Via Overnight Mail

May 6, 2005

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, Oregon 97310
Attn: Kim Resch

Re: Case No. UE-170

Dear Ms. Resch:

Please find enclosed the original and five copies of the Direct Testimony and Exhibits of Kevin C. Higgins filed on behalf of the Fred Meyers Stores and Quality Food Centers, Divisions Of Kroger Co. in the above referenced matter.

Copies have been served on all parties of record. Please place this document of file.

Very truly yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Enclosure
cc: Hon. Michael Grant
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served via regular mail, (unless otherwise noted), this 6th day of May, 2005.

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Michael L. Kurtz, Esq.

FM Exhibit 100
Witness: Kevin C. Higgins

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

In the Matter of Pacific Power & Light (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**)))))**	**Docket No. UE-170**

Direct Testimony of Kevin C. Higgins

on behalf of

Fred Meyer Stores

May 9, 2005

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 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 Principal in the firm of 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 phase of the proceeding?

A. My testimony is being sponsored by Fred Meyer Stores ("Fred Meyer"). Fred Meyer purchases more than 60 million kWh annually in the PacifiCorp distribution territory in Oregon. Fred Meyer takes service from PacifiCorp under rate schedules 28, 48, and 730.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. In 2001, I testified in the Portland General Electric restructuring proceeding (UE-115), and in 2003, I co-sponsored joint testimony regarding the stipulation that resolved the PacifiCorp rate case in that year, UE-147.

Q. Have you participated in any workshop processes sponsored by this Commission?

A. Yes. In 2003, I was an active participant in the collaborative process initiated by the Commission to examine direct access issues in Oregon, UM-1081.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in over fifty proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Colorado, Georgia, Idaho, Indiana, Michigan, Nevada, New York, Ohio, South Carolina, Utah, Washington, and Wyoming.

A more detailed description of my qualifications is contained in FM Exhibit 101, attached to my direct testimony.

<u>Overview and conclusions</u>

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

A. I have been asked to evaluate those cost-of-service and rate spread issues that are outside the parameters of the Partial Settlement, and to make any recommendations that might be necessary to ensure results that are just and reasonable.

Q. What conclusions and recommendations do you offer based on your analysis?

A. I offer the following conclusions and recommendations:

(1) While I do not agree with the PacifiCorp's cost-of-service methodology in all respects, the Company's use of marginal cost to determine the allocation of class cost responsibility is a generally reasonable approach. For purposes of this proceeding, Fred Meyer is choosing not to challenge the results of the Company's cost-of-service analysis.

(2) In determining rate spread, it is important to align rates with cost causation, to the greatest extent practicable. If subsidies are used to mitigate the impact of rate increases on selected customer classes, I recommend that the following approach be adopted:

(a) If the jurisdictional net rate increase is 6 percent or less (which is the case in this proceeding), the mitigation cap on net increases for individual rate schedules should be set by a fixed percentage differential of 3 percent, rather than "150 percent of average."

(b) In addition, the per-kWh subsidy paid to any rate schedule should be subject to a ceiling of 1.5 cents/kWh, in order to limit extensive subsidization from other classes and to encourage movement toward cost-of-service rates.

Cost-of-Service

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in the determination of appropriate rates for each customer class (or rate schedule). It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation, transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for causing the utility's costs to the various customer classes.

Q. Have you reviewed PacifiCorp's cost-of-service analysis filed in this proceeding?

A. Yes, I have reviewed the analysis presented by Company witness David L. Taylor.

Q. What basic approach to cost-of-service analysis does PacifiCorp utilize?

A. PacifiCorp determines its target revenue requirements and allocates system costs to Oregon using the Revised Protocol method. These Oregon-allocated costs are functionalized into categories, such as generation, transmission, distribution, etc.

PacifiCorp calculates each the proportionate share of function costs for each rate schedule by performing a marginal cost study. The marginal cost study produces a series of allocation factors that correspond to each major rate schedule's percentage share of marginal costs for each function. These allocation factors are then applied to the Oregon jurisdictional revenue requirements to determine each rate schedule's cost-of-service by function. For example, as Mr. Taylor points out, Residential customers are responsible for 39 percent of the marginal cost of generation in Oregon, according to the Company's marginal cost study. Therefore, the Residential rate schedule is allocated 39 percent of Oregon's generation-related revenue requirement.

