Oregon

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June 14, 2013

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: Docket No. UE 262 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Opening Testimony.

/s/ Kay Barnes
Kay Barnes
Filing on Behalf of Public Utility Commission Staff
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c: UE 262 Service List (parties)

PUBLIC UTILITY COMMISSION OF OREGON

UE 262

STAFF OPENING TESTIMONY OF

LINNEA WITTEKIND
BRIAN BAHR
GEORGE R. COMPTON
LANCE KAUFMAN

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision

June 14, 2013

CASE: UE 262
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 14, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Linnea Wittekind. I am a Senior Financial Analyst in the Energy – Rates, Finance, and Audit section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. As such, I introduce and summarize the Staff-sponsored adjustments to Portland General Electric's ("PGE" or "Company") filing in this docket, identified as UE 262. Second, I provide some detail regarding the partial settlement reached in principal with Portland General Electric, as well as Citizens' Utility Board of Oregon (CUB), Industrial Customers of Northwest Utilities (ICNU), Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Kroger), and City of Portland.

Q. PLEASE PROVIDE A LIST OF STAFF WITNESSES, EXHIBIT NUMBERS, AND THE SUBJECTS THAT EACH ADDRESSES.

A. The following Staff witnesses provide opening testimony:

Witness	Exhibit	Subject(s)
Wittekind	100	Revenue Requirement
Bahr	200	Pensions
Compton	300	Direct Access
Kaufman	400	Decoupling (SNA)

Q. IS THERE A DIFFERENCE BETWEEN THE REVENUE REQUIREMENT REQUESTED BY PGE AND THE AMOUNT STAFF PROPOSED?

A. Yes. To summarize, PGE requested an increase to revenue requirement related to base rates (excluding power costs) of approximately $104.8 million. Staff proposed seventeen adjustments that would lower PGE's request to increase revenue requirement and identified several other issues with PGE's filing. The details related to Staff's proposed adjustments are described in the following testimony. PGE's actual level of request is affected by the partial stipulation reached on many of the Staff adjustments and hence is slightly different (lower) than the $104.8 million. The exact values will be included in testimony supporting the partial stipulation and some values will be revised as information to be used in the docket becomes available throughout the year.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into three parts:

Part I explains the partial settlement.

Part II introduces the adjustments proposed by other Staff witnesses.

Part III addresses Senate Bill 967.

PART I – EXPLANATION OF PARTIAL SETTLEMENT

Q. PLEASE PROVIDE A LIST OF STAFF'S ADJUSTMENTS BELOW.

A. The table below provides an item number for each staff Adjustment, the initials of the Staff witness sponsoring the adjustment, and a notation whether the issue has been resolved through settlement.

S-0	MM	**Rate of Return**	**(Settled)**
S-1	PR	**Other Revenue**	**(Settled)**
S-2	PR	**Uncollectibles**	**(Settled)**
S-3	MG	**Working Cash**	**(Settled)**
S-4	Juliet J.	**Advertising**	**(Settled)**
S-5	Juliet J.	**Research & Development**	**(Settled)**
S-6	JC	**Other Revenue - Transmission**	**(Settled)**
S-7	Judy J.	**Customer Engagement Transformation Costs**	**(Settled)**
S-8	Judy J.	**Stock Issuance Fees**	**(Settled)**
S-9	Judy J.	**IT O&M**	**(Settled)**
S-10	Judy J.	**Removal of UM 1645**	**(Settled)**
S-11	JO	**Rate Base Reduction**	**(Settled)**
S-12	LW	**Wages & Salaries**	**(Settled)**

S-13 LW	**Various A&G**		**(Settled)**
S-14 PB	**Fee Free Bank Card Costs**		**(Settled)**
S-15 Juliet J.	**RC 841 Environmental Services**		**(Settled)**
S-16 LW	**Tax Deduction for Interest (FIT / SIT)**		**(Settled)**
S*	Adjustment due to rounding		

Q. ARE THERE OTHER OUTSTANDING ISSUES THAT HAVE NOT BEEN SETTLED.

A. Yes, Staff identified six outstanding issues following the June 3, 2013 settlement conference. The issues were: Pensions, Rate Spread / Rate Design, Load Forecast, SNA Fixed Charge Revenue Calculation ("Decoupling SNA"), Fee Free Bank Card Costs and Direct Access. Of the five, Rate Spread / Rate Design, Fee Free Bank Card Costs and Load Forecast have been settled in principal. The remaining issues will be addressed through testimony.

Q. PLEASE IDENTIFY WHICH REVENUE REQUIREMENT ADJUSTMENTS HAVE BEEN SETTLED.

A. Staff adjustments S-0 through S-16 were settled in principal.

Q. WHICH PARTIES AGREED TO THE SETTLEMENT.

A. PGE, CUB, ICNU, Kroger and City of Portland as well as Staff have agreed to the settlement in principal.

Q. HAS A FORMAL SETTLEMENT AGREEMENT BEEN FILED.

A. No, prior to the June 14, 2014 filing deadline for Staff opening testimony a formal settlement agreement has not been filed. However, one is currently being drafted by the parties.

PART II - INTRODUCTION OF STAFF WITNESSES

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR PENSIONS.

A. In Staff Exhibit 200, Staff witness Brian Bahr provides an explanation of Staff's position regarding PGE's request for authorization to set up a balancing account to track differences between forecasted and actual pension expense and return on cash contributions made in excess of Financial Account Statement (FAS) 87.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR DIRECT ACCESS.

A. In Staff Exhibit 300, Staff witness George Compton provides an explanation of Staff's position regarding Direct Access. Staff is proposing major prospective alterations to the long-term direct access policies and tariff (i.e., Schedule 129) of PGE. Most notably, Staff is proposing a five-year notice period for either leaving or returning to PGE generation cost of service rates. Staff also supports spreading Schedule 129 offset revenues to all customers on an ongoing basis.

Q. PLEASE IDENTIFY THE STAFF WITNESS FOR DECOUPLING (SNA).

A. In Staff Exhibit 400, Staff witness Dr. Lance Kaufman provides Staff's position regarding PGE's request to indefinitely extend Schedule 123. Staff recommends that that the fixed per customer revenue calculations be modified and improved to accurately reflect the pattern of declining usage for new connections, and that the modified Schedule be extended through 2016.

PART III – SENATE BILL 967

Q. WHAT ACTION(S) DOES STAFF TAKE TO ENSURE COMPLIANCE WITH SENATE BILL 967.

A. Staff ensures compliance with Senate Bill (SB) 967 (2011) through a series of data requests and Staff analysis. In UE 262, Staff issued Standard Data Request Nos. 123 – 127 which together address the areas of concern identified in Commission Order No. 12-130.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 262
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 14, 2013

WITNESS QUALIFICATION STATEMENT

NAME: Linnea Wittekind

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst,
Energy – Rates, Finance, and Audit Division

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: B.S. Western Oregon University
Major: Business with focus in Accounting
Minor: Entrepreneurship

EXPERIENCE: Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UG 221, and UE 246 and have filed comments in LC 50 and UI 314. I have also reviewed and analyzed a number of energy efficiency tariff filings. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings. I have performed operational audits of NW Natural, Cascade Natural Gas, and Portland General Electric as well as assisted in an operational audit PacifiCorp. Recently I've completed an audit regarding gas accounting best practices.

Through the Public Utility Commission of Oregon, I am a member of the NARUC Staff Subcommittee on Accounting & Finance.

I've attended a number of trainings which include, The Basics through the Center for Public Utilities, New Mexico State University, Best Practices in an Era of Renewables and Reduced Emissions through EUCI as well as Benchmarking the Performance of Electric and Gas Distribution Utilities also through EUCI. I've also attended the Advanced Regulatory Studies Program through the Institute of Public Utilities at Michigan State University.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UE 262
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 14, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Brian Bahr. I am a Senior Utility Analyst in the Energy - Rates, Finance, & Audit Section of the Oregon Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address PGE's request for authorization to set up a balancing account to track differences between forecasted and actual pension expenses and return on cash contributions made in excess of those recognized by Statement of Financial Accounting Standard No. 87 (FAS 87).[1] Since 1986, the Commission has allowed each utility to recover in rates its forecasted pension expense based on actuarial calculations of the utility's "Net Periodic Pension Cost," using the standards established by FAS 87.[2] PGE is now asking to recover in rates, in addition to its FAS 87 expense, the financing costs of cash contributions PGE has made in excess of its pension expense.

Q. WHAT EFFECT DOES THE COMPANY'S PROPOSED PENSION COST BALANCING ACCOUNT HAVE ON RATES IN THIS CASE?

A. PGE asserts that under the FAS 87 methodology, the 2014 test year pension expense included in revenue requirement would be $36.5 million

[1] *See* PGE/500, Barnett-Bell-Jaramillo/30-32.
[2] *See* Order No. 12-437 at 14.

(approximately $23.6 million after capitalization).[3] The pension cost balancing account PGE is proposing would include recovery of $19.8 million, amortized over a 15-year period. If the Commission approves the proposed pension cost balancing account, PGE asserts its revenue requirement in the 2014 test year would decrease by $14.5 million.[4] Regarding PGE's contributions to pensions in excess of recoverable FAS 87 expense, PGE is not requesting a return of this amount.[5]

Q. IS THERE ANOTHER DOCKET CURRENTLY OPEN THAT ADDRESSES THE TREATMENT OF PENSION COSTS?

A. Yes, Docket No. UM 1633, which is an investigation into the treatment of pension costs in utility rates, is currently open. This docket resulted from Order No. 12-408, issued by the Commission in a recent general rate case, Docket No. UG 221. Docket No. UM 1633 is a generic investigation intended to address the treatment of pension expenses in utility rates for all energy companies in Oregon.

Q. DOES PGE RECOGNIZE THAT ITS PROPOSAL FOR TREATMENT OF PENSION COSTS IN THIS CASE MAY BE AFFECTED BY THE PROGRESS AND RESULTS OF DOCKET NO. UM 1633?

A. Yes, the Company states in its opening testimony:

> *Q: Will the generic pension proceeding (Docket No. UM 1633) inform the type of recovery PGE will receive in this general rate case proceeding?*

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[3] *See* lines 14-15 of UE 262/PGE/500, Barnett-Bell-Jaramillo/28.
[4] *See* lines 12-21 of UE 262/PGE/500, Barnett-Bell-Jaramillo/30.
[5] *See* lines 18-22 of UE 262/PGE/500, Barnett-Bell-Jaramillo/31.

A: Possibly. In NW Natural's most recent rate case, the Commission called for a generic proceeding for Oregon utilities to evaluate pension cost recovery (Order No. 12-408, p. 5). Should the generic proceeding be completed during this proceeding its outcome could be incorporated.[6]

Q. WHAT IS STAFF'S POSITION REGARDING THE COMPANY'S PROPOSED PENSION COST BALANCING ACCOUNT?

A. Staff is currently working with the Company, intervenors, and other Oregon utilities to determine the potential effects of various ratemaking methodologies for pension costs. As the analysis is still incomplete, Staff does not have any recommendations at this time regarding recovery of pension costs.

Q. IS STAFF PROPOSING THAT CURRENT COMMISSION TREATMENT OF PENSION COSTS BE CONTINUED UNTIL COMPLETION OF DOCKET NO. UM 1633?

A. No, Staff may be amenable to a change in the treatment of recovery of pension costs in this docket. However, as this complex issue is still under analysis, Staff does not have a recommendation at this time.

Q. DOES STAFF PROPOSE AN ADJUSTMENT AT THIS TIME REGARDING PGE'S PROPOSED PENSION COST BALANCING ACCOUNT?

A. No, Staff does not propose an adjustment at this time, but emphasizes that an adjustment may be proposed in later rounds of testimony.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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[6] *See* lines 1-6 of UE 262/PGE/500, Barnett-Bell-Jaramillo/32.

CASE: UE 262
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

June 14, 2013

WITNESS QUALIFICATION STATEMENT

NAME:	BRIAN BAHR
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	FINANCIAL ANALYST, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE SUITE 215, SALEM, OR 97308-2115
EDUCATION:	Bachelor of Science, Accountancy, Brigham Young University, Provo UT
EXPERIENCE:	Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Senior Utility Analyst in the Rates, Finance, & Audit Section of the Energy Division.

Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration.

Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies.

Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UE 262
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 14, 2013

INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed in the Rates, Finance, and Audit Section of the Energy Division of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I represent the OPUC staff (Staff) in this docket regarding the subjects of rate spread and rate design.[1]

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found as Exhibit Staff/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will be presenting Staff's position on the single topic related to rate-spread/rate-design that was not settled by the parties at the conference held for that purpose on June 6, 2013.

Q. WHAT IS THAT TOPIC?

A. It has to do with the pricing and other key policies relating to the "Minimum Five Year Opt-Out" segment of PGE's large customer Long-Term Direct Access program.

[1] "Rate spread" refers to the assignment of respective portions of the overall utility revenue requirement to the various customer schedules. "Rate design" refers to the individual tariff pricing components which combine to recover the customer schedules' assigned revenue targets.

Q. PLEASE BRIEFLY DESCRIBE PGE'S LARGE CUSTOMER LONG-TERM DIRECT ACCESS PROGRAM?

A. In our regulated utility context, direct access customers are those who arrange to take a specified portion of their generation from some third-party source(s). Because the utility delivers that power to these customers, they continue to pay standard-tariff customer and distribution charges. Direct access customers also make payments, labeled the "Transition Cost Adjustment," under Schedule 129. The primary role of that "adjustment" is to make up for the fixed generation revenues that are lost owing to the direct access customers' departure from standard, cost-of-service status. The goal of the latter charge is to prevent the direct access service from being a burden to the other customers of PGE owing to the Company's having taken on fixed cost obligations under the expectation of being required to serve loads at a level including what came to be lost due to direct access. Full cost recovery would entail the remaining customers' having to bear costs that otherwise would have been borne by the direct access loads.

Q. YOU MENTIONED THE "MINIMUM FIVE YEAR OPT-OUT" SEGMENT OF THE SUBJECT DIRECT ACCESS PROGRAM. WHAT IS ITS RELEVANCE?

A. Under the "Minimum Five Year Opt-Out" program, for five full years the customer pays the transition adjustment fees as applicable to the loads being supplied by the third-party provider. The five year transition period is to allow PGE to adjust its generation portfolio to reflect the reduction in generation sales. After the period of five years from having given notice of its intention to fully withdraw as a generation customer, the direct access customer no longer is charged any transition fees.

Q. IN REVIEWING PGE'S DIRECT TESTIMONY IN THIS DOCKET I DON'T RECALL DIRECT ACCESS BEING MENTIONED AS A MATTER OF INTEREST OR CONCERN. IS THAT CORRECT?

A. Yes. Staff is raising the issue due to some concerns on our part with PGE's direct access policies[2] and tariff. In as much as PGE's rates are now being reviewed pursuant to the general rate case, this is an appropriate time to be considering how the direct access transition fees should be set in the future, and how the revenues from those fees should be spread among the various customer schedules. I also note that UE-267, a PacifiCorp docket, is also addressing this topic, motivated by the fact that PacifiCorp does not currently have the equivalent of PGE's long-term opt out tariff. Not surprisingly, Staff is, or will be, proposing sound and consistent direct access policies for both companies.

Q. HOW DO YOU PROPOSE TRANSITION CHARGES BE ESTABLISHED DURING THE FIVE YEAR OPT-OUT/NOTIFICATION PERIOD PRIOR TO CUSTOMERS LEAVING PGE GENERATION SERVICES ALTOGETHER?

A. The transition charges would be based on a comparison of market prices with rates based upon the then-current Commission-approved generation revenue requirement. The rationale and explanation for how this departs from the current PGE practice will be explained later in this testimony.

[2] The policies were a product of negotiation. As indicated later in this testimony, PGE also has concerns regarding its direct access tariff and underlying policies,

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCERNS AND RECOMMENDATIONS REGARDING THE FIVE-YEAR OPT-OUT SEGMENT OF PGE'S LONG-TERM DIRECT ACCESS PROGRAM?

A. They are as follows:

1. It is questionable whether Schedule 129, the long-term Direct Access tariff that is now in effect, fully captures the fixed generation costs that are "stranded" owing to the departure of the direct access loads. Staff is asking that Schedule 129 be revised.
2. Given that the burden or benefits of direct access are borne across the entire range of customer schedules, the Schedule 129 revenues, be they positive or negative, should be spread across all schedules, not just to Schedules 85 and 89 as per the current practice.
3. Schedule 129, is overly complex and cumbersome. Rather than rate uniformity, the direct access customers pay different rates depending upon when they enrolled in the five-year opt-out program. Staff believes that direct access customers on the minimum five-year program, i.e., regardless of when they enrolled, should pay the same loss-adjusted transition fees applicable for that year.
4. The current practice of setting the Schedule 129 rates five years in advance necessarily entails a loss of accuracy in projecting the market price component of the transition fees. Staff proposes that the market price component be updated annually, with the fixed-cost component being updated in conjunction with general rate cases.

5. The current required number of years of advanced return notification – two – seems inordinately small in view of the lead times required for a utility to most efficiently acquire the resources necessary to accommodate substantially increased loads. Staff is recommending a minimum of five years advanced notification by a direct access customer prior to its being allowed to return to full cost-of-service status.
6. The limits, both annual and cumulative, that are now placed upon how much load may be converted to direct access status may, conservatively, be too low.

Q. YOUR FIRST SUMMARY ITEM INDICATED THAT IT IS "QUESTIONABLE WHETHER THE LONG-TERM DIRECT ACCESS TARIFF, SCHEDULE 129, FULLY CAPTURES THE FIXED GENERATION COSTS THAT ARE 'STRANDED' OWING TO THE DEPARTURE OF THE DIRECT ACCESS LOADS." UPON WHAT BASIS DO YOU MAKE THAT CLAIM?

A. PGE's response to Staff Data Request No. 310, which asked for PGE to estimate its "stranded fixed generation costs" for the five years following 2014, showed a levelized five-year figure of $33/MWh. That amount is considerably above the values contained in PGE's Schedule 129.

Q. I NOTE FROM THE SECOND PARAGRAPH OF PGE'S RESPONSE TO THE JUST-CITED DATA REQUEST THAT: 1) THE COMPANY INTENDS TO ADD EXPENSIVE NEW RESOURCES TO ITS PORTFOLIO SOON AFTER THE END OF THE TEST PERIOD FOR THIS CASE, AND THAT: 2) THOSE RESOURCES ARE INCLUDED AS PART OF PGE'S $33/MWh STRANDED

COST ESTIMATE. WHAT IF THOSE RESOURCES WERE NOT BROUGHT ON BOARD, PARTLY DUE TO A SHIFT OF LOAD AWAY FROM COST-OF-SERVICE AND OVER TO DIRECT ACCESS. WHAT WOULD HAPPEN TO THE FIXED GENERATION COST ESTIMATE IN THAT EVENT?

A. Leaving the fixed generation revenue requirement at the indicated UE 262 level of $438.4 million leaves the estimate still above $22/MWh, which again is well above the average of the values shown in the current Schedule 129 tariff. And I must add that given the standard lead times and long-term commitments for major generation units, and given the requirement of the utility to meet all qualifying demands on a cost-of-service basis, one can't arbitrarily drop resources from a cost estimate based upon speculation regarding what loads may or may not materialize.

Q. YOUR SECOND SUMMARY POINT WAS TO SAY THAT THE SCHEDULE 129 REVENUES, BE THEY POSITIVE OR NEGATIVE, SHOULD BE SPREAD ACROSS ALL SCHEDULES, NOT JUST SCHEDULES 85 AND 89 – BECAUSE THE BURDEN OR BENEFITS OF DIRECT ACCESS ARE BORNE ACROSS THE ENTIRE RANGE OF CUSTOMER SCHEDULES. ON WHAT BASIS DO YOU MAKE THE CLAIM ABOUT THE BURDEN/BENEFIT NOT BEING LIMITED TO SCHEDULES 85 AND 89?

A. I make that claim on the basis of the way PGE's generation costs are initially allocated – i.e., on the basis of the *cost-of-service* schedules' respective proportional shares of the total of the *cost-of-service* loads. The direct access loads receive none of this initial allocation.[3] If, due to direct access, the sum of the cost-of-service loads goes down while costs (i.e., fixed generation costs) remain the same, then all the cost-of-service rate schedules' will see an increase in their generation revenue requirement commensurate with their increased proportional share of the loads.[4] The revenue requirement increases translate to price/rate increases.

PGE makes a similar point regarding the general nature of the cost shifts on page Cody–Macfarlane/6, lines 4-10 of UE262/PGE/1500. Also, the response to part b) of Staff's Data Request No. 311 is as follows:

> From PGE's perspective, the opportunity for customers to permanently leave COS [i.e., cost-of-service] on an annual basis gives participants the opportunity to shift costs to non-participants. This cost shift is accomplished by the re-spreading of fixed generation costs to non-participants….

To reiterate this second point, it is Staff's proposal to spread the Schedule 129 revenues across all cost-of-service schedules so as to attempt to neutralize the noted price increases.[5]

Q. YOUR THIRD SUMMARY POINT REFERS TO SCHEDULE 129 BEING OVERLY COMPLEX AND CUMBERSOME. WHAT DO YOU HAVE IN MIND?

A. Please refer to Exhibit Staff/302, which is a copy of page two of Schedule 129. Note mainly that every enrollment year in which a customer/load enters direct access gets its own set of five-year "Transition Cost Adjustments."

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[3] A *de facto* allocation comes through Schedule 129.

[4] The numerator component of each of the cost-of-service schedule's proportion will have remained the same while the denominator will have shrunk.

[5] The same outcome can be accomplished by allocating fixed costs to the direct access customers at the outset – in the manner currently done by PacifiCorp pursuant to its Schedule 100.

Q. DOES PGE RECOGNIZE THIS "COMPLEX AND CUMBERSOME" PROBLEM?

A. It does. PGE's response to part b) of Staff's Data Request No. 311 contained the following paragraph:

> Other drawbacks include the administrative burden of segregating customers by the numerous enrollment window vintages for the purpose of billing and rate determination, and the necessity of adopting complex true-ups to fixed generation charges and transition adjustments between rate cases.

Q. HOW MIGHT THE "DRAWBACK" OF SEGREGATING DIRECT ACCESS CUSTOMERS BY ENROLLMENT VINTAGE BE REMEDIED?

A. If one adopts the view that stranded fixed generation costs and avoided/ increased variable generation costs are based upon the magnitude of the direct access loads and not on how recently the particular loads left cost-of-service status, then all those loads would be assigned the same unit transition fees (adjusted perhaps for differential line losses) without regard for when they enrolled in direct access. That is Staff's recommendation – that the rates vintaging be eliminated. The unit transition fees paid by the direct access customers would not be affected by when they enrolled in the five-year opt-out program.

