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December 6, 2013

<u>Via Email</u>
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, B.C. V6E 2N7

<u>Attention:</u> Ms. Tannis Braithwaite, Acting Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively the Companies)

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

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO) Information Request (IR) No. 2 on PBR Methodology

Filed as Response to FEI-FBC BCPSO IR No. 3

On June 10 and July 5, 2013, FEI and FBC, respectively, filed the Applications as referenced above.

In an effort to differentiate the IR responses relating to the PBR Methodology which are the subject of the oral portion of the hearing jointly for the Companies from those IR responses which relate to other matters for the written portion of the hearing individually for each of FEI and FBC, the Companies will mark these IR responses as FEI-FBC BCPSO IR No. 3.

The Companies respectfully submit the attached response to FEI-FBC BCPSO IR No. 3 responses related to the PBR Methodology.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC. and
FORTISBC INC.

Original signed:

Diane Roy and Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (email only)

1.0 Reference: FBC Exhibit B-11, 1.10.1

FEI Exhibit B-6, 1.10.1

1.1 Please confirm that the referenced European Building Block approach relates only to Natural Gas Transmission, and not natural gas production or distribution. If not confirmed, please fully explain.

Response:

Confirmed. FEI and FBC were not able to find any readily available report for European natural gas distributors. However, in many of the European jurisdictions (such as France, Italy or Spain), the distribution utilities are also regulated under the building block approach. Further, please note that natural gas production is not regulated in Europe.

1.2 Please confirm that the referenced European Building Block approach relates only to Natural Gas Transmission, and not electric generation, transmission or distribution. If not confirmed, please fully explain.

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.1.1.

1.3 On lines 26 and 27, FEI and FBC state "Both Australia and New Zealand use the building block approach for both gas and electric utilities." Please provide an explanation of the nature of the building block approach used in Australia and New Zealand and provide references to support the response.

Response:

B&V provides the following response.

In Australia, the regulator reviews each component of costs for the regulatory control period. There is a separate determination of the OPEX and CAPEX based on forecasts for the control period. The X-Factor is set to allow the Company to adjust prices over the control period so as to recover the approved forecast of costs. Refer to for example the excerpt from the decision of the AER, with calculations performed on Table 12.6 on p.108 provided in Attachment 1.3.

2.0 Reference: FBC Exhibit B-11, 1.13.1

FEI Exhibit B-6, 1.11.1

2.1 Please fully explain how the proposed building block approach breaks the link between prices and costs, and is not just another way of forecasting cost of service costs over a longer period.

Response:

B&V provides the following response.

The question can actually be correct in either of the two descriptions because the answer depends on how the building block approach is developed. As practiced in Australia where the formula values are determined on cost of service forecasts rather than some factor external to the utility, the process is more like cost of service but with the added difference that incentives for efficiency improvements remain based on the difference between actual costs and forecast costs. That is, the utility has an incentive to keep costs below the forecast. If the building block approach is predicated on an externally-determined X-Factor as in the case of the FEI and FBC proposals the link between costs and prices is broken via a formula. Essentially, the response to the question depends on how the building block approach is developed and applied.

3.0 Reference: FBC Exhibit B-11, 1.11.1

FBC Exhibit B-15, 1.36.1

FEI Exhibit B-6, 1.11.4

FEI Exhibit B-6, 1.19.1

Preamble: In the response, to ICG 1.36.1, at page 63, FBC provides a table of capital expenditures. The row entitled "Transmission-Dist. - Stn. Base Capital" includes annual actual amounts that range from a low of $29.7 million in 2012 to a high of $52.1 million in 2007. Similarly, for FEI, in response to BCPSO 1.19.1 FEI provides a schedule of capital. The total actual, capital excluding CPCN, ranges from a low of $78.7 million in 2008 to a high of $102.6 million in 2012. Even for base capital there appears to be a large amount of variability.

3.1 Explain how, under proposed building block approach, customers would be compensated for lower costs, or pay for higher costs that arise simply due to lumpiness in base capital under PBR plan.

Response:

Other than a limited number of projects to be tracked outside of the PBR formula FEI and FBC will manage the lumpiness of capital projects within the overall spending envelopes allowed by the PBR formulas. If circumstances arise that require the utility to proceed with a higher-than-average number of "lumpy" projects in a particular year, and thus there is higher capital spending overall, and this is followed by a year with fewer of the "lumpy" projects, the costs or benefits of these year to year capital spending variances will simply work their way through the capital incentive construct within the PBR Plan. The lower or higher capital costs will cause increases or decreases in ROE and a corresponding effect on 50/50 earnings sharing.

4.0 Reference: FBC Exhibit B-11, 1.36.6

Preamble: In the response, to 1.36.6, FBC discusses unfilled vacancies. The BCPSO requires an understanding of the history of vacancies, and the level of vacancies included in the 2013 base.

4.1 Please provide the actual vacancies for each of 2008 – 2012 including the dollar impact for each of FEI and FBC.

<u>Response:</u>

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

4.2 Please provide the projected vacancies and dollar impact included in the 2013 base for each of FEI and FBC.

<u>Response:</u>

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

5.0 Reference: FBC Exhibit B-11, 1.37.3

FEI Exhibit B-6, 1.16.1 and 1.16.2

Preamble:

5.1 Please provide the compound growth rates for the actual O&M (FEI 1.16.1) and O&M per customer (FEI 1.16.2) for the actual years 2008-2012.

Response:

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

5.2 Please fully explain why the 2013 base O&M and O&M per customer do not reflect the actual compound growth rates.

Response:

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

5.3 Please provide the compound growth rates for the actual O&M and O&M per customer (FBC 1.37.3) for the actual years 2008-2012.

Response:

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

5.4 Please fully explain why the 2013 base O&M and O&M per customer do not reflect the actual compound growth rates.

Response:

This IR has been identified as relating to Non-PBR Methodology and will be submitted under separate cover as the responses to BCPSO IR2a.

6.0 Reference: FEI Exhibit B-6, 1.13.2

6.1 Please provide a breakdown of the revenue requirement approved in the 2010-2011 FEU RRA among the cost classifications (i) labour costs, (ii) materials costs, and (iii) capital costs.

Response:

This response addresses both FEI-FBC BCPSO PBR IRs 3.6.1 and 3.6.2.

A breakdown of the approved revenue requirements and 'capital' for the years 2010 – 2013 is detailed in the following table. The details for 2010 and 2011 are from Appendix A to Order G-141-09 and for 2012 and 2013 from FEI's Compliance filing, Attachment A, to the Commission, dated May 1, 2012 in respect to Commission Decision and Order G-44-12 dated April 12, 2012 and Section E, Schedule 15 of the September 6th Evidentiary Update for this Application (Exhibit B-15).

Labour and materials costs are detailed under Operating and Maintenance Expense and capital costs are detailed under Gas Plant in Service; FEI has also included the approved Rate Base.

	$000's			
	G-141-09 [1]		G-44-12 [2, 3]	
	2010	2011	2012	2013
Approved Revenue Requirement				
Cost of Gas	$ 987,970	$ 989,627	$ 659,338	$ 658,568
Operating & Maintenance Expense [3]				
- Labour	99,871	107,160	133,633	135,064
- Materials & Supplies	7,251	7,191	6,509	7,019
- All Other	99,342	100,329	86,850	93,920
Total Gross O&M Expense	206,464	214,680	226,992	236,003
Less Overhead Capitalized	(28,905)	(30,055)	(31,779)	(33,040)
Total Net O&M Expense	177,559	184,625	195,213	202,963
Property & Sundry Taxes	49,193	50,211	49,656	51,239
Depreciation & Amortization	88,893	88,588	123,928	142,912
Removal Cost Provision	8,038	11,290		
NSP Provision	5,963	1,025		
Other Operating Revenue	(22,455)	(24,394)	(24,673)	(24,789)
Income Taxes	24,923	24,564	24,170	28,049
Earned Return	184,217	192,934	212,598	216,404
Total Revenue Requirement	$ 1,504,301	$ 1,518,470	$ 1,240,230	$ 1,275,346
Approved Capital - Gross Gas Plant in Service (before Accumulated Depreciation)				
Opening Balance	$ 3,315,365	$ 3,453,394	$ 3,545,030	$ 3,774,425
CPCN Addition	27,603	-	93,115	-
Additions	134,591	135,993	131,149	129,870
AFUDC	230	241	1,948	1,769
Capitalized Overhead			31,779	33,041
Retirements	(50,498)	(51,250)	(24,958)	(33,806)
Transfer/Recovery	26,103	-	(3,638)	-
Closing Balance	$ 3,453,394	$ 3,538,378	$ 3,774,425	$ 3,905,299
Rate Base	$ 2,534,444	$ 2,628,772	$ 2,717,124	$ 2,767,988

Notes:

1. Details for 2010 and 2011 approved revenue requirements, labour costs, materials and supplies and capital are from the following pages of Appendix A to Order G-141-09: 25, 26, 29, 30, 49, 66 and 68.

2. Details for 2012 and 2013 approved revenue requirements, labour costs, materials and supplies and capital are from the following schedules of Attachment A of FEI's Compliance Filing dated May 1, 2012: 5, 6, 21, 41, 42, 48 and 51.
3. 2012 and 2013 Total Approved O&M is per FEI's Compliance Filing dated May 1, 2012. The allocation of the 2013 O&M is per Appendix F6 of the Application. The allocation of the 2012 O&M was undertaken in a consistent manner as 2013.

6.2 Please provide a breakdown of <u>the revenue requirement</u> approved in the 2012-2013 RRA among the cost classifications (i) labour costs, (ii) materials costs, and (iii) capital costs.

<u>Response:</u>

Please refer to the response to FEI-FBC BCPSO PBR IR 3.6.1.

7.0 Reference: FBC - BCUC 1.14.1

FEI - BCUC 1.5.1

Preamble: The referenced quote from Swinand offers a number of definitions for the X-Factor depending upon the jurisdiction and the manner in which the X-Factor is incorporated into the PBR formula/plan.

7.1 Given the way that FBC/FEI propose to use the X-Factor as part of its proposed PBR formula/plan what is the appropriate definition for the X-Factor as proposed in these Applications?

Response:

B&V provides the following response.

The X-Factor in these applications is best defined as an adjustment to the rate of inflation that reflects both productivity changes and a consumer dividend designed to share efficiency gains with customers through annual adjustments to the utilities' revenue requirement.

8.0 Reference: FBC – BCUC 1.17.1 and BCUC 1.54.1

FEI – 1.8.1

FBC – BCPSO 1.85.1

8.1 FBC indicates in its response to BCPSO 1.85.1 that its growth capital expenditures tend to be "lumpy" (i.e. not evenly spread over time). Do FEI and their consultants agree that this observation also applies to gas utilities such as FEI? If not, why not?

Response:

In general FEI and B&V consider that the concept of lumpy capital additions applies to all utilities and represents the fact that contrary to the underlying assumptions of traditional TFP analysis, units of capital are not available on a continuous basis but rather are added in discrete increments that may serve load growth in the current period as well as over the life of the asset. This means that the addition is designed to minimize costs over the life of the investment not just in the current period.

With respect to FEI's growth capital for new customer meters and services, these do not tend to be lumpy as the costs per addition of a new customer are relatively small compared to capex as a whole. However, growth capital for mains extensions can be considered lumpy depending on the characteristics and size of the extension.

8.2 To the extent growth capital expenditures are "lumpy" for electric (and gas) utilities, does this not suggest that the historical time frame used for TFP calculations needs to be sufficiently long enough to capture/reflect the spending associated with the measured growth in output?

Response:

B&V provides the following response.

No. The lumpy additions have an impact on future additions only to the extent that they delay the cost in the future. It is impossible to properly reflect this consideration historically because once the capacity has been installed it becomes sunk costs that must be recovered in the revenue requirement once it has been added to rate base as prudently incurred costs. This is why, for example, that in transitioning regulated utilities from regulation to competition, utilities have been allowed to recover stranded costs. It is also why the estimation of TFP under the current economic paradigm is unreliable unless a variety of real-life factors are considered beyond the assumptions used in the standard economic models.

8.2.1 If yes, please indicate what length of period would be required and why the value suggested is considered suitable.

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.8.2.

9.0 Reference: FBC – BCUC 1.19.3

FBC – BCUC 1.20.1

9.1 Using the B&V methodology (as set out in Appendix D2) what would be the resulting TFP value if the calculation only included 60% of the additions to capital plant made in each year and, correspondingly, only 60% of the costs of associated with those additions.

Response:

B&V provides the following response.

B&V does not have the data required to perform this analysis. This change impacts both output as measured by capacity and customer additions and also changes the level of inputs. Any such adjustments would be purely arbitrary and would result in estimates that could not be relied on for any results.

10.0 Reference: FBC – BCUC 1.47.1

Preamble: The response states: "If growth in inputs is faster than the growth in outputs TFP is negative".

10.1 When referencing inputs, is B&V referring to input values adjusted for the impact of inflation or do the input measures used also include inflationary effects?

Response:

B&V provides the following response.

Inputs and outputs can be physical measures or cost measures. For a multi-output firm the theoretically precise estimation of TFP requires marginal costs for inputs (equivalent to the price of the input under a competitive model) for the period being analyzed and this would be a nominal value, i.e. includes inflationary effects.

10.2 If inflationary effects are also included in the inputs values used, please confirm that the TFP estimate will also reflect historical input cost inflation.

Response:

B&V provides the following response.

As noted in the response to FEI-FBC BCPSO PBR IR 3.10.1, TFP uses the nominal price (marginal cost for the regulated firm buying inputs from other firms) of inputs to assess productivity over time.

11.0 Reference: FBC – BCUC 1.45.2

FBC – BCUC 1.49.1

Updated PEG Report, May 31, 2013, page 46
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf

Preamble: B&V claims that the PEG Study (done for Ontario) used the system coincident peak as its measure for capacity.

11.1 Please confirm that actual capacity measure used by PEG was "the highest annual peak demand measure for a distributor up to the year in question" and therefore would not vary from year to year based on each year's weather as suggested by B&V.

Response:

B&V provides the following response.

It is confirmed that the peak demand is the actual value for 2002 (unadjusted for weather) and the highest value occurring in the current year or prior years. This value is indeed more stable than using the year by year variable. Nevertheless, since there are a variety of factors including weather that impact this value from year to year, the measure has an underlying flaw in that it does not measure the growth in installed capacity from year to year. This results from the fact that customer growth on the distribution system requires the installation of new distribution capacity for transformers, circuit miles and potentially even for substations. The capacity proxy variable may not show growth in capacity simply because the weather variable differed from year to year. Even if the distributor added substantial new capacity in a given year but the weather was warmer in a winter peaking system or cooler in a summer peaking system than some prior period with fewer customers there could be no growth in the measure of capacity to accompany the actual increase in inputs to meet system design day load considerations. In a subsequent year there could be no growth in actual capacity but the weather could be hotter (in a summer peaking situation) than a prior period resulting in a substantial increase in the measured output but no increase in inputs. This is a fundamental flaw in the measurement of the capacity output.

12.0 Reference: FBC – BCUC 1.51.1.1

FBC – BCUC 1.51.2

FBC – BCUC 1.52.1

12.1 Please provide a schedule that for the 2007-2011 period breaks down total T&D capital expenditures as between growth versus infrastructure replacement and, then further separates out the spending for each that was approved via CPCN applications.

<u>Response:</u>

The requested information is provided in the following tables. The expenditures presented include loadings and AFUDC and exclude costs of removal.

