulators alike in that region. The X factor for power distributors in Ontario currently reflects the productivity trends of Ontario distributors. In Alberta, Dr. Makholm of NERA proposed a western peer group in his productivity study to calibrate the X factor in an early PBR proposal for Utilicorp Networks Canada.[17] Data are still available for a sizable western peer group and I include one in the results I present below.

Please provide your final recommendations concerning the base productivity trend.

Our final MFP index results for the full sample feature a 37-year service life for distribution assets and are detailed in Table 6a. It can be seen that MFP growth averaged 0.43% over the full sample period. Capital productivity growth averaged 0.26% whereas O&M productivity growth averaged 0.76%.

Analogous results using the alternative COS approach to measuring capital cost are detailed in Table 6b. It can be seen that MFP growth averaged 0.56% over the full sample period. Capital productivity growth averaged 0.51% whereas O&M productivity growth averaged 0.76%. In contrast to the utility witnesses, we thus provide some assurance that the results using our featured method of measuring capital cost are robust.

The analogous results using GD for the *rapid growth* sample outlined in our direct testimony are detailed in Table 6c. It can be seen that MFP growth averaged 0.78% over the

[17] The testimony itself was provided in response to EDTI-NERA-1 (Exhibit 198.01) in Proceeding 566.

Table 6a
US Power Distribution Productivity Trends: Full Sample with Geometric Decay Depreciation

Year	Output	Input	Productivity		
			O&M	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	1.44%	-0.11%	3.84%	0.60%	1.54%
1998	1.56%	2.71%	-5.64%	0.59%	-1.15%
1999	0.83%	0.08%	1.54%	0.39%	0.75%
2000	1.55%	0.61%	1.77%	0.57%	0.94%
2001	1.79%	0.86%	1.11%	0.84%	0.93%
2002	1.28%	-0.40%	4.52%	0.36%	1.68%
2003	0.75%	2.25%	-5.29%	0.01%	-1.50%
2004	1.11%	-0.26%	3.65%	0.40%	1.38%
2005	1.27%	0.12%	2.62%	0.42%	1.15%
2006	0.50%	0.53%	-0.03%	-0.05%	-0.04%
2007	1.06%	1.10%	-0.16%	0.21%	-0.04%
2008	0.56%	0.86%	-0.43%	0.04%	-0.31%
2009	0.25%	-0.51%	3.26%	-0.32%	0.76%
2010	0.41%	0.09%	0.29%	-0.04%	0.32%
2011	0.29%	-0.18%	0.73%	0.11%	0.47%
2012	0.57%	-0.50%	2.24%	0.61%	1.07%
2013	0.30%	0.41%	1.11%	-0.48%	-0.11%
2014	0.65%	0.83%	-1.52%	0.42%	-0.18%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.47%**	**0.76%**	**0.26%**	**0.43%**
1997-2007	**1.19%**	**0.68%**	**0.72%**	**0.39%**	**0.51%**
2008-2014	**0.43%**	**0.14%**	**0.81%**	**0.05%**	**0.29%**

[1]Annual growth rates are calculated logarithmically.

Table 6b-Revised

US Power Distribution Productivity Trends: Full Sample with Cost-of-Service Depreciation

			Productivity		
Year	**Output**	**Input**	**O&M**	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	1.44%	-0.43%	3.84%	0.91%	1.87%
1998	1.56%	2.41%	-5.64%	1.45%	-0.85%
1999	0.83%	0.03%	1.54%	0.35%	0.80%
2000	1.55%	0.46%	1.77%	0.74%	1.09%
2001	1.79%	0.71%	1.11%	1.20%	1.08%
2002	1.28%	-0.84%	4.52%	0.86%	2.12%
2003	0.75%	2.23%	-5.29%	0.29%	-1.47%
2004	1.11%	-0.49%	3.65%	0.50%	1.60%
2005	1.27%	-0.16%	2.62%	0.91%	1.43%
2006	0.50%	0.71%	-0.03%	-0.24%	-0.21%
2007	1.06%	0.65%	-0.16%	0.64%	0.41%
2008	0.56%	0.79%	-0.43%	-0.05%	-0.24%
2009	0.25%	-0.42%	3.26%	0.05%	0.67%
2010	0.41%	-0.31%	0.29%	0.93%	0.72%
2011	0.29%	-0.12%	0.73%	0.38%	0.41%
2012	0.57%	-0.05%	2.24%	-0.19%	0.62%
2013	0.30%	0.04%	1.11%	0.06%	0.26%
2014	0.65%	0.90%	-1.52%	0.43%	-0.26%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.34%**	**0.76%**	**0.51%**	**0.56%**
1997-2007	**1.19%**	**0.48%**	**0.72%**	**0.69%**	**0.71%**
2008-2014	**0.43%**	**0.12%**	**0.81%**	**0.23%**	**0.31%**

[1]Annual growth rates are calculated logarithmically.

Table 6c
US Power Distribution Productivity Trends:
Rapid Growth Sample with Geometric Decay Depreciation

			Productivity		
Year	**Output**	**Input**	**O&M**	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	2.63%	0.15%	7.25%	0.73%	2.48%
1998	2.78%	3.58%	-4.53%	0.12%	-0.80%
1999	2.44%	1.66%	1.73%	0.46%	0.78%
2000	2.33%	1.46%	2.06%	0.52%	0.87%
2001	2.04%	0.54%	4.35%	0.17%	1.50%
2002	2.10%	0.12%	6.92%	-0.24%	1.98%
2003	2.12%	5.06%	-11.24%	0.22%	-2.94%
2004	2.10%	0.96%	3.13%	0.09%	1.14%
2005	2.73%	2.24%	0.30%	0.62%	0.49%
2006	1.81%	1.42%	0.69%	0.26%	0.39%
2007	2.00%	0.79%	2.25%	0.60%	1.21%
2008	1.10%	-0.88%	4.66%	0.11%	1.98%
2009	0.53%	-1.42%	4.88%	-0.18%	1.96%
2010	0.49%	0.86%	-1.09%	-0.05%	-0.37%
2011	0.51%	-0.23%	1.61%	0.64%	0.74%
2012	0.73%	-0.78%	4.88%	0.58%	1.51%
2013	1.01%	0.29%	-1.47%	1.21%	0.72%
2014	1.19%	0.73%	-1.47%	1.23%	0.46%
Average Annual Growth Rates					
1997-2014	**1.70%**	**0.92%**	**1.38%**	**0.39%**	**0.78%**
1997-2007	**2.28%**	**1.64%**	**1.17%**	**0.32%**	**0.65%**
2008-2014	**0.79%**	**-0.21%**	**1.71%**	**0.51%**	**1.00%**

[1]Annual growth rates are calculated logarithmically.

full sample period. Capital productivity growth averaged 0.39% whereas O&M productivity growth averaged 1.38%.

The analogous results using GD for the *Mountain West* sample identified in our direct testimony are detailed in Table 6d. It can be seen that MFP growth averaged 0.86% over the full sample period. Capital productivity growth averaged 0.36% whereas O&M productivity growth averaged 1.57%.

We recommend basing the X factor for the Alberta distributors on our GD results for the rapid growth sample over the full 1997-2014 sample period for which we have gathered data. There are strong arguments for considering scale economies, and we are not considering the rising R&C average use trends of Alberta power distributors. The Commission may also wish to consider the 1.28% trend in the corrected and upgraded NERA/Utilities MFP indexes for the *full* 1973-2014 sample period, which we report in Table 2 using the common sample, data corrected for mergers, a volumetric index, a 37-year service life, and geometric decay.

Have other witnesses in this proceeding acknowledged that opportunities to realize scale economies are an important driver of productivity growth?

Yes. Dr. Meitzen, for example, stated in response to Meitzen-CCA/PEG-005 that

> Economies of scale are one determinant of a utility's TFP growth. In addition, as other research has shown, economies of density and capacity utilization are important sources of TFP growth in network industries.

2.2 Stretch Factor

Let's turn now to your concerns about the stretch factor recommendations of the utilities and their witnesses.

All of the utilities and Brattle proposed in their direct testimony to eliminate stretch factors. Brattle stated in response to question 70 in their testimony that "it would not be reasonable to anticipate additional cost savings over and above those implicitly assumed in the X factor because the distribution utilities in Alberta have been operating under PBR for some

Table 6d

US Power Distribution Productivity Trends: Mountain West Sample with Geometric Decay Depreciation

Year	Output	Input	Productivity		
			O&M	Capital	Mult-Factor
	[A]	[B]			[C=A-B]
1997	2.84%	1.02%	6.31%	0.00%	1.82%
1998	2.58%	3.38%	-0.25%	-0.98%	-0.81%
1999	2.57%	1.69%	3.83%	-0.05%	0.87%
2000	2.54%	0.93%	3.53%	1.04%	1.61%
2001	2.29%	0.24%	3.78%	0.33%	2.05%
2002	2.07%	-1.28%	13.27%	-1.20%	3.36%
2003	2.49%	5.50%	-13.79%	0.76%	-3.01%
2004	2.17%	3.36%	-4.77%	0.07%	-1.19%
2005	3.47%	1.38%	4.25%	1.00%	2.09%
2006	1.58%	1.06%	1.10%	0.52%	0.51%
2007	2.25%	0.39%	2.35%	1.43%	1.86%
2008	1.27%	0.35%	2.29%	-0.17%	0.92%
2009	0.77%	-0.99%	4.55%	-0.55%	1.76%
2010	0.67%	0.11%	1.86%	-0.04%	0.56%
2011	0.55%	-0.11%	1.24%	0.76%	0.66%
2012	0.82%	0.49%	1.35%	0.43%	0.33%
2013	1.12%	0.82%	-5.35%	1.62%	0.30%
2014	1.27%	-0.54%	2.80%	1.54%	1.82%
Average Annual Growth Rates					
1997-2014	**1.85%**	**0.99%**	**1.57%**	**0.36%**	**0.86%**
1997-2007	**2.44%**	**1.61%**	**1.78%**	**0.27%**	**0.83%**
2008-2014	**0.92%**	**0.02%**	**1.25%**	**0.51%**	**0.91%**

[1]Annual growth rates are calculated logarithmically.

time." [footnote removed] When asked in Brattle-CCA/PEG-017 if there are precedents for stretch factors in next generation PBR, they answered that "Dr. Brown and Dr. Carpenter are aware of few if any precedents that are directly relevant, given the unique nature of Alberta PBR plans and the circumstances of the Alberta utilities."

