WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF
RESPONSE TO DATA REQUEST

DATE PREPARED: December 7, 2011
DOCKETS: UE-111048/UG-111049
REQUESTER: Bench

WITNESS:
RESPONDER: Commission Staff
TELEPHONE:

REQUEST:

On November 4, 2010, the Washington Utilities and Transportation Commission (Commission) issued the Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets (Decoupling Policy Statement). In the Decoupling Policy Statement, the Commission examined several lost margin recovery mechanisms and stated its policy preference for full decoupling.[1] The Commission expressed interest in considering a full decoupling[2] mechanism for electric and natural gas utilities in the context of a general rate case, so as to "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."[3]

On June 13, 2011, Puget Sound Energy, Inc. (PSE) filed for general rate increases for electric and gas service, in Dockets UE-111048 and UG-111049, respectively. PSE's filing includes a proposal for a Conservation Savings Adjustment ("CSA") Rate "to mitigate the negative financial effects that conservation has on its ability to recover certain of its fixed costs." Exhibit TAD-1T at 10:8-10. In the interest of having a more complete record concerning the issues raised by PSE's proposal, the Commission requests that Staff examine full decoupling, as discussed in the Decoupling Policy Statement, as an option for PSE. In response to this Bench Request, Staff should provide the Commission with a discussion of the critical elements that a full decoupling proposal should contain, consistent with the Decoupling Policy Statement, including consideration of lost sales revenues that are potentially offset by avoided costs and other benefits. It should also indicate whether, based on the information it supplies the Commission, it believes that the Commission could make a final decision on a decoupling proposal by the end of this rate proceeding or whether more process may be necessary or desirable.4

---

[1] Wash. Util. & Trans. Comm., Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets (Decoupling Policy Statement), ¶¶ 27 - 37 (2010).

[2] Full decoupling recognizes not only lost margin, i.e., diminishing customer usage resulting in a utility under-recovering its fixed expenses in its volumetric charges, but also found margin, i.e., increasing customer usage whereby the utility over-recovers fixed expenses contained within its volumetric charges. Decoupling Policy Statement, ¶ 11.

[3] Decoupling Policy Statement, ¶ 28.

[4] While the Commission expects Staff to provide an analysis of PSE's proposal in light of the our Decoupling Policy Statement, we are neither directing Staff to, nor preventing it from, advocating full decoupling or

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF
RESPONSE TO DATA REQUEST

DATE PREPARED: December 7, 2011
DOCKETS: UE-111048/UG-111049
REQUESTER: Bench

WITNESS:
RESPONDER: Commission Staff
TELEPHONE:

Staff's filing should be made concurrently with its responsive case on December 7, 2011. Public Counsel and the Intervenors are also invited to present the Commission with full decoupling proposals, or other alternatives, by December 7, 2011. If it did not do so in preparation of its direct case, PSE may analyze alternative recovery mechanisms, including full decoupling, taking into account the Decoupling Policy Statement. If PSE wishes to provide such analysis, it must do so by December 7, 2011. Parties may address Staff's or each other's initial responses to this Bench Request in their January 17, 2012, rebuttal or cross-answering testimony.

RESPONSE:

Please see attached.

---

another alternative. Staff's response may be in the form of testimony, or may be presented in another form (*e.g.*, a narrative discussion), as Staff deems appropriate.

Table of Contents

UTC Staff Response to Bench Request on Full Decoupling

I. Background

On October 5, 2011, the Commission issued a Bench Request requesting its Staff to "examine full decoupling, as discussed in the Decoupling Policy Statement, as an option for PSE."[1] The Commission stated that Staff's response should provide "a discussion of the critical elements that a full decoupling proposal should contain, consistent with the Decoupling Policy Statement, including consideration of lost sales revenues that are potentially offset by avoided costs and other benefits."[2]

The Commission also asked Staff to indicate whether the Commission could make a final decision on a decoupling proposal in this case "based on the information [Staff] supplies" in this Bench Request response.[3] The Commission did not place any requirement or limitation on Staff advocating any particular position for or against full decoupling.[4]

II. Policy Options

While the Commission's Decoupling Policy Statement sets forth the Commission's policy regarding what constitutes an acceptable full decoupling mechanism, full decoupling is not the only policy option identified by the Commission:

> The guidance provided in this policy statement does not imply that the Commission would not consider other mechanisms in the context of a general rate case, including an appropriate attrition adjustment designed to protect the company from lost margin due to any reason.[5]

Staff has analyzed the issues and details surrounding full decoupling, particularly the complexities occasioned by a decoupling mechanism that would fully comply with the Commission's Decoupling Policy Statement, and Staff recommends in its testimony in Dockets UE-111048 and UG-111049 that a well-defended attrition adjustment would be much simpler, and more direct in addressing the objectives of full decoupling.[6] While this Staff recommendation for attrition analysis is beyond the literal scope of the Bench Request, Staff believes it appropriate to note this recommendation before responding to the details of the Bench

---

[1] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Notice of Bench Request (Bench Request) (October 5, 2011) at 2. The Decoupling Policy Statement to which the Commission refers was issued in 2010: *Utilities & Transp. Comm'n*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets (Decoupling Policy Statement) (November 4, 2010).
[2] Id.
[3] Id.
[4] Id. footnote 4.
[5] Decoupling Policy Statement at 22, ¶ 34.
[6] Exhibit No. __ (KLE-1T) and Exhibit No. __ (DJR-1T).

Request. Staff has also provided an analysis of limited decoupling in its response testimony to the Company's Conservation Savings Adjustment.

III. Overview and Format

Per the Commission's request, this Response discusses the critical elements[7] a full decoupling proposal should contain, and explains how a full decoupling mechanism can be consistent with the Decoupling Policy Statement. In order to provide the Commission a response that is more than an abstract discussion, Staff has prepared a Mechanism with terms applicable either to electric or gas operations.

While the Mechanism does not contain all of the details necessary for implementation, it is sufficiently concrete to permit a robust discussion of the key issues, and to identify the areas requiring further examination. Based on the material in this Response, the Commission likely cannot make a final decision on a decoupling proposal in this case. However, if the Commission decides to adopt a decoupling mechanism, it could give direction to the parties on the key elements of such a mechanism,[8] with the parties reporting back in a reasonable period of time after the close of this docket.

The format of this Response is to first define "full decoupling" as that term is used in the Decoupling Policy Statement (Section IV), then provide a brief identification of the objectives of a Decoupling Mechanism (Section V), followed by a list of Commission-required elements, plus additional elements the Commission may consider (Section VI). We then describe the Mechanism for electric and gas operations for the Company (Section VII and Appendix 2) and explain how it addresses each of the required elements (Section VIII). Appendix 1 shows the financial impact of full decoupling on PSE for both gas and electric, separately. Workpapers showing the calculations relied on by staff to develop the impacts are also included in the Response.

IV. "Full Decoupling" Defined

While neither the Commission's Bench Request nor its Decoupling Policy Statement contain a discrete definition of "full decoupling", the Commission's Decoupling Policy Statement describes full decoupling as "designed to minimize the risk to both the utilities and to ratepayers

---

[7] The Decoupling Policy Statement does not use the term "critical elements". Rather, it uses the terms "elements", "criteria", and "factors". E.g. Decoupling Policy Statement at 17 ¶ 28 (elements); at 18, ¶ 28 (criteria); and at 19, ¶ 28 (factors). Consequently, we use the term "element" to refer to each of these items.

[8] In particular, Staff believes the Commission should address the specific adjustment to the rate of return, the criteria for the exclusion of individual classes, the criteria for comparing conservation benefits between low-income and other customers, guidance on identification of incremental conservation, guidance on revisions to the service quality program, guidance on incorporation of a "K-Factor" and guidance on an adjustment to account for off-system sales.

of volatility in average use per customer by class regardless of cause, including the effects of weather,"[9] and states that full decoupling "reduc[es] the risk of volatility of revenue based on customer usage, both up and down, ... which in turn should benefit customers by reducing a company's debt and equity costs."[10]

The Commission also acknowledges "full decoupling" can co-exist with a cost adjustment mechanism such as an energy cost adjustment mechanism,[11] which Staff construes as allowing an exception to a "pure" full decoupling mechanism.[12]

Accordingly, in this Response, Staff applies a definition of "full decoupling" that assures the utility recovers a predetermined level of revenues (or revenues per customer) regardless of the customers' actual usage, but allows for the existence of an energy cost adjustment tariff, so that the revenues the utility recovers under such a tariff are considered in the design of the decoupling mechanism.

In defining decoupling, the Commission stressed that it should be considered in the context of a general rate case. Certain baselines are established during a general rate case as are key inputs to the operation of a decoupling mechanism. In particular, for revenue-per-customer decoupling, the establishment of the average use per customer during the test period and the revenue per customer during the test period are crucial values. Also, the capital structure and resulting rate of return will be a key value.

V. Objectives of Decoupling

Based on Staff's review of the Decoupling Policy Statement, we have identified the following overall objectives a full decoupling mechanism should address:

- Remove barriers to the utility acquiring all cost-effective conservation.
- Minimize the risk to both the utility and to ratepayers of volatility in total consumption (or average use per customer) by class regardless of weather or another cause.

---

[9] Decoupling Policy Statement at 8, ¶ 12.
[10] Id. at 16, ¶ 27.
[11] Id., i.e., the Commission's reference to full decoupling "combined with an energy cost recovery mechanism".
[12] Full decoupling would assure a specific revenue level (or specific revenue per customer level) associated with a specific Commission revenue requirement determination that covered all costs, including power costs. Under full decoupling, the utility would recover that specific revenue level (or revenue per customer level). The utility then would be subject to power cost variations over time, rather than deferring such variations for later recovery from customers (as the utility does under a power cost adjustment mechanism).

The other objectives to consider in designing a full decoupling mechanism are to eliminate both the utility's risk of declines in usage and the utility's incentive to increase usage, thus eliminating the disincentive to acquire conservation. At the same time, the full decoupling mechanism should assure the utility acquires the appropriate level and type of conservation, retain management incentives to reduce costs, assure the utility will meet its conservation acquisition targets, assure rates are reasonable and that service quality will not decline.

