BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

July 24, 2009

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction.

CUB is sponsoring three pieces of testimony in this docket. First, CUB is co-sponsoring with ICNU the testimony of Ellen Blumenthal (ICNU-CUB / 400). Ms. Blumenthal's testimony discusses PacifiCorp's proposed employee costs. Ms. Blumenthal expresses concern in her testimony with regard to the Company's proposal to increase the percentage of payroll charged to Oregon customers to 29.5%. This is a concern because the Company has provided no explanation for the increase in the Company's Oregon personnel. As a result, Ms. Blumenthal recommends that the Oregon allocation should be 19.7%, which is in line with the percentage of payroll charged to the state in 2007 and 2008. CUB supports this recommendation. Ms. Blumenthal also recommends that Oregon's share of the Company's payroll taxes and pensions and benefits be reduced to a level consistent with the revised payroll allocation. CUB also supports this recommendation.

Second, CUB is co-sponsoring the testimony of Mike Gorman (ICNU-CUB / 300). Mr. Gorman recommends that PacifiCorp's allowed rate of return on equity be set at 10.0% based on his calculations using five different modeling methods. This constitutes a decrease from PacifiCorp's initial request for an 11.0% rate of return. CUB agrees with Mr. Gorman that this rate of return is fair for PacifiCorp and its shareholders and will not place undue financial burden on the Company.

Rate spread and rate design have been treated largely as settled issues over the last decade. Recently, however, industrial customers have begun challenging the rate spread that had been considered to be the accepted practice. Staff has also begun challenging the previously-accepted standards for rate design.

As a prior witness on these issues in the early 1990s when the current methodology was developed, I would like to provide some background and color for these issues by discussing:

The theory that is behind the marginal cost approach used in Oregon, including the strengths and weaknesses of that approach.

I also wish to put forth:

The changes that CUB believes are necessary to improve upon the current marginal cost methodology.

II. Marginal Cost Theory and Oregon's Rate Spread.

After a utility's revenue requirement is established, regulators must determine rates that reflect the cost of providing utility service to customers. This goal is composed of two critical elements: the first is a determination of the costs of providing service to broad types of customers (rate spread to customer classes), and the second is a determination of how costs will be recovered from individuals in a particular class (rate design). In Oregon the methodology employed to calculate these critical elements is based on Marginal Cost Theory.

A. Marginal Cost Theory.

Marginal cost theory has been used in Oregon to guide both rate spread and rate design since the 1970s. Prior to adopting marginal cost theory, Oregon, like most states, used embedded cost theory. Embedded cost theory looks at the actual costs incurred by the utility and attempts to allocate those costs on the basis of cost causality. Marginal cost theory, on the other hand, begins not with the actual costs but with costs on the margin. The NARUC cost allocation manual lays out the basic theory of marginal cost pricing as follows:

> Marginal cost theory is derived from the neo-classical economics of the nineteenth century which states that in a perfectly competitive equilibrium, the amount consumers are willing to pay for the last unit of a good or service, equals the cost of producing the last unit, i.e., its marginal cost. As a result, the amount customers are willing to pay for a good equals the value of the resources required to produce it, and society achieves the optimal level of output for any particular good or service. In a competitive market, this equilibrium is achieved as each firm expands its output until its marginal cost equals the price established by the forces of supply and demand. For the utility monopoly, the regulator attempts to achieve the same allocative efficiency by accepting the level of service demanded by customers (the utility's obligation to serve) as a given, and setting price (or rates) equal to the utility's marginal cost for that level of output. The analyst defines the cost as the change in cost due to the production of one

> unit more or less of the product, and various approaches have been advanced to measure the utility's marginal cost.

The manual then discusses the primary criticism that has been laid against Marginal Cost Theory as follows:

> A deficiency of the marginal approach for ratemaking purposes is that marginal cost-based prices will yield the utility's revenue requirement based on embedded costs only by rare coincidence. Since regulatory agencies are bound not to let the utility over-earn or under-earn, revenues from rates must be reconciled to the allowed revenue requirement. As the rates are reconciled to the revenue requirements and prices diverge from marginal cost, the sought after marginal cost price signals may not be obtained. When prices do not exactly equal marginal cost there is no formal proof that the economic efficiency predicted by theory is achieved. Advocates of marginal cost pricing believe that approximations to marginal cost pricing must contribute to efficient resource allocation, although to an unspecifiable degree. Supporters of embedded cost pricing believe that the greater precision, verifiability and general simplicity of embedded cost methods outweigh any of the hoped for efficiency benefits of imperfect approximations to marginal cost pricing.[1]

B. Sunk Costs Are Not Marginal.

Application of Marginal Cost Theory typically involves the theoretical construction of a new optimal utility system. Once the new theoretical system is designed, its costs must be allocated. Costs are typically allocated to three categories: *customer-related costs*, *demand-related costs*, and *energy-related costs*. PacifiCorp refers to its customer-related costs as *commitment costs*. These are costs that are marginal to the customer, *i.e.* the costs vary with the addition of a new customer and should, in theory, also vary with the deletion of an old customer. Demand-related costs are costs that are marginal to demand; these costs vary with the demand a customer places on the system. In some cases demand-related costs pertain to an individual customer (non-coincidental), and in

[1] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992, page 14.

other cases demand-related costs pertain to a group of customers (coincidental). The energy-related costs are marginal to energy usage and vary with each unit of energy sold.

