Revisions to the Prefiled Rebuttal Testimony and Exhibits of Julia M. Ryan

Q. With respect to ICNU's testimony, do you believe it is appropriate to "normalize" power costs?

A. In establishing the PCA power cost baseline rate, it is reasonable to normalize loads for temperature variations and to normalize hydro generation or stream flows, assuming that is the best information available when rates are set. Weather and water are natural phenomena that are not affected by market forces. Otherwise, the best information regarding projected power costs for the rate year should be used when setting rates. Mr. Story provides additional information on this point in his rebuttal testimony.

Q. Have you updated power costs since PSE's original filing in April 2004?

A. Yes, the Company updated its power costs for purposes of this rebuttal testimony. The updated power costs are provided in Exhibit No. ___(JMR-22). Rate year power costs in this rebuttal filing are $813.~~4~~9 million, a $40.~~0~~6 million increase from the originally filed power costs of $773.4 million. Updating the gas price forecast for the rate year to a three-month average of forward strips for the period ended September 30, 2004, increases rate year power costs by $43.2 million. Also, the CanWest contract updates discussed by Mr. Markell in his rebuttal testimony would increase rate year power costs by an additional $1.2 million. This contract price update has not been included in the Company's power costs for rebuttal as an Accounting Petition, Docket No. UE-041846, is pending that will determine how the costs associated with this contract will be calculated during the rate year. As Mr. Story discusses, power costs need to be adjusted for this contract change based on the Commission's decision in the Accounting Petition docket. Other updates, such as changing from 60-year to 50-year hydro data, decrease rate year power costs by $~~3.2~~ 2.7 million. A reconciliation between the different power cost projections is provided in Exhibit No. ___(JMR-23).

Q. Do your updated power costs incorporate any of the other parties' suggestions?

A. Yes, as I discuss in more detail below, PSE has adopted Staff's recommendation regarding hydro and coal prices and some portions of their recommendation regarding gas price forecasts. PSE has also updated rate year capacity costs.

PSE does not agree or incorporate other suggestions by opposing parties, such as Staff and ICNU regarding wheeling charges, ICNU's proposals regarding hydro and gas price projections, or ICNU's recommendation to exclude costs associated with call options or to include "savings" associated with reduced transmission losses.

I. HYDRO ASSUMPTIONS

Q. What is the Company's reaction to WUTC Staff's proposal to use the 50-year hydro period from 1928 through 1977 in estimating power costs for the rate year?[2]

A. PSE is pleased that Dr. Mariam agrees with the Company that there are no statistical grounds to exclude any water years. (See Exhibit T-___ (YKGM-1T) at 25.)

Dr. Mariam does not agree to the use of 60 years of data because run-off volumes must

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[2] The 50-year period recommended by WUTC Staff uses stream flows for the years 1928 through 1977. The 40-year period last approved by the Commission used streamflow records for the years 1949 through 1987. The 60-year period proposed by the Company includes the stream flows for the years 1928 through 1987. At some time in the near future the historical data for 1988 through 1998, an additional 10 years, is expected to be available.

October 1, 2005, based upon a preliminary estimate provided to PSE by BPA. Since then, BPA has held several transmission rate workshops, and PSE has participated with other BPA customers in several preliminary rate case settlement discussions. BPA's latest estimate is for a ~~25.1~~ 17.7% increase in the rate under which PSE receives the majority of its transmission service.

The Company agrees with ICNU that, should a settlement with BPA be reached before the Commission's final order, the power costs should reflect what is agreed to between BPA and its customers. However, if there is no agreement prior to the Commission's final order, PSE proposes to use a ~~14~~ 17.7% increase, which is the approximate average increase in transmission rates foreseen by BPA for all classes of customers. PSE's rebuttal power costs reflect a ~~14~~ 17.7% rate increase in BPA's wheeling costs effective October 1, 2005, which increases power costs by $~~1.9~~ 2.5 million.