VI. Required Elements of a Full Decoupling Mechanism

Based on Staff's review of the Decoupling Policy Statement[13], we have identified the following elements that a full decoupling mechanism should include:

- True-up revenues annually to the assured level, subject to an earnings test, and net of the benefits of off-system sales and avoided costs due to decoupling-related conservation efforts.
- Apply full decoupling to each customer class unless it would be reasonable and lawful to apply full decoupling only to selected customer classes.
- Address the duration of full decoupling in terms of achieving its objectives or until the next general rate case.
- Reflect the impact of full decoupling on the capital structure and rate of return.
- Address utility management's potential disincentive to reduce costs, in light of the elimination of risk of revenue declines.
- Revenue recovery by the company under the mechanism will be conditioned upon a utility's level of achievement with respect to its conservation target.
- Provide benefits of conservation to low income customers roughly comparable to other ratepayers, or if not, provide a targeted low income program consistent with cost effectiveness standards.
- Describe the incremental conservation the utility intends to pursue in conjunction with the mechanism.
- Require appropriate reporting.

Because the Commission's list of elements is not exclusive,[14] Staff also addresses the following items:

---

[13] This list is based on the items listed or discussed in the Decoupling Policy Statement at pages 17-19, ¶ 28, page 16, ¶ 26, and page 8, ¶ 12.

[14] Decoupling Policy Statement at 19, ¶ 28 refers to "Other Factors Impacting the Public Interest" and notes that the criteria in the Decoupling Policy Statement are "not intended to limit the Commission's authority to review other factors". Moreover, while the Commission discusses the four "elements" in the context of a "utility's request for a

- How to address the incentive for a utility not to restore service promptly.
- Administrative burden on the Commission.

VII. Description of the Mechanism

The Mechanism described in Appendix 2 responds to the objectives and critical elements identified above. The following table summarizes Appendix 2 and outlines some additional items for Commission consideration.

Issue	Summary	Notes
Type of Decoupling Mechanism	Revenue Per Customer	
Frequency of Adjustments	Annual	July – June deferral period; November – October recovery period.
General Rate Case Frequency	Every four years	
Maximum Rate Adjustment Per Year	3%	Deferrals in excess of 3% are carried over at a short-term rate of interest.
Earnings Test	Deadband is 25 basis points above Overall Rate of Return	Earnings over the deadband are returned to customers
Conservation Test	Company recovers up to 120% of deferral, based on achievement of conservation target	Third-party evaluation of conservation savings required
Duration	Until Changed	Gives rating agencies assurance this is not a temporary measure
Classes excluded	Classes that do not participate in conservation programs	Only Gas Transportation Excluded
K-Factor	Optional	After 3 years, an annual percentage reduction in revenue per customer will be incorporated into the Mechanism unless a GRC is filed
Adjustment to account for off-system sales	Optional	Adjust usage by the amount of line-loss and adjust deferral by the average market value of the consumption deviation
Low-Income Conservation Provision	Optional	Percentage of company gross revenues devoted to low-income conservation programs
Service Quality	Optional	Usage adjusted by difference between 10-year average SAIDI and most recent SAIDI

full decoupling mechanism" (id. at 17, ¶ 28), Staff assumes any full decoupling mechanism should address these four elements as well.

VIII. How the Mechanism Addresses Each Commission-Required Element

A. Eliminating the Utility's Risk of Revenue Declines

The Commission specifically describes full decoupling as "eliminat[ing] the risk of recovery of declines in revenue".[15] We therefore assume that an acceptable full decoupling mechanism must assure revenues do not decline, at least on a per customer basis.

Under the Mechanism, the Company's revenues will not decline because the Company's allowed revenues would be based on the total volume sales per schedule figure resulting from the Company's most recent rate case. As long as the number of the Company's customers stays the same or increases, the Company's revenues will not decline from Commission-approved levels.

B. Annual True-Ups to the Rate Case-Determined Level of Revenues

The Commission describes the true-up element as an annual true-up for variations between revenues collected and Commission-determined revenues:

> *True-up Mechanism.* Where, between general rate cases, customer use by class deviates either higher or lower from that determined by the Commission when setting rates, a utility can seek an annual true-up of revenue attributed to each affected class of customer.[16]

In the related footnote, the Commission identifies the need to address a potential inequity related to revenues from new customers:

> We recognize that revenue associated with new customers is offset by the costs to serve those customers. If these revenues and costs are not in reasonable balance, we would consider excluding all or some new customer revenue from the mechanism or some other tool (*e.g.,* modifying a utility's line extension tariffs) to correct any demonstrated inequity.[17]

The Mechanism includes annual true-ups. Under the Mechanism, the Company would begin deferrals each year on July 1, and continue through June 30 of each year. By September 1 of each year, the Company will file a tariff to implement amortization of the deferral, with effective dates of November 1 through October 31.

---

[15] Id. at 16, ¶ 26.
[16] Id. at 17, Element 1, ¶ 28.
[17] Id. n. 44.

The level of deferred revenue the Company will be allowed to recover or refund is limited to a soft cap of three percent on annual rate changes and subject to: (a) an Earnings Test; and (b) a Conservation Test. The Company will calculate the Earnings Test first, followed by the Conservation Test, both based on the initial calculation of the initial deferral amount. The individual results of the tests will be cumulatively added to the deferral amount. The Earnings Test and the Conservation Test are discussed below.

C. Full Decoupling Lasts Until the Mechanism Achieves its Objectives or Until the Next General Rate Case

The Commission addresses the duration of a decoupling mechanism as follows:

> *Duration of Program.* The Commission will generally approve a full decoupling mechanism for the period required to achieve its objectives or until the filing of a utility's next general rate case. Under either circumstance, the burden is upon the utility to demonstrate the continued need for the mechanism.[18]

Decoupling experts recommend that a mechanism not have a "sunset" date, in order to allow the cost of capital benefits to be fully realized, but also recommend that companies with decoupling mechanism file a GRC every three to five years.[19] The Mechanism would remain in place until modified or cancelled by the Commission; and the Company must file a general rate case (GRC) within four years of the implementation of the Mechanism. As a result of each such GRC, the Commission will reset the baseline values identified in Appendix 2.[20] Any party may propose cancellation or modification of the Mechanism; such proposal should be in the context of a GRC.

D. Application to Customer Classes

The Commission described this criterion as follows:

> *Application to Customer Classes.* Generally, a full decoupling proposal should cover all customer classes. However, where in the public interest and not unlawfully discriminatory or preferential, the Commission will consider a proposal that would apply to fewer than all customer classes.[21]

---

[18] Id. at 19, Criterion 5, ¶ 28.
[19] Regulatory Assistance Project, Revenue Regulation and Decoupling, pages 21 and 38.
[20] See Appendix 2, Part 1.
[21] Decoupling Policy Statement at 18, Criterion 1, ¶ 28.

In the related footnote, the Commission explains its concern using an example of limited decoupling:

> As noted in [a prior footnote], a limited decoupling mechanism may result in cross-subsidies among rate classes. A reasonable mechanism would balance conservation program achievements by class with the revenue recovery expected from that class under the mechanism.[22]

The Mechanism for electric includes all customers. The Mechanism for gas includes all customers that participate in conservation programs.[23] See Appendix 1 and Workpapers for more details.

This issue begs a different question, however, i.e., whether decoupling should be on a class-by-class basis, or on a system basis. For example, the Puget PRAM was based on a single allowed-revenue-per-customer, regardless of size or class of the customer. By contrast, many decoupling mechanisms have different RPCs for each class.

The benefit of system-wide decoupling is that customer migration from one class to another has no effect on the utility's allowed revenue, so there is no incentive for the utility to encourage or require such migration. System-wide decoupling also is simpler, thereby reducing administrative burden. On the other hand, the advantage of class-by-class decoupling is that lost margins within a single class can be recovered within that class. In addition to fairness, class-by-class decoupling also may foster customer acceptance for decoupling. The Mechanism falls in-between, including all customers grouped by similar usage characteristics, except the very largest gas customers.

E. Impact on the Rate of Return

The Commission describes the need to measure the impact on return on equity (ROE) as follows:

> *Impact on Rate of Return.* Evidence evaluating the impact of the proposal on risk to investors and ratepayers and its effect on the utility's ROE.

The Commission contemplates reduction in debt costs as well as equity costs:

---

[22] Id. footnote 46.
[23] To simplify its analysis, Staff relied on PSE's CSA Rate proposal. For an explanation of the exclusion of gas transportation customers, see Exhibit No. __ (JAP-1T) at 34:15-16.

> 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.[24]

Under current regulation, the Company bears the risk of the effect that actual rate year loads have on the Company's ability to earn a fair return. Full decoupling insulates the Company from that risk. That risk reduction should be reflected in the rate of return.

The low end of Staff witness Mr. Elgin's discounted cash flow estimate range in this case is 9.00 percent, but that value could be lower under full decoupling. Moreover, the risk reduction impact could also affect capital structure (e.g., justify a lower equity ratio) as well as the cost of debt.[25, 26]

F. Earnings Test

The Commission includes an earnings test as an essential element of full decoupling:

> *Earnings test.* A proposed earnings test to be applied at the time of the true-up.[27]

The Commission does not further elucidate on the nature of the earnings test, e.g., the Commission does not explain the consequence if the utility earns in excess of the rate of return the Commission previously found to be appropriate. Accordingly, Staff considers an earnings "cap" and an earnings "band" to be within the scope of an earnings "test".