One problem with this approach is that customers receive no credit for equipment that has already been purchased. Much of the current utility system consists of sunk costs. For example, PacifiCorp's marginal commitment costs include the cost of a **new** meter and service drop, even though for most customers the utility did not purchase a new meter or service drop at today's cost. PacifiCorp purchased many of the meters years ago at lower costs. When an existing customer increases usage, the utility does incur incremental (marginal) production costs. For the existing customer, however, there is no marginal component to these sunk commitment costs.

C. There Are Many Variables Within the Application of Marginal Cost Theory.

Designing the new optimal utility system and allocating its costs to *customer, demand* and *energy* categories requires one to make a great many assumptions about the system. For several reasons, the approach taken to these assumptions can vary widely from utility to utility.

First, this theoretical new utility system is supposed to represent the optimal system that would be built in a competitive market, but there is no competitive market for a utility distribution system. This means that there are no models, other than the current utility system model, for use in making comparisons.

Second, these theoretical costs do not necessarily fit neatly into customer-related, demand-related, and energy-related categories used for allocation. The costs can vary with the number of customers, the demand those customers put on the system, or the number of units of electricity that are bought by the individual customers, but may also vary with other factors. Take, for example, the allocation of costs for theoretical utility poles. Quite simply, there is no obvious way to take the cost of a theoretical utility pole and say how much of that cost varies with the number of customers, how much of that costs varies with the volume of demand, and how much of that cost varies with the volume of energy. Indeed, it could logically be argued that the number of utility poles is primarily related to the geographical size of a utility's service territory and unrelated to the number of customers, the demand they place on the system, or the amount of energy they buy. In an embedded cost study, it would be feasible to take the revenue requirement associated with poles and allocate that to classes of customers based on the distance between those customers and their local substations. In a marginal cost study, however, poles must somehow be allocated as customer-related, demand-related and energy-related.

Third, in other commercial businesses marginal costs are a two-way street, meaning that a cost that is caused by the addition of new customers should go away with the loss of existing customers or that a cost that is caused by an increase in demand will in turn be eliminated by a decrease in demand. This is not the case for the utility industry. For example, take a chain of grocery stores. That chain will expand into a neighborhood based on the expected demand for food in that neighborhood. When demand for food increases, the chain expands, but when demand for food decreases, the chain will close some stores and contract. In the utility world, however, once a utility builds a distribution network, those costs become sunk investments that do not contract. This is because a utility can not abandon a neighborhood when demand for power decreases. As a result, the utility business is really about building one large, semi-permanent infrastructure in which few costs can decline when the number of customers declines.

Given these considerations, marginal cost theory is a poor fit for the utility industry which consists of regulated monopoly utilities with defined rate bases designed to promote investments in long-term and capital intensive infrastructure, through which costs are recovered over the life of those long-term investments. The monopolistic structure of the industry thus allows investors to make long-term investments in a utility's physical plant while earning a reasonable rate of return. It is clear from the foregoing that this is a much different industrial model than the competitive marketplace from which marginal cost theory was derived.

Because, as we have seen above, the goal is to fit a square peg (the embedded revenue requirement of a regulated monopoly utility) into a round hole (the marginal cost equilibrium price of a competitive market), many of the Marginal Cost Theory assumptions do not have a single "right" answer. And, therefore, the process of creating a new utility system, identifying its costs, picking a theoretical approach for allocating costs, and then actually separating those costs, involves hundreds of assumptions.

In the end, because Marginal Cost Theory is built on this pile of assumptions, a skilled advocate can turn the proper knobs and adjust the assumptions of the marginal cost analysis in a manner that allows the advocate to produce any result that he or she desires. For this reason, it is necessary to consider whether Oregon's approach to using marginal cost pricing and PacifiCorp's approach to marginal cost pricing are both reasonable and compatible approaches.

D. Is Oregon's Approach Reasonable?

Given that an analyst can produce nearly any set of desired results in a marginal cost analysis, it is important to begin a review of Oregon's marginal cost approach by seeking to determine whether the results that are being achieved by Oregon's use of Marginal Cost Theory for rate spread are reasonable. CUB Exhibit 102 shows the average retail price for residential, commercial and industrial customers in each state across the country in 2007, as provided by the Federal Energy Information Agency (EIA). From this chart we can see that Oregon's rate spread is very close to the national average. Residential customers in Oregon pay rates that are on average 117% of the average rate paid by all customers. Nationally, residential rates are 117% of the average rate paid by all customers. Industrial rates in Oregon are slightly higher and commercial rates are slightly lower than the national average when compared to average rates in the state.

Table 1: Oregon Rate Spread

	Residential Rate as % of Average Rate	Commercial Rate as % of Ave. Rate	Industrial Rate as % of Ave. Rate
National	117%	106%	70%
Oregon	117%	103%	72%
Washington	114%	103%	72%
California	113%	100%	78%

This table shows that Oregon's rate spread seems pretty reasonable. The allocation of costs to residential customers is in line with the national average and slightly higher than our neighbors to the north (who use an embedded cost theory) and our neighbors to the south. In Oregon, commercial customers are allocated slightly less costs than the average state and industrial customers are allocated slightly more than the average state. It is hard to see how Oregon's rate spread could be much closer to the national average for all three classes of customers. This suggests that the general approaches taken by Oregon have been reasonable.

E. Is PacifiCorp's Approach Reasonable?

While Oregon's approach to allocating costs among classes of customers is about average for the country, PacifiCorp's Oregon rate spread places a greater share of costs onto residential customers than the statewide average. Using information from the Oregon PUC's Annual Utility Statics publication[2], we can compare PacifiCorp's 2007 rate spread in Oregon to CUB Exhibit 102. Here, we find that PacifiCorp's approach in Oregon favors commercial customers at the expense of residential customers.

