EXHIBIT NO. ___(JKP-1T)
DOCKET NO. UE-14____
2014 PSE PCORC
WITNESS: JANET K. PHELPS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-14____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS ON BEHALF OF PUGET SOUND ENERGY, INC.

MAY 23, 2014

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS

CONTENTS

I. INTRODUCTION 1

II. TRANSMISSION CONTRACT RENEWALS 2

III. CONCLUSION 13

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Janet K. Phelps, and my business address is 10885 N.E. Fourth Street, Bellevue, Washington 98004. I am employed by Puget Sound Energy, Inc. ("PSE") as a Senior Energy Resource Planning Acquisition Analyst.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is the First Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-2).

Q. What is the purpose of your testimony?

A. This prefiled direct testimony presents the quantitative analysis related to the renewal of certain transmission contracts with the Bonneville Power Administration ("BPA") relevant to the December 1, 2014 to November 30, 2015 rate year in this proceeding. Please see the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), for a discussion of the prudence of these contract renewals.

II. TRANSMISSION CONTRACT RENEWALS

Q. Please describe the BPA transmission contracts that were renewed.

A. PSE considered twelve BPA transmission contracts because they all had renewal deadlines close in time. The renewal deadline for the 169 megawatt ("MW") contract was November 2013, and the renewal deadline for the eleven other contracts, which total 305 MW, was October 2013.[1] Table 1 is a list of the contracts.

Table 1. Transmission Contracts with Late 2013 Renewal Deadlines

	Mid-C Location	2014 Capacity (MW)	2015-2019 Capacity (MW)	Renewal Deadline	Start Date
1.	Rocky Reach	40	40	10/31/13	11/1/14
2.	Rocky Reach	40	40	10/31/13	11/1/14
3.	Rocky Reach	40	40	10/31/13	11/1/14
4.	Rocky Reach	5	5	10/31/13	11/1/14
5.	Rocky Reach	55	55	10/31/13	11/1/14
6.	Vantage	27	27	10/31/13	11/1/14
7.	Vantage	27	27	10/31/13	11/1/14
8.	Vantage	27	27	10/31/13	11/1/14
9.	Vantage	3	3	10/31/13	11/1/14
10.	Vantage	36	36	10/31/13	11/1/14
11.	Vantage	5	5	10/31/13	11/1/14
	Subtotal	**305**	**305**	**10/31/13**	**11/1/14**
12.	Vantage	209	169	11/30/13	12/1/14
	Total	**514**	**474**		

[1] Accordingly, the start date for the 169 MW contract is December 1, 2014 and the start date for the other eleven contracts is November 1, 2014.

All of these contracts are for transmission originating at the Mid-Columbia ("Mid-C") Hub. PSE uses this transmission to wheel short-term market purchases to PSE's system. The contracts each have five-year terms. Renewing contracts for five year terms allows PSE to retain rollover rights in the future. Therefore, PSE has the right of first refusal to renew that capacity after the contracts expire by requesting renewal one year in advance of the contract expiration.

The capacity of one of the contracts drops between 2014 and 2015 such that the total capacity of the contracts is 514 MW in the first year and 474 MW in the following years. The analysis was conducted using the capacities presented in Table 1. However, as indicated later, PSE chose to renew the transmission contracts at the 474 MW level.

Q. When did PSE evaluate these contract renewals?

A. PSE evaluated the contracts in October 2013 to make a decision in time for the October 31, 2013 and November 30, 2013 renewal deadlines.

Q. Please summarize PSE's approach to the analysis related to renewing the contracts.

A. PSE compared (i) the incremental portfolio cost of generation resources assuming renewal of the contracts with (ii) the incremental portfolio cost of generation resources assuming expiration of the contracts. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission

contracts.

Q. Please describe PSE's incremental portfolio cost of generation.

A. PSE's incremental portfolio cost of generation includes variable costs of PSE's existing generation assets and all capital and operating and maintenance ("O&M") costs associated with new units necessary to meet load and Renewable Portfolio Standard ("RPS") requirements during the 20-year study period.