	Estimated Capital Related to the Replacement of Existing Assets ($000s)				
	2007	**2008**	**2009**	**2010**	**2011**
Generation	20,275	15,609	18,818	17,575	16,667
Transmission and Stations	26,703	14,728	16,274	23,294	11,427
Distribution	10,417	8,474	12,517	12,605	8,359
General Plant	10,416	8,136	7,885	6,689	11,653
Total	**67,812**	**46,947**	**55,494**	**60,163**	**48,106**

	Estimated Capital Related to Growth ($000s)				
	2007	**2008**	**2009**	**2010**	**2011**
Generation	128	585	851	956	876
Transmission and Stations	42,365	32,234	33,711	57,344	15,360
Distribution	28,069	28,018	18,282	18,697	18,075
General Plant	5,366	3,794	4,385	4,879	5,948
Total	**75,928**	**64,631**	**57,228**	**81,875**	**40,259**

Capital Projects Subject to CPCN Applications (Approval Order)	Annual Expenditures ($000s)				
	2007	2008	2009	2010	2011
Kooteny 230 kV System Development Project (C-10-00)	(3,348)	64	-	-	-
South Okanagan Supply Reinforcement (C-3-03)	873	(106)	-	-	-
Kelowna Area Upgrade (C-18-04)	423	-	-	-	-
Nk'Mip Substation (C-1-06)	15,251	144	-	-	-
Kettle Valley Distribution (C-5-06)	18,378	4,802	473	-	-
Big White Transmission and Substation (C-17-06)	9,666	7,380	110	-	-
Ellison Distribution Source (C-4-07)	1,744	7,810	5,608	102	-
Black Mountain Distribution Source (C-7-07)	476	6,811	7,196	(6)	-
Ootischenia Substation (C-10-07)	492	5,492	142	-	-
Distribution Substation Automation Program (C-11-07)	-	1,108	1,784	1,488	2,162
Okanagan Transmission Reinforcement (C-5-08)	3,838	3,418	21,503	55,715	12,821
Benvoulin Substation (C-1-09)	-	-	4,110	11,435	993
Corra Linn U2 ULE (C-5-09)	-	-	33	3,505	12,090

12.2 Please provide a similar breakdown (based on the forecasts provided in Section C-5 of the Application) for the period 2014-2018.

Response:

The following table provides an estimate of the breakdown of forecast capital (excluding overheads and AFUDC and including costs of removal) for the 2014 – 2018 period between replacement of existing assets and growth.

The forecast capital expenditures are based on the five year capital forecast as discussed in Section C5 of the Application (Exhibit B-1), and not the capital expenditures as determined by the PBR formula. The forecast capital expenditures include expenditures related to Major Projects (including future CPCN applications) for the 2014 – 2018 period.

	Estimated Capital Related to the Replacement of Existing Assets ($000s)				
	2014	**2015**	**2016**	**2017**	**2018**
Generation	2,997	2,793	6,352	16,748	10,832
Transmission and Stations	13,442	7,068	6,101	10,642	20,326
Distribution	11,910	11,869	13,142	13,259	13,873
General Plant	16,706	17,604	6,586	4,912	4,871
Subtotal	**45,055**	**39,334**	**32,180**	**45,562**	**49,903**
	Estimated Capital Related to Growth ($000s)				
	2014	**2015**	**2016**	**2017**	**2018**
Generation	158	147	334	881	570
Transmission and Stations	10,139	5,331	4,602	8,027	15,332
Distribution	15,620	15,567	17,236	17,390	18,195
General Plant	18,143	19,118	7,152	5,335	5,291
Subtotal	**44,060**	**40,163**	**29,324**	**31,634**	**39,388**
Pension Adjustments	(345)	(789)	(1,233)	(1,608)	(1,915)
Total Capital Expenditures	**88,770**	**78,708**	**60,272**	**75,588**	**87,376**
Reconciliation to Table C5-3					
Less Major Projects (except AMI and PCB Compliance)	13,594	8,273	5,590	22,560	30,415
Total Forecast Capital Expenditures as per Table C5-3	**75,176**	**70,435**	**54,681**	**53,028**	**56,960**

Please also refer to the response to FBC BCUC IR 2.39.5 (Exhibit B-24).

13.0 Reference: FBC – BCUC 1.58.1

FBC – BCPSO 1.25.1

13.1 In the example provided in BCPSO 1.25.1, page 37, lines 13-19, please clarify whether the adjustment to opening rate base would also affect the opening rate base for the years subsequent to 2016.

Response:

Confirmed. The rate base adjustment would be carried forward in subsequent years of the PBR term.

14.0 Reference: FBC – BCUC 1.61.5

BCUC Reasons for Decision, G-180-10, Appendix B, page 8

14.1 In the Settlement Agreement regarding its F2011 Revenue Requirement, BC Hydro also agreed to report CEMI reliability metrics. Does FortisBC have the capability to track and report CEMI reliability metrics?

Response:

In theory, FBC could provide a CEMI metric, however at this time the Company is not reasonably able to do so. Tracking the CEMI metric would be labour intensive, and hence costly, relative to the information provided by the additional metric and therefore it has not been calculated to date. FBC notes that – unlike BC Hydro – it does not currently have an automated Outage Management System (OMS) and hence outage data would have to be manually analyzed to extract the required information. FBC suggests that it would be more appropriate to wait until after the implementation of the AMI and OMS systems before considering monitoring the CEMI statistics. Together, these systems will provide significantly more accurate outage information along with the ability to automate reliability metric calculations and minimize the costs associated with such reliability monitoring.

14.2 If yes, what are the CEMI-4 results for the last 3 years? If CEMI-4 cannot be reported, please indicate what CEMI values are available and provide the most recent three years' values.

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.14.1.

15.0 Reference: FBC - BPSO 1.13.5

15.1 Does the existence of the 90%/110% collar for capital expenditures trigger for rebasing, create a bias for FortisBC to substitute capital for O&M spending where possible?

<u>Response:</u>

FBC expects annual capital expenditures to be within the 90% / 110% range of formula-based allowances in most years so this would not be an issue. FBC agrees that the incentive balance between O&M and capital changes if capital spending falls outside of the 90% to 110% collar. However, based on experience in its previous PBR FBC does not believe this should be a concern. FBC's prior PBR had no capital incentive but there was earnings sharing on O&M variances from the formula level. Therefore the same capital / O&M substitution concern as noted in the question existed in that PBR (without any sheltering provision like the 90% / 110% collar) and this issue was not raised as a concern in that context. FBC has established capitalization policies and complies fully with accounting standards in terms of recording expenses as O&M or capital.

Under the proposed PBR plan, FBC will have the required flexibility and incentive to seek the most efficient combination of O&M and capital expenditures throughout the PBR term.

16.0 Reference: FBC – BCPSO 1.14.1

16.1 The original interrogatory asked for a comparison of actual BC CPI values for 2007-2012 with the actual values for the inflation index currently proposed. The response does not include the historical values for the inflation index proposed in the current Application. Please provide.

Response:

The historic calculation of the composite I-Factor compared to BC CPI for 2007 to 2012 is provided below.

	2007	2008	2009	2010	2011	2012
BC-AWE	3.4%	2.6%	0.8%	3.0%	2.8%	2.9%
BC-CPI	1.9%	2.3%	0.0%	1.5%	2.7%	1.3%
Labour	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Non-Labour	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
Composite I-Factor	**2.7%**	**2.4%**	**0.5%**	**2.3%**	**2.7%**	**2.2%**
BC CPI - Actual	**1.9%**	**2.3%**	**0.0%**	**1.5%**	**2.7%**	**1.3%**

FBC and FEI would expect the Composite I-Factor to be higher than BC CPI, as wages have recently increased at a greater rate than inflation, and the Companies have had those additional cost pressures within their own operations.

17.0 Reference: FBC – BCPSO 1.29.4

FEI – BCPSO 1.3.4

17.1 Would it be fair to re-word the statement such that it read – "negative TFP means that costs per unit of output are rising faster than input price inflation"? If not, why not?

<u>Response:</u>

B&V provides the following response.

No. Negative TFP means that the revenue requirement for the utility is rising faster than input price inflation net of changes in technical efficiency and scale economy effects.

18.0 Reference: FBC – BCPSO 1.33.1

FBC – ICG 1.6.1

18.1 Please provide a copy of the most recent Order by FERC that establishes the price cap index for oil pipelines and sets out how the results of the Khan methodology as used to set the oil pipeline index.

<u>Response:</u>

The most recent order, 2010, is provided in Attachment 18.1.

19.0 Reference: FEI – BCPSO 1.7.1
FBC – CEC 1.74.14, Attachment – Testimony of Alfred Khan
FBC – BCPSO 1.33.2
FEI – BCPSO 1.7.3
FBC – BCPSO 1.35.5
FBC – CEC 1.74.19

19.1 With reference to FBC – CEC 1.74.14 (Testimony of Alfred Khan, pages 10-12) and FBC – BCPSO 1.33.2, please confirm that in an I-X PBR formulation the Khan methodology does not base the X-Factor on the increase in costs relative to increase in output as established by the historical analysis pipeline costs and outputs but rather bases the X-Factor on the difference between the results of this analysis and the historical value for the I Factor.

Response:

Confirmed by B&V. Please refer to the response to FEI-FBC BCPSO PBR IR 3.19.2.1.

19.1.1 If not, please explain fully B&V's interpretation as to Khan's (and FERC's resulting) calculation of the X-Factor with reference to both Khan's Testimony and most recent Order issued by FERC.

Response:

Not Applicable. Please refer to the response to FEI-FBC BCPSO PBR IR 3.19.1.

19.2 Please confirm that in the case of FBC, application of the Khan Methodology would require taking results of the analysis performed by B&V (I.e. 3.95% to 6.24% from Appendix D2, page 10) and subtracting the historical escalation in FBC's proposed I-Factor over the period used in the B&V analysis in order to derive the X-Factor.

Response:

Not confirmed. Please refer to the response to FEI-FBC BCPSO PBR IR 3.19.2.1 for the reasons why this is not the case.

19.2.1 If not, please explain why? Note: If necessary, for purposes of responding to this question, assume the input price escalation experienced by the US utilities analyzed was similar to that experienced by FBC during the historical period covered by the analysis.

Response:

B&V provides the following response.

The use of the Khan Method is the basis for calculating TFP rather than merely calculating cost changes to be compared to price changes. The Khan Method has been adapted to measure the change in outputs (customer and capacity) compared to change in inputs using OPEX and Capital as the two inputs. The output index is based on measures of the physical outputs weighted by a measure of marginal productivity for each input. The input measure based on the Khan analysis represents the cost weighted shares as defined by the revenue requirement associated with each factor OPEX and Capital. The end result is a measure of the change in output and change in input over time and across utilities. In developing this measure, the results are transparent, easily understood and calculated and importantly require a limited number of assumptions to develop the TFP estimate that includes the way utilities operate in the real world. There is no need to make any assumption about how input prices change in the analysis because they are part of the revenue requirement and cause the utility to move along the most economic expansion path that reflects minimizing OPEX costs for fixed capacity and capital costs, essentially along a short-run average total cost path up to the point of tangency with the long-run cost curve and then to a new point on the long-run cost curve via a new short-run cost curve based on the addition of capital assets.

19.3 What was the historical escalation in FBC's proposed I-Factor over the period used in B&V's analysis?

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.16.1.

20.0 Reference: FBC – BCPSO 1.43.2

20.1 Over the proposed PBR period (2014-2018) what % of sustainment capital spending (per Section C-5 of the Main Application) is associated with system capacity improvements?

Response:

Any project associated with system capacity improvements is classified as growth and not sustainment; hence, by definition none of the sustainment capital identified in Section C5 of the Application is associated with system capacity improvements.

21.0 Reference: FBC – BCPSO 1.56.1 and 1.56.2

21.1 Please explain why FBC sets targets for customer satisfaction for purposes of its Corporate Scorecard but does not view it appropriate to do so for purposes of its proposed PBR plan.

Response:

FBC considers it appropriate to use customer satisfaction for its Corporate Scorecard measure, but to use it as an informational indicator in SQIs. The difference in treatment is driven by three facts:

- First, customer satisfaction is affected by matters outside of the control of the utility. For example, customer attitudes can be influenced by storm related unplanned outages, media coverage, and customer concerns about tiered electricity prices or collection policies.
- Second, not all factors influencing customer satisfaction scores can be objectively measured like a physical event such as a system outage. While the survey used to collect the customer satisfaction scores is defined in an objective manner, the results themselves are subject to the influence of customers' interpretation and perception of the issues. Such subjective interpretation of events by customers may lead to lower customer satisfaction results reported while results for the other SQIs may be meeting or exceeding their benchmarks. Please refer to FBC's Application (Exhibit B-1), Section A4.2 Strengthening Customer Focus for further discussion.
- Third, when the measure is used for internal purposes, FBC has greater flexibility to account for such external and subjective circumstances appropriately.

22.0 Reference: FBC – BCPSO 1.86.3

22.1 Are there planned substation upgrades over the 2014-2018 period for which FBC is not planning to make a CPCN application? If so, please identify the stations involved, the anticipated time and the anticipated costs.

Response:

All currently planned substation upgrades which will not be the subject of a CPCN application are already identified (including timing and costs) in Section 5.4.3 (Station Sustainment Capital) and Section 5.5.2 (Transmission and Station Growth Capital) of Exhibit B-1.

23.0 Reference: FBC – BCPSO 1.86.4

23.1 Please confirm that it is not just capital projects subject to a CPCN that can impact productivity by increasing costs without any change in capacity or number of customers.

<u>Response:</u>

Confirmed.

23.1.1 If confirmed, please explain why low capital cost projects that are subject to a CPCN should be excluded from the PBR formula while capital projects of a similar cost but that do not require a CPCN should be included in the PBR formula.

<u>Response:</u>

In the response to FBC BCPSO IR 1.86.3 (Exhibit B-11), FBC provided its rationale for filing CPCN applications for specific projects below the $20 million CPCN threshold. FBC's 2013 capital expenditure base to be used in the capital formula and the five-year forecast of base capital expenditures have been developed without the CPCN projects included. With these projects removed from the formula-based capital FBC believes, as explained in FBC BCPSO IR 1.86.4 (Exhibit B-11), that the remaining capital expenditures are representative of a more steady state situation. FBC can manage the remaining capital expenditures within the formula-based spending envelope, including accommodating the lumpiness from somewhat larger non-CPCN projects that may occur within the PBR term.

24.0 Reference: FBC - CEC 1.15.1

24.1 The response states that rates will be set each year with 100% of the X-Factor (0.5%) benefitting customers. Please confirm that, if FortisBC does not achieve this level of efficiency then, by virtue of the symmetric nature of the 50/50 ESM, half will be "clawed back" from customers.

<u>Response:</u>

Yes, the earnings sharing mechanism is symmetric. If FBC does not meet the level of efficiency of the X-factor 50% of the resulting shortfall in ROE will be recovered from customers. This treatment is the same approach to earnings sharing as has been included in FBC's and FEI's past PBR plans.

25.0 Reference: FBC – CEC 1.74.8

FEI – CEC 1.81.8

25.1 Is FBC or FEI proposing to reduce the capacity component of the system included in its PBR proposal (i.e. increase in customer count) in conjunction with the exclusion of CPCNs?

Response:

No. B&V explains that the exclusion of CPCN costs from the PBR calculation has no impact on the proxy measure for capacity used to adjust the revenue requirement prior to application of the adjustment formula.

25.1.1 If not, please explain how excluding CPCNs in FBC's and FEI's proposed PBR plans changes/reduces the output measure used by the plan.