Table 2: PacifiCorp Rate Spread

	Residential Rate as % of Average Rate	Commercial Rate as % of Ave. Rate	Industrial Rate as % of Ave. Rate
National	117%	106%	70%
Oregon	117%	103%	72%
PacifiCorp OR	122%	95%	70%

This table shows that PacifiCorp allocates a greater share of its costs onto residential customers than either the average Oregon utility or the average national utility. Industrial

[2] CUB Exhibit 103.

customers receive an average share of costs, while commercial customers are responsible for considerably less than the average cost share.

F. Are Industrial Rates Increasing Faster?

In recent years representatives of industrial customers have pointed out that they keep receiving larger rate increases in percentage terms than residential customers. This trend seems to suggest that industrial customers' rates are going up faster than residential customers' rates. In reality, however, residential rates have increased more overall than industrial rates. Because residential rates are significantly higher than industrial rates, residential customers can receive a smaller increase in percentage terms, even when they are receiving a greater increase in terms of cents/kilowatt hour. For example, let us assume that a rate case ended with a 1.2 cents/kWh increase on residential customers and a 1.0 cents/kWh increase on industrial customers. Residential rates are increasing by 20% more than industrial rates. However, because residential rates are higher to begin with, the increase in rates to residential customers is 15%, while the smaller monetary increase in industrial rates yields an increase of 21%.

Figure 1: Difference between Residential and Industrial Rates

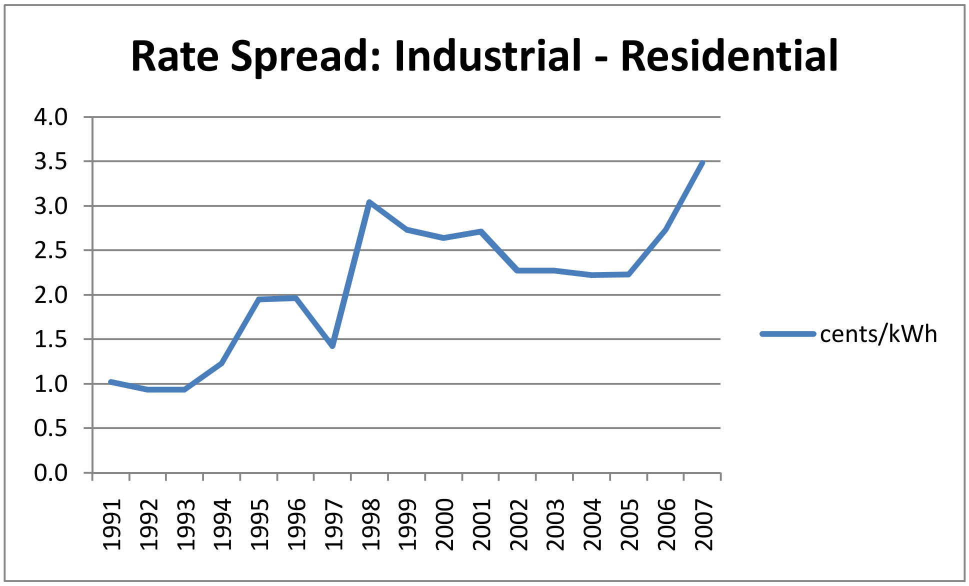

Figure 1 shows the difference between residential and industrial rates in cents/kWh since 1991.[3] The rate differential has steadily increased over the period, reaching 3.5 cents/kWh in 2007. The rates that are proposed in this docket will increase that difference to 4.0 cents/kWh. Clearly residential rates are increasing more in monetary terms than industrial rates.

III. PacifiCorp's Proposed Marginal Cost Study.

Consistent with the above section, CUB believes that PacifiCorp's Marginal Cost study places too much of the cost share onto residential customers. It is CUB's position that the Company's approach to distribution marginal costs – particularly its Feeder Model and the way it assigns a large portion of feeder costs as commitment-related costs – allocates altogether too many costs as commitment-related. Correcting this inequity will go a long way towards improving the allocation of costs between residential and small commercial customers.

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[3] CUB Exhibit 103.

In addition to the issue of allocation of costs between residential and industrial customers, CUB also believes that PacifiCorp's approach to marginal energy costs needs to be updated to recognize recent and expected statutory changes that are changing the Company's generation profile. First, Oregon's Renewable Portfolio Standard requires 25% of energy to be renewable by 2025. It makes little sense to model the marginal energy source as a natural gas combustion turbine when the Company is legally prohibited from meeting new marginal loads solely with natural gas combustion turbines. Second, as long-run energy costs are considered, all parties need to recognize that the US Congress is currently considering climate legislation that is expected to raise the cost of energy.

A. Distribution Marginal Costs

The biggest criticism of distribution marginal cost studies is the degree to which they assign costs as customer related. According to NARUC:

> The major issue in establishing the marginal cost of the distribution system is the determination of what portion of the cost, if any, should be classified as customer related rather than demand and energy related…
>
> Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customers classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones…
>
> The major debate over the classification of the distribution system, however, concerns the jointly used equipment rather than the dedicated equipment. At the margin, there is symmetry between the cost of adding one customer and the cost avoided when losing one customer. A number of analysts have argued, and commissions have accepted that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the

> cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.[4]

