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April 26, 2013

Mr. David E. Danner
Executive Director and Commission Secretary
Washington Utilities and Transportation Commission,
P.O. Box 47250
1300 S. Evergreen Park Drive, S.W.
Olympia, Washington 98504-7250

Re: Docket No. UE-130137/UG-130138 and UE-121697/UG-121705

Dear Mr. Danner:

Enclosed please find two originals and one (1) copy each of the PREFILED RESPONSE TESTIMONY OF KEVIN C. HIGGINS on behalf of THE KROGER CO. for filing in the above-referenced matters. I also include an additional sixteen (16) copies for internal distribution at the Commission. Please note that we also e-filed the above in both dockets on same date.

By copy of this letter, all parties listed on the Certificate of Service have been electronically served. Please place this document of file.

Very Truly Yours,

Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Enclosures
cc: Certificate of Service

EXHIBIT NO. ____(KCH-1T)
DOCKET NO. UE-130137/UG-130138
& UE-121697/UG-121705

2013 PSE EXPEDITED RATE FILINGS
& DECOUPLING PROPOSALS
WITNESS: KEVIN C. HIGGINS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-130137** **Docket No. UG-130138** **Docket No. UE-121697** **Docket No. UG-121705**

PREFILED RESPONSE TESTIMONY OF
KEVIN C. HIGGINS
ON BEHALF OF THE KROGER CO.

April 26, 2013

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RESPONSE TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

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

Q. On whose behalf are you testifying in the electric portion of the Expedited Rate Filing ("ERF") proceeding, UE-130137, and the electric portion of the decoupling proceeding, UE-121697?

A. My testimony is being sponsored by The Kroger Co. ("Kroger") on behalf of its Fred Meyer Stores and Quality Food Centers divisions. Kroger is one of the largest retail grocers in the United States, and operates approximately 120 facilities in the state of Washington, approximately 65 of which are located in the territory served by Puget Sound Energy ("PSE"). These facilities purchase more than 145 million kWh annually from PSE, and are served on Electric Rate Schedules 24, 25, 26, and 40.

I am simultaneously filing testimony in the gas portion of ERF proceeding, UG-130138, and the gas portion of the decoupling proceeding, UG-

121705 on behalf of Nucor Steel Seattle Inc. ("Nucor").[1] My testimony filed on behalf of Nucor is entirely consistent with the testimony I am presenting here on behalf of Kroger, but focuses on gas-related aspects of these cases.

Q. Please describe your professional experience and qualifications.

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

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

Q. Have you previously testified before this Commission?

A. Yes. I testified in the PSE 2011, 2009, 2007, 2006, 2004, and 2001 general rate cases and participated in the settlement discussions that resulted in partial settlement agreements pertaining to rate spread and rate design issues in those proceedings. I also testified in the 2009 proceeding that addressed the treatment of revenues from PSE's sales of Renewable Energy Credits ("RECs").

[1] Nucor Exhibit No. __ (KCH-5T).

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

A. Yes. I have testified in approximately 165 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, West Virginia, and Wyoming.

<u>Overview and Recommendations</u>

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

A. My testimony responds to the Expedited Rate Filing ("ERF") made by PSE on February 1, 2013 in Dockets UE-130137 and UG-130138, and to the Amended Decoupling Petition filed by PSE and the NW Energy Coalition ("Joint Parties") on March 1, 2013 in Dockets UE-121697 and UG-121705. My understanding is that both of these filings are being supported by the three parties to the Multiparty Settlement Agreement filed with the Commission on March 22, 2013. Consequently, my testimony is also responding to that Agreement.

Q. Please summarize your conclusions and recommendations.

(1) Kroger neither supports nor opposes the revenue requirement provisions proposed by PSE in the ERF, except as it is necessary to modify the return on equity ("ROE") applicable to electric and gas delivery rate base as part of any adoption of full revenue decoupling in these proceedings.

(2) PSE's proposed electric rate spread approach in the ERF is reasonable and I recommend that it be adopted if the ERF is approved.

(3) The K-factors proposed by the Joint Parties in the decoupling proceeding would introduce an automatic, predetermined cost escalator into rates. The proposed K-factor rate increases are not known and measurable adjustments presented in the context of a rate proceeding. Rather they are arbitrary and unsubstantiated rate increases that should be rejected by the Commission.

(4) I recommend that the entire revenue decoupling package proposed by the Joint Parties be rejected. Failing that, I recommend that the proposal be modified in several important ways. If full revenue decoupling is approved by the Commission, the proposal by the Joint Parties should be modified as follows:

(a) The ROE applicable to electric and gas delivery rate base should be reduced by 25 basis points in the ERF to reflect the reduction in PSE's risk. This adjustment would reduce the ERF electric revenue requirement by approximately $5.1 million and the ERF gas revenue requirement by approximately $3.1 million.

(b) The decoupling mechanism proposed by the Joint Parties should be modified to incorporate any found margin associated with growth in customer count as a credit against the proposed RDA balancing account.

(c) Customers with billings demands of greater than 350 kW (e.g., Rate Schedules 26, 31, and 40) should be excluded from the decoupling mechanism. At a minimum, before subjecting these customers to revenue decoupling, PSE should be required to investigate means through which its potential loss of fixed-cost recovery can be mitigated through rate design, including increasing its demand charges for delivery service to better align with the recovery of fixed costs.

(d) If the customer groups identified in 4(c) above are not excluded from the decoupling mechanism, then the mechanism should be modified such that a reasonable portion (e.g. 50%) of the demand-billed delivery revenues are excluded from the revenue decoupling adjustment (i.e., are treated as unvarying with kWh variations), similar to the treatment employed in Arizona, as discussed in my testimony.

(e) Schedule 139 should be redesigned as a demand charge for demand-billed customers. Failure to properly design Schedule 139 as a demand charge will result in shifting of cost responsibility among demand-billed customers.

Expedited Rate Filing - Dockets UE-130137 and UG-130138

Q. What is PSE seeking as part of its ERF?

A. As explained in the direct testimony of PSE witness Katherine J. Barnard, PSE is seeking approval of an ERF that would increase electric rates by $32.2 million, or 1.6 percent on average,[2] and reduce natural gas rates by $1.2 million, 0.1 percent on average (inclusive of gas costs).[3]

[2] Supplemental direct testimony of Katherine J. Barnard, p. 7.
[3] Ibid., p. 11.

Power costs and property tax-related costs are excluded from the calculation of the electric revenue deficiency because the former already has a separate recovery mechanism and the latter is proposed to have a separate tracker in this case. The template for determining the revenue deficiency is the Commission Basis Report ("CBR") filed by the Company, with certain modifications. Chief among the modifications is PSE's proposed use of end-of-period rate base rather than average-of-period rate base.

Q. What is Kroger's position with respect to PSE's proposed ERF revenue requirement?

A. Kroger neither supports nor opposes the core revenue requirement proposal associated with the ERF. As I understand PSE's proposal, the ERF is proposed to be a "one-time event" rather than an annual occurrence. Given the relatively modest size of the proposed ERF rate increase, Kroger has elected to focus its efforts on the Company's decoupling proposal, along with its appurtenant features, which have longer-term implications for customer rates and ratemaking policy than the ERF.

Q. Does this mean that your testimony has no implications for the ERF revenue requirement?

A. No. If full revenue decoupling is approved, I am recommending an adjustment to PSE's allowed return on equity ("ROE"), which has implications for the ERF revenue requirement. As I explain later in my testimony, I am recommending that the Commission reject PSE's decoupling proposal. If this recommendation is accepted, then my testimony would have no impact on PSE's proposed ERF revenue requirement.

Q. How does PSE propose to spread its proposed ERF electric rate increase across customer classes?

A. As explained by PSE witness Jon A. Piliaris, PSE based its proposed rate spread on the results of the cost of service model submitted with its compliance filing in UE-111048. These results were adjusted by removing the allocated costs related to the Power Cost Adjustment mechanism and property taxes. PSE's proposed rate spread assigns each customer class its share of the ERF-related costs, with the exception of two classes that would have exceeded the 3.0 percent limit in WAC 480-07-505 applicable to an expedited rate filing. The rate increase for these two classes was capped at 2.9 percent, with the shortfall of approximately $262,000 being absorbed by PSE.

Q. What is your assessment of PSE's proposed approach to rate spread?

A. In my opinion, the Company's rate spread approach is reasonable and I recommend that it be adopted if the ERF is approved.

<u>Revenue Decoupling - Dockets UE-121697 and UG-121705</u>

Q. What have PSE and the NW Energy Coalition proposed with respect to revenue decoupling?

A. As discussed in the supplemental direct testimony of Mr. Piliaris, the Joint Parties have put forth a rate plan and a pair of electric and gas decoupling proposals. The rate plan is a series of predetermined annual rate increases implemented through a metric that PSE calls the "K-factor." The proposed rate plan would extend at least through March 2016 and possibly through March 2017. As part of its proposal, and subject to certain caveats, PSE would not file its next general rate case before April 1, 2015, but would file it no later than April 1, 2016, unless otherwise agreed to by the parties in the Company's last general rate case.

The decoupling proposal envisions full revenue decoupling applied to fixed delivery costs for almost all electric and gas customer classes.[4] The revenue decoupling would be implemented through an "allowed revenue per customer" metric. The decoupling proposal is tied to the proposed rate plan in that each year's allowed revenue per customer would be increased via the K-factor. Thus, the overall proposal should be viewed as a combination "predetermined rate increase/decoupling" package extending over a multi-year period.

Q. What is your assessment of the Joint Parties' decoupling proposal?

A. I recommend that the entire package be rejected. Failing that, I recommend that the proposal be modified in several important ways.

Q. Please explain your reasons for recommending that the decoupling proposal be rejected.

A. Taken as a whole I do not believe this proposal constitutes good ratemaking, nor do I believe it is in the public interest. For purposes of this discussion, it is useful to separate the K-factor component of the rate plan from the rest of the decoupling proposal. Even though these components are tied

[4] The proposed exceptions are gas lighting, gas water heater rental, electric lighting, and electric retail wheeling. The rates for these classes, however, would be subject to the proposed K-factor increases. Gas customers served under special contracts are also excluded from the decoupling proposal.

together in the Joint Parties' proposal, decoupling does not require adoption of predetermined annual rate increases nor does a rate plan consisting of predetermined annual rate increases require decoupling. Indeed, the proposed K-factor scheme and the proposed decoupling mechanism are conceptually distinct, independent features that should be evaluated on their own merit.