I. CAPACITY COSTS

Q. **Do you have any proposed changes to the peaking costs presented in your pre-filed direct testimony?**

A. Yes, I do. The projected peaking costs for PSE's winter peaking needs in the rate year are being revised in connection with both the planning the Company is doing for the current year (November 2004-February 2005) and the projected volumetric needs for the rate year. In addition, the Company adjusted its available combustion turbine units' capacity to reflect increased availability at lower temperatures. The revised costs of $2.8 million reflect $1.2 million for transmission exchange agreements and $1.5 million for

GRC Power Cost Projections Reconciliation
Rate Year AURORA + Non-AURORA Power Costs

Power Costs

Changes Highlighted

9.30.04 Rebuttal Gas Price Update vs GRC Filing

GRC 9.30.04 REBUTTAL w/ Gas Price Update	Aurora	Not in Models	Total	Tenaska & March Point Disallowance	Total	Production O&M	Colstrip 500 KV	Net Costs for Revenue Requirements	
GRC 1.19.04 as filed	**$ 525,879**	**$ 205,494**	**$ 731,373**	**$ (11,993)**	**$ 719,380**	**$ 53,496**	**$ 492**	**$ 773,369**	
Reconciling Items:									
50 yr vs 60 yr hydro	(1,978)		(1,978)	-	(1,978)	-	-	(1,978)	H
Update Gas Forecast	56,440		56,440	-	56,440	-	-	56,440	G
Gas MTM		(9,784)	(9,784)		(9,784)			(9,784)	G
Update Coal Price & move adj to Aurora	2,406	(912)	1,495		1,495			1,495	Coal
Remove PSEG contract to Tenaska		323	323		323			323	Contracts
Douglas Settlement	-	(931)	(931)	-	(931)	-	-	(931)	G
Adjust Wheeling Incr from 15% to 14%		338	338		338			338	W
Adjust WNP3 Contract		(1,525)	(1,525)		(1,525)			(1,525)	Contracts
Capacity Cost Update		(2,746)	(2,746)		(2,746)			(2,746)	Cap
Fixed Fuel Costs for Encogen		28	28		28			28	G
Prudence & Buyout Disallowance	-	-	-	(1,761)	(1,761)	-	-	(1,761)	G
Colstrip O&M	-	-	-	-	-	1,151	-	1,151	Coal
Generation Impact for Freddy/Epcor			-		-	(62)		(62)	G
Normalized Major Maintenance	-	-	-	-	-	(422)	-	(422)	G
Net Change before CanWest	$ 56,868	$ (15,208)	$ 41,661	$ (1,761)	$ 39,899	$ 667	$ -	$ 40,566	
Rebuttal w/ Gas Price Updates b4 CanWest	**$ 582,748**	**$ 190,286**	**$ 773,033**	**$ (13,754)**	**$ 759,280**	**$ 54,163**	**$ 492**	**$ 813,935**	
CanWest Stlmt		1,577	1,577		1,577			1,577	CW
CanWest Replacement Gas Contracts MTM		(345)	(345)		(345)			(345)	CW
CanWest Change	$ -	$ 1,232	$ 1,232	$ -	$ 1,232	$ -	$ -	$ 1,232	
Net Change	$ 56,868	$ (13,976)	$ 42,893	$ (1,761)	$ 41,132	$ 667	$ -	$ 41,799	
GRC 9.30.04 rebuttal w/ CanWest	**$ 582,748**	**$ 191,518**	**$ 774,266**	**$ (13,754)**	**$ 760,512**	**$ 54,163**	**$ 492**	**$ 815,168**	
	-	-	-	-	0	-	-	-	

AURORA As Filed	$ 525,879
AURORA As Filed w/ 50 year Hydro	523,901
Decrease due to 50 vs 60 year Hydro	(1,978)

	As Filed	$	773,369
H	Hydro Update		(1,978)
G	Gas Price Update		43,508
Cap	Capacity Update		(2,746)
Coal	Colstrip Update		2,645
Contracts	Contracts Update		(1,202)
W	Wheeling		338
	Rebuttal before CanWest	$	813,935
CW	CanWest Update		1,232
	Rebuttal including CanWest	$	815,168
		$	-

Tenth Exhibit to
Prefiled Rebuttal Testimony
of Julia M. Ryan

Exhibit No. ___(JMR-22)

REVISED 12/09/04

GRC Power Cost Projections
Rate Year AURORA + Non-AURORA Power Costs
GRC 9.30.04 Gas Price Updates + 50 Year Hydro