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.25.1.

26.0 Reference: FBC – BCPSO 1.29.2

FBC – CEC 1.74.11

FEI – CEC 1.81.11

Preamble: The response to FBC-CEC 1.74.11 states: "The net result of a change in costs as a result of lower expenses would be to increase TFP".

26.1 Please confirm that, based on the definition of TFP set out in FBC-BCPSO 1.29.2 (and agreed to by FBC) a change in input costs would not impact the calculation of TFP if it was solely due to change in input prices, as the definition is based on physical changes outputs and inputs.

Response:

B&V provides the following response.

Confirmed. By definition, lower expenses means producing the output with fewer inputs, hence an increase in TFP.

26.1.1 If not confirmed, please explain why.

Response:

Please refer to the response to FEI-FBC BCPSO PBR IR 3.26.1.

Attachment 1.3

Final decision

Australian Capital Territory distribution determination

2009–10 to 2013–14

28 April 2009

AUSTRALIAN ENERGY REGULATOR

for each interest period equal to the 3–month bank bill rate[329] plus a 'margin' of 4.25 per cent.[330] As at 23 March 2009, the initial interest rate would be 7.28 per cent.[331] The AER notes that on 23 March 2009 the Bloomberg five year BBB fair yield was 7.41 per cent and the CBASpectrum five year BBB+ fair yield was 9.67 per cent. Further, the AER notes that the fair yields represent estimates for fixed interest bonds, not variable interest bonds. While there are ways with converting the yield of a variable rate bond to the yield of an equivalent fixed rate bond, the AER does not consider it appropriate to compare the yields on variable rate bonds with those of fixed rate bonds for the purpose of assessing the fair yield estimates from Bloomberg and CBASpectrum.

Given these considerations, the AER is of the view that Bloomberg fair yields are a better predictor of observed yields CBASpectrum fair yields alone or an average of Bloomberg and CBASpectrum fair yields. Consequently, the AER does not consider it reasonable to use the BBB+ fair yield reported by CBASpectrum or an average of Bloomberg and CBASpectrum fair yields to derive the Australian benchmark rate for corporate bonds with a maturity of 10 years and a credit rating of BBB+. The AER therefore maintains its draft decision to use Bloomberg fair yields for the purposes of determining the benchmark debt risk premium for ActewAGL.[332]

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk–free rate. For this final decision, the 20 business day moving average benchmark debt risk premium for the period ending 27 February 2009, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.49 per cent (effective annual compounding rate). Adding this debt risk premium to the nominal risk–free rate of 4.29 per cent provides a nominal return on debt of 7.78 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6.5.2(e) of the transitional chapter 6 rules, with the required margin between the 10–year CGS yield and observed Australian benchmark corporate bond yields corresponding to BBB+ credit rating and maturity of 10 years.

12.5.3 Expected inflation

AER draft decision

The AER determined a 10–year inflation forecast of 2.55 per cent per annum. The inflation forecast was based on a simple average of the Reserve Bank of Australia's (RBA) forecasts of short term inflation—currently extending out to two years—and the mid–point of the RBA's target inflation band for the remaining years in the 10–year period.

The AER did not accept the inflation forecast proposed by ActewAGL, which was based on advice commissioned from CEG. ActewAGL's inflation forecast was

329 Tabcorp, *Tabcorp bonds: prospectus for the issue of five year Tabcorp bonds to be listed on ASX*, 24 March 2009, p. 6.

330 Tabcorp, *Tabcorp bonds margin now set and offer now open*, 1 April 2009, p. 1.

331 The Tabcorp bond prospectus (on page 1) states that the initial interest rate would be between 7.03 per cent and 7.53 per cent. Based on the confirmed margin of 4.25 per cent this equates to an initial interest rate of 7.28 per cent.

332 The fair yield as a proxy for the corporate bond yield less the CGS yield as a proxy for the risk–free rate produces the debt risk premium.

calculated using a weighted average mean of professional economic forecasters' short–term inflation expectations and the mid–point of the RBA's long–term target inflation band, yielding an inflation rate of 2.51 per cent per annum.[333]

The AER determined that, consistent with recent transmission determinations, an inflation forecasting methodology based on the RBA inflation forecasts and the mid–point of the RBA's target inflation band is objective and represents the best estimate of forecast inflation.[334] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.

Revised regulatory proposal

In its revised regulatory proposal, ActewAGL did not agree with the AER's inflation forecasting methodology. ActewAGL stated that the AER should not have used an updated RBA inflation forecast inflation for 2009–10 in the draft decision, unless the proposed inflation forecast was significantly different to the forecast proposed by ActewAGL.[335] ActewAGL also stated that, because its proposed inflation forecasts for 2010–11 to 2013–14 were not significantly different from the AER's forecast inflation for these years, the AER had not demonstrated that ActewAGL's forecasts of inflation were unreasonable.[336]

To calculate a 10–year inflation forecast, ActewAGL's revised regulatory proposal used the AER's inflation forecasts for 2008–09 and 2009–10, adopted its regulatory proposal inflation forecasts for 2010–11 to 2013–14 and applied the mid–point of the RBA's target inflation band for the remaining years.[337] ActewAGL proposed that a geometric average be used as it is more accurate than a simple average. Based on this methodology, ActewAGL proposed an expected inflation estimate of 2.57 per cent per annum.[338]

AER considerations

In previous transmission determinations the AER has determined that a method that is likely to result in the best estimate of inflation over a 10–year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid–point of its target inflation band beyond that period (i.e. 2.5 per cent) for the remaining eight years. An implied 10–year forecast is derived by averaging these individual forecasts.

The AER does not agree that it should not have rejected ActewAGL's regulatory proposal inflation forecasts in the draft decision because the difference between the AER's forecasts and ActewAGL's was insignificant. The draft decision was made on the basis that the methodology proposed by ActewAGL was not likely to result in the best estimate of expected inflation.

ActewAGL proposed that a geometric average be used instead of a simple average because it provides a more accurate approach to determining the average 10–year

333 ActewAGL, *Regulatory proposal*, p. 210.
334 AER, *Draft decision*, pp. 139–140.
335 ActewAGL, *Revised regulatory proposal*, p. 10.
336 ActewAGL, *Revised regulatory proposal*, p. 10.
337 ActewAGL, *Revised regulatory proposal*, pp. 10, 49.
338 ActewAGL, *Revised regulatory proposal*, pp. 10, 49.

inflation forecast. The AER recognises there is considerable uncertainty in forecasting inflation. Having assessed ActewAGL's revised regulatory proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER also notes that the difference between applying a simple average and a geometric average is marginal.

The AER notes that ActewAGL has not provided any additional material in its revised regulatory proposal to justify a change to the AER's methodology or why an updated inflation forecast should not be adopted.

Inflation forecasts can change in line with market sensitive data. The recent change in short–term inflation expectations has been evident in the past six months, as demonstrated by the RBA's stance on monetary policy. In the draft decision the AER stated it would update the inflation forecast for its final decision. This is consistent with regulatory practice in Australia.

The AER has updated the inflation forecast for the first two years of the next regulatory control period using the latest published RBA inflation expectations as shown in table 12.5.[339] The AER considers that, consistent with its draft decision methodology and based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate for a 10–year period to be applied in the post–tax revenue model for this final decision.

Table 12.5: AER conclusion on inflation forecast (per cent)

	June 2010	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	Geometric average
Forecast inflation	2.75	2.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.47

Source: RBA, *Statement on monetary policy*, 6 February 2009, p. 65.

12.6 AER conclusion

The AER has determined a nominal vanilla WACC of 8.79 per cent for ActewAGL using the updated risk–free rate and debt risk premium, and other parameters prescribed under the transitional chapter 6 rules. Table 12.6 sets out the WACC parameter values used for this final decision. The AER's WACC is lower than ActewAGL's revised regulatory proposal WACC because of a lower nominal risk–free rate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

339 RBA, *Statement of Monetary Policy*, 6 February 2009, p. 65.

Table 12.6: AER conclusion on ActewAGL's WACC parameters

Parameter	AER conclusion
Risk–free rate (nominal)	4.29%
Risk–free rate (real)[a]	1.77%
Expected inflation rate	2.47%
Debt risk premium	3.49%
Market risk premium	6.00%
Gearing	60%
Equity beta	1.00
Nominal pre–tax return on debt	7.78%
Nominal post–tax return on equity	10.29%
Nominal vanilla WACC	8.79%

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging period in ActewAGL's regulatory proposal is reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by ActewAGL in support of its revised regulatory proposal does not reasonably justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

Having assessed ActewAGL's revised regulatory proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER notes that the difference between applying a simple average and a geometric average is marginal.

The AER maintains its draft decision to apply a methodology to determine a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years. The AER considers that, based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision.

12.7 AER decision

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the rate of return to apply to ActewAGL is 8.79 per cent.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs to apply to ActewAGL in respect of WACC parameters are as specified in table 12.6 of this final decision.

13 Service target performance incentive arrangements

13.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and how the AER intends to apply its service target performance incentive scheme (STPIS) arrangements to ActewAGL.

13.2 AER draft decision

In consultation with ActewAGL, the AER developed service performance data reporting requirements for the next regulatory control period. As foreshadowed in the AER's final decision on STPIS arrangements for the ACT and NSW determinations,[340] the data reporting requirements were aligned with the requirements of the national distribution STPIS, published in June 2008.[341]

The AER stated that it would collect and monitor ActewAGL's service performance data during the next regulatory control period but revenue would not be placed at risk under the data collection process during this period.[342]

While noting that full compliance may not be realised before the commencement of the next regulatory control period, the AER stated it expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, but no later than December 2009.[343]

13.3 Revised regulatory proposal

In response to the draft decision data collection requirements, ActewAGL proposed to implement a 'network connectivity solution' to establish the ability to record interruptions at the individual customer level.

It submitted that the solution will deliver accurate and timely data, compliant with the AER's reporting requirements.[344] ActewAGL stated that the solution will provide the ability to better plan and manage its network, assets, resources, reporting, fault resolution and provide customers with improved service.[345] However, it stated that the development of the network connectivity solution is a complex and lengthy project, and is not expected to be completed until 2013.[346] Given this, it noted that full

340 AER, *Final decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008.
341 AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme*, June 2008.
342 AER, *Draft decision*, p. 146.
343 AER, *Draft decision*, p. 146.
344 ActewAGL, *Revised regulatory proposal*, p. 20.
345 ActewAGL, *Revised regulatory proposal*, p. 20.
346 ActewAGL, *Revised regulatory proposal*, p. 21.

compliance with the data reporting requirements would not be achievable within the timeframe set in the draft decision.[347]

13.4 Submissions

The Energy Users Association of Australia (EUAA) and Energy Market Reform Forum (EMRF) made submissions in the context of STPIS arrangements for the NSW DNSPs. Specifically the EUAA and EMRF stated that a STPIS should be applied in the next regulatory control period.[348] The AER has considered these submissions in its review of STPIS arrangements for ActewAGL. Further details on the submissions are included in chapter 12 of the NSW DNSP final decision.[349]

13.5 Issues and AER considerations

Application of STPIS regime

The AER notes the EUAA's and EMRF's submissions that a STPIS should be applied during the next regulatory control period. In late 2007, the AER consulted on the STPIS arrangements to apply in the ACT and NSW for the next regulatory control period. The AER's decision, reasoning and responses to submissions received during that process are detailed in the STPIS final decision, published in February 2008.[350]

The AER will collect and monitor service performance data from ActewAGL during the next regulatory control period, and expects to apply financial rewards and penalties from the beginning of the 2014–19 regulatory control period. In addition, ActewAGL will continue to have an obligation to publish its performance data and report to the jurisdictional regulators in accordance with its utility licence. The AER considers that these two measures will continue to support the transparent reporting of reliability outcomes for ActewAGL's customers during the next regulatory control period. The collection of data will also ensure that a robust data set is available for setting meaningful and appropriate performance targets under the national distribution STPIS from 1 July 2014.

ActewAGL's network connectivity solution

The AER considers the scope of ActewAGL's proposed network connectivity solution to be an appropriate response to meeting the data reporting obligations for the next regulatory control period, as set out in the draft decision. It represents a significant project for ActewAGL and the AER acknowledges that it will take time before the new systems are fully operational. To this end, ActewAGL will not be expected to achieve full compliance with the requirements of the national distribution STPIS by December 2009. However, the AER does expect ActewAGL to implement the project as soon as practical.

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347 ActewAGL, *Revised regulatory proposal*, p. 21.
348 EUAA, *Submission to AER's draft decision and revised DNSP proposals – review of the regulatory proposals by the NSW electricity distributors*, 16 February 2009; and EMRF, *A response, AER NSW electricity distribution revenue reset, AER draft decision*, February 2009.
349 AER, *Final decision, NSW distribution determination*, section 12.4.
350 AER, *Final decision, STPIS ACT and NSW*, February 2008.

Attachment 18.1

133 FERC ¶ 61,228
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 342

[Docket No. RM10-25-000]

Five-Year Review of Oil Pipeline Pricing Index

(Issued December 16, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Establishing Index for Oil Price Change Ceiling Levels

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this Final Order concluding its third five-year review of the oil pricing index, established in Order No. 561. After consideration of the initial, reply and supplemental comments, the Commission has concluded that an index level of Producer Price Index for Finished Goods plus 2.65 percent (PPI-FG+2.65) should be established for the five-year period commencing July 1, 2011. At the end of this five-year period, the Commission will once again initiate review of the index to determine whether it continues to measure adequately the cost changes in the oil pipeline industry.

ADDRESS: Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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SUPPLEMENTARY INFORMATION:

133 FERC ¶ 61,228
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Five-Year Review of Oil Pricing Index — Docket No. RM10-25-000

ORDER ESTABLISHING INDEX FOR OIL PRICE CHANGE CEILING LEVELS

(Issued December 16, 2010)

1. On June 15, 2010, the Commission issued a Notice of Inquiry (NOI),[1] in which it proposed to continue using the Producer Price Index for Finished Goods plus 1.3 percent (PPI-FG+1.3) for the next five-year period beginning July 1, 2011. The Commission applies the index to existing oil pipeline transportation rates to establish new annual rate ceiling levels for pipeline rate changes. The NOI invited interested persons to submit comments on the continued use of PPI-FG+1.3 and to propose, justify, and fully support, any alternative indexing proposals. Comments and reply comments were due August 20, 2010, and September 20, 2010, respectively. Based upon full consideration of the comments and reply comments received, and for the reasons discussed below, the Commission finds that an index of PPI-FG plus 2.65 percent (PPI-FG+2.65) should be established for the five-year period commencing July 1, 2011.

[1] *Five-Year Review of Oil Pipeline Pricing Index*, 75 FR 34959 (June 21, 2010), FERC Stats. & Regs. ¶ 35,566 (2010) (NOI).

I. Background

A. Establishment of the Indexing Methodology

2. Congress in the Energy Policy Act of 1992 (EPAct 1992) required the Commission to establish a "simplified and generally applicable" ratemaking methodology for oil pipelines[2] that was consistent with the just and reasonable standard of the Interstate Commerce Act (ICA).[3] On October 22, 1993, the Commission issued Order No. 561,[4] promulgating regulations pertaining to the Commission's jurisdiction over oil pipelines under the ICA and fulfilling the requirements of the EPAct 1992. In Order No. 561, the Commission developed an indexing methodology for the purpose of allowing oil pipelines to change rates without making cost-of-service filings. The Commission found that the indexing methodology adopted in the final rule simplified and expedited the process of changing rates. The Commission further determined that the indexing methodology would ensure compliance with the just and reasonable standard of the ICA by subjecting the chosen index to periodic monitoring and, if necessary, adjustment. After extensive analysis of proposals from interested parties, the

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[2] Pub. L. No. 102-486, 106 Stat. 3010, § 1801(a) (Oct. 24, 1992). The EPAct 1992's mandate of establishing a simplified and generally applicable method of regulating oil transportation rates specifically excluded the Trans-Alaska Pipeline System (TAPS), or any pipeline delivering oil, directly or indirectly, into it. *Id.* § 1804(2)(B).