Footnote 15 from the Cascade Decoupling Mechanism Evaluation filed in Docket UG-060256 on July 11, 2011, evaluated the earnings cap:

> The addition of the earnings cap requirement, beyond the conservation performance criterion, means that the Washington decoupling mechanism is an example of a very

---

[24] Id. at 16-17, ¶ 27.
[25] For illustrative purposes based on limited experience with the Northwest Natural Gas Company decoupling mechanism in Oregon, about a 3% reduction in the equity capitalization ratio needed to sustain a given bond rating could result if full decoupling is implemented.
[26] Christensen (2005) evaluation of NWNG mechanism, at page 50, states: "According to CFO David Anderson the presence of DMN and WARM contributed to NW Natural attaining a score of "1" on S&P's business risk profile (in which 1 = best risk profile and 10 = worst risk profile). This rating has two effects. First, it allows NW Natural the flexibility to carry a lower share of equity in its capital structure if it chooses. Second, a favorable business risk profile rating allows NW Natural the flexibility to maintain a lower debt-service coverage ratio if it chooses."
[27] Decoupling Policy Statement at 17, Element 3, ¶ 28.

> strict decoupling mechanism having very strong customer protections. The objective of the earnings cap is to effectively prevent a "windfall profits" situation. It does so in this regard by placing a firm bound on increased rate of return, in order to help ensure that the decoupling mechanism does not facilitate excessive earnings by the utility. One unintended result of this earnings cap is that it could, in effect, penalize the utility for taking other actions (not relating to sales levels, e.g., cutting costs) if that provides them with a higher realized rate of return. If they do that (in effect, running their company more efficiently) they could lose the ability to recover the revenue shortfall from reduced sales, if their resulting earnings level exceeds the earnings cap. Essentially, this is a 'one-directional' limit that puts extra constraints on the company to the benefit of ratepayers. (It should be noted that the existence of this earning cap can be seen as helping to obviate the need for reducing the utility authorized rate of return, which is sometimes advocated as a concession in exchange for decoupling.)

And from page 25 of the same report:

> Given the current structure of the earnings cap, as an unintended side-effect, reducing costs could produce no net increase in earnings because the revenue recovery would be reduced to the earnings cap set in the prior rate case (for the pilot, 8.85%). So, in such a case, the current structure of the earnings cap might create a disincentive to create higher earnings through this type of improvement. As Cascade Natural Gas appears to have been taking steps to contain cost of service this concern may need to be noted in the further development of specifications for the earnings cap. This may be considered a form of "cost risk" (though from cost reduction) and cost-risk is not addressed by the decoupling mechanism.

In view of the lack of efficiency incentive in an earnings "cap", Staff believes an earnings "band" is more appropriate. For illustrative purposes, the Mechanism contains an Earnings Test based on a 25 basis point deadband above the rate of return established by the Commission in the Company's most recent general rate case that incorporates the effect of decoupling in establishing the rate of return.[28]

As discussed below, the opportunity to increase earnings through controlling costs is an important part of the current regulatory paradigm. The Earnings Test can help retain or even increase management's incentive to control costs and should be carefully integrated in the design of a mechanism.

The Commission could use the annual "commission-basis" report the Company files per WAC 480-100-257 (electric) and WAC 480-90-257 (gas). Currently, the Commission does not audit

[28] Staff bases the size of the deadband on national findings about the range of adjustments for rate of return, which vary from 25 to 100 basis points.

these reports, and if they are used in a decoupling mechanism, some auditing may be necessary. Staff considers the commission-basis reporting the best alternative for applying an Earnings Test; in addition, the Commission-basis report is based on weather-adjusted revenue, therefore using it for the Earnings Test incorporates weather effects into the Mechanism without double-counting the changes in usage already incorporated into the decoupling deferral.

The Earnings Test should be calculated as follows: If the rate of return from the commission-basis report is below the top of the deadband, no adjustment to the deferral amount is made. If the rate of return is above the top of the deadband, an adjustment to decrease recovery to the top of the deadband is incorporated into the deferral amount.

The process for evaluating whether the Company is earning within, above, or below the band should be a meaningful process, yet an efficient process as well. Staff assumes the Commission did not envision a general rate case-type process, for example.

G. Address Management's Potential Disincentive to Reduce Costs, in Light of Eliminating the Utility's Risk of Revenue Declines

The Commission described this factor as follows:

> with full decoupling comes a concern that, by eliminating the risk of recovery of declines in revenue, combined with an energy cost recovery mechanism that reduces an electric utility's financial risk due to changes in power costs, the utility could lose some of its incentive to manage the company in a manner that constantly looks to reduce costs ... we will require evidence and argument from the parties on this issue in the context of a request for a full decoupling mechanism.[29]

Full decoupling should eliminate the management incentive to concentrate on increasing sales, because that will not result in more revenue to the utility. Management should therefore focus on cost reductions, because that will enhance earnings between rate cases. Those cost reductions mean that when the next rate case occurs, the revenue requirement would grow at a slower rate than it otherwise would. The Earnings Test with the 25 basis point deadband does not remove this incentive to reduce costs.

On the other hand, decoupling could lead to extended periods between rate cases, because lost revenues due to sales reductions do not affect the utility's earnings. Therefore, the Mechanism requires the Company to file a general rate case within four years of the implementation of the Mechanism. While it is possible management would become less vigilant over costs under full decoupling, because revenues are assured, the periodic rate case requirement assures continuing

[29] Decoupling Policy Statement at 16, ¶ 26 (footnotes omitted).

Commission scrutiny of the Company's operations. A K-Factor should be incorporated into the Mechanism as an annual percentage reduction in revenue per customer after three years, unless a GRC is filed.

The Mechanism addresses management's efficiency incentives by giving the Company the benefit of the deadband used in the Earnings Test (mentioned in Section (F) above). By allowing the Company to retain profits up to 25 basis points higher than the Commission-determined rate of return, shareholders are rewarded for operational efficiencies.

H. Conservation Achievement

One key objective of full decoupling is to remove barriers to conservation achievement. The Commission conditions revenue recovery under full decoupling with achieving the conservation target:

> Revenue recovery by the company under the mechanism will be conditioned upon a utility's level of achievement with respect to its conservation target.[30]

Later, in its discussion about direct conservation incentives, the Commission explains further about its understanding of the conservation achievement.

> However, the EIA, in RCW 19.285.060(4), provides us with the express authority to provide such incentives: "The commission ... may consider providing positive incentives for an investor-owned utility to exceed the targets established in RCW 19.285.040." We do not read this provision to permit us to provide incentives to acquire conservation that is not cost-effective. Rather, we read this to suggest that, between the biennial conservation targets designed to determine what cost-effective conservation can be required, the electric utility may be able to acquire additional conservation as technology is improved, federal or other matching funds become available, or for other reasons that were not known at the time of the setting of the target.[31]

The requirement to condition approval on conservation achievement makes a great deal of sense in the context of limited decoupling, where the annual application of a decoupling mechanism is likely to result in a surcharge to customers. However, it was more difficult to apply this condition in the context of full decoupling, where the decoupling mechanism is just as likely to result in a refund to customers as in a surcharge.

---

[30] Id. at 17, ¶ 28.
[31] Id. at 20, ¶ 31, 32.

The Commission's linkage of conservation achievement to full decoupling is intended to transform the removal of a disincentive to invest in conservation (which is what we typically expect from full decoupling) into an incentive to invest in conservation (which is typically achieved through other tools). Therefore, because full decoupling by itself does not normally provide a specific incentive to invest in conservation, yet the Commission intends that any such mechanism should ensure achievement of conservation targets and achievement of incremental conservation over and above the targets, the Mechanism includes a Conservation Test.

I. Conservation Test

The Conservation Test is designed to both: (1) condition recovery on the Company's level of conservation achievement by multiplying the deferral amount by the proportion of conservation achieved during the prior year, and (2) encourage the utility to acquire additional conservation beyond the commission-approved target by allowing the company to multiply the deferral amount by up to 120 percent of the conservation achieved during the prior year.

While it is true that the Company must achieve certain conservation targets under the EIA for its electric operations, at the risk of substantial monetary penalty, the EIA contains no mechanism to encourage above-target performance, nor does the EIA apply to gas operations. However, the gas incentive mechanism already in place for PSE provides the Company an incentive to achieve its gas conservation targets.[32]

The conservation targets are taken from the Company's most recent IRP.[33] These targets will be contained in the decoupling tariff. If a surcharge is expected, the Company will adjust the deferral amount by multiplying the deferral amount by the proportion of savings it achieves in the previous year, up to a 120 percent cap. If a rebate is expected, the Company will adjust the deferral amount by multiplying the deferral amount by the inverse proportion of savings it achieves in the previous year, up to a cap of 120 percent.

The Mechanism requires third party verification of achieved conservation, to bring credibility to the process and assure reliable conclusions.

---

[32] *WUTC v. Puget Sound Energy, Inc,* UG-011571, Order 05 amending 12th Supplemental Order, Exhibit F – Settlement Terms for Conservation , (September 28, 2010). In addition, as described in Section K below, the Commission also expects the Company to identify incremental conservation that will be pursued, and the Conservation Test will document and reward the achievement of incremental conservation.

[33] In the case of electric targets, they may also be taken from Commission-approved targets under WAC 480-109-010.

J. Provide Comparable Conservation Benefits to Low Income Customers

The Commission described the low income criterion as follows:

> *Low-income.* A utility proposing a full decoupling mechanism must demonstrate whether or not its conservation programs provide benefits to low-income ratepayers that are roughly comparable to other ratepayers and, if not, it must provide low-income ratepayers targeted programs aimed at achieving a level of conservation comparable to that achieved by other ratepayers, so long as such programs are feasible within cost-effectiveness standards.[34]

Staff is having difficulty applying the criterion described in the Decoupling Policy Statement because it is not clear whether the Company could comply with this criterion by showing that the design of the Company's low-income programs provides an opportunity for "roughly comparable" access to conservation programs for customers across the economic spectrum.

The criterion also speaks in terms of actual benefits, which Staff assumes to mean that reductions in kWh due to conservation in low-income households must be "comparable to that achieved by other ratepayers". Either way, it is unlikely that data to conduct such analyses exists.