Q. IF THE ENROLLMENT YEAR IS NOT TO AFFECT THE TRANSITION FEES PAID BY THE VARIOUS DIRECT ACCESS CUSTOMERS IN A GIVEN YEAR, DOES THAT REQUIRE THOSE FEES TO BE ADJUSTED FOR ACCURACY OVER TIME SO AS TO TAKE INTO CONSIDERATION

CHANGING MARKET PRICES AND GENERATION REVENUE REQUIREMENTS?

A. Yes. It is our recommendation that the market price projection be updated annually and that the fixed generation values be adjusted coincident with any related Commission-ordered change to rates related to PGE generation costs. That is how we would resolve the fourth issue outlined early in this testimony. Note that the fixed costs portion would be the standard one year, per-unit revenue requirement, not some figure that collects some number of years of fixed costs.

Q. YOUR FIFTH DIRECT ACCESS-RELATED CONCERN WAS REGARDING THE SUFFICIENCY OF A TWO-YEAR NOTIFICATION PERIOD PRIOR TO REVERTING BACK TO COST-OF-SERVICE STATUS. WHAT IS STAFF'S POSITION ON THIS SUBJECT, AND WHAT IS ITS BASIS?

A. Staff Data Request No. 270 asked, "how much advanced notification is required to allow PGE to adjust its resource supply to accommodate the [50 MW] increased load in its long-term generation supply portfolio?" PGE's response is:

> "It takes roughly two to six years to adjust the long-term supply to accommodate the increased load, depending upon whether the assumed acquisition is for an existing resource, an under-construction resource, or a proposed new resource."

On that basis, Staff, somewhat conservatively, is recommending a five-year minimum notification period before a customer can return to a standard cost-of-service basis.

Q. A PACIFICORP POLICY PROPOSAL, AS PRESENTED IN A WORKSHOP ON THE SUBJECT HELD EARLIER THIS YEAR, MAKES THE LONG-TERM OPT-OUT PERMANENT. ACCORDINGLY PRIOR NOTIFICATION WOULD BE MOOT BECAUSE THERE WOULD BE NO POSSIBLE RETURN TO COST-OF-SERVICE STATUS. DOES STAFF SUPPORT A POLICY OF PRECLUDING CUSTOMER RETURN TO STANDARD GENERATION COST OF SERVICE RATES?

A. No. We do not support precluding customers from returning to cost of service generation rates as long as customers have paid the five years of transition charges to exit the utility generation service and have given the indicated five years advanced notice of their desire to so return. Consider a situation in the future where non-utility energy service becomes very expensive, making direct access cost-prohibitive in terms of a number of large customers' ability to stay in business. As a practical matter, one can imagine the pressure that would be brought to bear – in the interest of saving jobs, etc. – to allow the at-risk customers back into cost-of-service status. And from a legal point of view, what if the customer had actually gone out of business for a spell and then been acquired by a different owner? Could the associated load then be treated as that of a new customer rather than a permanently non-qualifying customer? Also, if the non-direct-access customers had been held harmless by the direct access customers' departure from cost-of-service status, why shouldn't they be treated at some future date on the same terms as any other large new customer – having served notification sufficient for the utility to most efficiently serve the returning loads?

Q. GIVEN THE RISKS TO THE UTILITY ASSOCIATED WITH DIRECT ACCESS, HAVE LIMITATIONS BEEN PLACED UPON ANNUAL AND CUMULATIVE DIRECT ACCESS ENROLLMENTS?

A. Yes. Respectively they are 30 MWs and 300 MWs.

Q. IN LIGHT OF THE REDUCTION IN RISK TO THE UTILITY ASSOCIATED WITH STAFF'S RECOMMENDED INCLINING FIXED-COST TRANSITION FEES AND THE EXTENDED NOTIFICATION PERIOD PRIOR TO A RETURN TO COST-OF-SERVICE STATUS, MIGHT IT BE APPROPRIATE (I.E., ADDRESSING YOUR SIXTH AND FINAL DIRECT ACCESS ISSUE) TO INCREASE THE ENROLLMENT LIMITS WHICH YOU JUST DESCRIBED?

A. My answer is "yes," but Staff has no specific recommendation at this time regarding how much those increases might be.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

CASE: UE 262
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

June 14, 2013

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Finance & Audit

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181), the 2008 and 2008 PGE General Rate Cases (UE 197 and UE 215), the 2009 PacifiCorp General Rate Cases (UE210 and UE 246), and the 2011Idaho Power General Rate Case (UE 233).

CASE: UE 262
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 14, 2013

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period H (2009), the Transition Cost Adjustment will be:

0.673 ¢ per kWh	January 1, 2010 through December 31, 2010
0.415 ¢ per kWh	January 1, 2011 through December 31, 2011
0.473 ¢ per kWh	January 1, 2012 through December 31, 2012
0.368 ¢ per kWh	January 1, 2013 through December 31, 2013
0.221 ¢ per kWh	January 1, 2014 through December 31, 2014
0.000 ¢ per kWh	after December 31, 2014

For Enrollment Period I (2010), the Transition Cost Adjustment will be:

1.545 ¢ per kWh	January 1, 2011 through December 31, 2011
1.374 ¢ per kWh	January 1, 2012 through December 31, 2012
1.083 ¢ per kWh	January 1, 2013 through December 31, 2013
0.818 ¢ per kWh	January 1, 2014 through December 31, 2014
0.625 ¢ per kWh	January 1, 2015 through December 31, 2015
0.000 ¢ per kWh	after December 31, 2015

For Enrollment Period J (2011), the Transition Cost Adjustment will be:

2.182 ¢ per kWh	January 1, 2012 through December 31, 2012
1.492 ¢ per kWh	January 1, 2013 through December 31, 2013
1.022 ¢ per kWh	January 1, 2014 through December 31, 2014
0.749 ¢ per kWh	January 1, 2015 through December 31, 2015
0.601 ¢ per kWh	January 1, 2016 through December 31, 2016
0.000 ¢ per kWh	after December 31, 2016

For Enrollment Period K (2012), the Transition Cost Adjustment will be: (R)

Period	Sch. 485 Secondary Voltage ¢ per kWh	Sch. 485 Primary Voltage ¢ per kWh	Sch. 489 Secondary Voltage ¢ per kWh	Sch. 489 Primary Voltage ¢ per kWh	Sch. 489 Subtransmission Voltage ¢ per kWh
2013	2.244	2.168	2.085	2.030	2.019
2014	1.548	1.495	1.395	1.369	1.370
2015	1.273	1.229	1.120	1.106	1.113
2016	1.055	1.018	0.901	0.897	0.909
2017	0.745	0.718	0.591	0.602	0.619
After 2017	0.000	0.000	0.000	0.000	0.000 (R)

CASE: UE 262
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 14, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lance Kaufman. I am a Utility Economist employed by the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony assesses Portland General Electric's (PGE or Company) Sales and Load Forecast for this proceeding's 2014 test year. My testimony also provides analysis of PGE's decoupling mechanism and marginal cost studies.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/401, consisting of 1 page. I prepared Exhibit Staff/402, consisting of 72 pages. I prepared Exhibit Staff/403, consisting of 2 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, LOAD FORECAST

Q. PLEASE DESCRIBE THE SALES AND LOAD FORECAST PROVIDED BY THE COMPANY

A. The Company's sales and load forecast is presented in PGE/1300. The Company forecasts total normal weather sales of 19,233 million kWh for test year 2014. This forecast is a 0.3% decrease from 2012 weather adjusted sales.

Q. PLEASE IDENTIFY THE SALES AND LOAD FORECASTS CONDUCTED BY THE COMPANY THAT DIRECTLY IMPACT RATES.

A. The Company estimates numerous models in the process of creating the sales and load forecast. The models generate two functional sets of forecasts. The rate schedule sales forecasts provide expected monthly sales for each month in the test year. The monthly peak MW and annual peak MW forecasts provide expected demand for each customer class during monthly and annual peak demand.

Q. WHAT PORTIONS OF THE RATE SETTING PROCESS ARE IMPACTED BY THE MONTHLY RATE SCHEDULE SALES FORECAST?

A. The monthly rate schedule sales forecasts are used to inform power costs, expected revenues, and decoupling adjustment calculations. The accuracy of the monthly rate schedule sales forecasts directly impact the extent to which the Company over or under collects revenue in the years following the rate case. The monthly rate schedule sales forecasts are also used to inform the monthly and annual peak MW forecasts. Any error in the sales forecasts will also flow through to the monthly and annual peak MW forecast.

Q. WHAT PORTIONS OF THE RATE SETTING PROCESS ARE IMPACTED BY THE MONTHLY AND ANNUAL PEAK MW FORECASTS?

A. The peak MW forecasts are important in allocating demand related costs to each rate schedule. The correct allocation of costs is necessary to achieve efficient and fair rates.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE COMPANY'S FORECASTS.

A. I have reviewed the Company's modeling methodology and replicated the Company's forecast results using data and statistical programs provided by the Company. I have performed a partial audit of the Company's programming code. The Company's data and programming used for their sales forecast were provided in responses to Staff DR Nos. 128-134, 200-202, and 306-308. The Company's results and methodology are consistent with the descriptions provided in PGE/1300. In reviewing the Company's methodology I have identified a number of opportunities to reduce bias and variance of the Company's forecast. These opportunities relate specifically to the Company's model specification, demand side management shape, demand side management double counting, and price elasticity double counting.

Q. WHAT IS FORECAST BIAS AND FORECAST VARIANCE?

A. A forecast is biased if it is expected to under estimate or over estimate sales. Forecast variance refers to the magnitude of the difference between the forecast and the actual values. If a forecast has a high variance but no bias, the forecast is expected to have a large deviation from the actual values, but the sign of the deviation cannot be predicted.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE TO THE COMPANY'S SALES AND LOAD FORECASTS?

A. I do not have adjustments to the forecasts at this time. However, PGE has agreed to work with staff and interested parties to discuss and identify any improvements to reduce bias in developing load forecasts. These discussions will occur outside of this docket UE 262.

ISSUE 2, DECOUPLING

Q. WHAT IS A DECUPLING MECHANISM?

A. A decoupling mechanism is a method of removing an energy company's incentive to increase or maintain energy sales. This incentive is also known as the throughput incentive.

Q. WHY DO COMPANIES HAVE AN INCENTIVE TO INCREASE SALES?

A. Energy rates are calculated to ensure that, if actual sales equal forecasted sales, the company will receive the approved revenue requirement for the test year. During off-peak hours and perhaps even most peak hours, the cost of generating and distributing additional energy is often less than the revenues received from the associated sale. If sales exceed forecasted levels, the company will increase its profits. The throughput incentive can inhibit firms from support of investing in least-cost energy resources.

Q. WHAT REGULATORY MECHANISMS ADDRESS THE CONCERN THAT COMPANIES MAY BE INCENTED TO INCREASE KWH SALES TO THE DTERIMENT OF COST EFFECTIVE CONSERVATION RESOURCES?

A. Decoupling mechanisms have been a tool to address what may be utility bias to increase sales. A goal of decoupling mechanisms are to break the link between utility profits and its sales levels. As with any regulatory mechanism, however, decoupling mechanisms provide utilities a different set of incentives.

Q. ARE THERE ANY BENEFITS ASSOCIATED WITH DECOUPLING MECHANISMS BESIDES BREAKINGTHE LINK BETWEEN A UTILITY SALES LEVEL AND ITS PROFITS?

A. Yes. Decoupling mechanisms have a number of additional benefits to both customers and the Company. The Sales Normalization Adjustment (SNA) used by PGE reduces the variance of a firm's average profit. Because the SNA stabilizes average profit the SNA can reduce some types of market risk. If this reduction in market risk reduces the Company's cost of debt and equity, customers will realize a cost savings to the extent such effects are captured in rates. A decoupling mechanism can also shift the burden of regulatory lag from the company to the customer with respect to resetting allowed revenues through establishing a margin per customer benchmark that is used to annually adjust allowed revenues for the utility. This can decrease the frequency that a company submits rate cases, and as a result reduce the associated costs for all parties.

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Q. DOES THE SNA MECHANISM TREAT ALL REVENUE EQUALLY?

A. No, the SNA decouples revenues associated with the fixed costs of generation, transmission, and distribution. The SNA does not address costs that increase and decrease with energy sales.

Q WHY IS THE DECOUPLING MECHANISM BEING ADDRESSED IN THIS RATE CASE?

A. The decoupling mechanism does not have a clear and uncontested net benefit for customers. Several parties, including Staff, Kroger, and the Citizens' Utility Board of Oregon, have previously objected to the design and implementation of the decoupling mechanism. The Commission approved temporary implementation of the decoupling mechanisms in Order No. 09-020, and extended the implementation to the end of 2013 with Order 10-478. If no action is taken in this rate case Schedule 123 will expire. One condition of extending the mechanism was that the Company had to initiate an independent evaluation of the decoupling policy in 2013.

Q. HAS THE INDEPENDENT EVALUATION BEEN COMPLETED?

A. Yes, the report is included as Exhibit Staff/402.

Q. WHAT ARE THE CONTENTS OF THE DECOUPLING EVALUATION REPORT?

A. The report answers questions identified by the Commission in Order No. 10-487. The report also responds to additional concerns raised by stakeholders. The report addresses program mechanics, PGE risk, PGE behavior, and provides a number of recommendations regarding the PGE decoupling mechanisms.

Q. WHAT CONCLUSIONS DO THE REPORT PROVIDE CONCERNING THE EFFECT OF THE DECOUPLING MECHANISM ON PGE BEHAVIOR AND PGE'S FINANCIAL RISK?

A. The report does "not find compelling evidence that the change in incentives led to significant changes in PGE's corporate behavior, though some actions were reported." (Staff/402 at p 69.) The report does "not find any evidence that the introduction of Schedule 123 reduced PGE's capital risk by a material amount." (Staff/402 at p 69.)

Q. WHAT IS YOUR ASSESEMENT OF THE REPORT'S CAPITAL RISK ANALYSIS?

A. The report uses three approaches to identify the impact of the decoupling mechanism on risk. The first is a statistical analysis of the standard deviation of normalized operating income for a 20 year panel of 40 utilities. The second is a review of the available literature regarding the relationship between decoupling and risk. The third is a review of PGE's credit agency reports.

The panel of 40 utilities in the first analysis includes15 firms that had decoupling mechanisms. Three firms had decoupling mechanism in place for the entire time period. The remaining firms had decoupling mechanisms in the final 3-5 years of the data set. The report's calculation for the effect of decoupling on risk does not account for selection bias. The three firms that operated with a decoupling mechanism for the entire period cannot contribute useful information to the model. This is because there are many firm specific factors that affect risk. Without observing the firms before they adopted a decoupling mechanism it is impossible to identify a causal relationship between the decoupling mechanism and capital risk.

For the firms that do adopt decoupling during the sample period there are insufficient observations subsequent to adoption to draw a statistical conclusion.

The second analysis does not provide any information specifically generated using PGE data. The literature review identifies four publications. Two report no statistically significant finding relating decoupling to risk. Two find that decoupling reduces cost of capital as a result of reduced revenue volatility.

Table 5.4.1 summarizes PGE credit reports by three agencies. Moody's and Standard & Poor's report on PGE's credit annually. Both Moody's and Standard & Poor's reports have a higher average rating for secured debt following the adoption of the decoupling mechanism in 2009. PGE's outlook is more often given a stable or positive outlook following 2009.

The Report's finding that the decoupling mechanisms do not impact PGE's risk decreases the value of decoupling as a regulatory tool. However, this finding is not concrete. The proactive efforts by utility companies to institute decoupling mechanisms and the promotion of such mechanism in annual shareholder reports suggest that decoupling provides some benefit to shareholders. The lack of statistical evidence is likely related to either model misspecification or insufficient data.

Q. WHAT CONCLUSION DOES THE REPORT PROVIDE CONCERNING THE EFFECT OF THE SNA ON CUSTOMER ECONOMIC RISK?

A. The report finds evidence that the SNA shifts economic risk from PGE to the customer.

Q. WHAT RECOMMENDATION DOES THE REPORT PROVIDE ABOUT CONTINUING THE DECOUPLING MECHANISM?

A. The report finds no “compelling reason to support the continuation or termination of Schedule 123.” (Staff/402 at p 70.) The report recommends continuing Schedule 123 based on the Energy Trust of Oregon’s (“ETO’s”) general support for PGE and the finding that Schedule 123 has caused minimal harm.

Q. WHAT HARM DOES THE REPORT IDENTIFY THAT IS ASSOCIATED WITH SCHEDULE 123?

A. The report identifies several areas of harm. Table 4.3.3b of Exhibit 402 demonstrates that under declining use per customer and an increased number of customers the SNA mechanism causes significant over-collection of fixed generation revenue. Residential customers have had declining use per customer and an increasing number of customers. The SNA has also resulted in additional collections from residential customers of $3,176,000 over the four years that Schedule 123 has been in effect.

The Lost Revenue Rate Adjustment (“LRRA”) results in a flat rate for all applicable schedules. However, not all schedules have an equal impact on the company’s recovery of fixed costs. The report finds that because each rate schedule experiences a variable level of energy efficiency installations and because each schedule imposes different fixed costs on the system the LRRA causes a cross subsidy of rate schedules.

The SNA appears to shift economic risk from PGE to customers. This is demonstrated in the report through regression analysis of Use per Customer (UPC). UPC is related to economic conditions. When the economy improves customers tend to respond by increasing energy use. However, after accounting for decoupling, customers do not respond significantly to changes in the economy.

One potential area of harm raised by the report but not specifically analyzed is the distributional affects of SNA deferrals. The SNA charge affects rates of all customers. It is possible that customers who reduce energy consumption will shift the burden of the fixed costs of generation, transmission and distribution to customers who don't reduce energy consumption. "Wealthier customers are more able to engage in conservation than low-income customers, with the result being an SNA induced shift in cost of cost recovery from high- to low-income customers." (Staff/402 p 68)The magnitude of such a shift has not been investigated.

Q. WHAT EVIDENCE CAN YOU PROVIDE REGARDING THE OVERCOLLECTION OF FIXED COST REVENUES?

A. The study finds that use per customer is decreasing over time. This is evident in tables 4.4.2 and 4.4.3. The decline in use per customer has two sources. The first is decreased use by existing buildings. The second is decreased use by new construction. Exhibit 403 demonstrates that use per customer is lower for newly constructed connections. Additionally, the high vacancy rates of first year connections results in very low use per customer costs for current year connections. New connections are more likely to have natural gas heating and appliances. Because Oregon experiences a winter coincident peak, natural gas heated homes represent a lower contribution to annual coincident peak.

The incremental generation, transmission and distribution costs for new construction is likely lower than the fixed generation costs attributed to existing customers.

Q. DOES THE REPORT PROVIDE ANY ADDITIONAL RECOMMENDATIONS CONCERNING THE DECOUPLING MECHANISMS?

A. Yes, the report provides two recommendations regarding the LRRA and three recommendations regarding the SNA. The report recommends removing the generation portion of the decoupling charge paid by Schedules 485 and 489. Staff supports this recommendation. The report also recommends the use of Schedule specific Lost Revenue Rates. Staff conversations with PGE and ETO indicate that at this time, Schedule specific rates may not be feasible. However, ETO is actively working on improving its energy efficiency tracking methodology and hopes to be able to provide schedule specific energy efficiency data. I recommend revisiting this issue when such data become available.

The report suggests considering the effect of removing weather normalization of sales from the actual data. Staff does not have sufficient data at this time to assess the feasibility of this recommendation. This process would significantly affect consumer incentives.

The report suggests modifying the SNA to reduce PGE's over collection of fixed costs. The report proposes a bifurcation of generation and transmission costs from distribution costs.

Q. WHAT IS STAFF'S ASSESMENT OF THE PROPOSED BIFURCATION OF GENERATION AND TRANSMISSION COSTS?

A. PGE's pattern of customer and energy growth are consistent with the over collection of fixed generation and transmission costs. The report's proposed bifurcation does not provide a clear methodology for calculating the decoupling adjustments. Staff proposes a simpler approach to correct for over-collection. Staff's approach is to calculate two distinct Monthly Fixed Charges Per Customer. The Base Monthly Fixed Charge should be calculated in the current manner and amounts to $56.77. The Secondary Monthly Fixed Charge should be calculated to reflect the observation that new connections place significantly less burden on the existing system than preexisting connections. The Secondary Monthly Fixed Charge is calculated by scaling the Base Monthly Fixed Charge by the relative size of new connections. This results in a Secondary Monthly Fixed Charge of $31.01[1].

[1] Both the Base Monthly Fixed Charge and the Secondary Monthly Fixed Charge are dependent on the final sales forecast, revenue requirement, and embedded cost analysis. Secondary Monthly Fixed Charge is calculated by dividing Base Montlhy Fixed Charge by average annual residential energy use and multiplying by average annualized energy use for customers connected within the previous year.

ISSUE 3, MARGINAL CUSTOMER COSTS

Q. PLEASE DESCRIBE THE ROLES THAT THE CALCULATION OF MARGINAL CUSTOMER COSTS PLAY IN THE CURRENT RATE CASE.

A. Marginal customer costs are used to allocate the customer related portion of the test year costs to each rate schedule. Marginal cost calculations inform both the rate spread and the rate design. The rate spread consists of identifying rate schedule specific revenue requirements. The rate design consists of designing a rate structure that provides customers with efficient incentives and collects the schedule specific revenue requirements.

Q. HAVE YOU IDENTIFIED ANY AREAS WHERE THE MARGIAL CUSTOMER COST CALCULATIONS CAN BE IMPROVED?

A. Yes. The Company makes a number of allocation assumptions that can be improved. Subsequent to the initial filing the Company has corrected several errors in the marginal cost calculations. The Company has agreed that the allocation of Key Customer Management (KCM) costs may be an area where further analysis could be useful for informing future general rate filings.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 262
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

June 14, 2013

WITNESS QUALIFICATION STATEMENT

NAME: Lance Kaufman

EMPLOYER: PUBLIC UTIILTY COMMISSION OF OREGON

TITLE: Utility Economist

ADDRESS: 550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.

EDUCATION: Bachelor of Business Administration, Economics, University of Alaska Anchorage 2005

Masters of Science, Economics, University of Oregon, 2009

Philosophical Doctorate, Economics, University of Oregon, 2013

EXPERIENCE: I have been employed as a Utility Economist at the Public Utility Commission since February, 2013. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies.

Prior to working for the OPUC I was an Economics instructor at the University of Oregon. I have taught courses in Public Finance and Public Economics, Urban and Regional Economics, and Microeconomics.

Previous to working for the University of Oregon, I worked as a Research Assistant for Impact Assessment Inc.