PacifiCorp does allocate the on-premises costs as customer-related, except in the case of large industrial customers who have dedicated conductors directly from a substation. [5] For the joint use equipment, PacifiCorp's approach varies. For some parts of the system such as line transformers, the Company uses what is called the "zero intercept" model of allocating marginal costs. Under this approach the Company uses a regression analysis of the cost of various sizes of transformers to determine what the cost of a transformer is with "zero" capacity. This is the cost that is assigned as customer- or commitment-related, with costs above this level being assigned to demand. On other parts of the system, such as poles and conductors, the Company uses a "minimum system" approach that takes the smallest size used in the feeder model and assumes that number to be the cost that is customer related. In general, the Company assigns too many costs as customer-related.

i. Customer Premises Equipment

Equipment that is dedicated to individual customers can be assigned as customer-related. For residential customers, this means the line drop, the meter, and the bill and billing costs. These costs are incurred when a new customer signs up for service. The bill and billing costs are truly marginal, meaning that adding a new customer will increase these costs, and a customer leaving the system will decrease these costs. For the meter and line drop the costs are incurred when a new customer signs up for service, but from

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[4] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, 1992, page 136.
[5] UE 210/PPL/Tab 1.2, page 12.

that point forward they are sunk costs. If the customer leaves the system, these costs do not decline. In this sense they are not truly marginal.

For this reason CUB recommends that customer-related costs be limited to new customers. In the marginal cost study, the customer cost in each rate class should be multiplied by the projected number of new customers, not the projected number of actual customers.

ii. Feeder study

PacifiCorp uses what it calls a Feeder Model to allocate the costs of its wires and poles between customer-related costs (commitment) and demand-related costs:

> The PacifiCorp Distribution Feeder Model is an Excel workbook that calculates the cost of building a hypothetical feeder (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical feeder is used rather than a sampling of actual existing feeders…The feeder model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the feeder. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite feeder using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the feeder between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.[6]

Earlier in this testimony we suggested that geographic size has more to do with a utility's number of poles than the number of customers or the total demand on the system. PacifiCorp's Feeder Model attempts to include elements related to geographic distance from the substation and density, but is still designed around allocating costs as marginal

[6] UE 210/PPL 907/Tab 1.2, page 5.

to the number of customers and marginal to the demand each customer puts on the system.

The beginning point of the Feeder Model is the assignment of customers to one of the 7 sections. This is done based on the average distance between customers and the substation. The vast majority of customers are on feeder Branch 7, which shares its costs with customers on all other feeders. 84% of residential customers, 83% of small commercial customers, and 90% of industrial customers are on this feeder line. The one exception is irrigation customers; fewer than 50% of them are on this shared feeder.

With line transformers, the Company uses regression analysis to determine the portion that is customer-related. With conductors, the Company simply assigns the costs on the two shared feeders as demand-related. On the other five feeders, the costs are assigned as primarily customer-related: 100% of the 1-Phase conductor and pole is customer related; 83% of the poles for 3-Phase conductor are customer related; and, 49% of the 3-Phase conductor is customer related.[7] CUB disagrees with this approach.

The exception to this Feeder Model is for large industrial customers with "dedicated feeders for exclusive use." For these customers, the Company divides the cost of their dedicated feeder by their demand to allocate their feeder cost as a demand cost.

CUB is struck by the contrast between a residential customer on hypothetical Feeder Branch 5 and a large industrial customer on a dedicated feeder. The residential customer shares the branch with 31.4 other residential customers, a handful of commercial customers, and almost 2 irrigation customers. The total number of customers on Feeder Branch 5 is 39.53. Residential customers make up 79% of the customers on Branch 5. In terms of demand, there is a total peak demand of 118.8 kW, with residential

[7] UE 210/PPL 907/Tab 1.2, page 10.

customers representing 62% of this peak demand. The size of the conductor has to meet the demand of all 118.8 kW. The total cost of the conductor and poles for both 1-Phase and 3-Phase conductor in Feeder Branch 5 is $237,422.[8]

The Company allocates 75% of the cost of this feeder branch to residential customers, who represent 62% of the peak demand on the branch. General Service customers with secondary voltage make up 27% of the demand, but only 14% of the customers. They are allocated 17% of the cost of this feeder branch. By assigning the cost of this feeder to customers primarily as a customer-related marginal cost, rather than a demand-related cost, residential customers pick up a greater share and commercial customers pick up a smaller share. As such, feeders that are shared by dozens of customers are allocated primarily as a customer-related cost, but feeders that are dedicated equipment to a single industrial customer are classified as demand-related.

Poles and conductors serve a single purpose: they are designed to transmit electricity from the substation to the customer. They carry energy. They have to be sized to meet the peak demand that is expected on them. Within PacifiCorp's Feeder Study, residential customers use 43% of the electricity that is transported on these poles and wires. Residential customers represent 55.1% of the peak load that these wires and poles are designed to carry. Yet, residential customers are allocated 73.3% of the cost of the poles and 64.4% of the cost of the wires.

PacifiCorp's Feeder Model is an improvement on the marginal cost methods that were formerly used in Oregon because it accounts for distance from the substation and density of customers. However, the PacifiCorp model over-assigns costs to residential customers and undercharges commercial customers by dividing up the costs of feeders

[8] UE 210/PPL 907/Tab 1.2, page 10.

primarily on a customer-related basis. CUB recommends that the costs of feeders be assigned to all classes of customers based on their share of overall demand.

B. Generation Marginal Cost: Energy

PacifiCorp describes its approach to marginal generation costs:

> The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided cost filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy and are added to the variable production cost of the CCCT to determine total avoided energy cost.[9]

CUB supports the use of the fixed cost of a simple cycle combustion turbine to define the fixed costs that are assigned to demand or capacity. However, CUB does not believe that the costs of a combined cycle unit that are greater than the fixed costs of a single-cycle should be used to define the marginal cost of energy.

i. SB 838 changed the marginal resource.