Q. What is your assessment of the K-factor proposal?

A. The K-factor proposal is an attempt to introduce an automatic, predetermined cost escalator into rates. The proposed K-factor for electric service is 1.03 and would apply to all revenue requirements except power costs and property taxes. Essentially, the K-factor hardwires a 3 percent annual cost increase into the applicable cost components, which would then automatically flow into customer rates. Extended over the potential term of the proposed rate plan (which could extend beyond the start of 2017), the revenue requirement for the affected electric cost components would increase 15.9 percent.

The proposed K-factor rate increases are not known and measurable adjustments presented in the context of a rate proceeding. Rather they are arbitrary and unsubstantiated rate increases that should be rejected by the Commission. PSE justifies the proposed level of these factors by referencing a calculation prepared by Ms. Barnard that results in an electric K-factor of 1.0406 measured over the period 2006-2011.[5] Ms. Barnard's calculation was prepared using rate base and depreciation expense increases over that time period combined with a projection of O&M inflation that includes a small productivity adjustment. However, a trend line of past cost increases (blended with an

[5] Supplemental direct testimony of Katherine J. Barnard, p. 7.

inflation forecast) does not constitute a reasonable basis for locking in broadly applicable rate increases in the future, particularly over a multi-year period.

Moreover, Ms. Barnard's K-factor results are very sensitive to the time period selected. Selecting a time period that starts just one year later (2007-2011) reduces her calculation of the electric K-factor from 1.0406 to 1.0329.[6] In addition, her measurement of the growth in rate base does not take into account that rate base in 2011 was skewed upward because the Company could not fully reflect the accumulated deferred income tax ("ADIT") that would have otherwise applied in that year. ADIT, which in this context is an offset to rate base, was truncated in 2011 because PSE registered a net operating loss for tax purposes that year and therefore could not fully utilize the bonus tax depreciation deduction otherwise available to the Company. The depreciation deduction can be carried forward for up to twenty years; thus PSE will ultimately realize this tax benefit – but customers did not see the benefit of the offset to rate base in 2011 associated with the carried forward amount. The upshot is that had ADIT not been truncated in 2011 due to the artifact of PSE's net operating loss, rate base would have been lower, and Ms. Barnard's K-factor would have been lower as a result. Adjusting for this circumstance further reduces Ms. Barnard's K-factor to 1.0322 over the 2007-2011 period. This calculation is presented in Kroger Exhibit No.__ (KCH-2).[7] My point here is not to quibble over the math behind the K-factor, but rather to observe that any "concession" PSE is making in proposing an electric K-factor of 1.03 is more apparent than real.

[6] This can be calculated from the information in PSE Exhibit No.__ (KJB-3). A similar impact occurs for the gas K-factor calculated by Ms. Barnard which would be reduced to 1.0299.
[7] This exhibit also presents a comparable recalculation of the K-factor for gas (pp. 3-4).

More generally, the Commission should be concerned about regulatory pricing formulations such as the K-factor proposal that reinforce inflation. This occurs when projections of inflation are built into formulas that are used to set administratively-determined prices, such as utility rates. Such pricing mechanisms help to make inflation a self-fulfilling prophecy. Regulators should use extreme caution before approving prices that guarantee inflation before it occurs.

A related, but distinct, concern involves the building of a K-factor "cost cushion" into the Company's base period costs. The cost increases represented by escalation factors may or may not come to fruition. In any case, PSE should be expected to strive to improve the efficiency of its operations on a continuous basis, and thereby lessen the net impact of inflation on its costs. It is not reasonable to gross up the Company's base period costs by an arbitrary escalation factor and pass these costs on to customers. As I pointed out above, there is nothing inherent in revenue decoupling that calls for this type of underlying cost escalation. If the Commission is inclined to approve revenue decoupling (my discussion below notwithstanding), the K-factor portion of the Company's filing can be readily excised and discarded.

Q. Has the K-factor concept advocated by PSE always been structured as an automatic, predetermined cost escalator?

A. No. The K-factor proposal has had an interesting recent history. In the Company's initial filing in this docket, the K-factor was structured as an adjustment that would account for changes in weather-normalized delivery revenue attributable to PSE-sponsored energy conservation.[8] Its sole purpose was to adjust allowed revenues-per-customer in the prior calendar year upward to account for energy conservation that was not otherwise captured in that period's billing determinants – because part of that period's billing determinants would also reflect underlying growth in usage-per-customer that would offset a portion of the energy conservation savings. PSE apparently believes it is entitled to capture the benefits of that underlying growth in usage-per-customer – even if full decoupling is implemented – and the K-factor was proposed as a means to allow the Company to do so. While the merits of PSE's initial K-factor arguments may be debatable, it was at least structured to capture the specific effects of energy conservation on its billing determinants. Fully fourteen pages of Mr. Piliaris's (initial) direct testimony are devoted to explaining and defending the K-factor.

This initial conceptualization behind the K-factor has now been completely abandoned by the Joint Parties in favor of a pure cost escalator. The rationale for the "new" K-factor bears no resemblance to the initial proposal. The only thing the new and old K-factors have in common is that they are each a means of increasing rates to customers.

Q. How does the size of the "new" K-factor compare to the original proposal filed by PSE?

A. In his initial direct testimony, Mr. Piliaris calculated electric system K-factors of 1.016880 (non-residential) and 1.017231 (residential) for calendar year 2011.[9] The "new" electric K-factor of 1.03 escalates costs at a 75 percent faster

[8] Direct testimony of Jon A. Piliaris, p. 15.
[9] PSE Decoupling Exhibit No.__ (JAP-5).

rate – and consequently will produce rate impacts on customers that are about 75 percent greater than the original formulation.

Q. Putting aside the matter of the proposed K-factor, what is your recommendation with respect to the revenue decoupling proposal being advanced by the Joint Parties?

A. I recommend that the revenue decoupling proposal be rejected, even if the K-factor component is removed. Failing that, I recommend that it be modified in several material ways.

Q. Please explain the reasons for your recommendation to reject the decoupling proposal.

A. I note at the outset that I have carefully reviewed the Commission's report and policy statement ("Report") on decoupling issued in Docket No. U-100522. I recognize that the Commission determined that it:

> ...will consider a full decoupling mechanism for electric and natural gas utilities, which will allow a utility to either recover revenue declines related to reduced sales volumes or, in the case of sales volume increases, refund such revenues to its customers. [Report at Par. 28]

However, in reaching this determination, the Commission identified two significant concerns that gave it pause. First, the Commission recognized that relatively few other state commissions have adopted any form of decoupling for electric utilities, and that only some of those mechanisms were full decoupling mechanisms. [Report at Par. 25] This condition is still true today. If the Commission were to adopt full revenue decoupling for PSE's electric service, the Commission would be in the company of a relatively small minority of commissions nationwide, a fact – and concern – recognized in the report and policy statement.

Second, the Commission expressed concern that full revenue decoupling, particularly in combination with an energy cost recovery mechanism that reduces an electric utility's financial risk due to changes in power costs, could cause a utility to lose some of its incentive to manage itself in a manner that constantly looks to reduce costs. [Report at Par. 26]

In light of these concerns, the Commission's willingness to consider full revenue decoupling places significant weight on the expectation that full revenue decoupling: (1) would benefit customers by *reducing utility equity costs* and (2) would include proper recognition of "found margin." A cornerstone finding in the Commission's report and policy statement holds as follows:

> …while a close call, we believe that a properly constructed full decoupling mechanism that is intended, between general rate cases, to balance out both lost and found margin from any source can be a tool that benefits both the company and its ratepayers. By reducing the risk of volatility of revenue based on customer usage, both up and down, such a mechanism can serve to reduce risk to the company, and therefore to investors, which in turn should benefit customers by reducing a company's debt and equity costs. This reduction in costs would flow through to ratepayers in the form of rates that would be lower than they otherwise would be, as the rates would be set to reflect the assumption of more risk by ratepayers. [Report at Par 27. Footnotes omitted.]

The proposal by the Joint Parties fails to deliver on this key attribute of revenue decoupling identified by the Commission; that is, the proposal fails to reduce the cost of PSE's equity that flows through to customers in exchange for the assumption of greater ratepayer risk. Moreover, the proposal does not provide for full recognition of found margin to offset the lost margin that would be charged to customers, and thus, is deficient in fully providing this offset that is highly emphasized in the Commission's report and policy statement. In short, the Joint Parties' proposal is a one-sided proposition that burdens customers with the negative characteristics of full revenue decoupling without providing the key benefits that the Commission stressed in its report and policy statement.

Q. What are the negative characteristics of full revenue decoupling from the perspective of customers?

A. At the most fundamental level, decoupling is as much a "revenue assurance" mechanism as it is a "conservation enabling" mechanism. As such, it is sure to capture a much wider range of effects than just customer responses to utility-sponsored energy efficiency programs, even though the latter constitutes the underlying justification for its adoption. For example, decoupling provides unwarranted insulation to the utility from the effects of price elasticity. Generally, all sellers of goods face a risk that price increases will reduce sales. But, with full revenue decoupling, if customers respond to utility rate hikes by reducing their electricity, fixed charges are increased to compensate the utility for any resultant reduction in per-customer usage. Such an increase reflects an undue transfer of risk from utilities to customers.

Further, to the extent that customers reduce usage in response to economic conditions or otherwise practice self-funded energy conservation, these behaviors will be captured in the decoupling adjustment and unduly increase rates to customers. The increase in rates to customers from these actions that would accompany full revenue decoupling is a further example of a transfer of utility business risk to customers, which is a negative characteristic of full revenue decoupling from a customer perspective. Even though, under certain circumstances, full revenue decoupling can result in decreased unit charges as well as increased unit charges, customers are not seeking to have their rates subject to this increased volatility.

Full revenue decoupling also suffers from the infirmities of single-issue ratemaking, which occurs when utility rates are adjusted in response to a change in a single cost or revenue item considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. To consider some costs or revenues in isolation might cause a commission to increase rates to remedy the single issue of concern without recognizing counterbalancing savings in another area. For this reason, single-issue ratemaking, absent a compelling public interest, is generally not sound regulatory practice.

In light of these drawbacks for customers, if full revenue decoupling is imposed on customers, then it is essential that the benefit of lower equity costs be recognized in customer rates. Failure to adjust ROE would ignore one of the central tenets in the Commission's report and policy statement.