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CASE: UE 262
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 14, 2013

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123

by

Daniel G. Hansen
Robert J. Camfield
Marlies C. Hilbrink

May 31, 2013

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Table of Contents

1. INTRODUCTION AND BACKGROUND

In January 2009, the Oregon Public Utility Commission ("OPUC" or "the Commission") issued Order 09-020 (the "Order"), which approved Schedule 123 for use by Portland General Electric ("PGE"). This schedule contains two components: the Sales Normalization Adjustment ("SNA"), which applies to residential and small commercial customers; and the Lost Revenue Recovery Adjustment ("LRRA"), which applies to larger non-residential customers.[1]

PGE's proposal to adopt the SNA and LRRA was motivated by the fact that a large portion of its fixed costs are recovered through volumetric (i.e., per-kilowatt-hour) rates, so that reductions in energy sales lead to reductions in revenues toward fixed cost recovery. This gives the utility a disincentive to promote conservation and energy efficiency for its customers, as success in these efforts would reduce utility revenues without inducing a corresponding reduction in utility fixed costs.

The proposal met with some resistance from OPUC Staff, Kroger, and the Citizens' Utility Board of Oregon ("CUB"). Arguments against the SNA included:

- It shifts risk from the utility to its ratepayers;
- It is likely to lead to over-collection of fixed cost revenues;
- Because the Energy Trust of Oregon ("ETO") is a third-party administrator of energy efficiency programs, the scope for PGE to affect customer energy efficiency decisions is limited;
- It produces a disincentive for PGE's customers to engage in conservation;
- It shifts economic risk (i.e., the adverse effects of a recession) from PGE to its ratepayers; and
- It is more focused on revenue assurance for the utility than it is on enabling customer conservation.

The Commission largely rejected these arguments in the Order and approved the mechanism, with two significant requirements: that PGE's authorized return on equity ("ROE") be reduced by 10 basis points in order to account for a reduction in utility risk;[2] and that an assessment of the effectiveness of the SNA and LRRA be completed no later than six months prior to schedule's expiration date. This report is intended to meet the latter requirement. The program's initial two-year authorization was extended in 2011. It is now due for re-authorization or cancellation on December 31, 2013.

The report is organized as follows. Section 2 provides descriptions of the SNA and LRRA mechanisms. Section 3 describes the evaluation requirements. Section 4 contains an evaluation of program mechanics. Section 5 considers the effect of Schedule 123 on PGE's risk. Section 6

[1] Non-residential customers with load exceeding one average megawatt (aMW) and Self-Directing customers are exempted from the LRRA.

[2] The Commission ruled that, while the SNA and LRRA do not shift risk from the utility to its ratepayers, they do reduce utility risk.

examines the effect of Schedule 123 on PGE's behavior. Section 7 summarizes the stakeholder interviews. Section 8 describes sources of potential harm from Schedule 123 that were not investigated in the study. Section 9 provides conclusions and recommendations.

2. DESCRIPTIONS OF THE SNA AND LRRA MECHANISMS

This section provides detailed descriptions of each mechanism contained in Schedule 123.

2.1 Sales Normalization Adjustment

The SNA applies to customers served on Schedules 7 (Residential Service), 32 (Small Nonresidential Standard Service), and 532 (Small Nonresidential Direct Access Service). It is a form of revenue per customer decoupling, in which monthly deferrals are based on the difference between *allowed* revenues toward fixed costs and *actual* revenues toward fixed costs (in this case adjusted to represent revenues under normal weather conditions[3]).

The monthly deferral calculation is shown in Equation 1.

Equation 1: $SNA\ Deferral_{m,c} = FCC_c \times Customers_{m,c} - EP^{SNA}{}_c \times Sales^{WN}{}_{m,c}$

The terms of the equation are defined in Table 2.1.

Table 2.1: Variables Included in the SNA Deferral Calculation

Variable	Description
$SNA\ Deferral_{m,c}$	The SNA deferral in month *m* for customer class *c*
$EP^{SNA}{}_c$	The Fixed Charge Energy Rate (in cents/kWh) for customer group *c*
$Sales^{WN}{}_{m,c}$	Weather-normalized sales (in kWh) to customer class *c* in month *m*
FCC_c	The Monthly Fixed Charge (in $/customer-month) for customer class *c*
$Customers_{m,c}$	The number of customers in month *m* and customer class *c*

This calculation is made each month, with the resulting value placed in a tracking account called the SNA Balancing Account. A positive value indicates that PGE under-recovered in that month (i.e., allowed revenue was higher than actual revenue). A negative value indicates that PGE over-recovered revenue in that month. Balances in the SNA Balancing Account accrue interest calculated using the Commission-authorized Modified Blended Treasury Rate.

Every twelve months, the balance is recovered from customers (if it is positive) or refunded to customers (if it is negative) through a change to the volumetric rate in the following year. Separate balancing accounts and rate changes are calculated for each schedule. Rate increases due to the SNA Balancing Account cannot exceed 2 percent of net rates on the applicable rate schedule (i.e., 7 or 32). Rate decreases are not subject to the 2 percent limit.

[3] The weather adjustment that converts observed sales into weather-normalized sales is conducted using the same methods used to forecast loads when setting base rates.

It can be useful to restate the SNA deferral calculation in the following way:
Equation 2a: $SNA\ Deferral_{m,c} = Customers_{m,c} \times (FCC_c - EP^{SNA}{}_c \times SalesPerCust^{WN}{}_{m,c})$, or
Equation 2b: $SNA\ Deferral_{m,c} = Customers_{m,c} \times (Allowed\ RPC_c - WN\ Actual\ RPC_{m,c})$

The terms of these equations are defined in Table 2.2.

Table 2.2: Variables Included in the Restated SNA Deferral Calculations

Variable	Description
$SNA\ Deferral_{m,c}$	The SNA deferral in month *m* for customer class *c*
$Customers_{m,c}$	The number of customers in month *m* and customer class *c*
FCC_c	The Monthly Fixed Charge (in $/customer-month) for customer class *c*
$EP^{SNA}{}_c$	The Fixed Charge Energy Rate (in cents/kWh) for customer group *c*
$SalesPerCust^{WN}{}_{m,c}$	Weather-normalized sales per customer (in kWh) to customer class *c* in month *m*
$Allowed\ RPC_c$	SNA allowed revenue per customer for customer group *c*
$WN\ Actual\ RPC_{m,c}$	Weather-normalized actual revenue per customer in month *m* for customer group *c*

Equation 2a is shown only to illustrate the intermediate step taken to derive Equation 2b from Equation 1. Equation 2b shows the SNA deferral in a manner that may make its effects easier to understand and interpret: it is the difference between the revenue per customer allowed under the SNA and the actual revenue per customer (based on weather normalized billed sales), multiplied by the number of customers served in the current month. This formulation of the SNA deferral more clearly shows that deferrals are only created in months when revenue per customer deviates from the "allowed" value.

2.2 Lost Revenue Recovery Adjustment

The LRRA applies to all customers that use less than one aMW except those served on Schedules 7, 32, and 532. It adjusts utility revenues to account for "lost revenues" associated with conservation and energy efficiency programs funded from sources other than Schedule 108 (Public Purpose Charge). Lost revenues are defined as the portion of revenues from volumetric rates that are intended to recover fixed costs (distribution, transmission, and generation).

As with the SNA, the LRRA includes a deferral calculation, which is shown in Equation 3. When PGE's base rates are set, the ETO's forecast of energy savings from energy efficiency and conservation programs is used. (I.e., sales reductions from ETO programs lead to less energy sold by PGE, which will lead to an increase in base rates, all else equal.) The LRRA adjusts utility revenues by reconciling differences between ETO's forecast sales reductions and its *ex post* estimates of sales reductions from its programs.

Equation 3: $LRRA\ Deferral_m = EP^{LRRA} \times (ETO^{Act}{}_m - ETO^{For}{}_m)$

The terms of the equation are defined in Table 2.3.

Table 2.3: Variables Included in the LRRA Deferral Calculation

Variable	Description
$LRRA\ Deferral_y$	The LRRA deferral in year *y*
EP^{LRRA}	The Fixed Charge Energy Rate (in cents/kWh)
ETO^{Act}_y	Energy savings reported by ETO (in kWh) in year *y*
ETO^{For}_y	ETO's forecast energy savings (in kWh) for year *y* when setting rates

LRRA deferral amounts are placed in a tracking account called the LRRA Balancing Account. A positive value indicates that PGE under-recovered in that year.[4] That is, when ETO's forecast of sales reductions is less than its *ex post* estimates of actual sales reductions, PGE is allowed to recover the difference through a future rate increase. Conversely, when the ETO over-forecasts sales reductions from conservation and energy efficiency programs, PGE refunds the over-recovery to customers through a future rate decrease. Balances in the LRRA Balancing Account accrue interest calculated using the Commission-authorized Modified Blended Treasury Rate.

Each year, the balance is recovered from customers (if it is positive) or refunded to customers (if it is negative) through a change to the volumetric rate in the following year. As with the SNA, rate increases cannot exceed 2 percent of net rates on the applicable rate schedule and rate decreases are not subject to the 2 percent limit. All applicable customers receive the same cent/kWh rate change from the LRRA.

3. EVALUATION REQUIREMENTS

The Order specified six issues to be addressed in the required evaluation of Schedule 123. Subsequent to the Order, meetings of stakeholders produced additions to the list of questions.[5] The final list is shown below.

1. Did the mechanisms effectively remove the relationship between the utility's sales and profits?
2. Did the mechanisms effectively mitigate the utility's disincentives to promote energy efficiency?
3. Did the mechanisms improve the utility's ability to recover its fixed costs?
4. Did the mechanisms reduce business and other financial risks? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.
5. What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanisms? Did the partial decoupling mechanisms affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality?

[4] The deferral amount is assumed to be recovered in equal amounts across the twelve months of the year, which is relevant in the calculation of interest received/paid on the LRRA Balancing Account.
[5] The stakeholders include CUB, ETO, Kroger, Northwest Energy Coalition, OPUC Staff, and PGE.

6. To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in UE 197 and in any subsequent general rate case?
7. PGE's mechanisms are based on a volumetric fixed charge. However, the amount of revenue available for fixed cost recovery may vary depending on the variable cost of the power being sold or purchased (Revenue/kWh minus variable power cost/kWh equals revenue available for fixed costs). Should the volumetric fixed charge decoupling rates be calculated in a different manner in order to account for this? For example, as the difference between total volumetric rates for both Schedules 7 and 32 and a measurement of short-run marginal energy costs such as the Mid-Columbia index?
8. What is the effect of a change in load (as included in these mechanisms) on PGE's costs? What is the effect of the change in load on revenue? Have the mechanisms accurately accounted for these changes? On a going forward basis are the mechanisms likely to accurately account for these changes?
9. Should the SNA mechanism be bifurcated such that the total kWh for each of Schedules 7 and 32 are fixed for and beyond the test period for purposes of recovery/refund of transmission and generation fixed revenue requirements? Calculation of the fixed revenue requirements for functions other than generation and transmission would be in the same manner as is currently done.
10. What is the interaction between the PGE decoupling mechanisms and the recent recession with regard to residential and small nonresidential customers?
11. How often should the fixed costs and use-per-customer parameters be updated?
12. What recommendations to the current PGE decoupling mechanisms would you suggest? Should it continue beyond 2013? Should it be terminated? Should it be modified? If so, what specific modifications should be made?

The remainder of this report consists of five sections. The guide below indicates the section in which each analysis question is addressed.

- Section 4: Questions 1, 2, 3, 6, 7, 8, 9, and 10.
- Section 5: Question 4.
- Section 6: Question 5.
- Section 7: Contribute to all questions.
- Section 8: Questions 11 and 12.

4. PROGRAM MECHANICS

4.1 Review of Program Mechanics

In order to evaluate the SNA and LRRA mechanisms, we reviewed spreadsheets provided by PGE that contain the calculations used to set the parameters (e.g., the SNA's Fixed Energy Charge Rate) and calculate the annual rate changes (via deferrals) attributed to each mechanism.

It may be useful to provide an overview of how the SNA Fixed Charge Energy Rate (FCER) is set, using Schedule 7 (residential customers) as an example.

Sales Normalization Adjustment
Table 4.1.1 contains the components of the FCER (under rates determined in Docket UE-215), showing that distribution and fixed generation are the two largest components, together accounting for 93.5 percent of the total FCER.[6] Because of the importance of these cost categories, we illustrate the derivation of each in Tables 4.1.2 and 4.1.3.

Table 4.1.1 Construction of the SNA Fixed Charge Energy Rate, *Schedule 7*

Cost Category	Fixed Charge Energy Rate (cents/kWh)
Distribution	2.826
Fixed Generation	2.495
Transmission and Ancillary Services	0.235
Generation Rate Design	0.114
Trojan Decommissioning	0.019
Total	**5.689**

Table 4.1.2 illustrates the derivation of the distribution component of the SNA's FCER. Distribution revenue is calculated by subtracting the following from the Schedule 7 required revenue amount: basic service charge revenue (which is already "decoupled" from sales); transmission revenue (which is included as its own component); franchise fees; and energy charge revenue (which is a combination of fixed generation costs, which are their own category, and expected variable fuel costs). The remainder of approximately $215 million is divided by forecast sales to arrive at the fixed distribution charge per kWh (2.826 cents / kWh).

Table 4.1.2 Derivation of the Distribution Component of the SNA, *Schedule 7*

Description	Amount ($000)
Schedule 7 Required Revenue	$858,636
– Basic Service Charge Revenue	$77,930
– Transmission Revenue	$17,861
– Franchise Fees	$22,042
– Energy Charge Revenue	$526,009
= Distribution Revenue	**$214,794**
÷ Forecast Sales, Schedule 7	7,601 MWh
Distribution Component of SNA	**2.826 cents / kWh**

Table 4.1.3 shows the derivation of the fixed generation component of the SNA. It begins with the total of projected production costs across all classes and subtracts forecast net variable power costs, which is the same measure of variable power costs used in PGE's power cost

[6] A parallel exercise could be conducted for the SNA Monthly Fixed Charge per Customer. The shares of total revenue by cost category would be the same as those implied by Table 4.1.1.

adjustment schedules (125 and 126). The remainder is presumed to represent the fixed generation revenue requirement in total, a portion of which is allocated to Schedule 7. The allocation factor is based on estimates of marginal energy and capacity costs, and results in 45.06 percent of fixed generation costs being allocated to Schedule 7.[7] The amount of approximately $190 million is divided by forecast sales to obtain fixed generation cost stated on a kWh basis.

Table 4.1.3 Derivation of the Fixed Generation Component of the SNA, *Schedule 7*

Description	Amount ($000)
Total Production Costs	$1,148,599
– Net Variable Power Costs	$727,762
= Fixed Generation Revenue Requirement	$420,837
x Capacity and Energy Allocator, Schedule 7	45.06%
= Fixed Generation Revenue Requirement, Schedule 7	$189,619
÷ Forecast Sales, Schedule 7	7,601 MWh
Fixed Generation Component	**2.495 cents / kWh**

Lost Revenue Recovery Adjustment

For the LRRA, it is instructive to demonstrate how the share of lost revenues (by cost component) is determined, using Schedule 83-S (large non-residential standard service for secondary customers with peak demand between 31 and 200 kW) as an example. Table 4.1.4 shows that distribution and fixed generation costs constitute the majority of the charge, which was also the case with the SNA.

Table 4.1.4 LRRA Lost Revenue by Cost Category, *Schedule 83-S*

Cost Category	Lost Revenue (cents/kWh)
Transmission and ancillary services	0.25
Distribution	1.78
Fixed generation[8]	2.28
Total	**4.32**

The LRRA is applicable to a wide range of customer classes, from small volume lighting schedules (e.g., Schedule 15) to primary service for large customers (Schedule 89-P). Expressed in cents per kWh, Table 4.1.5 shows the lost revenues calculated by PGE for each of the applicable rate schedules. Notice the wide range of charges, from a low of 3.17 cents/kWh to a high of 13.70 cents/kWh. While the range seems substantially smaller once one focuses on the schedules with the majority of the sales, significant differences remain. For example, the lost revenue rate for Schedule 83-S is 36 percent higher than the rate for Schedule 89-P.

[7] Marginal capacity costs are based on an assume $191.18 per kW simple cycle plant multiplied by PGE's projected peak load. The total cost is allocated to individual customer classes using a 4-CP allocator.
[8] Sales for direct access customers are removed in the calculation of the fixed generation component.

Because all applicable rate schedules receive the same LRRA adjustment charge (3.93 cents/kWh), the differences in lost revenues per kWh across rate schedules has led to some concerns that the LRRA leads to cross-subsidies. The information shown in Table 4.1.5 provides support for those concerns. However, there may be substantial administrative costs associated with rectifying the situation. In order to mitigate the potential for cross-subsidies to be introduced by the LRRA, the ETO would need to calculate conservation savings for each of PGE's LRRA-applicable rate schedules. Each schedule's lost revenue charge could then be applied to its own conservation-induced sales reductions to determine the total lost revenues by rate schedule.

If this remedy is not feasible or institutionally desirable (e.g., high administrative costs that outweigh the benefits), an intermediate solution is possible. That is, each LRRA-applicable rate schedule could be assigned a share of the ETO-measured conservation (perhaps based on total sales shares, as shown in the rightmost column of Table 4.1.5) and recovered at the schedule-specific lost revenue rates. This would *not* remove cross-subsidies due to differing levels of conservation across schedules, but it would mitigate cross-subsidies due to the application of a single LRRA charge across all rate schedules.

Table 4.1.5 LRRA Lost Revenue by Rate Schedule

Rate Schedule	Description	Lost Revenue (cents/kWh)	MWh Sales	Share of Sales
15	Outdoor area lighting	5.10	23,857	0.3%
38	Large non-res. TOD	7.66	33,511	0.5%
47	Small non-res irrigation	6.80	23,080	0.3%
49	Large non-res irrigation	4.77	67,653	1.0%
91	Street & highway lighting	5.16	108,227	1.6%
92	Traffic signals	4.11	4,733	0.1%
93	Recreational field lighting	13.70	576	0.0%
83-S	Large non-res, 31-200kW	4.32	2,771,767	40.0%
85-S	Large non-res, 201-1,000kW	3.69	2,340,481	33.8%
85-P	Large non-res, 201-1,000kW	3.47	289,091	4.2%
89-S	Large non-res, >1,000kW	3.39	561,706	8.1%
89-P	Large non-res, >1,000kW	3.17	697,704	10.1%
Total		**3.93**	**6,922,385**	**100.0%**

Schedule 123 Deferrals to Date

Table 4.1.6 contains the annual deferral amounts by year for each of the three parts of Schedule 123: the SNA for Schedule 7; the SNA for Schedule 32; and the LRRA. A positive number indicates utility under-recovery, leading to a surcharge on customer bills in the following year.

Across all years and customer groups, the net effect of Schedule 123 has been to increase utility revenues by approximately $576,000. The net effects vary across customer groups. Residential (Schedule 7) customers received surcharges in three of the four years, with a net effect of approximately $3.2 million across the four years. The experience so far has been mixed for the small commercial (Schedule 32) customers. The large commercial and industrial customers received rate reductions in three of the four years, with a net revenue refund of approximately $1.9 million. The result implies that the ETO estimates of conservation that have been incorporated within base rates tend to over-state the amount of conservation that ETO estimated after the fact, so that the lost revenues for the LRRA-applicable rate schedules were lower than expected.

Table 4.1.6 Schedule 123 Deferrals by Year ($000)

Year	SNA Schedule 7	SNA Schedule 32	LRRA	Total
2009	-$3,652	$1,829	-$1,072	-$2,895
2010	$3,873	$2,266	-$688	$5,452
2011	$381	-$2,428	-$602	-$2,649
2012	$2,574	-$2,394	$488	$668
Total	**$3,176**	**-$727**	**-$1,873**	**$576**

4.2 Addressing Required Evaluation Questions Related to Program Mechanics

Several of the required evaluation questions require an assessment of program mechanics. In this sub-section, we will address each one using the insights gathered from our investigation of the Schedule 123 mechanics. Note that many evaluation questions are answered in other sections of the report. The question numbering corresponds to that used in Section 3.

1. Did the mechanisms effectively remove the relationship between the utility's sales and profits?

No, Schedule 123 was not designed to completely remove the relationship between sales and profits. First, the schedule is not applicable to customers over 1 aMW, so changes in sales to these larger customers will continue to affect PGE's profit in the same manner that it would in the absence of Schedule 123.

Second, the LRRA applied to larger C&I (and some other) customers only adjusts utility revenues for changes in usage that can be attributed to ETO-sponsored conservation programs. The revenue effects of all other changes in sales to these customers are unchanged by Schedule 123.

Third, even for the SNA-eligible customers, the SNA does not affect the relationship between weather-induced fluctuations in sales and PGE revenue. Because this is a significant source of variability in sales to these customers, PGE's profits continue to be affected by variations in sales.

2. Did the mechanism effectively mitigate the utility's disincentive to promote energy efficiency?
Yes, for Schedules 7 and 32. The SNA appears to eliminate, at least the short-term, utility disincentives to promote conservation and energy efficiency.[9] The utility does not control weather conditions, so the fact that such variability is retained under the SNA does not affect PGE's incentives with respect to conservation.

For customers on the LRRA, the utility continues to have a disincentive to promote any conservation that it does not believe will be captured in ETO's estimates of program-induced conservation. In addition, under the LRRA the utility retains an incentive to *increase* customer sales. In contrast, under the SNA, PGE does not benefit from increases in use per customer.

3. Did the mechanisms improve the utility's ability to recover its fixed costs?
The answers to this question are specific to each mechanism. The LRRA is comparatively limited in scope: prevent/mitigate utility revenue attrition due to the ETO's conservation programs. The effectiveness of the LRRA in eliminating these losses is directly related to the accuracy of the ETO's estimates of conservation savings. If the estimated savings are accurate, PGE will continue to recover the fixed costs associated with the lost sales. PGE's recovery of fixed costs in the presence of other sales changes under the applicable rate schedules is unaffected by the LRRA.

For the SNA, the answer is considerably more complicated, and highly specific to condition. Under standard rates, the amount of net revenue collected by PGE to cover fixed costs is directly related to how much energy its customers (on Schedules 7 and 32) use. When current customers conserve or use less energy relative to test year levels, PGE recovers less revenue available to cover fixed costs. Conversely, when current customers use more energy, PGE recovers more revenue contribution toward fixed costs, when compared to test year levels. When a new customer joins the system, PGE gains revenue in approximate proportion to the customer's usage, recognizing that net impacts are highly specific to both load shape and the rate schedule under which new customers take service.

The SNA alters these outcomes. The SNA replaces the link between revenue and sales with a link between revenue and the number of customers served. This leads to two different types of effects: those attributable to changes in the number of customers served; and those resulting from changes in energy usage of existing customers.