Q. How does the determination of a rate schedule's cost-of-service affect its rates?

A. According to O.A.R. 860-038-0240, utilities must provide a cost-of-service rate option. Under this option, rates for any class of consumer must be based on the unbundled costs to serve that class. Consequently, once the jurisdictional revenue requirement is determined, the base rates for each rate schedule are set at cost-of-service.

Q. You stated that *base* rates are set at cost-of-service. In practice, have *overall* rates been limited to each rate schedule's respective cost-of-service?

A. No. In practice, this has not been the case. For example, in UE-147, after base rates were set at cost-of-service, explicit subsidy payments between classes were adopted to mitigate the impact of moving fully to cost-of-service for rate schedules whose rates were well below cost. I will address the issue of subsidy payments more fully later in my testimony.

Q. Turning back to PacifiCorp's cost-of-service study, do you have any observations regarding Mr. Taylor's analysis that you wish to make?

A. Yes. The use of marginal cost as the basis for allocating costs across customer classes is consistent with sound economic principles, and Mr. Taylor's overall approach appears to be reasonable. But as is typical for an analytical effort of this scope, PacifiCorp's study contains many assumptions and methodological components, and I do not agree with the Company's method in all respects.

For example, PacifiCorp limits the generation costs classified as "demand" to the fixed costs associated with a hypothetical simple-cycle generation facility. In my opinion, this approach understates demand costs and overstates energy costs. However, for purposes of this proceeding, Fred Meyer is choosing not to challenge the results of Mr. Taylor's analysis.

Q. How should PacifiCorp's cost-of-service results be utilized in this proceeding going forward?

A. As I stated above, PacifiCorp's marginal cost study produces a series of allocation factors. These allocation factors should be used to determine the base rates for each rate schedule, depending on the final revenue requirements approved by the Commission.

Q. Have you updated PacifiCorp's cost-of-service rate spread to incorporate the results of the Partial Stipulation?

A. Yes. The Partial Stipulation reduces PacifiCorp's requested revenue requirement by about $31 million. I have estimated the base rates that result from this reduction, prior to the determination of the remaining revenue issues in this proceeding. In making this calculation, I used the class allocation factors derived in PacifiCorp's marginal cost study. This calculation is shown in FM Exhibit 102.

FM Exhibit 102 shows that, prior to any further revenue requirement adjustments, the Partial Stipulation would result in an 8.7 percent base rate increase and a 3.0 percent net rate increase on a total jurisdictional basis.

Q. Why is there such a significant difference between the base rate increase and the net increase?

A. There are two primary reasons for this differential. First, current overall rates include the substantial costs of Schedule 94, the Deferred Accounting Adjustment, which is a surcharge that recovers excess power costs incurred during the western power crisis. This surcharge expires in the summer of 2005, which will lower net rates by about 5.3 percent – whereas base rates remain unaffected. Had no rate case been filed, net rates would fall about 5.3 percent by virtue of the termination of this surcharge.[1]

Second, PacifiCorp has recommended that customers receive a Miscellaneous Deferred Accounts Credit, as described by Company witness J. Ted Weston. The adoption of this credit reduces the net rate increase by $1.8

[1] Note also that Schedule 97, Sale of Centralia Credit, is scheduled to expire at the end of 2005, which will result in a net rate increase of approximately 3 percent at that time.

million, or 0.2 percent. Note, however, that this credit is only proposed to last one year. Upon its expiration, overall rates will rise by this 0.2 percent.

Together, these two factors explain virtually all of the difference between the base rate increase and the net rate increase.

Rate Spread and Inter-Class Subsidies

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

The Oregon Administrative Code provides important guidance in this regard: O.A.R. 860-038-0240 requires that rates for any class of consumer must be based on the unbundled costs to serve that class.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for classes that would experience significant rate increases from doing so. This principle of ratemaking is known as “gradualism.” When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

In PacifiCorp's Oregon tariff, rate mitigation is carried out through the Rate Mitigation Adjustment ("RMA"), Schedule 299, pursuant to which certain customer classes receive, and others pay for, inter-class subsidies.