Another ambiguity involves the breadth of the criterion. For example, it is not clear whether the comparison should be between all low-income ratepayers and non-low-income ratepayers, between the low-income and non-low-income participants in the Company's conservation programs, or between just the participants in low-income assistance programs and the other residential ratepayers.

The core problem is that we do not know which residential customers are low-income customers, and which are not – and the composition of each group is continuously changing. The utilities do not maintain data on the economic status of their customers, and we do not suggest they should.

If the Commission's goal is to use only the program participant portion of the customer base, it might be possible for the Company to compare use per customer between low-income and non-low-income customers who are also conservation program participants. The Company could then determine what respective proportion of load had been reduced by using the relative conservation achievement. This might be acceptable as a criterion for comparing participant benefits from conservation programs, even though it would not be acceptable for rate design.[35]

---

[34] Decoupling Policy Statement at 18, Criterion 4, ¶ 28.
[35] Exhibit No. __ (DJR-1T).

However, there is a degree of fluidity in the low-income participant pool rendering any calculation of a reduction in kWh suspect.[36]

K. Describe the Incremental Conservation the Utility Intends to Pursue

The Commission describes this criterion as follows:

> *Incremental Conservation.* Evidence describing any incremental conservation the company intends to pursue in conjunction with the mechanism.[37]

The Mechanism uses the Company's IRP to identify the conservation the Company intends to pursue. However, the IRP does not identify the "incremental" conservation the Company would pursue with full decoupling versus without decoupling.

Staff does not have information regarding what additional conservation the Company would achieve with full decoupling compared to the status quo. The Company, like any other electric utility in this state, is statutorily required to "pursue all conservation that is cost-effective, reliable and feasible."[38] Because this statutory requirement applies whether or not the Company is decoupled, the only cost-effective "incremental conservation" the Company would acquire due to full decoupling would be:

a) conservation the Company would acquire earlier in time than the Company otherwise has planned, and
b) conservation opportunities that become available after the targets are set, for example, as a result of new energy efficiency technology becoming available.

Again, Staff has no estimate of the amount or type of conservation this would involve, but has designed the Conservation Test to measure and encourage investment of this kind.

L. Accounting for the Net Benefits of Off-System Sales and Costs Avoided Due to the Utility's Conservation Efforts

The Commission requires an accounting for certain off-system sales and avoided costs:

> *Accounting for Off-System Sales and Avoided Costs.* A description of the method the company intends to use to determine the financial benefits associated with off-system

[36] Only about one-half of the households receiving energy assistance in one year also participate in the following year.
[37] Decoupling Policy Statement at 18, Criterion 3, ¶ 28.
[38] RCW 19.285.040(1).

sales or avoided costs attributable to the utility's conservation efforts and then to net these benefits against the true-up provided in this mechanism.[39]

In the related footnote, the Commission explains:

> In principle, for every megawatt hour saved through the operation of the utility's conservation program, it has the opportunity to either sell the same in the appropriate market (off-system sales), or avoid having to purchase or produce electricity to meet its load requirements. The accounting of this form of found revenue differs between electric utilities with power cost adjustment mechanisms and those without. After rates have been set for an electric utility that does not have a power cost adjustment mechanism, the marginal avoided cost of producing or buying electricity, or the marginal revenue (net of marginal cost) from the sale of electricity made surplus by conservation not incorporated into the calculation of the power costs, is a direct benefit to the utility shareholders. For utilities with a power cost adjustment mechanism, loads are projected in a future test year, with reductions in the load for the expected conservation levels. Consequently, for the effective rate year following the setting of rates, only conservation above the expected level of conservation would result in an opportunity to reduce power costs or realize additional revenues from incremental sales. In the years after the projected rate year, the marginal avoided cost of producing or buying electricity, or the marginal revenue (net of marginal cost) from a sale of electricity made surplus by conservation, is a direct benefit.[40]

The Commission reinforced this statement in the part of the Bench Request that requires Staff to "[consider] lost sales revenues that are potentially offset by avoided costs and other benefits."[41]

There are two separate categories of benefits from utility conservation efforts that should be considered. The first are power costs: fuel, purchased power, sales for resale, and transmission by others. The second consists of distribution (and even transmission) capacity deferrals.

If a utility has a fuel and purchased power adjustment mechanism that automatically flows through all changes in power costs, the costs and benefits of concern to the Commission would be addressed in the power cost mechanism and it would be sufficient to simply allow such a power cost mechanism to operate outside the otherwise "full" decoupling mechanism. As we noted earlier, the Commission's Decoupling Policy Statement allows for such power cost mechanisms in tandem with full decoupling.

---

[39] Decoupling Policy Statement at 17, Element 4, ¶ 28.
[40] Id. n. 45.
[41] Bench Request at 2.

However, PSE does not have a full pass-through power cost adjustment mechanism (PCA), due to the $20 million dead band.[42] That $20 million dead band greatly exceeds the amount of power cost savings (and also the amount of benefits through additional wholesale power sales opportunities) likely to be achieved through Company-sponsored energy efficiency programs.

Because PSE's PCA does not capture any of the power cost impacts of reduced sales due to efficiency, special attention needs to be paid to power costs in designing a full decoupling mechanism.

The simplest way to do this in the context of a full decoupling mechanism would be to subtract the average power cost avoidance from the decoupling deferral. Simply stated, if sales dropped 500,000 kWh, and the average wholesale rate during that period was $.05/kWh, then the deferral amount would be reduced by $25,000. The "average wholesale rate" could be taken from actual market averages during the decoupling year, or it could be set in advance.

The Company's wholesale power costs would also need to be adjusted to reflect the marginal line losses associated with load changes. Using the same example, if PSE's retail electric sales dropped by 500,000 kWh at the distribution level, this would imply PSE actually avoided more like 550,000 kWh of wholesale power supply (at a marginal distribution line loss level of 10%).

The second category of cost avoidance due to a decline in retail sales due to conservation consists of distribution system capacity deferrals. These are much more complex. For example, if the utility targets energy efficiency programs to those distribution circuits that are scheduled for capacity upgrades, it can reduce or avoid the cost of those upgrades. This enables the utility to serve new customers – and generate new revenues from those customers – without expanding the distribution system capacity.

The Company has cited the need to replace distribution circuit components as a major issue in this rate case,[43] and if the capacity of required transformers and distribution lines can be reduced, cost savings can be achieved.

Under conventional regulation, the utility makes investments in distribution upgrades, and then includes those upgrades in rate base. If (and when) these costs accumulate to the point that the utility earns less than a fair rate of return, the utility files a rate case. Decoupling does not "change" this framework, but it may affect it.

With deferral decoupling, as done in California and Hawaii, the annual attrition calculation takes into account the expenditures the utility has made in the previous year, net of accumulated depreciation during that year. This approach would flow through to consumers the distribution capacity savings that result from deferrals or downsizings due to energy efficiency.

---

[42] Exhibit No. __ (SA-1CT) at 5.
[43] Exhibit No. __ (SML-1T), 19-33.

Revenue per customer (RPC) decoupling, on the other hand, is done differently. The allowed revenue is based on some historical average of costs. If the mechanism is designed "correctly", the allowed RPC equals the cost the utility incurs as the customer count grows. Therefore, the mechanism should include a "K-factor", or attrition factor, or a percentage adder or deduction over time to accurately account for non-linear relationships between incremental costs and additional customers.

On the other hand, if the utility is able to reduce its distribution expenditures (for any combination of new and existing customers) through energy efficiency below the historical level required, then a historically accurate level of revenue per customer may exceed the incremental cost the utility will actually incur. If this were to happen, the utility would effectively retain that savings until the next rate case (and, if the savings were large, might be able to forestall a rate case for a long time). While Staff considers this unlikely for the Company, where the majority of the utility's distribution system investment is associated with existing customers, not new customers, this is important to consider in the design of the mechanism.

Simply stated, the K-factor must be determined under the assumption that the utility will target energy efficiency investments to achieve distribution investment savings. Identifying the correct K-factor requires extensive understanding of the Company's distribution construction budget and the causative factors leading to component replacement. This area in particular will require additional work prior to the implementation of decoupling.

The Mechanism could account for the net benefits of off-system sales and costs avoided due to the utility's conservation efforts by calculating the allowed revenue per customer on a basis net of power costs (adjusted for marginal line losses). For example, if average revenue per residential customer were $1,000 per year, average usage were 10,000 kWh per year, marginal line losses were 10%, and average market prices were $.05/kWh, the Mechanism would allow $450 per year in non-power revenues per customer. ($1,000 – (10,000 x 1.1 x $.05)) = $450. In computing the deferral amount, any deviation in sales from the allowed level would also be adjusted by the average power cost grossed up for marginal line losses.

M. Reports to the Commission on How the Full Decoupling Mechanism is Working

On the reporting issue, the Commission states:

> *Reports.* For companies authorized to implement full decoupling, the Commission may require the utility to file periodic reports so the Commission may evaluate the success and impact of the program. The reported information must be made available to

representatives of customer groups, and other interested parties, so they too can evaluate the program and its impact on the utility and its ratepayers.[44]

The Mechanism calls for the Company to file quarterly reports on the rolling 12-month status of the full decoupling deferral accounts. These reports are necessary for the Commission to track the size of the deferral accounts, and make recommendations on frequency of true-ups, which can change if usage varies dramatically.

Also, by June 1 of each year, the Company would file its third-party evaluation, measurement, and verification reports on conservation achievement. These reports are necessary to determining whether or not the Company met its conservation targets, and how the Conservation Test should adjust any recovery or rebate.

N. Other Factors

The Commission does not limit the elements or criteria it will consider when evaluating a full decoupling mechanism:

> *Other Factors Impacting the Public Interest.* The criteria listed above are not intended to limit the Commission's authority to review other factors affecting its analysis of full decoupling as a regulatory tool, including whether it remains in the public interest to continue its use by a particular utility.[45]

Service Quality

In order to address the possible incentive for a utility not to restore service promptly (because getting customers back on line sooner does not affect the revenues the utility collects), service quality assurance is necessary. Under decoupling, usage from the current year will be adjusted back to the baseline usage amount. If current year usage is lower due to outages, the Company would recover revenue associated with outage-related usage, thus increasing net operating income unless a System Average Interruption Duration Interval (SAIDI) adjustment is performed.