Drs. Meitzen and Weisman noted in their testimony that there are arguments for lowering the stretch factor in second-generation PBR. In response to CCA information requests, however, both endorsed zero stretch factors. Dr. Weisman stated in response to EDTI-AUC-014 that "It was perhaps most common in incentive regulation plans in the telecommunications industry to eliminate the stretch factor in second- and subsequent-generation incentive regulation plans."

How do you respond?

Convincing evidence has not been presented that Alberta utilities are superior cost performers. However, the large supplemental revenue requested for capital suggests a serious decline in capital productivity. Hence, the continuation of positive stretch factors appears to be a "no brainer." I made several arguments in favor of continued stretch factors in my direct testimony and venture some additional arguments here.

I stated in my 2011 direct testimony in AUC ID 566 that the stretch factor for Alberta power distributors should lie in the interval [0.13, 0.50].[18] The upper bound of this interval was the average of the itemized stretch factors in the PBR plans of North American energy utilities which had been approved up to that time. The lower bound was drawn from PEG's incentive power research.

Please elaborate on your incentive power research.

[18] AUC Proceeding 566, Exhibit 307.01, p. 64.

PEG has developed an incentive power model that estimates the typical cost performance improvements that will be achieved by utilities under alternative, stylized regulatory systems. Results can be obtained for companies at various levels of initial operating efficiency. Clients who have supported the development of this model include the Ontario Energy Board and US and Canadian gas distributors. I provided working papers on our research to the Brattle group in response to a data request in Proceeding ID 566.

The model sheds light on how cost performance is likely to improve in Alberta under PBR. At the onset of PBR, Alberta energy distributors had been operating for many years under a two-year rate case cycle. There were no earnings sharing mechanisms. I assumed that this regulatory system would be replaced with one with a five-year rate case cycle and an earnings sharing mechanism.

Based on my experience, I believe that US energy distributors typically hold rate cases about every three years. Earnings sharing mechanisms are uncommon. Assuming a normal level of operating efficiency, the incentive power model indicated that the stronger performance incentives of a three-year rate case cycle would generate 24 basis points of average annual performance gains in the long run. Thus, customers would benefit from more rapid productivity growth just by basing X on the peer group productivity trend. The model also indicated that the long run annual average performance gain under Alberta PBR would be 27 basis points higher than the norm under American regulation. Half of 27 basis points is about 13 basis points, the lower bound of my range of reasonableness.

How might this analysis be adopted to evaluate the need for stretch factors in second generation PBR?

Note first that the average itemized stretch factor in approved PBR plans for North American energy utilities has fallen modestly since my 2011 survey to 0.42%, as shown on Table 6 of my direct evidence. As for the incentive power research, the AUC ultimately chose a system with a five-year term that *excludes* earnings sharing but *includes* an efficiency carryover mechanism (“ECM”) and a capital tracker. The incentive power result for a five-year plan with earnings sharing should be a reasonable proxy for the result under the current system.

Utility witnesses have argued that one round of PBR is likely to have eliminated the "low-hanging fruit" of inefficiencies. The incentive power model sheds light on this issue. Note first that the model indicated a 27 basis point acceleration in the average annual performance gain under PBR in the *long* run relative to the norm for the productivity peer group, not in the first plan period. For the first two PBR plan periods, the model indicated that the average annual performance gain would rise by 39 basis points.

What are the precedents for second-generation stretch factors?

Stretch factors have been included in a number of second generation or later PBR plans for energy utilities, including those of Boston Gas, the FortisBC utilities, and Ontario power distributors. Three generations of PBR plans for Ontario have included a stretch factor, including the current plan. The OEB explained why it continues to include stretch factors in PBR plans in a decision on fourth-generation PBR, stating that:

> The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.[19]

Stretch factor assignments in the 3rd and 4th generation Ontario power distribution PBR plans have been updated annually to reflect company performance in cost benchmarking studies. These benchmarking studies began as assessments of *O&M* cost performance in the Ontario 3rd generation PBR plan and were expanded to assess *total* cost performance in the Ontario 4th generation PBR plan.

[19] Ontario Energy Board (2013), EB-2010-0379, *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* issued on November 21, 2013 and as corrected on December 4, 2013, p. 18-19.

Similarly, after several generations of PBR plans, the British Columbia Utilities Commission approved stretch factors of 0.2% for FortisBC Energy Inc. (formerly Terasen Gas) and 0.1% for FortisBC (formerly West Kootenay Power) for their current plans. The Commission also endorsed the possibility of including stretch factors in future generations of PBR plans that are based on benchmarking evidence. The Commission believed that there was

> a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.** [20] [Emphasis in original]

In contrast to the opposition to stretch factors by all utility witnesses in this proceeding, I have advocated the inclusion of stretch factors in second generation or later PBR plans in testimony for several utility clients.[21] Dr. Meitzen's colleague Dr. Philip Schoech has also advocated a positive stretch factor for a utility client. The following exchange occurred in oral testimony when he was a witness for Union Gas, a large Ontario gas utility.

> MR. THOMPSON You came up with a stretch factor of 0.4%. That's your recommendation. Is that right?
>
> MR. SCHOECH Yes, we determined that that was a reasonable stretch factor.
>
> MR. THOMPSON And what did you consider in coming up with that number?
>
> MR. SCHOECH Well, as my colleague indicated, it is a subjective number. I guess what we did was we looked at the way the stretch factor had been addressed in other jurisdictions. It seemed that a range of 0.25 to, say, 0.75 was reasonable. And the discussions with Union led us

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[20] British Columbia Utilities Commission (2014), *Decision,* In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 96.

[21] See, for example, my X factor recommendations for Central Maine Power in 2007 and Gaz Metro in 2012. These recommendations were detailed in CCA-EDTI Attachment 1b.

> to the position where we found 0.4% an acceptable stretch factor — a recommended stretch factor, I might add.[22]

Telecommunications precedents are also of interest given the opposition of Drs. Weisman and Meitzen, who are experts in the field of telecom PBR, to the imposition of a stretch factor for their client, EDTI. While we have never done a full survey of telecom PBR precedents, several examples of second-generation stretch factors were identified with very little work.

- The US Federal Communications Commission approved stretch factors in second-generation PBR plans for AT&T and the interstate services of incumbent local exchange carriers.[23]
- The Illinois Commerce Commission approved a second-generation stretch factor in 2002 for Ameritech Illinois (formerly Illinois Bell), a large local exchange carrier. The proceeding apparently involved Dr. Meitzen. The Commission stated in its decision that

> AI in its Briefs seems to suggest that under the Plan, ratepayers were only to receive a consumer dividend for the first term of the plan. The implication therefore is that once the original term of the plan expired, so to would the consumer dividend. We reject this implication. Ratepayers are to receive the first cut from any improvements which arise from technological and regulatory change under the original term of the Plan and just as importantly any modification or extension thereof.[24]

It should also be noted that the lack of an explicit stretch factor in many second generation PBR plans does not necessarily indicate commission disapproval of the notion since

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[22] Hearing Volume 6, Ontario Energy Board Docket RP-1999-0017, June 2000.

[23] Federal Communications Commission, FCC 93-326, Report Adopted June 24, 1993 in CC Docket 92-134. Federal Communications Commission, FCC 97-159, Fourth Report and Order Adopted May 7, 1997, in CC Dockets, 94-1 and 96-262. The latter decision was subsequently overturned by the US Court of Appeals for the District of Columbia Circuit in 1999.

[24] December 30, 2002 order in Illinois Commerce Commission case 00-0764, p. 100.

X factors in many second generation plans were the outcomes of settlements. For example, the three approved price cap plans of Central Maine Power ("CMP") were all resolved with Commission-approved settlements. These settlements set an explicit value for the overall X factor, referred to in Maine as a productivity offset, without identifying specific values for a productivity differential, input price differential, stretch factor, output differential, or any other possible components of an X factor. Nevertheless, stretch factors were frequently discussed in these proceedings. In the proceeding leading to the most recently approved price cap plan, Dr. Lowry, as a witness for CMP, recommended a stretch factor of 0.4%.

Based on this evidence, we believe that continuation of the current 0.20% stretch factor is prudent. Statistical benchmarking can yield stretch factors that are specific to each company's level of operating efficiency. A 0% stretch factor should be reserved for companies that score well in credible independent benchmarking studies.

Has Dr. Weisman commented on the potential role of statistical benchmarking in utility regulation?

Yes. He was a witness in a PBR proceeding in which I provided statistical benchmarking evidence on behalf of the same client, AmerenUE, in 2002. In an article coauthored with Dr. Sappington, he commented in 1994 that

> Basing the firm's compensation on performance measures that are relative to those of similar firms can serve an analogous role. The performance of other firms that operate in similar environments can sometimes serve as a benchmark against which to assess the regulated firm's performance. (Recall also that yardstick competition of this type has been proposed for natural gas pipelines.) When the regulated firm in question is shown to perform better than other firms in comparable settings, evidence of greater diligence or ingenuity on the part of the regulated firm is provided. Such evidence can help to justify enhanced compensation for the firm. Of course, it is critical that the comparison group of firms be carefully selected. Observed differences in performance must be due to differences in diligence or ingenuity, not to exogenous environmental differences, if

they are to motivate the regulated firm and enhance perceptions of fairness. [25]

The incentives yielded by the current regulatory system are one issue in deciding whether the stretch factor should be continued. What then of Dr. Weisman's comment in response to EDTI-AUC-014 that "the Commission's scrutiny of these capital tracker applications is the antithesis of the proverbial 'rubber stamp' that the intervenors seem to think is the *modus operandi* underlying the Commission's analysis, deliberations and decisions?"