[3] 49 U.S.C. app. 1 (1988).

[4] *Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act*, Order 561, FERC Stats. & Regs. ¶ 30,985 (1993), *order on reh'g*, Order No. 561-A, FERC Stats. & Regs. ¶ 31,000 (1994), *aff'd*, *Association of Oil Pipe Lines v. FERC*, 83 F.3d 1424 (D.C. Cir. 1996) (AOPL I).

Commission adopted an index of PPI-FG minus 1 percent (PPI-FG-1), which was supported by a methodology developed by Dr. Alfred E. Kahn (Kahn Methodology) on behalf of a group of shippers. The Commission also committed to review every five years the continued appropriateness of the index in relation to industry costs.

3. In the first five-year review, which established the index level for 2001-2006, the Commission deviated from the Kahn Methodology, and, based upon a different analysis, concluded that the index should be retained as PPI-FG-1.[5] The U.S. Court of Appeals for the District of Columbia (D.C. Circuit) reviewed and remanded the Commission's order because the Commission failed to justify a departure from the Kahn Methodology used in Order No. 561.[6] On remand, the Commission used the Kahn Methodology to set an index level of an unadjusted PPI-FG for the five-year period beginning July 2001. This order on remand was upheld by the D.C. Circuit.[7]

4. In the second five-year review, the Commission proposed to retain the rate of an unadjusted PPI-FG. However, based upon the data presented during that proceeding, the

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[5] *Five-Year Review of Oil Pipeline Pricing Index*, 93 FERC ¶ 61,266 (2000) (First Five-Year Review), *aff'd in part and remanded in part sub nom. AOPL v. FERC*, 281 F.3d 239 (D.C. Cir. 2002) (AOPL II).

[6] *AOPL II*, 281 F.3d 239.

[7] *Five-Year Review of Oil Pipeline Pricing Index*, 102 FERC ¶ 61,195 (2003) (First Five-Year Review Remand Order), *aff'd sub nom. Flying J Inc. v. FERC,* 363 F.3d 495 (D.C. Cir. 2004).

Commission adopted an index of PPI-FG+1.3, which was again calculated using the Kahn Methodology.[8]

B. The Kahn Methodology

5. The Kahn Methodology measures changes in operating and capital costs on a per barrel-mile basis using Form No. 6 data from the prior five-year period (for example, between 2004 and 2009 in this proceeding).[9] The Kahn Methodology does not include direct measures of the capital costs related to rate of return on investment or income taxes; as a proxy for this data, the Kahn Methodology relies upon changes over the five year period in net carrier property per barrel-mile.

6. The Kahn Methodology assigns a weight to the Form No. 6 operating expenses relative to the net plant using an "operating ratio."[10] The weighted operating expense and the weighted net plant are then added together to establish the cumulative cost change for each pipeline.[11]

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[8] *Five-Year Review of Oil Pipeline Pricing Index*, 114 FERC ¶ 61,293 (2006) (Second Five-Year Review).

[9] Specifically, this data is drawn from the Form No. 6: Carrier Property, page 110; Accrued Depreciation, page 111; Operating Revenues and Operating Expenses, page 114; Crude and Products Barrel-Miles, page 600. To the extent this information is incomplete, alternate data reported in the Form No. 6 has been substituted.

[10] The "operating ratio" = ((Operating Expense at Year 1 / Operating Revenue at Year 1) + (Operating Expense at Year 5 / Operating Revenue at Year 5))/2. If the operating ratio is greater than one, then it is assigned the value of 1 under the Kahn Methodology.

[11] Cumulative Cost Change = (1-operating ratio) * net plant + operating ratio * operating expenses.

7. Once these cumulative cost changes have been calculated for each pipeline with sufficient Form No. 6 data, the Kahn Methodology culls a data set consisting of pipelines with cumulative per-barrel-mile cost changes in the middle 50 percent of all pipelines. Later applications of the index also culled a data set consisting of pipelines with cumulative cost changes in the middle 80 percent of all pipelines. This trimming is done to remove statistical outliers, or spurious data points that could bias the sample in either direction.

8. For each of the two data sets (the middle 50 percent and the middle 80 percent), the Kahn Methodology considers three different measures of central tendency. One measure is the median of each data set. Another measure, the weighted mean, calculates an average barrel-mile cost change in which each pipeline's cost change is weighted by its barrel-miles. A third measure, the un-weighted average, calculates the simple average of the percentage cost change per barrel-mile for each pipeline. For each data set, a composite, is calculated by taking the simple average of the median, the weighted mean, and the un-weighted mean. Table 1 provides a description of the statistical values of central tendency used by parties to develop the index.

Line	**Middle 80 percent**	**Middle 50 percent**
A	Median	Median
B	Weighted Mean	Weighted Mean
C	Un-weighted Mean	Un-weighted Mean

D	Composite of 80 percent = (A+B+C)/3	Composite of 50 percent = (A+B+C)/3

Table 1

In the most recent index review, the industry-wide cost index differential was calculated by averaging the middle 50 composite and the middle 80 composite on Line D and then comparing that value to the PPI-FG index data over the same period. The index level was then set at PPI-FG plus (or minus) this differential.

9. The Kahn Methodology has evolved during the course of prior index reviews. In Order Nos. 561 and 561-A, the Commission only considered the middle 50 percent and did not consider the middle 80 percent. In the first and second five-year index reviews, the Commission considered both the middle 50 percent and the middle 80 percent. Also, in Order Nos. 561 and 561-A, as well as the first review, the Commission merely cited Kahn's Methodology to demonstrate that it produced index levels that were close, although not exactly the same as, the proposed index levels of PPI-FG-1 (in Order Nos. 561 and 561-A) and an unadjusted PPI-FG (in the first review). In the second five-year review, the Commission used the Kahn Methodology itself to set the precise index levels by averaging the middle 50 and middle 80 composites relative to PPI-FG over the prior five-year period.

II. <u>Comments from Industry</u>

10. Comments were filed by the American Trucking Associations, National Propane Gas Association (NPGA), Tesoro Refining and Market Company and Sinclair Oil

Corporation (Sinclair/Tesoro, collectively), Air Transport Association of America (ATA), Society for the Preservation of Oil Pipeline Shippers (SPOPS), the Association of Oil Pipe Lines (AOPL), Valero Marketing and Supply (Valero), and Navajo Refining Company, L.L.C. (Navajo).

11. Reply Comments were filed by the Canadian Association of Petroleum Producers (CAPP), the Pipeline Safety Trust, Sinclair/Tesoro, Platte Pipe Line Company (Platte), ATA, Navajo, AOPL, and SPOPS.

12. On September 24, 2010, the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) filed a Motion for Leave to File Out-of-Time and Comments and NPGA filed late Reply Comments.

13. On October 8, 2010, Valero filed Supplemental Reply Comments and on October 20, 2010, AOPL filed a Response (October 20 Response).

A. Proposals for New Index Rates

14. In comments and reply comments, several parties proposed departures from existing index levels. AOPL proposes an index of PPI-FG plus 3.64 percent (PPI-FG+3.64) as the oil pipeline pricing index for the five-year period beginning July 1, 2011. AOPL states that its witness, Dr. Ramsey Shehadeh, applied the Kahn

Methodology to a data set including an initial sample of 110 pipelines,[12] calculating the following data regarding pipeline cost changes for the 2004-2009 period:

Line	Middle 80 percent	Middle 50 percent
Median	4.26	4.26
Weighted Mean	9.91	7.07
Un-weighted Mean	8.81	5.74
Composite	7.66	5.69

Table 2[13]

15. AOPL calculated an average annual pipeline cost growth rate of 6.68 percent based upon the middle 50 composite growth rate and the middle 80 composite growth rate. AOPL notes that the PPI-FG geometric mean rate of growth for the years 2004 through 2009 is 3.04 percent. AOPL concludes actual oil pipeline cost increases during the years 2004 through 2009 exceeded PPI-FG at a rate of 3.64 percent (6.68 minus 3.04). Thus, Dr. Shehadeh proposes an index rate for the five-year period beginning July 1, 2011, of PPI-FG+3.64.

16. In contrast, Valero and its expert, Mr. Matthew O'Loughlin, contend that an index equal to an unadjusted PPI-FG more accurately reflects pipelines' actual cost changes.

[12] AOPL states that Dr. Shehadeh began his analysis using cost data reported by the oil pipelines in the Form No. 6 for the years 2004 through 2009. According to AOPL, Dr. Shehadeh then removed from this data set any pipelines that did not report data for any year in that period, as well as the Trans Alaska Pipeline System carriers and any pipelines that had FERC Form No. 6 reporting errors or incomplete FERC Form No. 6 data.

[13] Shehadeh August 20 Decl. at Exhibit A5.

Valero states that Mr. O'Loughlin applies a modified version of the Kahn Methodology. First, Mr. O'Loughlin proposes to exclude pipelines that experienced large rate base changes from the data set used to calculate index levels. Second, to determine cost changes between 2004 and 2009, Mr. O'Loughlin measures the cost change per barrel-mile between 2004 and 2009 using the "Total Cost of Service" and barrel-miles reported on page 700. Unlike the other Form No. 6 data used in the Kahn Methodology, the page 700 data includes an interstate total cost of service calculated under the Opinion No. 154-B Methodology used to determine oil pipeline rates. Following these procedures, Mr. O'Loughlin derives the following data:

Line	**Middle 80 percent**	**Middle 50 percent**
Median	2.6	2.6
Weighted Mean	4.9	3.3
Unweighted Mean	3.9	2.9
Composite	3.8	2.9

Table 3[14]

17. Mr. O'Loughlin notes that the middle 50 composite of 2.9 percent is very close to the PPI-FG of 3.0 percent over the last five years and supports an index of an unadjusted PPI-FG. In Mr. O'Loughlin's view, the middle 50 is the most appropriate for

[14] O'Loughlin August 20 Aff. ¶ 6. Mr. O'Loughlin explains that he only reports data to the nearest tenth because, in his view, more precision is not useful given the wide ranging distribution of annual percentage cost changes experienced by the pipelines in the measurement group. O'Loughlin September 20 Aff. ¶ 5 n.3.

determining index levels, and should be used instead of the composite of the middle 50 and the middle 80.

18. Other parties endorsed either the views expressed by AOPL or Valero. Platte states that it is a member of AOPL and filed to provide further support for AOPL's request of an index of PPI-FG+3.64. On the other hand, NPGA states that it supports the arguments and recommendations espoused by Mr. O'Loughlin on behalf of Valero, including the use of a PPI-FG without any adjustment. Navajo states that it prefers Valero's proposal to establish an index level of PPI-FG.

19. Other parties also proposed differing index levels. In reply comments, CAPP and its expert Mark Pinney state that if AOPL's analysis is reproduced using constant 2004 barrel-miles instead of the recession-influenced 2009 data, the annual cost increase between 2004 and 2009 is PPI-FG plus 1.62 percent (PPI-FG+1.62), which CAPP observes is much closer to the current PPI-FG+1.3 than the index level proposed by AOPL. SPOPS asserts that the index should be set at zero until all pipeline over-recoveries are at just and reasonable levels and Navajo proposes to deny index increases to pipelines that are currently over-recovering. Navajo also proposes to base the index upon changes in operating and maintenance costs and to allow indexed increases only to the proportion of the pipeline's rate that can be attributed to such operating and maintenance costs.

20. Other parties, as discussed below, without proposing particular index levels, urge the Commission to reassess the index methodology to avoid over-recoveries. Some

parties also raised procedural concerns and argued for various changes to the Commission's Form No. 6 reporting requirements.

III. Discussion

21. The Commission adopts an index level of PPI-FG+2.65. The Commission rejects the procedural challenges to the validity of the NOI and to consideration of any modifications to the Kahn Methodology. The Commission's proposed index level of PPI-FG+2.65 is supported by the Kahn Methodology as applied by AOPL, except that the Commission adopts Valero's proposal to calculate the index using only the middle 50 percent and not the middle 80 percent of the data set.

A. Procedural Arguments

1. The Validity of the Notice of Inquiry

a. Comments

22. The American Trucking Association and Sinclair/Tesoro challenge the validity of the NOI. These parties state that the NOI contains no justification for the index of PPI-FG+1.3 specified in the NOI. Sinclair/Tesoro emphasizes that an agency must reveal an adequate explanation of the basis for its proposal and that the rulemaking is procedurally defective and should be withdrawn. Sinclair/Tesoro avers that the Commission provided no data analysis or support showing that it has evaluated the reasonableness of PPI-FG+1.3 as the appropriate index for determining rate ceilings.

23. AOPL asserts that these criticisms of the NOI are baseless. AOPL posits that the Commission's methodology for calculating its index is well-known to industry participants and that there exists an "opportunity for interested parties to participate in a

meaningful way in the discussion and final formulation of rules."[15] AOPL further emphasizes that Dr. Shehadeh has provided data supporting his result pursuant to the established methodology and states the Commission can rely upon these calculations and data.

b. <u>Commission Determination</u>

24. The Commission rejects the assertion that the NOI is procedurally defective. The Commission inaugurated its five-year review of the indexation methodology proposing to continue the existing indexing level of PPI-FG+1.3 while inviting interested parties "to propose, justify, and fully support, any alternative indexing proposals."[16] By soliciting comments on the current index level, the Commission follows the same procedure that it used in the previous five-year review proceeding for allowing parties to present evidence that the index level should be modified.[17]

25. Moreover, the Commission subsequently received extensive on-the-record comments and workpapers from AOPL, Valero, and other parties. The analysis contained within these findings is based upon Form No. 6 data, which is publically available on the Commission website and was utilized extensively by both AOPL and

[15] AOPL Reply Comment at 38 (quoting *Connecticut Light and Power Co. v. Nuclear Regulatory Commission*, 673 F.2d 525, 528 (D.C. Cir.)).

[16] NOI, FERC Stats. & Regs. ¶ 35,566 at P 4.

[17] The current indexing level of PPI-FG+1.3 was developed in the Commission's prior five-year review proceeding. Second Five-Year Review, 114 FERC ¶ 61,293. This proceeding involved extensive record evidence and comments from shippers, and the record from that proceeding remains available on the Commission website.

Valero. Furthermore, although the Commission's mechanisms for assessing revisions to the index may evolve over time, the parties are familiar with the types of data that have been considered by the Commission in the past, including the variants of the Kahn Methodology. The Commission has considered comments, reply comments, supplemental reply comments, and an even later response, giving each party more than adequate opportunity to respond. Both the data used in this proceeding and any potential changes from the methodology used in the past index review have been subject to ample opportunity for examination and comment. It is clear that the technical support for the index level adopted in this proceeding has been provided to the parties with adequate opportunity for analysis and comment.

2. Scope of this Proceeding

a. Comments

26. In reply comments, AOPL argues that the Commission must adhere to the methodology applied in prior proceedings, and AOPL contends that the changes proposed by Valero and its expert Mr. O'Loughlin (using page 700 data, excluding pipelines with large rate base changes, and using only the middle 50 percent) are beyond the scope of the five-year review initiated by the NOI.

