BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY

DOCKET NOS. UE-050684 and UE-050412

REBUTTAL TESTIMONY OF JIM LAZAR (JL-1T)

ON BEHALF OF

PUBLIC COUNSEL

DECEMBER 7, 2005

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I. INTRODUCTION AND OVERVIEW

Q. Please state your name, address, and occupation.

A. Jim Lazar, 1063 Capitol Way S. #202, Olympia, Washington. I am a consulting economist specializing in utility rate and resource analysis.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked to respond to Mr. Cavanagh's testimony regarding what he calls "decoupling" of the utility revenue stream from its sales volume. While I agree with Mr. Cavanagh that some elements of traditional utility regulation create some unintended incentives that may adversely affect utility willingness to support energy efficiency programs, I will show that the approach he has proposed would be significantly worse for consumers than the status quo.

Q. What are your principal findings?

A. The purpose of a decoupling mechanism is to prevent net income attrition as a result of energy conservation efforts by a utility. Mr. Cavanagh's proposal does not achieve that purpose.

PacifiCorp ("Pacific Power" or "Pacific") is already effectively decoupled, simply because any loss of retail sales can lead to an increase in wholesale sales at higher prices. This is very unusual, but it is expected to persist for many years, and renders the concept of a decoupling *mechanism* irrelevant.

I find that Mr. Cavanagh has failed to consider the impact of the wholesale power market in his proposal. If Pacific Power reduces retail sales through conservation (or any other means), the power that now flows to retail customers could be sold in the wholesale market. Based upon Pacific Power's estimate of the prices it could obtain in the wholesale market, I conclude that Pacific's net income would increase by $6.8 to $12.8 million per year if the 1% per year conservation effort identified by Mr. Cavanagh were to take place. This is in contrast to the $21 million reduction in net income resulting from this level of conservation effort testified to by Mr. Cavanagh. The difference is that Mr. Cavanagh has failed to take the wholesale revenues Pacific would enjoy into account.

Under Mr. Cavanagh's proposal, Pacific would not only be allowed to retain the wholesale market revenues, but would also receive $21 million in additional compensation from Pacific's billpayers. The net effect of his proposal would be to increase Pacific Power revenues by $27.8 to $33.8 million over the five-year period compared with maintaining current sales volumes.

The status quo – no decoupling mechanism and no power cost adjustment mechanism – would allow the Company a reward of $6.7 to $12.8 million from implementing such conservation efforts over a 5-year period. In the context of a company with approximately $25 million per year in return on equity (at Mr. Hill's recommended ROE and Capital Structure), the current incentive is quite substantial.

Because wholesale prices are projected to exceed Pacific's retail rates for many years, a properly designed decoupling mechanism (i.e., one that keeps the utility profit-neutral) would require a rebate to consumers of the excess wholesale revenues the utility will receive if retail sales decline. Needless to say, this would weaken the existing incentive for Pacific to pursue conservation opportunities compared with the current situation, where it is allowed to retain the wholesale revenues.

Basically, this is the wrong approach to decoupling, applied to the wrong company at the wrong time. Decoupling is a tool to use when a loss of sales results in a loss of net income; Pacific is subject to quite the opposite at the present time.

Q. Please summarize your qualifications.

A. I have been engaged in utility consulting continuously since 1982. I have appeared before this Commission in numerous proceedings involved Pacific Power and each of the other regulated electric and gas utilities. I have also appeared before numerous other regulatory commissions in Washington, Oregon, California, Arizona, New Mexico, Idaho, Montana, Hawaii, and Illinois, and before the Federal Energy Regulatory Commission. I am an Associate with the Regulatory Assistance Project, a group that provides training and technical assistance to utility regulators throughout the world. My clients include consumer advocates, regulatory bodies, utilities, and environmental groups. The Natural Resources Defense Council, Mr. Cavanagh's employer, is one of my clients. My education and experience are set out in Exhibit No. ___ (JT-4), an attachment to the Joint Testimony which I filed in this proceeding, together with witnesses Joelle Steward and Kathryn Iverson.

Q. What are the key elements that you address?

A. My testimony has the following elements:

First, I summarize Mr. Cavanagh's proposal as I understand it, so that the context of my rebuttal evidence is not ambiguous.

Second, I discuss how the "coupling" that Mr. Cavanagh criticizes is a byproduct of a very important and necessary element of test-year ratemaking, and that the adverse impacts he identifies are relatively minor compared with the positive incentives that the overall regulatory framework provides.

Third, I discuss the theory and practice of decoupling, including a discussion of the four-year experiment with decoupling in this state, on the Puget Sound Power and Light Company (now Puget Sound Energy, PSE, or Puget) system.

Fourth, I discuss the specific shortcomings of Mr. Cavanagh's proposal. Foremost among these are the failure to recognize the risk shifting that his proposal involves, and the failure to include a cost of capital adjustment as a part of the proposal.

Fifth, I discuss how the current and projected wholesale market situation makes the concern he has raised in this proceeding irrelevant. Pacific's marginal costs are significantly higher than its rates, and its opportunity to make off-system sales at prices higher than its retail rates are quite clear.

Finally, I discuss some important alternatives to the type of decoupling mechanism that could address the issue Mr. Cavanagh is concerned about. Like his decoupling proposal, each of these has advantages and disadvantages. It may be that none of the alternatives are unambiguously "better" than the status quo, but I believe that all of the alternatives are superior to the approach proposed by Mr. Cavanagh.

II. SUMMARY OF THE CAVANAGH PROPOSAL

Q. Please summarize Mr. Cavanagh's proposal as you understand it.

A. As I understand his proposal, the utility's revenue requirement would be segregated into a "fixed" and a "variable" component. The fixed cost component would be computed on a per-customer basis in the general rate case. The fixed costs would still be included in rates primarily on a volumetric basis. If sales per customer in any given rate year were lower than in the test year, the Company would be allowed a surcharge in the subsequent rate year to recover the lower recovery of fixed costs resulting from lower sales per customer. Conversely, if sales per customer in a rate year were higher than in the test year, a downward adjustment would be applied to rates in a future rate year to rebate the over collection.

Q. Do you agree that the linkage Mr. Cavanagh notes between utility sales volumes and utility profitability is a hindrance to utility investment in energy efficiency options under current regulation?

A. Yes, where it occurs, it tends to hinder utility support of energy conservation programs. However, as I discuss later in my testimony, there are a number of ways to address this issue, several of which do not have the adverse impacts on management incentives to control costs that Mr. Cavanagh's proposal entails. I would also note that many utilities without decoupling mechanisms have adopted significant energy efficiency programs. One recent example is PSE, which doubled its program as part of the settlement of its 2001 rate case. *WUTC v. Puget Sound Energy*, Docket No. UE-011570, UG-011571, Twelfth Supplemental Order, Appendix A (Settlement Stipulation), Exh. F.

III. "COUPLING" IS A BY-PRODUCT OF TEST-YEAR REGULATION

Q. How does traditional regulation treat fixed and variable costs, and how are changes in those costs accommodated as sales volumes change?

