BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY

Respondent.

DOCKET UE-140762 ET AL.

DIRECT TESTIMONY OF GLENN A.WATKINS (GAW-1T)

ON BEHALF OF

PUBLIC COUNSEL

OCTOBER 10, 2014

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I. INTRODUCTION AND SUMMARY

Q: Please state your name and business address.

A: My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, Virginia 23235.

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

A: I am Executive Vice President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel).

Q: Please describe your professional qualifications.

A: Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 34-year career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous gas, electric, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, North Carolina, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in Economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in Exhibit No. GAW-2.

Q: What is your ratemaking experience within Washington State?

A: I have testified on behalf of Public Counsel in numerous electric and gas rate cases over the last several years including the 2007, 2009, and 2011 electric and gas rate cases involving Puget Sound Energy,[1] the 2009 and 2013 Pacific Power & Light Company rate cases,[2] and the 2009, 2013 and 2014 Avista rate cases.[3]

Q: What is the purpose of your testimony is this proceeding?

A: Technical Associates has been engaged to review and evaluate the appropriateness of Pacific Power & Light Company's ("PacifiCorp" or "Company") class cost of service study ("CCOSS"), class revenue (rate) spread, and Residential fixed customer charges. The purpose of my testimony is to comment on PacifiCorp's proposals in these regards and provide my recommendations in these areas.

II. CLASS COST OF SERVICE

Q: Please briefly explain the concept of a CCOSS and its purpose in a rate proceeding.

A: Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, PacifiCorp has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

[1] Dockets UE-072300, UG-072301, UE-090704, UG-090705, UE-111048, and UG-111049.
[2] Dockets UE-090205 and UE-130043.
[3] Dockets UE-090134 and UG-090135, UE-120436 and UG-120437, UE-140188 and UG-140189.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers such that the utility's total cost must be allocated to various customer groups. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are typically directly assigned to that customer or group in the CCOSS. Most of the costs are jointly incurred to serve all or most customers; therefore, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor, e.g., peak demand, energy usage, number of customers, etc.

Q: In your opinion, how should the results of a CCOSS be utilized in the ratemaking process?

A: Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs.

These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q: Has the United States Supreme Court opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A: Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the Federal Energy Regulatory Committee (FERC)), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[4]

Q: Does your opinion, and the statement of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A: Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard,

[4] *Colorado Interstate Gas Co. v. FERC et al.*, 324 U.S. 581, 589, 65 S. Ct. 829 (1945).

when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q: Please explain how you proceeded with your analysis of the Company's CCOSS.

A: In conducting my analysis, I reviewed the structure and organization of the Company's CCOSS sponsored by company witness, Ms. Joelle R. Steward and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed PacifiCorp's selection of classification and allocation factors utilized to assign specific rate base, revenue, and expense accounts.

Q: Did you find the Company's study to be mathematically accurate?

A: Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Ms. Steward's CCOSS to be mathematically accurate.

Q: What cost allocation methodology did Ms. Steward utilize to assign generation and transmission-related plant and expenses?

A: Ms. Steward has utilized what is generally known as the Peak & Average ("P&A") method to assign generation and transmission-related plant and expenses. Under this approach, generation and transmission plant is classified as partially demand-related and partially energy-related. Specifically, Ms. Steward utilized the Company's West Control Area 2013 load factor to determine the amount of plant classified as demand versus energy.[5] It should be noted that in PacifiCorp's last rate case, the Company also proposed the P&A method, but referred to this as a "Revised Peak Credit" method.[6]

Q: What other methodologies are used to allocate generation-related plant and expenses?

A: In addition to the P&A method employed by PacifiCorp, there are several other demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* discusses at least 13 embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise *Principles of Public Utilities Rates*.[7]

Q: Why do so many generation allocation methods exist for the electric industry?