In the former category (change in customers served), the SNA only alters PGE's revenue to cover fixed costs to the extent that the added or lost customers are different in size from the average of current customers served (based on the test-year forecast of sales). That is, when average-sized customers join (or leave) PGE's system, the revenue effects of standard rates and

[9] The utility's longer-term incentive to grow load to "put more steel in the ground" and thus have a higher rate base upon which to earn a rate of return is not addressed by Schedule 123. However, with ETO goals of approximately 1% incremental conservation per year, this longer-term incentive may not be relevant for PGE.

the SNA are the same (i.e., because there is no SNA deferral when use per customer does not change). If a larger-than-average customer joins the system, PGE collects *less* revenue under the SNA than it would under standard rates. Conversely, if a smaller-than-average customer joins the system, PGE collects *more* revenue under the SNA than it would under standard rates. Whether the adoption of the SNA improves PGE's ability to recover fixed costs in this situation therefore depends on: the size of the customer; whether PGE's estimates of the marginal cost to serve a customer is accurate and closely related to the size of the customer.[10] We explore the relationship of the SNA to PGE's marginal costs more in Section 4.3.

The second type of change to consider under the SNA is the effect of changes in usage by current customers. In this second case, the differences between the SNA and standard rates are more significant. Increases in sales above test-year levels lead to a higher share of recovery of fixed costs under standard rates, but not under the SNA.[11] Conversely, conservation (or reduced energy usage) on the part of current customers leads to lower coverage of fixed costs under standard rates, but not under the SNA. Thus, it appears that the SNA improves PGE's ability to recover its fixed costs, with the caveat that it does not address fixed-cost recovery issues that arise because of deviations from normal weather conditions (e.g., customers using more energy in a hot summer).

7. PGE's mechanism is based on a volumetric fixed charge. However, the amount of revenue available for fixed cost recovery may vary depending on the variable cost of the power being sold or purchased. (Revenue/kWh minus variable power cost/kWh equals revenue available for fixed costs.) Should the volumetric fixed charge decoupling rates be calculated in a different manner in order to account for this? For example, as the difference between total volumetric rates for both Schedules 7 and 32 and a measurement of short-run marginal energy costs such as the Mid-Columbia Index?

No, we believe that the current method is effective. The fixed generation component of the SNA is calculated by subtracting net variable power costs from total production costs (where both represent test-year forecasts). This results in a reasonable estimate of the total fixed generation costs, which are subsequently allocated to rate schedules and unitized using the forecast number of customers and sales. This estimate does not change with variable power costs. That is, if one were to recalculate the fixed generation costs under the assumption of higher market prices, both total production costs and net variable power costs would increase, leaving the difference (fixed generation costs) unchanged.

[10] We do not favor excluding or separately tracking new customers under decoupling mechanisms. Excluding new customers from the decoupling mechanism removes the utility's incentive to ensure that new customers are as energy efficient as possible. Separately tracking new customer adds to the complexity and administrative costs of the mechanism, and still requires a forecast of the average size of new customers. Differences between the forecast and the average size of the customers actually added will continue to exist.

[11] Note that if actual fixed costs are equal to regulatory-allowed fixed costs within the test year, revenues over-recover regulatory costs, other factors constant.

However, it may be the case that the SNA produces fixed generation cost recovery that differs from what would have occurred in its absence. Whether the effect of the SNA is to increase or decrease PGE's fixed generation cost recovery, when compared to test year allowed cost levels, depends on a variety of factors, including:

- Whether variable power costs (e.g., wholesale market energy prices) are higher or lower than forecast values;
- Whether changes in sales are due to a change in the number of customer served or a change in the usage of existing customers;
- Whether the number of customers is increasing or decreasing; and
- Whether use per customer is increasing or decreasing.[12]

We do not find reason that PGE's SNA mechanism introduces bias in fixed cost generation revenues because of the use of a fixed per-customer and per-kWh fixed cost generation component. A separate, but related question regarding whether the generation and transmission components of the SNA should be treated differently than the distribution component is addressed in Section 4.3.

4.3 The Relationship between SNA Revenues and Marginal Costs

The SNA allows PGE's revenue toward fixed costs to increase as it serves more customers. The sixth evaluation requirement (listed in Section 3) concerns the relationship between the SNA's allowed revenue per customer and the marginal cost of serving additional customers. Here is the requirement:

6. To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in UE 197 and in any subsequent general rate case?

Many factors could lead to an increase in fixed costs over time, including changes in the utility's cost function (e.g., increases in costs associated with planned distribution system maintenance) or the addition of customers to the system. The SNA is designed as though fixed costs are directly related to the number of customers served. The analysis requirement listed above appears to ask about the extent to which fixed costs have evolved in a manner consistent with the design of the SNA.

Two pieces of evidence are available to assist in answering this question. First, we can see how the Monthly Fixed Charge per Customer has evolved since the introduction of the SNA. Table 4.3.1 contains the SNA Monthly Fixed Charges per Customer, by Schedule and rate case (i.e., time period). When the SNA was introduced, the allowed revenue per customer month was $41.38 for residential customers and $63.47 for small commercial customers. By the subsequent rate case (UE-215), PGE had added customers in both of these rate classes. In addition, the SNA charges increased for both groups, to $49.94 and $75.81 respectively. These

[12] Note that if use per customer doesn't change relative to test-year levels, the SNA doesn't produce a deferral regardless of the number of customers served. In this case, the SNA can't alter the amount of generation fixed cost revenue that PGE collects.

are direct indications that the fixed costs covered by the SNA increased over time. PGE's current filing (UG-262) proposes a further increase in those charges, which is also associated with an increase in the number of customers served. The relatively small increases in the number of customers served relative to the increases in the SNA Monthly Fixed Charges makes it highly unlikely that customer growth was a significant driver of the increased per-customer charges (e.g., compared to the costs associated with modernizing existing infrastructure). However, the values in Table 4.3.1 do indicate that the per-customer "fixed" costs vary over time, and have tended to increase in recent years.

Table 4.3.1: SNA Parameters across Rate Cases

Docket and Timeframe	Number of Customers		SNA Monthly Fixed Charge per Customer	
	Schedule 7	Schedule 32	Schedule 7	Schedule 32
UE-197 (2009-2010)	715,517	84,620	$41.38	$63.47
UE-215 (2011-current)	721,537	86,153	$49.94	$75.81
UE-262 (as filed)	734,050	88,797	$56.77	$95.05

Table 4.3.2 presents a comparison of the SNA fixed charges and the marginal costs associated with serving an additional customer, using information from PGE's marginal cost of service study from UE-215. While this table does not reveal the incremental costs associated with the new customers added between rate cases, it does provide estimates of the costs of adding customers, using methods applied by PGE for cost allocation purposes.

In the parlance of PGE's marginal cost study, costs are estimated for three functions of integrated electricity services[13] customer-related costs (e.g., transformation, metering, billing), distribution (transport services); and generation (power supply). Customer-related costs are expressed in dollars per customer month and, for the immediate purposes, require no adjustment. Distribution costs are presumed to be exclusively driven by peak loads, and are thus expressed in $/kW-year. Using class-level sales data and an assumption of a 60 percent load factor, we estimated demand of approximately 2kW per customer for Schedule 7 and 3.3kW for Schedule 32. Generation capacity costs are estimated by PGE to be $191.18 per kW-year which, in turn, is multiplied by the estimates of demand (2kW, 3.3kW). This result is combined with the customer and distribution costs to obtain estimates of marginal costs per customer covering customer (i.e., incremental interconnection services) and demand-related costs. Note that marginal energy costs including energy and line losses are not covered.

In Table 4.3.2, PGE's marginal cost estimates are compared to the annual revenue per customer allowed under the SNA (12 x the SNA Monthly Fixed Charge per Customer). For each of the three schedules/customer groups, the marginal cost to serve is higher than the revenue allowed under the SNA. A significant portion of the non-fuel marginal cost to serve an additional customer is associated with generation capacity. For a defined timeframe, such level

[13] Transmission and ancillary services are omitted because they are of comparatively small magnitude with respect to customer-, distribution-, and generation capacity-related cost categories.

of generation capacity cost may not necessarily be *on the margin*, and thus actually reflected in PGE's financial costs, as it serves an additional customer. We anticipate that, within an annual timeframe, customer- and load-related distribution costs are perhaps more representative of PGE's actual experience *on average*, recognizing the wide variation in the underlying costs across individual customers served. That is, within an annual period, if PGE serves additional load through wholesale market purchases (or a reduction in wholesale market sales), the value of these transactions is accounted for in its power cost adjustment schedules. Under such condition, PGE is exposed to cost recovery shortfalls (or may be long) to the extent that: a) the costs are not accounted for in the Schedule 125 forecast; and/or b) the Schedule 126 variance mechanism does not fully compensate PGE for the cost variance relative to the forecast.

Table 4.3.2: Comparison of SNA Revenue per Customer and Marginal Costs using UE-215 Rates

Category	Schedule 7	Schedule 32, Single Phase	Schedule 32, Three Phase
Customer-related	$154	$194	$380
Distribution	$123	$235	$191
Generation Capacity	$383	$625	$625
Marginal Cost (non-fuel)	**$660**	**$1,054**	**$1,196**
SNA Fixed Charge per Customer Year	**$599**	**$910**	**$910**

There are two additional questions that relate to PGE's marginal costs, which are addressed below.

8. What is the effect of a change in load (as included in this mechanism) on PGE's costs? What is the effect of the change in load on revenue? Has this mechanism accurately accounted for these changes? On a going-forward basis is this mechanism likely to accurately account for these changes?

In the absence of the SNA, the retail rates define the effect of a change in sales on PGE's revenue. Schedule 126 (the true-up schedule) could alter revenues in the longer term if wholesale costs to serve are higher or lower than expected. With the SNA, the utility's revenue stream depends on the source of the increased sales. In the case of sales (and therefore revenue) increases from current customers, PGE retains the portion that covers variable energy costs but refunds the portion for coverage of non-variable costs (assuming that the load level is above test-year sales estimates). In the case of new customers, PGE realizes an increase in revenue, as though a typical (average-sized) customer joins the system.

Regarding the effect of a change in load on PGE's cost, we again refer to PGE's marginal cost of service study. Therein, estimates of marginal customer- and capacity-costs imply that PGE loses money (increases earnings) as the number of customers increases (decreases). Implicitly, then, marginal costs are above the average cost of service). However, the *true* incremental costs associated with increased/decreased energy sales or customers are highly specific to context, and can vary dramatically depending on the circumstances—e.g., whether the load change during a peak hour or an off-peak hour, the specific location of the customer within PGE's distribution system, the customer's size and load factor, or wholesale market conditions, or whether PGE is comparatively short or long in capacity (evidence clearly suggests that PGE is capacity short, currently).

Note: standard rates do not necessarily do a good job of associating changes in revenues and the true changes in costs. The relevant question is whether the SNA tracks the true underlying costs on the margin vis-à-vis standard rates. As the discussion proceeds, we will demonstrate that the SNA does not appear to perform worse than standard rates across all possible outcomes, but the particular outcome is specific to conditions (e.g., cost conditions, sales levels, etc.).

11. Should the mechanism be bifurcated such that the total kWh for each of Schedules 7 and 32 are fixed for and beyond the test period for purposes of recovery/refund of transmission and generation fixed revenue requirements? Calculation of the fixed revenue requirements for functions other than generation and transmission would be in the same manner as is currently done.

The question suggests an alternative SNA design in which the allowed revenue level (rather than revenue per customer) for the generation and transmission components of the SNA is fixed. In the current SNA formulation, the allowed revenue changes when the number of customers served changes. Under standard rates, however, revenues change with changes in sales level, as volumetric charges (i.e., $/kWh) are the basis to recover fixed generation costs.

It is useful to illustrate the impacts of these methods on utility revenues through a highly stylized example. Suppose rates are set using projections of 100 customers, each using 1,000 kWh during the test year. For the test year, normalized fixed generation costs are $2,500, or $0.025 per kWh (and $25.00 per customer). Tables 4.3.3a and 4.3.3b below illustrate how fixed generation costs are recovered as use-per-customer (UPC) and the number of customers served deviates from test-year levels, other factors constant.

The columns in the table present alternative levels of use per customer ("UPC"), including 5% changes (decreases and increases of 50 kWh) from the test-year level of 1,000 kWh per customer—i.e., alternative sales scenarios of 950 and 1,050 kWh, respectively. The rows contain three scenarios of the number of customers served, including the test-year level (100) and alternative scenarios of 95 and 105 customers.

Three results panels are presented in Table 4.3.3a, including *Sales*, which shows the total sales for each of the nine scenarios examined.[14] The middle panel, labeled "Revenue, Standard Rates", shows the realized revenue (for fixed generation costs) obtained under each scenario,

[14] Sales are calculated as the product of the number of customers and use per customer.

presuming that costs are recovered with volumetric charges—for each scenario, revenue is the product of sales and $0.025/kWh.

The bottom panel, labeled "Revenue with Decoupling", shows the realized revenue for fixed generation costs under the implementation of a revenue-per-customer decoupling mechanism. The calculation of the adjustment from the "Standard Rates" panel, to obtain the results shown in this third panel is as follows:

Decoupling Adjustment = # of customers x $0.025/kWh x (1,000 kWh – Scenario UPC)

Table 4.3.3a: Example Illustrating Scenarios of Fixed Generation Cost Recovery

Outcome	Number of Customers	Use Per Customer		
		1,000 kWh	950 kWh	1,050 kWh
Sales	100	100,000	95,000	105,000
	95	95,000	90,250	99,750
	105	105,000	99,750	110,250
Revenue, Standard Rates	100	$2,500	$2,375	$2,625
	95	$2,375	$2,256	$2,494
	105	$2,625	$2,494	$2,756
Revenue with Decoupling	100	$2,500	$2,500	$2,500
	95	$2,375	$2,375	$2,375
	105	$2,625	$2,625	$2,625

Shown below in Table 4.3.3b are the differences between the realized revenue for coverage of fixed generation costs, under each scenario, and the $2,500 in fixed generation costs set during the rate case proceeding. In the top panel, *Revenue Under Standard Rates*, the utility recovers the allowed revenue only when the number of customers and UPC are at test-year levels. When sales exceed test-year levels, utility recovers greater revenue (e.g., by $256 under the higher scenarios for both number of customers (105) and UPC (1,050)); realized revenues are below test year fixed generation costs when sales are below test-year levels, which occurs in 5 of the 9 nine scenarios.

Table 4.3.3b: Example Illustrating Scenarios of Fixed Generation Cost Recovery

Difference from Test-year Fixed Generation Costs	Number of Customers	Use Per Customer		
		1,000 kWh	950 kWh	1,050 kWh
Revenue Under Standard Rates	100	$0	-$125	$125
	95	-$125	-$244	-$6
	105	$125	-$6	$256
Revenue with Decoupling	100	$0	$0	$0
	95	-$125	-$125	-$125
	105	$125	$125	$125

Scenario results differ under decoupling, where the amount of revenue for recovery of fixed generation costs depends entirely on the number of customers served (e.g., the utility under-recovers by $125 when it serves 95 customers, regardless of the level of UPC).

One scenario is of particular interest: *increased number of customers and decreased sales.*[15] Here, standard rates obtain a modest under-recovery of fixed generation costs (-$6), while the decoupling mechanism results in *increased* revenue for fixed generation costs (+$125) despite the fact that less total load is served.

In summary, under standard rates, in which fixed costs are recovered with volumetric rates, the utility over- or under-recovers test year fixed generation costs in proportion to changes in *sales*. Under revenue-per-customer decoupling, the utility over- or under-recovers such costs in proportion to changes in *the number of customers*. Neither approach guarantees that test year (fixed generation) costs are matched by revenues. Among the four scenarios in which UPC and the number of customers deviate from test-year values, decoupling improves the test year cost-revenue match vis-à-vis standard rates under 4 of the 8 alternative scenarios (where "improves" is defined as a reduced difference between collected revenues and test-year costs, when compared to standard rates). Accordingly, it does not appear that decoupling performs worse than standard rates.[16]

Yet, a bifurcation of the decoupling mechanism such that allowed fixed generation revenue remains constant regardless of the number of customers served or the level of UPC ensures, in our example, that the service provider realizes revenues equivalent to allowed fixed generation costs. This appears to improve on the scenario outcomes obtained under both standard rates and decoupling, notwithstanding incentive associated with a lock-in revenue-test year cost approach.

[15] Number of customers rises to 105 but total sales declines to 99,750 kWh.

[16] One could argue that decoupling may be expected to perform worse than standard rates if it is most likely that a) the number of customers will increase; and b) UPC will decrease due to successful conservation. Based on historical trends, the former seems very likely but there is mixed evidence on the latter. (E.g., reductions in UPC due to successful conservation programs may be offset by increased prevalence of energy-intensive end uses.)

Note that the above discussion compares realized revenues and test-year fixed costs. In this case, "fixed cost" refers to the absence of a relationship between the level of total costs and short-term fluctuations in sales. However, the fixed-cost basis of rates is financial costs, either observed or estimated for defined timeframes, such as historical or projected test years. Financial costs and changes in fixed costs through time (e.g., between general rate proceedings) often change significantly. Including foreseeable events as well as unanticipated contingencies, the list is long: accounting measures of the worth of facilities decline as a result of capital depletion; physical capital is replaced, where incremental costs are several fold that of net plant value; storm activity that imposes major service dislocations on consumers and foregone revenues on utilities; generator unit outages caused by equipment failures; and distribution service failures precipitated by unanticipated high loads; and environmental compliance costs. None is associated with output quantities, either changes in energy sales or the number of customers served. If such events are inherently "inflationary" to electricity tariff prices, bifurcation of decoupling would reduce the utility's ability to recover its fixed generation costs. If the number of customers served increases at a relatively modest rate (of perhaps 1 percent per year), the decoupling mechanism is compatible with inherent inflationary pressures.

However, there is an alternative that is likely to be superior to either of these options (continuing the current methodology or fixing allowed generation and transmission revenue). It begins by bifurcating fixed generation and transmission costs, but instead of fixing the amount of allowed revenue, it is set at an index of industry-wide input cost measures. This prevents the utility from being harmed by exogenous increases in costs, prevents them from benefitting from exogenous decreases in costs, and provides it with an incentive to outperform the industry average (i.e., it is not a cost tracker – the utility benefits or suffers from deviations from industry-average costs). In this way, an incentive regulation component is integrated into the decoupling mechanism, the details of which would require additional exploration.

In conclusion, there is good cause for the separation of generation and transmission (G&T) from distribution under PGE's SNA decoupling mechanism, as the underlying G&T costs are more closely related to sales volumes than the number of customers served, other factors held constant. Nonetheless, PGE's current approach to decoupling does not appear to function worse than standard rates, at least under the initial review conducted herein. In addition, locking in revenues to match test-year costs for G&T could be punitive if the G&T functions are facing rising cost pressures. Finally, bifurcation may be a preferred approach and obtain improved results if the amount of revenue is tied to an industry cost index. Specific results, however, are highly conditional to market context and cost pressures facing the G&T functions; further analysis is necessary in order to explore more fully how such approach might be best constructed.

4.4 Statistical Analysis of Use per Customer

The SNA adjusts utility revenues for the effects of deviations of sales per customer from forecast levels (used when base rates are set) due to any cause except weather.[17] For the most part, this characteristic reduces risk for both the utility and its ratepayers, where we define "risk" as the variability of revenue (or bills) toward fixed costs over time. That is, by preventing utility over- and under-recovery of fixed costs, the mechanism also prevents ratepayer over- and under-payment of fixed costs.[18]

However, there are two cases in which the SNA may shift risk from the utility to its ratepayers: *economic* risk and *rate* risk. For example, if an economic recession causes customers to reduce their usage in an attempt to save money, the fixed-cost portion of the resulting bill reduction will be paid to the utility in the following year through an SNA-induced rate increase.[19] Thus, the SNA could make a bad situation worse for ratepayers even as it would mitigate the adverse effects of the recession for PGE. A similar argument can be made regarding a customer who conserves in the face of rising energy costs.[20]

A conserving customer does not directly pay back the fixed-cost portion of its bill reduction. Rather, those costs are spread across all customers in its rate class through an SNA-induced rate increase in the following year. The SNA only affects rates and revenues through changes in class-level use per customer. Therefore, in order to determine whether the SNA shifts economic risk from PGE to its customers, we examine the effect of economic conditions on class-level use per customer. The economic risk is only shifted from PGE to its customers if there is a statistically significant relationship between the two factors (i.e., if UPC declines during recessions). Similarly, rate risk can only be shifted from PGE to its customers if there is a statistically significant relationship retail volumetric rates and class-level UPC.[21]

Figures 4.4.1 and 4.4.2 illustrate the potential difficulty in identifying an effect of economic conditions on use per customer that is distinct from an SNA effect. Figure 4.4.1 shows UPC

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[17] Recall that the mechanism attempts to remove the effects of weather by adjusting sales so that they represent sales at normal weather conditions.

[18] Note that this discussion does not apply to the LRRA, which only affects revenues and bills when forecast conservation differs from observed (estimated) conservation.

[19] In more formal economic terms, the recession reduces customer income, which (if electricity is a normal good) causes customers to reduce their electricity use. The resulting reduction in sales leads to a positive SNA deferral, increasing rates in the following year and further reducing customer welfare.

[20] It should be noted that in all cases, customer conservation leads to a reduction in total customer bills (all else equal) even after accounting for the effect of the SNA deferral, as variable energy costs are not included in the SNA.

[21] Weather is another source of revenue and bill risk, but the SNA excludes the effect of weather on sales from its deferrals. In comments, Staff indicated the possibility of other sources of risk shifting: efficiency gains, changes in population, and technological innovations. We do not consider these sources in this study due to data limitations (e.g., we do not have information on appliance efficiency levels and saturation rates). However, we do not expect these sources of risk to be as volatile in the near term as the sources we do consider. For example, we expect economic conditions and electricity commodity prices to change much more rapidly than average electric intensity (reflecting efficiency gains and technological innovations) or population levels.

values for customers on Schedules 7 and 32. Figure 4.4.2 shows the Oregon unemployment rate and gross domestic product (GDP). In both figures, the vertical line indicates the date on which the SNA became effective. As Figure 4.4.2 shows, the SNA was implemented in the midst of a worsening of economic conditions. The coincidence of these two events (the recession and the implementation of the SNA) may make it difficult for the statistical model to separate the effect of each on UPC.