A. Traditional regulation involves setting a system revenue requirement based upon "test year" investments and expenses, and dividing this by system test year sales volumes to create rates. Those rates recover all of the fixed and variable costs of the utility, based on test year conditions. The assumption is that utility costs and utility revenues will generally grow in near-lockstep as the number of customers grows and the level of sales increases. As the utility serves additional customers, it will need to invest in additional power plants, additional transmission facilities, additional distribution lines, hire additional employees, buy more fuel, and generally incur more of all of the costs that went into setting the original rates. The additional sales will bring additional revenues, and those revenues will compensate the utility for the additional costs.

Q. What is it about the traditional regulatory model that gives rise to the "coupling" problem that Mr. Cavanagh is concerned about?

A. In the short run, the utility's fixed costs to serve existing customers do not change. While generation and transmission assets can be redeployed to serve new customers or wholesale markets, distribution lines to individual customers are characterized by high fixed costs, and can only serve the customers connected to them. If the utility encourages those customers to reduce their consumption, it will lose distribution margins, and, generally, profits will decline. In the very long run, this might lead to a different configuration of the distribution system (smaller conductors, smaller transformers, etc), with reduced fixed costs, but in the meantime, the utility's profits suffer.

Q. Does the same characteristic apply to the generation and transmission system?

A. Generally not. On an "island" utility, with no access to the wholesale market, the situation might be similar. The utility would have fixed costs for generating facilities, and would only avoid some fuel costs in response to lower sales. Even on an island system, however, if the overall number of customers were growing, the utility could use those generating facilities freed up by declining sales by some customers to serve different customers. Furthermore, even on an island system, the utility would first reduce output at its least economic generating facilities, and might avoid costs comparable to the lost revenues.

On an interconnected system like that of Pacific Power and Light Company, things are a bit more complex. Any reduction in retail sales means that the utility balances supply and demand by some combination of the following:

a) Reducing the amount of fuel used to generate electricity;

b) Selling un-needed power on the wholesale market; or

c) Purchasing less power from other utilities on the wholesale market.

If the incremental cost of power in the market is less than the average cost embedded in rates, the utility may suffer some earnings attrition if sales decline. Conversely, if the incremental cost of power exceeds the average cost embedded in rates, the utility average power supply cost would decline in response to lower sales. Basically, the distinction between “fixed” and “variable” costs is much less important for generation and transmission facilities, because the markets for the output of these facilities is not “fixed.” For all of these reasons, “decoupling” mechanisms have traditionally been directed only at the distribution margins of utilities, not at the bulk power supply fixed costs.

Q. Under what conditions will traditional regulation work just fine without any decoupling mechanism?

A. If the utility is operating under economic equilibrium conditions, a decoupling mechanism is unnecessary. Equilibrium is defined as a condition where average cost, short-run marginal cost, and long-run marginal cost are all equal. In such a situation, if rates were set to recover average costs, any increase or decrease in sales would have no effect on earnings, because the short-run marginal costs would be the same as the average costs unless a regulatory mechanism (such as a fully-reconciled fuel adjustment mechanism) altered the balance.

Q. Is this situation really possible in a modern utility?

A. Yes it is, in large part because utilities typically have a mix of generating resources with different fixed and variable operating costs. For example, imagine a utility with the following mix of costs:

Table 1 : Sample Utility Cost Mix

Cost Element X $1,000	Fixed Cost	Variable Cost	Variable Cost/kWh	MWh	Revenue Requirement / kWh
Hydropower	$900	$100	$.001	100,000	$.01
Coal Power	$1,000	$1,500	$.015	100,000	$.025
Natural Gas Power	$500	$5,000	$.05	100,000	$.055
Subtotal Power Supply	$2,400	$6,600	$.022	300,000	$.03
Transmission	$1,200	$300	$.001	300,000	$.005
Distribution	$3,600	$900	$.003	300,000	$.015
Total System:	$7,200	$7,800	$.026	300,000	$.05

In this situation the utility's average cost (and rate) is $.05/kWh. The incremental and decremental resource available to the utility in the short run in response to changes in retail sales is a natural gas kilowatt-hour, and the variable cost change from a change in sales level would be $.05/kWh, the same as the current revenue. Therefore an increase or decrease in retail sales in the short run would have no effect on the net income of the utility as long as the variation was within the increment of power provided by the high variable-cost generating resource. The mix of fixed and variable costs is irrelevant.

I have not taken this example to the next step – looking at long-run marginal costs. However, if the incremental power resource in the long run was a combined-cycle unit with total costs of $.04/kWh, and the marginal cost of transmission and distribution $.01/kWh (both plausible figures), then the utility's long-run marginal cost, short-run marginal cost, and average cost would all be $.05/kWh.

Q. Has Mr. Cavanagh demonstrated that Pacific Power is not operating at or near the equilibrium condition you have identified above?

A. No he has not. Mr. Cavanagh has looked at average costs, and divided those average costs into fixed and variable components. Nothing in his testimony looks at marginal costs. What is important in determining if a short-run change in sales volumes will benefit or harm profitability is to look at short-run marginal costs. In fact, as I will show later, Pacific Power has short-run marginal costs that are *higher* than its retail rates, and therefore its profitability will *increase* if retail sales volumes decline.

Using the example above, under Mr. Cavanagh's proposal, however, there is $.024/kWh in "fixed" costs on the system. Mr. Cavanagh's proposal would apparently reward the Company with an additional $.024 in revenue if the sales declined, and penalize the Company by that amount if sales increased, even though the change in revenues at current rates is fully compensatory to the Company for its incremental and decremental costs.

As is evident, in this hypothetical example, the traditional regulatory model, setting rates based on test year conditions, and assuming that variations in costs will generally track variations in sales is more accurate than the decoupling method proposed by Mr. Cavanagh. The problem is quite simple: his method decouples based on *average* costs, while the utility's profitability is a function of short-run *marginal* costs which may be very different from average costs.

Q. Are you suggesting that a decoupling mechanism is always inferior to the traditional regulatory framework?

A. No, not at all. But a decoupling mechanism needs to be designed to achieve the goal of net revenue neutrality, and Mr. Cavanagh's proposal fails that crucial element.

IV. DECOUPLING THEORY AND PRACTICE

Q. Are you generally familiar with the history of decoupling experiments in the United States?

A. Yes, there have been several. The first I am aware of were in the state of Maine in the 1980s. The utilities there had high average costs and rates, and low short-run marginal costs. Under those conditions, their resistance to energy efficiency programs was inevitable. The Maine PUC implemented a decoupling mechanism that had the following elements:

a) A separation of variable power supply costs into a fuel adjustment mechanism, trued up to "cost" in annual power cost adjustment proceedings;

b) A revenue per customer collection for distribution costs which was trued up based on growth in customers served.

Q. Did the Maine system stay in effect for very long?

A. No. The state generally went into an economic decline shortly after it was initiated, and the utilities' fixed costs were distributed over declining sales volumes. The resulting rate pressure brought about an abandonment of the program.