A: Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the

[5] Load factor is defined as: average demand divided by peak demand. The energy portion is equal to the system load factor while the demand portion is equal to 1 minus the load factor.
[6] Direct Testimony of Craig Paice, Exhibit No. CCP-1T, p. 5 (Docket UE-130043).
[7] James C. Bonbright, et al., *Principles of Public Utility Rates*, (Second Edition, 1988), p. 495.

physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs, i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that PacifiCorp experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To further complicate matters the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to generation costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (kW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy, i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q: Please explain.

A: Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know actual class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, a cost allocation method that recognizes both the capacity requirements of the utility as well as the need to minimize energy costs over the course of a year will incorporate a simplified approach but will still reasonably reflect cost causation.

Q: Is the P&A method utilized by PacifiCorp in this case the same as the Peak Credit method, which has been utilized by all utilities in Washington for the last 20-plus years?

A: No. The P&A and Peak Credit methods are distinctly different both conceptually as well as mathematically. The P&A and Peak Credit methods both recognize energy usage and peak load (demand). However, the Peak Credit method, also known as the Equivalent Peaker method in other jurisdictions, combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal costs studies, whereas the P&A method is strictly an embedded (historical) cost allocation approach.

The Peak Credit method relies on forward-looking planning information in order to classify a utility's total generation plant between energy-related and demand-related based on the relationship of projected capital and operating costs of a peaker unit relative to a base load unit. The theory underlying the Peak Credit method is that peaker units are utilized to serve incremental peak load, whereas base load units are utilized primarily to serve energy requirements over the course of the year. It should be noted that the foundation of the Peak Credit methodology lies within short-run marginal cost theory and was developed from what is known as the National Economic Research Associates ("NERA") short-run marginal cost method in which a peaker unit serves as the basis for marginal generation costs. The P&A method does not rely on forecasted or planning data but rather is dedicated to embedded or historical costs.

Q: Is a distinction between the Peak Credit and P&A methodologies particularly important?

A: It may or may not be as far as this Commission's policies are concerned. That is, for many years, this Commission has endorsed and supported the forward-looking nature of the Peak Credit method and as explained earlier, all three investor-owned utilities in the State have used the Peak Credit method for many years. However, PacifiCorp's portfolio of production assets is somewhat atypical of a traditional integrated electric utility. PacifiCorp serves several western states and has separate control areas within its various service areas.

The Company dispatches its generation assets throughout its various control areas on an economic basis to minimize total running (energy) costs in a given hour. This dispatch may include the Company's owned resources as well as purchased power. Furthermore, for many years, PacifiCorp utilized its contract for firm capacity with Bonneville Power Administration ("BPA") as the basis for determining the demand component within the true Peak Credit methodology. It is my understanding that the Company's firm capacity sales agreement with BPA expired in 2011. As discussed earlier, the P&A method is not based on a forward-looking concept but, rather, is based entirely on the historical relationship between average usage (kWh energy) and peak load.

Q: In your opinion, is the P&A method a reasonable approach to allocate PacifiCorp's costs across its retail classes?

A: With a caveat, yes. Given the somewhat unique circumstances of PacifiCorp's portfolio of production assets coupled with its allocation of these assets to various control areas, it is my opinion that the P&A method serves as a reasonable basis for allocating the Company's costs to the various retail classes. The P&A method reasonably reflects cost causation as it correctly recognizes that PacifiCorp's generation facilities (and attendant costs) are planned, built, and operated (dispatched) in order to minimize total energy costs as well as meet peak load responsibility.

Q: Please discuss and explain the caveat concerning the use of the P&A method for PacifiCorp.

A: As noted earlier, Ms. Steward utilized the 2013 Western Control Area system load factor to classify production and transmission plant between demand-related and energy-related components. Ms. Steward has defined the Company's Western Control Area as Oregon, Washington, and California. In developing her system load factor, Ms. Steward has utilized the highest peak load for a single hour during 2013. This approach is commonly known as the 1-CP approach. For purposes of this case, Ms. Steward's calculations resulted in a load factor of 57% such that her "energy" component is equal to the load factor (57%), while the demand component is one minus the load factor (43%). The concern I have is the reasonableness and stability of Ms. Steward's calculated 43% demand ratio on both a historical and forward-looking basis.