Q. How does PSE calculate the portfolio costs?

A. PSE calculates the portfolio costs on a net present value ("NPV") basis. The analysis was conducted using the Portfolio Screening Model III ("PSM III"), which is an optimization model PSE uses to identify the least cost portfolio of resources such that the total peak capacity of the portfolio's resources meets PSE's peak capacity need along with the RPS need over 20 years. PSE uses PSM III to develop PSE's Integrated Resource Plan ("IRP") and to evaluate bids for generation resources provided by outside parties in response to Requests for Proposals ("RFP"). In this case, the portfolio costs with and without the contract renewals were calculated based on six scenarios, which are discussed later in my testimony.

Q. How was the transmission renewal analysis related to PSE's 2013 IRP?

A. PSE used the PSM III model in the 2013 IRP Base Scenario as the starting point for the transmission analysis. The model contained data on PSE-owned resources

and forecasted load, financial data, dispatch data from the AURORA dispatch model, and costs of alternative resources such as natural gas-fired combined cycle units, peaking units and wind resources.

Q. Please describe the AURORA dispatch model.

A. As discussed in the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), AURORA is a regional dispatch model that uses market fundamentals and advanced dispatch logic to model energy markets in the Western Electricity Coordinating Council (WECC) region of the United States. PSE uses energy, cost, revenue and price data from the AURORA model in its PSM III model.

PSE updated the 2013 IRP PSM III model to reflect more recent input data for the transmission analysis, specifically the load forecast, transmission costs and dispatch data from a new AURORA run. PSE conducted this AURORA analysis in the fall of 2013, and it is distinct from the AURORA analysis used to estimate power costs for the rate year in this proceeding.

Q. Please summarize the sets of analyses modeled by PSE in considering renewal of the transmission contracts.

A. PSE modeled two sets of analyses in considering the renewal of the BPA transmission contracts:

(i) The first set of analyses assumed that PSE would be able to redirect two non-Mid-C transmission contracts of 94 MW

and 23 MW (a total of 117 MW) to the Mid-C Hub for all years 2016 and beyond.

(ii) The second set of analyses assumed that PSE would not be able to redirect two non-Mid-C transmission contracts of 94 MW and 23 MW (a total of 117 MW) to the Mid-C Hub for all years 2016 and beyond. Under this second set of analyses, both non-Mid-C Contracts would expire in 2016, thereby reducing the total amount of transmission contracts available to meet peak capacity need through market purchases at the Mid-C Hub relative to the first set of analyses.

Q. Was PSE able to redirect the two non-Mid-C contracts to the Mid-C Hub for all years 2016 and beyond?

A. No. PSE's efforts to redirect the two non-Mid-C contracts to the Mid-C Hub for all years 2016 and beyond were unsuccessful due to constraints on BPA's transmission system.

Q. Why did PSE conduct analyses using the first set of analyses that assumed that PSE could redirect the two non-Mid-C contracts?

A. PSE conducted analyses using the first set of analyses that assumed that PSE could redirect the two non-Mid-C contracts because, at the time of such analyses, PSE was unaware that redirection would not be an option. Therefore, PSE conducted the transmission renewal analyses using both sets of analyses. Subsequent to the decision to renew the transmission contracts, BPA informed PSE that the two non-Mid-C contracts could not be redirected.

Q. Did PSE model any scenarios within each of the two sets of analyses?

A. Yes. Within each set of analyses described above, PSE modeled three scenarios:

(i) The first scenario modeled the portfolio cost assuming all transmission contracts expiring in October/November 2014 would be allowed to expire.

(ii) The second scenario modeled the portfolio cost assuming the full amount of all transmission contracts expiring in October/November 2014 would be renewed.

(iii) The third scenario modeled the portfolio cost assuming the transmission contracts expiring in October/November 2014 would be partially renewed at an annual capacity 100 MW less than the full amount of all transmission contracts up for renewal.