Q. How was Schedule 299 implemented in UE-147?

A. In the UE-147 settlement, the parties agreed to pay subsidies to those customer classes whose cost-based rates would have resulted in a net increase that was greater than 150 percent of the jurisdictional average net increase.

Q. Do you believe this same decision rule should be adopted in this proceeding?

A. No. I believe the same principle can apply, but the formula for implementation should be modified in two ways. First, since the jurisdictional net rate increase will be 3 percent or less in this proceeding,[2] the "150 percent of average" cap should be replaced by a fixed percentage differential. This change will better accommodate movement in the direction of cost causation, while still providing significant mitigation. An inflexible "percentage-of-average" cap on a relatively small average net increase does not provide enough opportunity for rates to move *relative to one another* to permit those classes that are paying above-cost rates (via subsidies) to move materially closer to their actual costs-of-service.

Second, I recommend placing a ceiling on the per-kWh subsidy paid to any rate schedule at 1.5 cents/kWh, in order to limit extensive subsidization from other classes and to encourage movement toward cost-of-service.

[2] As shown in FM Exhibit 102, page 1.

Q. You state that a "percentage-of-average" cap on a relatively small average net increase does not provide enough opportunity for rates to move relative to one another. Please explain.

A. To see this point, consider what might happen if PacifiCorp's revenue requirement is reduced by another $26 million in this proceeding.

In PacifiCorp's initial filing, the Company sought a 12.5 percent base rate increase, which translated into a 6.7 percent net increase. Application of the "150 percent cap" would have meant that no class would receive more than a 10 percent net increase – or about 3.3 percentage points above average. For this magnitude of increase, the 150 percent cap is appropriate.

Now assume that PacifiCorp's revenue requirement is reduced another $26 million below the Partial Stipulation amount. In such a case, base rates would increase by $45 million over current rates[3] – about 5.5 percent – but the overall *net* rate increase would be *zero*.[4] Algebraically, capping each class's net increase to 150 percent of system average would mean each individual class would receive an identical net increase of zero, irrespective of any relative movements in their respective costs-of-service. As a practical matter, application of a 150 percent cap in this situation would tend to lock in future subsidy payments for classes that paid subsidies in the immediate past, in order to shield classes paying below-cost rates from incurring any impact greater than the average. This would be an unfortunate and unintended demonstration of the adage that "no good deed goes

[3] That is, $71 million - $26 million = $45 million.
[4] As shown in FM Exhibit 103, the Partial Stipulation reduces PacifiCorp's requested net rate increase to $26 million, prior to the consideration of the contested revenue issues. A further reduction of $26 million would result in a jurisdictional net rate increase of zero.

unpunished." Rate spread would be driven entirely by gradualism, with no weighting toward cost causation.

Q. Please describe your recommended modification to the "150 percent of average" cap.

A. In instances in which the jurisdictional net rate increase is 6 percent or less, the mitigation cap should be set by a fixed percentage differential, rather than a "percentage of average." Specifically, I recommend using a fixed percentage differential of 3 percent. This differential appropriately balances the tradeoff between gradualism and cost-of-service. Under my proposal, the decision rule for applying the rate mitigation cap would state that in the event that the overall jurisdictional net rate increase was 6 percent or less, the RMA would be applied to ensure that no class would experience a net rate increase greater than 3 percentage points greater than the jurisdictional net rate increase, subject to a maximum subsidy of 1.5 cents per kWh. Adoption of this mechanism would provide substantial rate mitigation, while allowing some meaningful movement of rates toward cost.

Q. In the hypothetical case in which the final revenue requirement was exactly equal to PacifiCorp's initial request minus the adjustments in the Partial Stipulation, what would be the result of applying your recommended rate mitigation proposal?