To illustrate, in PacifiCorp's last rate case, which was only one year ago, the Company calculated and utilized a materially lower demand ratio of 38%. In addition, the Company's traditional Peak Credit methodology resulted in a demand ratio of about 35%.[8] The Company's update to its 2013 Integrated Resource Plan ("IRP") indicates that load growth will be less than originally projected such that the PacifiCorp's coincident peak load in the Western Control Area (OR, WA, and CA) is

[8] Direct Testimony of Craig Paice, Exhibit CCP-1T, p. 5 (Docket UE-130043).

forecasted to be 3,269 megawatts ("MW") in 2014 and 3,307 MW in 2015.[9] These projected loads for planning purposes stand in contrast to the peak load used within Ms. Steward's load factor calculation of 4,048 MW. Whether Ms. Steward's utilization of 4,048 MW is an anomaly due to weather or whether it inappropriately includes interruptible and/or other non-firm load is unknown. However, it is apparent that Ms. Steward's calculated load factor for this case differs significantly from recent history as well as what is projected in the near future. To illustrate, the Company's update to its 2013 IRP forecasts Washington load factors to be 71.7% in 2014 and 71.8% in 2015. This approximate 72% load factor means that on a forward-looking basis, a demand component for production and transmission costs would more reasonably be about 28% (1 minus 72%).[10]

As a result of the apparent load factor anomaly utilized by Ms. Steward in the current CCOSS as well as the obvious instability resulting from the use of a single hour's peak demand, I recommend that for purposes of classifying production and transmission plant within the CCOSS, either the forward-looking load factor as developed in the most recent IRP should be utilized or an average of multiple hours highest peak loads within a single year or multiple years annual peak loads be used to determine a reasonable load factor.[11]

Q: Are significantly different CCOSS results obtained when a more reasonable, and stable, demand classification factor is utilized?

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[9] PacifiCorp 2013 Integrated Resource Plan Update, March 31, 2014, p. 26.

[10] *Id*., p. 26 (2014 average demand of 2,344 MW divided by peak load of 3,269 MW and 2015 average demand of 2,373 MW divided by peak load of 3,307 MW.)

[11] Even though a single year's 4-CP, 6-CP, or 8-CP would be preferable to a single hourly observation, my preference would be to utilize near-term projected peak and average loads as developed within the Company's IRP as these better reflect the planning and forward-looking nature of the Company's utilization of its generation and transmission resources.

A: While the CCOSS results certainly change as a result of using a lower 30% demand classification than the 43% utilized by Ms. Steward, I am not sure I would go as far as to say that these results are significantly different -- particularly in light of my opinion that CCOSS results should only be used as a guide in evaluating class revenue responsibility. The exception may relate to the Dedicated Facilities class wherein the indexed rate of return decreases from 72% to 46% of the system average rate of return.

To illustrate the differences that do occur as a result of using a more appropriate production/transmission demand classification ratio, I have utilized the Company's proprietary CCOSS model and substituted its proposed 43% demand classification with a more reasonable demand classification ratio of 30%. A summary of class rates of return at present rates are provided in the table below while a summary table utilized in the same format as Ms. Steward's Exhibit No. JRS-2 is provided in my Exhibit No. GAW-3:

PacifiCorp – Washington CCOSS Results At Current Rates
Under Alternative Generation/Transmission Demand Classification