Q. How is ROE addressed in the Joint Parties' decoupling proposal?

A. The proposal contains no adjustment in the Company's ROE to reflect full revenue decoupling. Rather, the Joint Parties propose to allow PSE to continue to earn the 9.8% ROE ordered by the Commission in Docket Nos. UE-111048 and UG-111049, subject to an earnings test. The earning test would allow PSE to earn up 25 basis points above its overall rate of return on rate base before rebating to customers 50 percent of the earnings in excess of this level.[10]

Q. Have other commissions required reductions in allowed ROE when adopting revenue decoupling?

A. Yes. The reductions have generally ranged between 10 basis points and 50 basis points.

For example, the Public Service Commission of Maryland reduced the ROE for Potomac Electric Power Company ("Pepco") by 50 basis points upon approval of a Bill Stabilization Adjustment ("BSA"), a form of decoupling, stating the following in its July 19, 2007 order:

> The BSA, which the Commission has approved, will provide insurance that Pepco will achieve its level of revenue approved in this case. Thus, Pepco is less risky with the BSA than without it. In response to this decline in risk, all parties recognize the appropriateness of reducing Pepco's return on equity by some amount...Given that approval of the BSA will result in improved cost recovery by Pepco, the Commission shall reduce Pepco's ROE by 50 points, to 10 percent.[11]

Concurrent with its decision in the Pepco rate case, the Public Service Commission of Maryland also applied at 50 point reduction to Delmarva Power & Light Company's ROE due to approval of a BSA.[12]

Pepco received the same 50 basis point ROE reduction in the Washington D.C. jurisdiction, when the District of Columbia Public Service Commission approved a BSA in its September 28, 2009 order, stating:

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[10] Supplemental direct testimony of Jon A. Piliaris, p. 19.

[11] Order No. 81517, Case No. 9092, *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rates and Charges for Electric Service and for Certain Rate Design Changes.* Order at 72.

[12] Order No. 81518, Case No. 9093, *In the Matter of the Application of Delmarva Power and Light Company for Authority to Revise its Rates and Charges for Electric Service and for Certain Rate Design Changes*. July 19, 2007.

Given the positive financial implications associated with the implementation of the BSA as discussed by Pepco Witness Morin, OPC Witness Larkin and AOBA Witness Oliver, the Commission finds that a 50 basis point adjustment to the return on equity is reasonable. A 50 basis point reduction in ROE as part of the approval of the BSA balances the ledger by providing a benefit to consumers in exchange for the benefit to the Company and shareholders of reaping lowered business risk.[13]

The Tennessee Regulatory Authority decided upon a 25 basis point ROE reduction for Chattanooga Gas Company as a result of approving a decoupling mechanism in its November 8, 2010 order, stating:

...[T]he panel found that the evidence presented by the parties made clear that decoupling impacts the return on equity by reducing risks, although both parties presented different views on both the direction and magnitude of the required adjustment. Having carefully reviewed the record, the panel voted unanimously to adopt the conservative estimate of a twenty-five basis point reduction to equity return based upon the rate design adopted by the panel.[14]

Similarly, in 2009, the Public Utilities Commission of Nevada reduced Southwest Gas Company's ROE by 25 basis points due to approval of a decoupling provision.[15]

In 2007, the New York State Public Service Commission ordered a 10 basis point reduction to the allowed ROE of National Fuel Gas Distribution Corporation ("NFG") as a result of adopting a decoupling mechanism, stating:

Given that the revenue decoupling mechanism we are adopting may reduce NFG's earnings volatility, that most of the companies in Staff's proxy group do not have revenue decoupling mechanisms, and that the effects of revenue decoupling mechanisms have long been considered by investors and factored into the financial market data for natural gas firms, we will apply a 10 basis points

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[13] Order No. 15556, Formal Case No. 1053, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* Order at 9.

[14] Docket No. 09-00183, *Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs and Implementation of a Revenue Decoupling Mechanism*. Order at 45.

[15] Docket No. 09-04003, Opening findings of fact and conclusions of law, *Application of Southwest Gas Corporation for authority to increase its rates and charges for natural gas service for all classes of customers in Southern and Northern Nevada*. November 3, 2009.

reduction to NFG's 9.20% cost of equity and will set its allowed return on equity at 9.10%.[16]

The New York State Public Service Commission also approved a settlement that reduced St. Lawrence Gas Company's ROE by 10 basis points due to the adoption of a decoupling mechanism on December 18, 2009.[17]

In its February 5, 2008 order, The Illinois Commerce Commission similarly ordered a 10 basis point ROE reduction for North Shore Gas Company and The Peoples Gas Light & Coke Company upon approval of a Volume Balancing Adjustment ("VBA"), a pilot decoupling program:

> The Commission finds that Rider VBA will lessen the Utilities' risk associated with their cash flow. Moreover, we agree with Staff's recommendation that there should be a downward adjustment to the cost of common equity to account for the reduced risk associated with the accepted riders...Overall, we find the record to support a downward adjustment, and in the absence of an exact calculation we find it reasonable to reduce the return on common equity by ten (10) basis points for the duration of the pilot program.[18]

In its January 31, 2011 order, the Massachusetts Department of Public Utilities set an ROE of 9.60% for Western Massachusetts Electric Company (which had requested an ROE of 10.50%), and stated the following:

> In sum, we find that the revenue decoupling mechanism that we have approved in this case will reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement.[19]

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[16] Case 07-G-0141, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service*. Order at 40-41. December 21, 2007.

[17] Case 08-G-1392, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. for Gas Service.*

[18] Docket No. 07-0241, *North Shore Gas Company: Proposed general increase in natural gas rates*; Docket No. 07-0242, *The Peoples Gas Light and Coke Company: Proposed general increase in natural gas rates* (Consolidated). Order at 99.

[19] D.P.U. 10-70, *Petition of Western Massachusetts Electric Company, pursuant to G.L. c. 164,§94 and 220 C.M.R.§§ 5.00 et seq. for Approval of a General Increase in Electric Distribution Rates and a Revenue Decoupling Mechanism.* Order at 283.

In the Northwest, the Public Utility Commission of Oregon reduced the ROE for Portland General Electric Company ("PGE") 10 basis points to reflect the reduction in PGE's risk attributable to the approval of a decoupling mechanism.[20] I note, however, that PGE's full revenue decoupling mechanism applies only to residential customers and small commercial customers with billing demands of 30 kW or less. Customers with demands between 30 kW and 1000 kW are subject to a lost fixed cost recovery mechanism, but not full revenue decoupling. Customers with billing demands greater than 1000 kW are not subject to any lost fixed cost recovery mechanism at all.

Q. What is your recommendation to the Commission regarding the treatment of PSE's ROE if full revenue decoupling is adopted?

A. If full revenue decoupling is adopted, I recommend that PSE's ROE be reduced by 25 basis points for the functions subject to the decoupling mechanism (i.e., electric and gas delivery). This adjustment lies well within the range of ROE adjustments adopted by other commissions and is reasonable in light of the mitigation of earnings volatility that the mechanism would provide for PSE.

Q. Why is a 25 basis point reduction in ROE reasonable in light of the mitigation of earnings volatility that the mechanism would provide for PSE?

A. I examined the volatility of PSE's usage per customer over the period 2002-2011 and measured the ROE impact of this volatility using the ERF volumetric delivery revenue applied to the Company's proposed ERF rate base for electric and gas delivery services. This analysis is presented in Kroger

[20] Order No. 09-020, Docket No. UE 197, *In the Matter of Portland General Electric Company, Request for a General Rate Revision.* January 22, 2009. Order at 29.

Exhibit No. __ (KCH-3), pages 4-7. My analysis shows that the deviations in PSE's usage per customer over this period produces impacts of up to 75 basis points (with an average of 33 basis points absolute value) for the electric delivery system and up to 167 basis points (with an average of 84 basis points absolute value) for the gas delivery system. The 25 basis point ROE adjustment lies well within this range of earnings volatility and is a reasonable adjustment for removing this source of earnings volatility for the Company.

Q. How should a 25 basis point ROE adjustment be applied in this proceeding if full revenue decoupling is adopted?

A. The adjustment should be applied as part of the ERF proceeding. I have presented such adjustments as part of Exhibit No.__ (KCH-3), pages 1-2. The adjustments result in a reduction in the ERF electric revenue requirement of approximately $5.1 million and in the ERF gas revenue requirement of approximately $3.1 million.

Q. Is the ERF proceeding the appropriate venue for making this adjustment?

A. In the current circumstances, yes. As a threshold matter, the Commission's report and policy statement makes it clear that decoupling would only be considered by the Commission as part of a *general* rate case. [Report at Par. 18, 28, and 36, also esp. FN 33] The Commission is clear that the requirement for a general rate case is intended to allow for the consideration of the impact of reduced utility risk on ROE:

> In the past, the Commission has indicated that it may consider a decoupling mechanism outside the context of a general rate case...However, as was discussed at some length in this proceeding, because a decoupling mechanism may provide reduced risk for the company, it stands to reason that such reduced

risk may impact the company's appropriate return on equity. [Report at FN 33, citation omitted.]

To the extent that decoupling is considered in the current proceeding – outside a general rate case – it will obviously require an exception to this requirement as articulated in the report and policy statement. If such an exception is granted, any exception should be limited to making allowances for venue as opposed to substance; that is, an ROE adjustment to recognize the reduction in utility risk attributable to decoupling should be considered just as it would be in a general rate case proceeding. Any arguments by decoupling advocates that ROE cannot be adjusted in this proceeding because it is not a general rate case should be given no weight because considering decoupling outside a general rate case is itself precluded in the first instance. One reasonable course of action is simply to reject the decoupling proposal submitted by the Joint Parties precisely because it is occurring outside a general rate case. However, if an exception is granted to consider decoupling outside a general rate case, then a corollary exception must be granted to considering ROE. The venue selected by the Joint Parties should not be device by which the Commission's intent in considering ROE adjustments is circumvented.

As the ERF is occurring in conjunction with the decoupling mechanism, the ROE adjustment can readily be applied as part of determining the ERF revenue requirement. The Commission has determined an allowed ROE for PSE as recently as May 7, 2012.[21] This allowed ROE was established in a context in which PSE did not have an approved revenue decoupling mechanism. If full

[21] Docket Nos. UE-111048 and UG-111049.

revenue decoupling is approved in this proceeding, the ERF would provide the Commission the opportunity to make an explicit adjustment to the Company's allowed ROE to reflect the reduction in the Company's risk, consistent with the considerations discussed in the Commission's report and policy statement.

Q. Previously in your testimony you stated that the proposal by the Joint Parties does not provide for full recognition of found margin to offset the lost margin that would be charged to customers. Please explain.

A. The concept of found revenue is discussed at some length in the Commission's report and policy statement. The Commission's statement emphasizes that a properly constructed full decoupling mechanism would balance out both lost and found margin from *any* source. [Report at Par. 27. Emphasis added.] The full revenue decoupling proposal advanced by the Joint Parties recognizes found margin only to the extent that it may affect allowed revenue per customer. The proposal provides no recognition of found revenue that would be associated with growth in the number of customers. Under the terms of the proposal, the full benefit of incremental fixed cost recovery associated with new customers accrues solely to PSE.