This is one of several complaisant remarks Dr. Weisman has made in his evidence to avoid hard truths that inconvenience his client. In reality, it is very difficult for any Commission to render decisions concerning optimal distribution investment policies. Decisions concerning deferrable capex are especially difficult. The supplemental revenue obtained from trackers has been enormous. If capital trackers with substantially full true ups to actuals don't seriously weaken utility performance incentives, why was there any need for the AUC to abandon biennial rate cases in the first place?

3. Capital Trackers

Turning next to the issue of capital trackers, all of the utilities have argued for their continued need in next generation PBR. What are your views?

We believe that a system of PBR that features I-X attrition relief mechanisms based on industry cost trends may occasionally require supplemental revenue to compensate utilities for needed capex surges. Capital trackers can provide this revenue, thereby reducing utility operating risk and facilitating their operation under PBR.

Trackers also have notable disadvantages and implementation challenges.

- Trackers raise regulatory cost and weaken capex containment incentives.

[25] Sappington, David, and Weisman, Dennis, "Designing Superior Incentive Regulation; Modifying Plans to Preclude Recontracting and Promote Performance," *Public Utilities Fortnightly*, Vol. 132, No. 5, March 1, 1994, p. 27.

- As Weisman and Sappington observed in their white paper last year for EDTI, utilities are incentivized to game the tracker system. Substantial extra revenue can, after all, potentially be produced at the modest cost of a regulatory initiative.
- I-X+G (where G stands for growth in customers or all billing determinants) escalation between rate cases is usually insensitive to capex surges. However, it also bolsters utility margins between rate cases since the revenue associated with each plant addition made before the current plan rises while the cost of these assets tends to fall due to mechanistic depreciation of the rate base. The X factor is based in part on the productivity growth of a peer group, which was slowed by capex surges like those for which utilities seek compensation. I-X+G thus provides a "budget" for capex surges paid out in regular installments rather than when it is most needed.

Have utilities acknowledged the reality of these capital revenue surpluses?

Yes. EDTI acknowledged that I-X+G can generate capital revenue surpluses in the 2013 capital tracker proceeding 2131 when it stated that

> [F]or certain [proposed] Trackers, EDTI will recover a higher amount of return and depreciation under the PBR Formula than it will incur. As such, these Trackers result in K factor adjustments that are negative (i.e., they reduce EDTI's PBR rates rather than increase them). The negative K factor adjustment occurs in relation to these Trackers because they are previously completed one-off projects that were outside of the ordinary course of EDTI's business operations. The negative K factor adjustment arises from the fact that the net book value associated with the original rate base addition for the project in question is declining on EDTI's books every year due to the effects of depreciation (i.e., the return of capital).[26]

What does the existence of these capital revenue surpluses say about the need for trackers?

[26] AUC Proceeding 2131, Exhibit 38.01, paragraph 296.

Capital revenue surpluses produced by this feature of PBR can mitigate the short-term revenue shortfalls on plant additions, if not in the year of the surge then over time. There is thus a material risk of *over*compensation if trackers provide utilities with full compensation for their short-term revenue losses due to capex surges. This weakens utility incentives to contain capex and can deny customers a fair share of the benefits of PBR. Utilities can pocket "prepayments" for surges and then request full compensation for the surges.

The need for supplemental revenue for capex thus depends on the extent to which the following conditions hold:

- Capex requirements are unusually high (e.g., for example, due to an exogenous event, unusual uses of capex (e.g., a major undergrounding program) or unusually large need to replace aging assets).
- The regulatory system before PBR featured frequent rate cases that promptly passed the benefits of depreciation on to customers.
- Required capex surges are concentrated in the early years after a switch from traditional rate regulation to PBR.
- Required capex surges occur in the *middle* of plan periods and not around the time of the rate case, when they are easier to self-finance.
- Capex was low in recent years, since this reduces the rate base that makes surpluses possible between rate cases.

When high capex is fully compensated by trackers the following outcomes can therefore be envisioned.

1. If the need for capex surges is unusually low, I-X+G (where G is the extra revenue from demand growth) may substantially overcompensate utilities for needed surges that do occur.
2. If the utility experiences normal capex surges, revenue from I-X+G may roughly compensate the utility in the long run but not in the short run.

3. The utility experiences abnormally large capex surges, I-X+G may provide inadequate compensation in the long run as well as the short run.

Under outcome 2 (and even under outcome 1) short-term revenue shortfalls may be deemed intolerable even though I-X+G provides adequate compensation in the long run. For example, utilities may oppose PBR at the outset or off-ramp provisions will be triggered that cause a suspension of PBR.

What conclusions should the Commission draw from your analysis?

Based on this analysis, and the following facts, we acknowledge that there are some grounds for providing Alberta distributors with more compensation than I-X+G can provide, at least in the early years of PBR.

- Alberta has traditionally had a resource-based economy that occasionally experiences rapid growth. This can trigger surges in energy distributors' capex to expand service and adapt to the expansion of other kinds of infrastructure.
- Alberta distributors operated for many years under frequent rate cases that passed through to customers the full benefits of depreciation on older assets.
- Distributors have recently had some reasons for high capex. These include rapid economic growth in the province and the "echo effect" occasioned by the need to replace plant added during the growth surge that occurred from the middle of the 1970s to the early eighties.

Notwithstanding these realities, the need for supplemental capital revenue should diminish in Alberta going forward, for several reasons.

- Energy distributors generally have less need for capex surges than vertically integrated electric utilities because their systems grow gradually as the economies of their service territories expand. That is why North American-style I-X regulation has been applied chiefly to energy distributors, and extra revenue for capex has often been addressed chiefly by Z factors.

- Economic growth has slowed markedly in Alberta from the pace of recent years. Growth will resume to varying degrees in the service territories of distributors after the recession. The pace may be brisk in some service territories but will likely be slower than in the recent boom. Remarks by FortisAlberta in paragraph 13 of its direct evidence are consistent with this view.

> When the first generation of PBR was implemented, Alberta was in a period of high economic activity primarily driven by the oil and gas sector. This high growth began to slow in 2015 following the rapid drop in oil prices and subsequent slowdown in related developments. Despite the current economic climate, FortisAlberta continues to experience modest, albeit much slower, growth.[27]

- Under circumstances like these, unusually large opportunities should be available to realize economies of scale and density. There should be less need for prebuilds of growth-related capacity and for projects triggered by infrastructure construction in other sectors of the economy. Opportunities should abound to grow into recently constructed facilities that were sized to accommodate future growth.
- Depreciation of the large plant additions that occurred in the rapid-growth years immediately prior to PBR will slow cost growth.
- The substantial capital cost being tracked in current PBR plans will be addressed by I-X in the next plan, adding a sizable new flow of capital revenue surpluses.
- The percentage increase in revenue needed to finance "echo effect" replacement capex is diminished by the fact that Alberta distribution systems have grown substantially since the era when the plant requiring replacement was added.
- High replacement capex due to the echo effect will eventually tail off. For FortisAlberta, this kind of capex never posed an outsized financing problem. Growth-related capex was advanced as the company's biggest challenge and growth has now stalled.

[27] Exhibit 20414-X0073, p. 5.

- The power distribution industry is experiencing technical change that may slow future cost growth. For example, time-sensitive pricing using AMI can slow peak demand growth, and there are many other potential "smart grid" innovations.
- Reforms to PBR such as more incentivized capital trackers with diminished overcompensation and scope can strengthen capex containment incentives.

For all of these reasons, the capital productivity growth of Alberta distributors has the potential to rise abruptly in the future, slowing cost growth abruptly, if not for all utilities in the next plan then very probably in subsequent plans. Alberta distributors should be able to achieve the MFP growth of their American peers in the longer run. That would require productivity growth well *in excess of* the peer group norm in many future years and not just a return to the peer group norm.

EDTI stated in paragraph 119 of its March 23 submission that

> **the shortfall identified above primarily stems from the fact that EDTI's rate base reflects blended (or average) (i) life-cycle asset replacement rates and (ii) asset installation costs that [are] each substantially lower than the rates and costs that EDTI is currently experiencing and will continue to face over the second PBR term. As a result, applying I-X to the capital costs (ie., return and depreciation) reflected in EDTIs base rates will fail to come anywhere close to funding EDTI's required capital investment over the next generation PBR Term without a capital funding mechanism, just as it would have during the first generation PBR Plan.[28]**

How do you respond?

It is an absolutely normal part of utility operation for replacement assets to cost far more than the original assets. This is therefore a necessary but by no means sufficient reason why a tracker might be needed. Many utilities subject to PBR have funded replacement investments over the years from I-X revenue. A tracker should be used for situations when other factors also come into play and are material, such as a surge in the required *quantity* of capital.

[28] Exhibit 20414-X0074, p. 57.

Please summarize the capital tracker proposals of the distributors.

We begin with EDTI because it has shown some intellectual leadership in Alberta PBR to date and has proposed options for next generation PBR that are also mentioned by the other utilities. In paragraph 121 of its evidence, EDTI divides its capex into two broad categories. One is "recurring (i.e., non-idiosyncratic) capital projects and programs".[29] EDTI states in paragraph 124 that these are projects or programs that are "ongoing or foreseeable, and that are partially but not fully funded through the I-X component of the PBR Plan."[30,31] In paragraph 126, EDTI states that this category would include the "vast majority" of its capital projects.[32]

EDTI describes the other class in paragraph 121 as "truly idiosyncratic capital projects, projects that are not funded under the I-X component of the PBR plan to any extent and projects driven by third parties (other than growth projects)."[33,34] Examples offered in paragraph 125 are "the Work Centre Redevelopment project, the Advanced Metering Infrastructure project, and third party driven relocation-related projects as well as contributions for AESO required projects and contributions to Transmission projects for Distribution."[35]

Under EDTI's proposal, projects of the latter kind would continue to be addressed by the current tracker mechanism. Two options are proposed for recurring, ongoing, and foreseeable projects.