	Rate of Return		Indexed (Relative) Rate of Return	
Class	Company @ 43% Demand	PC @ 30% Demand	Company @ 43% Demand	PC @ 30% Demand
Residential	3.55%	4.24%	61%	73%
Small General Service	10.17%	10.05%	176%	174%
LG Gen Service <1,000KW	7.56%	7.08%	131%	122%
LG Gen Service >1,000 KW	6.62%	5.55%	115%	96%
Dedicated Facilities	4.16%	2.65%	72%	46%
Agricultural Pumping	9.32%	8.81%	161%	152%
Street Lighting	9.85%	8.02%	170%	139%
Total WA Jurisdictional	5.78%	5.78%	100%	100%

Q: Ms. Steward addressed three of Staff's recommended CCOSS changes from the 2013 rate case in her direct testimony. Do you have any comments or response to Ms. Steward's evaluation of Staff's recommended changes?

A: Yes. The three Staff recommendations that Ms. Steward addressed relate to: (a) classifying generation and transmission costs based on 200 hours of peak load (100 highest summer and 100 highest winter hours) instead of a single system peak; (b) a separate demand/energy classification specifically used for solar and wind resources; and (c) the direct assignment of corporate (large) account manager expenses to Schedule 48T (Dedicated Facilities) customers.

With regard to Staff's first recommendation to classify generation and transmission-related costs based on 200 hours of peak load, I generally concur with Ms. Steward that for classification purposes, and in the spirit of recognizing peak load responsibility as well as energy utilization, the use of 200 hours of peak load reflects too much averaging such that the relationship between peak load and energy utilization (average load) is inappropriately distorted. However, I also concur with Ms. Steward and Staff that for allocating demand-related generation and transmission costs, the current practice of developing class allocation factors based on 200 hours of peak load is appropriate.

With regard to Staff's recommendation to separate demand and energy used for solar and wind resources, I also concur with Ms. Steward that it is inappropriate to pigeonhole this one type of generating resource without specific recognition of other resources. While it is true that wind and, to a lesser extent, solar are not reliable resources for dispatching or planning purposes, the P&A approach considers a utility's composite resources. Indeed, it is my opinion that for cost allocation purposes, if an analyst advocates a specialized and unique classification factor for one type of resource it should also do so for all other resources. In fact, I often use this approach when utilizing a Base/Intermediate/Peak ("BIP") method in that I calculate separate demand and energy classification factors for each specific generation resource. In summary, I am concerned that a bias may be introduced by isolating only one resource while ignoring all others on an individual basis.

With regard to Staff's third recommendation concerning the direct assignment of corporate (large) account manager expenses to Schedule 48T (Dedicated Facilities) customers, Ms. Steward concedes that Staff's recommendation may have merit. However, she has not reflected Staff's recommended modification in her CCOSS because "the impact on cost of service results is minimal." Furthermore, Ms. Steward claims that Staff's recommendation "singles out one customer service cost for one type of customer." I disagree with Ms. Steward on this issue and concur with Staff's recommendation. It is well known that costs should be directly assigned when practical and when a particular customer or class of customers impose a significantly different level of costs than all other customers. Therefore, I recommend for future CCOSS, the Company adopt Staff's recommendation relating to the direct assignment of corporate (large) account manager expenses.

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III. CLASS REVENUE ALLOCATION (RATE SPREAD)

Q: Please provide a summary of the Company's proposed allocation of its requested $27.2 million overall increase to individual rate classes.

A: The following table summarizes Ms. Steward's proposed base rate revenue allocation (rate spread):

PacifiCorp's Proposed Base Rate Revenue Increases
($000)

Class	Current Base Rate Revenue	Proposed Increase $	Proposed Increase %
Residential	$140,088	$13,316	9.5%
Small General Service	$48,473	$2,053	4.2%
LG Gen Service <1,000KW	$66,810	$6,350	9.5%
LG Gen Service >1,000 KW	$26,036	$2,475	9.5%
Dedicated Facilities	$24,941	$2,371	9.5%
Agricultural Pumping	$12,666	$537	4.2%
Street Lighting	$1,622	$69	4.2%
Recreational Field Lighting	$26	$1	4.2%
Partial Requirements Service	$292	$28	9.5%
Total Sales to Std. Tariff Cust.	$320,954	$27,200	8.5%

Q: What factors did Ms. Steward consider in developing her proposed class revenue increases?

