BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon	)))))	**DOCKET NO. UE-246**

DIRECT TESTIMONY AND EXHIBITS OF

NEAL TOWNSEND

ON BEHALF OF

FRED MEYER STORES

JUNE 20, 2012

DIRECT TESTIMONY OF NEAL TOWNSEND

Introduction

Q. Please state your name and business address.

A. Neal Townsend, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Director for Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Fred Meyer Stores and Quality Food Centers ("Fred Meyer"), divisions of The Kroger Co. Fred Meyer purchases over 52 million kWh annually from PacifiCorp in Oregon, and primarily takes service under Schedule 730.

Q. Please describe your educational background.

A. I received an MBA from the University of New Mexico in 1996. I also earned a B.S. degree in Mechanical Engineering from the University of Texas at Austin in 1984.

Q. Please describe your professional experience and background.

A. I have provided regulatory and technical support on a variety of energy projects at Energy Strategies since I joined the firm in 2001. Prior to my employment at Energy Strategies, I was employed by the Utah Division of Public

Utilities as a Rate Analyst from 1998 to 2001. I have also worked in the aerospace, oil and natural gas industries.

Q. Have you testified previously before this Commission?

A. Yes. I filed joint testimony in support of the Stipulation in PacifiCorp's last Oregon general rate case, Docket No. UE-217.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in utility regulatory proceedings before the Arkansas Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Public Utility Commission of Texas, the Utah Public Service Commission, the Virginia Corporation Commission, and the Public Service Commission of West Virginia. A more detailed description of my qualifications is contained in Attachment A, attached to this testimony.

<u>Overview and Conclusions</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the rate design for Schedule 200 Base Supply Service applicable to customers served under Schedule 30/730. In addition, I provide a recommendation on the design of PacifiCorp's proposed Power Cost Adjustment Mechanism (PCAM).

Q. Please summarize your recommendations to the Commission.

A. I offer the following recommendations:

(1) I recommend improving the alignment between costs and charges for the Schedule 200 rates applicable to Schedule 30/730. I recommend setting the Schedule 200 demand charge at 70% of demand-related generation costs.

(2) I recommend that, if the Commission approves a PCAM for PacifiCorp, it be designed to share the costs and benefits of NPC deviations between the Company and its customers.

<u>Schedule 200 Rate Design</u>

Q. Can you please describe PacifiCorp's Schedule 200?

A. Yes. Schedule 200 is intended to recover generation-related costs except the Net Power Costs ("NPC") which are recovered in Schedule 201. These non-NPC generation costs include both demand-related and energy-related costs. While Schedule 201 is updated annually in the Transition Adjustment Mechanism ("TAM") proceedings, Schedule 200 does not change between general rate cases.

Q. What are the components of Schedule 200?

A. For energy-billed billed customers, Schedule 200 recovers both demand-related and energy-related costs in energy charges. For demand-billed customers, the Schedule 200 charges include both demand and energy charges. As it applies to Rate Schedule 30/730, the Schedule 200 demand charge is currently $1.25 per kW. PacifiCorp is proposing to increase this charge to $1.30 per kW. PacifiCorp's proposed energy charges are 2.761 cents per kWh for the first 20,000 kWh and 2.394 cents for each additional kWh.

Q. What is your assessment of PacifiCorp's proposed Schedule 200 rates applicable to Schedule 30/730?

PacifiCorp's proposed demand charge will significantly under-recover demand-related generation costs. The results of the Company's cost-of-service study indicate demand-related generation costs of $11.4 million for Schedule 30/730 Secondary. However, only $4.4 million, or 39%, of these costs will be recovered through PacifiCorp's proposed Schedule 200 demand charge. Furthermore, while I am not challenging the results of the Company's cost-of-service study, only approximately 17% of generation costs are classified as demand-related. This overall percentage strikes me as very low relative to other utility cost analyses I have reviewed.

Q. Was the issue of Schedule 200 demand charges addressed in PacifiCorp's last Oregon general rate case, Docket No. UE-217?

A. Yes, it was. The Parties to the Stipulation agreed that the Schedule 200 demand charge applicable to Schedule 30 would be increased from $1.00 per kW to $1.25 per kW. PacifiCorp agreed to confer with interested parties prior to filing its next general rate case (i.e. the instant case) "to discuss how to best achieve the goal of eliminating intra-class subsidies in Schedule 200, including, but not limited to, moving demand charges toward full cost-of-service in a timely manner."[1]

Q. Does PacifiCorp's rate design proposal for Schedule 200 make significant progress toward meeting this goal?

[1] Source: Docket No. UE-217 Stipulation filed July 10, 2010, Section 17(b), p. 6.