A. This result is shown in FM Exhibit 103, and is summarized in Table KCH-1, below.

Table KCH-1
Net Rate Spread @ $71 Million Base Rate Increase
w/ Fred Meyer Recommended Mitigation Proposal

Rate Schedule	RMA 299	Net Rate Change After Mitigation
Residential 4	0	5.03%
GS 23	Credit	6.05%
GS 28	Charge	-3.33%
GS 30	Charge	-3.33%
Large GS 48	0	3.48%
Part Req 47	0	5.43%
Ag Pumping 41	Max Credit	19.74%
Ag Pump – Other	Max Credit	19.65%
Outdoor Light 15	Charge	-3.33%
Street Lighting 50	Charge	-3.33%
Street Lighting 51	Charge	-3.33%
Street Lighting 52	Charge	-3.33%
Street Lighting 53	Charge	-3.33%
Rec Field Lighting 54	Charge	-3.33%
Retail Total	Net = 0	3.05%

Q. In your example, how did you determine which rate schedules would pay the subsidy?

A. I started funding the subsidy with the rate schedule that would otherwise receive the smallest net increase (or largest net reduction). This rate schedule funds the subsidy until its net rate increase equals that of the rate schedule receiving the second-lowest net rate increase, at which point this second rate schedule joins in the funding. This process continues, adding successive rate schedules as necessary, until the requisite subsidy funding level is reached. When the targeted funding level is reached, each of the subsidy-paying rate schedules will be experiencing the same net rate increase. To the extent a subsidy must be paid, I believe this approach is reasonable.

Q. The Sale of Centralia Credit, Schedule 97, is projected to terminate at the end of 2005. Does your analysis of the net rate increase in FM Exhibit 103 take this into account?

A. No. As any change in base rates is likely to occur while Schedule 97 is still in effect, I opted to calculate the net rate increase in FM Exhibit 103 under the assumption that Schedule 97 would still be in place. However, in the alternative, it would not be unreasonable for the definition of "net rate increase" to treat Schedule 97 as moving to zero, which will likely occur around the end of 2005. Such a change would not affect my mitigation proposal – it would simply be applied to a different net rate increase.

Q. In your calculation in FM Exhibit 103, were any rate schedules subject to the 1.5 cents per kWh subsidy ceiling?

A. Yes. The subsidy payment to Agricultural Pumping (Schedule 41) reaches 1.5 cents per kWh, and is therefore capped at that level.

Q. Can you elaborate on why you believe this per-kWh ceiling on the subsidy receipt is appropriate?

A. Yes. Currently, Schedule 41 receives a subsidy payment of 1.926 cents per-kWh, and under PacifiCorp's filed proposal, this subsidy actually would have increased to 2.472 cents per kWh. Under the Company's proposal, the subsidy would have been paid, primarily, by Schedules 28 and 30 (and their companion Direct Access Schedules 728 and 730) – rate schedules whose generation charges are very similar to those of Schedule 41, as shown in Table KCH-2, below. In other words, Schedules 28 and 30 would have been called upon to pay a subsidy in excess of 2 cents/kWh to a rate schedule that otherwise paid very similar generation rates as themselves. From a ratemaking perspective, this sort of transfer appears to be fundamentally inequitable. Therefore, a per-kWh ceiling on the magnitude of the subsidy credit is appropriate.

Table KCH-2

Comparison of Unbundled Generation Rates
Secondary Voltage
(cents/kWh)

Rate Schedule	Current	PacifiCorp Initial Proposal[5]
28, First 20,000 kWh	3.408	3.893
28, All additional kWh	3.309	3.780
30, First 20,000 kWh	3.353	3.894
30, All additional kWh	3.334	3.870
41, Summer, all kWh	3.269	3.943
41, Winter, 1st 100 kWh/kW	4.935	5.952
41, Winter, all other kWh	3.269	3.943

Q. In the event that the Commission chooses to award Schedule 41 a subsidy in excess of 1.5 cents per kWh, how should the excess amount should be funded?

A. A subsidy of that magnitude would appear to me to be less governed by the principle of gradualism than by a broader social policy of subsidizing certain activities, such as irrigation. If that is the case, the cost for the social policy should

[5] While the level of these rates will change with the Partial Stipulation and any subsequent generation-related revenue adjustments, the relationship among these rates will not vary significantly.

be borne by society as a whole. In a ratemaking context, this would mean levying a comparable charge on each rate schedule to fund the subsidy.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ESTIMATED IMPACT OF UE-170 PARTIAL STIPULATION
ON THE UNBUNDLED REVENUE REQUIREMENT ALLOCATION BY RATE SCHEDULE

(Assumes PacifiCorp's Requested ROE)