Under the Mechanism, at the time of each annual deferral filing, the Company should adjust actual sales (up or down) to the level implied by holding SAIDI to the ten-year system average. This will assure that decoupling-related revenues due to slow system restoration after outages do not inure to the benefit of shareholders. In addition, the Commission should thoroughly review

[44] Decoupling Policy Statement at 19, Criterion 6, ¶ 28.
[45] Id. at 19, Criterion 7, ¶ 28.

the utility's existing service quality program whenever decoupling is imposed. In the case of PSE, particular attention should be given to meaningful customer service guarantees and the impact of meter failures.

Administrative Burden

Lastly, in considering full decoupling, significant increases in the amount of staff time and resources required to review company filings should be expected; unaudited commission-basis reports, decoupling tariff filings of true-up mechanisms, decoupling quarterly reports, conservation potential assessments, conservation programs, conservation evaluation reports, low-income conservation programs, among others. Careful consideration of the benefits and drawbacks of full decoupling should include a review of the Commission's administrative burden.

Appendix 1

UTC Staff Response to Bench Request on Full Decoupling

Summary of Electric Decoupling Effects

Line					
1	Existing Change in Load			5%	(See Deferral Tab, highlighted cells)
2	and Change in Customer Count			-2%	(See Deferral Tab, highlighted cells)
3	Class by Class Deferral		$	(31,402,980)	(See Deferral Tab, Rows 6-27)
4	Earnings Test	+	$	(6,704)	(See Earnings Tab, Scenario 3)
5	Conservation Test	+	$	(4,980,536)	(See Conservation Tab, Scenario 2)
6	Final Deferral Amount	=	$	(36,390,220)	
7	System Deferral		$	(28,793,801)	(See Deferral Tab, Rows 29-50)

Appendix 1

UTC Staff Response to Bench Request on Full Decoupling

Summary of Gas Decoupling Effects

Line				
1	Existing Change in Load		6%	(See Deferral Tab, highlighted cells)
2	and Change in Customer Count		0%	(See Deferral Tab, highlighted cells)
3	Class by Class Deferral		$ (4,580,807)	(See Deferral Tab, Rows 6-27)
4	Earnings Test	+	$ (12,379,851)	(See Earnings Tab, Scenario 3)
5	Conservation Test	+	$ 176,590	(See Conservation Tab, Scenario 2)
6	Final Class by Class Deferral Amount	=	$ (16,784,068)	
7	System Deferral		$ (16,249,429)	(See Deferral Tab, Rows 29-50)

Appendix 1

Workpapers

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Earnings Test

	2010 GRC	2% growth in all Scenario 1	2% growth in expenses Scenario 2	2% growth in revenue Scenario 3	
Revenue	$ 2,183,578,830	$ 2,227,250,407	$ 2,183,578,830	$ 2,227,250,407	
Expenses	$ 1,770,598,295	$ 1,806,010,261	$ 1,806,010,261	$ 1,770,598,295	
Rate Base	$ 4,904,756,946	$ 5,002,852,085	$ 4,904,756,946	$ 4,904,756,946	
ROR	8.42%	8.42%	7.70%	9.31%	
Band	0.25%				
Deadband High	8.67%				
Deferral amount					$ (31,402,980)
Portion of ROR overearned		0.00%	0.00%	0.64%	
Minimum amount to be returned to customers		$ -	$ -	$ 31,409,684	$ (31,409,684)
Additional amount to be deferred					$ (6,704)

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Conservation Test

Under Recovery	Target	Scenario 1	Scenario 2	Scenario 3
	340,119,000	374,130,900	293,560,144	442,154,700
		110.0%	86.3%	130.0%
Percentage Achieved		110.0%	86.3%	120.0%
Percentage Multiplier	$ -			
Deferral Amount		$ -	$ -	$ -
Amount Added to Recovery				

Under Rebate	Target	Scenario 1	Scenario 2	Scenario 3
	340,119,000	374,130,900	293,560,144	442,154,700
		110.0%	86.3%	130.0%
Percentage Achieved		90.9%	115.9%	83.3%
Percentage Multiplier	$ (31,402,980)			
Deferral Amount		*$ 2,854,816*	*$ (4,980,536)*	*$ 5,233,830*
Amount Added to Rebate				

Target based on 2011 ACP tab in JAP Workpapers 11-13-15-17-21
Scenario 2 achievement based on 2010 Elec Consv tab in JAP Workpapers 11-13-15-17-21

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Baselines

Line No.		Source	Group R - Schedule 7	Group C - Schedules 24-26, 29, 31, 35, 43 & 57	Group V - Schedules 40, 46, 49, 448, 449, 458 & 459	Total Company
	(a)	(b)	(c)	(d)	(e)	
1	***2009 GRC (UE-090704)***					
2	Total Proforma Revenue	UE-090704 WP	$ 1,104,542,863	$ 825,673,386	$ 87,994,621	$ 2,018,210,870
3	Less: Basic Charge Revenue	UE-090704 WP	$ 83,893,121	$ 28,423,719	$ 947,480	$ 113,264,320
4	Less: Allocated Power Costs	UE-090704 WP	$ 772,470,708	$ 598,005,470	$ 73,053,560	$ 1,443,529,738
5	Net Decoupled Revenue	(2)-(3)-(4)	$ 248,179,034	$ 199,244,197	$ 13,993,581	$ 461,416,812
6						
7	Base Year Sales (kWh)	UE-090704 WP	10,949,843,923	9,529,158,184	3,304,174,547	23,783,176,654
8						
9	Base Year Customers	UE-090704 WP	11,566,455	1,599,022	1,270	13,166,747
10						
11	Base Monthly Use Per Customer	(7)/(9)	947	5,959	2,601,712	1,806
12						
13	2009 GRC Revenue/Unit (¢/kWh)	(5)/(7)x100	2.2665	2.0909	0.4235	1.9401
14						
15	Base Monthly Revenue/Customer	(11)*(13)	$ 21.46	$ 124.60	$ 11,018.25	$ 35.04

* 2009 GRC is based on 2008 Test Period.

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Deferral

Results	
Class by Class Deferral	$ (31,402,980)
System Deferral	$ (28,793,801)

		Schedule 7						Schedules 24, 25, 26, 29, 31, 35, 43 & 57						Schedules 40, 46, 49, 448, 449, 458 & 459					
Line No.	Month	Base Revenue per Customer	Current Customers (1)	Allowed Revenue	Current Usage (2)	Actual Revenue	Deferral	Base Revenue per Customer	Current Customers	Allowed Revenue	Current Usage	Actual Revenue	Deferral	Base Revenue per Customer	Current Customers	Allowed Revenue	Current Usage	Actual Revenue	Deferral
	(a)	(b)	(c)	(d) = (b)*(c)	(e)	(f) = (e)*.02265	(d)-(f)												
1	Jan-10	$ 21.46	952,803	$20,444,029	1383498283	$ 31,356,989	$ (10,912,959)	$ 124.60	125,553	$15,644,456	896690961.6	$ 18,748,911	$ (3,104,456)	$ 11,018.25	149	$1,641,719	279917587	$ 1,185,451	$ 456,268
2	Feb-10	$ 21.46	952,803	$20,444,029	1157322024	$ 26,230,704	$ (5,786,674)	$ 124.60	125,553	$15,644,456	855245010.4	$ 17,882,318	$ (2,237,862)	$ 11,018.25	149	$1,641,719	284604033	$ 1,205,298	$ 436,421
3	Mar-10	$ 21.46	952,803	$20,444,029	1093632622	$ 24,787,183	$ (4,343,154)	$ 124.60	125,553	$15,644,456	840526304.4	$ 17,574,564	$ (1,930,109)	$ 11,018.25	149	$1,641,719	265261874	$ 1,123,384	$ 518,335
4	Apr-10	$ 21.46	952,803	$20,444,029	1005793654	$ 22,796,313	$ (2,352,284)	$ 124.60	125,553	$15,644,456	805776479	$ 16,847,980	$ (1,203,525)	$ 11,018.25	149	$1,641,719	281630210	$ 1,192,704	$ 449,016
5	May-10	$ 21.46	952,803	$20,444,029	904434055	$ 20,498,998	$ (54,969)	$ 124.60	125,553	$15,644,456	792838648.3	$ 16,577,463	$ (933,008)	$ 11,018.25	149	$1,641,719	280126802	$ 1,186,337	$ 455,382
6	Jun-10	$ 21.46	952,803	$20,444,029	821447066	$ 18,618,098	$ 1,825,932	$ 124.60	125,553	$15,644,456	783601005.7	$ 16,384,313	$ (739,858)	$ 11,018.25	149	$1,641,719	274392552	$ 1,162,052	$ 479,667
7	Jul-10	$ 21.46	952,803	$20,444,029	753116844	$ 17,069,393	$ 3,374,636	$ 124.60	125,553	$15,644,456	807422675.5	$ 16,882,401	$ (1,237,945)	$ 11,018.25	149	$1,641,719	277829459	$ 1,176,608	$ 465,112
8	Aug-10	$ 21.46	952,803	$20,444,029	735390805	$ 16,667,633	$ 3,776,397	$ 124.60	125,553	$15,644,456	813523754.2	$ 17,009,968	$ (1,365,513)	$ 11,018.25	149	$1,641,719	281601234	$ 1,192,581	$ 449,138
9	Sep-10	$ 21.46	952,803	$20,444,029	768267073	$ 17,412,773	$ 3,031,256	$ 124.60	125,553	$15,644,456	813523754.2	$ 17,009,968	$ (1,365,513)	$ 11,018.25	149	$1,641,719	276272861	$ 1,170,016	$ 471,704
10	Oct-10	$ 21.46	952,803	$20,444,029	772934818	$ 17,518,568	$ 2,925,462	$ 124.60	125,553	$15,644,456	792020633.1	$ 16,560,359	$ (915,904)	$ 11,018.25	149	$1,641,719	285145068	$ 1,207,589	$ 434,130
11	Nov-10	$ 21.46	952,803	$20,444,029	964492286	$ 21,860,218	$ (1,416,186)	$ 124.60	125,553	$15,644,456	885324223.7	$ 18,511,244	$ (2,866,789)	$ 11,018.25	149	$1,641,719	289759598	$ 1,227,132	$ 414,588
12	Dec-10	$ 21.46	952,803	$20,444,029	1300290901	$ 29,471,093	$ (9,027,064)	$ 124.60	125,553	$15,644,456	1124	$ 23,387,188	$ (7,742,095)	$ 11,018.25	149	$1,641,719	3	$ 1,185,451	$ 456,268
			11,433,636		11860620432	$ 264,287,962	$ (18,959,610)		1,506,636		9833987146	$ 205,618,837	$ (17,885,370)		1,788		3968555595	$ 14,258,633	$5,442,000

Note (1) Customer count based on JAP-4 Workpapers Page 33. In an actual filing, current customers should be actual monthly customers.
Note (2) Usage data based on billing data load shapes and 2010 energy usage info from JAP-4 Workpapers Page 37
In an actual filing, current usage should be actual monthly current usage.