Changes Highlighted

General Rate Case Rate Year: March 2005 - February 2006

		Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Rate Year
501	Coal Fuel	$ 3,524	$ 3,428	$ 2,848	$ 3,012	$ 3,524	$ 3,524	$ 3,428	$ 3,524	$ 3,428	$ 3,524	$ 3,626	$ 3,331	$ 40,719
547	Natural Gas Fuel	5,755	4,618	4,169	4,341	7,291	12,077	13,831	9,878	10,506	11,747	13,402	10,916	108,531
555	Purchase & Interchange	57,732	43,390	32,823	40,654	33,694	34,242	37,130	51,434	60,064	75,823	72,717	61,696	601,398
557	Other Power Supply	562	562	562	562	562	562	562	562	562	562	544	544	6,708
565	Wheeling	3,373	3,390	3,386	3,549	3,763	3,573	3,880	4,057	4,018	3,975	3,927	3,916	44,806
447	Secondary Sales	(1,128)	(1,642)	(448)	(1,295)	(5,162)	(4,981)	(3,887)	(2,570)	(2,680)	(1,662)	(1,318)	(1,122)	(27,896)
	Subtotal	$ 69,817	$ 53,746	$ 43,338	$ 50,822	$ 43,671	$ 48,996	$ 54,944	$ 66,885	$ 75,897	$ 93,969	$ 92,899	$ 79,281	$ 774,266
456	Non-Core Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal with Non-Core Gas	$ 69,817	$ 53,746	$ 43,338	$ 50,822	$ 43,671	$ 48,996	$ 54,944	$ 66,885	$ 75,897	$ 93,969	$ 92,899	$ 79,281	$ 774,266
	Load in MWh	1,913,303	1,657,048	1,577,190	1,478,858	1,508,755	1,537,626	1,499,973	1,690,860	1,881,084	2,141,613	2,177,709	1,859,919	20,923,938
6.40%	Delivered Load	1,790,852	1,550,997	1,476,250	1,384,211	1,412,194	1,439,218	1,403,975	1,582,645	1,760,695	2,004,550	2,038,336	1,740,884	19,584,806

Revenue Requirement Adjustments:

			Original File	Rebuttal
Before adjustment			$ 774,266	
Tenaska Buyout Disallowance	50.0%	$ 21,442	(10,721)	
Tenaska Prudence Disallowance	1.2%	$ 164,337	(1,972)	
March Point 2 Prudence Disallowance	3.0%	$ 35,351	(1,061)	
Net Power Costs			$ 760,512	
Production O&M (including ben & p/r tax)			54,163	
Colstrip 500 KV Expense			492	
Subtotal Costs for Revenue Requirement			$ 815,167	
Remove CanWest Impact:			(1,232)	
Net Costs for Revenue Requirement			$ 813,935	
As Filed Net Costs			$ 773,369	$ 813,417
Difference			$ 40,566	$ 518

GRC Power Cost Projections
Rate Year AURORA + Non-AURORA Power Costs
GRC 1.19.04 50 Year Hydro

Changes Highlighted

General Rate Case Rate Year: March 2005 - February 2006

		Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Rate Year
501	Coal Fuel	$ 3,524	$ 3,429	$ 2,848	$ 3,012	$ 3,524	$ 3,524	$ 3,429	$ 3,524	$ 3,429	$ 3,524	$ 3,626	$ 3,331	$ 40,726
547	Natural Gas Fuel	5,543	4,965	4,605	4,559	7,026	11,594	14,061	10,231	10,434	10,950	11,940	10,026	105,934
555	Purchase & Interchange	53,627	40,324	30,843	38,105	31,707	32,258	34,324	46,845	54,619	69,248	67,580	57,313	556,792
557	Other Power Supply	562	562	562	562	562	562	562	562	562	562	544	544	6,708
565	Wheeling	3,373	3,390	3,386	3,549	3,763	3,573	3,880	4,057	4,018	3,975	3,927	3,916	44,806
447	Secondary Sales	(990)	(1,743)	(530)	(1,315)	(4,683)	(4,832)	(4,124)	(2,974)	(2,558)	(1,528)	(1,160)	(969)	(27,406)
	Subtotal	$ 65,639	$ 50,927	$ 41,714	$ 48,472	$ 41,899	$ 46,679	$ 52,131	$ 62,245	$ 70,503	$ 86,732	$ 86,457	$ 74,162	$ 727,560
456	Non-Core Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal with Non-Core Gas	$ 65,639	$ 50,927	$ 41,714	$ 48,472	$ 41,899	$ 46,679	$ 52,131	$ 62,245	$ 70,503	$ 86,732	$ 86,457	$ 74,162	$ 727,560
	Load in MWh	1,913,303	1,657,048	1,577,190	1,478,858	1,508,755	1,537,626	1,499,973	1,690,860	1,881,085	2,141,614	2,177,709	1,859,919	20,923,938
6.40%	Delivered Load	1,790,852	1,550,997	1,476,249	1,384,211	1,412,194	1,439,218	1,403,975	1,582,645	1,760,695	2,004,550	2,038,335	1,740,884	19,584,806