A. No, it does not. The Company has proposed only a 5 cent per kW increase in the Schedule 200 demand charge for Schedule 30/730. The resulting revenues would be substantially below demand-related generation costs.

Q. From a customer's perspective, why should it matter if PacifiCorp proposes a demand charge that does not fully recover its demand-related costs?

A. If a utility proposes a demand charge that is below the cost of demand, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case with PacifiCorp's proposal. For a rate schedule such as Schedule 30/730, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors are required to subsidize the costs of the lower-load-factor customers within the class. The subsidy is different for each higher-load-factor customer and consists of the net increase in rates paid by these customers as a result of setting energy charges above energy-related costs and demand charges below demand-related costs.

Q. How do you define "higher-load-factor customers"?

A. For purposes of this discussion, I use this term to refer to customers whose load factors are greater than the average for the rate schedule.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. What is your recommendation with respect to Schedule 200 rate design applicable to Schedule 30/730?

A. Ideally, the Schedule 200 demand and energy charges should each be set at 100% of classified non-NPC generation costs. However, full movement to cost-based rates in a single step is sometimes opposed on the grounds of intra-class rate impacts. Taking this potential argument into account, for purposes of this case, I recommend setting the Schedule 200 demand charges for Rate Schedule 30/730 at 70% of demand-related generation costs. Concomitant with this change, there should be a corresponding adjustment (reduction) in the Schedule 200 energy charges to achieve the target revenue requirement. My rate design, presented in Exhibit FM/101, maintains the proportional relationships that currently exist between the first block energy charge (first 20,000 kWh) and second block energy charge (all additional kWh).

Q. How does the alignment of Schedule 200 costs and charges resulting from your proposal compare with that of PacifiCorp?

A. The cost alignment of my rate design proposal is presented in Exhibit FM/102, and is compared to PacifiCorp's proposal in Table FM-1 below. As shown in Table FM-1, my proposal produces charges that are better aligned with costs than PacifiCorp's proposal.

Table FM-1
Alignment of Schedule 200 Costs and Charges at PacifiCorp's Requested Revenue Requirement for Schedule 30/730 (Sec)

Classification	PacifiCorp Proposed Charge	% of Cost	Fred Meyer Proposed Charge	% of Cost
Demand ($/kW)	$1.30	39%	$2.34	70%
Energy First Block (¢/kWh)	2.761	132%	2.430	116%
Energy Second Block (¢/kWh)	2.394		2.107	

Q. Have you prepared a rate impact analysis of your recommended changes to Schedule 200 rate design for Schedule 30?

A. Yes. The rate impact analysis is presented in Exhibit FM/103. Page 1 of the exhibit compares Schedule 30 Secondary bill impacts at various load factors under Fred Meyer's proposal. For ease of comparison, Page 2 of the exhibit presents the bill impacts resulting from PacifiCorp's rate design proposal. Exhibit FM/103 demonstrates that the rate impacts from my rate design proposal are reasonable. Like the Company's proposal, my proposed rate design results in a smaller rate impact on higher-load-factor customers than lower-load-factor customers. However, my recommended rate design better aligns Schedule 200 costs and charges.

Q. Your proposed Schedule 200 rate design was calculated using PacifiCorp's proposed revenue requirement. How should your proposed rate design be implemented if the Commission adopts a revenue requirement that is less than PacifiCorp's request?

A. To the extent that the Commission approves a revenue requirement for Schedule 200 that is less than PacifiCorp is seeking, the reduction should be applied pro rata to the demand and energy revenues that I am recommending at PacifiCorp's requested revenue requirement.

<u>**Power Cost Adjustment Mechanism**</u>

Q. Please describe PacifiCorp's proposed Power Cost Adjustment Mechanism ("PCAM").

A. As explained in the direct testimony of PacifiCorp witness Gregory N. Duvall, the Company has proposed an adjustment mechanism that "would provide dollar-for-dollar recovery of prudent NPC and would not use sharing bands, deadbands, or an earnings review."[2] The PCAM would be filed annually, and would recover the difference between Base Net Power Costs set in the TAM filing and Actual Net Power Costs.