1. EDTI calls Option 1, its preferred approach, the "F Factor" (aka "K-bar") approach. Supplemental revenue would compensate the utility for any positive difference between

[29] Exhibit 20414-X0074, p. 57.

[30] Exhibit 20414-X0074, p. 58.

[31] These were described by EDTI in previous documents as "Category 2" projects.

[32] Exhibit 20414-X0074, p. 59.

[33] Exhibit 20414-X0074, p. 57.

[34] These were described by EDTI in previous submissions as Category 1 and 3 projects.

[35] Exhibit 20414-X0074, p. 58.

its forecasted capital cost and the capital revenue generated by I-X+G over the years of the PBR plan.

2. Option 2 is a more incentivized version of the current capital tracker approach in which there are "limited, prospective only true ups" of revenue to actual capital costs.[36] In other words, retrospective true ups of tracker revenue to actual costs would be eliminated.

EDTI recommends a continuation of the current tracker system should the Commission reject both of these options.

Please summarize the proposals of the other utilities.

ATCO

The current tracker system would continue for unstable and/or unpredictable projects. For all other projects, ATCO recommends a "modified K factor" approach that is similar to EDTI's Option 2. Under this approach, true ups to actuals would be limited. Other aspects of the current tracker system would continue. Only revenue shortfalls would apparently be considered for tracker treatment. The current criteria (including the accounting test), materiality thresholds, and Capital Tracker MFR would be maintained.

AUI

AUI prefers to operate under a continuation of the current tracker system. However, it is open to reducing the frequency of true ups.

ENMAX

EPC will employ the existing K factor mechanism in its 2015-2017 Capital Tracker application. It is open to the "modified" K factor" proposed by Brattle in next-generation PBR.

[36] Exhibit 20414-X0074, p. 66.

EPC notes in paragraph 53 of its evidence that "the modified K factor mechanism would rely on the same accounting test and materiality thresholds used in the existing K factor mechanism."[37]

Fortis

Fortis groups its capex programs into two categories. Category 1 includes Customer Growth as well as Externally Driven projects. Externally Driven projects include those for distribution line moves, substation associated upgrades, and AESO contributions. Category 2 is essentially "Sustainment" capital and includes the Company's programs for Cable Replacement and Compliance, Safety, Aging Systems and Reliability, Transportation Equipment, and Information Technology.

The current tracker approach is envisioned in next generation PBR for Category 1 projects. However, Fortis notes that it "has considered" several new ratemaking treatments for Category 2 projects.[38] A Modified K Factor seems to have the greatest appeal for Fortis. It would limit true-ups and extend the period between applications.

An F factor approach has also been considered by Fortis that involves multiyear forecasts of Category 2 capital costs and associated I-X+G revenue. F would be updated for debt costs and I and Q factors but would not be trued up for actual plant additions. Accounting tests would apparently be applied to *individual* projects. Fortis states in paragraphs 104-5, for instance, that

> FortisAlberta's Sustainment capital expenditures would be forecast at the start of the PBR term for each year of the term. These forecasts would be included in the accounting test to determine the qualifying Type 2 capital trackers....Those that meet the criteria for capital trackers, including the materiality thresholds, would form the basis for the F factor....Actual expenditure profiles between the projects could be different, and these differences might not be considered in the

[37] Exhibit 20414-X0069, p. 23.

[38] Exhibit 20414-X0073, p. 28.

> accounting test over the PBR term. This could result in some programs no longer requiring funding or, alternatively, requiring funding not provided by the F Factor.[39]

A K-Bar approach has also been considered in which forecasts of plant additions would be replaced with historical average plant additions adjusted for inflation.

Important aspects of the current capital tracker approach would continue. Fortis states in paragraph 111 that

> The capital tracker criteria, including the accounting test, should continue to determine what projects and programs qualify for tracker treatment. The second tier materiality thresholds should continue to apply to all qualifying capital projects in the aggregate.[40]

What summary comments do you have about the utility submissions?

I have several.

- The companies wish to continue key aspects of the current tracker system, such as the current accounting tests and materiality thresholds. They tout benefits of continuing the system, such as the fact that these provisions are well developed and understood by the utilities, customer groups, and the Commissions. This may indicate that these provisions are quite favorable to their interests.
- All of the utility submissions narrowly address the Commission's questions about how capital trackers can be upgraded to *strengthen incentives* and *reduce regulatory cost*. Little or no consideration is paid to how to improve the balance of PBR plan benefits between utilities and customers.

[39] Exhibit 20414-X0073, pp. 30-31.

[40] Exhibit 20414-X0073, p. 33.

- The utilities have, to a first approximation, proposed in their evidence ways to enhance their earnings opportunities (including new opportunities to game the system) and reduce regulatory cost without increasing the share of benefits enjoyed by customers or materially jeopardizing the recovery of capital cost.

This should cause the Commission concern, for several reasons.

  - Ensuring that customers receive a fair share of benefits is one of the AUC's five PBR principles, and is generally held as a requirement for regulation to be just and reasonable.
  - Ways of strengthening performance incentives and reducing regulatory cost that also improve the customer share and/or reduce the assurance of cost recovery were largely ignored. For example, Dr. Weisman, Brattle, and the utilities did not propose to raise materiality thresholds or exclude some kinds of capex from tracker eligibility.

What are your views about the continuation of the ratemaking treatment of capital under the current PBR plan?

The general pros and cons of capital trackers were discussed above. We believe that the particular approach chosen in Alberta has been especially problematic. There are problems with respect to most of the AUC's five principles for PBR plan design.

- Regulatory cost is high because a high proportion of capex has been eligible for supplemental revenue and reviews are annual.
- It is difficult for any commission or intervenor to review the need for capex surges. As Dr. Weisman notes in paragraph 93 of his direct evidence, "the regulator is required to second guess the company's operating practices, a task that is fraught with difficulty."[41]

[41] Exhibit 20414-X0074, Appendix A, p. 33.

- Capex containment incentives are unusually weak, since a high percentage of capex has in many cases been eligible for tracker treatment and there are substantially full true ups of tracker revenue to actual cost. As Dr. Weisman noted in paragraph 92, "ongoing adjustments for unusual capital projects might limit incentives to minimize overall production costs (AUC PBR Principal 1). Incentives can be diluted particularly severely by a full true-up of actual CAPEX associated with the capital tracker and forecast CAPEX."[42]
- Review of the need for supplemental funding is also difficult. As Dr. Weisman notes in paragraph 91, “it can be difficult to distinguish between projects that are outside the normal course of a company's operations and those that are not."[43] Further, "the plan may provide the company with an incentive to identify (and possibly exaggerate) ‘positive’ capital trackers, but overlook (or understate the impact of) ‘negative’ capital trackers."[44]
- Customers are denied a fair share of the benefits of PBR because they are overcompensating utilities for their short-term revenue shortfalls and will be denied the full benefits of industry productivity growth in both the short and long run.
- Customers are experiencing rate increases commensurate with the negative capital productivity growth that US power distributors have experienced only under extreme circumstances such as a hurricane.[45] This is likely due to a combination of legitimate need for high capex, strategic timing of capex, weak capex containment incentives, and artful tracker applications.

The principle most fully embraced in the current system is that distributors have a reasonable opportunity to recover their cost of service. Remarkably, distributors are afforded a

[42] Exhibit 20414-X0074, Appendix A, p. 33.

[43] Exhibit 20414-X0074, Appendix A, p. 32.

[44] Exhibit 20414-X0074, Appendix A, p. 33.

[45] See our response to CCA-Utilities-10 for elaboration on this disturbing statement.

good chance of recovering their capital costs *each and every year*. This is a "bumper bowling" approach to PBR in which the lower bound of expected outcomes is that distributors earn their allowed ROE. This approach to PBR may prove worse for customers than a return to traditional regulation.

What in your view are the underlying causes of these poor outcomes?

We believe that the problems experienced in Alberta can be traced to certain decisions the AUC made in the implementation of the current PBR system, and importantly the utilities' response to these decisions.

- Capital trackers give utilities a good chance of recovering their capital costs every year.[46]
- The seemingly strict general guidelines for capital tracker eligibility approved in Decision 2012-237 were replaced in Decision 2013-435 with a much more permissive financial accounting test.
- No consideration is paid to capital revenue surpluses. For example, negative K factors were prohibited and no remedy was approved for *intertemporal* double counting even though its existence is undeniable.
- Distributors have artfully prepared their capital tracker applications so that a high percentage of the annual cost of their capex has often been approved for tracker treatment.[47] A common strategy is to choose a very small base revenue for the test that results in a high proportion of capex cost being deemed eligible for supplemental revenue. For example, ATCO Gas compares the cost of replacement capex to the highly depreciated annual cost (as escalated by I-X+G) of assets nearing replacement. AltaGas compares the cost of replacement capex to the escalated annual cost of similar capex at

[46] It should be noted that no analogous decision was made with respect to O&M expenses. These will typically be higher than the O&M revenue in some years and lower in others.

[47] See for example, our response to CCA-Utilities-008 for further discussion of this problem.

an early stage in the same replacement program. Approved accounting tests have accorded tracker treatment for what appears in some cases to be routine capex.

- There are substantially full true ups of capital tracker revenues to actuals.
- Rationales for raising the X factor (e.g., to reflect the outsized opportunities to realize scale economies in Alberta) to strike a better balance between utility and customer interests were not considered and the opportunity for added balance was thus rejected.