		System					
Line No.	Month	Base Revenue per Customer	Current Customers (1)	Allowed Revenue	Current Usage (2)	Actual Revenue	Deferral
	(a)	(b)	(c)	(d) = (b)*(c)	(e)	(f) = (e)*.019401	(d)-(f)
1	Jan-10	$ 35.04	1,078,505	$37,795,287	2556046787	$ 49,589,903	$ (11,794,615)
2	Feb-10	$ 35.04	1,078,505	$37,795,287	2295470093	$ 44,534,415	$ (6,739,128)
3	Mar-10	$ 35.04	1,078,505	$37,795,287	2197774977	$ 42,639,032	$ (4,843,745)
4	Apr-10	$ 35.04	1,078,505	$37,795,287	2092854209	$ 40,603,465	$ (2,808,177)
5	May-10	$ 35.04	1,078,505	$37,795,287	1978016651	$ 38,375,501	$ (580,214)
6	Jun-10	$ 35.04	1,078,505	$37,795,287	1880716094	$ 36,487,812	$ 1,307,475
7	Jul-10	$ 35.04	1,078,505	$37,795,287	1818510467	$ 35,280,922	$ 2,514,365
8	Aug-10	$ 35.04	1,078,505	$37,795,287	1826831297	$ 35,442,354	$ 2,352,933
9	Sep-10	$ 35.04	1,078,505	$37,795,287	1874453031	$ 36,366,263	$ 1,429,024
10	Oct-10	$ 35.04	1,078,505	$37,795,287	1826550317	$ 35,436,903	$ 2,358,384
11	Nov-10	$ 35.04	1,078,505	$37,795,287	2041806602	$ 39,613,090	$ (1,817,803)
12	Dec-10	$ 35.04	1,078,505	$37,795,287	2472428628	$ 47,967,588	$ (10,172,301)
			12,942,060		24861463173	$ 482,337,247	$ (28,793,801)

Note (1) Customer count based on JAP-4 Workpapers Page 33
Note (2) Usage data based on billing data load shapes and 2010 energy usage info from JAP-4 Workpapers Page 37
In an actual filing, current usage should be actual monthly current usage.

Percentage Changes
-2% in customers
5% in usage

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Load Shapes

Load Shapes for Rate Groups	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Group R (Residential, Schedule 7)	12%	10%	9%	9%	8%	7%	6%	6%	7%	7%	8%	11%
Group C (Commercial Schedules 24-35, 43, 50-59)	9%	9%	9%	8%	8%	8%	8%	8%	8%	8%	8%	9%
Group T (Wheeling Schedules 40, 46, 49, 448, 449	8%	8%	8%	8%	8%	8%	8%	8%	9%	8%	8%	9%
System	10%	9%	9%	8%	8%	8%	7%	7%	8%	7%	8%	10%

Source data from PSE Response to Staff Data Request 96, Attachment A, and JAP-4 Workpapers pages 25 and 37

		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	
Residential	7	1265930828	1058974663	1000697484	920322929.9	827576706.1	751641818.2	689118187.9	672898479.1	702980975	707252063	882531286	1189794275	10669719694
subtotal		1265930828	1058974663	1000697484	920322929.9	827576706.1	751641818.2	689118187.9	672898479.1	702980975	707252063	882531286	1189794275	10669719694
Sec Volt (kW<50)	24	249897244.4	229454600.7	220765444.7	209566492.4	202892225	197371053.6	199529416.8	205911415.5	208133105	196489359	208079390	247067089	2575156836
Sec Volt (kW>50 & <350)	25	259026820.8	247279356.6	244889060.2	235073975.4	233876818.3	231240079.2	234918100.5	240701571.9	242691621	230519688	236998327	260183934	2897399353
Sec Volt (kW>350)	26	183842240	178282880	176050080	170518873.9	167548079.2	169366820	175621880	179379240	177639980	167735880	163532280	174976620	2084494853
Pri Volt	31,35,43	130374741.9	129727710	129404208.4	123756399.6	122612709.3	120393910.6	110047929.1	114448588.9	117628293	116151951	117562007	130382991	1462491439
Lighting	50-59	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	7574460.5	90893526
Subtotal		830715507.6	792319007.8	778683253.8	746490201.8	734504292.4	725946323.9	727691787	748015276.7	753667459	718471338	733746464	820185095	9110436008
Campus	40	48063072	55003792	49692260	48310675.23	56201575.31	54705422	60743493.99	60230473	58213417	56592757	55963132	54463988	658184057.5
High Volt	46,49	43967270	45386860	43184760	45436960	45777209.58	47447540	46581340	46473610	59465392	50601208	51452130	53951200	579725479.6
Wheeling	448, 449	174282443	170380804	159492362	174194535	164533047	158903321	157001312	161210519	158525396	155651238	163870934	167261258	1965307169
Subtotal		266312785	270771456	252369382	267942170.2	266511831.9	261056283	264326146	267914602	276204205	262845203	271286196	275676446	3203216706
System total		2362959121	2122065127	2031750119	1934755302	1828592830	1738644425	1681136121	1688828358	1732852639	1688568604	1887563945	2285655817	22983372408

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Earnings Test

	GRC	2% growth in all Scenario 1	2% growth in expenses Scenario 2	2% growth in revenue Scenario 3	
Revenue	$ 1,055,321,057	$ 1,076,427,478	$ 1,055,321,057	$ 1,076,427,478	
Expenses	$ 933,327,814	$ 951,994,370	$ 951,994,370	$ 933,327,814	
Rate Base	$ 1,658,305,524	$ 1,691,471,635	$ 1,658,305,524	$ 1,658,305,524	
ROR	7.36%	7.36%	6.23%	8.63%	
Band	0.25%				
Deadband High	7.61%				
Deferral amount					$ (4,580,807)
Portion of ROR overearned		0.00%	0.00%	1.02%	
Minimum amount to be returned to customers		$ -	$ -	$ 16,960,657	$ (16,960,657)
Additional amount to be deferred					$ (12,379,851)

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Conservation Test

Under Recovery

	Target	Scenario 1	Scenario 2	Scenario 3
	4,790,000	4,311,000	4,982,058	6,227,000
Percentage Achieved		90.0%	104.0%	130.0%
Percentage Multiplier		90.0%	104.0%	120.0%
Deferral Amount	$ -			
Amount Added to Recovery		$ -	$ -	$ -

Under Rebate

	Target	Scenario 1	Scenario 2	Scenario 3
	4,790,000	4,311,000	4,982,058	6,227,000
Percentage Achieved		90.0%	104.0%	130.0%
Percentage Multiplier		111.1%	96.1%	83.3%
Deferral Amount	$ (4,580,807)			
Amount Added to Rebate		*$ (508,979)*	*$ 176,590*	*$ 763,468*

Target based on 2011 Gas Consv tab in JAP Workpapers 12-14-16-19
Scenario 2 achievement based on 2010 Gas Consv tab in JAP Workpapers 12-14-16-19

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Baselines

Line No.		Source	Residential (23,53)	Firm Sales (31,41)	Interruptible Sales (85,86,87)	Total Company
	(a)	(b)	(c)	(d)	(e)	
1	***2010 GTIF (UG-101644)***					
2	Total Margin Revenue	UG-101644 WP	$ 288,601,991	$ 102,186,801	$ 6,603,291	$ 397,392,082
3	Less: Basic & Minimum Charge Revenue	UG-101644 WP	$ 84,101,780	$ 27,262,673	$ 976,187	$ 112,340,640
4	Net Decoupled Revenue	(2)-(3)	$ 204,500,211	$ 74,924,128	$ 5,627,104	$ 285,051,442
5						
6	Base Year Sales (therms)	UG-101644 WP	547,201,677	272,517,298	60,562,884	880,281,859
7						
9	Base Year Customers	UG-101644 WP	8,410,178	683,662	4,665	9,098,505
10						
11	Base Monthly Use Per Customer	(7)/(9)	65	399	12,982	97
12						
13	2010 GTIF Revenue/Unit ($/therms)	(5)/(7)	0.3737	0.2749	0.0929	0.3238
14						
15	Base Monthly Revenue/Customer	(11)*(13)	$ 24.31	$ 109.58	$ 1,206.06	$ 31.33

* 2010 GTIF is based on 2009 Test Period.