Two years ago, the Oregon legislature passed SB 838, the Renewable Energy Standard. SB 838 requires Oregon utilities to acquire 25% of their power from new renewable sources by 2025. PacifiCorp must comply with this law. In order to comply, PacifiCorp is investing heavily in new wind resources. On the margin, resource investments for energy are flowing towards wind.

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[9] UE 210/PPL/907/Tab 1.2, page 1-2.

A reasonable approach to SB 838 may be for utilities to invest in wind for energy and invest in SSCT for capacity. In the long-run, utilities (after 2025) will need to ensure that 25% of energy comes from qualifying renewable resources on the margin. In the medium term (between now and 2025), utilities will have to ensure that a much greater level of marginal energy comes from renewables in order to move towards compliance in 2025.

PacifiCorp has filed its 2008 IRP with the Oregon PUC. It contains the following major long-term resource development between now and 2018:

Wind: 1313 MW

Geothermal: 35 MW

Energy Efficiency: 904 MW

Load Control: 205 to 325 MW

Gas-fired capacity: 831MW

Coal upgrades: 170 MW

If we assume a 35% capacity factor for wind, and 95% for gas-fired resources, then the expected ratio of marginal energy developed with wind versus gas is 37% wind to 63% gas. PacifiCorp's current IRP filing forecasts the present value cost of wind on the west side of its service territory as 10.39 cents/kWh.[10] PacifiCorp's marginal cost study places the marginal energy cost related to a gas-fired plant as 5.57 cents kWh. Recognizing that 37% of marginal energy will come from wind and 63% will come from gas yields a marginal energy cost of 7.35 cents/kWh.

[10] PacifiCorp 2008 IRP, page107

Because the focus of PacifiCorp's marginal cost study with regards to energy is the long-term marginal cost, the Company must recognize its legal requirement to develop significant new renewable generation resources.

ii. Climate and Carbon

It also should be recognized that long-run marginal costs of electric generation include costs associated with carbon regulation. As the electric industry confronts climate change, it has begun to recognize the costs of carbon in its planning and resource choices. This is appropriate and prudent, since the cost of carbon regulation will likely fall on customers.

In its 2008 IRP, PacifiCorp states that an $8/ton carbon regulatory cost would increase the operating cost of a gas-fired CCCT by $3/MWh. If the carbon regulatory cost is $45/ton, it will add $19/MWh to the cost of a gas-fired CCCT.[11] Because the marginal cost study is a forward-looking analysis that focuses on long-run costs, it must include carbon regulatory costs. PacifiCorp's workpapers do not identify such a cost being included in the forecast of marginal energy costs. If carbon costs were not included in this analysis, they should certainly be added.

C. Generation Marginal Costs: Capacity.

PacifiCorp splits it generation cost into capacity and energy. The Company uses the cost of a Single Cycle Combustion Turbine to define the cost associated with a marginal increase in capacity. The Company allocates this capacity cost to customers based on the Coincidental Peak load for each month (12 CP). CUB believes that this method is appropriate.

[11] PacifiCorp 2008 IRP, page 33.

Other parties may argue that the capacity costs should be assigned to only the highest peak of the year (1 CP). PacifiCorp's Oregon territory is winter-peaking, so assigning the full capacity cost to the winter peak places the burden of capacity costs onto the heating load of residential customers. This argument does not fit with the principle of cost causality. If PacifiCorp was investing in peaker capacity for a single day's load, the Company might decide that it makes more sense to purchase that power on the spot market. But peaker capacity is needed throughout the year, so it makes sense for the Company to look at peak loads throughout the year when assigning marginal capacity costs.

In PacifiCorp's TAM filing that is currently before the Commission, the Company's Gadsby plant is the most marginal of the Company generating units. This plant has high operating costs and is only deployed when demand is great enough to justify its costs.[12] In 2010, it is forecast to run 6 months of the year: June, July, August, September, October and November.[13] But this forecast reflects normalized operations, and capacity resources are most valuable when the utility is operating outside of normal conditions. It is, therefore, useful to look at actual operations.

CUB Exhibit 105 shows the operation of Gadsby in 2008 and for the first 4 months of 2009. In 2008, Gadsby ran 7 months of the year, from June through December. In 2009 the plant has run in January, February and March, marking 10 straight months of operation. Based on this actual operation history, CUB believes that assigning the capacity costs to monthly coincidental peaks is an appropriate methodology.

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[12] UE 207/PPL/103/Duvall/5 and 10.
[13] UE 207/PPL/103/Duvall/5

IV. Marginal Cost and Rate Design.

Like rate spread, rate design has largely been a settled issue for the last 10 years, but that seems to be changing. In last year's PGE ratecase, the PUC staff advocated charging customers higher rates in the summer:

> …this testimony is dedicated to Staff's recommendation to set prices that better reflect PGE's time-based variations in costs. This would be achieved by 1) introducing seasonally varied rates to all the major customer schedules; 2) adding a third block to the residential rate in the summer, and 3) carving out a super-peak period from the on-peak period as applied in the summer to large industrial customers (Schedule 89).[14]

A. CUB Generally Supports the Current Rate Design.

Under Oregon law, it is required that rates be based on the utility's cost of providing service, not the marginal cost of electricity. In addition, customers are given an option of time-of-use rates, if they desire such rates. For residential customers, Oregon has historically used an inverted rate structure, where the price for the first block of energy purchased each month is less than the price for the second block of energy. This design allows utilities to charge customer rates that reflect the cost of service, but also send customer price signals that encourage conservation through the second, higher-cost rate block. The marginal cost to most customers is in the second rate block, so that is the rate that should be used to evaluate energy efficiency investments.