Q. If the Commission were to approve a PCAM for PacifiCorp, are you supportive of PacifiCorp's proposed design?

A. No. PacifiCorp's proposal does not provide for any risk-sharing between the Company and customers. Instead, the proposed PCAM would simply pass through 100 percent of NPC variances between annual TAM filings. The balance

[2] PAC/900 Direct Testimony of Gregory N. Duvall, p. 29, lines 6-7.

collected in the proposed PCAM would not exclude variances resulting from normal business risks typically borne by the utility. This type of 100 percent cost pass-through seriously reduces the Company's incentive to manage its fuel and purchased power costs as well as it would manage them if the Company remained fully responsible for the energy cost risk between TAM filings.

Should the Commission approve a PCAM, I recommend adoption of a sharing mechanism to provide a more equitable balance between customer and shareholder interests. One option is to adopt a 70/30 sharing mechanism in which 70 percent of the difference between Base NPC and Actual NPC is allocated to customers and 30 percent is allocated to PacifiCorp. Such power cost sharing provisions are in place in PacifiCorp's Utah and Wyoming jurisdictions. I believe that a 70/30 sharing mechanism would provide the proper balance to ensure sufficient management incentive to control costs, in a more direct and efficient manner than after-the-fact prudence audits. This sharing ratio still shifts the substantial majority of responsibility for recovering NPC deviations on customers, but it meaningfully aligns Company and customer interests through shared benefits and costs.

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE 30/730 SECONDARY PROPOSED RATE DESIGN COMPARISON

Schedule No. 30/730 - Composite
Large General Service - (Secondary)

	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	PacifiCorp Proposed Price	PacifiCorp Proposed Dollars	Fred Meyer Proposed Price	Fred Meyer Proposed Dollars
Transmission & Ancillary Services Charge								
per kW	3,412,157	kW	$1.34	$4,572,290	$1.24	$4,231,075	$1.24	$4,231,075
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	250	bill	$385.00	$96,208	$514.00	$128,444	$514.00	$128,444
Load Size 201-300 kW, per month	2,413	bill	$115.00	$277,493	$154.00	$371,599	$154.00	$371,599
Load Size > 300 kW, per month	6,496	bill	$301.00	$1,955,389	$403.00	$2,618,012	$403.00	$2,618,012
Load Size Charge								
≤ 200 Kw, per kW	1,359	kW	No Charge		No Charge		No Charge	
201-300 kW, per kW	643,173	kW	$1.35	$868,284	$1.80	$1,157,711	$1.80	$1,157,711
>300 kW, per kW	3,320,260	kW	$0.65	$2,158,169	$0.85	$2,822,221	$0.85	$2,822,221
Demand Charge, per kW	3,412,157	kW	$3.43	$11,703,699	$4.60	$15,695,922	$4.60	$15,695,922
Reactive Power Charge, per kvar	667,305	kvar	65.00 ¢	$433,748	65.00 ¢	$433,748	65.00 ¢	$433,748
Energy Charge - Schedule 200								
Demand Charge, per kW	3,412,157	kW	$1.25	$4,265,196	$1.30	$4,435,804	$2.34	$7,984,447
1st 20,000 kWh, per kWh	187,732,515	kWh	2.950 ¢	$5,538,109	2.761 ¢	$5,183,295	2.430 ¢	$4,561,900
All additional kWh, per kWh	1,026,570,446	kWh	2.558 ¢	$26,259,672	2.394 ¢	$24,576,096	2.107 ¢	$21,629,839
Subtotal	1,214,302,961	kWh		$58,128,257		$61,653,927		$61,634,918
Populus to Terminal Adjustment (80), per kW	3,412,157	kW	-$0.130	-$443,580	$0.00	$0	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	187,732,515	kWh	0.030 ¢	$56,320	0.000 ¢	$0	0.000 ¢	$0
All additional kWh, per kWh	1,026,570,446	kWh	0.026 ¢	$266,908	0.000 ¢	$0	0.000 ¢	$0
Subtotal				$58,007,905		$61,653,927		$61,634,918
Schedule 201								
1st 20,000 kWh, per kWh	187,732,515	kWh	3.096 ¢	$5,812,199	3.096 ¢	$5,812,199	3.096 ¢	$5,812,199
All additional kWh, per kWh	1,026,570,446	kWh	2.685 ¢	$27,563,416	2.685 ¢	$27,563,416	2.685 ¢	$27,563,416
Total	1,214,302,961	kWh		$91,383,520		$95,029,542		$95,010,533
			Change		Change	$3,646,022		$3,627,013

Rate Design Target	
Sch 30 Secondary Target Rev	$95,017,046
Sch 200 Generation Demand Costs	$11,422,407
Gen Demand Recovery Target %	70%
Generation Demand Target $	$7,995,685
Generation Demand Collected	$7,984,447

Data Source: Exhibit PAC/1302, Griffith/6.