With the two sets of analyses and three scenarios for each set, PSE modeled a total of six scenarios:

Including redirected 117 MW in 2016 and beyond in existing capacity:
- Scenario 1: No renewal of 474 MW of transmission capacity (514 in 2014)
- Scenario 2: Full renewal of 474 MW of transmission capacity (514 in 2014)
- Scenario 3: Partial renewal - at 374 MW of transmission capacity (414 in 2014)

Excluding 117 MW in 2016 and beyond from existing capacity:
- Scenario 4: No renewal of 474 MW of transmission capacity (514 in 2014)
- Scenario 5: Full renewal of 474 MW of transmission capacity (514 in 2014)
- Scenario 6: Partial renewal - at 374 MW of transmission capacity (414 in 2014)

Q. Please describe PSE's capacity need from PSE's 2013 IRP.

A. PSE's most recent IRP, the 2013 IRP, shows a peak capacity need beginning with a 12 MW need in 2017 and growing to 100 MW in 2020. The peak capacity need in the IRP assumes that all existing transmission is renewed when available and

used for short term market purchases to meet need. If the transmission contracts were not renewed, the need would be greater and would begin sooner, in 2014.

Q. Has the estimate of need changed since the 2013 IRP was prepared?

A. Yes. Since the 2013 IRP was published in May 2013, the estimated capacity need has changed.

Q. Please discuss the changes to the estimated capacity need.

A. Three changes impacted the calculation of estimated capacity need. First, PSE has implemented a change in how it returns contractual losses for energy delivered using its BPA transmission contracts. Previously PSE compensated BPA for transmission losses using existing Mid-C transmission capacity to physically return energy to BPA at the Mid-C, which is the approach assumed in the 2013 IRP. PSE's updated method for returning losses to BPA is to buy energy at the Mid-C and schedule this directly to BPA at the same location, the Mid-C, rather than use PSE's Mid-C transmission capacity to physically return energy to BPA. Effectively, the updated methodology for providing loss returns to BPA provides an additional 70 MW of transmission to serve PSE's westside load.

Second, the load forecast used to determine the capacity need for the analysis was updated with a draft version of the F2013 load forecast, which was released after the 2013 IRP was published. The updated peak load and conservation levels

provided in the draft F2013 load forecast used in the analysis caused the estimate of capacity need to increase.

Finally, the total amount of Mid-C transmission available in 2014 and 2015 was reduced by 42 MW as compared to the 2013 IRP. The 2013 IRP had assumed that two existing non-Mid-C transmission contracts of 94 MW and 23 MW (117 MW total) could be redirected for additional Mid-C transmission capacity in 2014 and 2015. As noted above, at the time this transmission analysis was conducted, which was after the 2013 IRP was published, attempts to redirect the 23 MW transmission contract to the Mid-C had been unsuccessful and thus the 23 MW contract could not be assumed to provide additional Mid-C transmission capacity in 2014 and 2015. Of the 94 MW, 75 MW has been filled with a short term power contract through February 2015, while attempts to redirect the remaining 19 MW to Mid-C have been unsuccessful. Thus, a total of 42 MW (23 from one contract and 19 from the other contract) assumed in the 2013 IRP to meet peak capacity need through transmission contracts in 2014 and 2015 could not be assumed to provide peak capacity in those years at the time the transmission renewal analysis was conducted, and the transmission available to meet peak capacity was adjusted downward accordingly in all six scenarios. In April 2014, PSE received and accepted the opportunity from BPA to redirect the 23 MW to Mid-C for 13 months, May 2014 through May 2015.

Q. Was there a difference in capacity need between the two sets of scenarios modeled for the transmission analysis?

A. Yes. In Scenarios 4, 5 and 6, which are described earlier in my testimony, PSE assumed it would not be able to redirect the 94 and 23 MW contracts (117 MW total) to Mid-C in 2016 and the following years. This increases the capacity need in those years.