Source: JAP-14

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Deferral

Results	
Class by Class Deferral	$ (4,580,807)
System Deferral	$ (16,249,429)

Line No.	Month	Schedule 23, 53 Allowed Revenue per Customer	Current Customers (1)	Allowed Revenue	Current Usage (2)	Actual Revenue	Deferral	Schedules 31, 41 Allowed Revenue per Customer	Current Customers	Allowed Revenue	Current Usage	Actual Revenue	Deferral	Schedules 85, 86, 87 Allowed Revenue per Customer	Current Customers	Allowed Revenue	Current Usage	Actual Revenue	Deferral
	(a)	(b)	(c)	(d) = (b)*(c)	(e)	(f) = (e)*.3737	(d)-(f)												
1	Jan-10	$ 24.31	703,450	$ 17,104,028	84115540	$ 31,433,977	$ (14,329,949)	$ 109.58	56,862	$ 6,230,891	34060213	$ 9,363,152	$ (3,132,261)	$ 1,206.06	379	$ 457,501	15010257	$ 1,384,453	$ (936,952)
2	Feb-10	$ 24.31	703,450	$ 17,104,028	69238694	$ 25,874,500	$ (8,770,472)	$ 109.58	56,862	$ 6,230,891	27706179	$ 7,616,429	$ (1,385,537)	$ 1,206.06	379	$ 457,501	13802055	$ 1,282,211	$ (824,710)
3	Mar-10	$ 24.31	703,450	$ 17,104,028	63157192	$ 23,601,843	$ (6,497,814)	$ 109.58	56,862	$ 6,230,891	25146202	$ 6,912,691	$ (681,800)	$ 1,206.06	379	$ 457,501	0	$ -	$ 457,501
4	Apr-10	$ 24.31	703,450	$ 17,104,028	54783101	$ 20,472,445	$ (3,368,416)	$ 109.58	56,862	$ 6,230,891	31275357	$ 8,597,596	$ (2,366,705)	$ 1,206.06	379	$ 457,501	12393856	$ 1,151,389	$ (693,889)
5	May-10	$ 24.31	703,450	$ 17,104,028	40576860	$ 15,163,573	$ 1,940,456	$ 109.58	56,862	$ 6,230,891	24786799	$ 6,808,393	$ (577,502)	$ 1,206.06	379	$ 457,501	10262863	$ 953,420	$ (495,919)
6	Jun-10	$ 24.31	703,450	$ 17,104,028	28539035	$ 10,665,037	$ 6,438,991	$ 109.58	56,862	$ 6,230,891	20764766	$ 5,708,234	$ 522,657	$ 1,206.06	379	$ 457,501	9680108	$ 899,282	$ (441,782)
7	Jul-10	$ 24.31	703,450	$ 17,104,028	18050620	$ 6,745,517	$ 10,358,512	$ 109.58	56,862	$ 6,230,891	15499234	$ 4,260,739	$ 1,970,152	$ 1,206.06	379	$ 457,501	7553129	$ 701,686	$ (244,185)
8	Aug-10	$ 24.31	703,450	$ 17,104,028	14377130	$ 5,372,734	$ 11,731,295	$ 109.58	56,862	$ 6,230,891	8486250	$ 2,332,870	$ 3,898,021	$ 1,206.06	379	$ 457,501	4737685	$ 440,131	$ 17,370
9	Sep-10	$ 24.31	703,450	$ 17,104,028	16456757	$ 6,149,890	$ 10,954,138	$ 109.58	56,862	$ 6,230,891	110876	$ 30,480	$ 6,200,411	$ 1,206.06	379	$ 457,501	9617754	$ 893,489	$ (435,989)
10	Oct-10	$ 24.31	703,450	$ 17,104,028	24905552	$ 9,307,206	$ 7,796,824	$ 109.58	56,862	$ 6,230,891	11599760	$ 3,188,774	$ 3,042,117	$ 1,206.06	379	$ 457,501	5363448	$ 498,264	$ (40,764)
11	Nov-10	$ 24.31	703,450	$ 17,104,028	49989017	$ 18,680,895	$ (1,576,867)	$ 109.58	56,862	$ 6,230,891	27629711	$ 7,595,408	$ (1,364,516)	$ 1,206.06	379	$ 457,501	9499503	$ 882,504	$ (425,003)
12	Dec-10	$ 24.31	703,450	$ 17,104,028	83837566	$ 31,330,099	$ (14,226,070)	$ 109.58	56,862	$ 6,230,891	44909960	$ 12,345,748	$ (6,114,857)	$ 1,206.06	379	$ 457,501	15444459	$ 1,434,790	$ (977,290)
			8,441,397		548,027,065	$ 204,797,714	$ 450,627		682,345		271,455,307	$ 74,760,514	$ 10,179		4,552		113,365,116	$ 10,531,619	$ (5,041,613)

Note (1) Customer count based on PSE Rate Design Gas spreadsheets. In an actual filing, current customers should be actual monthly customers.
Note (2) Usage data based on billing data load shapes and 2010 energy usage info from PSE Gas Rate Design spreadsheets.
In an actual filing, current usage should be actual monthly current usage.

Line No.	Month	System Allowed Revenue per Customer	Current Customers (1)	Allowed Revenue	Current Usage (2)	Actual Revenue	Deferral
	(a)	(b)	(c)	(d) = (b)*(c)	(e)	(f) = (e)*.3238	(d)-(f)
1	Jan-10	$ 31.33	760,691	$ 23,830,707	134618915	$ 43,589,605	$ (19,758,897)
2	Feb-10	$ 31.33	760,691	$ 23,830,707	111051395	$ 35,958,442	$ (12,127,734)
3	Mar-10	$ 31.33	760,691	$ 23,830,707	96192002	$ 31,146,970	$ (7,316,263)
4	Apr-10	$ 31.33	760,691	$ 23,830,707	97816990	$ 31,673,141	$ (7,842,434)
5	May-10	$ 31.33	760,691	$ 23,830,707	74483737	$ 24,117,834	$ (287,127)
6	Jun-10	$ 31.33	760,691	$ 23,830,707	56711075	$ 18,363,046	$ 5,467,661
7	Jul-10	$ 31.33	760,691	$ 23,830,707	38804265	$ 12,564,821	$ 11,265,886
8	Aug-10	$ 31.33	760,691	$ 23,830,707	26536970	$ 8,592,671	$ 15,238,036
9	Sep-10	$ 31.33	760,691	$ 23,830,707	22416558	$ 7,258,481	$ 16,572,226
10	Oct-10	$ 31.33	760,691	$ 23,830,707	41739737	$ 13,515,327	$ 10,315,380
11	Nov-10	$ 31.33	760,691	$ 23,830,707	87631178	$ 28,374,976	$ (4,544,268)
12	Dec-10	$ 31.33	760,691	$ 23,830,707	145344668	$ 47,062,603	$ (23,231,896)
			9,128,294		933347490	$ 302,217,917	$ (16,249,429)

Note (1) Customer count based on JAP-4 Workpapers Page 33
Note (2) Usage data based on billing data load shapes and 2010 energy usage info from JAP-4 Workpapers Page 37
In an actual filing, current usage should be actual monthly current usage.

Percentage Changes
0% in customers
6% in usage

933,347,490	290,089,848	(4,580,807)

Workpapers

UTC Staff Response to Bench Request on Full Decoupling

Load Shapes

Load Shapes for Rate Groups	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Group R (Residential, Schedule 16, 23, 53)	15%	13%	12%	10%	7%	5%	3%	3%	3%	5%	9%	15%
Group C (Commercial Schedules 31, 41, 61)	13%	10%	9%	12%	9%	8%	6%	3%	0%	4%	10%	17%
Group I (Interruptible Schedules 85, 86, 87)	13%	12%	0%	11%	9%	9%	7%	4%	8%	5%	8%	14%
System	14%	12%	10%	10%	8%	6%	4%	3%	2%	4%	9%	16%

Source data from PSE Response to Staff Data Request 96, Attachment A

		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	
Residential	16,23,53	82,046,992	67,535,994	61,604,046	53,435,888	39,579,004	27,837,210	17,606,724	14,023,572	16,052,057	24,293,081	48,759,699	81,775,854	534550121
subtotal		82046992	67535994	61604046	53435888	39579004	27837210	17606724	14023572	16052057	24293081	48759699	81775854	534550121
Com'l & Ind'l	31,61	29595528	24074373	21849859	19676578	15384907	12480387	8707355	7373818	96343	10079228	17812500	30412985	197543862
Large Volume	41,41T	219	199	287	7499340	6135567	5562624	4760306	91	0	86	6195628	8610372	38764719
Subtotal		29595747	24074573	21850146	27175918	21520475	18043011	13467661	7373909	96343	10079314	24008128	39023357	236308582
Interruptible	85,85T	1815728	4735329	0	1435146	1121093	919186	556805	1625446	1032509	1840139	1033935	1838160	17953477
Limited Interrupt	86,86T	3334121	0	0	2817046	2399979	2401950	2034588	0	623307	0	2225238	3460659	19296889
Non-Exclusive Interrupt	87,87T	0	0	0	0	0	0	0	0	1643926	0	0	0	1643926
Subtotal		5149850	4735329	0	4252192	3521073	3321136	2591393	1625446	3299743	1840139	3259172	5298820	38894292
System total		116792589	96345896	83454193	84863999	64620551	49201356	33665779	23022927	19448142	36212533	76026999	126098030	809752995

Appendix 2

Generic Full Decoupling Mechanism (Generic Mechanism)

NOTE: Though there would be separate decoupling mechanisms for electric and gas operations, the provisions of the Generic Mechanism are the same in concept for each type of service. Differences exist for items such as units sold (kilowatt-hours versus therms, for example). Accordingly, the description below describes one mechanism, but notes differences between gas and electric where appropriate.