The Commission has been wary of considering capital revenue surpluses because this can weaken performance incentives and raise regulatory cost. How do you respond?

These considerations are legitimate but must be balanced against others.

- Ignoring capital revenue surpluses can deny customers a fair share of plan benefits, and this is also a stated goal of PBR in Alberta.
- Consideration of revenue surpluses by some means can strengthen incentives for tracked capex by narrowing the scope of eligible capex or reducing overpayment.
- Much of the capital revenue surplus that occurs between rate cases due to I-X+G results from the *mechanistic* decline in rate base due to depreciation. Incentives are not weakened by taking account of the resultant surpluses until assets approach the end of their service lives.

What are Dr. Weisman's views on the need to ensure that a utility has a fair chance to recover its expected capital costs each and every year?

In response to information request Weisman-CCA/PEG-037 EDTI stated that

> Dr. Weisman does not believe that a utility earning below (or, for that matter, above) its target rate of return in any one given year under PBR is dispositive of rates that are not just and reasonable... Dr. Weisman does not believe that the Commission should seek to increase the earnings variability of the regulated firm by design as part of the PBR plan. That said, it is generally true that under PBR the regulated firm agrees to bear greater risk in exchange for the prospect of greater reward. This greater degree of risk bearing may translate into a greater degree of earnings variability, ceteris paribus.

Let's turn now to the utilities' proposals for new ratemaking treatments. Please comment first on the proposed F factor approach.

Given the unhappy experience with capital trackers thus far in Alberta, we believe that some thought should be paid to setting revenue for most kinds of capital cost using multiyear cost forecasts. This approach, sometimes called the "building block" approach, is applied to *all* costs in Australian and British PBR and is available in Ontario under the "Custom IR" option.

Potential advantages of this approach include the following.

- Capex containment incentives would likely be considerably stronger than under the current system since, once budgets are set, utilities pocket all underspends.
- Surpluses from costs that are growing more slowly than the corresponding I-X+G revenue can be available to fund capex surges. Overcompensation of revenue shortfalls might then be reduced.
- Annual tracker proceedings can be much more limited.

Disadvantages to this approach are also considerable, and many have already been recognized by this Commission.

- Regulatory cost is still fairly high, since business plans must be approved in advance for a wider range of projects than under the current system. In Britain, a PBR proceeding for a utility that makes controversial cost forecasts can take three years.
- Utilities can seek and receive advanced blessing for ill-advised business plans, to that extent weakening their cost containment incentives. Were the regulator to rule at a later date that the plan was imprudent in retrospect, utilities and their expert witnesses would argue that such reconsideration amounted to "recontracting" or an attempt to "claw back" plan benefits.
- As Dr. Weisman comments in paragraphs 84-85 of his direct evidence, "the forward looking approach the plan entails may provide the companies with incentives to exaggerate actual capital investment needs." Further, "the companies may have an

incentive to identify (and possibly exaggerate) ‘positive’ capital trackers, but overlook (or understate the impact of) ‘negative’ capital trackers."[48]

- Due to information and resource asymmetries, it is difficult for regulators and stakeholders to assess the prudence of multiyear total cost forecasts.
- Customers are not ensured the benefits of industry productivity growth.
- The AUC may be less inclined to incur the large expenditures made by their Australian and British counterparts on independent engineering and benchmarking expertise in order to sharpen their views of utility cost escalation requirements. Competent independent experts are sometimes difficult to source and deploy.
- There is a danger to customers in permitting the utility to alternate between a building block approach and simpler indexing from one plan period to the next. As we have seen, Alberta utilities are experiencing a temporary capex surge that has already ended for FortisAlberta. As it winds down for the other distributors, productivity growth should accelerate greatly. There is no reason to believe that the productivity growth of Alberta distributors cannot match or exceed that of a proper US peer group in the longer run. In principle, distributors could therefore use an F factor for one plan period, then operate for one or multiple plans without one, and then request a return to an F factor for some catch up capex. Dr. Weisman discussed the problem of strategic cost shifting in his response to Weisman-CCA/PEG-26&27.

Are there precedents for a PBR approach that combines indexation of revenues (or rates) for O&M expenses with a forecast-based approach to revenues (or rates) for capital?

Yes. An approach similar to this is currently used by Toronto Hydro-Electric. A "hybrid" approach has also been used periodically in multiyear rate plans of California energy utilities since the 1980s. Revenue for O&M expenses is indexed for inflation. Revenue for capital has a

[48] Exhibit 20414-X0074, Appendix A, pp. 30-31.

predetermined "stairstep trajectory that reflects expected growth in capital cost. The extra step of calculating an F factor is sidestepped.

A similar approach was proposed by our client Central Maine Power in a 2013 PBR initiative in Maine. The Maine Public Utilities Commission was so opposed to the idea that it rejected it at an early stage in the proceeding, stating that

> We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the CRM [Capital Expenditure Recovery Mechanism] introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.[49]

Do you have any concerns about the particular approach to F Factor design proposed by the utilities in this proceeding?

Yes. Some parties (e.g., ATCO) seem to be proposing a fragmented approach to the development of F Factors in which only revenue *shortfalls* are considered. Dr. Weisman states in paragraph 97 of his direct evidence that "Under Alternative B, EPCOR's ability to true-up its Category 2 Trackers during the PBR term would be limited to the share of the company's annual forecast capital cost for *each Category 2 tracker* that is funded by the approved Capital Tracker K factor adjustment."[50] Yet EDTI provides a spreadsheet illustrating the operation of its proposed F factor that seems to include capital revenue surpluses.

Even where the F factor does reflect an aggregate cost forecast, negative values may not be allowed. Dr. Weisman, for example, states in paragraph 78 that "The company identifies at

[49] Maine PUC, Order of Partial Dismissal, Docket No. 2013-00168, August 2013, p. 7.

[50] Exhibit 20414-X0074, Appendix A, p. 34 [emphasis added].

the start of the PBR regime any additional F (forward-looking) factor adjustment that is required for (expected) revenue sufficiency."[51] EDTI notes in paragraph 124 that "The F Factor is a capital funding mechanism that will be used to address EDTI's capital funding *shortfall* for projects or programs that are ongoing or foreseeable."[52] [italics added]

Note, finally, that the utilities have not commented on the freedom they might have to revert to a more conventional I-X plus tracker system at a later date.

Is it realistic to think that capital cost growth could occasionally be less than I-X+G?

Certainly. Otherwise, companies would never be able to achieve the capital productivity growth of the peer group in the longer run. The growth in capital cost can slow abruptly when surges in replacement capex end and no capex is needed due to exogenous shocks. Capex is lower and the annual cost of recent surges declines due to depreciation.

Do you have any suggestions for improving the F Factor approach?

Yes. Revenue surpluses should be included in the calculations. Negative F factors should be permitted and not be optional.

- Capital cost forecasts can be informed by indexing and benchmarking studies. It can make sense to set budgets for some kinds of capex based on an average of past values (as in California), subject to escalation for construction cost inflation.

- Budgets for some kinds of capex can be established formulaically. For example, two formulas are used to set capex budgets in the current PBR plan of Fortis BC Energy. One is for growth capital and the other for sustainment and other capital.

[51] Exhibit 20414-X0074, Appendix A, p. 29.

[52] Exhibit 20414-X0074, p. 58.

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

- Treatment of overspends can be treated differently from the treatment of underspends. For example, no compensation might be offered for overspends on F factor budgets while underspends are shared 50/50.

Please discuss the Ontario Energy Board's directives in the use of benchmarking in Custom IR plans.

In its decision on a Renewed Regulatory Framework for Electricity that sanctioned Custom IR plans, the OEB explained that

> The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast….
>
> The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

> - the distributor's forecasts (revenues and costs, including inflation and productivity);
> - the Board's inflation and productivity analyses; and
> - benchmarking to assess the reasonableness of distributor forecasts.
>
> Expected inflation and productivity gains will be built into the rate adjustment over the term. [53]

Later in its decision the Board issued the following clarification.

> The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.
>
> The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4th Generation IR and the Annual IR Index, and will inform the Board's review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor's rates are set, the distributor will continue to be included in the Board's benchmarking analyses.
>
> Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.[54]

In light of your concerns about the F Factor approach, is there something to be said for sticking

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[53] Ontario Energy Board (2012), *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* issued on October 18, 2012, p. 19-20.

[54] Ontario Energy Board (2012), *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* issued on October 18, 2012, p. 60.

with a system of I-X regulation and capital trackers?

Yes. The I-X approach to PBR is a reasonable alternative to the all-forecast approach if done correctly. It was widely used in North American telecom regulation for many years, usually without capital trackers. The I-X approach has also been used with some success for energy utilities in the United States, Canada, and New Zealand. ENMAX just completed a term of I-X PBR for its distribution services, with satisfactory results. I-X has applied to most power distributors in Ontario for many years, and capital trackers have been used sparingly there. Central Maine Power operated under I-X for nearly two decades, from 1995 to 2013, with very limited use of capital trackers. During this period the company achieved productivity growth well above that of regional peers, with noteworthy capex economies.

What are your views of the modified K factor approach?

We believe an argument can be made for strengthening capital tracker incentives by limiting in some fashion the true-up of tracker revenue to actuals. The utilities are generally proposing that there be no true-up, but other options are available.

- Variances between forecasted and actual cost can be shared in a predetermined way (e.g., 50/50).
- Treatment of overspends can be treated differently from the treatment of underspends. For example, no compensation might be offered for overspends while underspends are shared 50/50.

These approaches provide customers with some protection against exaggerated cost forecasts.

Dr. Weisman reviews the EDTI proposal in his evidence and gives it high marks. For example, he states in paragraph 104 that

> **EDTI's PBR proposal seeks to fine tune the incentive properties of the first-generation PBR. Specifically, the proposal seeks to (1) identify elements of the current PBR regime that can be improved upon by providing more high-powered incentives for**

firm efficiency; and (2) identify opportunities to improve regulatory efficiency by reducing the degree of regulatory intervention required over the PBR term.[55]

How do you respond?