SCHEDULE 200 CLASSIFIED COST RECOVERY COMPARISON
SCHEDULE 30 SECONDARY

Line No.		Target Schedule 200 Revenues [1]	PacifiCorp Proposed Revenues	PacifiCorp Proposed Classified Cost Recovery %	Fred Meyer Proposed Revenues	Fred Meyer Proposed Classified Cost Recovery %
1	(a)	(b)	(c)	(d)	(e)	(f)
2	Generation Energy - Other (non-NPC) (Sch 200) - Demand	$11,422,407	$4,435,804	38.8%	$7,984,447	69.9%
3	Generation Energy - Other (non-NPC) (Sch 200) - Energy	$22,541,774	$29,759,391	132.0%	$26,191,739	116.2%
4	Total Schedule 200	$33,964,181	$34,195,195	100.7%	$34,176,186	100.6%

Note: 1. Schedule 200 classified target revenues derived by applying the Functional Revenue Requirement Allocation Factors (Exhibit PAC/1205, Paice/1 Revised) to the results of PacifiCorp's marginal cost study (Exhibit PAC/1204, Paice/1).

Fred Meyer Recommended Rate Design

Monthly Billing Comparison

Delivery Service Schedule 30 + Cost-Based Supply Service

Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,364	$2,614	10.57%
	30,000	$2,962	$3,160	6.68%
	50,000	$4,157	$4,251	2.26%
200	40,000	$4,166	$4,548	9.17%
	60,000	$5,361	$5,639	5.19%
	100,000	$7,751	$7,821	0.91%
300	60,000	$6,107	$6,667	9.18%
	90,000	$7,899	$8,303	5.12%
	150,000	$11,484	$11,577	0.81%
400	80,000	$7,950	$8,651	8.81%
	120,000	$10,340	$10,833	4.77%
	200,000	$15,120	$15,197	0.51%
500	100,000	$9,819	$10,672	8.69%
	150,000	$12,806	$13,400	4.64%
	250,000	$18,781	$18,855	0.40%
600	120,000	$11,687	$12,693	8.61%
	180,000	$15,272	$15,966	4.55%
	300,000	$22,441	$22,513	0.32%
800	160,000	$15,424	$16,736	8.50%
	240,000	$20,204	$21,100	4.43%
	400,000	$29,763	$29,828	0.22%
1000	200,000	$19,161	$20,778	8.44%
	300,000	$25,136	$26,233	4.37%
	500,000	$37,085	$37,144	0.16%

* Net rate including Schedules 91, 199, 290 and 297.

** Data Source: Griffith OR CY2013 Rate Design Model (Exhibit PAC /1303, p. 9)

PacifiCorp Proposed Rates

Monthly Billing Comparison

Delivery Service Schedule 30 + Cost-Based Supply Service

Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,364	$2,575	8.92%
	30,000	$2,962	$3,150	6.37%
	50,000	$4,157	$4,301	3.46%
200	40,000	$4,166	$4,461	7.08%
	60,000	$5,361	$5,611	4.67%
	100,000	$7,751	$7,911	2.08%
300	60,000	$6,107	$6,532	6.97%
	90,000	$7,899	$8,257	4.54%
	150,000	$11,484	$11,708	1.95%
400	80,000	$7,950	$8,468	6.51%
	120,000	$10,340	$10,768	4.14%
	200,000	$15,120	$15,369	1.65%
500	100,000	$9,819	$10,441	6.34%
	150,000	$12,806	$13,317	3.99%
	250,000	$18,781	$19,068	1.53%
600	120,000	$11,687	$12,414	6.22%
	180,000	$15,272	$15,865	3.88%
	300,000	$22,441	$22,766	1.45%
800	160,000	$15,424	$16,361	6.07%
	240,000	$20,204	$20,961	3.75%
	400,000	$29,763	$30,163	1.34%
1000	200,000	$19,161	$20,307	5.98%
	300,000	$25,136	$26,058	3.67%
	500,000	$37,085	$37,560	1.28%

* Net rate including Schedules 91, 199, 290 and 297.

** Data Source: Griffith OR CY2013 Rate Design Model (Exhibit PAC /1303, p. 9)