Q. What other experiments are you familiar with?

A. The California Energy Recovery Adjustment Mechanism (ERAM) is the largest such experiment. The Puget Sound Power and Light Company Periodic Rate Adjustment Mechanism (PRAM) was another example. There was a decoupling mechanism for Pacific Power in Oregon from 2002 – 2004. There are a number of natural gas utilities with distribution margin adjustment mechanisms; Northwest Natural Gas has such a mechanism in Oregon, known as the Distribution Margin Normalization (DMN) mechanism. Finally, there are some electric cooperatives that have established rate designs with high monthly customer charges and in which the only variable component of rates is the purchased power charge, a crude form of decoupling that creates other problems.

Q. Please describe the Puget PRAM in general terms?

A. The PRAM was ordered by the Commission in 1991, in Docket No. UE-901183. It had the following elements:

a) Costs were separated into "power" and "non-power" categories, with explicit definitions of each by account.

b) "Power" costs were recovered through annual tariff changes to provide for actual cost recovery;

c) "Non-Power" costs were computed on a $/customer basis, to be adjusted each year based on growth in customers; any changes in revenue due to sales variation were to be trued up in the annual adjustments.

d) The Company was required to make a general rate case filing at least every three years.

Q. How long did the PRAM remain in operation?

A. It was terminated by the Commission in Docket UE-951270; the final PRAM rate adjustment took place in 1997.

Q. What were the reasons that the PRAM was terminated?

A. There were several. First and foremost, the PRAM allowed recovery of sharply rising power supply costs with limited regulatory oversight. Second, the Company was seeking a merger with Washington Natural Gas. The 5-year rate plan negotiated as a part of the merger was designed to make rates predictable for the term of the plan, but the PRAM tended to make rates less predictable. Finally, there was strong opposition to the inclusion of certain cost accounts in the "non-power" category of the PRAM that was allowed to rise with increasing customer count.

Q. In your opinion, what are the most important lessons learned from the various decoupling experiments to date?

A. First, it is essential that the cost accounting be well understood and well defined in advance. The PRAM suffered from misclassification of costs into those to be tracked on an "actual" basis versus those to be tracked on a per-customer basis.

Second, it is important that limits be placed on the amount by which rates can change as a result of a decoupling adjustment. Customers value stability, and plan their budgets (and business expansion plans) on predictable costs.

Finally, the shift in risk that a decoupling mechanism imposes needs to be recognized, and the increased risk borne by billpayers needs to be recognized in setting the utility capital structure and revenue requirement.

V. ISSUES WITH THE CAVANAGH PROPOSAL

Q. What are your principal concerns with the proposal advanced by Mr. Cavanagh?

a) The proposal fails to recognize the difference between "variable" costs and "marginal" costs, and erroneously uses average variable costs as the basis for decoupling;

b) The proposal acknowledges, but does not incorporate, the presence of a wholesale power supply market for disposition of surplus power made available when retail sales decline from conservation efforts;

c) The proposal needs specific accounting principles to operate, and these cannot be developed unless and until an interstate cost allocation methodology is defined;

d) The proposal fails to incorporate the fact that new customers are expected to use less electricity than existing customers, and that the line extension policy already provides for recovery of the costs associated with this lower usage;

e) The design of Pacific's proposed PCAM directly conflicts with the approach that Mr. Cavanagh has proposed.

f) The proposal fails to recognize the risk shift and corresponding need for a cost of capital adjustment;

g) The proposal would result in significantly higher risks and costs to consumers, without any compensation or demonstrated benefits.

I will address each of these in turn.

Q. What is the problem you note with Mr. Cavanagh's use of "variable" costs as the basis of his decoupling proposal?

A. Pacific Power has selected a resource portfolio consisting primarily of coal-fired generation. This is characterized by high fixed costs for generating facilities and transmission. In addition, Pacific has classified most of the maintenance costs of the coal plants as "fixed" costs (generally labor costs are considered variable costs in accounting terms). It has one natural gas generating unit serving the western system, at Hermiston.

By using a "fixed/variable" split of costs, Mr. Cavanagh has defined the majority of Pacific's costs in the category to be "trued up" under his proposal – with rates increased to recovery foregone fixed costs if sales decline. Only a small portion of total costs are considered "variable" in his proposal – and much of the variable costs are fuel costs for coal plants. However, to accurately reflect what happens in a utility, the proposal would need to look not at the *average* of variable costs, but at the *marginal* variable costs, those that will actually change in response to a change in sales. It's pretty obvious that Pacific's coal generation will not change in response to sales variations. Even absent a wholesale market, the Company would vary the output from Hermiston first, because it has the highest variable costs.

In fact, Pacific Power's system is really quite similar to the hypothetical utility system I described above, with the majority of its power coming from low-cost hydro and coal power, and its incremental power coming from higher-cost natural gas generation. Mr. Cavanagh has not proposed any method to measure the Company's incremental costs (or avoided costs) against incremental variations in sales volumes that might result if his proposed approach were implemented.

Q. How does the presence of a wholesale market affect the validity of Mr. Cavanagh's proposal?

A. Pacific Power is not an "island" utility. It is heavily interconnected to the east, north, and south of Washington. If the utility has a surplus, it can either curtail generation at its own power plants, or it can sell power to other utilities. If it needs additional power, it can either generate that power by running its available (typically higher variable-cost) power plants, or it can buy power on the market. At virtually every hour of the year, Pacific is a buyer or seller in the marketplace. The testimony of Mr. Buckley and Mr. Falkenberg addresses the Company's wholesale operations in greater detail.

Q. If Pacific's retail sales decline, can Pacific recover substantially all of its generation costs by making sales in the wholesale market?

A. Yes. Pacific's average cost of generation is $.037/kWh according to Mr. Taylor's unbundled cost of service study. PacifiCorp Response to ICNU Data Request No. 4.1 The wholesale market is projected to remain well above that level for the entire duration of Pacific's market forecast (through the year 2035). In fact, as I discuss below, the wholesale market is projected to remain above Pacific's average retail rates for the duration of the Company's forecast.

The point is that the Company's "variable" cost in response to changes in sales volumes is not what Mr. Cavanagh's exhibit shows it to be. It is much higher, reflecting both the fact that the Company has some high-cost generation it can dispatch, and the fact that the Company can sell into the wholesale market if it has a surplus of power. In either case, the decremental cost or incremental revenue that the Company would experience is much different from the "variable" cost portrayed by Mr. Cavanagh.

Q. Has Mr. Cavanagh presented a mechanism that is sufficiently defined to be implemented by the Commission?

A. No, he has not. A decoupling mechanism needs to have specific accounting methods set forth to track the costs that are to be "trued up" and a specific mechanism proposed to implement that true-up. Mr. Cavanagh has presented neither.

This is particularly true for a multi-state utility like Pacific, where generating facilities and transmission lines serve multiple states and must be allocated between those states. The parties in this proceeding have presented several different interstate allocation schemes. Each would have a different set of power supply costs, and the tracking mechanisms required for a decoupling mechanism would need to be consistent with the methodology adopted by the Commission. For the past two decades, we have been finessing Pacific's interstate power supply cost allocation; to attempt to superimpose a decoupling mechanism on an undefined set of power supply costs assigned to Washington is essentially impossible.