A: Ms. Steward considered the results of her CCOSS as well as gradualism.

Q: Is Ms. Steward's proposed class rate spread to the Residential and Small General Service classes reasonable?

A: Yes. Ms. Steward's proposed 9.5% increase to the Residential class and 4.5% increase to the Small Commercial class reflects movement towards allocated costs (both under Ms. Steward's CCOSS as well as my revised CCOSS), yet reasonably considers the concept of gradualism wherein the Residential class will sustain a somewhat larger percentage increase than the overall system average and the Small

Commercial class will incur a smaller percentage increase than the overall system average.

Q: To the extent the Commission authorizes an overall increase less than the $27.2 million requested by the Company, how should this ultimate increase be spread across rate classes?

A: I recommend the Company's proposed class revenue allocation (rate spread) be scaled-back in a proportional manner, i.e., individual rate class increases will be scaled-back proportionally to the increases proposed by Ms. Steward.

IV. RESIDENTIAL RATE DESIGN (CUSTOMER CHARGE)

Q: Please explain PacifiCorp's current and proposed Residential rate structures.

A: Currently, PacifiCorp's Residential rates include a fixed monthly customer charge plus a two-tiered inverted block energy charge rate structure for all energy (kWh) consumed. Although the Company proposes to maintain its current rate structure in this case, it proposes a significant shift in revenue collection from volumetric to fixed monthly charges. Specifically, PacifiCorp is proposing to increase the Residential customer charge by 81%, from $7.75 to $14.00 per month.

Q: Is PacifiCorp's proposed 81% increases to Residential customer charges reasonable or in the public interest?

A: No. The proposed increases violate the regulatory principle of gradualism, violate the economic theory of efficient competitive pricing, and are contrary to effective conservation efforts.

Q: Does PacifiCorp's proposal to collect a substantial portion of Residential distribution revenue from fixed monthly charges comport with the economic

theory of competitive markets or the actual practices of such competitive markets?

A: No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[12] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q: Please briefly discuss how prices are generally structured in competitive markets.

A: Under economic theory, efficient price signals result when prices are equal to marginal costs.[13] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage, i.e. volume-based pricing.

Q: Please briefly explain the economic principles of efficient price theory and how short-run fixed costs are recovered under such efficient pricing.

A: Perhaps the best known micro-economic principle is that in competitive markets

[12] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).
[13] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

(i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q: Please explain how efficient pricing principles are applied to the electric utility industry.

A: Universally, utility marginal cost studies include three separate categories of marginal costs: demand, energy, and customer. Consistent with the general concept of marginal costs, each of these costs vary with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy costs measure the incremental change in costs resulting from an incremental change in kWh (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer. Therefore, marginal customer costs only reflect costs such as service lines, meters, and incremental billing and accounting costs.

Q: Please explain how this theory of competitive pricing should be applied to regulated public utilities, such as PacifiCorp.

A: Due to PacifiCorp's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, i.e., the level of kWh (electric) consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q: Is the electric utility industry unique in its cost structures, which are comprised largely of fixed costs in the short-run?

A: No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Accordingly, PacifiCorp's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve are otherwise more energy efficient, or those who use less of the commodity for any reason pay less than those who use more electricity.

Q: How are high fixed customer charge rate structures contrary to effective conservation efforts?

A: High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[14] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[15] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[16]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV

[14] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[15] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636, p. 7 (Apr. 9, 1992).
[16] *Id.* p. 8 (alteration in original).

is the best method for doing that.[17]

Recently, some public utilities have begun to advocate SFV Residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q: Are conservation and efficiency gains a new risk to public utilities?