27. AOPL contends that in the prior five year review, the Commission limited the purpose of the review to adjustments to the index, not whether the index should be changed. AOPL adds that because the existing methodology was promulgated as part of a Commission rulemaking, replacing that methodology requires a new rulemaking. AOPL asserts that in the NOI, the Commission requested comments on the appropriate

index level, but gave no indication it was changing its methodology. Moreover, AOPL adds that to the extent the Commission departs from its prior methodology, the Commission must establish that the methodology is justified. In contrast to Mr. O'Loughlin's proposal, AOPL states that Dr. Shehadeh derived the index of PPI-FG +3.64 with the same methodology used by Dr. Kahn and adopted by the Commission in prior proceedings and accepted by the D.C. Circuit.

28. In supplemental reply, citing *FCC v. Fox Television Stations, Inc.*,[18] Valero states that the Commission only needs to establish that the new policy is permissible under the statute, that there are good reasons for the new policy, and that the agency believes it to be a better policy. Valero emphasizes that the most reasonable course of action available to an agency is not always to maintain its current policy unchanged.

29. Valero also dismisses AOPL's argument that a new rulemaking process is required to adopt Mr. O'Loughlin's proposals. Valero reiterates that it is not proposing a change to this legislative rule embodied in the regulations, but only a change in data inputs to that methodology. Valero also contends that all parties, including AOPL, are on notice of the alternative proposals before the Commission.

30. Additionally, Valero disagrees with AOPL's contention that the NOI does not contemplate an analysis such as the O'Loughlin approach. Valero states that the Commission invited parties to submit comments proposing, among other things, alternative indexing proposals. Valero argues that AOPL mistakes Mr. O'Loughlin's

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[18] 129 S.Ct. 1800 (2009).

improvements to data sources as a change in the methodology itself. Rather, Valero contends Mr. O'Loughlin's approach constitutes a better approach to utilizing the same methodology.

31. Similarly, on reply, Navajo avers that FERC adopted the Kahn Methodology only upon the express caveat that its initial conclusions were not necessarily "a choice for all time" and that the ICA required monitoring of the index. Navajo adds that an agency may depart from past policy or precedent so long as the Commission acknowledges the change and supports its new decision with reasoned decision-making and substantial evidence. SPOPS also emphasizes that the Commission has the flexibility to modify its indexing methodology.

32. In its response, AOPL reiterates that Mr. O'Loughlin's methodology is a fundamental departure from the established methodology and would require a new rulemaking initiated by a Notice of Proposed Rulemaking. AOPL states that *Fox Television* also made clear that an agency must still provide a reasoned explanation for its decisions and that a more detailed justification is required when the prior policy engendered serious reliance interest. Valero, according to AOPL, downplays this reliance inappropriately. AOPL states that the reliance interest was not a reliance on any precise pricing index, but rather that the pipelines have a continued expectation that the Commission will apply the established methodology in calculating the index.

b. <u>Commission Determination</u>

33. The Commission rejects AOPL's assertion that modifications to the methodology for evaluating changing pipeline costs are beyond the scope of this proceeding. The NOI

invited "interested persons to submit comments on the continued use of PPI+1.3 and to propose, justify, and fully support, any alternative indexing proposals."[19] Thus, by inviting parties to submit "to propose, justify, and fully support any alternative indexing proposals," the Commission provided notice to AOPL and others that the Commission would consider different methodologies for calculating the Index, such as the proposals advanced by Valero, among others.[20] Although the D.C. Circuit rejected in 2003 proposed changes to the Kahn Methodology for assessing changing pipeline costs, the Court rejected this proposal because the Commission had neither addressed concerns regarding the new methodology nor justified its methodological shift.[21] The Court did not hold that the Commission cannot make justified modifications to the Kahn Methodology. As the Commission did in prior five-year reviews of the indexing level, the Commission will give consideration to alternative methodologies for calculating the index.[22]

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[19] NOI, FERC Stats. & Regs. ¶ 35,566 at P 4.

[20] AOPL has been given an opportunity to respond to these proposals, and AOPL has filed reply comments and an October 20 Response that vigorously critique the proposed alterations to the Kahn Methodology.

[21] *AOPL II*, 281 F.3d at 248.

[22] AOPL argues that in the last indexing review, the Commission stated that the purpose of the five-year review was to determine "what extent the PPI-FG should be adjusted to better reflect those cost changes, *not whether the method for determining* pipeline costs should be changed." Second Five-Year Review, 114 FERC ¶ 61,293 at P 46 (emphasis added). However, in that passage, the Commission was referring to a proposal by the shipper parties for an entirely new rulemaking to re-assess the means for tracking pipeline costs justified, in part, by criticism of the data in Form No. 6. *Id.* *See also* ATA, Lion Oil Company, National Cooperative Refinery

B. Proposed Changes to the Kahn Methodology

1. Rate Base Screening Methodology

a. Valero Initial and Reply Comments

34. To develop the data set for the Index, Valero urges the Commission to apply a "rate base screening" methodology that excludes pipelines experiencing both: (a) a rate base increase (through expansion) or decrease (through divestiture) greater than 50 percent during the 2004-2009 period and (b) recovery of cost changes during the 2004-2009 period through some means other than incremental rate increases via the index, such as a cost-of-service filing or a settlement agreement.[23] For pipelines with rate base changes greater than 50 percent, Valero also excluded (a) any pipeline with a major divestiture or (b) any pipeline that acquired another pipeline where the pipeline divesting the assets continued to exist after the divestiture. In conducting the assessment of

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Association, Sinclair/Tesoro, Response, Docket No. RM05-22, at 13-14 (filed January 23, 2006). However, elsewhere in Second Five-Year Review, when parties did not propose a new rulemaking and instead proposed changes using the existing information reported to the Commission, as Mr. O'Loughlin has done here, the Commission evaluated those changes and did not find them to be beyond the scope of the five-year review process. Second Five-Year Review, 114 FERC ¶ 61,293 at P 30-36 (rejecting proposal to use "the arithmetic average of the geometric mean of each pipeline's cumulative unit cost change, as opposed to Dr. Kahn's method of calculating the geometric mean of the arithmetic average of cumulative unit cost change.").

[23] Using the rate base screening methodology, Mr. O'Loughlin excluded 25 pipelines that he states experienced major rate base changes during the 2004-2009 period. O'Loughlin August 20 Aff. ¶ 10. Twelve pipelines with rate base changes of more than 50 percent remained in the data set because, according to Mr. O'Loughlin, they did not appear to have requested alternative ratemaking treatment and no major acquisition or divestiture was identified. O'Loughlin October 8 Aff. ¶ 15.

pipelines with major rate base changes, Mr. O'Loughlin also excluded pipelines with what he concluded were unreliable data.

35. Valero justifies the rate base screening methodology because, citing Order Nos. 561 and 561-A, Valero avers that the index is intended for normal, not extraordinary, changes. Valero contends that large rate base changes are "extraordinary" and that cost changes of this nature are typically recovered by a cost-of-service filing or settlement, not incremental rate changes pursuant to the index.

36. Thus, if the index level reflects cost data from the pipelines experiencing rate base changes, Valero argues that pipelines receiving annual index increases that did not construct major expansions would obtain a windfall due to an index inflated for cost changes not experienced by normal pipelines. Furthermore, Valero argues that pipelines that constructed major expansions would receive double compensation, first, through a cost-of-service or other rate changing methodology related to the expansion and, second, through an inflated index. Furthermore, regarding divestitures and acquisitions, Valero and its witness O'Loughlin also aver that comparisons between the period before the divestitures or acquisitions and after those transactions are meaningless because the systems being compared are different.

37. Valero argues that measures taken by the Commission in prior proceedings do not fully correct the biases caused by the inclusion of these pipelines. For example, Valero asserts the usage of the middle 80 percent or middle 50 percent of the sample data set in the prior rate proceedings does not adequately mitigate the effect of the inclusion of the pipelines with major rate base changes.

38. Valero states that otherwise applying Dr. Shehadeh's methodology, while using Valero's rate base screening methodology reduces his recommended index from PPI-FG+3.64 to PPI-FG+2.6. Valero also states that excluding the pipelines with large rate base expansions would not frustrate expectations because these pipelines do not typically use indexing to recover increased costs, and the index has never previously been set at PPI-FG+3.64 and there could have been no expectation that this index level would be approved.

b. <u>AOPL Reply Comments</u>

39. AOPL states that if a pipeline experiencing a rate base change is truly a statistical outlier, it will be excluded by using the middle 50 and middle 80 data sets as applied in the Kahn Methodology. AOPL states that Mr. O'Loughlin's "rate screening methodology" is a highly subjective, results-driven attempt to eliminate pipelines with higher cost changes. This, AOPL argues, biases the data set downward before any application of statistical measures. AOPL emphasizes that an appropriate statistical method for excluding outliers must be systematic and objective.

40. AOPL contends Mr. O'Loughlin's "double-recovery" argument lacks consistency with the structure of the index methodology. According to AOPL, under the Commission's regulations, if a pipeline files a cost-of-service rate increase, those rates form the ceiling for that year, but in the next index year, the pipeline must apply the applicable index, whether it is higher or lower. AOPL asserts that, rather than reflecting "double recovery," this merely follows the appropriate operation of the index under the Commission's regulations, which permit annual changes in rate ceilings due to actual

industry-wide cost changes as compared to PPI-FG. AOPL further argues that Mr. O'Loughlin's double-recovery argument would also discourage pipeline expansions and improvements by excluding pipelines that would undertake significant expansion projects or that incur significant expenses in compliance with safety regulations.

41. AOPL also contends that the inclusion of pipelines with large rate base changes in the data set does not create a windfall because, under the indexing methodology, pipeline costs are merely increasing to reflect increased costs across the industry. AOPL's witness Dr. Shehadeh states that whether a pipeline "used a rate mechanism other than indexation is irrelevant to the value of the information that these pipelines can provide as evidence for indexing pipeline costs."[24]

42. AOPL further claims that in Order No. 561, the Commission established the Index level at PPI-FG-1 to account for a wave of asset retirements that resulted in significant rate base changes. AOPL states that it would now be inconsistent to exclude rate base changes when those changes relate to pipeline expansions. AOPL states that the disqualification from the data set pipelines that undertake significant expansion will discourage pipeline expansions and improvements.

c. Other Shipper Reply Comments

43. In reply comments, NPGA, ATA and Navajo expressed support for Valero's rate base screening methodology.

[24] Shehadeh September 20 Decl. at 11.

d. Valero Supplemental Reply Brief

44. Responding to AOPL, Valero disputes the assertion that the rate base screening methodology understates cost changes experienced by a typical pipeline operator. Valero states that Mr. O'Loughlin's analysis applied an objective filter which removed pipelines experiencing cost increases and cost decreases of more than 50 percent. Valero notes that pipelines that underwent expansions and major capital investments often sought to recover those costs by means other than the price index; to Valero, this suggests that the cost increases were extraordinary.

45. In response to AOPL's and Dr. Shehadeh's argument that volume increases offset the cost increases, Valero states that it would not have been necessary or cost-justified to adopt increased cost-based rates if increased volumes fully offset any new costs. Valero adds that if volumes had increased commensurately with costs on these pipelines, then the pipelines with large rate base changes would not be at the high end of the measurement group in terms of cost-of-service per barrel-mile changes.

46. Valero also avers that Dr. Shehadeh's claim that the rate base screening methodology would have increased the index adjustment factor established in Order No. 561 contradicts his claim that Mr. O'Loughlin's methodology biases results downward and leads to an inappropriately low index.

e. AOPL October 20, 2010 Response

47. AOPL states that once an initial rate is set for a pipeline expansion, indexing becomes the primary method for changing oil pipeline rates. According to AOPL, there is no reason to exclude pipelines filing a cost-of-service or settlement rate when

examining industry-wide cost changes and that the presence of ratemaking alternatives do not justify setting the index below overall industry levels. AOPL avers that if pipelines undertaking significant infrastructure investment are excluded from the measurement of cost changes, the index will be inappropriately low, causing more pipelines to use other ratemaking methods and undermining the purpose of the index.

f. Commission Determination

48. The Commission will not adopt Valero's proposal to exclude pipelines experiencing major rate base changes from the data set. To determine which pipelines should be trimmed from the data sample, the Commission has relied upon the level of the cost changes, not the reasons why a particular pipeline's changing costs might be anomalous. Thus, in assessing Form No. 6 data in prior index proceedings, the Commission has trimmed the data sets to remove outliers, such as the 25 percent of pipelines with the greatest cost increases per barrel-mile and the 25 percent with the greatest decreases. As discussed below, the Commission in this proceeding will trim the data set to pipelines in the middle 50 percent of cost changes. To the extent that a particular pipeline's cost change is an anomalous outlier compared to the changes on other pipelines, using the middle 50 percent of cost changes, should remove any distorting impact resulting from the pipeline's presence in the index.[25]

[25] To the extent that large rate base changes are associated with disproportionately large cost shifts, AOPL's expert Dr. Shehadeh explains that 18 of the 25 pipelines removed by Mr. O'Loughlin due to rate base changes were excluded when the data set was reduced to the middle 50 percent using Dr. Shehadeh's methodology. Shehadeh September 20 Decl. at 12.

49. In contrast to this simplified methodology, the rate base screening methodology proposed by Valero selectively emphasizes one factor that may cause a substantial change in pipeline costs per barrel-mile while ignoring other factors. There is no doubt that substantial changes in rate base can alter the per barrel-mile costs of a particular pipeline. However, costs per barrel-mile can also be altered by shifting customer demand, increased competition, economic changes, or changing product supplies. As Valero's expert Mr. O'Loughlin notes, there is a wide range in the changes in pipeline per barrel-mile costs,[26] and much of this variability[27] is unrelated to the significant rate base changes cited for exclusion by Mr. O'Loughlin. By selectively modifying the data set based upon one potential cause for cost changes, Mr. O'Loughlin risks distorting the index calculation.

50. Moreover, the index is pursuant to a Congressional mandate to develop a "simplified and generally applicable ratemaking methodology…."[28] Consistent with this mandate of general applicability, the Commission is reluctant to inquire into the particular circumstances of every pipeline and selectively remove pipelines that

[26] O'Loughlin August 20 Aff. ¶¶ 44-45, Figure 14.

[27] For example, Mr. O'Loughlin explains that, using his own methodology, of the 97 pipelines in his data set, which has been culled pursuant to the rate base screening methodology, there "are 20 pipelines that experienced average cost increases greater than 10% per year and 10 pipelines that experienced average cost decreases of more than 10% per year over the five-year period." O'Loughlin August 20 Aff. ¶ 45.

[28] Energy Policy Act of 1992 Pub. L. No. 102-486 Sec. 1801(a), 106 Stat. 3010 (Oct. 24, 1992).

experienced cost changes due to one particular factor from the data set used to calculate the index.[29]

51. Furthermore, large rate base changes can reflect changing pipeline costs. The cost of new investment associated with rate base increases reflects industry cost experience related to pipeline infrastructure on a barrel-mile basis. These rate base changes also provide important information regarding industry capital requirements. A rate base change, like any other change in the business circumstances of a pipeline, is only an outlier if a pipeline's per barrel costs change in a manner disproportionate to those changes experienced by other pipelines.