Q. Please summarize the capacity need you have described.

A. Table 2 presents the capacity surplus and need from the 2013 IRP including the adjustments discussed above.

Table 2. PSE Capacity Surplus (Need*) (MW)

	2014	2015	2016	2017	2018	2019	2020
2013 IRP	124	140	102	(12)	(61)	(105)	(100)
Scenarios 1, 2, 3 with 2016-2020 Redirect	229	222	195	47	(21)	(77)	(74)
Scenarios 4, 5, 6 without 2016-2020 Redirect	229	222	78	(75)	(146)	(202)	(199)

*Capacity need figures include 7 percent operating reserves.

Q. What resources were used to meet capacity need?

A. The analysis used peakers to fill capacity need. Peakers are generators that can ramp up and down quickly in order to meet spikes in need. The assumed peaker costs were the same as the generic peaking costs presented in the 2013 IRP. These cost estimates were based on a market study conducted in 2012, in which Black and Veatch examined peaking technologies and developed cost estimates

for use in PSE's analysis. The generic peakers were used to fill capacity need in the analysis because they were the least cost resource among all generic resources in the 2013 IRP. Each generic peaker was assumed to provide 206 MW of peak capacity. The analysis did not include any specific bids from outside parties as resource options because the most recent RFP was in 2011 and was not current.

Q. What were the results of the analysis?

A. The results of the analysis showed that renewing the full capacity of transmission contracts resulted in a lower portfolio cost as compared to allowing the full capacity of transmission contracts to expire in October/November 2014 or requesting a partial renewal of the transmission contracts at an annual capacity 100 MW less than the full amount of all transmission contracts up for renewal. The net present value of the incremental portfolio cost of all six scenarios is presented in Table 3. These results are consistent with findings of the 2013 IRP.

Table 3: Summary of Portfolio Costs

Scenario	Net Present Value of Portfolio Cost ($000)	Change in Cost Compared to No Renewal Scenario ($000)	Peaker Capacity Built Through 2020 (MW)
Including redirected 117 MW* in 2016 and beyond:			
1: No renewal	$11,991,527	$0	618
2: Full renewal	$11,559,936	($431,591)	206
3: Partial renewal (100 MW less)	$11,569,078	($422,449)	206
Excluding redirected 117 MW* in 2016 and beyond:			
4: No renewal	$12,200,417	$0	618
5: Full renewal	$11,588,018	($612,699)	206
6: Partial renewal (100 MW less)	$11,767,755	($432,662)	412
*117 MW capacity was ultimately not able to be redirected.			

Q. Why did PSE decide to renew the full amount of transmission capacity rather than a smaller amount?

A. PSE decided to renew the full amount of transmission rather than request a partial renewal because Mid-C transmission is the least cost resource compared to all other generic resources in the 2013 IRP. In addition, renewing the full amount of transmission contracts provides PSE with rollover rights for the full amount of transmission at the end of the next contract allowing maximum flexibility for responding to future market conditions. If any amount of transmission is given up, it is highly unlikely that PSE will be able to obtain that amount in the future through BPA's Network Open Season ("NOS") process. PSE can sell excess capacity on a short-term basis in the market.

Q. Would your conclusions have been different had PSE been aware that it could redirect the 23 MW to Mid-C for May 2014 through May 2015?

A. No. Including the redirected capacity for those 13 months would have affected all scenarios similarly, so the relationship between the scenarios with respect to portfolio costs would not have changed and the conclusions would have remained the same.

Q. Did PSE renew the full 514 MW for 2014?

A. No. The total capacity of contracts up for renewal, as shown in Table 1 above, was 514 MW in 2014 and 474 MW in 2015 and beyond. Because PSE's peak

capacity need was surplus in 2014, PSE renewed all of the contracts at the 2015 levels, so the renewed capacity is 474 MW beginning in 2014. Reducing the 2014 transmission contract renewal amount slightly lowers the portfolio cost in all scenarios, therefore renewing at the 474 MW level for all years does not change the conclusion of the original analysis.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.