Figure 4.4.1: Use per Customer for Schedules 7 and 32

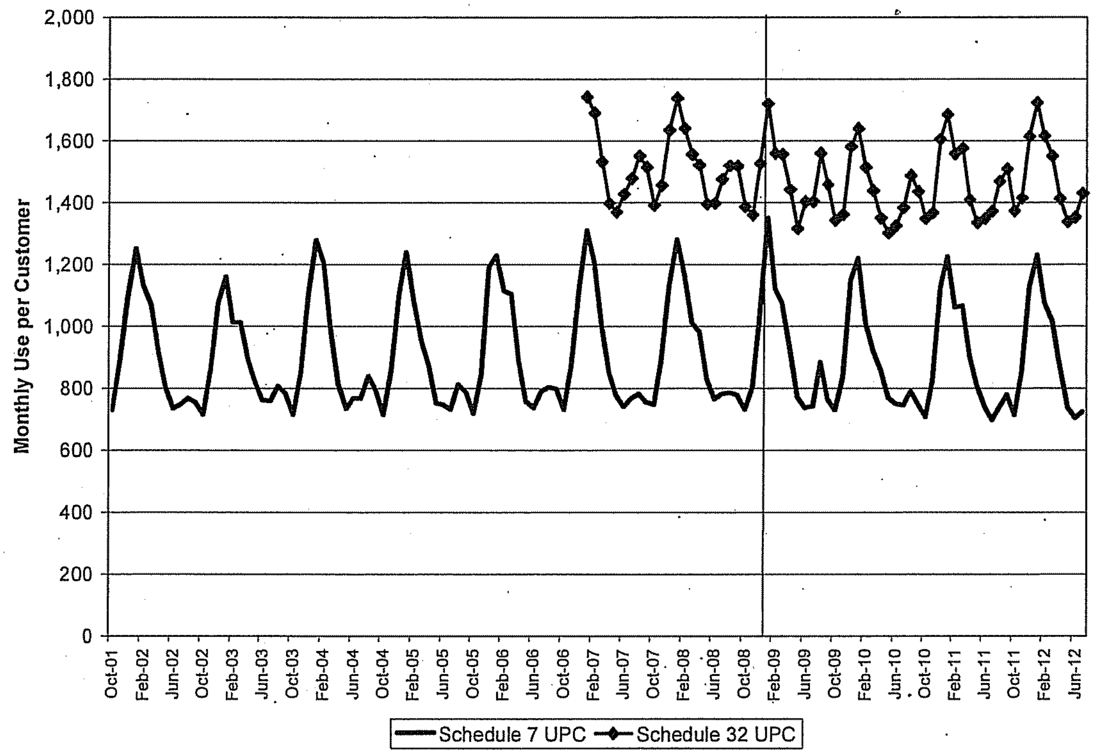
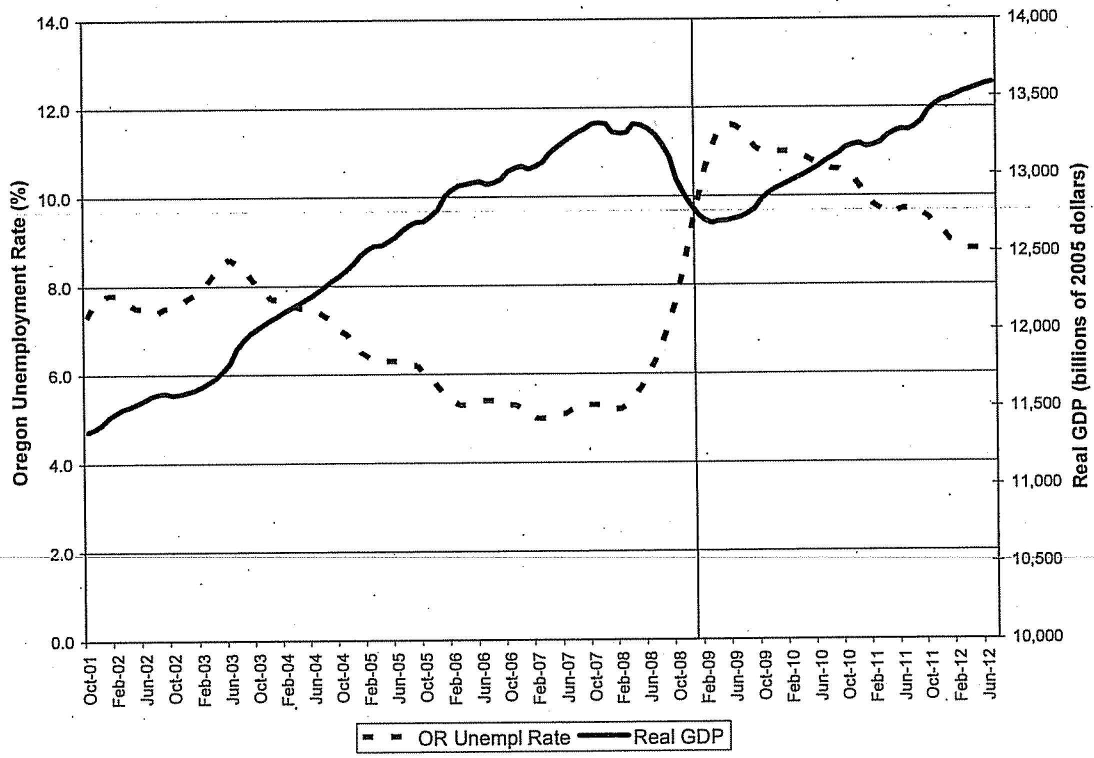


Figure 4.4.2: Oregon Unemployment Rate and Real Gross Domestic Product



The statistical model is shown in Equation 4.

Equation 4:

$$UPC_{c,t} = a + b_{CDD} \cdot CDD_t + b_{HDD} \cdot HDD_t + b_{Econ} \cdot Econ_t + b_{Trend} \cdot Trend_t + b_{Rate} \cdot Rate_{c,t}$$
$$+ \sum_{i=2}^{12} b_i \cdot Month_{i,t} + e_t$$

Table 4.4.1: Variables Included in the Statistical Models

Variable Name / Term	Description
$UPC_{c,t}$	Use per customer for customer group *c* in month *t*
a and the various *b*'s	The estimated parameters
CDD_t	Cooling degree days in month *t*
HDD_t	Heating degree days in month *t*
$Econ_t$	Economic conditions in month *t*
$Trend_t$	Time trend variable
$Rate_{c,t}$	The average retail rate for customer group *c* in month *t*
$Month_{i,t}$	An indicator variable for month *i* at time *t*
e_t	The error term

Separate models are estimated for each rate schedule (7 and 32).[22] The dependent variable is UPC for the rate schedule in question. Weather conditions are accounted for through the CDD and HDD variables.[23] The economic variable is either the Oregon unemployment rate or the natural log of real GDP. The time trend variable increments 1/12 each month, such that the estimated coefficient on the variable is interpreted as the annual change in UPC, controlling for other included factors. The rate variable is constructed as the average retail rate calculated from the rates for each usage block (converted to 2005 dollars using the Consumer Price Index), the block sizes and UPC for the customer class and month in question. The month indicator variables account for seasonal patterns in UPC not captured by the weather variables.[24] In some models, we include an SNA indicator variable that equals 0 prior to February 2009 and 1 after. This variable is intended to capture any changes in UPC that occurred because the SNA was in place.

Five alternative model specifications were estimated for each rate schedule. The first includes only weather and monthly indicator variables. These results are intended to demonstrate that a very large portion of fluctuations in UPC can be explained by only weather and seasonal patterns. The four additional specifications all contain the time trend variable, the average retail rate, and one measure of economic conditions (either real GDP or the Oregon unemployment rate). Finally, we estimate specifications with and without the SNA indicator variable. Because the SNA was introduced in the midst of a recession, it may be useful to examine the relationship between UPC and economic conditions with and without the SNA variable.

For each specification, we report the number of observations (N) and the R-squared value, which is the proportion of the variation in UPC that is explained by the included variables.[25] Asterisks are included to indicate the level of statistical significance of the estimated effect of the variable in question.[26] The absence of an asterisk means that the coefficient is not statistically significantly different from zero (i.e., the estimates indicate that the variable has no effect on UPC).

Table 4.4.2 contains the estimates for the Schedule 7 models.[27] The R-squared value for the first model (0.976) shows that over 97 percent of the variation in UPC can be explained by just the

[22] Prais-Winsten estimation is conducted to account for serial correlation, which is the tendency for the regression error in a given time period to be related to the error in the previous time period.
[23] $CDD_m = \Sigma_d \max\{0, (MaxTemp_d + MinTemp_d) / 2 - 65\}$. $HDD_m = \Sigma_d \max\{0, 65 - (MaxTemp_d + MinTemp_d) / 2\}$. In both equations, *m* refers to the month in question and *d* indexes the days of that month.
[24] In all of the models we estimate, the monthly indicator variables are jointly statistically significant. That is, they capture variation in UPC that the other included variables do not.
[25] R-squared ranges from 0 to 1, where 0 indicates that the variables do not explain any variation in UPC and 1 indicates that the variables explain all of the variation in UPC.
[26] Three asterisks indicate a p-value less than 0.01; two asterisks indicate a p-value less than 0.05; and one asterisk indicates a p-value less than 0.10.
[27] While the monthly indicator variables are included in all models, we do not report their estimated coefficients for compactness.

weather and monthly indicator variables. The second column of results contains the following results of interest:

- A statistically significant time trend, indicating an 8.9 kWh per year reduction in UPC;
- A statistically significant effect of real GDP on UPC, with a 1 percent increase in real GDP corresponding to a 3.47 kWh increase in UPC; and
- No relationship between the average retail rate and UPC.

The third column of results replaces the GDP variable with the Oregon unemployment rate (where, for example, 8 percent is represented as 8.0). This change does not affect the CDD and HDD variables (which are doing most of the work in explaining changes in UPC), but it does reduce the magnitude of the time trend effect from -8.9 to -2.5. The unemployment rate is statistically significant, but only at the 90 percent level (whereas the GDP variable was significant at the 99 percent level). The size of the effect indicates that a 1 percent increase in the unemployment rate reduces UPC by 3.1 kWh.

Columns 4 and 5 show how the results are affected by introducing an indicator for the dates during which the SNA was in effect. Once again, the coefficients on the weather variables are not affected. However, the introduction of the SNA variable causes the estimates on the economic and time trend variables to lose their statistical significance. The SNA indicator itself is statistically significant in the Oregon unemployment model (column 5), indicating that UPC was 38.2 kWh lower when the SNA was in effect, all else equal. This is approximately 4 percent of the average UPC across all months.[28]

[28] In comments, Staff requested that we include an interaction between the economic variable and he SNA dummy variable to see whether the SNA makes customers more or less responsive to economic shocks. Specifically Staff stated that "the analysis identifies that customers are less responsive to economic variables in the presence of the SNA. The findings could be driven by the correlation between the dummy variable and the economic variables. Alternately, the results could be driven by a structural break caused by the introduction of the SNA." We conducted this test for the models shown in the fourth and fifth columns of Tables 4.4.2 and 4.4.3. There is only one model (the GDP model for Schedule 7 customers) in which the interaction variable is statistically significantly different from zero (at the 90 percent level). However, the other coefficients do not appear to be altered reasonable ways. Specifically, the results imply no statistically significant effect of economic conditions on UPC before or after implementation of the SNA; and a statistically significant *increase* in UPC after introducing the SNA (all else equal). In summary, we believe that Staff's theory that the results in Tables 4.4.2 and 4.4.3 reflect "correlation between the dummy variable and the economic variables" is much more plausible than the theory that the "SNA makes customers more or less responsive to economic shocks."

Table 4.4.2: Statistical Model Results, *Schedule 7*

Variable	Weather & Month Only (1)	GDP, No SNA (2)	OR Unempl, No SNA (3)	GDP, SNA (4)	OR Unempl, SNA (5)
CDD	0.76***	0.76***	0.76***	0.76***	0.74***
HDD	0.68***	0.70***	0.70***	0.70***	0.70***
Trend		-8.9***	-2.5**	-5.6	0.3
ln(Real GDP)		347***		221	
OR Unempl:			-3.1*		1.7
Avg. Rate		4.59	-0.07	5.05	3.27
SNA				-13.1	-38.2**
Constant	726***	-2,549**	749***	-1,382	683***
N	130	130	130	130	130
R-squared	0.976	0.984	0.983	0.984	0.982

Table 4.4.3 shows the results for Schedule 32 customers. There are some similarities to the residential results, namely:

- Weather and seasonal factors explain a very high proportion of the variation in UPC;
- There is no statistically significant relationship between UPC and retail rates; and
- There is some evidence of a downward trend in UPC, but the finding is not robust across specifications.

The key differences between the Schedule 7 and 32 results are:

- The relationship between UPC and economic conditions is more robust for Schedule 32. The coefficient on the economic variable is statistically significant in each of the Schedule 32 models.
- There no statistically significant relationship between Schedule 32 UPC and the SNA indicator variable. That is, we do not find lower UPC during the dates in which the SNA was in effect, all else equal.

Table 4.4.3: Statistical Model Results, *Schedule 32*

Variable	Weather & Month Only (1)	GDP, No SNA (2)	OR Unempl, No SNA (3)	GDP, SNA (4)	OR Unempl, SNA (5)
CDD	0.84***	0.91***	0.89***	0.91***	0.89***
HDD	0.44***	0.42***	0.41***	0.42***	0.41***
Trend		-17.6***	-0.8	-12.6*	-0.3
ln(Real GDP)		1,246***		1,030***	
OR Unempl.			-12.8***		-12.1***
Avg. Rate		21.43	23.70	33.78	26.25
SNA				-23.8	-5.9
Constant	1,354***	-10,486***	1,289***	-8,564***	1,260***
N	67	67	67	67	67
R-squared	0.969	0.972	0.972	0.973	0.972

Overall, the statistical models show:

- A relationship between UPC and economic conditions, indicating that the SNA shifts some economic risk from PGE to its ratepayers;

- No relationship between UPC and retail prices, indicating that the SNA **does not** shift rate risk from PGE to its ratepayers.
- Limited evidence that the SNA has affected UPC, with a statistically significant estimate showing up in only one of the residential (Schedule 7) models.

The limited effect of SNA on UPC is perhaps not surprising, as conservation effects may be expected to be somewhat small initially and build over time. The SNA indicator variable estimates an overall conservation effect during SNA, beginning the month after its introduction.[29]

While the estimates indicate that the SNA shifts economic risk from PGE to its customers, it may help to provide some context for the magnitude of the changes in UPC that occur as economic conditions change. Table 4.4.4 is an attempt to provide that context. It shows the percentage change in UPC[30] that occur under two scenarios of changes in economic conditions:

- "Since SNA Implementation" represents the simulated effects on UPC using the changes in economic conditions that have occurred since the introduction of the SNA, which are a 1.1 percentage point decrease in the Oregon unemployment rate and a 0.06% increase in real GDP.
- "Peak to Trough" is a sort of worst-case scenario, representing the change in economic conditions that occurred during the most recent recession: a 5 percentage point increase in the Oregon unemployment rate and a 5 percent decrease in real GDP.

Table 4.4.4: Simulated Effects of Changes in Economic Conditions on UPC

SNA Variable Included?	Economic Variable	Since SNA Implementation		Peak to Trough Scenario	
		Schedule 7	Schedule 32	Schedule 7	Schedule 32
No	Real GDP	2.3%	5.0%	-1.9%	-4.2%
	OR Unemployment	0.4%	1.0%	-1.7%	-4.3%
Yes	Real GDP	n/a	4.2%	n/a	-3.5%
	OR Unemployment	n/a	0.9%	n/a	-4.1%
	Average	**1.3%**	**2.8%**	**-1.8%**	**-4.0%**

The results in Table 4.4.4 show that a shift in economic risk from PGE to its ratepayers does not necessarily result in a negative outcome for the ratepayers. Because economic conditions have improved since the introduction of the SNA, we estimate that they have caused UPC to increase, contributing to SNA-induced rate decreases for customers. The magnitude of the increase in UPC is 0 percent (i.e., no statistically significant effect, shown as "n/a") to 2.3

[29] We estimated alternative models that allowed the time trend in UPC to change after the introduction of the SNA (rather than changes in the overall level of UPC, as the SNA indicator variable estimates). The pattern of the results does not change. The only statistically significant effect of the SNA on the time trend in UPC occurs in the same model in which we estimate a statistically significant effect of the SNA on the level of UPC (the Schedule 7 model with the Oregon unemployment rate).

[30] Percentage changes are calculated using the average UPC across the sample period in the denominator. These values are 903 kWh for Schedule 7 and 1,481 kWh for Schedule 32.

percent for Schedule 7 customers and 0.9 to 5.0 percent for Schedule 32 customers. Note that the percentage changes in UPC overstate the percentage change in the overall retail rate since the SNA only covers revenues toward fixed costs.

The "Peak to Trough" scenario provides an idea of the size of SNA effects as a result of a somewhat severe recession. The resulting reductions in UPC for both customers on rate schedules lead to SNA-induced rate increases in the following year. For Schedule 7 customers, UPC decreases by 0 to 1.9 percent; while for Schedule 32 customers, the decrease ranges from 3.5 to 4.3 percent. Note that the SNA-induced rate increases are capped at 2 percent of total revenues (including variable costs not covered by the SNA) with no ability for the utility to recover the excess in future time periods. The simulated decrease in UPC for Schedule 32 may be large enough to reach this cap. (Recall that there is no cap on the rate reduction that SNA produces.)

It is interesting to note that, despite the statistical evidence that the SNA shifts economic risk from PGE to its ratepayers, Standard & Poor's credit analyses continued to note the adverse effects of the recession on PGE's finances, as reflected in this excerpt from S&P's February 2010 analyses.

> The 'BBB' corporate credit rating and stable outlook on Portland General Electric Co. (PGE) reflect Standard & Poor's Ratings Services' opinion that the company's financial risk profile is under strain due to a recessionary environment that is particularly severe in Oregon; falling electric sales that have reduced cash flows in 2009, despite a recently approved decoupling mechanism that covers only residential customers; a high level of capital investment, of which a large portion is not discretionary; and collateral requirements tied to the company's hedging strategy for its sizable power purchases.

Therefore, while it appears that the SNA shifts economic risk to residential and small commercial customers, S&P believes that PGE continues to be exposed to a significant amount of economic risk. This will be discussed further in Section 5, which examines the effect of Schedule 123 on PGE's risk.

4.5 Discussion of Weather Effects and the SNA

The SNA weather normalizes sales, so that sales fluctuations due to deviations from normal weather conditions are excluded from the SNA deferral calculations. As a general matter, we have been opposed to the removal of weather effects from decoupling mechanisms, based on three objections:

- Added complexity and reduced transparency;
- The possibility of biased deferrals (i.e., that tend to favor either PGE or its customers) if the normal weather definition used to set rates does not accurately reflect average weather conditions going forward; and
- The lost opportunity to reduce weather risk for both the utility and its ratepayers.

In the case of the SNA, the first issue may not be significant since the method used to weather normalize sales matches the method used to adjust test-year sales to represent normal weather conditions when setting rates.

The second issue relates to the fact that if historical "normal" weather conditions do not match "normal" weather conditions going forward (e.g., because of climate change), the deferrals will be skewed toward either PGE or its ratepayers. For example, if the normal weather conditions during summer months are set "too low" (i.e., assuming fewer CDDs than the going-forward average), PGE will tend to benefit from the weather normalizations in the SNA.[31]

The most significant issue is that excluding the effects of weather variability in the SNA misses an opportunity to reduce risk for both PGE and its ratepayers. That is, in an unusually hot summer (or cold winter), PGE will over-recover its fixed costs at the expense of its ratepayers. Conversely, in an unusually mild summer or winter, PGE will under-recover its fixed costs to the benefit of its ratepayers. If the decoupling mechanism removes the possibility for the utility to over- or under-recover, it also removes the possibility that ratepayers will over- or under-pay for fixed costs.

The only complicating factor is that the decoupling deferrals affect rates in the following year, such that customers do not experience the benefit of the weather risk mitigation in real time (they benefit over the course of one to two years). If a mild weather year (which would produce a rate increase through the SNA) is followed by a hot summer or cold winter, the inclusion of weather in the SNA would have the potential to exacerbate customer risk by increasing rates during a year in which weather conditions are producing increases in customer bills. We evaluated the potential for this to occur using Schedule 7 data from 2002 through 2012.

PGE provided us with monthly billed sales with and without weather normalization, which we consolidated into annual values. Column 1 of Table 4.4.5 shows the weather normalization amount expressed as a percentage of total sales. For example, in 2002 the deviation from normal weather conditions caused sales to be 0.3 percent lower than they otherwise would have been. In the absence of the SNA, this leads to lower utility revenue toward fixed costs. With the current SNA, nothing changes because the effect of weather is removed from deferrals. However, if weather effects are included in the SNA deferral, the result would be an increase in rates in 2003 to account for lower than expected sales in 2002.

Columns 2 and 3 attempt to approximate the class-level bill change (relative to the bill in normal weather) under two circumstances: excluding weather effects from the SNA (which, in this case, is the equivalent of having no SNA at all), and including weather effects in the SNA. In column 2, we assume that the bill change is 90 percent of the change is sales, based on an approximate amount of revenue collected from volumetric rates versus the monthly customer

[31] To see this, consider an unusually hot summer month. If the normal weather definition is too mild, the metered sales will be adjusted too far down, creating a larger SNA surcharge than would have been produced under the "true" normal weather definition. Similar examples can be constructed for winter months.

charge. In column 3, we combine the current-year effect in column 2 with the decoupling deferral from the *previous year* (because the SNA deferral does not affect rates until the following year). We assume that 50 percent of Schedule 7 revenue is affected by the SNA.

If it is the case that mild weather years are consistently followed by hot summers (or cold winters), we would expect the inclusion of weather effects in the SNA deferrals to add to the variability of the annual bill changes. The bottom-most column of the table shows that this is not the case, with the standard deviation of the bill changes being reduced from 1.5 percent to 1.4 percent as weather effects are included in the SNA. Note that in both cases, the average percentage bill change is zero percent, which indicates that the normal weather measures properly reflected the average weather that occurred during this time period.

Table 4.4.5: Effect of Weather Fluctuations on Schedule 7 Bills

Year	Weather Normalization as % of Billed Sales	Bill Change Excluding Weather Effects	Bill Change Including Weather Effects
	(1)	(2)	(3)
2002	-0.3%	-0.3%	
2003	-2.3%	-2.1%	-1.9%
2004	-2.4%	-2.2%	-1.0%
2005	-1.1%	-1.0%	0.2%
2006	0.3%	0.3%	0.9%
2007	1.0%	0.9%	0.8%
2008	1.4%	1.3%	0.8%
2009	2.3%	2.1%	1.4%
2010	-0.4%	-0.3%	-1.5%
2011	2.0%	1.8%	1.9%
2012	-1.0%	-0.9%	-1.8%
Standard Deviation		1.5%	1.4%

Note that utility and customer risk can be further reduced at the cost of some additional complexity. That is, monthly customer bills could be adjusted for the expected effects of weather on fixed cost recovery, with the decoupling true-up occurring at the end of the year. For example, in a hot summer month, the weather adjustment would slightly reduce customer bills to compensate for the over-recovery of fixed costs. The billed revenue following this adjustment would be used in the monthly decoupling deferral calculations (in order to account for non-weather effects).