12 Months Ended December 31, 2006 Forecast

			(A)	(B)	(D)	(E)	(I)	(J)	(M)	(N)	(O)	(R)	(S)	(U)
			Residential	**General Service Sch 23**		**General Service Sch 28**		**General Service Sch 30**		**Large Power Service Schedule 48T**			**Sch 41**	**Street**
		Total											Irrigation	Lighting
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	**Total Operating Revenues**	$792,332	$389,311	$74,320	$48	$116,436	$1,170	$66,066	$4,401	$38,668	$68,765	$19,309	$10,351	$3,487
2	**MWH**	13,265,983	5,079,177	1,110,753	728	2,087,230	22,353	1,341,152	91,525	901,394	1,872,828	614,130	119,204	25,509
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$551,833	$216,355	$48,419	$31	$87,279	$899	$56,287	$3,731	$37,174	$73,138	$22,688	$5,068	$763
6	Transmission	$54,546	$21,706	$4,952	$3	$8,618	$88	$5,576	$369	$3,626	$6,961	$2,090	$508	$49
7	Distribution	$285,855	$180,358	$40,437	$15	$27,470	$218	$13,395	$840	$6,759	$6,276	$0	$7,020	$3,067
8	Customer - Billing	$12,410	$10,046	$1,411	$1	$498	$3	$49	$3	$110	$72	$1	$197	$19
9	Customer - Metering	$15,344	$11,439	$2,203	$33	$877	$62	$203	$64	$38	$105	$23	$294	$1
10	Customer - Other	$8,679	$7,203	$942	$0	$283	$2	$53	$3	$54	$35	$0	$96	$9
11	Total	$928,667	$447,107	$98,365	$84	$125,025	$1,272	$75,562	$5,011	$47,761	$86,586	$24,803	$13,182	$3,909
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	39.21%	8.77%	0.01%	15.82%	0.16%	10.20%	0.68%	6.74%	13.25%	4.11%	0.92%	0.14%
16	Transmission	100.00%	39.79%	9.08%	0.01%	15.80%	0.16%	10.22%	0.68%	6.65%	12.76%	3.83%	0.93%	0.09%
17	Distribution	100.00%	63.09%	14.15%	0.01%	9.61%	0.08%	4.69%	0.29%	2.36%	2.20%	0.00%	2.46%	1.07%
18	Ancillary Service	100.00%	39.21%	8.77%	0.01%	15.82%	0.16%	10.20%	0.68%	6.74%	13.25%	4.11%	0.92%	0.14%
19	Customer - Billing	100.00%	80.95%	11.37%	0.00%	4.02%	0.02%	0.39%	0.02%	0.89%	0.58%	0.01%	1.59%	0.16%
20	Customer - Metering	100.00%	74.55%	14.36%	0.22%	5.72%	0.40%	1.32%	0.42%	0.25%	0.69%	0.15%	1.91%	0.01%
21	Customer - Other	100.00%	82.99%	10.85%	0.00%	3.26%	0.02%	0.61%	0.04%	0.62%	0.40%	0.00%	1.10%	0.11%
22	Embedded DSM - (mWh)	100.00%	38.29%	8.37%	0.01%	15.73%	0.17%	10.11%	0.69%	6.79%	14.12%	4.63%	0.90%	0.19%
23	Regulatory & Franchise	100.00%	49.13%	9.38%	0.01%	14.70%	0.15%	8.34%	0.56%	4.88%	8.68%	2.44%	1.31%	0.44%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$486,591	$190,775	$42,695	$27	$76,961	$793	$49,632	$3,290	$32,779	$64,491	$20,006	$4,468	$673
28	Transmission	$63,874	$25,419	$5,799	$4	$10,092	$103	$6,529	$433	$4,246	$8,151	$2,448	$594	$58
29	Distribution	$227,661	$143,641	$32,205	$12	$21,877	$174	$10,668	$669	$5,383	$4,999	$0	$5,591	$2,443
30	Ancillary Services	$6,750	$2,646	$592	$0	$1,068	$11	$688	$46	$455	$895	$278	$62	$9
31	Customer - Billing	$22,363	$18,103	$2,543	$1	$898	$5	$88	$5	$199	$129	$1	$356	$35
32	Customer - Metering	$24,059	$17,936	$3,455	$52	$1,376	$97	$318	$101	$60	$165	$36	$461	$2
33	Customer - Other	$10,329	$8,573	$1,121	$0	$336	$2	$63	$4	$64	$41	$0	$114	$11
34	Embedded DSM - (mWh)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
35	Regulatory & Franchise T	$19,434	$9,549	$1,823	$1	$2,856	$29	$1,620	$108	$948	$1,687	$474	$254	$86
36	Total	$861,062	$416,643	$90,232	$98	$115,464	$1,214	$69,607	$4,655	$44,133	$80,557	$23,243	$11,900	$3,316
37														
38	**Ratio of Operating Revenue to Revenue Requirement - (Target)**	92.02%	93.44%	82.37%	49.21%	100.84%	96.40%	94.91%	94.55%	87.62%	85.36%	83.07%	86.99%	105.14%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$68,730	$27,332	$15,912	$50	($972)	$44	$3,541	$254	$5,465	$11,793	$3,934	$1,549	($170)
42	(Line 36 - Line 1)													
43														
44	**Base Rate Percent Increase (Decrease)**	8.67%	7.02%	21.41%	103.23%	-0.83%	3.73%	5.36%	5.77%	14.13%	17.15%	20.37%	14.96%	-4.89%
45	(Line 41 / Line 1)													
46														
47	**Total Amount of Riders**[1]	($17,656)	($8,329)	($7,281)	($5)	$4,624	$50	($463)	($32)	($1,180)	($2,452)	($804)	($1,934)	$152
48														
49	**Total Net Rates (Base plus Riders)**	$843,407	$408,314	$82,951	$94	$120,088	$1,263	$69,144	$4,623	$42,953	$78,105	$22,439	$9,965	$3,468
50	(Line 36 + Line 47)													