The current rate design has been in place for many years, and is well-understood by customers. CUB has serious concerns about seasonal pricing for residential customers:

[14] UE 197/Staff/500/Compton/7.

i. Customers support simplicity in pricing.

Time-of-Use pricing is currently not very popular with customers. This should not be surprising, as people have busy lives and don't necessarily desire to have to worry about what time they turn on the dishwasher. This condition can also be observed in other industries. It wasn't long ago that wireless phone plans were divided into daytime minutes, evening minutes, and weekend minutes. Some companies began to offer "anytime" minutes, and customers began to gravitate towards plans that did not differentiate between time periods. Now nearly all wireless plans maintain an "anytime" pricing structure.

ii. Customers pay for electricity after they use it.

Electricity is not like gasoline. With gasoline, the price is posted at the station before the customer purchases it. With electricity, the customer is billed after the fact. Many customers may not know that seasonal rates are in effect until after they are billed, when it is too late to change their consumption patterns. In addition, this timing creates a problem for temporary rates. If seasonal pricing goes from July 1 to September 30, customers will not see the full effect of it until their August bills. If a customer's billing cycle is the 7th of the month, then they will not see a bill that reflects much of the higher-cost season until the middle of August, which is half way through the high cost billing period.

iii. Minimizing rate changes is an explicit goal of regulation in Oregon, as established by the Oregon Legislature.

Under Oregon law, the Commission may allow deferred accounting "in order to minimize the frequency of rate changes."[15] While utility costs change regularly throughout the year, Oregon has tried to limit rate increases. On the natural gas side, most rate changes go into effect with the purchased gas adjustment in the fall. On the electric side, annual power cost dockets and the renewable adjustment clauses are both set so that rates go into effect in January. There are good reasons to try to minimize the number of changes in rates. Customers notice when rates change. Customer groups like CUB hear from our members when rates change, and we suspect that the utility and the Commission also hears from customers after a rate change. A single high-cost season will require two additional rate changes each year.

iv. Summer seasonal rates do not fit well with the hydro system.

Oregon's hydro system becomes flush with water during the spring as snowfall melts. This pushes wholesale electric prices down. Prices remain depressed until the hydro system has released much of this run-off. When this happens depends on annual hydro conditions – some years, there is good hydro production well into July that keeps wholesale electric prices low. This annual variability makes it very difficult to define when the high cost summer peak season should begin.

v. For PacifiCorp, seasonal pricing will have dramatically different effects depending on where a customer lives.

Because seasonal pricing raises rates at some times of the year, it must lower rates at other times of the year to be revenue neutral. PacifiCorp, more so than any other Oregon

[15] 757.259(2)(e)

utility, serves a diverse service territory. The Company serves much of the Oregon Coast, which has mild winters and mild summers. Seasonal rates would benefit these customers; they would enjoy lower rates in the off-season, but would be relatively unaffected by the higher rates in the peak-season. PacifiCorp serves parts of Portland, where winters and summers are not quite so mild, but are still moderate. The impact in this area would largely depend on whether the customer has air conditioning and space heating. In Southern Oregon, the Company's territory has mild winters and hotter summers. Seasonal rates that target the summer would harm customers there, but seasonal rates that target winter would not. In Eastern Oregon, the Company's territory has cold winters and hot summers. Seasonal rates would have a significant cost impact in these communities.

vi. Finally, we urge the Commission to consider the current economic climate.

Changes in rate design shift costs between individual users. While the Company is asking for a 6.3% rate increase for residential customers, changes in rate design would likely mean that some customers would get increases well in excess of that amount. Crook County in Central Oregon is served by PacifiCorp. Its unemployment rate is 22.6%.[16] It also has some of the hottest summer weather in Oregon. CUB urges the Commission to keep these customers in mind if it considers significant changes in rate design.

[16] CUB Exhibit 106.

V. Conclusion.

CUB Exhibit 106 shows the unemployment rates by county in Oregon. PacifiCorp serves many of the hardest hit areas of the state, including the following counties:

PacifiCorp County	Unemployment Rate
Crook	22.6
Douglas	17.2
Deschutes	15.8
Klamath	15.7
Jefferson	15.5
Linn	15.4
Josephine	15.3

This is a hard time for many PacifiCorp customers. It is a time when the utility should be doing everything it can to keep its costs down. Instead, PacifiCorp is seeking a rate hike, including asking the PUC to raise its ROE by a significant amount. As the Commission looks at PacifiCorp's filing to determine what rate is fair, just and reasonable, it must view this rate filing in the context of the economic conditions in PacifiCorp's Oregon service territory.

CUB asks the Commission to reject the Company's proposal to increase its ROE. Instead, the Commission should grant the ROE and capital structure proposed by Mike Gorman, CUB and ICNU's cost of capital witness.

CUB asks the Commission to accept the recommendations of Ellen Blumenthal, CUB and ICNU's witness who looked at staffing issues. Her adjustments ensure that

Oregon is not being charged for inflated PacifiCorp employee counts by reducing the number of new PacifiCorp employees and by reflecting the historical allocation of PacifiCorp staff to Oregon.

CUB urges the Commission to make changes to the marginal cost methodology to create a better split of distribution costs between residential and commercial customers, and to reflect the requirements of utilities to purchase renewable power.

Finally, CUB urges the Commission to adopt the rate design proposed by the Company.