If and when the Commission adopts a specific interstate allocation methodology (possibly in this proceeding), it would then be possible to devise an accounting framework to allow the types of deferrals that Mr. Cavanagh is proposing. Until then, I really don't see how it could be done.

Q. If new customers are using less power than existing customers, would this affect the appropriateness of Mr. Cavanagh's proposal?

A. Yes. The Company's line extension policy (Rule 14) provides for an allowance based on the expected revenue of a new customer (and therefore their contribution to distribution system cost recovery). If new customers are using decreasing amounts of power and paying smaller bills, then it is appropriate to adjust the line extension policy to reflect this.

Q. Would you expect this to be the case – new customer using less power than the average of existing customers?

A. Generally, yes. New homes and commercial buildings are more efficient due to newer energy codes. New lighting systems, HVAC systems, and appliances are more efficient due to both codes and federal standards. I have examined this data for Puget and for Avista, but not for Pacific, but expect the same situation to prevail – new customers using less power than the average of existing customers.

Q. Has Mr. Cavanagh taken this into account?

A. No. It appears that his proposed method would automatically increase rates for existing customers if new customers used less power than the system average. This is because the allowed "revenue per customer" is based on the current average revenue, without regard to the possible fact that new customers are using less power. In effect, under Mr. Cavanagh's proposal, existing customers will provide the Company the same level of revenue from lower-use new customers as it enjoys from existing customers, even though the line extension policy should (and, in the case of the non-residential sector, does) already make the Company whole for the lower use of new customers.

Q. Pacific has proposed a power cost adjustment mechanism (PCAM) in this proceeding. If that mechanism were approved, would Mr. Cavanagh's proposal be appropriate?

A. No. While I have not studied the PCAM in detail, and both Staff and Public Counsel have submitted testimony opposing the PCAM, I have looked at the relationship between the Company's proposed PCAM and Mr. Cavanagh's proposed decoupling mechanism. The PCAM would flow through changes in power supply costs, including wholesale revenues, but it would do so in a very specific way that is designed to *not* result in under-recovery of power supply related fixed costs.

Q. Does Mr. Cavanagh's proposal recognize the risk shift that occurs when the Company is allowed to collect additional revenues when sales volumes decline?

A. No, Mr. Cavanagh has not recognized this risk shifting in his proposal.

Q. Have utilities previously recognized the impact of automatic adjustment mechanisms on the cost of capital?

A. Yes. In Cause U-81-41, Puget's witness Dr. Charles Olson testified that the automatic adjustment mechanism for power supply cost could be expected to lower the company's required return on capital (including return on equity).[1]

Q. Has the Commission previously noted the relationship between automatic adjustment clauses and the utility cost of capital?

A. Yes. When Puget initially requested and received its first adjustment mechanism for power costs, the Energy Cost Adjustment Clause (ECAC), customer bills became more volatile. When it terminated that mechanism, the Commission

[1] *Puget Sound Power and Light Company*, Docket U-81-41, 6th Supplemental Order, p.5.

noted that an adjustment clause should produce a reduction in the cost of capital, stating:

> If no such downward adjustment can be demonstrated by the parties in the next general rate case, then the Commission will have to seriously question the ECAC's raison d'etre.[2]

Several years later, when The Washington Water Power Company (now Avista Utilities) requested a power cost adjustment mechanism, the Commission denied the request, stating:

> Any power cost adjustment clause involves a regulatory tradeoff between the goals of rate stability and earnings stability. Earnings stability benefits a company and its stockholders, while ratepayers seek stable rates. If, through establishment of a PCA, a company receives the advantage of earnings stability, some of that benefit must be passed on to ratepayers to compensate them for enduring rate instability….The Commission reiterates the requirement that a downward cost of capital adjustment must be demonstrated.[3]

Q. Does the financial community recognize that revenue adjustment mechanisms like decoupling are beneficial to investors?

A. Yes. Both Moody's and Standard and Poor's have recognized this in various publications.

In response to Public Counsel Data Request No.166, Pacific supplied a Moody's Investor Service presentation dated May, 2005, relating to natural gas distribution companies. It states:

> Moody's believes that having utility rate designs that compensate the gas LDC for variations in conservation as with variations in weather would serve to stabilize the utility's credit metrics and credit ratings.

Standard and Poor's has gone so far as to segregate different utilities into different "risk profile" categories based on the different business risks they face. Those utilities with both supply and volumetric (weather, business cycle and

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2 *Puget Sound Power and Light Company*, Cause U-81-41, 6th Supplemental Order, p. 20.
3 *The Washington Water Power Company*, Docket No. U-88-2363-P, First Supplemental Order, p. 10.

conservation) risk have significantly higher risk profiles (Risk Profiles 4 – 7) than those with adjustment clauses to cover these risks. Northwest Natural Gas, which has both a purchased gas adjustment mechanism and the Distribution Margin Normalization (decoupling) mechanism is assigned the very lowest risk profile. In their rating scheme, Northwest Natural Gas has a Risk Profile of 1; prior to the decoupling mechanism, it was rated a 2. Each 1-step change in the S&P Risk Profile allows about a 2% reduction in the equity capitalization rate for the utility to be able to maintain any given bond rating.

Q. Has Northwest Natural's mechanism been recognized for reducing the Company's risk?

A. Yes. Prior to the implementation of the DMN process, S&P assigned Northwest Natural Gas a business profile risk rating of "2." After the mechanism was implemented, it was reduced to a "1" which is the lowest risk category. The evaluation report of the DMN process prepared for the Oregon PUC stated:

> [NWNG] CFO David Anderson believes that DMN and WARM were contributing factors to NW Natural obtaining the best rating in the Standard & Poor's (S&P) business risk profile (scoring a 1 on a scale of 1 to 10). Similarly, he believes that DMN and WARM contributed to the upgrade in NW Natural's S&P bond rating from A to A+. An improved risk profile has several beneficial effects. It allows NW Natural to maintain smaller lines of credit, reduce the share of equity in its capital structure, and maintain a lower coverage ratio.[4]

Q. Why is it logical that this risk shift should allow a lower equity capitalization ratio?

A. The amount of equity required to protect bondholders from the risk of default is a function of the variability of earnings. If a utility is exposed to fuel cost risk, weather risk, business cycle risk, and conservation risk, there is a higher

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[4] Christensen and Associates, A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural Gas, March 31, 2005, p. 72.

probability that a succession of adverse years will eat up the equity in the Company, exposing bondholders to the possibility of default than would be the case if utility customers absorbed all of these risks. Municipal utilities like Seattle City Light sometimes build up "drought reserves" to carry them through adverse conditions; for investor-owned utilities, the retained earnings provide the same sort of buffer. If the volumetric risk can be passed through to consumers within a year, the utility does not need to have such a high level of retained earnings, which translates into a lower equity capitalization ratio.

Q. Do advocates of decoupling generally recognize the risk shifting that occurs under decoupling, and the lower cost of capital that should accompany decoupling?