We note first that this commentary displays the bias that has pervaded both Dr. Weisman's analysis for EDTI and the proposals of EDTI and the other utilities. The goal of their participation in the regulatory reform initiative is to selectively strengthen the performance incentives and improves the regulatory efficiency of a system that provides a high likelihood of capital cost recovery and denies customers a fair share of plan benefits.

What of Dr. Weisman's concluding statement in paragraph 110 that "EDTI's proposal for the second-generation PBR is fully aligned with the AUC's five PBR principles and the relevant economics literature. The proposal seeks to improve upon the first-generation PBR plan with respect to important dimensions of performance (including firm efficiency and regulatory efficiency) and therefore represents a best practices PBR regime for the 21st century"?[56]

It will take us several paragraphs to detail all the falsehoods in this statement.

- The proposal is not *fully* aligned with the AUC's five PBR principles because it puts an unusually high emphasis on the Company's cost recovery and very little emphasis on customers' share of benefits.
- The statement that the proposal is fully aligned with the relevant economics literature is also off base. He likely means by this that the regulatory literature suggests that stronger incentives and lower regulatory cost are good, and his proposal would accomplish this. But there is not an extensive (much less an applauding) literature supporting *either* the combination of I-X regulation and the peculiarly permissive cost

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[55] Exhibit 20414-X0074, Appendix A, pp. 36-37.

[56] Exhibit 20414-X0074, Appendix A, p. 38.

trackers in Alberta *or* a forecast-based approach to setting revenue requirements. Further, the literature largely ignores how to equitably share the benefits of PBR between utilities and their customers.

- A proposal does not constitute "best practices" PBR simply because it makes improvements on the current system in a couple of areas. Neither is it best practices because it was, in Dr. Weisman's opinion, the best of the limited options that Dr. Weisman and Dr. Sappington considered in their white paper.

Dr. Weisman notes in paragraph 11 that "The regulatory economics literature recognizes that a primary objective of economic regulation is to emulate a competitive market standard."[57] He further notes in paragraph 13 that "the focus of PCR [price cap regulation] is placed on fostering the process of innovation and discovery."[58] Do you agree?

We of course agree with these statements as regulatory economists but note that what Dr. Weisman is endorsing in this proceeding is an approach to PBR in which capital revenue never falls below the utility's forecasted capital cost. This does not remotely resemble a competitive market standard. A plan that does not guarantee full compensation to utilities for their expected short term capital revenue shortfalls better emulates competition and is a better way to launch them on a voyage of innovation and discovery.

Dr. Weisman states in paragraph 14 that "the Commission should be willing to accept some transitory distortions in static efficiency (prices that diverge from competitive levels) in order to encourage dynamic efficiency (optimal investment in innovation over time)."[59] Your response?

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[57] Exhibit 20414-X0074, Appendix A, p. 5.

[58] Exhibit 20414-X0074, Appendix A, p. 6.

[59] Exhibit 20414-X0074, Appendix A, p. 7.

By this he apparently means that the Commission should make sure that capital revenue equals forecasted cost and then not worry if it is *higher*. But this argument cuts both ways. Dynamic efficiency is also encouraged by exposing utilities to the risk of capital revenue shortfalls. He nonetheless endorses capital proposals that will ensure that companies will be unlikely to experience such shortfalls.

What of Dr. Weisman's statement in paragraph 85 that "this first-best approach to capital additions preserves to the greatest extent possible the high powered incentive properties of [price cap regulation] and is therefore fully aligned with AUC PBR Principle 1."[60]

The F Factor is clearly not a "first-best" approach to the problem since many alternatives potentially dominate it and many were not considered. To cite but one example, there is a well-developed approach in Britain that merits consideration. In response to a data request, Dr. Weisman indicated that he is not an expert on British PBR.[61]

Dr. Weisman states in paragraph 82 of his direct evidence that the F Factor approach "leverages familiarity with telecommunications style price-cap regulation while explicitly accounting for the unique characteristics of the energy sector."[62] Do you agree?

No. A plan in which most capital revenue is based on a forecast of capital cost is very different from telecommunications-style price caps. In the telecom sector, utilities operated under I-X mechanisms that often reflected estimates of industry productivity trends. Capital trackers were rare. Utilities did not assert an entitlement to supplemental revenue to compensate them for capex surges.

The very different flavor of telecom PBR is underlined in several of Dr. Weisman's own

[60] Exhibit 20414-X0074, Appendix A, p. 31.

[61] Weisman-CCA/PEG-034(d)

[62] Exhibit 20414-X0074, Appendix A, p. 30.

publications. For example, he states on p. 357 of an *Information Economics and Policy* paper that

> A key tenet of PCR is that the firm agrees to bear greater risk in return for the prospect of greater reward. This observation suggests that deficient earnings alone would not be sufficient to qualify the price-regulated firm for an appeal to [the US Supreme Court's] *Hope* [decision] for relief from financial distress.[63]

On p. 367 of the same paper he states that

> The basic premise underlying the discussion in this article is that PCR represents a fundamental change in the nature of the regulatory contract and a wholesale shift in risk bearing from consumers to the regulated firm.[64]

He states on p. 344 of a *Review of Industrial Organization* paper that

> For the incumbent firms, price cap regulation had significant appeal on two fronts. First, it severs the link between a firm's costs and its earnings.[65]

and on p. 352 that

> The traditional regulatory compact under which most utilities operate does not guarantee full cost recovery, but it does provide for a 'reasonable opportunity' to recover prudently-incurred costs. In the transition from ROR regulation to price cap regulation, the firm foregoes virtually all downside financial protections."[66] [footnote removed]

Sappington and Weisman state on p. 12 of a *Public Utilities Fortnightly* paper that

> Under pure PCR, the earnings of a regulated company are divorced entirely from

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[63] Weisman, Dennis, "Is There *'Hope'* for Price Cap Regulation?" *Information Economics and Policy*, Vol. 14, 2002, pp. 349-370.

[64] Weisman, Dennis, "Is There *'Hope'* for Price Cap Regulation?" *Information Economics and Policy*, Vol. 14, 2002, pp. 349-370.

[65] Lehman, Dale and Weisman, Dennis, "The Political Economy of Price Cap Regulation," *Review of Industrial Organization*, Vol. 16, 2000, pp. 343-356.

[66] Lehman, Dale and Weisman, Dennis, "The Political Economy of Price Cap Regulation," *Review of Industrial Organization*, Vol. 16, 2000, 343-356.

> both its realized production costs and its investment decisions. Maximum average price levels (price caps) are specified in advance and remain unaltered as the magnitude of the company's realized production costs change or its investment patterns and performance vary. In this respect, the company bears the full financial implications of its actions.[67]

Dr. Weisman states in paragraph 61 of his testimony that

> **At the time when PCR adoption was increasing most rapidly in the U.S. telecommunications sector, sustained or increasing productivity growth rates often were feasible for two primary reasons. First, the demand for communications services was increasing. Second, information processing costs (which are a key component of the costs of supplying switched telecommunications services) were declining. Increasing output levels and declining input costs both promote increasing productivity growth rates.[68]**

He states in paragraph 69 that it is generally recognized that

> **Moore's Law has operated to dramatically reduce the cost of providing telecommunications services over time. Moore's Law operates to a lesser degree in electric power than it does in telecommunications. Hence, one possibility is that X factors based on historical, industry productivity growth trends understate forward-looking productivity growth in the telecommunications industry at the same time that they overstate forward-looking productivity growth in the electric power industry. This may also help to explain why PCR has been widely deployed in the telecommunications sector, but its adoption in the electricity sector has been far less ubiquitous."[69]**

How do you respond?

Dr. Weisman stated in response to Weisman-CCA/PEG-001 that "Dr. Weisman is an expert on incentive regulation and regulatory economics, but does not consider himself an

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[67] Sappington, David, and Weisman, Dennis, "Designing Superior Incentive Regulation," *Public Utilities Fortnightly*, Vol. 132, No. 4, February 15, 1994, 12-15.

[68] Exhibit 20414-X0074, Appendix A, p. 23.

[69] Exhibit 20414-X0074, Appendix A, pp. 25-26.

expert on empirical productivity measurement." This theory on why capital trackers weren't adopted in telecom PBR should be taken with a sizable grain of salt for this reason alone. There are many other reasons to think that the relevance of telecom experience should not be readily dismissed.

- Despite rapid productivity growth, telecom utilities were subject to financial stresses during their PBR years. Utilities were subject to high X factors or rate freezes. Kridel, Sappington, and Weisman note on p. 289 of their *Journal of Regulatory Economics* article that "it is important to recall that investment in network modernization was a frequent prerequisite for the adoption of incentive regulation at the state level."[70] Abel (2000, pp. 66-68) concludes that:

> Under price-cap regulation, telephone prices have either fallen or remained the same, productivity has generally increased, *modern infrastructure has been deployed at a more rapid pace*, and firms have performed at least as well financially relative to the other methods of regulation available. … In addition, the evidence so far suggests that the response has been more pronounced under pure price-cap regulation compared to hybrid plans having an earnings sharing component. This result is particularly true along the productivity and *network modernization* dimensions.[71] [italics added]

This corresponds with Dr. Weisman's response to WEISMAN-CCA/PEG-025 where he stated that "In fact, Dr. Weisman's recollection is that in the immediate aftermath of implementing price cap regulation, productivity growth rates did not show dramatic improvement—likely because of the transitory 'adjustment costs' these firms would have had to bear."

[70] Kridel, Donald, Sappington, David, and Weisman, Dennis, "The Effects of Incentive Regulation in the Telecommunications Industry: A Survey," *Journal of Regulatory Economics*, Vol. 9, 1996, 269-306.