I demonstrate this result in Exhibit No. __ (KCH-4) in which I modified the inputs in PSE Exhibit Nos.__ (JAP-18) and (JAP-22) to assume a faster rate of growth in customer count than PSE is projecting, while holding usage-per-customer (i.e., allowed revenue per customer) constant for both residential and non-residential customers. I also removed the effect of prior deferrals because deferral recovery impacts the decoupling unit charge, but does not change the apportionment of forward-looking revenue requirements between PSE and customers. As shown in Exhibit No. __ (KCH-4), lines 13-14, 100 percent of the incremental revenue recovered from the incremental customers accrues to PSE, with no recognition as an offset to lost revenues. In my opinion, the proposal is deficient in providing for full recognition of found margins and should be rejected. If full revenue decoupling is approved by the Commission, the mechanism proposed by the Joint Parties should be modified to incorporate any found margin associated with growth in customer count as a credit against the RDA balancing account.

Q. If full revenue decoupling is adopted should it apply to all electric rate schedules?

A. No. The Joint Parties have already proposed to exclude lighting and retail wheeling customers. I believe these exclusions are appropriate. However, it does not go far enough.

Maintaining a "fixed-cost recovery per customer" target – as incorporated into the Joint Parties' proposal – is not an appropriate rate design objective for classes of customers that have heterogeneous populations, and/or whose class composition shows a wide range of usage levels, such as occurs with larger non-residential customers. The fixed-cost recovery per customer of these classes will be very sensitive to the *composition* of these customers. In short, given the tremendous diversity among non-residential customers, targeting "average fixed-cost recovery per customer" as a ratemaking metric for these customers is without merit. Certainly, attempting to attribute to utility-sponsored energy conservation projects changes in "average fixed-cost recovery per customer" of non-residential customers is an unreasonable stretch.

Changes in the overall economy are far more likely to influence fixed-cost recovery per customer for non-residential customers than energy conservation programs. Application of decoupling to these customers would result in undue changes in rates in response to factors that are unrelated to energy conservation.

The recent experience of Detroit Edison is instructive in this regard. In early 2010, Detroit Edison implemented a full revenue decoupling mechanism tied to average energy usage per customer; the decoupling mechanism included larger non-residential customers, just as proposed by the Joint Parties in this case. This revenue decoupling mechanism ("RDM") had been approved the prior year by the Michigan Public Service Commission ("MPSC") against my recommendation and the recommendations of several other witnesses.[22] By late 2010, Detroit Edison concluded that that the usage-per-customer revenue RDM was subject to the very shortcomings I am warning about here and was failing to accomplish its intended purpose, particularly for larger customers. In the words of Detroit Edison witness Don M. Stanczak:

> Edison's current RDM compares average actual electric use per customer by customer class to the level of average electric use per customer used to set Edison's base rates in the last rate case, Case No. U-15768. Increases, if any, in average energy use per customer will be multiplied by the average per kWh revenue, from the last rate case, for each class; this total amount will result in customer credits. Similarly, any reductions in average energy use per customer will be multiplied by the average per kWh revenue from the last rate case, with the total being surcharged to customers...
>
> Edison's pilot RDM has been in operation since February of 2010. Based on our experience, it is clear that Edison's current RDM does not meet the requirements

[22] Michigan Public Service Commission, Case No. U-15768.

> of a well designed RDM. Edison's current RDM is highly sensitive to changes in the number of customers, particularly relative to Commercial and Industrial (C&I) customer classes, which have far fewer absolute numbers of customers than the residential class. More specifically, small changes in numbers of customers, due to such things as plant closing, customer additions, migration among customer classes, including migration to Electric Choice, and the like, have a huge impact on changes in average use per customer. As I indicated earlier, this is particularly true for the C&I customer classes which tend to have relatively low customer counts and high average electric use per customer.
>
> ...[G]iven the sensitivity to customer counts, Edison's current RDM could result in Edison improperly being required to issue refunds to customers even though Edison's [energy optimization ("EO")] programs are producing the planned sales reductions and or even if Edison's sales are declining on an absolute basis. Similarly, the RDM could as likely result in Edison surcharging customers even though its EO programs are not producing the planned energy reductions. In summary, the current Edison RDM is not accomplishing its intended purpose.[23]

Detroit Edison proposed to abandon its revenue decoupling mechanism in favor of a lost-revenues approach. Although the MPSC did not allow Detroit Edison to make this change, the MPSC's decision was ultimately rendered moot when the Michigan Court of Appeals found that the MPSC lacked authority to approve or direct the use of a revenue decoupling mechanism for an electric utility. The upshot here is that Detroit Edison's experience provides a cautionary tale about the hazards of broadly applying revenue decoupling to all classes of customers and all sources of changes in average customer usage.

Q. How have jurisdictions in the western United States treated larger non-residential customers when electric decoupling mechanisms have been adopted?

A. I am aware of only two major electric utilities in the western U.S. outside of California that have implemented full revenue decoupling: Idaho Power and

[23] Michigan Public Service Commission, Case No. U-16472. Pre-filed direct testimony of Don M. Stanczak, pp. 14-16, October 29, 2010.

Portland General Electric. Appropriately, neither of these utilities applies revenue decoupling to large non-residential customers. Idaho Power's decoupling mechanism only applies to residential customers and small commercial customers consuming 2,000 kWh per month or less. As discussed above, PGE's revenue decoupling mechanism applies only to residential customers and small commercial customers with billing demands of 30 kW or less. Customers with demands between 30 kW and 1000 kW are subject to a lost fixed cost recovery mechanism, but not revenue decoupling. Customers with billing demands greater than 1000 kW are not subject to any lost fixed cost recovery mechanism.

Q. Are you aware of any other utilities in the western U.S. that initially proposed full revenue decoupling for all customers but ultimately decided to exclude larger customers?

A. Yes. In 2011, Arizona Public Service Company proposed full revenue decoupling as part of a general rate case. Like this Commission, the Arizona Corporation Commission ("ACC") had adopted a policy statement encouraging revenue decoupling. However, consequent to settlement discussions, APS withdrew its full revenue decoupling proposal and, along with a broad spectrum of stakeholders, agreed to a lost fixed cost recovery mechanism ("LFCR") that applies only to residential customers and non-residential customers with demands below 400 kW. The LFCR mechanism includes a rate design option that allows residential customers to "opt out" of the LFCR program.

I helped negotiate the APS settlement agreement that replaced APS's full revenue decoupling proposal with the LFCR. Kroger is signatory to that agreement. The APS settlement agreement was approved by the ACC in 2012.

Q. What was the rationale for excluding larger non-residential customers from APS's LFCR mechanism?

A. APS correctly recognized that much of its concern about recovery of lost margins associated with energy conservation could be addressed through rate design for its larger customers. In particular, a concerted effort was made to ensure that as much of the utility's fixed costs as practicable were recovered from customer and demand charges for demand-billed customers.

This approach mitigated APS's concerns because both APS and the ACC Staff concluded that revenue from demand charges would not be as sensitive to changes in average customer usage as revenue from kilowatt-hour charges would be. Indeed, in determining the revenue adjustment for the LFCR, the mechanism not only excludes the portion of distribution and transmission costs that is recovered through the customer charge, it also excludes 50 percent of such costs recovered through non-generation/non-transmission demand charges.

Q. Does this latter point have implications for the revenue decoupling mechanism proposed by the Joint Parties?

A. Yes. PSE proposes no such exclusion for the revenues recovered from demand charges. Indeed, the metric that PSE intends to use to measure "actual" revenues-per-customer for non-residential customers is *imputed* based solely on changes in kilowatt-hour sales[24] – even though a substantial portion of the revenues collected for delivery service from demand-billed customers is in the form of demand charges. To the extent that revenue sensitivity of PSE's demand revenues is less than that of kilowatt-hour revenues, this imputation will overstate the changes in revenue-per-customer attributable to changes in -per-customer (for demand-billed customers). In short, the "actual" revenues-per-customer that the Joint Parties propose to use in the calculation of the decoupling rider for demand-billed customers is not actually *actual* – and will likely overstate the decoupling adjustment for these customers. The likelihood of this overstatement is even greater when one considers that PSE's tariff contains demand ratchets for Schedules 26-P, 31, and 49, which further dampen the volatility of revenues collected from the demand charge.

Q. What is your recommendation to the Commission regarding PSE's proposed imputation of changes in revenue-per-customer for demand-billed customers using only kilowatt-hour sales?

A. The imputation proposed by the Joint Parties is problematic and underscores the inherent inapplicability of full revenue decoupling for larger non-residential customers. If full revenue decoupling is adopted by the Commission, customers with billings demands of greater than 350 kW (e.g., Rate Schedules 26, 31, and 40) should be excluded from the mechanism. At a minimum, before subjecting these customers to revenue decoupling, PSE should be required to investigate means through which its potential loss of fixed-cost recovery can be

[24] See for example, PSE Exhibit No.__ (JAP-22), p. 2, lines 5-7.

mitigated through rate design, including increasing its demand charges for delivery service to better align with recovery of fixed costs.

If these customers are not excluded from the mechanism, then the mechanism should be modified such that a reasonable portion (e.g. 50%) of the demand-billed delivery revenues are excluded from the revenue decoupling adjustment (i.e., are treated as unvarying with kWh variations), similar to the treatment employed in Arizona.

Q. What rate design is proposed by the Joint Parties for recovering the decoupling rate adjustment?

A. The Joint Parties propose to recover the decoupling rate adjustment (Schedule 139) through a kWh charge.

Q. If a revenue decoupling mechanism is adopted, do you believe this proposed rate design is reasonable?

A. No. Schedule 139 does not have an appropriate rate design for demand-billed customers. The decoupling adjustment would consist exclusively of delivery-related costs. Although PSE maintains that it is "unable to determine" its current rate design for delivery services (because its rates are not functionally unbundled),[25] there can be little question that the preponderance of these costs are demand-related.

The costs of distribution service – the major component of delivery service – are properly classified as either customer-related or demand-related; they are not generally considered to be energy-related. There is little or no reason for the cost of distribution service to be recovered using an energy charge from

[25] PSE Response to Kroger Data Request 3-003.

demand-billed customers. Consequently, if revenue decoupling is adopted and it is applied to non-residential customers, Schedule 139 should be designed as a demand charge for demand-billed customers. Failure to properly design Schedule 139 as a demand charge will result in shifting of cost responsibility among demand-billed customers.