Note 1. Total amount of riders includes the tailblock adjustment for Schedules 28 & 30.

Estimated Impact on PacifiCorp's Requested Functionalized Revenue Increase

Ln #		Estimated Revenue Requirement Impact	Functional Allocator	Generation	Transmission	Distribution	Ancillary	Consumer - Billing	Consumer - Metering	Consumer - Other	Franchise Fees	Total[1]
1	PacifiCorp's Original Request	102.2		41.0	18.7	37.3	0.0	1.0	1.5	0.4	2.3	102.0
2												
3	Net Power Costs	(8.0)	Generation	(8.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.0)
4	Line Losses	(9.2)	Generation	(9.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.2)
5	Operating Rev. for OPUC	(0.1)	Revenue	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)
6	Incentive Programs	(5.5)	Labor	(2.4)	(0.2)	(1.7)	0.0	(0.4)	(0.5)	(0.2)	0.0	(5.5)
7	Non-Labor A&G Costs	(6.1)	GP	(2.6)	(1.1)	(2.3)	0.0	(0.1)	(0.1)	(0.0)	0.0	(6.1)
8	Other Revs.	(2.2)	456 Rev	(0.7)	(1.4)	(0.1)	0.0	0.0	(0.0)	0.0	0.0	(2.2)
9	Bridger Coal	(2.4)	Generation	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.4)
10	Misc. Corrections - Ditbal	1.3	DITEXP	0.6	0.4	0.4	0.0	0.0	0.0	0.0	0.0	1.3
11	Misc. Corrections - Hermiston/Gadsby	1.0	Generation	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
12	Misc. Corrections - WSCC/Little Mtn.	0.3	PT	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
13	Total	(31.0)		(23.6)	(2.3)	(3.7)	(0.0)	(0.5)	(0.6)	(0.2)	(0.0)	(31.0)
14												
15	PacifiCorp's Stipulated Rev. Requirement	71.2		17.3	16.4	33.6	(0.0)	0.5	0.9	0.1	2.3	71.0