[71] Abel, Jaison, "The Performance of the State Telecommunications Industry Under Price-Cap Regulation: An Assessment of the Empirical Evidence," NRRI Report 00-14, Columbus, OH: The National Regulatory Research Institute, September 2000.

Sappington and Weisman state on p. 136 of their *Information Economics and Policy* paper that

> often, incentive regulation plans that provide long-term earnings potential for the regulated firm will foster increased investment by the firm in the short run. The investment (which may take the form of more modern operating equipment, for example) will be designed to reduce operating costs in the long run.[72]

Competition mounted, slowing demand growth, and utilities were not protected from this under the price cap system of regulation.

- The notion that productivity growth accelerated under price caps has been challenged by some experts. For example, LRCA, working for the US Telecom Association, reached a different conclusion.

> [W]e believe there is no basis for increasing the X-Factor as competition in LEC [Local Exchange Carrier] markets intensifies. In fact, the evidence indicates that the X-Factor should be reduced... Loss of demand growth to competitors could reduce measured TFP growth by 0.6% to 2.0% per year. [73]

In a later project, Christensen Associates' showed that there not a sustained jump in TFP growth for the ILECs ("Incumbent Local Exchange Carriers") during the 1990s. TFP growth from 1988 to 1998 was 3.2%, while TFP growth in the subperiods of 1988-1993 and 1993-1998 were not noticeably different.[74]

[72] Sappington, David and Weisman, Dennis, "Potential Pitfalls in Empirical Investigations of the Effects of Incentive Regulation Plans in the Telecommunications Industry," *Information Economics and Policy*, Vol. 8, 1996, 125-140.

[73] Meitzen-CCA/PEG-2016APR15-001, Attachment 6, p. 14-15.

[74] Meitzen-CCA/PEG-2016APR15-001, Attachment 1, Table 17.

- An X factor that is 100 basis points below actual MFP growth would not, in any event, necessarily have ensured that ILECs did not incur short term revenue shortfalls during capex surges.
- Operation under "pure PCR" gave utilities strong incentives to contain capex without declines in service.

Dr. Weisman states in paragraph 74 that "capital trackers are now commonplace in the electric power and natural gas industries. In fact, the use of capital trackers is arguably more the rule than the exception."[75] He cites a recent survey you prepared for the Edison Electric Institute to substantiate this claim. How do you respond?

Our extensive survey work on capital trackers in US utility regulation reveals that they are in use today for at least one gas or electric utility in most US jurisdictions. This is not to say that most US energy utilities operate under capital cost trackers, however. Furthermore, the conditions under which these trackers are approved are commonly quite different from those in Alberta. Multiyear rate plans are rare, and fully forecasted test years are not used in most rate cases. Notwithstanding the lack of these financial benefits, the scope of capital trackers in the US is typically much more limited than in Alberta.

What are your views about offering utilities a menu of alternative PBR approaches, like regulators do in Ontario?

Our many reservations about a building block treatment of capital cost have already been noted. Most of the larger power distributors in Ontario have opted for the Custom IR approach. This may reflect a widespread need in Ontario for catchup capex after years of operating under I-X regulation with limitations on the use trackers. However, their choices may also reflect their view that this approach is more utility-friendly.

[75] Exhibit 20414-X0074, Appendix A, p. 27.

Notwithstanding these disadvantages of an Ontario-style menu, we believe that there may be merit in permitting one utility to operate under a building block treatment of capital revenue in the next plan period to learn more about the pros and cons of this alternative system. However, this would involve large regulatory startup costs and a risk of unforeseen outcomes comparable to that which the AUC has encountered with its current system of I-X and trackers.

Are other kinds of menus worth considering?

Yes. We encouraged the Commission to consider a menu approach to PBR on p. 73 of our direct evidence.[76] One promising use of menus is to incentivize utilities to reveal, through their choice between options, their cost containment potential and to share benefits with customers. Britain's energy utility regulator Ofgem is now in its third generation of information quality incentive ("IQI") mechanisms that feature menus in PBR plans for jurisdictional utilities in Britain. This approach requires Ofgem to develop an independent view, informed by engineering and benchmarking work, of each utility's future efficient cost for up to an 8-year period. The revenue requirement for each utility is based primarily on Ofgem's cost forecasts. However, the IQI offers utilities a schedule of financial rewards that vary with the extent to which their cost forecasts are similar to Ofgem's and to the costs that they ultimately incur.

Alternative menus can be designed for use in the context of a PBR plan in which there is an I-X mechanism that reflects industry input price and productivity trends.[77] As one example, PEG has developed stylized "revenue option" approaches and considered them with our incentive power model, as discussed further in the attachment to our supplemental response to CCA-AUC-011. In the Alberta context, a company might be given the option at the end of the next PBR plan of forgoing a rebasing provided that it did not request supplemental revenue during this plan for reasons other than exogenous shocks.

[76] Exhibit 20414-X0082, p. 73.

[77] The American economists Crew and Kleindorfer wrote several articles on menus that can be used in I-X regulation.

CCA noted in response to CCA-AUC-017 (c) that "[Dr. Lowry's] thoughts on this complicated issue continue to evolve." Please provide your latest views on needed reforms in the regulatory treatment of capital in Alberta PBR.

We have outlined in our direct evidence and our responses to AUC information requests various reforms to the current PBR system in Alberta so that it can do a better job of fulfilling the Commission's five principles for PBR. These reforms can be grouped into the following categories.

1. Continue cautiously with relatively liberal use of capital trackers (trackers will continue then to be a prominent feature of regulation) but make more benefits of negative trackers available to customers in ways that don't unduly raise regulatory cost or weaken performance incentives.
    - Continue tracking capital costs of assets once tracking is initiated (as in the PBR plans for the Fortis companies in British Columbia) so that customers get the full benefit of the subsequent mechanistic depreciation on taxes and the return on rate base. If, for example, a certain portion of the annual cost of an asset qualifies for supplemental revenue during one plan term, that portion of the cost of that asset can be Y factored in future plans. To strengthen incentives, the last years of an asset's service life could be exempted from tracking.
    - Raise the X factor the higher are K factor revenues in order to increase the likelihood that customers receive the benefits of industry productivity growth in the long run. This approach would make X factors company-specific. Equivalently, let utilities borrow revenue escalation rights between plan years and plans.
2. Let utilities keep the benefits of potential "negative trackers" between rate cases. However, acknowledge this benefit and the potential for overcompensation and use it to scale back the role of trackers. In other words, make utilities self-finance a growing portion of their short-term revenue shortfalls from the benefits of I-X+G that they are sure to experience between rate cases.
    - Restrict the kinds of capex eligible for tracking.

- Raise materiality thresholds.
- Don't compensate the utility for a "dead zone" in estimated revenue shortfalls that is defined by the materiality thresholds.
- Reduce compensation for capex surges by the benefits of potential negative trackers that utilities previously received between rate cases, with appropriate interest.
- Compensate a set fraction of the short term revenue shortfalls.
- Use an historical review window for computing tracker revenue, with no compensation for the resultant regulatory lag. For example, the extra revenue in 2019 for a given class of capital could be the revenue shortfall demonstrated for 2018 using an accounting test. The Commission could thereby sidestep an advance review of the reasonableness of capex plans if it wished.
- Revise tracking procedures (e.g., accounting test and grouping rules) to avoid unnecessary tracking.
- Deny trackers for capex surges in the last year of the plan period that result from exogenous events.

3. The following miscellaneous reforms in the ratemaking treatment of capital also merit consideration.
    - Incentivize trackers by having utilities absorb some of the variances between actual and predicted capex.
    - Spend more money on independent engineering and statistical cost research so that regulators and stakeholders can develop better views on capex requirements. The extra work could be undertaken by in-house experts of the AUC or intervenors or outsourced by either party to consultants.
    - Develop improved reporting for increased transparency and ease of understanding the trackers and their financing including better minimum filing requirements for tracker applications and more relevant and detailed annual Rule 005 reporting

which accounts for PBR and trackers. We understand that this area is further discussed by CCA witness Jan Thygesen.

Please note the following about these varied reform options.

- The reform package that the Commission prefers will depend on which of its current policies it is willing to compromise on or reverse.
- Some reforms are complementary. For example, there is no reason not to combine a more incentivized ratemaking treatment of the variances between actual and forecasted capex with one of the various remedies for overcompensation.
- Different approaches can be used for different kinds of assets. Suppose, for example, that trackers providing *full* compensation for short-run revenue shortfalls for capex surges triggered by external events such as storms, floods, or forest fires are "here to stay" using a K factor (or Z factor), even though I-X usually provides an adequate budget for such events over many years. Then costs of such assets that are approved for tracker treatment can be subject to ongoing Y factor treatment in future plans even as distributors are permitted to keep revenue surpluses for other asset classes but supplemental revenue for capex surges in these classes is greatly restricted.
- If utilities are allowed to keep capital revenue surpluses between rate cases, the rationale for restricting recourse to trackers *increases* over time because utilities will have accumulated more years of benefits. These "up-front payments" loom especially large given the time value of money. Trackers for assets with short replacement cycles could be eliminated as early as the next plan period.
- Several of the reforms I have mentioned address several problems simultaneously. For example, an historical review window reduces regulatory cost and strengthens performance incentives, in addition to reducing overcompensation for short-term revenue shortfalls. In contrast, a higher X to reflect outsized opportunities for scale economies gives more benefits of PBR to customers at negligible regulatory cost but doesn't make headway on the other problems.

- It is difficult to base changes in the ratemaking treatment of capital on a detailed quantitative exercise without being drawn into the chore of appraising specific capex programs. Rough judgments of pros and cons of reforms may ultimately be required by the Commission to arrive at a suitable reform package.
- There are solid grounds for instituting some capital tracker reforms BEFORE the end of the term of the current PBR plans.
    - Serious problems have been identified.
    - The reforms we have discussed generally will NOT weaken performance incentives or claw back the benefits of performance gains already achieved. Indeed, if they are implemented now rather than later they are less likely to be interpreted by utilities as part of a clawback strategy.