52. Moreover, the index serves as a means of recovery for some pipelines with significant rate base changes. According to data provided by Mr. O'Loughlin, several of the pipelines that Mr. O'Loughlin identified as experiencing significant rate base changes relied upon indexed rates (or at least did not seek some other form of recovery, such as a cost-of-service filing).[30] The fact that a non-trivial number of pipelines experiencing rate

[29] The D.C. Circuit has previously recognized the importance of an index that is relatively simple to derive. *AOPL II*, 281 F.3d at 247 (quoting EPAct 1992, at § 1801(a)). The complexity of Mr. O'Loughlin's rate base screening methodology is demonstrated by Appendix F of his September 20 Affidavit, in which Mr. O'Loughlin examines the circumstances of 37 pipelines that experienced rate base changes greater than 50 percent. To apply the rate base screening methodology, for each pipeline with a change in rate base exceeding 50 percent, Mr. O'Loughlin examined tariff filings, assessed acquisition and divestiture activity, probed into the reliability of the pipeline's reported data, researched whether the pipeline had sought rate increases pursuant to the index, and generally sought to determine why the rate base changes occurred.

[30] O'Loughlin September 20 Aff. ¶ 54 n.75, Appendix F at 8-10.

base changes continued to use the indexing methodology reinforces the inclusion of pipelines with rate base changes in the data set.

53. Additionally, merely because a pipeline seeks recovery of rates outside the indexing methodology, for example through a cost-of-service, does not establish that the pipeline should be excluded from the data set used to develop the index. The changing costs that compelled the pipeline to seek recovery outside the indexing methodology nonetheless reflect industry cost experience. Moreover, for those pipelines with significant rate base increases, Mr. O'Loughlin's decision to include only those pipelines where the pipeline opted to continue to use the index could skew the index downward; this is because the pipelines continuing to use the index are more likely to be the pipelines where the rate base change decreased per-barrel mile costs.

54. Valero repeatedly cites language in Order Nos. 561 and 561-A that the index accounts only for "normal," not "extraordinary" changes.[31] However, this language does not support Valero's proposal to exclude pipelines experiencing major rate changes from the data set used to determine the index level. In these passages, "extraordinary" referred to pipelines experiencing changed per barrel-mile costs that were greater than the changing costs experienced by other pipelines regardless of the causes underlying any particular pipeline's cost changes. Thus, even though a rate base change of 50 percent is a significant occurrence, it is only "extraordinary" as Order Nos. 561 and 561-A used that term to the extent that it causes an anomalous change in costs per barrel-mile.

[31] Valero Supplemental Reply Comment at 14-15 (citing Order No. 561-A, FERC Stats. & Regs. ¶ 31,000 at 31,097).

55. Valero's contention that including pipelines with rate base changes in the data set used to determine index will lead to double-recovery is without merit. After making a cost-of-service filing, the cost-of-service rate becomes the ceiling rate for that year[32] and pipelines are authorized to increase their rates pursuant to the index in subsequent years.[33] Valero's argument ultimately rests upon the contention that the index is inflated by the inclusion of pipelines experiencing rate base changes. However, as noted previously, such inflation of the index only occurs if the rate base changes lead to changes in per barrel-mile costs that are anomalous. To the extent that the rate base change leads to an anomalous cost increase or decrease, it will be excluded by the data set trimming as discussed below.

2. <u>Data Trimming and the Middle 50</u>

a. <u>Valero Initial and Reply Comments</u>

56. Valero urges the Commission to calculate the index using a data sample trimmed to the middle 50 percent, i.e. removing the 25 percent of pipelines with the greatest cost increases and the 25 percent of pipelines with the greatest cost decreases. Although Valero acknowledges that recent index proceedings have considered both the middle 50 and middle 80 percent, Valero contends that trimming the data set to the middle 80

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[32] 18 CFR § 342.3(d)(5).

[33] However, further undermining Valero's double-recovery argument, the Commission has denied an increase pursuant to the index when the cost-of-service filing supporting the existing rate already incorporated the cost changes covered by the index. *See SFPP, L.P.*, 117 FERC ¶ 61,271 (2006) (denying an index increase because the cost-of-service rate, which used a 2005 base period, already reflected the 2005 cost changes covered by the index).

percent inadequately accounts for outliers due to the widely varying average annual cost changes. Valero adds that the middle 80 includes pipelines with anomalous characteristics, such as very high costs per barrel-mile or the absence of rate base.

b. AOPL Reply Comments

57. AOPL opposes trimming the sample data set to the middle 50 percent of pipelines. Dr. Shehadeh responds to Mr. O'Loughlin's proposal by stating that the wide distribution of pipeline cost changes (as opposed to a normalized bell curve) does not support ignoring the middle 80 percent in favor of the middle 50 percent. Rather, Dr. Shehadeh claims that the wide distribution supports the use of the middle 80 percent, rather than the middle 50 percent because it would be more inclusive and represent a larger number of pipelines.

c. Valero Supplemental Reply Comments

58. Valero contends, contrary to AOPL's assertions, that Mr. O'Loughlin's use of the middle 50 percent data set is justified and consistent with Commission policy. Valero asserts that the Commission's methodology has varied over the years, and in Order Nos. 561 and 561-A, the Commission used an analysis of only the middle 50 percent of the data set, not a composite of the middle 50 percent and middle 80 percent of the data set. Valero's Mr. O'Loughlin emphasizes that the middle 50 percent better serves the goal of excluding extraordinary data points. Mr. O'Loughlin also identifies an additional three pipelines in the middle 80 percent that he states have unusual characteristics, such as a cost of capital under two percent or, in another case, no rate base yet a positive depreciation expense.

d. AOPL’s October 20, 2010 Response

59. In its response, AOPL reiterates its position that both the middle 50 percent and middle 80 percent should be used. AOPL reiterates its contention that the wide distribution of pipeline cost changes does not support assigning no weight to the middle 80 percent. AOPL also challenges the three pipelines Mr. O’Loughlin identified as anomalous, noting that one was excluded from Dr. Shehadeh’s data set and that the others showed overall cost changes that were not all that different from other pipelines. AOPL states that as the Form No. 6 data has improved, there is no merit to limiting the data set.

e. Commission Determination

60. The Commission will use the middle 50 percent of the data set to determine the appropriate index level. This use of the middle 50 percent is consistent with the Commission's approach when it adopted the indexing methodology. In Order Nos. 561 and 561-A, the initial rulemaking establishing the indexing methodology, the Commission used only the middle 50 percent of the data set to determine the appropriate indexation level. In that proceeding, neither the Commission nor Dr. Kahn considered the middle 80 percent. In the second review, Dr. Kahn introduced the middle 80 percent to his analysis.[34] Given that the two data sets supported the same resulting index-level of an unadjusted PPI-FG, using both (as opposed to just the middle 50) was not discussed or contested, as there was little substantive impact from this departure from the Order

[34] Kahn Decl. at 13 (August 31, 2000) (Docket No. RM00-11-000).

No. 561 methodology.[35] In the second and most recent 5-year review, the composite usage of the middle 50 and the middle 80 reoccurred, but again the relative merits of the middle 50 and middle 80, and the departure from the prior Order No. 561 methodology were not weighed or discussed.

61. Given the more fully developed record presented here, the Commission returns to its approach in Order Nos. 561 and 561-A to use the middle 50 percent as the most appropriate method for trimming the data sample. The purpose of the index is to permit a simplified recovery for normal cost changes, not to enable recovery for extraordinary cost increases or decreases.[36] The middle 50 percent more appropriately adjusts the index levels for "normal" cost changes as opposed to the middle 80 percent, which, by definition, includes pipelines relatively far removed from the median. Furthermore, some of these more dramatic cost changes may be due to circumstances on a particular pipeline that are not broadly shared across the industry. Even when accurate data is reported, pipelines in the middle 80, as opposed to the middle 50, are more likely to have cost changes resulting from factors particular to that pipeline, such as a rate base expansion, plant retirement, or localized changes in supply and demand. Using the middle 50 ensures that pipelines with relatively large cost increases or decreases do not distort the index.

[35] The composite of the middle 50 and middle 80 were very similar in that proceeding at 1.32 percent and 1.2 percent, respectively. Id.

[36] Order No. 561-A, FERC Stats. & Regs. ¶ 31,000 at 31,097 (noting that the purpose of the Index is to ensure recovery of "normal" cost changes, not "extraordinary" cost changes).

62. The Commission further observes that our adoption of the middle 50 provides a better remedy for some of the concerns Mr. O'Loughlin used to justify his rate base screening methodology. Of the 25 pipelines Mr. O'Loughlin seeks to exclude via the rate base screening methodology, 18 are excluded by using the middle 50 percent in the Kahn Methodology as applied by Dr. Shehadeh.[37] More generally, the adoption of the middle 50 is a less subjective and more simplified method (consistent with the EPAct 1992) of removing potentially anomalous data than selective removal of certain pipelines with particular characteristics from the data sample. The middle 50 also is preferable to such selective screening methods because it avoids the risk that the index is skewed because certain cost changes (such as rate base changes) are selectively excluded while other significant changes (changes in local supply and demand) are incorporated.

63. The Commission accordingly concludes that the middle 50 provides a robust data sample for determining changing barrel-mile costs. The middle 50 percent of pipelines represents 76 percent of total barrel-miles in 2004 subject to the index,[38] and thus for this index calculation, the Commission finds it unnecessary to include the middle 80 percent to obtain a representative sample of the data. Finally, the use of the middle 50 minimizes the risk of including pipelines that experienced either large increases or decreases in cost (or errant data) that may be included in an 80 percent sample, while still capturing changes from a broad spectrum of the pipeline industry.

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[37] Shehadeh September 20 Decl. at 12. Only 13 of the 25 are excluded in the middle 80 percent. *Id.* The number of excluded pipelines include four companies that Dr. Shehadeh removed due to missing data. Shehadeh September 20 Decl. at 12 n.15.

[38] AOPL Comments at 14-15; Dr. Shehadeh August 20 Decl. at 10 n.23.

3. Page 700 Data

a. Valero's Initial and Reply Comments

64. Valero and Mr. O'Loughlin aver that the Commission should adopt page 700, which uses the Opinion No. 154-B methodology to derive a total cost-of-service for interstate pipeline companies. Valero states there are several advantages to using the page 700 data as opposed to the other Form No. 6 data relied upon by the Commission in the past.

65. Valero asserts that by relying upon page 700 data, the Commission can avoid using net carrier property as a proxy for actual changes in allowed return and income tax. Valero notes that the Commission has previously questioned the effectives of net carrier property as a proxy for changes in capital costs. Valero further states that Mr. O'Loughlin's analysis shows that the change in net plant is typically greater than the change in allowed return and income tax. Additionally, Valero argues that net plant data reported on Form No. 6 can also include purchase accounting adjustments (PAAs), which the Commission does not allow for ratemaking purposes absent a showing of substantial benefits to ratepayers.

66. Valero also contends that the "operating ratio" weighting methodology as applied by Dr. Shehadeh leads to a distorted analysis. The operating ratio is set between zero and one based upon the ratio of operating expenses to revenues. If operating expenses exceed revenues, then the operating ratio is set to one, meaning that no weight is assigned to capital costs (net plant under the prior methodology) in the formula. Thus, Valero contends that for fifteen pipelines in Dr. Shehadeh's data set, the weight for the index of

changes in net plant is zero percent, making the index of changes in net plant irrelevant. Valero contends that its proposed methodology using data from page 700 obviates the need for the operating ratio because the total cost of service on page 700 incorporates both operating and capital costs.

67. Valero explains that operating expense, net carrier property, and barrel-mile data, which are reported on pages 110-111, 300-303, and 600-601 of the Form No. 6, include intrastate, as well as interstate, pipeline information. The solution, Valero contends, is to use the data on page 700 of the Form No. 6, which includes only interstate information.

b. Other Shipper Comments

68. In their comments, other parties addressed Valero's proposal to use page 700. ATA emphasized that any analysis of costs should be based on the interstate costs reported on page 700. ATA emphasizes that page 700 contains the information available to shippers to provide a screening tool to determine whether a "pipeline's cost of service or per-barrel/mile costs" are so divergent from revenues as to warrant a challenge to the rates. ATA stresses that it is appropriate to use the same data to develop the index as is used to determine whether a pipeline is recovering its costs.

69. NPGA likewise submits that any proper analysis of operating costs should be based on interstate operations and costs and not on costs that reflect intrastate operations. Thus, NPGA urges the use of page 700 data.

70. In reply comments, SPOPS urges that to the extent the Commission continues to apply its methodology, the Commission should use the primary source for the

jurisdictional costs of service for the pipelines, the page 700 and the underlying workpapers, not the secondary source methodology demanded by AOPL.

c. **AOPL's Reply Comments**

71. AOPL opposes the use of page 700 data. AOPL argues that the page 700 data is more volatile due to the return element underlying the page 700 total cost-of-service data. Specifically, AOPL contends that stock market fluctuations make the rate of return highly sensitive to the end-year selected by the Commission (i.e., 2008 versus 2009) for calculating the index. According to AOPL, the Form No. 6 net carrier property data is preferable because it reflects actual changes in capital costs while assuming that the competitive cost of capital remains constant.

72. AOPL also argues that if rate of return from page 700 is used to measure cost increases, increases in pipeline efficiency will not result in lower indexation levels. AOPL explains that pipeline returns are based on a proxy group and as the profitability increases for companies in the proxy group, returns will likely increase. As a result, using return from page 700 will tend to increase, as oppose to decrease, future index levels.

73. AOPL also disagrees with Mr. O'Loughlin's claim that page 700 data is superior to Form No. 6 data because page 700 data does not include intrastate costs. AOPL counters that oil pipelines often make intrastate and interstate movements through the same pipeline segments. Thus, AOPL believes that it is reasonable to assume that both interstate and intrastate cost changes are likely to be representative of interstate cost changes.

74. AOPL argues that Mr. O'Loughlin mistakenly describes the page 700 data as new and instead suggests that the information Mr. O'Loughlin proposes to use has been available to the Commission for many years.

d. <u>Valero Supplemental Reply</u>

75. Responding to AOPL, Valero asserts that pipeline efficiency gains will not distort the return information from page 700 because basic finance theory provides that an increase in a company's current and future cash flow increases the equity value of the company. Regarding AOPL's contention that volatility in the page 700 return data will skew results, Valero argues that Dr. Shehadeh, by analyzing the rate of return in isolation from the allowed return and income tax allowance, obtained a result that is not fully indicative of a pipeline's capital costs. Valero further argues that recessionary declines in petroleum demand increased the average cost of service per barrel mile for 2009. Valero concludes that if the recessionary volatility in barrel-miles is reflected in developing unit costs, the prevailing rates of return as reported in the cost-of-service calculations on page 700 of the Form No. 6, must also be used.

76. Valero disputes AOPL's contention that an interstate cost-of-service value was reflected on page 700 as early as 1994. Valero states that a reliable total interstate-only cost-of-service data and the specific line items composing the interstate cost of service, including jurisdictional rate base, were not available until 2000. Valero states that the Commission has not previously addressed the possibility of using this interstate, page 700 data in the index.

77. Valero also challenges Dr. Shehadeh's claim that the interstate-only operating and maintenance expense and depreciation expense data reported on page 700 are unsuitable for the rate index methodology because the data contain various accounting, allocation, and normalizing assumptions. Rather, Valero contends that because the calculations of operating and maintenance expense must be consistent with the Commission's Opinion No. 154-B methodology and because changes in those components impact the costs a pipeline can recover in rates, those considerations are appropriate for determining the price index.