Note 1: $102.0 million derived from PPL/405, Taylor/2

ESTIMATED IMPACT OF UE-170 PARTIAL STIPULATION
ON PACIFICORP'S ORIGINAL FILED FUNCTIONALIZED REVENUE REQUIREMENT

(Assumes PacifiCorp's Requested ROE)
12 Months Ended December 31, 2006 Forecast

		ROR	ROE	**Total**	**Production**	**Trans-mission**	**Distribution**	**Ancillary**	**Consumer Billing**	**Consumer Metering**	**Consumer Other**	**Retail Service** a	**Public Purposes** b
2	Functionalized Situs Revenues @ Earned	5.89%	5.42%	815,355,929	483,594,779	49,385,718	218,499,601	6,949,653	22,557,692	23,866,504	10,501,981	-	-
3	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-
4	Total Oregon General Business Revenue			815,355,929	483,594,779	49,385,718	218,499,601	6,949,653	22,557,692	23,866,504	10,501,981	-	-
5													
6	Target Increase in Return	8.72%	11.13%	61,567,835	25,276,137	11,512,253	23,029,892	0	588,399	932,790	228,363		
7													
8	Add												
9	Uncollectible Expense			283,258	113,694	51,783	109,912	0	2,647	4,196	1,027	-	-
10	Franchise Tax			2,264,926			2,264,926						
11	Other Revenue Based Taxes			250,978	100,737	45,882	97,386	0	2,345	3,718	910	-	-
12	Inc Taxes - State			4,504,794	1,849,404	842,328	1,685,051	0	43,052	68,250	16,709	-	-
13	Inc Taxes - Federal			33,151,911	13,610,228	6,198,906	12,400,711	0	316,830	502,272	122,965	-	-
14	Total Increase Needed			102,023,704	40,950,200	18,651,152	39,587,877	0	953,274	1,511,226	369,974	-	-
15	**Estimated Stipulation Impact**			**(30,975,999)**	**(23,633,883)**	**(2,282,674)**	**(3,720,003)**	**(1,176)**	**(489,520)**	**(610,257)**	**(238,487)**		
16													
17	Total Oregon General Business Revenue @	8.72%	11.13%	886,403,633	500,911,096	65,754,197	254,367,476	6,948,477	23,021,446	24,767,474	10,633,469	-	-
18	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-
19	Total Unbundled Revenue Requirement			886,403,633	500,911,096	65,754,197	254,367,476	6,948,477	23,021,446	24,767,474	10,633,469	-	-
20													
21	Rate Base			2,178,447,928	894,342,765	407,336,795	814,864,120	1	20,819,271	33,004,822	8,080,155		
					41.054%	18.698%	37.406%	0.000%	0.956%	1.515%	0.371%	0.000%	0.000%

Source:
Total Column : Exhibit PPL/901, Page 1.0
Row 1: DLT Exhibit 2
Row 8: Uncollectible 0.278%
Row 9: Franchise Tax @ 2.220%
Row 10: Other Revenue Based Taxes 0.046%
Row 11: Inc Taxes - State 6.600%
Row 12: Inc Taxes - Federal 35.00%
Row 14: KCH-2, p. 2
Row 20: DLT Exhibit 2

Notes:
a - Retail Services are conducted as unregulated activities.
b -DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

ESTIMATED IMPACT OF UE-170 PARTIAL STIPULATION
ON PACIFICORP'S ORIGINAL FILED FUNCTIONALIZED REVENUE REQUIREMENT

December 31, 2006 Functionalized Revenue - Including Partial Stipulation

($ 000)

		A	B	C	D	E	F	G	H	I	J	
Line No.	Description	Generation	Transmission	Distribution	Ancillary	C Billing	C Metering	C Other	DSM	Franchise Fees	Total	
1	Target Functional Revenue Requirement	500,911	65,754	234,361	6,948	23,021	24,767	10,633	(0)	20,006	$886,404	
2												
3	Percent of Total	56.51%	7.42%	26.44%	0.78%	2.60%	2.79%	1.20%	0.00%	2.26%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$486,591	$63,874	$227,661	$6,750	$22,363	$24,059	$10,329	$0	$19,434	$ 861,062	$68,730
6												
7	Other Revenues											71,048
8	Partial Requirements - Sch. 36 pri (to 23 pri)										$1	$0
9	Partial Requirements - Sch. 36 pri (to 28 pri)										$51	-$8
10	Partial Requirements - Sch. 36 pri (to 30 pri)										$253	-$41
11	Partial Requirements - Sch. 47 pri										$7,990	$752
12	Partial Requirements - Sch. 47 trn										$4,313	$663
13	USBR Billed Revenue										$8,841	$1,132
14	AGA										$1,404	$0
15	Lighting										$2,914	-$153
16	Employee Discount										($425)	($28)
17	Total Oregon Situs Revenue										$886,403	68,730
18												
19	Special Contracts										$0	
20	Removal of USBR Imputed Revenue										($8,841)	
21	Total Oregon Revenue										$877,563	