1) Establishment of Generic Full Decoupling Mechanism (Generic Mechanism): The Washington Utilities and Transportation Commission (the Commission) will establish the Generic Mechanism in a general rate case (GRC). The Generic Mechanism will remain in place, unless modified or cancelled by the Commission. The Company will file a general rate case within four years of the implementation of the Generic Mechanism. The Commission will establish the following baseline values in that GRC, and will update these values in subsequent rate cases:

   a) Rate of Return: The rate of return approved by the Commission in the Company's most recent GRC, which will be set with the consideration of the impact of decoupling on risk to investors and ratepayers.

   b) Average Use Per Customer (Base UPC): The Base UPC will be the Base Sales divided by the Base Customers for each schedule and for each month of the test period in the GRC.

      i) Total Volume Base Sales (Base Sales): The Base Sales of [electric: kilowatt-hour; gas: therm] calculated for each schedule and for each month of the test period in the

GRC. The Base Sales will be temperature-adjusted if the respective rate schedule is temperature sensitive.

ii) Total Base Customers (Base Customers): The [electric/gas] Base Customers calculated for each schedule and for each month of the test period in the GRC.

c) Base Revenue Per Customer (RPC): The RPC will equal the Net Decoupled Revenue divided by the number of Base Customers for each schedule and for each month of the test period in the GRC.

i) Net Decoupled Revenue (NDR): NDR will equal the total revenue less the basic charge revenue and any allocated power costs.

d) Base Revenue Per Unit (RPU): The RPU (also known as the margin rate or fixed cost) for each rate schedule [electric: sales rate less energy cost per kilowatt-hour; gas: sales rate less purchased gas cost per therm] calculated by dividing the Net Decoupled Revenue by the Base Sales.

2) Application of the Mechanism: The Mechanism applies to all [electric/gas] customers of the Company, except:

a) Electric – customers served under schedules with minimum bills or other rate designs that cover all fixed costs outside of the volumetric charge for kilowatt-hours [List electric schedules].

b) Gas – customers served under schedules with minimum bills or other rate designs that cover all fixed costs outside of the volumetric charge for therms [List gas schedules].

3) Calculation of Monthly Deferral Amount: Following the end of each month, the Company will compare the Allowed Revenue from the current month with the Actual Revenue for the current month.

a) Calculate Current Allowed Revenue (Allowed Revenue) – the Company will calculate Allowed Revenue by taking the Base RPC per rate schedule for the current calendar month multiplied by the number of customers per rate schedule for the current calendar month (Current Customers).

b) Calculate Current Actual Revenue (Actual Revenue) – the Company will calculate Actual Revenue by taking the Base RPU per rate schedule for the current calendar month multiplied by the total volume of [electric: kilowatt-hour; gas: therm] sales per rate schedule for the current calendar month (Current Sales).

c) Comparison of Revenue Between Current Month and Base Year – the Company will calculate the difference between Allowed Revenue and Actual Revenue for the month for each rate schedule mentioned in (1c) above, to calculate the fixed distribution costs that are either under-recovered or over-recovered in the current year, as compared to the test year.

d) One Hundred Percent (100%) of Revenue Difference Deferred – the Company will defer 100 percent of the revenue difference, either positive or negative, and record that amount in a separate account for later recovery or rebate. The Company will accrue interest on the deferred balance at the level of the 1-year Treasury Constant Maturity, as of January 15 of the deferral year, as calculated by the United States Treasury and published in the Federal Reserve's Statistical Release H.15.

4) Deferral Periods Coincident with Company's Annual Energy Cost Adjustment (ECA): The accumulated monthly deferred revenue will be addressed coincident with the Company's Energy Cost Adjustment (electric: power cost adjustment mechanism; gas: purchased gas adjustment), currently beginning July 1 and ending June 30 of each year. Consequently,

unless the Generic Mechanism begins on July 1, the first year of the mechanism will be a transition in which the Company likely will defer more than, or less than, 12 months of revenue.

5) Annual Decoupling Rate Adjustment Filing Coincident with ECA: On or before September 1 of each year, the Company will file a proposed decoupling rate adjustment. The decoupling rate adjustment will be implemented at the same time as the new ECA rate. The tariff will reflect recovery of the deferred revenue the Company recorded for the prior deferral period, after application of the "Soft Cap" described in (6) and an "Earnings" test and a "Conservation" test, as explained in (7) below.

6) Soft Cap of Three Percent on Average Bill Increases and Carry-Over of Remaining Balances: If the Commission approves the decoupling rate adjustment, the Company will transfer the deferred revenue amount approved for either recovery or rebate to a balancing account, subject to an annual soft cap of three percent on average bill increases. Any amount over the soft cap will remain in the deferral account until the next filing. The revenue either recovered or rebated during the period will adjust the balancing account. The Company will add any deferred revenue remaining in the balancing account at the end of the year, resulting from over- or under-collection, to the new revenue deferrals to determine the amount of the proposed surcharge or rebate for the following year, subject to Commission approval. Otherwise, the Company will write off any deferred revenue the Commission does not approve for recovery or rebate.

The Company will include, with its tariff, workpapers showing application of the two tests explained below. A sample tariff for the decoupling rate adjustment will be included with the Company's baseline GRC that implements decoupling.

7) Earnings and Conservation Tests: The level of deferred revenue the Company will be allowed to recover or refund is subject to: (a) an Earnings test and (b) a Conservation test. The Company will calculate the Earnings Test first, followed by the Conservation Test, both based on the initial calculation of the deferral amount described above. The individual results of the tests will be cumulatively added to the deferral amount.

a) Earnings Test – The Earnings test will compare the Company's approved Rate of Return (ROR) from the most recent GRC with the annual "Commission-basis" operating results[1] for [electric/gas] service, which the Company files with the Commission by April 30 each year, reporting results for the previous calendar year.

i) The Earnings test is based on a 25 basis point deadband above the approved ROR from the most recent GRC. If the rate of return from the Commission-basis results is below this deadband, the surcharge or rebate is passed through to customers without change.

ii) If the Commission-basis result is more than 25 basis points above the ROR, the company will calculate the minimum amount to be returned to customers by taking the difference between the Commission-basis result and the top of the deadband, multiplied by the GRC rate base. For example, if the GRC ROR is 7.75 percent, then the top of the deadband is 8.00 percent. If the Commission-basis report shows that the Company earned 8.13 percent, then 0.13 percent would be multiplied by the GRC rate base to calculate the minimum amount to be returned to customers.

iii) If there is a surcharge, the Earnings test will cause the amount of the surcharge to be reduced by the minimum amount calculated above. If the value of the minimum

[1] The use of restating adjustments may need further consideration.

amount is greater than the surcharge, it is possible that the Earnings test would result in a rebate.

iv) If there is a rebate, the Earnings test will require the rebate to be at least the minimum amount calculated above. If the rebate is already larger than the minimum amount, there will be no change to the deferral amount. If the rebate is smaller than the minimum amount, then the rebate will be increased to equal the minimum amount.

b) Conservation Test – The Conservation test links the Company's recovery or rebate of deferred amounts to the Company's achievement of the pre-established Conservation target savings [electric/gas] during the prior year.

i) If a surcharge is expected, the Company will calculate an adjustment to the deferral amount by multiplying the deferral amount by the proportion of savings it achieves in the previous year, up to a 120 percent cap. For example, if the Company achieves 62 percent of its savings target, it will reduce the surcharge by 38 percent of the deferral amount. If the Company achieves 120 percent of its savings target, it will increase the surcharge by 20 percent of the deferral amount. If the Company achieves more than 120 percent of its savings target, it will increase the surcharge by only 20 percent of the deferral amount.

ii) If a rebate is expected, the Company will calculate an amount to be added to the rebate by multiplying the deferral amount by the inverse proportion of savings it achieves in the previous year, up to a cap of 120 percent. For example, if the Company achieves 86 percent of its savings target, it will increase the rebate by 16

percent[2] of the deferral amount. If the Company achieves 120 percent of its savings target, it will reduce the rebate by 17 percent[3] of the deferral amount.

iii) Conservation Targets – The Company's [electric: most recently approved biennial conservation targets per WAC 480-109-010; gas: most recently acknowledged Integrated Resource Plan (IRP)] sets forth a Washington [electric/gas] conservation target savings level by year.[4] These target savings levels for the next two years will be used as the target savings for purposes of the Generic Mechanism, and will be shown in the Generic Mechanism tariff.

iv) Updating Conservation Targets – Within two months of the Commission [electric: approval of biennial conservation targets per WAC 480-109-010; gas: acknowledgement of its next IRP], the Company will revise its Generic Mechanism tariff to update its [electric/gas] conservation targets consistent with that [electric: target; gas: IRP].

v) Independent Review of Conservation Savings: The Company will retain and use independent professional efficiency evaluators (with consideration for Certified Measurement and Verification Professionals) to evaluate the results of conservation savings the Company reports for decoupling purposes. The Company will select the entity to perform the independent review through an "RFP" process. The independent review will be supervised jointly by the Company and Commission Staff. The scope of the audit and review will include an appropriate sampling of projects to verify the work completed, savings recorded, and a review of the

[2] (1/.86 = 1.16) and (1 - 1.16 = -.16) This works because the rebate is a negative number.
[3] (1/1.2 = .83) and (1 - .83 = .17)
[4] The expected cost to achieve the savings targets will be found in the Company's most recent Biennial Conservation Plan.

engineering estimates used to estimate the savings. The cost of the audit will be funded through conservation tariff rider funds. The Company will file the report from the independent reviewer on June 1 of [electric: even; gas: odd] numbered years.

vi) A low-income conservation metric will be selected by the Commission and observed by the Company during the Mechanism's operation.

8) Accounting and Quarterly Reporting for the Mechanism: The Company will record the deferred revenue in account 186 – Miscellaneous Deferred Debits. The Company will transfer the amount the Commission approves for recovery into a 182.3 - Regulatory Asset account for amortization of the surcharge revenue received. On the income statement, the Company will record both the deferred revenue and the amortization of the deferred revenue through Account 407 - Regulatory Debits and Credits, in separate sub-accounts.

The Company will file a quarterly report with the Commission showing pertinent information regarding the decoupling rate adjustment. This information will include a spreadsheet showing the monthly revenue deferral calculation for the last 12 months, as well as the current and historical monthly balance in the deferral account.

9) Cancellation of Mechanism: After five years, any party may propose cancellation or modification of the mechanism. Such proposal should be in the context of a GRC.