WITNESS QUALIFICATION STATEMENT

NAME:	Bob Jenks
EMPLOYER:	Citizens' Utility Board of Oregon
TITLE:	Executive Director
ADDRESS:	610 SW Broadway, Suite 308 Portland, OR 97205
EDUCATION:	Bachelor of Science, Economics Willamette University, Salem, OR
EXPERIENCE:	Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, and UM 1355. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates. Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.
MEMBERSHIP:	National Association of State Utility Consumer Advocates Board of Directors, OSPIRG Citizen Lobby Telecommunications Policy Committee, Consumer Federation of America Electricity Policy Committee, Consumer Federation of America

Average Retail Price for Electricity By State, 2007

(Cents per kilowatthour)

Census Division State	Residential	Commercial	Industrial	Transportation	All Sectors	Rates as Percent of All Sectors Rate: Residential	Commercial	Industrial
New England	16.70	14.71	12.74	10.87	15.08	111%	98%	84%
CT	19.11	15.39	12.92	14.18	16.45	116%	94%	79%
MA	16.23	15.20	13.03	9.24	15.16	107%	100%	86%
ME	16.52	12.94	14.11	-	14.59	113%	89%	97%
NH	14.88	13.91	12.27	-	13.98	106%	99%	88%
RI	14.05	12.67	12.04	-	13.12	107%	97%	92%
VT	14.15	12.29	8.92	-	12.04	118%	102%	74%
Middle Atlantic	13.95	13.22	7.78	10.35	12.31	113%	107%	63%
NJ	14.14	12.99	10.08	11.14	13.01	109%	100%	77%
NY	17.10	15.92	8.71	10.96	15.22	112%	105%	57%
PA	10.95	9.20	6.87	7.72	9.08	121%	101%	76%
East North Central	9.74	8.49	5.90	6.84	7.97	122%	107%	74%
IL	10.12	8.57	6.61	6.43	8.46	120%	101%	78%
IN	8.26	7.29	4.89	10.09	6.50	127%	112%	75%
MI	10.21	8.77	6.47	9.76	8.53	120%	103%	76%
OH	9.57	8.67	5.76	9.98	7.91	121%	110%	73%
WI	10.87	8.71	6.16	-	8.48	128%	103%	73%
West North Central	8.31	6.79	5.08	7.25	6.83	122%	99%	74%
IA	9.45	7.11	4.74	-	6.83	138%	104%	69%
KS	8.19	6.83	5.13	-	6.84	120%	100%	75%
MN	9.18	7.48	5.69	8.27	7.44	123%	101%	76%
MO	7.69	6.34	4.76	6.16	6.56	117%	97%	73%
ND	7.30	6.58	5.24	-	6.42	114%	102%	82%
NE	7.59	6.39	4.78	-	6.28	121%	102%	76%
SD	8.07	6.61	5.09	-	6.89	117%	96%	74%
South Atlantic	10.03	8.66	5.67	9.39	8.68	116%	100%	65%
DC	11.18	12.01	9.32	11.32	11.79	95%	102%	79%
DE	13.16	11.21	8.93	-	11.35	116%	99%	79%
FL	11.22	9.75	7.76	9.73	10.33	109%	94%	75%
GA	9.10	8.07	5.53	6.42	7.86	116%	103%	70%
MD	11.89	11.58	9.41	10.15	11.50	103%	101%	82%
NC	9.40	7.43	5.47	9.09	7.83	120%	95%	70%
SC	9.19	7.74	4.83	-	7.18	128%	108%	67%
VA	8.74	6.38	5.07	6.73	7.12	123%	90%	71%
WV	6.73	5.85	3.95	6.42	5.34	126%	110%	74%
East South Central	8.35	8.07	5.04	10.31	7.01	119%	115%	72%
AL	9.32	8.70	5.27	-	7.57	123%	115%	70%
KY	7.34	6.76	4.47	-	5.84	126%	116%	77%
MS	9.36	8.92	5.75	-	8.03	117%	111%	72%
TN	7.84	8.09	5.19	10.31	7.07	111%	114%	73%
West South Central	11.15	9.26	7.14	8.65	9.27	120%	100%	77%
AR	8.73	6.91	5.25	-	6.96	125%	99%	75%
LA	9.37	9.13	6.77	13.91	8.39	112%	109%	81%
OK	8.58	7.33	5.41	-	7.29	118%	101%	74%
TX	12.34	9.87	7.79	8.40	10.11	122%	98%	77%
Mountain	9.31	7.77	5.68	7.56	7.69	121%	101%	74%
AZ	9.66	8.27	6.05	-	8.54	113%	97%	71%
CO	9.25	7.62	5.97	7.18	7.76	119%	98%	77%
ID	6.36	5.14	3.87	-	5.07	125%	101%	76%
MT	8.77	8.10	5.16	-	7.13	123%	114%	72%
NM	9.12	7.66	5.60	-	7.44	123%	103%	75%
NV	11.82	10.09	8.28	9.98	9.99	118%	101%	83%
UT	8.15	6.54	4.52	7.44	6.41	127%	102%	71%
WY	7.75	6.25	4.10	-	5.29	147%	118%	78%
Pacific Contiguous	11.82	11.19	7.89	8.33	10.71	110%	104%	74%
CA	14.42	12.82	9.98	8.37	12.80	113%	100%	78%
OR	**8.19**	**7.20**	**5.06**	**6.71**	**7.02**	**117%**	**103%**	**72%**
WA	7.26	6.55	4.57	5.74	6.37	114%	103%	72%
Pacific Noncontiguous	20.56	17.58	16.86	-	18.29	112%	96%	92%
AK	15.18	12.19	12.63	-	13.28	114%	92%	95%
HI	24.12	21.91	18.38	-	21.29	113%	103%	86%
U.S. Total	**10.65**	**9.65**	**6.39**	**9.70**	**9.13**	**117%**	**106%**	**70%**

source: Oregon Utility Statistics, published annually by the Oregon Public Utility Commission