Q. Does this conclude your response testimony?

A. Yes, it does.

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-130137** **Docket No. UG-130138** **Docket No. UE-121697** **Docket No. UG-121705**

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Kevin C. Higgins, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies, L.L.C., in Salt Lake City, Utah;

2. He is the witness who sponsors the testimony entitled "Response Testimony of Kevin C. Higgins on Behalf of the Kroger Co.";

3. Said testimony was prepared by him;

4. If inquiries were made as to the facts in said testimony and exhibits he would respond as therein set forth; and

5. The aforesaid testimony is true and correct to the best of his knowledge, information and belief.

Kevin C. Higgins

Subscribed and sworn to or affirmed before me this 23rd day of April, 2013, by Kevin C. Higgins.

Notary Public

Notary Public
DANIKA HOLMES
Commission #606101
My Commission Expires
February 07, 2015
State of Utah

ELECTRIC K-FACTOR CALCULATION USING 2007 TO 2011 ESCALATION FACTORS WITH ADJUSTMENT FOR NOL CARRYFORWARD IMPACT

LINE NO.		2011 GRC REVENUE REQUIREMENT A	% OF REVENUE REQUIREMENT B	ESCALATION FACTOR C	WEIGHTED ESCALATION D
					(Col B x Col C)
1	ELECTRIC				
2	Ratebase related	189,360,556	28%	5.3%	1.48%
3	Expense excl depn	338,591,412	50%	1.9%	0.95%
4	Depn/Amort	150,830,212	22%	3.5%	0.78%
5	Total Electric ERF related Revenue Requirement	678,782,179	100%		**3.22%**

ELECTRIC K-FACTOR CALCULATION PRESENTED BY PSE[1]

LINE NO.		2011 GRC REVENUE REQUIREMENT A	% OF REVENUE REQUIREMENT B	ESCALATION FACTOR C	WEIGHTED ESCALATION D
					(Col B x Col C)
1	ELECTRIC				
2	Ratebase related	189,360,556	28%	6.0%	1.68%
3	Expense excl depn	338,591,412	50%	1.9%	0.95%
4	Depn/Amort	150,830,212	22%	6.5%	1.44%
5	Total Electric ERF related Revenue Requirement	678,782,179	100%		**4.06%**

1. Data Source: PSE Exhibit No. ____ (KJB-4)

PUGET SOUND ENERGY
ANNUAL GROWTH RATE BASED ON GRC COMPLIANCE FILING WORKPAPERS - ADJUSTED FOR NOL CARRYFORWARD
ELECTRIC OPERATIONS

Ln. No.	Test Year	2004 GRC Sep-03	2006 GRC Sep-05	2007 GRC Sep-07	2009 GRC Dec-08 (Note 1)	2011 GRC Dec-10 (Note 1)	% Annual Growth in O&M 2004GRC - 2011GRC 7.25	2006GRC - 2011GRC 5.25	2007GRC - 2011GRC 3.25	2009GRC - 2011GRC 2.00
1	**Load (input tab)**									
2	Electric	19,334,018,640	20,339,226,968	21,283,655,838	21,821,673,792	21,143,300,002	1.2%	0.7%	-0.2%	-1.6%
3										
4	**Electric Expenses**									
5	Other Power Supply Expense	52,551,925	77,648,296	96,183,223	107,091,100	124,341,933	12.6%	9.4%	8.2%	7.8%
6	PCA Transmission	485,960	862,248	1,136,455	1,523,617	1,419,635	15.9%	10.0%	7.1%	-3.5%
7	Transmission & Distribution Expense	63,736,286	65,086,999	75,095,489	82,334,864	92,084,397	5.2%	6.8%	6.5%	5.8%
8	Customer Account & Services Expenses	37,542,803	37,706,383	41,878,822	44,367,720	49,173,646	3.8%	5.2%	5.1%	5.3%
9	Admin & General Expenses	70,951,920	74,379,848	81,986,794	89,886,009	99,871,160	4.8%	5.8%	6.3%	5.4%
10	Total Electric Expenses	225,268,893	255,683,774	296,280,783	325,203,310	366,890,771	7.0%	7.1%	6.8%	6.2%
11										
12	**Electric Depreciation**									
13	Production	37,335,853	59,620,924	51,741,842	50,072,838	93,722,074	13.5%	9.0%	20.1%	36.8%
14	PCA Transmission	4,859,223	4,861,051	3,805,774	4,056,906	3,843,499	-3.2%	-4.4%	0.3%	-2.7%
15	Transmission & Distribution	71,715,862	76,838,397	87,146,104	92,434,248	101,680,414	4.9%	5.5%	4.9%	4.9%
16	General , Intangible	11,381,296	10,068,281	19,226,023	15,196,346	20,477,642	8.4%	14.5%	2.0%	16.1%
17	Non-Tracker	-	-	-	13,993,264	-	0.0%	0.0%	0.0%	0.0%
18	Electric Depreciation	125,292,233	151,388,653	161,919,743	175,753,602	219,723,630	8.1%	7.4%	9.8%	11.8%
19	Total T&D and General	83,097,158	86,906,678	106,372,127	107,630,594	122,158,056	5.5%	6.7%	4.3%	6.5%
20										
21	**Electric Amortization**									
22	Production	4,713,860	3,004,881	5,612,906	11,298,008	11,275,733	12.8%	28.6%	23.9%	-0.1%
23	Transmission &Distribution	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%
24	General , Intangible	19,142,502	19,349,756	25,514,388	28,304,530	25,477,630	4.0%	5.4%	0.0%	-5.1%
25	Non-Tracker	1,498,249	2,793,718	1,805,160	2,112,845	3,194,525	0.0%	0.0%	0.0%	0.0%
26	Electric Amortization	25,354,610	25,148,354	32,932,455	41,715,383	39,947,889	6.5%	9.2%	6.1%	-2.1%
27	Total T&D and General	19,142,502	19,349,756	25,514,388	28,304,530	25,477,630	4.0%	5.4%	0.0%	-5.1%
28										
29	T&D/General Depn & Amort (ln19 + ln27)	102,239,659	106,256,434	131,886,516	135,935,123	147,635,687	5.2%	6.5%	$\boxed{3.5\%}$	4.2%
30										
31	**Electric Ratebase**									
32	Production	751,245,624	1,234,946,228	1,246,912,240	1,583,950,372	2,330,849,778	16.9%	12.9%	21.2%	21.3%
33	PCA Transmission	120,648,501	113,206,055	107,422,863	102,337,940	94,699,228	-3.3%	-3.3%	-3.8%	-3.8%
34	Transmission & Distribution (Note 1)	1,408,241,596	1,395,944,754	1,641,251,984	1,922,288,883	2,155,751,803	6.0%	8.6%	8.8%	5.9%
35	General , Intangible , Other (Note 1)	221,758,096	203,380,656	180,138,722	-	-	-100.0%	-100.0%	-100.0%	0.0%
36	Non-Tracker	42,776,224	29,838,500	127,847,726	188,037,777	255,040,634	0.0%	0.0%	0.0%	0.0%
37	Electric Ratebase	2,544,670,041	2,977,316,193	3,303,573,535	3,796,614,971	4,836,341,442	9.3%	9.7%	12.4%	12.9%
38	Total T&D and General	1,629,999,692	1,599,325,411	1,821,390,706	1,922,288,883	2,155,751,803	3.9%	5.9%	$\boxed{5.3\%}$	5.9%

(Note 1) For the 2009 GRC, 2011 GRC and 2011 CBR, General, Intangible and Other plant is included on line 35.

GAS K-FACTOR CALCULATION
USING 2007 TO 2011 ESCALATION FACTORS WITH ADJUSTMENT FOR NOL CARRYFORWARD IMPACT

LINE NO.		2011 GRC REVENUE REQUIREMEN A	% OF REVENUE REQUIREMEN B	ESCALATION FACTOR C	WEIGHTED ESCALATION D
					(Col B x Col C)
1	GAS				
2	Ratebase related	127,391,821	30%	4.9%	1.47%
3	Expense excl depn	186,153,835	44%	1.9%	0.84%
4	Depn/Amort	108,609,792	26%	2.2%	0.56%
5	Total Gas ERF related Revenue Requirement	422,155,448	100%		**2.87%**

GAS K-FACTOR CALCULATION
PRESENTED BY PSE[1]

LINE NO.		2011 GRC REVENUE REQUIREMEN A	% OF REVENUE REQUIREMEN B	ESCALATION FACTOR C	WEIGHTED ESCALATION D
					(Col B x Col C)
1	GAS				
2	Ratebase related	127,391,821	30%	5.5%	1.66%
3	Expense excl depn	186,153,835	44%	1.9%	0.84%
4	Depn/Amort	108,609,792	26%	5.1%	1.30%
5	Total Gas ERF related Revenue Requirement	422,155,448	100%		**3.80%**

1. Data Source: PSE Exhibit No. ____ (KJB-4)

PUGET SOUND ENERGY
ANNUAL GROWTH RATE BASED ON GRC COMPLIANCE FILING WORKPAPERS - ADJUSTED FOR NOL CARRYFORWARD
NATURAL GAS OPERATIONS