A. Yes. Decoupling was initiated in Maine by Commissioners who then went on to form the Regulatory Assistance Project, or RAP (of which I am an Associate). In 1994, RAP published a major review and discussion of decoupling, in a paper entitled "Regulatory Reform: Removing the Disincentives." In that report, the authors (and creators of both the Maine and Washington decoupling mechanisms) wrote:

> While the existing decoupling mechanisms shift weather and economic risks from the utility to customers, this is not necessarily undesirable. Both weather and business cycles cause sales, and hence revenue and earning levels, to fluctuate. This earning volatility in turn is one of the factors that determines a utility's cost of capital5. The more volatile a utility's earnings, the higher its cost of capital. Because utility rates include a rate-of-return based on the company's cost of capital, customers of utilities without decoupling mechanisms pay for increased utility volatility through higher, although more stable, electricity prices. *Id.*, p.9.

Q. What would be the effect of reducing the Risk Profile of a utility through decoupling, if that were flowed through the cost of capital adjustment?

A 2% reduction in the equity capitalization ratio, applied to Pacific's $600 million rate base, would produce about a $1 million reduction in the revenue requirement, as shown in my Exhibit No. ___ (JL-2). I believe that this is a conservative estimate of the impact that should be assumed for a properly designed decoupling mechanism (one that makes the Company net revenue neutral for sales volume variations due to weather, conservation and the business cycle, but not for fuel costs or wholesale market risk).

Q. What are the demonstrated benefits that Mr. Cavanagh has cited for his proposal?

A. Mr. Cavanagh starts on page 4 of his testimony with the premise that Pacific's fixed cost recovery is strongly tied to its retail sales volumes. That is clearly false, because Pacific has access to the wholesale market as well, and as I have discussed and will clarify below, the wholesale market is currently even more rewarding than the retail market.

He goes on page 8 to cite the Northwest Power and Conservation Council's ambitious savings targets as evidence that a greater commitment is needed. At the April 28, 2005, Northwest Power and Conservation Council briefing to the Commission, Dick Watson, former director of Power Planning, indicated that the Washington-regulated utilities were generally meeting their share of the Council's savings targets. See, Exhibit No. ___ (JL- 3).

Mr. Cavanagh indicates that the California PUC has set savings targets in the realm of 1% of system sales for its utilities. Pacific's Response to Public Counsel Data Request No. 169 shows that this company is already achieving nearly that level of savings, despite a relatively stagnant service territory without the opportunity for efficiency in new buildings that the California utilities (and that a utility like Puget) would enjoy.

Finally, as I discuss below, the proposed decoupling mechanism would actually penalize Pacific Power for investment in energy efficiency if the wholesale market benefits are included in the formula as Mr. Cavanagh agrees they should be at page 9 of his testimony.

Frankly, while I agree with Mr. Cavanagh that utilities may face disincentives to invest in efficiency when their earnings are tied to retail sales volumes, I find that this predicate is simply not the case for Pacific. First, the Company's earnings are presently inversely correlated to retail sales volumes, and second, the Company is responding quite well to the incentives it is facing at this time.

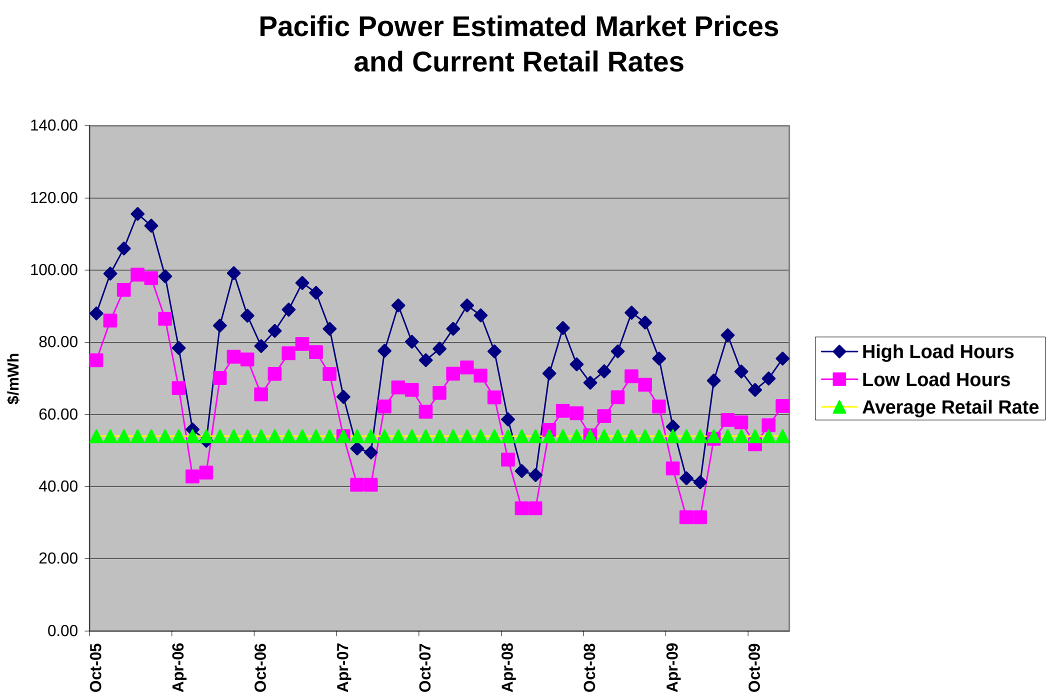
Mr. Cavanagh's proposal would expose consumers to unjustified higher prices to pay for sales reduction due to weather, business cycle variations, and conservation, without any compensation whatsoever. It is not clear that the problem Mr. Cavanagh seeks to solve is applicable to this utility. It is quite clear, on the other hand, that the framework of his proposal is flawed, due to confusing average variable costs with marginal costs, and a failure to recognize the impact of wholesale transactions. Finally, the lack of a cost of capital adjustment is a fatal flaw to the proposal, based on clear Commission direction with respect to power cost adjustment clauses in the past.

VI. THE WHOLESALE MARKET IS ABOVE THE RETAIL MARKET

Q. How do Pacific's current retail rates in Washington compare with wholesale market rates in the Pacific Northwest?

A. The Company's current retail rates average $.054/kWh, based on the data shown on Mr. Griffith's Table A. Residential rates average $.061/kWh, and industrial rates in Schedule 48T are $.042/kWh. By comparison, the wholesale market for the next twelve months is forecast by Pacific at $.084/kwh -- about 55% above the average retail rate. While the current price spike is not projected to be indefinite, higher prices are likely to persist into the future, with wholesale prices remaining above average retail rates over the long run. The graph below compares Pacific's current retail rates to Pacific's forecast of wholesale market prices for the next 5 years, as provided in the response to Public Counsel Data Request No. 163:

Table 2:



Q. How is it possible that wholesale prices can be higher than retail prices if Mr. Cavanagh testifies at page 8 that "This would of course not be possible if, as would normally be true in competitive wholesale power markets, wholesale prices reflect operating costs only, leaving no opportunity for recovery of fixed costs associated with retail service"?