Rate Spread @ $71M Revenue Increase
with Maximum Net Rate Increase to Any Class Capped at 3% Over Average Retail Net Rate Increase
and RMA 299 Credit Capped at 1.5¢/kWh

		Present				Base Rate Increase = $71 Million					Change			
	Sch	Base Rates	Other Adders	RMA 299 Adder	Net Rates	Base Rates	TailBlock Adj.	Other Adders	FM Proposed RMA 299 Adder	Net Rates	Base Rate Difference	%	Net Rate Difference	%
Residential	4	$389,311	$9,295	($9,854)	$388,752	$416,649		($8,329)	$0	$408,320	$27,338	7.02%	$19,568	5.03%
Gen. Svc. <31 kW	23	$74,368	$2,501	$1,434	$78,303	$90,327		($1,356)	($5,930)	$83,041	$15,959	21.46%	$4,738	6.05%
Gen. Svc.31-200 kW	28	$117,664	$4,620	$3,292	$125,576	$116,722	$325	($2,699)	$7,047	$121,396	($942)	-0.80%	($4,180)	-3.33%
Gen. Svc. 201-999 kW	30	$70,762	$3,131	$2,671	$76,564	$74,510	($325)	($1,839)	$1,670	$74,015	$3,748	5.30%	($2,549)	-3.33%
Large Gen. Svc >= 1000 kW	48	$126,742	$6,893	$4,980	$138,615	$147,879		($4,437)	$0	$143,442	$21,137	16.68%	$4,827	3.48%
Partial Req. Svc >= 1000 kW	47	$10,889	$149	$339	$11,377	$12,314		($319)	$0	$11,995	$1,425	13.09%	$618	5.43%
Agricultural Pumping Svc.	41	$10,351	$267	($2,296)	$8,322	$11,899		($146)	($1,788)	$9,965	$1,548	14.96%	$1,643	19.74%
Agricultural Pumping - Other	41	$7,709	$203	($1,745)	$6,167	$8,850		($112)	($1,359)	$7,379	$1,141	14.80%	$1,212	19.65%
Outdoor Area Lighting Svc.	15	$1,584	$26	$21	$1,631	$1,506		($17)	$88	$1,577	($78)	-4.92%	($54)	-3.33%
Street Lighting Svc.	50	$1,251	$24	$17	$1,292	$1,189		($15)	$75	$1,249	($62)	-4.96%	($43)	-3.33%
Street Lighting Svc. HPS	51	$2,883	$37	$33	$2,953	$2,742		($20)	$133	$2,855	($141)	-4.89%	($98)	-3.33%
Street Lighting Svc.	52	$232	$4	$3	$239	$221		($3)	$13	$231	($11)	-4.74%	($8)	-3.33%
Street Lighting Svc.	53	$538	$18	$11	$567	$512		($11)	$47	$548	($26)	-4.83%	($19)	-3.33%
Recreational Field Lighting	54	$65	$2	$0	$67	$62		($1)	$4	$65	($3)	-4.62%	($2)	-3.33%
Total		$814,349	$27,170	($1,094)	$840,425	$885,382	$0	($19,304)	$0	$866,078	$71,033	8.72%	$25,653	3.05%
Employee Discount		($397)	($9)	$10	($396)	($425)		$9	$0	($416)	($28)	7.05%	($20)	5.05%
Total Sales with Employee Discount		$813,952	$27,161	($1,084)	$840,029	$884,957	$0	($19,295)	$0	$865,662	$71,005	8.72%	$25,633	3.05%
AGA Revenue		$1,404			$1,404	$1,404				$1,404	$0	0.00%	$0	0.00%
Total Sales with Employee Discount & AGA		$815,356	$27,161	($1,084)	$841,433	$886,361	$0	($19,295)	$0	$867,066	$71,005	8.71%	$25,633	3.05%