Ln. No.	Test Year	2004 GRC Sep-03	2006 GRC Sep-05 (Note 1)	2007 GRC Sep-07	2009 GRC Dec-08	2011 GRC Dec-10	% Annual Growth in O&M: 2004GRC - 2011GRC	2006GRC - 2011GRC	2007GRC - 2011GRC	2009GRC - 2011GRC
1							7.25	5.25	3.25	2.0
2	**Load**									
3	Gas	1,033,465,074	1,038,450,901	1,084,208,169	1,120,309,121	1,072,668,096	0.5%	0.6%	-0.3%	-2.1%
4										
5	**Gas Expenses**									
6	Other Power Supply Expense	1,162,087	1,555,800	1,769,111	1,881,592	1,959,232	7.5%	4.5%	3.2%	2.0%
7	Transmission & Distribution Expense	26,259,234	34,532,486	43,207,192	52,101,244	49,783,566	9.2%	7.2%	4.5%	-2.2%
8	Customer Account & Services Expenses	23,088,164	25,038,278	27,397,683	29,110,812	31,704,844	4.5%	4.6%	4.6%	4.4%
9	Admin & General Expenses	32,698,303	41,714,840	40,022,534	43,076,879	43,995,146	4.2%	1.0%	3.0%	1.1%
10	Total Gas Expenses	83,207,788	102,841,404	112,396,520	126,170,527	127,442,788	6.1%	4.2%	3.9%	0.5%
11										
12	**Gas Depreciation**									
13	Production & Gas Storage	1,076,351	1,294,251	934,365	1,011,473	1,278,337	2.4%	-0.2%	10.1%	12.4%
14	Transmission & Distribution	52,617,414	59,340,713	75,944,262	80,729,161	85,358,207	6.9%	7.2%	3.7%	2.8%
15	General , Intangible , Other	4,182,553	4,321,030	10,051,696	7,109,187	9,195,128	11.5%	15.5%	-2.7%	13.7%
16	Gas Depreciation	57,876,318	64,955,994	86,930,323	88,849,821	95,831,672	7.2%	7.7%	3.0%	3.9%
17	Less Prod, Storage, LNG	1,076,351	1,294,251	934,365	1,011,473	1,278,337	2.4%	-0.2%	10.1%	12.4%
18	Net Gas Depreciation (ln17 - ln18)	56,799,967	63,661,743	85,995,958	87,838,349	94,553,335	7.3%	7.8%	3.0%	3.8%
19										
20	**Gas Amortization**									
21	Production & Gas Storage	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%
22	Transmission & Distribution	21,162	82,646	303,738	403,917	219,232	38.1%	20.4%	-9.5%	-26.3%
23	General , Intangible, Other	9,579,622	11,220,066	13,783,889	15,214,871	12,558,889	3.8%	2.2%	-2.8%	-9.1%
24	Gas Amortization	9,600,784	11,302,712	14,087,627	15,618,788	12,778,120	4.0%	2.4%	-3.0%	-9.5%
25										
26	T&D/General Depn & Amort (ln19 + ln26)	66,400,751	74,964,455	100,083,585	103,457,137	107,331,456	6.8%	7.1%	$\boxed{2.2\%}$	1.9%
27										
28	**Gas Ratebase**									
29	Production & Gas Storage	22,042,681	25,973,805	27,896,986	27,244,685	39,751,535	8.5%	8.4%	11.5%	20.8%
30	Transmission & Distribution	925,750,507	1,037,271,755	1,191,070,429	1,301,847,809	1,395,558,583	5.8%	5.8%	5.0%	3.5%
31	General , Intangible , Other	118,543,578	106,130,161	90,793,405	85,446,599	101,077,864	-2.2%	-0.9%	3.4%	8.8%
32	Working Capital	1,345,790	10,976,022	37,506,872	52,980,352	78,334,208	75.2%	45.4%	25.4%	21.6%
33	Gas Ratebase	1,067,682,556	1,180,351,743	1,347,267,693	1,467,519,443	1,614,722,190	5.9%	6.2%	5.7%	4.9%
34	Less Production related	(22,042,681)	(25,973,805)	(27,896,986)	(27,244,685)	(39,751,535)				
35	Less Working Capital	(1,345,790)	(10,976,022)	(37,506,872)	(52,980,352)	(78,334,208)				
36	Total T&D and General	1,044,294,085	1,143,401,915	1,281,863,835	1,387,294,407	1,496,636,448	5.1%	5.3%	$\boxed{4.9\%}$	3.9%
37	Misc Adj. (Open)	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%
38	Net T&D and General	1,044,294,085	1,143,401,915	1,281,863,835	1,387,294,407	1,496,636,448	5.1%	5.3%	4.9%	3.9%

(Note 1) The 2007 GRC depreciation results shown on line 19, included a $9.3M adjustment resulting from the 07 Depreciation study approved in that filing. Had the adjustment occurred in the 2006 GRC, the compound growth factor for the 2006 to 2011 period would have been 5.1%

2006 Gas Depreciation	63,661,743	
2007 GRC Depreciation Adjustment	9,262,448	
	72,924,191	5.1%

Kroger ROE Adjustment For Revenue Decoupling Adjustment to Electric ERF

PUGET SOUND ENERGY-ELECTRIC
EXPEDITED RATE FILING INCREASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2012

LINE NO.	DESCRIPTION		EXPEDITED RATE FILING
1	RATE BASE	$	2,621,991,642
2	RATE OF RETURN		**7.68%**
3			
4	OPERATING INCOME REQUIREMENT		201,368,958
5			
6	RESTATED OPERATING INCOME		184,563,096
7	OPERATING INCOME DEFICIENCY		16,805,862
8			
9	CONVERSION FACTOR		0.620346
10	REVENUE REQUIREMENT DEFICIENCY	**$**	**27,091,110**
11	REDUCTION FROM PSE DEFICIENCY	**$**	**(5,071,992)**

PSE Proposed ERF Revenue Deficiency[1]

PUGET SOUND ENERGY-ELECTRIC
EXPEDITED RATE FILING INCREASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2012

LINE NO.	DESCRIPTION		EXPEDITED RATE FILING
1	RATE BASE	$	2,621,991,642
2	RATE OF RETURN		**7.80%**
3			
4	OPERATING INCOME REQUIREMENT		204,515,348
5			
6	RESTATED OPERATING INCOME		184,563,096
7	OPERATING INCOME DEFICIENCY		19,952,252
8			
9	CONVERSION FACTOR		0.620346
10	REVENUE REQUIREMENT DEFICIENCY	**$**	**32,163,102**

1. Data Source: PSE Exhibit No. ____ KJB-03, p. 1 of 3.

Kroger ROE Adjustment For Revenue Decoupling Adjustment to Gas ERF

PUGET SOUND ENERGY-GAS
EXPEDITED RATE FILING INCREASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2012

LINE NO.	DESCRIPTION		EXPEDITED RATE FILING
1	RATE BASE	$	1,592,297,567
2	RATE OF RETURN		**7.68%**
3			
4	OPERATING INCOME REQUIREMENT		122,288,453
5			
6	RESTATED OPERATING INCOME		124,969,751
7	OPERATING INCOME DEFICIENCY		(2,681,297)
8			
9	CONVERSION FACTOR		0.620346
10	REVENUE REQUIREMENT DEFICIENCY	**$**	**(4,322,261)**
11	REDUCTION FROM PSE DEFICIENCY	**$**	**(3,082,124)**

PSE Proposed ERF Revenue Deficiency[1]

PUGET SOUND ENERGY-GAS
EXPEDITED RATE FILING INCREASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2012

LINE NO.	DESCRIPTION		EXPEDITED RATE FILING
1	RATE BASE	$	1,592,297,567
2	RATE OF RETURN		**7.80%**
3			
4	OPERATING INCOME REQUIREMENT		124,199,210
5			
6	RESTATED OPERATING INCOME		124,969,751
7	OPERATING INCOME DEFICIENCY		(770,540)
8			
9	CONVERSION FACTOR		0.621335
10	REVENUE REQUIREMENT DEFICIENCY	**$**	**(1,240,137)**

1. Data Source: PSE Exhibit No. ____ KJB-04, p. 1 of 3.

Kroger ROE Adjustment For Revenue Decoupling

Kroger Proposed ERF Cost of Capital

Basis Point Reduction to ROE = 25

PUGET SOUND ENERGY-ELECTRIC & GAS
ADJUSTED PRO FORMA COST OF CAPITAL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
2011 GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PRO FORMA CAPITAL %	COST %	COST OF CAPITAL
1	SHORT TERM DEBT	4.00%	2.68%	0.11%
2	LONG TERM DEBT	48.00%	6.22%	2.99%
3	PREFERRED	0.00%	0.00%	0.00%
4	EQUITY	48.00%	9.55%	4.58%
5	TOTAL	100.00%		7.68%
6				
7	AFTER TAX SHORT TERM DEBT ((LINE 1)* 65%)	4.00%	1.74%	0.07%
8	AFTER TAX LONG TERM DEBT ((LINE 2)* 65%)	48.00%	4.04%	1.94%
9	PREFERRED	0.00%	0.00%	0.00%
10	EQUITY	48.00%	9.55%	4.58%
11	TOTAL AFTER TAX COST OF CAPITAL	100.00%		6.59%

PSE Proposed ERF Cost of Capital[1]

Docket Number UE-111048
From Compliance Filing

PUGET SOUND ENERGY-ELECTRIC & GAS
PRO FORMA COST OF CAPITAL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
2011 GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PRO FORMA CAPITAL %	COST %	COST OF CAPITAL
1	SHORT TERM DEBT	4.00%	2.68%	0.11%
2	LONG TERM DEBT	48.00%	6.22%	2.99%
3	PREFERRED	0.00%	0.00%	0.00%
4	EQUITY	48.00%	9.80%	4.70%
5	TOTAL	100.00%		7.80%
6				
7	AFTER TAX SHORT TERM DEBT ((LINE 1)* 65%)	4.00%	1.74%	0.07%
8	AFTER TAX LONG TERM DEBT ((LINE 2)* 65%)	48.00%	4.04%	1.94%
9	PREFERRED	0.00%	0.00%	0.00%
10	EQUITY	48.00%	9.80%	4.70%
11	TOTAL AFTER TAX COST OF CAPITAL	100.00%		6.71%

1. **Data Source: PSE Exhibit No. KJB-03 Electric ERF Workpaper.**

Kroger ROE Adjustment For Revenue Decoupling
Valuation of Usage per Customer Deviations from Customer Usage Trendline

Line No.	Electric System	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1	Residential												
2	Annual MWh Deviation from Trendline (MWhs/Customer)[1]	0.403	(0.309)	(0.048)	(0.125)	(0.216)	(0.068)	0.089	0.182	0.265	0.214	(0.397)	0.008
3	Residential Customers[1]	811,388	826,187	840,107	854,088	877,711	893,713	910,498	926,080	939,440	947,300	952,803	957,025
4	2013 ERF Test Year Volumetric Delivery Revenue ($/kWh)[2]	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981	$ 0.025981
5	Value of Deviation from Trendline ((= Ln. 2 x 1000 x Ln. 3) x Lr	$ 8,496,300	$ (6,631,199)	$ (1,045,377)	$ (2,770,650)	$ (4,921,650)	$ (1,574,086)	$ 2,111,097	$ 4,385,673	$ 6,475,607	$ 5,275,427	$ (9,818,240)	$ 191,596
6	Non-Residential												
7	Annual MWh Deviation from Trendline (MWhs/Customer)[1]			0.362	(1.812)	(0.427)	(0.550)	0.394	2.207	2.352	0.894	(2.117)	(1.303)
8	Total Non-Residential Customers[1]			107,527	112,417	113,218	115,943	118,371	119,351	121,265	122,118	122,255	122,898
9	2013 ERF Test Year Volumetric Delivery Revenue ($/kWh)[2]			$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668	$ 0.020668
10	Value of Deviation from Trendline ((= Ln. 7 x 1000 x Ln. 8) x Ln. 9)			$ 805,453	$ (4,211,120)	$ (999,655)	$ (1,317,584)	$ 964,977	$ 5,444,199	$ 5,894,659	$ 2,256,923	$ (5,349,906)	$ (3,310,332)
11	Total Value of Deviation (= Ln. 5 + Ln. 10)			$ (239,925)	$ (6,981,770)	$ (5,921,304)	$ (2,891,670)	$ 3,076,074	$ 9,829,872	$ 12,370,266	$ 7,532,350	$ (15,168,146)	$ (3,118,736)
12	**Total Absolute Value of Deviation (= Abs(Ln. 11))**			**$ 239,925**	**$ 6,981,770**	**$ 5,921,304**	**$ 2,891,670**	**$ 3,076,074**	**$ 9,829,872**	**$ 12,370,266**	**$ 7,532,350**	**$ 15,168,146**	**$ 3,118,736**
13	100 Basis Point in Equity - Revenue Requirement Impact (= Ln. 28)			$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520	$ 20,142,520
14	**Return on Equity Impact - Basis Points ((= Ln. 12 ÷ Ln. 13) x 100)**			**1**	**35**	**29**	**14**	**15**	**49**	**61**	**37**	**75**	**15**
15	**Basis Points - 10 Year Average (= Avg(Ln. 14)):**	33											