A. In wholesale markets, prices generally reflect the variable costs (fuel, labor, water chemistry, emission rights, etc) of the highest cost resource that is needed to bring supply into line with demand on the entire interconnected grid. Pacific has a mix of resources with fixed and variable costs, which, taken together, have an average cost significantly lower than the variable costs of the marginal resources currently serving the market. Pacific's resources are primarily coal and hydro; the "marginal" resource in the western states is normally a natural gas-fired generator.

It is really quite simple to see this in the context of current natural gas prices. Pacific is forecasting natural gas to remain above $10 this year, and above $7 for the next several years. PacifiCorp Response to Public Counsel Data Request No.163. This is consistent with other market indicators I have reviewed. At $8, the variable fuel cost of a simple-cycle combustion (typically the marginal unit on-peak in the West) is about $90/mWh, and the variable fuel cost for a combined-cycle unit like Hermiston (typically the marginal unit off-peak in the West) is about $66/mWh. Meanwhile, as shown in Mr. Taylor's unbundled cost of service study, even at the Company's requested cost of capital, the average cost of all of its generation is only $37/mWh. PacifiCorp Response to ICNU Data Request No. 4.1.

The table below compared Pacific's margins in the market based on these simplified market indicators:

Table 3: Pacific Market Margins

Type of Sale	Average Cost of Power	Revenue	Margin
Residential	$.037	$.061	$.024
All Retail	$.037	$.054	$.017
Wholesale Off-Peak	$.037	$.066	$.029
Wholesale On-Peak	$.037	$.090	$.053

As is evident, Pacific can enjoy higher margins on its wholesale sales than on retail sales.

Q. What does this mean with respect to decoupling of Pacific's sales volumes from its net revenue?

A. Wholesale prices are $.02 to $.04 greater than Pacific's retail rates. Under this condition, if a properly-designed decoupling mechanism were implemented, Pacific would be required to rebate $.02 to $.04 to consumers for each kilowatt-hour of reduced retail sales, so that its margins would be unaffected by the reduction of retail sales. The decoupling mechanism would work exactly the opposite of how it has historically worked in California, simply because the cost relationships are quite the opposite. In California, retail consumers needed to compensate the utility for lost margins when retail sales declined. Pacific enjoys greater margins when retail sales decline.

During the period when the ERAM was developed, California utilities had been characterized by retail rates in excess of $.10/kWh, and wholesale markets below $.05/kWh. Under those conditions, the concerns raised by Mr. Cavanagh make more sense.

Pacific has quite the opposite situation, with wholesale prices exceeding retail rates. The Company's own forecast indicates this is likely to continue for several years. In Washington, in order to achieve the same result as the Maine, California, or Puget decoupling experiments, Pacific would need to rebate gained margins in response to lower retail sales. Basically, the long term investment that Washington electric consumers have made in hydro and coal-fired resources is paying off with retail prices that reflect power costs that are far below average.

Q. What is the fundamental flaw in Mr. Cavanagh's logic at page 9, where he discusses the "normal" wholesale market allowing for recovery of only variable costs?

A. Mr. Cavanagh has failed to recognize that it is not the average cost that matters, but the incremental cost of power supply needed to serve increasing or decreasing sales volumes. Pacific's average resource bears little resemblance to the market's incremental resource. Pacific's resource mix consists mostly of older coal plants with low capital and operating costs, plus a bit of hydro and the Hermiston gas plant. Hermiston means that Pacific's marginal resource is similar to the market's marginal resource, but it is a small part of the resource portfolio, and does not affect the average cost very much.

The problem is that Mr. Cavanagh has proposed a true-up mechanism based on Pacific's average costs, when in fact what Pacific experiences is its own marginal cost and/or the market marginal cost.

VII. CALCULATION OF THE IMPACT OF THE CAVANAGH PROPOSAL

Q. Mr. Cavanagh testifies, at page 7 that a 1% decline in sales would result in a $1.4 million loss to Pacific's shareholders, and that over a 5-year period, this would lead to a $21 million loss to Pacific's shareholders. Have you independently analyzed the impact of Mr. Cavanagh's proposal?

A. Yes, Mr. Cavanagh's analysis is flawed for several reasons. As I demonstrate, his proposal would allow a reward, before taxes, of $27.8 to $33.8 million over a five-year period. Without Mr. Cavanagh's proposed mechanism (i.e., the status quo), Pacific would still enjoy a reward of $6.8 to $12.8 million as a result of programs that result in 1% per year reduction in loads due to conservation.

Q. What are the primary errors in Mr. Cavanagh's analysis?

A. Mr. Cavanagh has started with an erroneous assumption that fixed costs would go unrecovered if retail sales declined. He has multiplied the fixed costs by the sales decline, and terms this a loss to Pacific's shareholders. First, he has used average costs, not marginal costs in measuring the impact. Second, the loss of retail sales for Pacific would be offset by a gain in wholesale sales, which has a significantly different impact than his assumption of zero recovery of fixed costs. Third, he has failed to take tax impacts into effect associated with any change in revenue; the amounts that he has identified are before tax, and would be mitigated by about 40% on an after-tax basis to produce the impact on shareholders.

Q. Please describe the analysis you have prepared?

A. First, I have started with Mr. Cavanagh's assumption of a 1% per year reduction in sales due to conservation efforts. This results in approximately 40 million kilowatt-hours per year not sold at Pacific's retail rates. I have calculated the revenue impact of losing 40 million kilowatt-hours in the first year, 80 million in the second year, and so on.

Second, I have recognized the losses that would have been incurred in making those retail sales (11% for most customers at secondary voltage; 7% for primary voltage customers). These losses are avoided if the sales are not made. This results in about 44 million kilowatt-hours being available for sale on the wholesale market.

Third, I have applied the wholesale loss factor of 4.48% to this figure, meaning that about 42 million additional kilowatt-hours can be sold at the wholesale rate as a result of conserving 40 million kilowatt-hours at the retail level.

Fourth, I have multiplied this by the wholesale market prices for each of five years as presented by Pacific in response to Public Counsel Data Request No. 163. I have recognized the effect of 42 million kilowatt-hours in the first year, 84 million in the second year, and so forth.

Finally, I have subtracted the lost retail revenues from the gained wholesale revenues to compute the estimated net impact on Pacific's revenue.

Implicitly, I have assumed that Pacific's fixed costs and variable costs are unchanged – it is generating and/or purchasing the same number of kilowatt-hours at the same cost in both situations. In both cases, they take into their system enough power to serve the current load. The only difference is to whom they are selling the power, and the price at which it is sold. In the "conservation" case, the sales of the conserved kilowatt-hours are made at wholesale instead of retail rates.

Q. Did you assume that the conservation occurred among the residential class, or among all customers?

A. I calculated this three different ways, recognizing that the retail rates for different customer classes vary. I first computed it assuming that all lost retail sales were from residential customers, at the average residential rate of $.061/kWh. I made a second calculation assuming that the lost retail sales were experienced across all classes, at the average Pacific retail rate of $.054/kWh. In each of these two analyses, I assumed that the increased wholesale sales would be made at the "flat" market rate – that is, for power throughout the day and throughout the year.

Q. Pacific has an inverted residential rate. If the lost retail sales were from the residential tail block, wouldn't the lost revenues be greater?