OPUC Staff has expressed concern that including weather effects in the SNA would "decrease the customer incentive to invest in weatherization improvements." We do not find this to be a compelling argument. The primary reason is that decoupling does not adversely affect customer-level incentives to engage in conservation or energy efficiency. That is, the SNA deferral generated from the conservation of any one customer is spread across all customers in the class, creating a "free rider"-like situation. Since the customer's decision to conserve will not affect the rate it pays, the presence of the SNA should not change its incentive to pursue conservation. The Oregon Commission agreed with this view in Order 09-020, even expanding on the argument (correctly, we believe) as follows: "an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide *more* incentive for an individual customer to become more energy efficient."[32]

4.6 Discussion of LRRA Design Issues

In Section 7, we describe the feedback that we received from various stakeholder groups. In this section, we address two objections to the LRRA that Kroger conveyed to us. The first is that Direct Access customers who commit to purchasing generation services from non-PGE energy service providers for five years (e.g., Schedule 485 customers) should be exempted from the generation component of the LRRA since they do not face this charge under their standard tariff. This appears to be a reasonable concern. Our review of the methods used to set the dollar per-kWh LRRA adjustment charge is that PGE does not over-recover due to this concern, as it excludes Direct Access sales from the calculation of the generation services charge. However, it does appear to be the case that the current methods cause cross-subsidies between Schedules 485 and 489 and the other LRRA-applicable rate schedules (because all rate schedules pay the same per-kWh LRRA charge). Therefore, we recommend removing the generation component from the LRRA charge for Schedules 485 and 489.

The second concern raised by Kroger is that the LRRA allows the utility to recover lost revenues due to conservation, but does not account for "found revenues" due to increases in sales from other sources. That is, the "found revenues" result when increases in sales above test-year levels lead to over-recovery of test-year fixed costs because of the recovery of fixed costs through volumetric rates. Under standard ratemaking, the utility does not give these added revenues back. Kroger proposes that PGE only be allowed to recover lost revenues from ETO programs for sales reductions below test-year levels (i.e., the minimum of the estimated ETO sales reductions and the amount by which PGE's sales are below test-year levels).

Our objection to this proposal is that it assumes that PGE does not face a disincentive to promote ETO's conservation programs. That is, in the absence of the LRRA, PGE is made worse off by successfully promoting the ETO's programs, regardless of whether PGE is in a position of total over- or under-recover of fixed costs. Kroger's proposal limits the ability of the LRRA to meet the objective of resolving the utility's incentive problem, such that the utility will only have its disincentive removed when total sales are at or below test-year levels (at which point PGE will be paid under the LRRA in the same manner as currently designed). When sales are above test-year levels, PGE will lose revenue when it succeeds in promoting the ETO's programs.

Finally, Staff recommended that we evaluate the inclusion of energy savings due to the LED conversion of street lights, as introduced in Advice No. 12-17. Staff notes that the policy has not

[32] Order 09-020, page 28.

yet resulted in decoupling deferrals, though they are expected to be included in the 2014 decoupling tariff.

Our understanding is that PGE is converting its existing high-pressure sodium (HPS) streetlights with LED streetlights, which are expected to use approximately 60 percent less energy than the equivalent HPS fixture. Although the streetlight tariffs contain per-kWh charges, usage on these tariffs (Schedules 91 and 95) is not metered. Rather, usage is calculated from the fixture's wattage and the estimated number of operating hours (from sunrise/sunset tables).

HPS lighting is covered under Schedule 91 and LED lighting is covered under Schedule 95. The two tariffs have identical volumetric rates for distribution, transmission, and generation services. According to Advice No. 12-17, the Schedule 123 LRRA adjustment is calculated as "the difference in the amount of energy used by each streetlight being converted, then multiplying that cumulative amount by the fixed amount in the energy charges." We interpret the "fixed amount in the energy charges" to mean the LRRA charge applied to all LRRA-eligible customers.

The appropriateness of the application of Schedule 123 to LED streetlights depends upon how the Schedule 95 rates were established. Because its rates are identical to those of Schedule 91, it appears that the volumetric rate levels were established based on the cost to serve (and sales to) HPS fixtures. Provided that the fixed costs associated with serving LED streetlights is similar to those of HPS streetlights (which appears to be a reasonable assumption), then the treatment of LED streetlights in Schedule 123 is appropriate. That is, rates would have been designed under the assumption that PGE would experience the higher sales from HPS streetlights. Had it designed its rates under the assumption of the lower usage levels of the LED streetlights, the streetlight rates would have been higher. Therefore, crediting PGE for the lost revenues associated with conversions should provide them with a level of fixed cost recovery consistent with the level of revenue allowed in the rate case.

Alternatively, if the Schedule 91 and 95 volumetric rates were designed under the assumption that some LED fixtures would be in place (hence reducing sales relative to using only HPS fixtures), the LRRA deferrals should be calculated in comparison to the level of LED sales assumed when setting rates (i.e., producing LRRA deferrals only when LED energy savings exceed the level assumed when setting rates). However, our interpretation of the information provided to us indicates that PG&E has not included LED fixtures when setting street lighting rates.

5. PGE RISK

5.1 Introduction to the Risk Analysis

This section explores the relationship between decoupling plans and the cost of capital. A commonly advanced position is that by stabilizing revenue flows, decoupling lowers capital risk, and thus the cost of capital for service providers like PGE who have implemented decoupling plans. The core question under investigation is as follows: do quantitative analyses, empirical evidence, and technical studies provide a sufficient foundation to infer that PGE's decoupling plan gives rise to lower cost of capital? If the company's cost of capital is reduced under decoupling, by how much?

We approach the question in three ways. First, we assess the impact of decoupling on the total returns to capital across a sample of decoupled utilities, measured as operating income. Second, we summarize other studies on the effect of decoupling on utility risk. Third, we review reports by credit ratings agencies to obtain their views on the effect of Schedule 123 on PGE's risk.

Of these methods we use, only the third is based solely on data relating to PGE. The statistical analysis of the effect of decoupling on utility risk includes PGE in its sample of 44 utilities (only some of which have revenue decoupling). The outside studies that we review in Section 5.3 evaluate the experience of other decoupled utilities, but were not intended to be evaluations of PGE's specific mechanism or circumstances.

5.2 Relationship between Decoupling and Capital Risk

By removing the revenue effects of non-weather induced sales fluctuations on revenues, the SNA would appear to stabilize the flow of revenue to cover short-run fixed costs. For most utilities, lower (higher) sales levels result in a corresponding decline (rise) in operating income and shareholder returns. As a consequence, energy policy focused on conservation may not be incentive compatible with the profit objectives of privately held utilities. By preserving revenue flows, particularly under the condition of declining sales quantities, decoupling mitigates (or possibly resolves) the tension between policy goals and revenue and profit objectives of service providers.

At the most general level, risk refers to uncertainty—essentially, the variation or range of potential future outcomes. Risk is inherent to all resource commitments affected by uncertain future outcomes. For capital resources, the relevant risk metric is the variation in prospective returns. Risk associated with future returns is determined by many factors including business risk, which in turn cover a host of events and phenomena that impact observed and expected variation in operating income—the accounting returns to capital invested in the main function(s) of the firm.

Relevant short-term business risks can include performance of the regional economy, revenue coverage of varying fuel charges (variable costs), storm activity, and the routine impact of weather on sales quantities. Long-term business risks can include the effects of rising fixed costs (charges on investment, fixed O&M) associated with serving existing or new customers, and increased peak demands. In addition, capital investment for facility replacement and environmental compliance and regulatory governance are often cited as a factor of business risks.

In summary, the focus of the analysis is whether decoupling plans affect business risks, and thus the cost of capital. Under decoupling, business risks, including operating income and equity returns, could be altered by reducing the variation in returns to book capital. Because variation in book returns is positively associated with capital risks, lower variation seemingly reduces capital risks and thus the cost of capital, other factors constant. We measure PGE's risk as the *variation in operating income*, stated as the standard deviation of normalized operating income.

The analysis is conducted using a sample of 44 electricity service providers, some of which have a decoupling plan in place for a portion of the analysis period. Table 5.2.1 lists the sampled utilities, along with some descriptive information.

Table 5.2.1: Utilities included in the Analysis Sample

Utility	Decoupling Docket	Decoupling Date	Other Stabilization Mechanism?	Related Gas Operations?
Alabama Power Company			X(1)	
Avista Corporation				X
Appalachian Power Company			X	
Baltimore Gas and Electric Co.	Letter Order	Nov 2007		X
Central Hudson Gas and Electric	09-E-0588	Jun 2009		X
Cleco Power LLC			X(1)	
Connecticut Light and Power			X	X
Consolidated Edison Co. of New York	07-E-0523	Mar 2008		X
Consumers Energy Company	U-15045	Nov 2009		X
Dayton Power and Light Company				
Delmarva Power & Light Company	C-9093	Jul 2007		
El Paso Electric Company				
Empire District Electric Company			X	
Idaho Power Corporation	IPC-E-04-15	2007	X	
Indiana Michigan Power Company			X	
Interstate Power and Light Company				X
Kansas City Power and Light Company			X(2)	
Massachusetts Electric Company	DPU-0939	Nov 2009		X
Narragansett Electric Company				X
New York State Electric & Gas Corp.	09-E-0715,0716	Sep 2010		X
Niagara Mohawk Power Corporation	10-E-0050	Jan 2011		X
Northern States Power				X
NorthWestern Energy	D2009.9.129; D2007.7.82	Dec 2010		X
Oklahoma Gas and Electric Company			X	X
Orange and Rockland Utilities, Inc	07-E-0949	Jul 2008		X
Pacific Gas and Electric		1980s		X
Portland General Electric Company	UE-215	Jan 2009		
Potomac Electric Power Company	C-9092	Jul 2007		
Public Service Company of Colorado				X
Public Service Co. of New Hampshire				X
Public Service Co. New Mexico				
Public Service Co. of Oklahoma				X
Puget Sound Energy Inc.				
San Diego Gas & Electric Company		1980s		X
Southern California Edison Co.		1980s		
Southern Indiana Gas & Electric Co.				X
Tampa Electric Company				
Tucson Electric Company				X
United Illuminating Company	08-07-04	Jan 2009		
Western Massachusetts Electric Co.	DPU-10-70	Jan 2011		X
Westar Energy, Inc.				X
Wisconsin Power and Light Company				X
Wisconsin Public Service Company	6690-UR-119	Dec 2008		X

The sampled utilities include electric-only utilities such as Dayton Power and Light (a subsidiary of AES Corporation), Idaho Power Company, and UIL Holdings as well as utilities which have substantial gas operations, non price-regulated business activities, or are part of larger holding companies. Examples include Consumers Energy which has sizable gas operations; Alabama Power, subsidiary of Southern Company; Appalachian Power, subsidiary of American Electric

Power; and San Diego Gas and Electric, subsidiary of Sempra Energy, also with large gas operations.[33]

For each utility, we determined the year (if any) in which they implemented a revenue decoupling mechanism. Three sources were used to determine this:

- "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations", by Pamela Morgan of Graceful Systems, LLC (December 2012).
- "State Electric Efficiency Regulatory Frameworks", by the Institute for Electric Efficiency (July 2012).
- Direct testimony of R. V. Hevert on behalf of Potomac Electric Power Company before the Public Service Commission of the District of Columbia, Docket FC-1103, Exhibit PEPCO B-8 (March 2013).[34]

The risk measure, *variation of operating income*, is calculated for each sampled utility using FERC Form 1 data collected for 1993 through 2011.[35] As mentioned above, provided that changes in revenues and costs are not perfectly correlated, variability of revenue is reflected directed within operating income.[36] For electric utilities, a high share of total cost is fixed for the reporting period and, at least arguably, all but the *very long run*. As a consequence, variation in revenue translates into variation in operating income. This is clearly the case for all utilities except perhaps those that have implemented broadly defined cost trackers or formula rates. Operating income constitutes the return on capital (physical assets) committed by investors to utility operations—i.e., for the convenience and necessity of the public. To the degree that decoupling mitigates the variation in operating income, business risks and thus capital risks would seem to be reduced.

[33] It is important to recognize that, while the above sample is arguably of adequate size and sufficiently representative of industry-wide experience, it does not incorporate all power systems. Notable large and comparatively small systems not incorporated in the analysis include Allete Incorporated; Ameren Corporation; Black Hills Corporation; CenterPoint Energy, Inc.; Dominion Resources, Inc.; Central Maine Power; DTE Energy Company; Duke Energy Corporation; Entergy Corporation; Exelon Corporation; FirstEnergy Corporation; MGE Energy, Inc., NextEra Energy, Inc.; NV Energy, Inc.; Otter Tail Corporation; Pinnacle West Capital Corporation; PPL Corporation; Public Service Enterprise Group Incorporated; Scana Corporation; and Wisconsin Energy Corporation. In virtually all cases, these predominantly larger power systems do not have subsidiaries with decoupling plans in place (e.g., Ameren Corporation, DTE Energy, Scana Corporation). In the case of Central Maine Power, subsidiary of Iberdrola, a price cap plan has been in place for some time. Beginning in 2009, Puget Sound Energy has been privately held by foreign investors, Macquarie Group.

[34] Mr. Hevert lists Regulatory Research Associates as the source of the information contained in his exhibit.

[35] The FERC Form 1 reports originate from 1938, and are currently available electronically for the 1993-2011/12 timeframe. Form 1 reports cover virtually all privately held retail electricity service provides across the U.S.

[36] It is useful to mention that operating income can vary, either up or down, for any number of reasons unrelated to changes in sales quantities and revenue. Examples include changes in corporate tax rates, rates of book depreciation, insurance charges, or unexpected changes operating expenses. Of real concern would be the transfer of the investment costs associated with the construction of sizable new facilities from construction to plant-in-service.

The analysis procedures are as follows. First, annual operating income for each utility is normalized by the utility's capital, measured as "book assets." Book assets are calculated as year-end gross plant minus accumulated depreciation and construction work in progress (CWIP), plus regulatory assets. This measure of book capital is essentially a rate base proxy. Normalization of operating income is necessary, as the sampled utilities vary substantially according to size, the intensity that capital is employed within the process of delivering services, and growth in the underlying capital stock and perhaps driven by changes in resource mix over time and changes in book interest costs.[37,38] The net result of this procedure—operating income normalized by book assets—is similar to return on rate base.

We then calculate the standard deviation of the normalized operating income across every three year window from 1993 through 2011 (e.g., 1993 to 1995, 1994 to 1996, etc.).[39] As a sensitivity analysis, results are reported with and without the investor-owned utilities (IOUs) from California (PG&E, SCE, and SDG&E), as these utilities have had unusual experiences in a couple of ways (extreme wholesale market prices during the deregulation crisis around the turn of the century; and an unusually comprehensive combination of decoupling mechanisms and other cost trackers).

Figures 5.2.1 and 5.2.2 illustrate the normalized operating income and its 3-year standard deviation (respectively) for three sets of utilities: those that have had decoupling at any time during the sample timeframe (excluding the California IOUs); those that have never had decoupling; and PGE.

[37] Other rate base proxy definitions are plausible and, for two reasons, the measure used here will certainly contain some degree of error. First, fuel stocks, stores inventory, and accumulated deferred income taxes are excluded from the proxy, and there is no attempt to account for working capital. Second, some utilities included some share of construction work in progress within the rate base in lieu of capitalizing interest on construction. Third, at a detail level, rate base definitions evolve through time.

[38] There may be reason to reflect costs in real terms if historical inflation varies significantly over the historical period. Real terms would be warranted under two conditions. First, if there are substantial differences in asset growth across the utilities. For utilities with fast rising gross assets due to grow or other reasons, the cost rate for long-term outstanding debt will follow current debt yields more closely than utilities where assets are changing slowly. Such differences show up in book interest costs, and thus observed and required normalized operating income. The ample supply of capital with respect to demand, augmented significantly by the monetary policy of the U.S. Federal Reserve beginning in November 2008 and referred to as quantitative easing. As a result, comparatively fast asset growth can cause book interest costs to decline. For this reason, the coefficient of variation of operating income is used in addition to standard deviation of normalized operating income.

A second condition is differences in the underlying rate of inflation across U.S. regions. All evidence suggests that this is not the case.

[39] We conducted a sensitivity analysis using the standard deviation calculated across 5 years. The results were qualitatively the same as those presented here.

Figure 5.2.1: Average Normalized Operating Income by Utility Type

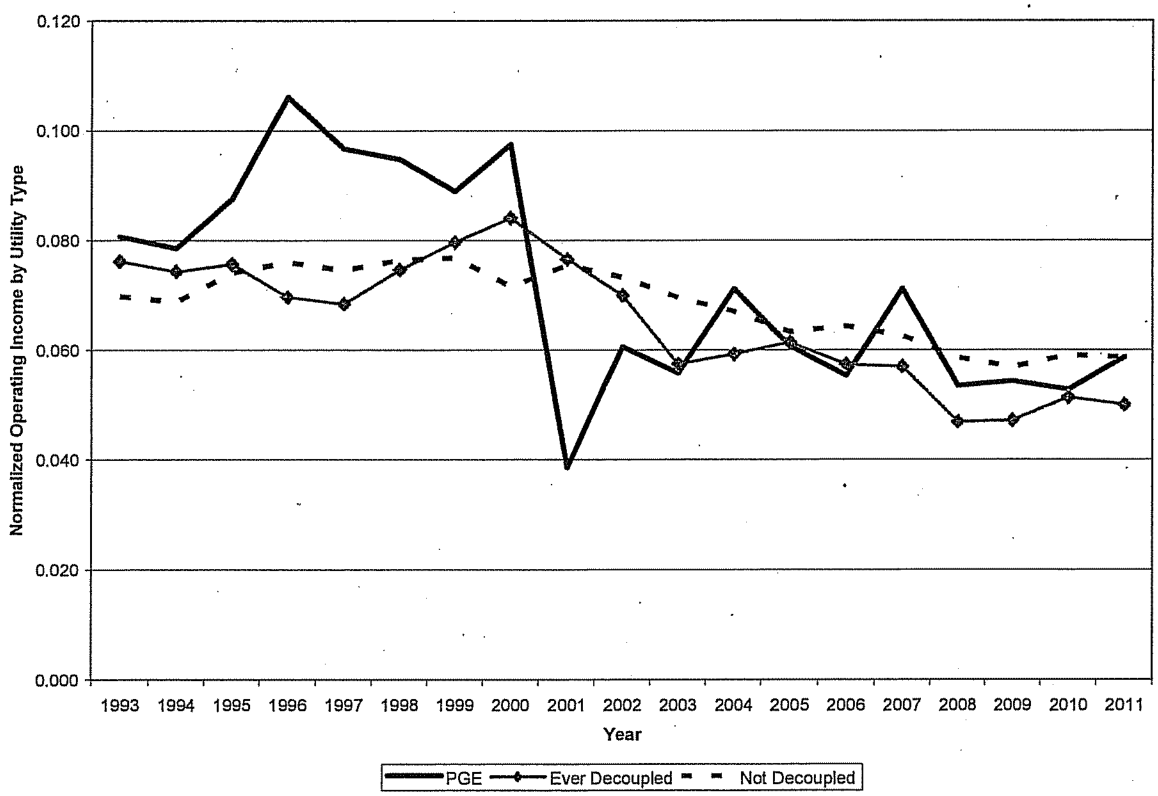
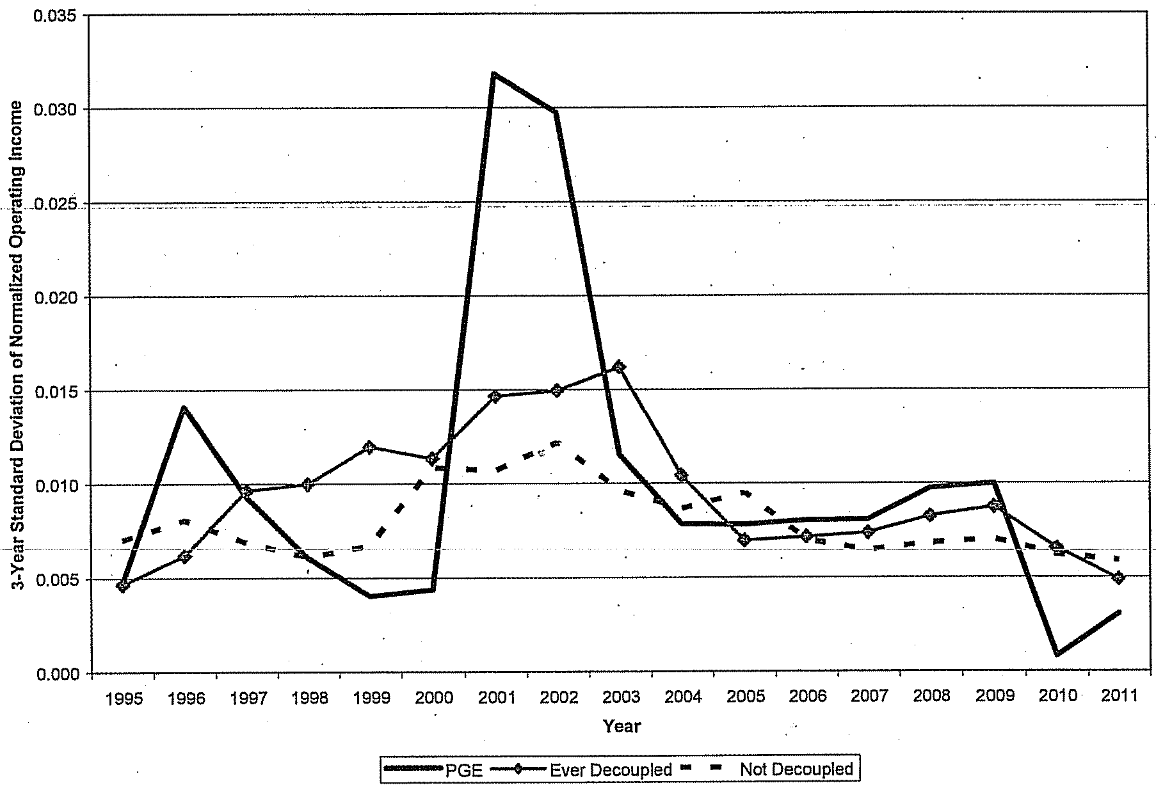


Figure 5.2.2: Three-year Standard Deviation of Operating Income by Utility Type



Some observations on these figures:

- PGE appears to have more variable returns than the other utilities, but this is just an artifact of comparing a single utility to an average of utilities (15 ever-decoupled utilities and 25 never-decoupled utilities).
- For all utilities, the level and variability of returns declines sometime after the year 2000.
- The variability of PGE's returns appears to stabilize beginning in 2008, at a level that is somewhat low compared to the returns in previous years.[40] While Schedule 123 may contribute to this reduction in variability, the effect starts too early for this to clearly be the case. Note that PGE also had its Annual Power Cost Update and Annual Power Cost Variance Mechanism (Schedules 125 and 126) approved just before the beginning of this period of reduced variation in returns. These mechanisms are more likely to have contributed to the reduced variation in returns (to the extent that the observed outcomes are not just due to random variations in returns).