A: No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average Residential electric usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q: As a public policy matter, what is the most effective tool that regulators have to promote cost effective conservation and the efficient utilization of resources?

A: Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing

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[17] *Id.* pp. 128-129.

structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q: A customer's total electric bill is comprised of a base rate component and a fuel cost component. These fuel-related costs are volumetrically priced and represent a significant portion of a customer's bill. Does the volumetric pricing of this component overshadow the need for a proper pricing signal from distribution rates?

A: No. The rationale of fixed charge pricing approaches escapes me as an economist. This notion implies that even though marginal rates may be inefficiently structured, this error is acceptable due to other aspects within a customer's electric bill. To me, this argument is no more plausible than establishing rates that provide for clearly excessive monopolistic profits under the notion that the additional cost to consumers only represents a small portion of their energy bills and/or cost of living.

Q: Earlier in your testimony you explained that volumetric pricing predominates in competitive markets. Is there any data or experience regarding the pricing of utility services that have recently been deregulated?

A: Yes. Retail electric competition for electric generation services exists in several states. Invariably, customer choice for generation supply is volumetrically priced. However, competition for electric generation alone does not necessarily provide a good apples-to-apples comparison with the bundled services provided by PacifiCorp.

Texas has implemented total retail electric competition for most of the State's ratepayers, including distribution service. Under the Texas model, consumers select their electricity provider for all bundled electric services including generation, transmission, distribution, and metering. The customers' selected service provider supplies all services from the generator to the meter box. Electric providers compete for customers and are free to set their own prices and pricing structure.

Q: How are competitive Residential electric rates structured in Texas?

A: Every competitive electric service provider in Texas has a volumetric component within their rate structure. With regard to Residential fixed monthly customer charges, there are two different pricing structures: those with traditional fixed monthly customer charges (regardless of consumption); and those that have a minimum bill amount. The following is a summary of recent rate structures regarding customer charges for the 28 providers that offer competitive Residential electric service in Texas:

	Number Of Providers	Percentage Of Providers
Fixed charge waived with usage threshold	21	75%
Traditional fixed monthly customer charge	7	25%
Total	28	100%

Of the seven providers utilizing a traditional fixed monthly customer charge, the average customer charge is $6.94 per month. Regarding the 21 competitive providers that waive a fixed fee with a minimum threshold of usage, the average customer charge is $9.14 per month. The details supporting these amounts are provided in my Exhibit No. GAW-4.

From this data, 25% of the providers have maintained the traditional fixed monthly customer charge, and 75% of the providers waive any fixed fees once a minimum level of consumption (KWH) is achieved.[18]

This example illustrates that when prices for a service similar to PacifiCorp's operations are established based on competition and determined by the market (customers and sellers), the resulting rate structure is similar to that found for most other competitive goods and services, i.e., predominantly based on volumetric pricing, and not fixed charge pricing.

Q: Notwithstanding the efficiency reasons as to why regulation should serve as a surrogate for competition, are there other relevant aspects to the pricing structures in competitive markets *vis a vis* those of regulated utilities?

A: Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

[18] As indicated in the notes to Exhibit No. GAW-3, customer charges are waived with minimum monthly usages ranging from of 500 KWH to 2,000 KWH.

Q: Have you conducted any studies or analyses to indicate the levels at which PacifiCorp's Residential customer charges should be established?

A: Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include a return (margin), interest, and depreciation associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q: Have you conducted direct customer cost analyses applicable to PacifiCorp's Residential class?

A: Yes. I conducted a direct customer cost analysis for PacifiCorp's Residential class. The details of this analysis are provided in my Exhibit No. GAW-5.

As indicated in the exhibit, the Residential direct customer cost is in the range of $7.31 to $7.50.[19]

Q: Why is it appropriate to exclude corporate overhead and other indirect costs in developing Residential customer charges?