A. Yes, but I believe the wholesale revenues would also be greater due to the higher value of the peaking power that would be freed up. Pacific's tail block rate is $.068/kWh presently, compared with an average residential rate of $.061. For this reason I made a third calculation assuming that the lost retail sales were at this higher rate. However, because the tail block applies primarily to water heat and space conditioning usage, I also assumed that the wholesale sales resulting from this conservation would be made at the winter wholesale rates for high load hours.

Q. What is the result of this analysis?

A. The table below summarizes the analysis contained in Exhibit No. ___ (JL-4). It shows that the 1% per year reduction in retail sales would result in an increase of revenues to Pacific Power Washington operations:

Table 4:

Summary Of Impacts of 1% Per Year Decline in Retail Sales

	Average Rate All Classes	**Average Residential Rate**	**Residential End Block Rate**
First Year Lost Retail Revenues	$ (2,089,694)	$ (2,340,100)	$ (2,595,593)
First Year Gained Wholesale	$ 3,551,833	$ 3,572,102	$ 4,392,760
Net Impact	$ 1,462,139	$ 1,232,002	$ 1,797,167
Year 1 Combined Impact	$ 1,462,139	$ 1,232,002	$ 1,797,167
Year 2 Combined Impact	$ 1,938,217	$ 1,472,316	$ 2,259,252
Year 3 Combined Impact	$ 2,144,797	$ 1,441,594	$ 2,688,417
Year 4 Combined Impact	$ 2,309,376	$ 1,368,632	$ 2,882,180
Year 5 Combined Impact	$ 2,446,522	$ 1,268,080	$ 3,150,438
Cumulative 5-Year Impact	$ 10,301,050	$ 6,782,623	$ 12,777,455
Cavanagh Testimony	$ (21,000,000)	$ (21,000,000)	$ (21,000,000)
Difference	**$ 31,301,050**	**$ 27,782,623**	**$ 33,777,455**

Q. Please summarize the results of your independent analysis of the impact that a 1% per year conservation effort would have on Pacific's revenues.

A. The first column of figures shows the effect if the reduction in sales were across all classes, at the system average rate and the system average loss factor. It indicates that Pacific would receive a net of $10.3 million in additional revenue if the sales were shifted to the wholesale market. This contrasts with Mr. Cavanagh's assumption that Pacific would suffer a $21 million loss, for a difference of $31.3 million between what I estimate would occur and Mr. Cavanagh's estimate without consideration of the wholesale revenues.

The second column assumes that all lost sales were from residential customers, at the average residential rate and the residential loss factor. Because these rates are higher than average, while the expected wholesale revenue is almost identical (a different loss factor is the only difference), the net increase in revenues to Pacific is smaller, only $6.8 million. This, however, is still nearly $28 million higher than Mr. Cavanagh's calculation without consideration of wholesale market impacts.

The final column shows the impact if all of the lost sales were from the higher-priced residential tailblock, but the wholesale sales that resulted were exclusively during high load hours of the winter months. It shows that the additional wholesale market benefits from shaping exceed the additional retail revenue loss from the tail block. The additional revenue to Pacific is $12.8 million, or nearly $34 million above Mr. Cavanagh's estimate.

Q. Which of these do you feel is the most accurate representation of the impact of a 1% per year reduction in retail sales?

A. I believe that the three examples together define a range of reasonable outcomes. First, the impact on revenues will not be precisely what I have shown, because the mix of savings across customer classes is not precisely predictable, and therefore the lost retail sales revenue shown is approximate. Second, the wholesale market can be very volatile, and it would not be reasonable for me to assume that Pacific's estimates prepared in September of this year will be precisely accurate for the next five years, and so the gained wholesale revenue shown is approximate.

The point is that when reasonable estimates of wholesale revenues are incorporated into the analysis, along with appropriate loss factors and accounting for revenue sensitive items, the dire consequences described by Mr. Cavanagh are reversed, with clear evidence that under current market conditions, Pacific would benefit from reduced retail sales.

Q. **Are you predicting that this relationship will continue for five years?**

A. Pacific's forecast of wholesale prices (corroborated by other market indicators I have reviewed) suggests that the relationship will continue. However, a 5-year forecast depends on a highly volatile wholesale market that I do not claim the expertise to forecast, as well as on what happens to Pacific's retail rates during this period. In this particular proceeding, the recommendations of Staff and Public Counsel would result in reduced retail rates, in which case the net benefit of shifting retail sales to wholesale would be greater than shown. If Pacific's retail rates rise over the 5-year period, the benefit would narrow. However, I see a low probability that Pacific would suffer a net loss of revenue from energy conservation efforts during this period.

VIII. ALTERNATIVES TO DECOUPLING

Q. What are some of the alternatives to the type of complex decoupling mechanism that Mr. Cavanagh has proposed?

A. There are many alternatives that eliminate any real or perceived adverse impact on earnings of reduced retail sales. I will briefly discuss the following alternatives:

a) Block Rates That Reflect Marginal Costs in the Tailblock
b) Fixed / Variable Rate Design
c) Lost Margin Recovery Mechanism for DSM Programs
d) DSM Shareholder Incentives
e) Creating a Conservco – Separating DSM Programs from the Utility

Q. What type of rate design would eliminate long-run impacts of conservation on net earnings?

A. A rate design that set the incremental price for incremental usage equal to the long-run marginal cost of supplying service would mean that the utility would gain or lose the same amount of revenue as it incurs or avoids in cost when loads change.

In the residential class, usage above 600 kWh per month is typically associated with water heat and usage over 1,200 kWh per month typically involves space conditioning. These are both highly time-sensitive loads, and in the case of space-conditioning, highly seasonal. The load factors associated with these are on the order of 40% for water heat and 20% for space heat. Consequently, when production, transmission, and distribution costs are considered, the price for this usage should be much higher than for other loads. Pacific's inverted block rate is a good example of a rate design that moves the rate for incremental usage closer to incremental cost.

Q. What would those tail block rates need to be to equalize rates with long-run marginal costs?

A. The wholesale market is in the $.07/kWh range off-peak, and $.10/kWh range on-peak. Space conditioning demands have low load factors, and I have therefore assumed that they are experienced primarily during on-peak periods. Transmission and distribution demand costs amount to about $.02/kWh for water heat and $.04/kwh for space heat, again based on the typical load factors for each. The ideal residential rate design for Pacific would look something like the table below. I have reduced the first block rate to roughly offset the increase in the second and third blocks.

Table 5: Sample Alternative Residential Rate Design

Usage Block	Power Supply Cost	Delivery Cost	Total Rate
0 – 600 kWh	$.02	$.01	$.03
600 – 1,200 kWh	$.07	$.02	$.09
1,200 kWh +	$.10	$.04	$.14

The problem with this type of rate design is that the utility's long-run marginal costs may be quite different from its short-run marginal costs (which would not include changes in the transmission or distribution demand costs). In a warm winter, the utility would still incur capacity costs to serve a cold-year load, but would not receive the expected revenue. The short-run revenue instability would create additional risks for shareholders (which would need to be compensated in the revenue requirement).