Line No.		
16	**100 Basis Point Valuation:**[3]	
17	ERF Current Earnings on Rate Base	$ 184,563,096
18	ERF Rate Base	$2,621,991,642
19	ERF Current Return on Rate Base	7.04%
20	ERF Wtd. Cost of Debt - Short Term	0.11%
21	ERF Wtd. Cost of Debt - Long Term	2.99%
22	ERF Equity Ratio	48.00%
23	ERF Current Return on Equity	8.21%
24	100 Basis Point in Equity - Earnings Impact	$ 12,585,560
25	ERF State Utility Tax	3.873%
26	ERF Federal Income Tax Rate	35.00%
27	ERF Effective Tax Rate (SUT + FIT)	37.52%
28	100 Basis Point in Equity - Revenue Requirement Impact	$ 20,142,520

1. **Data Source: Exhibit No. KCH-3, p. 5**
2. **Data Source: PSE Workpaper 2013.02.27 Workpapers JAP-12 JAP-14 JAP-16 JAP-18 JAP-22.xlsx**
3. **Data Source: PSE Workpaper KJB-03-WP Electric ERF.xlsx in Docket UE-130137/UG-130138**

Kroger ROE Adjustment For Revenue Decoupling

Summary of Annual Electric Usage Per Customer (MWhs)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential MWhs	9,862,423	9,435,883	9,795,652	9,874,116	10,048,040	10,343,830	10,661,024	10,909,218	11,123,905	11,147,821	10,609,457	11,022,331
Commercial MWhs	7,677,194	7,953,165	8,012,539	8,222,167	8,449,565	8,647,478	8,939,155	9,226,215	9,453,940	9,488,763	9,100,518	9,181,261
Industrial MWhs	4,026,344	2,540,722	1,416,106	1,372,815	1,352,660	1,357,973	1,368,672	1,364,264	1,304,662	1,148,060	1,160,588	1,214,233
Total Non-Residential MWhs	11,703,538	10,493,887	9,428,645	9,594,982	9,802,225	10,005,451	10,307,827	10,590,479	10,758,602	10,636,823	10,261,106	10,395,494
Residential Customers	811,388	826,187	840,107	854,088	877,711	893,713	910,498	926,080	939,440	947,300	952,803	957,025
Commercial Customers	98,768	100,756	103,593	108,465	109,238	112,030	114,488	115,578	117,521	118,423	118,595	119,265
Industrial Customers	4,095	4,002	3,934	3,952	3,980	3,913	3,883	3,772	3,744	3,695	3,660	3,633
Total Non-Residential Customers	102,863	104,757	107,527	112,417	113,218	115,943	118,371	119,351	121,265	122,118	122,255	122,898
Annual Usage Per Residential Customer (MWhs)	12.155	11.421	11.660	11.561	11.448	11.574	11.709	11.780	11.841	11.768	11.135	11.517
Annual Usage Per Commercial Customer (MWhs)	77.729	78.935	77.346	75.805	77.350	77.189	78.080	79.827	80.445	80.126	76.736	76.982
Annual Usage Per Industrial Customer (MWhs)	983.294	634.942	359.981	347.409	339.836	347.041	352.486	361.666	348.498	310.699	317.129	334.269
Annual Usage Per Residential Customer (MWhs)	12.155	11.421	11.660	11.561	11.448	11.574	11.709	11.780	11.841	11.768	11.135	11.517
12 Year Trend	11.752	11.730	11.708	11.686	11.664	11.642	11.620	11.598	11.576	11.554	11.532	11.510
Annual MWh Deviation from Trend	0.403	-0.309	-0.048	-0.125	-0.216	-0.068	0.089	0.182	0.265	0.214	-0.397	0.008
Annual % Deviation from Trend	3.43%	-2.63%	-0.41%	-1.07%	-1.85%	-0.58%	0.77%	1.57%	2.29%	1.86%	-3.44%	0.07%
.nnual Usage Per Non-Residential Customer (MWhs)			87.686	85.352	86.578	86.296	87.081	88.734	88.720	87.103	83.932	84.587
10 Year Trend			87.324	87.165	87.005	86.846	86.687	86.527	86.368	86.209	86.049	85.890
Annual MWh Deviation from Trend			0.362	-1.812	-0.427	-0.550	0.394	2.207	2.352	0.894	-2.117	-1.303
Annual % Deviation from Trend			0.42%	-2.08%	-0.49%	-0.63%	0.46%	2.55%	2.72%	1.04%	-2.46%	-1.52%

* MWh totals reflect year end figures; customer counts for all classes reflect annual average

Data Sources:

1) Dockets 121697-121705 PSE Resp Kroger DR4-002, Attach A & B
2) 2013.02.27 Workpapers JAP-12 JAP-14 JAP-16 JAP-18 JAP-22.xlsx
3) PSE Response to Public Counsel Data Request No. 105

Kroger ROE Adjustment For Revenue Decoupling
Valuation of Usage per Customer Deviations from Customer Usage Trendline

Line No.	Gas System	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1	Residential												
2	Annual Therm Deviation from Trendline (Therms/Customer)[1]	82.773	(37.599)	16.195	(8.901)	(56.527)	(39.845)	(20.365)	1.455	39.571	31.936	(60.885)	52.192
3	Residential Customers[1]	531,835	548,497	564,494	583,439	610,181	629,639	649,324	666,756	681,267	689,438	694,086	700,039
4	2013 ERF Test Year Volumetric Delivery Revenue ($/Therm)[2]	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850	$ 0.363850
5	Value of Deviation from Trendline (= Ln. 2 x Ln. 3 x Ln. 4)	$ 16,017,349	$ (7,503,589)	$ 3,326,222	$ (1,889,644)	$ (12,549,706)	$ (9,128,271)	$ (4,811,315)	$ 353,020	$ 9,808,761	$ 8,011,151	$ (15,376,000)	$ 13,293,664
6	Non-Residential												
7	Annual Therm Deviation from Trendline (Therms/Customer)[1]			409.981	1.168	(369.788)	(344.463)	(33.287)	213.971	438.434	(273.264)	(502.102)	459.350
8	Total Non-Residential Customers[1]			49,872	50,713	52,874	53,890	54,805	55,565	56,894	57,386	57,009	56,933
9	2013 ERF Test Year Volumetric Delivery Revenue ($/Therm)[2]			$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080	$ 0.176080
10	Value of Deviation from Trendline (= Ln. 7 x Ln. 8 x Ln. 9)			$ 3,600,205	$ 10,432	$ (3,442,754)	$ (3,268,587)	$ (321,223)	$ 2,093,459	$ 4,392,188	$ (2,761,206)	$ (5,040,156)	$ 4,604,908
11	Total Value of Deviation (= Ln. 5 + Ln. 10)			$ 6,926,427	$ (1,879,212)	$ (15,992,460)	$ (12,396,858)	$ (5,132,538)	$ 2,446,480	$ 14,200,949	$ 5,249,945	$ (20,416,156)	$ 17,898,572
12	**Total Absolute Value of Deviation (= Abs(Ln. 11))**			**$ 6,926,427**	**$ 1,879,212**	**$ 15,992,460**	**$ 12,396,858**	**$ 5,132,538**	**$ 2,446,480**	**$ 14,200,949**	**$ 5,249,945**	**$ 20,416,156**	**$ 17,898,572**
13	100 Basis Point in Equity - Revenue Requirement Impact (= Ln. 28)			$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589	$ 12,229,589
14	**Return on Equity Impact - Basis Points ((= Ln. 12 ÷ Ln. 13) x 100)**			**57**	**15**	**131**	**101**	**42**	**20**	**116**	**43**	**167**	**146**
15	**Basis Points - 10 Year Average (= Avg(Ln. 14)):**	84											

Line No.		
16	**100 Basis Point Valuation:**[3]	
17	ERF Current Earnings on Rate Base	$ 124,969,751
18	ERF Rate Base	$ 1,592,297,567
19	ERF Current Return on Rate Base	7.85%
20	ERF Wtd. Cost of Debt - Short Term	0.11%
21	ERF Wtd. Cost of Debt - Long Term	2.99%
22	ERF Equity Ratio	48.00%
23	ERF Current Return on Equity	9.89%
24	100 Basis Point in Equity - Earnings Impact	$ 7,643,028
25	ERF State Utility Tax	3.852%
26	ERF Federal Income Tax Rate	35.00%
27	ERF Effective Tax Rate (SUT + FIT)	37.50%
28	100 Basis Point in Equity - Revenue Requirement Impact	$ 12,229,589

1. **Data Source: Exhibit KCH-3, p. 7**
2. **Data Source: PSE Workpaper 2013.02.27 Workpapers JAP-11 JAP-15 JAP-17 JAP-19 JAP-23.xlsx**
3. **Data Source: PSE Workpaper KJB-04-WP Gas ERF.xlsx in Docket UE-130137/UG-130138**