What is your current thinking about the best reform package?

We have tried to equip the AUC with a large menu of potential reforms that gives the Commission some flexibility depending on which of its current policies it is willing to change. Here is our current thinking on a package of reforms for next generation PBR.

- Given the many problems capital trackers have given rise to, we are drawn to remedies that scale back the role of trackers. These remedies generally reduce overcompensation and have additional advantages.
    - An historical review window strengthens performance incentives and can reduce regulatory cost considerably insofar as the regulator can sidestep approval of capex forecasts. However, this approach will typically not by itself reduce the scope of capex eligible for filing.
    - Tracking only a set fraction of capital revenue shortfalls that exceeds the materiality threshold strengthens performance incentives but does not reduce regulatory cost. The scope of capex eligible for tracker treatment will not change.
    - Raising materiality thresholds and excluding certain kinds of capex from

eligibility for tracking are both remedies that strengthen performance incentives and can materially reduce regulatory cost by reducing the scope of capex eligible for tracking.

This approach will expose the utilities to greater risk but also encourage discovery and innovation.

- Tracking of capex surges required by external events can continue. This could in principle be addressed through Z factors rather than the K factor. In either event, overcompensation can be reduced and incentives strengthened by such means as selectively passing the benefits of depreciation of these projects through to customers via Y factors.
- To give the utilities more flexibility, they may be permitted to "borrow" allowed revenue escalation from other years and other plans.
- More money should be spent on independent engineering and statistical cost research expertise so that regulators and stakeholders can develop better views on capex requirements.
- Reporting and filing requirements should be improved.
- Remaining trackers should be further incentivized by limiting the true up of tracker revenue to actuals.
- If the AUC agrees to base X on Dr. Lowry's productivity research, accounting tests can use a somewhat lower X factor that reflects the slower productivity growth trend of capital rather than the multifactor productivity trend. This would slightly reduce the scope of capex eligible for tracking with resultant improvements in incentives and regulatory cost.

Several utilities have proposed a continuation of the current materiality thresholds. Why do you believe that they should be raised?

Higher materiality thresholds strengthen capex containment incentives at the same time that they address overcompensation for short-term revenue shortfalls and reduce regulatory costs. With higher thresholds on *individual* projects, utilities will recognize that they are "on their own" between rate cases when it comes to many smaller projects. A higher *aggregate* threshold will meanwhile signal to the utility that it can hope for supplemental revenue only in years when a capex surge is unusually large. Of course, higher materiality thresholds also strengthen utility incentives to bunch capex and to artfully combine capex categories so that they clear thresholds. Regulatory vigilance would be needed to prevent this outcome.

Are materiality thresholds higher in other jurisdictions?

Yes. Our research suggests that materiality thresholds in Ontario are substantially higher. One problem with the Alberta approach is that the mid-term convention for valuing plant makes it possible for utilities to qualify for tracker treatment in the latter years of a PBR plan just because they made large plant additions in the first year of the PBR plan or in the year prior to the plan's start. Even if the mid-term convention were suspended, however, we believe that materiality thresholds in Ontario would still be considerably higher.

What are your thoughts concerning a change in the kinds of capex that are eligible for tracker treatment?

In Decision 2012-237, Criterion 2 for capital tracker eligibility was that "ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party".[78] It further explained that

> the second criterion generally limits the scope of eligible capital projects to those required for replacement of aging infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources

[78] Decision 2012-237, paragraph 592, p. 126.

> of revenue that offsets the cost of new capital. The new sources of revenue can come in the form of increased customers and load growth and also through contributions in aid of construction.[79]

We strongly encourage the Commission to return to this sensible approach and to make required echo effect capex surges one of few that are eligible for tracker treatment. In the alternative, the Commission should at least search for reasonable ways to narrow the kinds of capex eligible for tracker treatment. Growth-related capex is certainly one category that should be considered for exclusion. In addition to all of the reasons for exclusion of this category that the Commission has already acknowledged, we note the following.

- It is sometimes rational to "prebuild" growth related capex. It might, for example, be more cost effective to build a substation that temporarily exceeds the needs of a growing suburban area than to add to the substation's capacity at a later date. It should be noted, however, that if the growth actually materializes productivity growth should thereafter surge. The utility may capture the lion's share of the benefit under the current system.
- The slowdown in Alberta economic growth should reduce the need for prebuilds of growth-related projects for some time to come.
- Brisk system growth that might occasion growth-related capex also gives rise to outsized scale economies.
- In an accounting test for growth-related capex, it is reasonable to ascribe to these assets ALL of the revenue that results from growth in billing determinants (or, in the case of revenue caps, from customers).

Other capex categories can also be reasonably considered for tracker ineligibility. For example, assets with short replacement cycles (e.g., tools, vehicles, and software) may be

[79] Decision 2012-237, paragraph 595, p. 127.

excluded because they are more easily self-funded by the surplus revenue that I-X produces between rate cases.

When considering the exclusion of asset categories, it must be remembered that only so many remedies for overcompensation of short-term revenue shortfalls can be implemented simultaneously. For example, if growth-related assets are not eligible for tracking, this weakens the argument for using the full I-X+G formula in accounting tests for assets that are eligible.

Are there precedents for limiting the scope of capex eligible for tracking in PBR plans?

Yes. We have already noted that eligibility for capital trackers in the United States is generally quite limited. Many PBR plans have not Y factored any kind of capex. However, capex due to exogenous events is usually addressed by Z factor provisions.

4. Efficiency Carryover Mechanism

The utilities and their witnesses generally favor a continuation of the current efficiency carryover mechanism. How do you respond?

The rationale for ECMs is to counteract some of the adverse incentives that result under PBR plans from a periodic rebasing of revenue to cost. The following adverse incentives are notable.

- Due to the compression of the payback period, utilities have less incentive in the later years of a plan to incur the upfront costs that may be needed to achieve long term performance gains.
- There is also less incentive for utilities to contain cost in a historical reference year that provides the foundation for the forward test year. For example, there would be less incentive to strike a hard bargain with labor unions and other input vendors.
- Utilities are incentivized to defer certain expenditures in the later years of a PBR plan and then ask for supplemental revenue to finance them in subsequent plans. In the absence of an earnings sharing mechanism, customers may then "pay twice" for some of the

same costs. Dr. Weisman agrees with this rationale for ECMs in his response to Weisman-CCA/PEG-013.

To counteract such incentives, ECMs can reward utilities for offering customers good value in later PBR plans, and can penalize them for offering customers poor value. I discussed in my direct testimony ECMs that involve a comparison of the revenue requirement ("RR") (or underlying cost) in the next plan period to some kind of a benchmark. The ECM could take the form of a targeted incentive mechanism. The revenue requirement in the forward test year could, for example, correspond to the following formula.

$$RR_{t+1} = Cost_{t+1} + \alpha(Benchmark_{j,\,t+} - Cost_{j,\,t+1})$$

where α is a share of the value implied by benchmarking. Note that the formula allows for the possibility that only a subset *j* of the total cost is benchmarked. This could be the subset that is easier to benchmark. The variance between the cost benchmark and actual cost can alternatively be used to adjust the X factor. This would typically take the form of a stretch factor adjustment.

This kind of ECM clearly strengthens the utility's incentive to contain the cost of service in the forward test year. Moreover, by making the *test* year the focus of the appraisal rather than the years of the prior plan period, this ECM also guards against strategic deferrals and promotes a fair share of plan benefits for customers.

The choice of a benchmark is an important consideration in the design of this kind of ECM. We discussed two methods for calculating a benchmark in our direct evidence. One was to escalate the cost established in the last forward test year by a suitable escalation index. This could be the I-X+G formula used in the prior plan.

Many variations on this theme are possible. For example, instead of benchmarking *cost*, the *productivity* growth that is implicit in the test year cost since the level approved in the last rate case can be compared to the productivity growth of the peer group. This guards against any failure of the inflation measure in the I-X+G mechanism to accurately track input price inflation.

Cost (or the revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research that is completely independent of the Company's cost. We have noted that statistical benchmarking is used by the Ontario Energy Board to update stretch factors annually. Benchmarking is also used extensively in PBR by the Australian Energy Regulator and by Ofgem in Britain. Benchmarking studies have occasionally been filed by US utilities in support of stretch factors or forward test year cost proposals. Public Service of Colorado, for example, has filed benchmarking studies of its forward test year proposals for the cost of its gas utility and its vertically integrated electric utility.

Please note the following with respect to both of these options.

- The ECM should ideally apply to *total* cost, including capital cost that has been tracked. The O&M expenses of Alberta energy distributors are fairly inconsequential because they provide few customer services. However, the Commission may wish to apply such an ECM only to O&M expenses. In that event, it may be desirable to base any benchmark index on the *O&M* productivity trend of the peer group if this differs from the multifactor productivity trend.
- When costs of deferred capex can be recovered through a tracker, the utility may be incentivized to request recovery of deferred capex after the rebasing. This is an argument for not basing the ECM on cost in the previous plan. Strategic deferrals have complicated the administration of ECMs in Australia.
- Both of these options have been considered in our incentive power research. This research is discussed in considerable detail in the attachment to our supplemental response to CCA-AUC-011. Assuming an *historical* test year, PEG examined the revenue requirement at the start of a new plan that is based $\alpha\%$ on the actual cost in the last year of the previous plan and $(1-\alpha)\%$ on the revenue requirement in that year. This effectively permits the company to share $(1-\alpha)\%$ of any deviation between its cost and the revenue requirement. We also considered a plan in which revenue at the start of the next plan period is based partly on an external benchmark. The greater incentive power of this alternative results from the fact the benchmark is completely external.

Thus, the utility will not consider that lower cost in the upcoming test year will produce a tougher benchmark in future plan updates.

Does this conclude your testimony?

Yes it does.