78. Valero states that Dr. Shehadeh's preferred data source, the operating and maintenance expense data on page 114 of the Form No. 6, can contain accounting reserves that are not permitted for ratemaking. Valero states that carriers should not be permitted to use these discretionary changes in accounting reserves to influence the change in unit costs used to determine the level of index to be used for annual adjustments.

e. AOPL October 20, 2010 Response

79. AOPL renews its arguments that (a) intrastate costs are representative of interstate costs; (b) inclusion of the rate of return from page 700 would make the index more volatile; (c) net plant is a preferable measure of return for the purposes of establishing the index than the page 700 data; and (d) the page 700 data has been available during prior indexing proceedings.

80. AOPL also argues that Valero's proposed usage of page 700 ignores serious accounting issues. AOPL states that, in order to derive a unit cost for each carrier,

Mr. O'Loughlin divides the total cost-of-service reported on page 700 by the total throughput reported on page 700. AOPL states that the page 700 cost-of-service figure provides each carrier's interstate cost-of-service using an Opinion No. 154-B methodology. However, AOPL states that the barrel-mile data on page 700 includes interstate and intrastate volumes. AOPL explains that the instructions on page 700 indicate that the barrel-mile figure should be the same as that reported on page 600, and the barrel-mile figure on page 600 includes "all oils" received by the pipeline, not just interstate oils. AOPL contends that there could be a mismatch between the interstate only costs and the interstate and intrastate volumes.

81. AOPL defends the data in Form No. 6. AOPL states that while PAAs reflected in Form No. 6 are generally not allowed to be reflected in regulated rates, these adjustments are appropriate when calculating cost changes because the PAAs reflect the opportunity cost of capital. Moreover, AOPL states that PAAs do not create the perverse incentives in the calculation of an industry-wide index that they do when calculating an individual pipeline's rates. Also, AOPL also contends that although the accounting reserves in Form No. 6 present timing issues for the purposes of a ratemaking proceeding, they also represent real costs of doing business that are properly reflected in the calculation of the rate index.

82. AOPL also defends the usage of the operating ratio. AOPL states that applying a weight of one to operating expenses and zero to net plant is appropriate for a company where operating costs are greater than revenue.

f. Commission Determination

83. The Commission does not adopt Mr. O'Loughlin's proposal to use page 700 data because there is a mismatch between the page 700 total cost-of-service, which includes only interstate data, and the page 700 throughput data, which includes interstate and intrastate data.

84. As the shipper parties emphasize, the total cost of service data on page 700 relates solely to interstate costs. However, the throughput data used by Mr. O'Loughlin from page 700 reports a combination of interstate and intrastate volumes. As AOPL explains in its October 20 Response, the barrel-mile information listed on page 700 provides that the barrel-mile figure should be the same as that reported on line 33a of page 600 of the Form No. 6. The instructions for page 600 refer to the inclusion of "all oils received" by the pipeline and makes no distinction between interstate and intrastate volumes. Consequently, pipelines may be reporting both interstate and intrastate volumes on page 700.

85. Thus, Mr. O'Loughlin's calculations compare one set of costs (interstate costs) with a different set of throughput (combined interstate and intrastate). Changes in transported throughput on a particular movement cause changes in the costs related to the very same movement. Thus, it is an axiomatic rule of ratemaking that the same set of costs and volumes must be used to determine rates. To obtain an accurate measurement of changing per barrel-mile costs for purposes of establishing an index level, the methodology must match the throughput used in the methodology to the costs incurred to transport the throughput used in the methodology. Given that page 700 does not match

interstate costs with interstate volumes, the Commission rejects its usage in the methodology.

4. Adjustments for Declining Throughput

a. Comments

86. In reply comments, CAPP asserts that the index should not be inflated by the decline in throughput between 2004 and 2009. CAPP contends that the widespread recession caused the reduction in 2009 barrel miles and that such throughput declines cannot be expected to continue for another five years. CAPP states that its expert Mark Pinney replicated AOPL's analysis using constant 2004 barrel miles and the resulting increase equated to PPI-FG plus 1.62 percent. CAPP argues that it is inconsistent with the purpose of an inflation adjusted index to allow changes in volumes to affect index levels and that increasing the index due to declining volumes will be self-perpetuating. CAPP also argues that allowing a generic index increase based on 2009 barrel-mile data contradicts Commission ratemaking policy for new pipeline facilities by using barrel-mile data instead of capacity as billing determinants.

87. Also in reply, ATA states that U.S. Energy Information Administration (EIA) estimates project an increase in total crude oil and petroleum consumption from 2010 to 2011. ATA thus advocates establishing an index using constant 2009 volumes for 2011 through 2016 as a "conservative" approach more favorable to pipelines.

88. In its October 20 Response, AOPL contends that adjusting actual historical throughput to assume constant volume levels is speculative and directly contrary to the Commission's established methodology. AOPL also challenges CAPP's suggestion that

the Commission uses capacity to measure costs instead of actual throughput, stating that because the oil pipeline industry is a highly capital intensive industry, when throughput declines, costs do not decline proportionally. AOPL adds that CAPP treats volumes as remaining constant but makes no attempt to adjust for fuel and power costs that are dependent upon volume levels. Moreover, AOPL adds that contrary to CAPP's assertion that the decline resulted from the 2009 recession, more than 60 percent of the throughput decline occurred between 2004 and 2005. Thus, AOPL states that capacity should not be used to measure costs.

b. Commission Determination

89. The Commission rejects CAPP's and ATA's proposal to use constant barrel-miles in the Kahn Methodology rather than the actual barrel-mile levels.

90. The Commission finds it appropriate to continue to rely upon historical data in applying the Kahn Methodology. The D.C. Circuit has upheld the Commission's reliance upon historical data finding that the usage of historical data is consistent with the mandate to apply "'a simplified and generally applicable ratemaking methodology.'"[39]

91. Moreover, CAPP's and ATA's analysis of cost changes assuming constant volumes are problematic because they utilize asynchronous data. Regarding CAPP's proposal to use constant 2004 barrel-miles, the 2009 costs reflect the expenses associated with the lower 2009 volume levels. Since certain costs (such as fuel and power) increase and decrease with volume levels, using 2004 data volume data with 2009 operating costs

[39] *AOPL II*, 281 F.3d at 247 (2003) (quoting EPAct 1992, at § 1801(a)).

will not present an accurate depiction of the change in per barrel-mile costs. By applying an upward adjustment to 2009 volumes without adjusting for the costs that would have been incurred as a result of those higher volumes, CAPP imposes a downward distortion on the change in pipeline costs calculated under the Kahn Methodology. Similarly, ATA's proposal to assume constant 2009 volumes is defective because it does not adjust 2004 costs so that the 2004 costs reflect the lower 2009 volumes.

92. The Commission further rejects CAPP's argument that it is inappropriate to allow the indexing methodology to be calculated based upon declining volumes. Declining volumes require pipelines to increase rates in order to meet revenue needs and, for existing oil pipelines, the Commission uses existing volumes, not capacity, to determine rates.[40] Thus, much as in a cost-of-service, such declining volumes should lead to increased pipeline recovery levels in the indexing methodology.

93. Finally, CAPP fails to demonstrate that the declining throughput for the 2004-2009 period resulted primarily from the unusual economic conditions in 2008 and 2009 as opposed to changes reflected throughout the prior five-year period. As Dr. Shehadeh demonstrates, more than 60 percent of the decline in barrel-miles during the 2004-2009 period recorded on Form 6 occurred between 2004 and 2005,[41] and was unrelated to the recession in 2008 and 2009. Thus, it is not the case that the index level has been distorted by the recession in 2008 and 2009.

[40] *See* 18 CFR § 346.2(b)(2). Moreover, it is not clear how this capacity information could be obtained in the application of the index, since pipelines report throughput in Form No. 6, not capacity.

[41] Shehadeh October 20 Decl. at 29.

5. Applying the Index Only to Operations and Maintenance Costs

a. Comments

94. In its comments and reply comments, Navajo urges the Commission to apply the index only to operating and maintenance costs and not to costs attributable to depreciation, return, and income tax allowances. Navajo asserts that depreciation is not affected by inflation because depreciation is based upon equity investment, a historical cost. Navajo further contends that the two components of return – return on equity (in the form of increased deferred return) and cost of debt – already incorporate an inflation component. Thus, Navajo asserts that automatically granting pipelines an additional inflation-based index increase would enable pipelines to "double-dip" the inflation element. Third, Navajo asserts that the income tax allowance should not be increased automatically by an index, because one of its two components (the tax rate) generally is fixed by law and does not vary based on inflation, and the second component (rate of return on equity) already accounts for inflation.

95. Instead, Navajo avers that the index should only be applied to operating and maintenance (operating and maintenance expense) costs. Navajo acknowledges that the Commission previously rejected this approach as too complicated in Order Nos. 561 and 561-A, but Navajo notes that the Commission now collects categorical cost data from pipelines on page 700 of Form No. 6 and the Commission could apply the index only to operating and maintenance costs as recorded on page 700. Thus, Navajo states that the Commission could use the change in operating and maintenance expense costs identified

by O'Loughlin to develop the indexed rate.[42] Navajo explains that under its proposal, for each pipeline seeking an annual index increase, the index rate could be applied to the part of the rate attributable to operating and maintenance expense. Navajo elaborates that if the operating and maintenance expense costs were 40 percent of a pipeline's cost of service on page 700 of its Form No. 6, the index-based rate increase should equal the pre-existing ceiling rate times the index multiplied by "0.4."

96. In reply comments, ATA states that it agrees that applying an index adjustment to items not subject to inflation misaligns cost recovery with cost increases. ATA also alleges this provides a disincentive to invest in infrastructure.

97. In reply comments and its October 20 Response, AOPL asserts that the Commission has twice rejected the selective indexing proposal advocated by Navajo. AOPL states that Navajo's proposal is beyond the scope of this proceeding. Moreover, AOPL asserts that because the Commission measures capital cost changes by comparing changes in net carrier property, the Kahn Methodology does not incorporate inflation for either return or income tax allowance as alleged by Navajo. Rather, AOPL asserts, the methodology is based upon the assumption that the competitive rate of return on capital does not change.

98. AOPL adds that the Commission has twice previously rejected Navajo's proposal, first in Order No. 561 and in the first five year review on the basis that it would be

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[42] To derive this rate, Navajo relies upon Mr. O'Loughlin's showing a change in the O&M costs for the middle 50 percent of oil pipelines of 5.0 percent and a change for the composite of the 50 and 80 percent of 5.4 percent. O'Loughlin August 20 Aff. ¶ 49, Figure 15.

difficult to administer and create perverse incentives. AOPL states that Navajo has provided the Commission with no valid reason to reverse its prior rulings. Furthermore, AOPL asserts that under Navajo's proposal, each pipeline would be required to perform calculations to determine its own pipeline specific index, a fundamental change from the "generally applicable" ratemaking methodology required by the EPAct 1992.

b. Commission Determination

99. The Commission rejects Navajo's proposal. The Commission has twice rejected proposals similar the one advocated by Navajo. In Order No. 561 as affirmed by the D.C. Circuit, the Commission concluded that limiting index increases to operating and maintenance costs would create perverse incentives for pipelines to direct a disproportionate amount of their spending to operating and maintenance costs and to neglect capital expenditures.[43] Moreover, because new investment may be substantial and would not be covered by the index, many companies would be required to file cost-of-service cases to recover significant increases in cost.[44]

100. In addition to creating perverse incentives, the Commission's prior orders noted that Navajo's proposal would also undermine the statutory mandate to establish a

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[43] Order No. 561, FERC Stats. & Regs. ¶ 30,985 at 30,951-52, *aff'd AOPL I,* 83 F.3d at 1437. The Commission returned to the issue in the first five year review, again rejecting the proposal on the basis that it could cause perverse consequences. First Five-Year Review, 93 FERC at 61,854-55.

[44] Order No. 561, FERC Stats. & Regs. ¶ 30,985 at 30,952.

generally applicable and simplified methodology.[45] The availability of page 700 data does not change this conclusion. Under Navajo's proposal, the index would not be generally applicable. Each pipeline would receive its own annual index adjustment to the ceiling rate dependent upon the pipeline's specific level of operating costs as reported on page 700. Navajo's proposal is also contrary to the purpose of a simplified methodology. Requiring pipelines to multiply the index level by the ratio of "operating and maintenance" expenses to "total cost-of-service" on page 700 before applying the index to a pipeline's existing ceiling rate will increase the likelihood of disputes in each annual application of the index as parties challenge those particular components of page 700 data.

101. Furthermore, Navajo's arguments are theoretically unsound. Capital costs are a component of a pipeline's total costs, and any index that tracks actual cost changes must account for changing capital costs. The Commission also rejects Navajo's argument that for income tax and rate of return, the index double-counts inflation. The Kahn Methodology uses net carrier property as a proxy for income tax and rate of return, and net carrier property does not contain any internal inflation-related adjustments.[46]

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[45] Order No. 561, FERC Stats. & Regs. ¶ 30,985 at 30,951-52; First Five-Year Review, 93 FERC at 61,854-55.

[46] Because it is not presented by the facts here, the Commission does not address whether using rate of return data that incorporated an inflation component would, in fact, be inappropriate for deriving the index. Similarly, the Commission does not address issues related to using actual page 700 tax allowance data because the index currently uses a proxy for income tax costs.

6. Separate Indices for Crude and Product Pipelines

a. Comments

102. In its comments, Valero and its witness O'Loughlin recommend one index for crude and product pipelines. However, Valero avers that differences in cost changes experienced between crude and product pipelines could argue in favor of separate indices for these two groups. Valero states that using his methodology, Mr. O'Loughlin determined that the median annual change in unit costs is 2.1 percent for products pipelines and 3.3 percent for crude pipelines. The composite index for the middle 50 percent of the datasets is 2.3 percent for products pipelines and 4.3 percent for crude pipelines.

103. In reply comments, ATA advocates the adoption of separate indices for crude and product pipelines, asserting that separate indices would allocate costs more equitably among shippers. ATA emphasizes that doing otherwise would force product shippers to subsidize crude shippers. The ATA urges that the data to produce separate indices is readily available, noting that of the 97 pipelines included within Mr. O'Loughlin's analysis, 31 were classified as crude pipelines and 45 were classified as product pipelines. NPGA also states that, as established by Mr. O'Loughlin, the disparity in cost changes between crude pipelines and product pipelines supports the development of separate indices.

104. In its reply comments and October 20 Response, AOPL represents that the Commission has previously rejected separate indices and emphasizes that Valero witness

O'Loughlin ultimately concluded that the Commission should apply one index to all oil pipelines.

b. <u>Commission Determination</u>

105. Mr. O'Loughlin has provided some evidence to indicate that product and crude pipelines have experienced different levels of cost change. However, neither Mr. O'Loughlin, ATA, nor NPGA offered an explanation for why this cost disparity between crude and product pipelines exists. ATA and NPGA rely upon Mr. O'Loughlin's testimony, but Mr. O'Loughlin recommends using one index for all pipelines,[47] and ATA and NPGA otherwise have failed to demonstrate that the Commission should depart from its prior policy applying one uniform index to all pipelines. Thus, on the record presented here, the Commission will continue to apply one index to both crude and product pipelines.