[40] In Figure 5.2.1, PGE's returns become fairly constant at approximately 5.4 percent. In Figure 5.2.2, the relatively constant returns are reflected in the somewhat steep decline in the standard deviation from 2009 to 2010.

The utilities grouped in the "ever decoupled" category implemented their mechanisms on different dates, making it difficult to infer the effect of decoupling from these figures. In addition, there are other relevant characteristics of utilities that are not accounted for in the figures, including the presence (or nature) of cost trackers. In order to properly account for the different decoupling start dates and other firm- and time-specific effects, we estimated a statistical model to determine whether the implementation of revenue decoupling is associated with a reduced variation in utility returns.

Specifically, we estimated a statistical model that attempts to explain the three-year standard deviation of normalized operating income as a function of three explanatory factors:

- Utility fixed effects, which control for utility characteristics that do not change over time;[41]
- Fixed year effects, which control for factors that may affect utility operating income in each three-year window (e.g., economic conditions); and
- The presence of revenue decoupling, calculated as a moving average across the three-year window.[42,43]

Because some utilities implement decoupling during the timeframe while others do not, this method can be interpreted as a "differences-in-differences" estimator. That is, the decoupling effect is estimated as the change in utility "risk" (measured as the variation in operating income) following the introduction of decoupling, compared to the risk level experienced by the utility prior to decoupling and the level of risk experienced by all utilities (with or without decoupling) in each year.

The statistical model is formally described in Equation 5 and Table 5.2.2.

Equation 5:

$$VOI_{c,t} = a_c + b_{Decouple} \cdot Decouple_{c,t} + \sum_{i=1996}^{2011} b_i \cdot Year_{i,t} + e_{c,t}$$

[41] For example, utility fixed effects may control for utility size or regulatory environment.

[42] For example, if the utility had decoupling in all three years, the value of this variable is unity. If the utility had decoupling during only one of the three years, the value is 1/3. Note that this indicator variable does not account for design differences across decoupling mechanisms, such as whether the effects of weather are included in the deferrals.

[43] We conducted a sensitivity analysis using the 1-year and 2-year lags of the decoupling indicator to account for the fact that decoupling deferrals affect utility revenues with a lag. The use of these alternative decoupling indicators does not affect the reported results. In conjunction with this, we examined an alternative dependent variable that is based on the three-year moving average of the normalized returns. That is, because decoupling deferrals affect utility revenues with a lag, the year-to-year returns could be exacerbated by decoupling even if longer-term returns are made more stable. We evaluated this moving average in the same manner as the single-year outcome: by calculating the three-year standard deviation of the variable and including it has the left-hand-side (dependent) variable in the regression model. These specifications (including current and lagged decoupling indicators) do not provide any evidence of a link between decoupling and reduced utility risk.

Table 5.2.2: Variables Included in the Statistical Risk Model

Variable Name / Term	Description
$VOI_{c,t}$	Variation of Operating Income for utility *c* in year *t*
a_c	The estimated utility-specific fixed effects
$b_{Decouple}$	The estimated effect of decoupling on $VOI_{c,t}$
$Decouple_{c,t}$	An indicator variable for whether utility *c* is decoupling at time *t*
b_i	The estimated fixed year effects
$Year_{i,t}$	An indicator variable for year *i* at time *t*
$e_{c,t}$	The error term

If revenue decoupling is associated with a reduction in the variability of utility operating income, the analysis would find a negative and statistically significant coefficient on the decoupling variable ($b_{Decouple}$). Table 5.2.3 shows the estimated coefficients on the decoupling variable with and without including the California IOUs. The standard error of the estimate is in parentheses.

Table 5.2.3: Estimates of the Effect of Decoupling on the Variability of Utility Returns

Measure	Full Sample	Excluding Calif. IOUs
Decoupling Coefficient	0.010 (0.009)	-0.0006 (0.002)
Number of Observations	744	693
Number of Utilities	44	41
R-squared	0.10	0.08

In both models, we find no statistically significant effect of revenue decoupling on the variability of utility net operating income. There are a couple of potential explanations for this finding. First, it could be that the effects of decoupling are small in comparison with all of the factors that can affect utility risk. If this is the case, there is little justification for reducing the utility's allowed return on equity (ROE) upon the implementation of decoupling. Second, it could be that the relatively limited experience to date with revenue decoupling has not provided a large enough sample from which to estimate statistically significant effects of revenue decoupling on utility risk. That is, in order to examine risk, we need to be able to observe how the variability of an outcome changes over time.

The amount of data required to be able to adequately examine this effect may exceed the amount of experience that we observe in the current data. Note that a number of the utilities that have decoupling are relatively recent adopters, such that they provide a limited amount of experience from which to infer the effect of the mechanism on risk.

In the next sub-section, we will provide a summary of other studies of the effect of decoupling on utility risk. The findings are consistent with ours, with little indication of a significant effect.

5.3 Studies and Testimony Regarding the Effect of Decoupling on the Cost of Capital

This discussion highlights the expressed views and conclusions reached by others regarding the effect of decoupling on the cost of capital, as expressed in studies and testimony.

Comments by John Reed, Concentric Energy Advisors before the Massachusetts Department of Utilities (DPU Docket 07-50, Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources)

The issue is set up as: "To the extent that decoupling affects investors' required returns, that effect should be reflected in rates, which raises the question of whether an explicit adjustment in ROE is warranted when decoupling is approved." In response, the prepared comments go on to say: "To date, there is no evidence suggesting that investors' required returns are reduced as a result of the approval of decoupling mechanisms. The recent expansion in the use of decoupling mechanisms is in response to significant market changes, and the policy responses to these changes, in the past few years." The discussion cites various incremental changes in the underlying business environment for utilities, then stating: "Decoupling mechanisms are an effective means to offset these incremental risks, but they certainly cannot be viewed as warranting a reduction in allowed returns when the recently-created risks they offset were never previously reflected in rates...Furthermore, there is analytical and anecdotal evidence supporting the position that investors' required returns are unaffected by the implementation of decoupling measures."

The discussion goes on offer empirical evidence, stating: "CEA performed an analysis to compare the price-to-book ("P/B") ratio of utilities that have received approval to implement decoupling mechanisms to the average P/B of a group of peer companies to test for any measurable change in relative valuations.[44] On average, the relative P/B of the utilities receiving approval to implement decoupling did not increase during the month following the approval, when compared to the month preceding the approval."[45]

The discussion continues with conclusions regarding the issues, as follows: "Our analysis and understanding of the markets suggests that investors have developed the expectation that decoupling is the logical way forward to offset recently created incremental risks, and of providing benefits to customers and utilities alike...The significant and growing number of utilities that have implemented decoupling measures and the fact that decoupling mechanisms largely or entirely offset recently created incremental risks, helps explain why the market response to the approval of decoupling measures has been neutral."

"The Impact of Decoupling on the Cost of Capital: An Empirical Investigation" by Brattle Group, March 2011

[44] CEA notes that the analysis controlled for general market movements by creating a P/B Index for utilities.
[45] It isn't clear that this is a proper comparison, either in terms of methodology—i.e., analysis of Price/Book ratios—or the selection of timeframe for evaluation of changes in Price/Book ratios.

This often cited discussion paper uses multi-stage DCF model to assess the impacts of decoupling on the cost of capital. Section 2 of the paper states: "to date, about one-fifth of regulatory decisions that we have reviewed related to decoupling for gas and electric utilities have concluded that decoupling does reduced a utility's cost of capital, and accordingly these decisions have reduced the allowed ROE. The reductions in allowed ROE have ranged from 10 to 50 bps." The Brattle discussion paper succinctly sets up the issue, stating: "Decoupling stabilizes revenues, but net income can still vary. Although depreciation and interest expense are relatively stable, other costs can change quickly between rate cases. At times of rapid capital investment, like the present for utilities that are facing significant environmental retrofits, depreciation and interest may also increase rapidly so that general rate cases are frequently required....A more targeted question is whether decoupling reduces the non-diversifiable risk that determines the cost of capital in financial markets?" The Brattle study rates or scores decoupling plans for some 46 natural gas utilities and then compares "current stock prices with forward-looking forecasts of cash flows from the business." Brattle concludes its analysis as follows: "Our statistical tests do <u>not</u> support the position that the cost of capital is reduced by adoption of decoupling. If decoupling decreases the cost of capital, the tests strongly suggest that the effect must be minimal because it is not detectable statistically."

"Decoupling: Impacts on the Risk of Public Utility Stocks", a Presentation by Richard A. Michelfelder, of Rutgers University and Managing Consultant, AUS Consultants, Delivered before the Society of Utility Regulatory and Financial Analysts

The discussion presents a statistical analysis of the implied impacts of decoupling on equity risk premia for electricity stocks. Like our study, the discussion sets out the problem in terms of variation in operating cash flow (net short-term margin including depreciation/operating income). The analysis focuses on equity market risk premia and includes two risk metrics, including GARCH estimation of share price volatility[46] and systematic risks in the context of Capital Asset Pricing Model. The analysis is monthly in frequency. The study concludes that decoupling mechanisms have no statistically significant effect on the cost of equity capital, for utilities.

"Decoupling Impacts on the Cost of Capital", a presentation by Jim Lazar, The Regulatory Assistance Project, before the Minnesota Public Utilities Commission, April 15, 2008.

The discussion focuses on mechanics of decoupling mechanisms and changes in the overall cost of capital obtained through reduced equity participation in total capital. More specifically, Lazar argues that the mitigation of business risks, facilitated by decoupling, allows for a more intensive use of debt within the capital structure, thus lowering the overall cost of capital, holding the cost rates of debt and equity constant.[47]

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[46] Analysis of capital market risks, conducted for the immediate report, also utilizes GARCH methods in order to ferret out impacts of decoupling mechanisms on the cost of capital.
[47] This result is somewhat curious in view of the famous 1958 discussion by Franco Modigliani and Merton Miller (referred to as MM), presented as propositions I and II, show that under defined conditions, the cost of capital to the firm is indifferent to the relative shares of debt and equity within total capital.

"Revenue Regulation and Decoupling: A Guide to Theory and Application", The Regulatory Assistance Project, June 2011.

The report at chapter 10 states: "Decoupling can significantly reduce earnings volatility due to weather and other factors, and can eliminate earnings attrition when sales decline, regardless of the cause..." The report summarizes the expressed view on decoupling and cost of capital as follows: "The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity, but this generally requires many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.

Summary of Studies

In our view the Brattle Group and analysis presented by Richard Michelfelder are viable and provide useful insight. Specifically, unless it can be shown that decoupling mitigates operating income, and such effects translate into observable reductions in equity and debt risk premia, it is prudent to presume that decoupling mechanisms, in isolation of the effects of other risk factors—both those that are increasing and those that are decreasing, have no measurable impact on the cost of capital.

5.4 Credit Rating Reports and Debt Cost Rates

Ratings agencies produce periodic reports on the creditworthiness of companies. In this sub-section, we provide our review of impact of decoupling on debt cost rates based on information extracted from these reports. This evidence includes the assessments of the creditworthiness of the outstanding debt of PGE, as reported by credit rating agencies including Moody's Investor Services, Fitch Ratings, and Standard & Poor's Corporation. Conclusions reached by rating agencies regarding creditworthiness of PGE's outstanding debt can be inferred from the ratings and narratives provided by these agencies. It is useful to review the credit ratings over time and, at a general level, gauge how PGE's credit ratings have been potentially impacted by Schedule 123. For PGE, we summarize the credit ratings of rating agencies in Table 5.4.1, below. The table is augmented with synopsis of rating agency reviews of PGE and its credit worthiness over recent years, 2006-2012.[48]

[48] The immediate study does *not* explore whether differentials in the underlying debt cost rate exist, between utilities with decoupling plans and those without. Addressing the potential for differential risks and resulting debt cost rates would involve the examination of market bond yields for specific maturity dates on outstanding debt issues of highly similar terms (i.e., call provisions, security provisions including the pledge of physical property as collateral for selected issues such as first mortgage bonds). Empirical evidence shows that, for outstanding debt issues, the yield-to-maturity measures of cost rates are not necessarily ordered according to differences in credit ratings by rating agencies.

Table 5.4.1: Summary of PGE Credit Reports by Agency

Agency	Year	Senior Secured Debt	Unsecured Debt, Revolver	Commercial Paper	Outlook
Moody's	2006	Baa1	Baa2	P-2	Stable
	2007	A3	Baa2	P-2	Stable
	2008	Baa1			
	2009	A3	Baa2	P-2	Positive
	2010	A3	Baa2	P-2	Stable
	2011	A3	Baa2	P-2	Stable
	2012	A3	Baa2	P-2	Stable
Fitch[49]	2006	A-	BBB+	F-2	Stable
Standard & Poor's	2006	BBB+	BBB	A-2	Negative
	2007	BBB+	BBB	A-2	Negative
	2008	BBB+	BBB	A-2	Stable
	2009	A	BBB+	A-2	Negative
	2010	A-	BBB	A-2	Stable*
	2011	A-	BBB	A-2	Stable
	2012	A-	BBB	A-2	Stable

* Rating of August 27, 2010.

Review of PGE's Credit Worthiness, by Standard and Poor's[50]

January 31, 2008: S&P cites several strengths favorable to PGE including "An above-average framework for the recovery of capital and power costs that includes: a forecast test year...an annual mechanism to update power costs based on projections; and a power cost adjuster that tracks differences between actual costs and those authorized in rates...". S&P cites weaknesses including, at the time, PGE's sizable capital program, and a weakening of PGE's financial measures including its funds from operations. S&P assigns a BBB+ rating to PGE's secured outstanding long-term debt.

August 26, 2009: The updated outlook is reduced to "Negative" from S&P's rating in 2008, citing PGE's considerable level of expenditure for capital in the near term, as well the effects of the national recession. S&P cites reduced electricity sales, stating "...particularly severe in Oregon, falling electric sales that are pressuring cash flows in 2009 despite a recently approved decoupling mechanism..."

August 26, 2011: S&P continues to rate PGE as investment grade (BBB) but also rates first mortgage bonds as A-. The discussion cites PGE's settled rate case of December, 2010. S&P

[49] Reported April 18, 2006. Fitch suspended further rating of PGE in November of 2006.

[50] Standard & Poor's has issued numerous credit reports for PGE in recent years. This includes comparatively small changes in credit ratings and outlook, as reported a calendar period. As a result, within a year, small differences can be observed from one report to another.

goes on to mention PGE's favorable internal cash and near-term declines in capital requirements. S&P indicates that PGE faces risks regarding the full recovery of the costs of the Trojan nuclear plant. In particular, S&P makes a favorable mention of the renewable energy tracker, the recognition of costs in rates outstanding a standard rate case proceeding.

December 19, 2011: The review cites PGE's continued levels of adequate liquidity, and a favorable business risk profile. PGE's outlook is judged stable, and S&P's investment credit ratings for long-term unsecured debt and short term debt are set at BBB and A-2, respectively.

February 21, 2012: This most recent review by Standard and Poor's reiterates previous assessments: that PGE focuses on its core utility function, and has favorable regulatory governance including near-term recovery (non GRC-based) of power costs. S&P cites credit metrics including funds from operations (FFOs) that closely approximate levels reflected in previous reviews. S&P states: "Debt levels and leverage have remained abut the same since an increase in 2008...If cash flow remains robust, we anticipate debt leverage to improve slightly. However, capital spending may trend higher beyond our outlook horizon as additional mandated renewable energy resources and other infrastructure costs rise." S&P goes on to state: "The stable outlook reflects our anticipation that credit metrics will not materially diminish..."

Review of Credit Worthiness of PGE, by Fitch Ratings

May 11, 2006: Fitch Ratings assigned PGE with a favorable financial outlook (Stable), citing the Company's strong underlying credit metrics. Key elements mentioned within the review include, as cited by Fitch, "constructive" regulatory environment, comparatively low debt ratio (43%), and high liquidity position. Concerns raised during the review by Fitch include, as implied, costs associated with the Boardman Coal Plant outage, and the pending regulatory outcome regarding the remand by Court of Appeals of the PUC decision regarding the recovery of investment costs associated with the Trojan nuclear plant.

Review of Credit Worthiness of PGE, by Moody's Investor Service

August 17, 2007: In summary, Moody's review of PGE's credit risks is quite similar to that of S&P's performance review. Moody's review was published not long following PGE's separation from its previous corporate affiliation. Moody's cites PGE's favorable market context, its industrial sales mix in particular, and fair regulatory governance, stating "We currently view PGE's business and regulatory risk profile as consistent with the high end of the Baa rating category." Moody's mentions the new annual power cost update tariff (PCAM) which "provides a means for rate adjustments to reflect updated forecasts of net variable power costs for future calendar years." Also, Moody's cited PGE's somewhat higher equity ratio, with the stated objective of 50% equity participation in total capital.

June 29, 2010: This credit review update reaffirms PGE's continued stable outlook, though makes mention of weaker credit measures over the previous 15 months. The credit review cites reduced sales volumes attributable to weather and conservation, and the Company's collaborative relationship with the Oregon PUC and PGE's moderate near-term capital program.

June 30, 2011: Once again, Moody's affirms the previously determined credit ratings including Baa2 (Issuer), A3 (secured debt -first mortgage bonds), Baa2 (unsecured debt and revolver), and P-2 (commercial paper). At this time, Moody's cites PGE's comparatively supportive regulatory environment, improved financial results, and diverse resource base. In the review, Moody's mentions the power cost adjustment mechanism (PCAM), renewable resource cost tracker, and revenue decoupling.

March 16, 2012: This brief review cites PGE's supportive regulatory environment. Moody's warns of the potential downward movement in its overall credit ratings for the PGE, should the Company experience weakened internal cash flow.

Summary of Credit Reports

Over the recent years 2006-2012, the credit worthiness of PGE has been gauged by the three major credit rating agencies. The reviews, several of which are cited above, make frequent mention of cost trackers and occasional reference to PGE's recently implemented sales decoupling mechanism. The analysis finds virtually no change in the credit worthiness of PGE over these years, which includes a major change in regulatory governance in the form of cost trackers that cover significant shares of total costs. Particularly in the S&P reports, the impact of PGE's revenue decoupling mechanism on operating income (and internal flow of funds) is portrayed as minor when compared to the effects of the Company's PCAM cost tracker. Accordingly, revenue decoupling appears to have not significantly affected PGE's debt costs.

6. PGE BEHAVIOR

The fifth required area of analysis calls for an exploration of the changes in PGE's "culture or operating practices resulting from the implementation of the partial decoupling mechanism." In this section, we review a variety of aspects of PGE's behavior, including marketing materials, advertising expenses, customer satisfaction surveys, and reports of activities related to energy efficiency and conservation going back to 2006.

A recurring theme in this section is that it is difficult to attribute specific changes in PGE's behavior (or changes in measures affected by PGE's behavior) to the implementation of Schedule 123. Other factors affecting PGE occurred in a similar timeframe, including the passage of Senate Bill 838 (SB 838) in 2007, which allowed for additional funding to support conservation and energy efficiency. While we observe increases in ETO program performance and conservation program funding in the ensuing years (including the years following the introduction of Schedule 123 in 2009), we have no way of knowing what would have occurred in the absence of Schedule 123. While the increase in ETO funding is most certainly attributable to SB 838, would program performance for PGE customers have suffered in the absence of the SNA and LRRA? As we will describe later in the report, the ETO has told us that its program performance improves when they have the utility as a partner, but even they have a difficult time determining the extent to which Schedule 123 produced changes in PGE's behavior.

6.1 Operating Practices

In response to our data request regarding PGE's internal policies and procedures, PGE provided the following.

Labor Compensation Practices and Policies
PGE has not implemented any changes in labor practices and policies directly resulting from the implementation of the SNA or LRRA.

Organizational Changes (e.g., the allocation of staff across company functions)
PGE has hired several employees to provide outreach to customers concerning the energy efficiency and conservation programs. The funding for these employees and associated promotional expenses is provided through Schedule 110 Energy Efficiency Customer Service.

Customer Service Resources and Practices
PGE has multiple channels available in which residential and business customers may contact the Company with inquiries about energy efficiency. These include telephone, email, mobile devices, community offices, and U.S. mail. PGE is the first stop for many customers who have inquiries about consumption, what, if any, tools are available to help to reduce their usage, as well as energy efficiency options and energy audits.

Customer Service Representatives (CSRs) and Business Team Energy Experts are trained to assist customer with their inquiries and engage in fact finding questions wit h the customer. If CSRs are unable to troubleshoot and resolve the customer's inquiry, customers are referred to the ETO for assistance and additional information relating to incentives and energy efficiency. PGE CSRs either fill out a consultation request which is passed to the ETO, which in turn contacts the customer to discuss further or set up an appointment, or the call is transferred to the ETO.

PGE also has outreach programs designed to inform and educate customers about EE through brochures and collateral materials, community and business forums, as well as internal Energy Expert resources that are available to assist customers about consumption, energy efficiency options, and areas for potential upgrades for efficiencies through ETO involvement.

In 2012, PGE implemented a new customer self-service tool called Energy Tracker that is available through a secure site accessed through PGE's web site. This tool provides tips related to usage and ways customers can save energy.

CA Energy Consulting Commentary
Of the responses provided by PGE in this section, the change that appears to be the most consistent with decoupling is the introduction of the Energy Tracker, which is an on-line tool that provides customers with detailed information about their usage and ways in which the customer can conserve. In theory, this kind of effort is enabled by revenue decoupling (e.g., the SNA), but not by alternatives such as the LRRA. That is, the Energy Tracker provides customers with information that may lead them to conserve, but does not necessarily result in easily

measured savings. In order for PGE to recover lost revenues under a mechanism such as the LRRA, the energy savings must be measured and attributed to a specific ETO program. This is not the case for the SNA, as the lost revenues associated with *any* reduction in sales (except those caused by deviations from normal weather) regardless of the source. Because of this, the SNA removes PGE's disincentive to offer "informational" programs such as the Energy Tracker, whereas the LRRA does not. Of course, it is possible that PGE would have offered the Energy Tracker in the absence of the SNA.