Oregon	Residential	Commercial	Industrial	All Sectors				res - ind
2007	8.08	6.26	4.6	6.6	122%	95%	70%	3.48
2006	6.92	5.85	4.19	5.88	118%	99%	71%	2.73
2005	6.31	5.56	4.01	5.51	115%	101%	73%	2.3
2004	6.24	5.51	4.02	5.46	114%	101%	74%	2.22
2003	6.37	5.68	4.1	5.58	114%	102%	73%	2.27
2002	6.4	5.67	4.13	5.5	116%	103%	75%	2.27
2001	6.52	5.51	3.81	5.25	124%	105%	73%	2.71
2000	6.41	5.43	3.77	5.14	125%	106%	73%	2.64
1999	6.23	5.39	3.5	4.96	126%	109%	71%	2.73
1998	6.15	5.33	3.11	4.66	132%	114%	67%	3.04
1997	5.97	5.25	4.55	5.29	113%	99%	86%	1.42
1996	5.76	5.18	3.8	4.9	118%	106%	78%	1.96
1995	5.52	4.94	3.57	4.62	119%	107%	77%	1.95
1994	5.5	5.03	4.27	4.94	111%	102%	86%	1.23
1993	5.28	5.05	4.35	4.91	108%	103%	89%	0.93
1992	5.2	5.07	4.28	4.85	107%	105%	88%	0.92
1991	5.16	5.08	4.14	4.8	108%	106%	86%	1.02

POLES

	% Customers	% kW Load	% Energy	cost assigned	% of cost
Residential	83.8%	55.1%	43.0%	817616	73.3%
Commercial	14.7%	34.7%	36.0%	242404	21.7%
Irrigation	1.4%	2.0%	1.8%	33712	3.0%
Industrial	0.0%	8.2%	19.2%	21499	1.9%
Total	100.0%	100.0%	100.0%	1115231	

CONDUCTOR

Sector	% Customers	% kW Load	% Energy	cost assigned	% of cost
Residential	83.8%	55.1%	43.0%	662177	64.4%
Commercial	14.7%	34.7%	36.0%	277574	27.0%
Irrigation	1.4%	2.0%	1.8%	47478	4.6%
Industrial	0.0%	8.2%	19.2%	40307	3.9%
Total	100.0%	100.0%	100.0%	1027536	

Monthly Megawatts Generated

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09
Gas Plant																
Currant Creek	287,512	273,530	271,837	266,820	234,978	153,351	187,648	276,259	222,289	204,556	189,056	231,749	3,461	230,023	174,879	6,788
Chehalis	-	-	-	-	-	-	-	-	130,128	164,766	140,984	152,580	248,644	240,726	225,555	182,105
Gadsby	(461)	(431)	(435)	(690)	(89)	26,747	40,032	42,093	45,511	35,462	27,740	16,598	17,872	7,253	2,293	(414)
Gadsby CT	9,662	4,799	(132)	4,533	6,135	28,565	30,710	30,649	34,935	36,399	32,465	31,798	31,390	28,182	23,352	22,914
Hermiston	173,444	158,356	146,021	169,472	137,807	66,116	132,688	158,959	148,102	171,621	166,487	173,064	158,119	141,178	153,416	113,232
Lake Side	289,351	271,147	213,631	291,213	157,932	149,391	217,039	255,841	329,354	188,436	245,473	252,521	270,950	257,070	259,222	197,273
Little Mountain	10,735	9,910	10,110	9,683	9,362	8,862	2,300	7,282	9,321	10,426	10,407	11,169	11,003	9,725	10,363	9,784
West Valley	16,102	17,539	15,450	37,520	39,674	-	-	-	-	-	-	-	0	0	0	0
Total Gas Generation	786,345	734,850	656,482	778,551	585,799	433,032	610,417	771,083	919,640	811,666	812,612	869,479	741,439	914,157	849,080	531,682

Unemployment Rates

	Jun-09
U.S.	9.50%
Oregon	12.20%
Baker County	11.20%
Benton County	8.40%
Clackamas County	11.40%
Clatsop County	10.00%
Columbia County	14.70%
Coos County	14.10%
Crook County	22.60%
Curry County	14.50%
Deschutes County	15.80%
Douglas County	17.20%
Gilliam County	7.70%
Grant County	14.50%
Harney County	18.90%
Hood River County	8.50%
Jackson County	13.70%
Jefferson County	15.50%
Josephine County	15.30%
Klamath County	15.30%
Lake County	12.10%
Lane County	13.20%
Lincoln County	11.80%
Linn County	15.40%
Malheur County	10.30%
Marion County	12.00%
Morrow County	10.00%
Multnomah County	11.70%
Polk County	10.00%
Sherman County	8.70%
Tillamook County	10.50%
Umatilla County	10.60%
Union County	12.50%
Wallowa County	12.90%
Wasco County	10.90%
Washington County	10.40%
Wheeler County	9.60%
Yamhill County	13.20%

Source: Oregon Employment Department

UE 210 – CERTIFICATE OF SERVICE

I hereby certify that, on this 24th day of June, 2009, I served the foregoing OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON in docket UE 210 upon each party listed in the UE 210 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending an original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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