C. <u>Allegations of Pipeline Over-Recovery</u>

1. <u>Comments</u>

106. In their comments, several shippers – Sinclair/Tesoro, the Trucking Association, ATA, NGPA, SPOPS, and Navajo –reject the notion that the index reflects actual pipeline cost changes. Sinclair/Tesoro argues that it is unlikely the pipeline industry is experiencing cost increases equal to the broader economy since the last review. In support, Sinclair/Tesoro cites depressed cost levels in areas specific to pipeline operation, such as labor, energy, and materials used in pipeline construction. In contrast, Sinclair/Tesoro represents that PPI-FG has recovered more rapidly, almost completely

[47] O'Loughlin August 20 Aff. ¶ 61.

rebounding to its mid-2008 peak. Thus, Sinclair/Tesoro states that it is not appropriate to maintain the prior period rate ceiling of PPI-FG+1.3.

107. In its comments, ATA states that, based upon a sample of 73 Commission-regulated pipelines, over 30 pipelines have reported over-recoveries for some or all of the years from 2002 – 2009, and that these pipelines reported over-recoveries of approximately $1.9 billion. ATA asserts that this could cause parties to defer capital expenditures because returns on depreciated assets exceed those provided by new investments. Moreover, ATA suggests it is suspicious that pipelines that are under-recovering by substantial amounts have not filed a cost-of-service rate increase. In Reply Comments, ATA further emphasizes that pipelines experience non-uniform cost changes. ATA states that the Commission should be "careful" in designing any index to be applied to pipelines generally.

108. In addition to reiterating ATA's concerns regarding over-recovery, NPGA states that the major propane pipelines are now controlled by one company and that as a result shippers have experienced a pattern of increased costs through new fees, reduced service, sale of necessary assets to a pipeline affiliate, and operating penalties. Although NPGA acknowledges that pipelines as a whole are reporting an under-recovery, NPGA states that this does not relieve the Commission of its duty to ensure that each individual carrier's rates are just and reasonable and the existence of such a disparity merely indicates that the index does not reflect actual changes in pipeline cost. NPGA and ATA urge the Commission to require pipelines showing over-recoveries to show cause why their rates should not be considered unjust and unreasonable.

109. Similarly, SPOPS avers that oil pipelines are consistently over-recovering their costs. Accordingly, SPOPS proposes an index rate of zero until pipeline profits return to a just and reasonable level. SPOPS states that since the inception of the index the Commission has allowed pipelines to increase their rates by 39 percent, even though by 2009, 41 oil pipelines reported excess profits totaling over $200 million per year. In its comments, SPOPS includes in these profits the income tax allowance for Master Limited Partnerships (MLP), which do not incur income taxes. SPOPS states that it is difficult to challenge rate increases pursuant to the index. SPOPS states, as a result, the Commission has abdicated its responsibility under the ICA, emphasizing that not even "a little unlawfulness" is permitted, and that the Commission index as applied by the Commission tolerates unlawfulness.

110. In reply, Navajo states that it has reservations about basing the index on PPI-FG. Navajo states that nothing in the record demonstrates that pipeline costs inherently correlate with general rates of producer price inflation. In addition to claiming that pipelines have been over-recovering, on reply, Navajo also state that pipelines should not receive the benefit of automatically-approved rate increases when the pipeline reports that it is over-recovering. Navajo states that withholding the index from pipelines that are over-recovering can be accomplished through page 700, and thus is not any less administratively efficient than the Commission's current approach nor, in Navajo's view, does it increase litigation.

111. AOPL in its Reply Comments and October 20 Response states that the Commission properly rejected similar arguments during the prior 5-year review. AOPL

notes that the Commission's rationale in past proceedings accepts that some pipelines may over-earn while others under-earn as an inherent attribute of the index. AOPL asserts that the pertinent issue is not the overall level of pipeline cost, but rather how the index compensates for changes in pipeline costs. AOPL also states although page 700 data may show excess revenues, it does not mean a pipeline rates are not just and reasonable. According to AOPL, there are several other mechanisms other than an Opinion No. 154-B methodology to establish a pipeline’s rates, including market-based rates and negotiated rates. In addition, AOPL contends the shippers’ allegations do not reflect actual pipeline cost recovery. Based on Dr. Shehadeh's calculations, AOPL claims approximately two-thirds of pipelines’ page 700 calculations report under-earning on an Opinion No. 154-B basis. AOPL responds to Sinclair's claim that the pipeline industry experienced cost changes in alignment with the global economic recession by stating it is speculative and is contrary to actual changes in costs as Dr. Shehadeh shows in his calculations using the Kahn Methodology.

2. <u>Commission Determination</u>

112. The fact that some pipelines may be over-recovering is not contrary to the establishment of a general index level for all pipelines. The purpose of the index is to track cost changes using a generally applicable and simple method, and does not involve an assessment of whether each of the various pipelines are over- or under-recovering their costs. This can be seen in the application of the index. When a pipeline proposes an indexed rate change, the Commission is not subject to a statutory duty to examine the

whole rate.[48] Rather, the Commission's inquiry is limited to a comparison of the changes in the rates and costs from year to year.

113. As the Commission explained previously, inherent to the application of any industry-wide pipeline index, some pipelines will over-earn while others will under-earn.[49] However, the Kahn Methodology ensures that that indexed changes are consistent with recent industry-wide historical norms.[50] To the extent that the customers of a particular pipeline determine that the underlying rates on a particular pipeline are unjust and unreasonable, those parties may file a complaint against that particular pipeline's rates pursuant to the ICA and the Commission regulations. Moreover, even when considering pipeline over-recoveries and under-recoveries (as opposed to cost changes), Dr. Shehadeh presented evidence that in 2009, the oil pipeline industry as a whole was under-earning by approximately 17 percent.[51]

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[48] Second Five-Year Review, 114 FERC ¶ 61,293 at P 57. This is consistent with the grandfathering of the then-existing rates under the EPAct 1992. EPAct 1992, at § 1803.

[49] Order No. 561, FERC Stats. & Regs. ¶ 30,985 at 30,948-49; Second Five-Year Review, 114 FERC ¶ 61,293 at P 57.

[50] Contrary to Sinclair/Tesoro's claims and Navajo's allegations, as discussed above, the empirical evidence presented using the Kahn Methodology demonstrates that pipeline costs per barrel-mile have increased at a rate exceeding changes in PPI-FG over the past five-years. There is no indication that an adjusted PPI-FG is inadequate for tracking cost changes.

[51] Shehadeh September 20 Decl. at 32-33.

D. Other Factors Affecting Pipeline Costs Raised by the Parties

114. Although not linked to any particular modification of the index methodology, the comments urged the Commission to consider general issues related to pipeline integrity and the MLP business structure.

1. Pipeline Integrity and Regulatory Safety Costs

a. AOPL Initial Comments

115. AOPL states that costs have increased due to assessment and re-assessment of pipeline structural integrity and remediation required by the Pipelines and Hazardous Materials Safety Administration (PHMSA), an agency of the United States Department of Transportation. AOPL, supported by the Declaration of William R. Byrd, stresses that assessment requires expensive technology (including rental of inline inspection tools), labor intensive processes (involving excavation and manual inspection), and remediation. Mr. Byrd represents that "compliance with the integrity management regulations is likely to be the largest single variable cost item for most pipelines and these costs show no signs of decreasing."[52]

116. Mr. Byrd projects pipeline integrity costs to continue increasing because inline inspection tools are becoming more expensive and more likely to detect pipeline anomalies requiring correction. AOPL states that PHMSA has imposed increasingly stringent obligations and that new or expanded regulatory requirements may be imposed by Congress during the reauthorization of the Pipeline Safety Act, which AOPL expects to occur later in 2010 or 2011.

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[52] AOPL Comment at 19 (quoting Byrd Decl. at 7).

117. AOPL and Mr. Byrd identify other regulatory obligations over the past five years that have increased costs, including public awareness program regulations and operator qualification regulations. AOPL and Mr. Byrd explain that costs in the next five years are likely to increase due to new PHMSA control room management regulations, new PHSMA guidelines regarding land-use on or near pipeline rights-of-way, new chemical facility anti-terrorism standards promulgated by the Department of Homeland Security, and issues regarding greenhouse gas emissions issued by the Environmental Protection Agency.

118. In separate comments, PHMSA also represents that pipeline safety and integrity regulations have imposed significant compliance costs over the past eight years. Further, PHMSA notes the possibility of future regulatory changes and that it anticipates the cost of these activities will continue to impose significant financial burdens.

b. <u>Reply Comments</u>

119. Several reply comments noted increased costs related to pipeline integrity. Platte, an interstate liquids pipeline, expects to incur more than $2 million above historic levels of integrity related costs for the foreseeable future. Platte notes that significant additional costs may appear in damage prevention initiatives, valve spacing, leak detection, and increased focus on preventing small releases. The Pipeline Safety Trust notes that it is currently recommending that Congress increase PHMSA’s jurisdiction over hazardous liquid pipelines and that Congress direct PHMSA to expand integrity management and other safety-related requirements.

120. Other parties challenged AOPL’s contention that the pipeline integrity costs

supported an elevated index level. Valero notes that accounting treatment of pipeline costs was not consistent prior to 2006, when the Commission clarified the accounting practices for integrity programs.[53] Thus, Valero states that AOPL, by comparing changes in account 320 between 2004 and 2009, overstates the changes in pipeline integrity costs. Valero also emphasizes that account 320 costs, which include both interstate and intrastate data, are only 14.4 percent of the total cost-of-service. Moreover, Valero notes that the Commission has previously rejected adjustments to the index based upon estimates of anticipated increases in pipeline integrity costs.[54] Lastly, Valero asserts that claims of future increases in regulatory expenses are speculative.

121. ATA, in its reply, states that pipeline integrity cost increases are already appropriately accounted for in the years 2004 through 2009. ATA states that the Pipeline Integrity Management program was established in 2002, and that the program required hazardous liquid pipeline operators to develop a written plan to initially assess the integrity of their pipelines over a roughly five year period with baseline assessments to be 50 percent completed by September 30, 2004, and 100 percent completed by March 31, 2008. After the baseline assessment, the assessments are to be repeated every five year period.

122. SPOPS also avers that future costs are speculative and inconsistent with a backward looking methodology. SPOPS asserts that a large increase rewards pipelines

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[53] Valero Reply Comment at 8 (citing *Jurisdictional Public Utilities and Licensees, Natural Gas Companies, and Oil Pipeline Companies*, 111 FERC ¶ 61,501 (2005)).

[54] Valero Reply Comment at 10 (citing *AOPL II*, 281 F.3d at 247).

with unjust and unreasonable rates and that the pipelines not recovering their costs are free to file for rate increase. Sinclair/Tesoro also assert that more stringent safety regulations are not unique to pipelines as environmental regulations have also imposed costs on shippers, and that it is unfair to impose these costs alone on shippers.

c. AOPL October 20, 2010 Response

123. AOPL states that it relies on Mr. Byrd's declaration to explain that Dr. Shehadeh's calculations are consistent with real-world industry experience, and to show that establishing an index below PPI-FG+3.64 would frustrate expectations on which past pipeline investments have been made, among other things.

124. AOPL also states that Mr. Byrd's testimony is consistent with the comments of PHMSA, which state, among other things, that regulations have imposed significant compliance costs and events, including the Deepwater Horizon oil spill, have also caused PHMSA to expand its integrity management regulations. AOPL disagrees with SPOPS' suggestion that pipelines should seek to recover these safety and integrity management costs through cost-of-service filings, arguing that such an approach is inconsistent with the implementation of a generally applicable ratemaking methodology. AOPL argues that if pipelines were required to use cost-of-service filings to recover these kinds of costs, the efficiency gains which were intended by EPAct in implementing the generally applicable index methodology would be lost.

d. Commission Determination

125. AOPL and other parties have submitted this information regarding future costs for Commission consideration, but they have not proposed to depart from the Kahn

Methodology's reliance upon historic data. Moreover, future costs projections related to regulatory changes are speculative and inappropriate for inclusion in the index.[55] Accordingly, the evidence presented regarding prospective regulatory changes does not alter the Commission's determination regarding the appropriate index level as calculated based upon historic costs.

2. <u>Master Limited Partnerships</u>

126. CAPP contends that the Commission should not grant an increased allowance merely to enhance cash flow requirements that may be attributable to the MLP form of business. CAPP states that due to federal tax laws, MLPS generally distribute all available cash flow to unit holders in the form of quarterly distributions. CAPP argues that the form of business organization and operation may create a tension between how a pipeline makes prudent safety and integrity-related decisions without contravening cash distribution constraints. CAPP argues that the Commission should not view the cash requirements of MLPs as a legitimate basis for increasing the revenue flow generated by regulated rates. SPOPS also claims that the MLP structure attracts capital to the pipeline industry but, rather than making investments in infrastructure, diverts the equity capital away in payouts to the general and limited partner investors.

127. AOPL responds in its Supplemental Reply Comments that shippers made substantially similar arguments during the prior five-year review period, and the Commission rejected them. Furthermore, AOPL states it is not seeking "an increased allowance" to enhance MLP cash flow requirements. AOPL asserts neither the cash flow

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[55] *AOPL II*, 281 F.3d at 247.

requirements of MLPs nor the dividend policies of corporate-owned pipelines are part of the calculation of changes in oil pipelines costs. Nor is there any "tension" between pipeline safety and capital investment and MLP cash distribution requirements, as CAPP contends. AOPL contends the issue is not about the pipeline organizational structure, but whether pipelines will be able to recover sufficient revenue to fund their operations. Accordingly, AOPL argues shippers provide no valid basis to abandon the established methodology.

a. **Commission Determination**

128. All pipelines, regardless of business form, experience changes in cost. The index is designed to enable pipelines be able to recover sufficient revenue to fund their operations, whether or not the pipeline's business form is as an MLP. The middle 50 Kahn Methodology allows the Commission to appropriately exclude outliers and to track general changes in pipeline costs whatever the form of the business. Accordingly, the discussion regarding MLPs does not alter the Commission's determination regarding the appropriate index level.

E. **Revisions to Form No. 6**

1. **Comments**

129. ATA and NPGA aver that Form No. 6 should be revised to segregate cost and revenue for each regulated common carrier and or system and to supply separate page 700 data for each oil pipeline or system included in the report. To enhance transparency, ATA and NPGA also asserts that Form No. 6 should be revised to require the pipeline to file all workpapers that fully support the data reported on Form No. 6 page 700, including

a total cost-of-service. ATA and NPGA also assert that pipelines must file Form No. 6 before initiating an index rate increase. ATA and NPGA also argue that the Commission should change the interest rates applicable to refunds as provided in 18 CFR § 340.1(c)(2)(i) to reflect the pipeline's rate of return as reported on Form No. 6, page 700.

130. SPOPS urges, in its reply comments, that shippers and customers should be allowed access to the workpapers underlying page 700. SPOPS also contends that the page 700 data should reveal both the nominal and the real rate of return on equity, including the amount of dollars of equity both collected in rates and dollars placed in rate base. SPOPS states that the current rate of return on equity must be known to determine the need for the index increase to attract capital.

131. In reply comments, AOPL argues that the Commission has addressed and rejected the proposal regarding segmented data and workpapers. AOPL states the Commission in its ruling explained that page 700 is designed to be a preliminary screening tool for pipeline rate filings and not form the basis of a decision or demonstrates the just and reasonableness of proposed or existing rates. AOPL asserts the Commission has revisited this issue as recently as December 2008 and upheld its initial views.

2. Commission Determination

132. The Commission finds that the proposals to modify Form No. 6 are outside the scope of this proceeding, which is to set the going-forward index level.

<u>The Commission orders:</u>

Consistent with our review and verification of the sample pipeline Form No. 6 data, and the application of the previously approved Order No. 561 methodology to that data, the Commission determines that the appropriate oil pricing index for the next five years, July 1, 2011 through June 30, 2016, should be PPI-FG+2.65.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.