Kroger ROE Adjustment For Revenue Decoupling

Summary of Annual Gas Usage Per Customer (Therms)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential Therms	517,560,806	463,308,672	502,615,197	500,115,953	489,036,221	510,034,801	533,369,999	556,836,805	589,404,601	585,626,039	519,526,707	597,470,758
Commercial Therms	322,466,722	298,101,594	318,299,125	310,781,177	308,292,328	313,536,406	329,068,240	342,576,754	374,332,327	348,111,622	331,761,168	366,533,110
Industrial Therms	205,914,470	181,231,499	183,865,249	175,850,687	176,050,686	177,998,198	184,326,997	188,092,553	178,130,927	164,585,024	160,840,256	176,481,232
Total Non-Residential Therms	528,381,192	479,333,092	502,164,374	486,631,864	484,343,014	491,534,604	513,395,236	530,669,307	552,463,255	512,696,646	492,601,424	543,014,342
Residential Customers	531,835	548,497	564,494	583,439	610,181	629,639	649,324	666,756	681,267	689,438	694,086	700,039
Commercial Customers	46,003	47,124	46,984	47,872	50,041	51,093	52,019	52,826	54,177	54,726	54,390	54,341
Industrial Customers	3,025	2,942	2,888	2,841	2,833	2,797	2,786	2,739	2,717	2,660	2,619	2,593
Total Non-Residential Customers	49,028	50,065	49,872	50,713	52,874	53,890	54,805	55,565	56,894	57,386	57,009	56,933
Annual Usage Per Residential Customer (Therms)	973.160	844.688	890.382	857.186	801.461	810.043	821.424	835.144	865.160	849.425	748.505	853.482
Annual Usage Per Commercial Customer (Therms)	7,009.689	6,325.942	6,774.688	6,491.920	6,160.815	6,136.582	6,325.975	6,485.044	6,909.486	6,361.011	6,099.635	6,745.087
Annual Usage Per Industrial Customer (Therms)	68,074.650	61,611.932	63,665.253	61,897.461	62,137.364	63,642.762	66,161.880	68,669.891	65,551.569	61,868.255	61,424.577	68,069.388
Annual Usage Per Residential Customer (Therms)	973.160	844.688	890.382	857.186	801.461	810.043	821.424	835.144	865.160	849.425	748.505	853.482
12 Year Trend	890.386	882.287	874.187	866.087	857.988	849.888	841.788	833.689	825.589	817.489	809.390	801.290
Annual Therm Deviation from Trend	82.773	-37.599	16.195	-8.901	-56.527	-39.845	-20.365	1.455	39.571	31.936	-60.885	52.192
Annual % Deviation from Trend	9.30%	-4.26%	1.85%	-1.03%	-6.59%	-4.69%	-2.42%	0.17%	4.79%	3.91%	-7.52%	6.51%
Annual Usage Per Non-Residential Customer (Therms)			10,069.148	9,595.801	9,160.310	9,121.101	9,367.743	9,550.467	9,710.396	8,934.163	8,640.791	9,537.709
10 Year Trend			9,659.167	9,594.633	9,530.099	9,465.564	9,401.030	9,336.496	9,271.962	9,207.427	9,142.893	9,078.359
Annual Therm Deviation from Trend			409.981	1.168	-369.788	-344.463	-33.287	213.971	438.434	-273.264	-502.102	459.350
Annual % Deviation from Trend			4.24%	0.01%	-3.88%	-3.64%	-0.35%	2.29%	4.73%	-2.97%	-5.49%	5.06%

* Therm totals reflect year end figures; customer counts for all classes reflect annual average

Data Sources:

1) Dockets 121697-121705 PSE Resp Kroger DR4-003, Attach A

2) 2013.02.27 Workpapers JAP-11 JAP-15 JAP-17 JAP-19 JAP-23.xlsx

Found Revenues: Accrual of PSE Delivery Revenues with Growing Customer Counts (Electric Example)

Usage Per Customer Held Constant

		Estimated Delivery Revenues Based on PSE Forecasted Customer Count					
		May 1, 2013-April 30, 2014		May 1, 2014-April 30, 2015		May 1, 2015-April 30, 2016	
Line No.		Residential	Non-Residential Schedules	Residential	Non-Residential Schedules	Residential	Non-Residential Schedules
1	2013 Allowed Volumetric Delivery Revenue Per Customer (as Filed by PSE)	$303.37	$1,791.41	$315.38	$1,852.79	$327.75	$1,916.01
2	*Forecasted Rate Year Customer Count (as Filed by PSE)*	*963,047*	*122,833*	*980,677*	*124,707*	*1,000,218*	*126,876*
3	Forecasted Rate Year Usage per Customer (kWhs)	**10,987**	**85,281**	**10,987**	**85,281**	**10,987**	**85,281**
4	Estimated Recoverable Volumetric Delivery Revenue	$292,159,612	$220,043,840	$309,286,008	$231,055,062	$327,821,562	$243,095,759
5	Forecasted Rate Year Base Sales (kWh)	10,580,952,000	10,475,312,000	10,774,653,716	10,635,111,210	10,989,350,164	10,820,126,982
6	Rate Year Volumetric Delivery Revenue Per Unit ($/kWh)	**$0.027612**	**$0.021006**	**$0.028705**	**$0.021726**	**$0.029831**	**$0.022467**

		Estimated Delivery Revenues based on a 4% Annual Increase in Customer Count					
		May 1, 2013-April 30, 2014		May 1, 2014-April 30, 2015		May 1, 2015-April 30, 2016	
		Residential	Non-Residential Schedules	Residential	Non-Residential Schedules	Residential	Non-Residential Schedules
7	2013 Allowed Volumetric Delivery Revenue Per Customer (as Filed by PSE)	$303.37	$1,791.41	$315.38	$1,852.79	$327.75	$1,916.01
8	*Hypothetical Forecasted Rate Year Customer Count*	*1,001,569*	*127,746*	*1,041,632*	*132,856*	*1,083,297*	*138,170*
9	Forecasted Rate Year Usage per Customer (kWhs)	**10,987**	**85,281**	**10,987**	**85,281**	**10,987**	**85,281**
10	Estimated Recoverable Volumetric Delivery Revenue	$303,845,997	$228,845,594	$328,509,834	$246,154,113	$355,050,612	$264,735,395
11	Forecasted Rate Year Base Sales (kWh)	11,004,190,080	10,894,324,480	11,444,357,683	11,330,097,459	11,902,131,991	11,783,301,358
12	Rate Year Volumetric Delivery Revenue Per Unit ($/kWh)	**$0.027612**	**$0.021006**	**$0.028705**	**$0.021726**	**$0.029831**	**$0.022467**
13	**Difference in Recoverable Volumetric Delivery Revenue**	**$11,686,384**	**$8,801,754**	**$19,223,826**	**$15,099,051**	**$27,229,050**	**$21,639,636**
14	**Difference in Volumetric Delivery Revenue Per Unit**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**

Data Source: 2013.02.27 Workpapers JAP-12 JAP-14 JAP-16 JAP-18 JAP-22.xlsx

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the parties listed on the attached Certificate of Service by regular U.S. mail and electronic mail (when available) this 26th day of April, 2013.

Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.

MASTER SERVICE LIST

As of: 4/26/2013 Docket: 130137

Original MSL Date: 2/4/2013

Status	**Name and Address**	**Phone & Fax**	**Added**	**By**
Assistant Attorney General	Brown, Sally Assistant Attorney General WUTC PO Box 40128 Olympia, WA 98504-0128 sbrown@utc.wa.gov	Tel: (360) 664-1193 Fax: (360) 586-5522	2/13/2013	Higgins, Joni
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Intervenor□s Counsel or Representative	Roseman, Ronald L Attorney At Law 2011 - 14th Avenue East Seattle, WA 98112 ronaldroseman@comcast.net	Tel: (206) 324-8792 Fax: (206) 568-0138	3/18/2013	Higgins, Joni
Intervenor□s Counsel or Representative Representing: Nucor Steel Seattle, Inc.	Xenopoulos, Damon E Brickfield, Burchette, Ritts & Stone, P.C. 1025 Thomas Jefferson Street NW; Eighth Floor-West Tower Washington, DC 20007 dex@bbrslaw.com	Tel: (202) 342-0800 Fax: (202) 342-0807	3/22/2013	Higgins, Joni
Intervenor	Nucor Steel Seattle, Inc. Nucor Steel 2424 SW Andover Seattle, WA 98106-1100		3/28/2013	Higgins, Joni
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Intervenor	Quality Food Centers, Inc. Quality Food Centers, Inc. 10116 N.E. 8th Street Bellevue, WA 98004		4/4/2013	Higgins, Joni
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MASTER SERVICE LIST

As of: 4/26/2013 Docket: 121697

Original MSL Date: 10/26/2012

Status	Name and Address	Phone & Fax	Added	By
Assistant Attorney General	Brown, Sally Assistant Attorney General WUTC PO Box 40128 Olympia, WA 98504-0128 sbrown@utc.wa.gov	Tel: (360) 664-1193 Fax: (360) 586-5522	2/13/2013	Higgins, Joni
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Petitioner□s Counsel or Representative	Goodin, Amanda Earthjustice 705 Second Avenue STE 203 Seattle, WA 98104 agoodin@earthjustice.org	Tel: 206-343-7340 Fax: 206-343-1526	10/26/2012	Wyse, Lisa
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Intervenor	Finklea, Ed Executive Director NORTHWEST INDUSTRIAL GAS USERS 326 Fifth Street Lake Oswego, OR 97034 efinklea@nwigu.org	Tel: (503) 303-4061 Fax: (503) 303-4941	11/2/2012	Higgins, Joni
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Intervenor□s Counsel or Representative	Davison, Melinda Attorney Davison Van Cleve 333 S.W. Taylor STE 400 Portland, OR 97204 mail@dvclaw.com	Tel: (503) 241-7242 Fax: (503) 241-8160	1/8/2013	Wyse, Lisa
Intervenor	Carr, John Industrial Customers of Northwest Utilities 818 SW 3rd Avenue # 266 Portland, OR 97204 jcarr@icnu.org		3/28/2013	Higgins, Joni
Petitioner	Johnson, Ken Director, Rates & Regulatory Affairs Puget Sound Energy (E012) PO BOX 97034, PSE-08N Bellevue, WA 98009-9734 ken.s.johnson@pse.com	Tel: (425) 462-3495 Fax: (425) 462-3414	10/26/2012	Wyse, Lisa
Intervenor	The Kroger Co. The Kroger Co. 1014 Vine Street Cincinnati, OH 45202	Tel: (513) 762-4538 Fax: (513) 762-4012	3/28/2013	Higgins, Joni
Intervenor	Eberdt, Charles M Manager The Energy Project 3406 Redwood Ave Bellingham, WA 98225 CHUCK_EBERDT@oppco.org	Tel: (360) 255-2169 Fax: (360) 671-2753	3/18/2013	Higgins, Joni
Petitioner□s Counsel or Representative	Carson, Sheree Perkins Coie, LLP 10885 N.E. Fourth Street STE 700 Bellevue, WA 98004-5579 scarson@perkinscoie.com	Tel: (425) 635-1400 Fax: (425) 635-2400	10/26/2012	Wyse, Lisa

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