[19] As indicated in Exhibit No. GAW-5, the cost ranges are the result of utilizing a cost of equity range of 9.0% to 10.0%.

A: Like all electric utilities, PacifiCorp is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to PacifiCorp's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q: Are there any other key policy considerations regarding the appropriate customer charges for PacifiCorp's Residential customers that you would like to address?

A: Yes. In a recent PacifiCorp rate case (Docket No. UE-100749), the Commission rejected any increase to PacifiCorp's Residential customer charge of $6.00. In that case, the Commission observed the current difficult economic times confronted by ratepayers and that "many customers will view any basic charge increase as an additional increase above and beyond the rates approved in this Order."[20]

Furthermore, the Commission opined that lower energy charges (as a result of increasing customer charge rates and revenue) could result in reduced deployment of energy efficiency. Finally, the Commission concluded that "not recovering some of the "basic" costs through the basic charge does not mean those costs will not be recovered; rather, those costs will just be recovered through the variable charges."[21]

Q: PacifiCorp customers have questioned why such a large increase in the basic customer charge is requested, given that meter reading costs have presumably fallen with the use of automated meter reading. Have you analyzed the trends in PacifiCorp's customer-related costs over the last several years?

A: Yes, as mentioned earlier, I participated and presented expert testimony in

[20] Order 06, p. 114, ¶ 333 (Docket UE-100749).
[21] *Id*.

PacifiCorp's 2009 general rate case (Docket UE-090205). In that case, I also conducted a direct customer cost analysis that identifies specific customer-related investments and expenses. The following is a comparison of 2009 and current residential customer-related investments and expenses:

PacifiCorp
Comparison of Direct Residential Customer-Related Costs

Investment/Expense	2009	2014
Rate Base		
Services Gross Plant	$28,413,748	$40,027,456
Meters Gross Plant	$8,800,670	$7,717,033
Services Depr. Reserve	$8,477,339	$15,893,239
Meters Depr. Reserve	$4,428,906	$1,862,519
Net Investment (Meters+Services)	$24,308,173	$29,988,731
O&M Expenses		
Meter Operations	$537,888	$394,033
Customer Installations	$513,300	$479,333
Meter Reading	$1,558,056	$784,769
Records & Collections	$3,380,211	$3,045,554
Maintenance of Meters	$331,893	$305,671
Total O&M	$6,321,348	$5,009,360
Depreciation Expense		
Services	$641,489	$973,343
Meters	$325,375	$295,117
Total Depreciation	$966,864	$1,269,460

As can be seen in the table above, the Company's net investment in Residential services and meters has increased slightly during the last five years (from $24.3 million to $30.0 million). However, Residential meter reading expense has been reduced by almost 50% from $1.558 million in 2009 to a current level of $0.785

million. Furthermore, customer records and collections expenses have been reduced by about 10% from $3.380 million to $3.046 million.

Q: What conclusions can be drawn from your comparison of the Company's direct Residential customer-related costs?

A: While net investment has increased slightly, the Company's movement to automated meter reading and other operational changes has reduced the cost of reading meters and maintaining customer accounts. Indeed, in the 2009 case, I also calculated a "customer cost" revenue requirement using a similar cost of equity (9.96%) as that used in this case for my upper range of customer costs (10.0% return on equity). The direct monthly Residential customer cost revenue requirement in 2009 was $8.09 as compared to the current estimate (at 10.0% return on equity) of $7.50. As such, we can see that PacifiCorp's customer costs have declined over the last five years and it is interesting to note that in the Company's 2010 general rate case, the Commission rejected the Company's proposal to increase Residential customer charges and kept this customer charge at $6.00 per month.

Q: Based on your overall experience as well as the studies and analyses you conducted for this case, what is your recommendation regarding the appropriate customer charges for PacifiCorp's Residential customers?

A: Considering all factors, I recommend no increase to the current Residential customer charge of $7.75 per month.

Q: Does this complete your testimony?

A: Yes.