Q. What utilities have this type of rate design?

A. Rates with tailblocks based on long-run marginal cost are increasingly common among water utilities. These utilities make huge investments to serve summer-peaking irrigation load, and many have established 3-block (Seattle, Olympia) and 4-block (Lacey) rates. These insure that the customers who impose only a sporadic demand on the utility pay the full costs of the reserve capacity needed to meet that sporadic demand, so that those costs are not shifted onto customers with more stable usage patterns. Seattle's current water rate is of the following form:

Table 6: Seattle Water Rate Design

Usage Block	**Rate per 100 Cubic Feet (Inside Seattle; higher rates outside city limits)**
Off-Peak (Sept. 16 – May 15)	$2.53
Summer, first 500 Cubic Feet	$2.88
Summer, Next 1300 Cubic Feet	$3.35
Summer, Over 1800 Cubic Feet	**$8.55**

Source: http://www.ci.seattle.wa.us/util/Services/Water/Rates/RESIDENTIA_200312020910286.asp.

Q. What would a fixed/variable rate design look like?

A. A fixed/variable rate design would recover all of the utility's fixed costs in a monthly fixed fee, with a variable rate to recover only variable power supply costs. An example might be those of some electric cooperatives buying all of their power from the Bonneville Power Administration for $.03/kWh, for whom all power costs are variable, but essentially all other costs are fixed:

Table 7: Sample Fixed/Variable Rate Design

Rate Element	**Rate**
Customer Charge	$25/month
Energy Charge	$.033/kWh ($.03 + 10% line losses)

Such a rate design provides complete stability to the utility in the short run, making it indifferent from a net revenue perspective to the customer's usage in any given month or year. This type of rate completely ignores the shape or season of the customer's load, the impact that load has on long-term resource costs for Bonneville, or the incremental cost of meeting load growth or installing additional distribution capacity. Mr. Cavanagh has criticized this type of rate design at page 4 of his testimony, and I concur in his criticism.

Q. What is a lost margin recovery mechanism?

A. Lost margin mechanisms are simple methods targeted at conservation program savings to eliminate the real or perceived adverse impact on earnings from lower sales. A number of regulatory commissions have approved mechanisms for utilities to recover the lost distribution margins associated with their conservation program efforts. These are as simple as estimating the conservation savings of specific programs, measuring the distribution margin embedded in rates, and allowing for a surcharge to recover those lost margins. An example of this exists in Hawaii, where Hawaiian Electric Company (HECO) has been allowed lost margin recovery for its conservation programs since 1992. That is the subject of a proceeding now underway, and I expect the mechanism will change significantly.

Q. What are the problems associated with lost margin mechanisms?

A. There are two problems. First, they may create an incentive for the utility to present flawed data on the amount of savings. If a utility invests in "conservation" that does not work, but submits documentation suggesting significant savings, it can collect *both* a lost margin recovery payment *and* continue to make sales that generate distribution margins. Second, lost margin mechanisms can have significant cumulative effects if a utility goes many years without a general rate case, building up very large surcharges which can engender consumer opposition to cost-effective conservation programs.

Q. Can the problems with lost margin mechanisms be overcome?

A. I believe so. An independent evaluation contractor accountable to the Commission should be utilized to measure savings. The term of lost margin recovery should be limited to three years; after that time, if the utility finds a shortfall in revenue, it would need to file a general rate case. In Hawaii, where I have experienced this mechanism, there are no interconnections and no wholesale sales, and the utility has a fully-reconciled power cost adjustment mechanism, so all marginal power cost impacts are flowed through. For a utility like Pacific, with extensive interconnections and without a fuel adjustment clause, a means of recognizing wholesale market impacts would be essential.

Q. What type of shareholder incentive programs have been used to overcome utility reluctance to implement conservation programs?

A. Washington had a 2% bonus return on equity for conservation investments from 1980 to 1990. It was not particularly effective. Hawaii has a shared-savings incentive in place that has been fairly effective, but is now controversial mostly because the utility has gone 13 years without a general rate case.

Q. What other type of shareholder incentives do you think could be considered?

Other types of incentives that could be considered include tying the rate of return to change in usage per customer, or linking executive compensation inversely to changes in sales volumes.

Q. What about separating conservation programs entirely from the utilities. Is this a realistic option?

A. Yes it is, and both Oregon and Vermont have done so with quite beneficial effects. Efficiency Vermont receives a percentage of each utility's revenue, and invests this in statewide energy efficiency programs. The Energy Trust of Oregon does the same thing, except that (to date) it has contracted with some utilities to continue operating the programs. In both cases, however, since the conservation funding is under the control of an entity that does not care about lost revenues, and has as its only mission to achieve cost-effective conservation, the lost margin issue is irrelevant to program design or implementation.

Q. Of these alternatives to decoupling, which do you think are most promising for Washington?

A. I believe that a combination of rate design changes and independent program management are the best option.

Rates should be based on long-run incremental costs, with tail blocks high enough to recover marginal demand and energy costs to serve space conditioning loads. The rate design joint testimony in this proceeding moves in this direction for the residential class.

I also believe that the Commission should explore separating conservation funding from the utilities, so that the lost margin and executive compensation issues do not interfere with optimal program design. In my opinion, even a properly designed decoupling mechanism is a second-best approach to conservation program development. Prices that accurately reflect the high cost of meeting sporadic loads, and program funding to assist customers in avoiding these costs, will work well to achieve system goals.

Q. Is there an adequate record in this proceeding to move forward with either Mr. Cavanagh's decoupling proposal or any of the alternatives you have discussed?

A. I do not believe so. Any of the options would require an extensive Commission process to implement. I do not suggest that Mr. Cavanagh's proposal for a decoupling mechanism, nor my limited description above of alternatives, is adequate to support a move to this type of incentive regulation in this proceeding. If the Commission desires to explore options to align utility interests with consumer interests, including decoupling and its alternatives, it should convene a docket for that purpose.

Q. Would it be wise to move forward with Mr. Cavanagh's proposal on a pilot basis for a limited test period?

A. No. In my opinion, a poorly designed decoupling mechanism would be a step in the wrong direction. As proposed by Mr. Cavanagh, the Company's current conservation programs would become a poorly designed and inappropriate profit center, compensating the utility with bonus payments for lost revenues, when in fact the utility would experience gained revenues in the wholesale market.

Alternatively, if the decoupling mechanism were properly designed to be "earnings neutral" it would require Pacific to refund wholesale sales revenues to the extent they exceed lost retail revenues. This would effectively penalize Pacific Power for pursuing conservation programs due to the relatively unusual situation of Pacific's retail rates being lower than wholesale market prices. The status quo is a stronger incentive for conservation than a formal decoupling mechanism under these conditions.

In a California-type situation, with a power cost adjustment mechanism to address wholesale power transactions, and with relatively high retail rates compared with wholesale market prices, a decoupling mechanism is probably appropriate. In Washington with the mix of resources and the character of costs on the Pacific Power system, it is not. The Company is already effectively "more than decoupled."

Q. Does this complete your rebuttal testimony?

A. Yes.