Revenue Requirement Adjustments:

Before adjustment			$ 727,560
Tenaska Buyout Disallowance	50.0%	$ 18,360	(9,180)
Tenaska Prudence Disallowance	1.2%	$ 143,972	(1,728)
March Point 2 Prudence Disallowance	3.0%	$ 35,704	(1,071)
Net Power Costs			$ 715,581
Production O&M (including ben & p/r tax)			54,626
Colstrip 500 KV Expense			492
Net Costs for Revenue Requirement			$ 770,700
As Filed Net Costs			773,369
Difference			(2,669)

	Original File	Rebuttal
As Filed Net Costs	$ 773,369	$ 813,417
Difference	$ (2,669)	$ (42,717)

Eleventh Exhibit to the
Prefiled Rebuttal Testimony of
Julia M. Ryan

Exhibit No. ___(JMR-23)

REVISED 12/09/04

Rate Year AURORA + Non-AURORA Power Costs

Rate Year: March 2005 through February 2006

Changes highlighted

Row	Account	Item	%	As Filed	Change	(No Gas Updates) Rebuttal	Gas Price Change	Rebuttal w/ Gas Price Updates	CanWest Change	Rebuttal w/ Gas Price Updates + CanWest
1	501	Coal Fuel		39,224	1,502	40,726	(8)	40,719	-	40,719
2	547	Natural Gas Fuel		106,378	(445)	105,934	1,365	107,298	1,232	108,531
3	555	Purchase & Interch:		562,021	(5,229)	556,792	44,606	601,398	-	601,398
4	557	Other Power Supply		6,708	-	6,708	-	6,708	-	6,708
5	565	Wheeling		44,468	338	44,806	-	44,806	-	44,806
6	447	Secondary Sales		(27,103)	(303)	(27,406)	(490)	(27,896)	-	(27,896)
7		**Subtotal**		$ 731,696	$ (4,136)	$ 727,560	$ 45,473	$ 773,034	$ 1,232	$ 774,266
8	456	Non-Core Gas		(323)	323	-	-	-	-	-
9		**Subtotal with Non-C**		$ 731,373	$ (3,813)	$ 727,560	$ 45,473	$ 773,034	$ 1,232	$ 774,266
10										
11		**Load in MWh**		20,923,938	(0)	20,923,938	0	20,923,938	-	20,923,938
12		6.40% **Load**		19,584,806	(0)	19,584,806	0	19,584,806	-	19,584,806
13										
14		**Revenue Requirement Adjustments:**								
15		Before adjustment		$ 731,373	$ (3,813)	$ 727,560	$ 45,473	$ 773,034	$ 1,232	$ 774,266
16		Tenaska Buyout Disallowance	50.0%	(9,201)	21	(9,180)	(1,541)	(10,721)	-	(10,721)
17		Tenaska Prudence Disallowance	1.2%	(1,724)	(3)	(1,728)	(244)	(1,972)	-	(1,972)
18		March Point 2 Prudence Disallowance	3.0%	(1,067)	(4)	(1,071)	11	(1,061)	-	(1,061)
19		**Net Power Costs**		$ 719,381	$ (3,799)	$ 715,581	$ 43,698	$ 759,280	$ 1,232	$ 760,512
20		**Production O&M (including ben & p/r tax)**		53,496	1,130	54,626	(463)	54,163	-	54,163
21		**Colstrip 500 KV Expense**		492	-	492	-	492	-	492
22		**Net Costs for Revenue Requirement**		**$ 773,369**	**$ (2,669)**	**$ 770,700**	**$ 43,235**	**$ 813,935**	**$ 1,232**	**$ 815,167**
23		**As Filed Net Costs**		**773,369**		**773,369**		**773,369**		**773,369**
24		**Difference**		0		(2,669)		40,566		41,798
25										
26					**Per Original Rebuttal**	**$ 770,182**	**$ 43,235**	**$ 813,417**	**$ 1,232**	**$ 814,650**
27					**Change**	**$ 518**	**$ -**	**$ 518**	**$ -**	**$ 518**

Eleventh Exhibit to the
Prefiled Rebuttal Testimony of
Julia M. Ryan

Exhibit No. ___(JMR-23)

REVISED 12/09/04