6.2 Rate Design

Revenue decoupling can change the utility's incentive to pursue certain rate design objectives that are viewed as being consistent with conservation objectives. For example, the utility may support lower monthly customer charges, thereby shifting revenue toward volumetric rates and increasing customer-level incentives to conserve. In addition, the utility may support steeper block pricing structures (e.g., increasing the rate for usage in excess of 1,000 kWh per month relative to the rate for the customer's first 1,000 kWh) in an attempt to discourage customers from using more energy. In the absence of decoupling, both of these rate design changes increase the variability of utility revenues in response to changes in sales. By reducing or removing the link between sales and revenue, decoupling can mitigate the effect of these rate design changes on the variability of utility revenues.

Because the SNA does not account for the effect of weather on sales, PGE does not receive the same amount of stability in sales as it would under a "full" decoupling mechanism (i.e., one that includes the effects of weather). This may explain the rate design proposals that PGE has put forth in UE-215 and UE-262. Our review of the rate design testimony from UE-215 and UE-262 indicates that the presence of the SNA did not appear to affect PGE's proposed rate design for Schedules 7 and 32. In its proposed residential rate design within UE-215, PGE gave most of its attention to modifying the size of the initial usage block, which had been 250 kWh. PGE initially proposed a three-block structure (0 to 500; 501 to 1,000; and over 1,000 kWh), while the case resolved with a two-block structure with a 1,000 kWh break point. PGE does not propose to increase the share of revenues collected in the second block in its UE-262 testimony. (Alternatively, it proposes to maintain a 0.722 cents/kWh difference between the first and second block prices.)

PGE agreed to, but did not propose, a decrease in the single-phase customer charge from $10 to $9 per customer month. In UE-262, PGE is proposing to increase this charge back to $10 per customer month, but to simultaneously decrease the three-phase customer charge from $14 to $10 per customer month. (In testimony, PGE supports this change on the basis of tariff simplicity and the fact that very few Schedule 7 customers take three-phase service.)

In summary, we do not find evidence that PGE factored the presence of the SNA into its rate design proposals. Perhaps this is not surprising given that the SNA does not cover weather-induced fluctuations in sales. If OPUC and other stakeholders believe that rate designs with lower customer charges and higher tail-block prices help encourage conservation, we would recommend altering the SNA to include the effects of weather in its adjustments, perhaps under the condition that the rate design changes are implemented.

6.3 Support for Conservation Programs

In Oregon, the ETO is responsible for administering conservation and energy efficiency programs. However, there is still a role for utilities to work with the ETO to increase awareness of and participation in the ETO's programs. One way to evaluate the effect of the SNA and LRRA on PGE's behavior is to examine changes in their work with the ETO across time.

Unfortunately, it is difficult for us to ascribe such changes to the introduction of Schedule 123. The primary reason for this is that energy efficiency and conservation program funding increased substantially over our relevant timeframe (beginning in 2006) due to SB 838. It is also important to note that the ETO attributes some of its success in conservation to the fact that PGE is a very active partner, and believes that PGE's commitment to the programs is helpful in achieving its goals.[51] Therefore, we believe it is worthwhile to provide an overview of the activities PGE has engaged in that demonstrate its support for conservation programs, despite the difficulty in attributing those activities to Schedule 123.

Table 6.3.1 shows annual incentives paid to PGE customers for energy efficiency activities and energy efficiency savings achieved by PGE customers (aMW) from 2006 to 2012. Energy savings from efficiency have grown in all years except from 2007 to 2008, which saw a steep one-time decline in savings from industrial customers. Incentives paid to PGE customers have more than tripled since 2006, but have steadily remained between 35 and 40 percent of ETO's total incentives paid.[52]

Table 6.3.1: Incentives Paid to and Conservation Achieved by PGE Customers[53]

Year	Incentives paid to PGE Customers ($000)	PGE Energy Efficiency Savings (aMW)
2006	10,565	14.1
2007	11,006	22.5
2008	15,479	18.6
2009	20,836	20.4
2010	26,665	25.6
2011	33,470	28.2
2012	36,626	32.2

[51] Section 7 of this report provides details of our interview with Margie Harris, the Executive Director of the ETO.
[52] The ETO also pays energy efficiency incentives to customers of Pacific Power, NW Natural, Cascade Natural Gas, and Avista.
[53] Statistics taken from ETO annual reports produced to the OPUC from 2006 to 2012.

Even though gains in efficiency and conservation may not be attributable to the SNA or LRRA, PGE's support for the ETO and advocacy for increased funding to the ETO may be the result of decoupling incentives. PGE states that "Schedule 123 has significantly alleviated concerns that PGE otherwise would have had regarding the negative impacts on fixed cost contributions that result from increased energy efficiency funding to the [ETO]."

PGE also points out that they have devoted additional resources to conservation outreach. Specifically, through funding provided by Schedule 110, PGE hired several employees and paid for associated promotional advertising. Again, while these activities cannot be directly attributed to decoupling, PGE may have been less willing to commit these resources in the absence of Schedule 123.

Funding for energy efficiency activities is also provided by SB 838. A detailed summary PGE's efforts supported by that funding can be found in ETO annual reports beginning in 2008. The timing of SB 838 (approved for PGE in the second quarter of 2008) and variations in reporting conventions make it difficult to perform a before-and-after comparison of activities with respect to decoupling. It is clear, however, that PGE engaged in conservation outreach prior to 2009 and that those efforts continued or expanded thereafter. Tables 6.3.2 and 6.3.3 contain descriptions of PGE's activities in support of the ETO in 2008 and 2012, respectively.

Table 6.3.2: PGE Support for the ETO, *2008*

Category	Activity
General	Assigned PGE liaison to Energy Trust
	Coordinated with ETO and other utilities on joint ad campaign
Commercial	Launched "Save More, Matter More" energy efficiency campaign urging business customers to make a pledge to save energy
	Included three efficiency ads in fall ad campaign
	Added EE case studies to PGE Web site
	Made over 50 presentations organizations
	Generated 72 qualified leads to the ETO
Industrial	Added manufacturing case study to PGE Web site
	Targeted small industrial customers for "Save More, Matter More"
Residential	Included ETO program information in 8 of 12 monthly *Update* newsletters
	Launched On-line Energy Analyzer
	Fielded EE advertising on television and other media

Table 6.3.3: PGE Support for the ETO, *2012*

Category	Activity
Commercial and Industrial	Featured energy efficiency articles and tips in several editions of *Energize*, quarterly bill insert, and *Business Connection*, bi-monthly e-newsletter
	Launched fifth annual "Save More, Matter More" campaign resulting in 487 requests for free energy consultations and 71 qualified leads to the ETO
	Engaged in several direct mail EE ad campaigns
	Three dedicated Outreach Specialists engaged in consultations, customer calls, presentations, and various other activities
	Outreach Specialists generated 550 qualified leads to ETO
Residential	Featured energy efficiency articles and tips in several editions of *Update*, monthly bill insert, and *Home Connection*, bi-monthly e-newsletter
	Delivered 141,531 Energy Saver Kits to PGE customers
	Distributed free showerheads and compact fluorescent bulbs
	Weatherized homes
Heat Pump Activity	Conducted three 2-month heat pump promotions resulting in 390 leads to PGE-approved contractors
	Funded and facilitated two training sessions for contractors to learn about the ETO's ductless heat pump program guidelines

Our evaluation of the ETO reports is that PGE's activities in support of ETO expanded over time. However, we cannot determine whether this is due to increases in overall funding levels due to SB 838, a change in PGE's reporting conventions across years, or a change in PGE's behavior due to a reduction or elimination of its disincentive to promote conservation and energy efficiency.

6.4 Marketing Activities

Decoupling may affect a utility's priorities with respect to the allocation of advertising expenses. Decoupling is most often thought of as a means to remove the utility's disincentive to promote conservation and energy efficiency. In this case, the utility may shift its marketing efforts more toward advertising that promotes these programs. A less commonly cited effect also occurs, which is that decoupling reduces the utility's incentive to promote programs that *increase* use per customer, as the revenues gained from those efforts would be returned to customers as a rate reduction through the SNA deferral. We examined PGE's marketing efforts to determine whether changes occurred that are consistent with these theories.

Table 6.4.1 shows the allocation of PGE's advertising expenses from 2006 through 2012. Across the categories, the only statistically significant trend is the increase in the expenses related conservation programs. This is likely due to the increase in available funds enabled by SB 838.

Since 2006, total annual advertising expenses across all categories peaked in 2010 and dropped significantly in 2011 and 2012 to their lowest levels. That is, conservation promotion does not appear to have added to advertising expenditures, but instead supplanted marketing activities that may have otherwise been included in the other two categories.

Table 6.4.1: Category Shares of PGE Advertising Expenses

Year	Shares of Advertising Expenditures:		
	Image/Brand	Information & Retail Delivery	Conservation
2006	31%	69%	0%
2007	26%	74%	0%
2008	30%	65%	5%
2009	31%	59%	10%
2010	36%	54%	11%
2011	5%	79%	16%
2012	20%	61%	20%

A review of print and online newsletters mailed to customers directly or included as bill inserts revealed few discernible changes in content that may be associated with decoupling. Prior to implementing Schedule 123, PGE often included energy efficiency and conservation items in its customer materials, and that did not change after 2009. We paid particular attention to messaging directed at residential customers through a two-page monthly bill insert, titled "Update." A simple count of items related to energy savings, as classified in annual editorial calendars, reveals that the number of items increased from an average of 22 stories per year before and including 2009 to 26 stories thereafter. Relative to items related to corporate citizenship, which could be considered analogous to image advertising, stories about energy saving initiatives appeared more often and with a larger share of stories after 2009 (omitting the anomalous 2007 counts).

Table 6.4.2: Count of References to Energy Savings and Corporate Citizenship in Residential Customer Newsletter (Update, 2006-2012)

Year	Number Items in Update Addressing "How does PGE..."		Ratio (Energy Savings/Corporate Citizenship)
	"... Help me save energy?"	"...Make my community better for me and my family?"	
2006	21	20	1.1
2007	26	7	3.7
2008	21	15	1.4
2009	21	21	1.0
2010	26	20	1.3
2011	25	21	1.2
2012	27	18	1.5

In our review of the residential bill inserts, we also investigated whether there were any load growth programs that PGE stopped promoting after the implementation of the SNA. That is, the SNA removes both PGE's disincentive to promote conservation and its incentive to promote load growth (in terms of use per customer). The only potentially relevant finding from this investigation was that PGE appeared to cease promotion of its outdoor area lighting program in October 2008. While this type of service is safety related, it could also be considered a load growth initiative, in that it represents a new end use for existing customers. However, PGE informed us that this change was unrelated to the SNA and that it intends to promote this type of lighting again in the future.

6.5 Customer Satisfaction

PGE monitors customer satisfaction through annual and quarterly reports from three market research firms. In this section, we summarize customer satisfaction survey results from J.D. Power and Associates (JDP), Market Strategies International (MSI), and TQS Research, Inc. (TQS).

JDP produces annual reports of customer satisfaction in the electric utility industry, with separate reports for business and residential customers. Along with the executive summary, which summarizes results for the entire industry, PGE also receives PGE-specific details regarding components of customer satisfaction and indicating PGE's rank within the West Region and across the industry.[54]

[54] For business customer reports prior to 2010, JDP ranked PGE relative to all utilities serving greater than 25,000 business customers in the West Region. Beginning in 2010, JDP further split utilities by size segment, where midsize utilities are defined as those having between 25,000 and 85,000 business customers and large utilities have greater than 85,000 business customers. A similar modification was made in 2008 with respect to residential utility rankings. Beginning in 2008, residential utilities within each region are split into large (500,000 or more

PGE provided annual JDP customer satisfaction results from 2006 through 2012. Because this information is confidential, we will only describe results in terms of PGE's rank within its peer group (large utilities in the West Region) or PGE's score relative to the average score in that group (benchmark). The following categories are of particular interest:

- Overall Customer Satisfaction Index[55]
- Power Quality & Reliability
- Price
- Customer Service
- Awareness of Energy Efficiency and Conservation Programs[56]

Tables 6.5.1 and 6.5.2 list PGE's rank within the West Region from 2006 to 2012 for business and residential customers, respectively. For both customer groups, PGE has ranked in the top half of the West Large Segment since 2009 in all categories with only one exception. In 2011, PGE ranked 7th out of 13 utilities with residential customers in the Price category, which is consistently PGE's weakest area for both customer groups.

Table 6.5.1: PGE's Rank among Large West Region Utilities, *Business*

Year	Overall CSI	Power Quality & Reliability	Price	Customer Service
2006	9 of 12	5 of 12	8 of 12	2 of 12
2007	5 of 12	3 of 12	7 of 12	5 of 12
2008	5 of 13	2 of 13	7 of 13	1 of 13
2009	1 of 19	1 of 19	5 of 19	2 of 19
2010	2 of 12	1 of 12	4 of 12	4 of 12
2011	2 of 12	2 of 12	2 of 12	2 of 12
2012	2 of 12	2 of 12	3 of 12	2 of 12

residential customers) and midsize (125,000 to 499,999 residential customers) categories. PGE is considered a large utility with respect to both residential and business customers.

55 The Overall CSI is a weighted composite of satisfaction results in six categories: Billing & Payment, Price, Power Quality & Reliability, Communications, Customer Service, and Corporate Citizenship.

56 This measure was reported beginning in 2008 for residential customers and 2009 for business customers.

Table 6.5.2: PGE's Rank among Large West Region Utilities, *Residential*

Year	Overall CSI	Power Quality & Reliability	Price	Customer Service
2006	6 of 12	4 of 12	10 of 12	3 of 12
2007	3 of 13	2 of 13	4 of 13	1 of 13
2008	3 of 13	2 of 13	5 of 13	2 of 13
2009	3 of 13	3 of 13	5 of 13	1 of 13
2010	3 of 13	2 of 13	4 of 13	2 of 13
2011	3 of 13	2 of 13	7 of 13	4 of 13
2012	3 of 13	2 of 13	5 of 13	2 of 13

Figures 6.5.1 and 6.5.2 show how PGE's score in each category (relative to the average large West Region utility, expressed as a ratio) evolved from 2006 to 2012 for business and residential customers, respectively. With respect to business customers, the trend in each category is upward sloping suggesting that PGE has improved customer satisfaction relative to its peers. Residential customer satisfaction appears to have peaked in 2007 and has remained relatively flat between 2008 and 2012.[57] For both customer groups, almost every data point from 2008 forward is greater than one, indicating cases where PGE outperforms its benchmark.

[57] Residential satisfaction with customer service has declined consistently since 2007 relative to the average large West region utility. This is due primarily to increases in satisfaction for the benchmark utility rather than a decline in PGE's customer service.

Figure 6.5.1: PGE Satisfaction Scores Relative to Average, *Business*

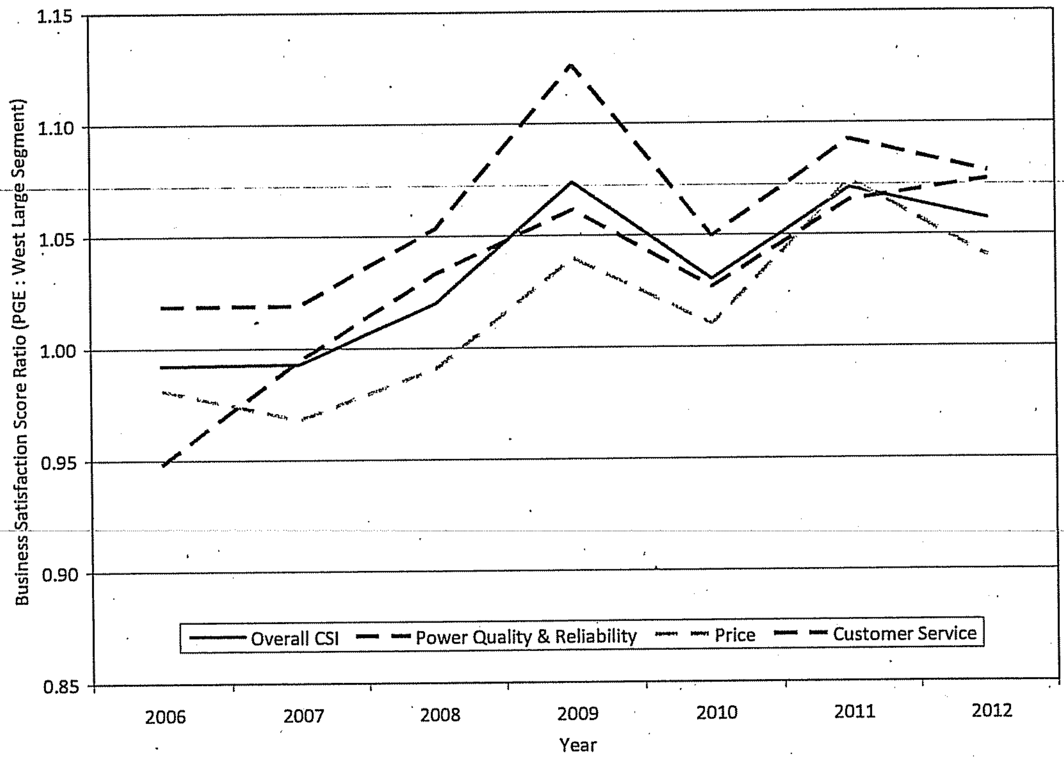
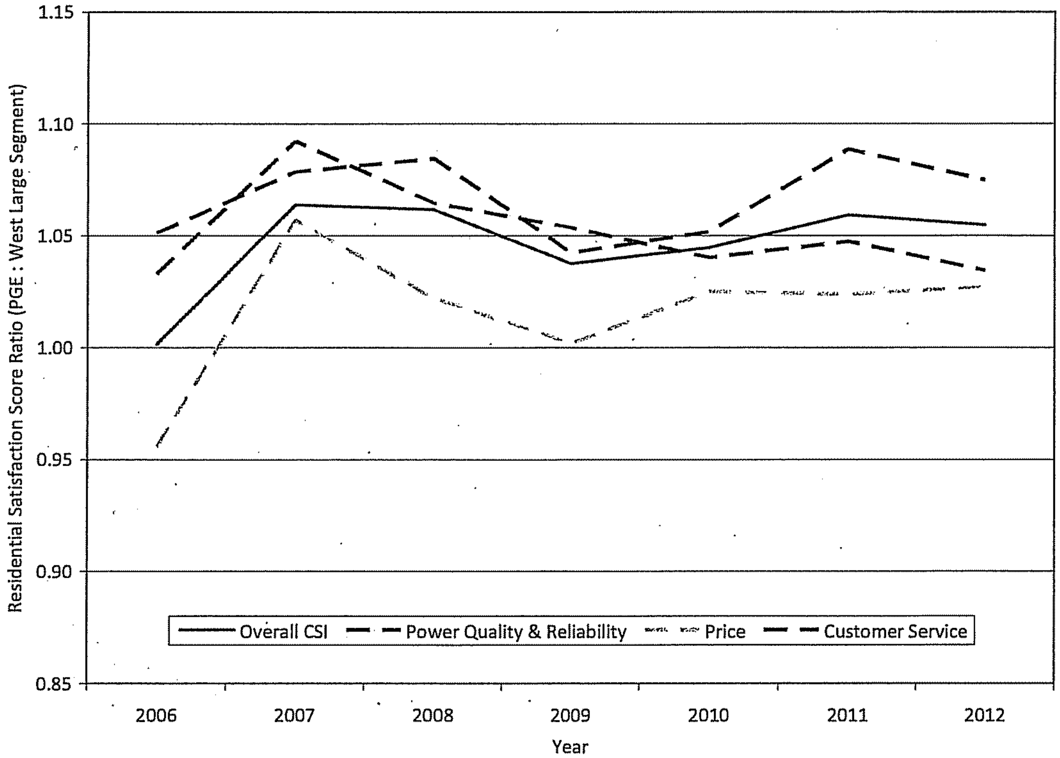
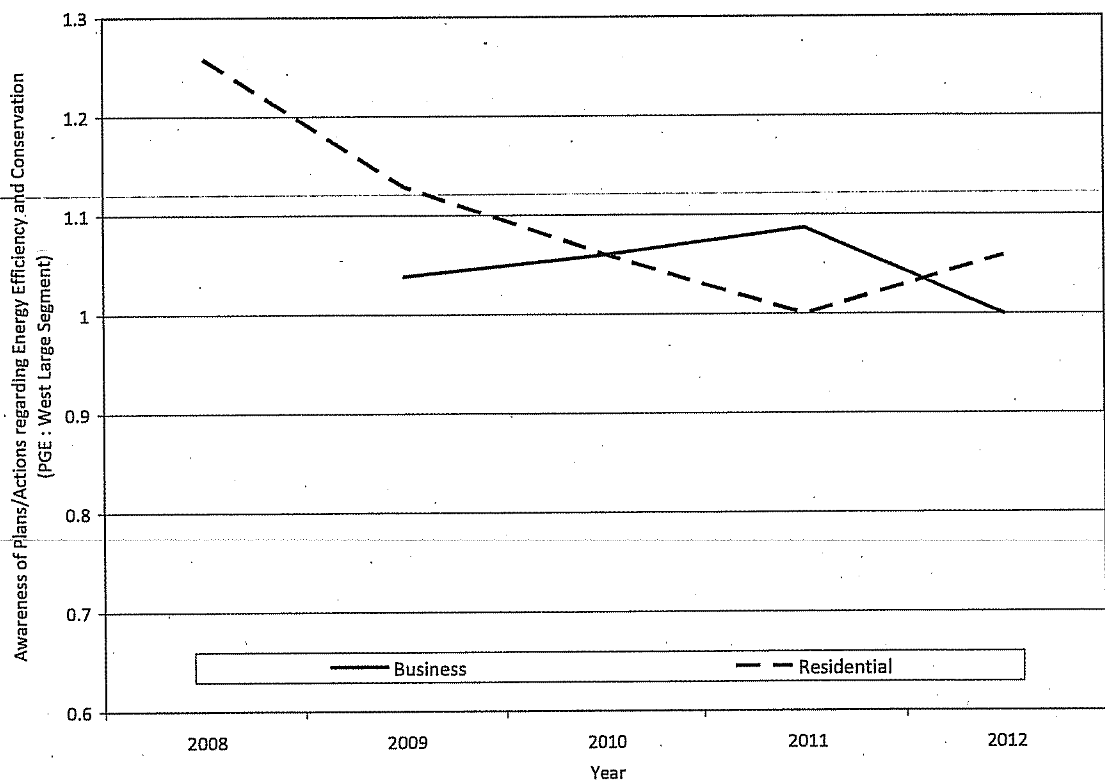


Figure 6.5.2: PGE Satisfaction Scores Relative to Average, *Residential*



In 2008 and 2009 JDP began tracking customer awareness of utility actions with respect to energy efficiency programs and conservation. Figure 6.5.3 provides awareness statistics as a ratio of the share of aware customers at PGE relative to the average large West Region utility. For both customer groups, the ratios are always greater than or equal to one, indicating that PGE's awareness is consistently on par or better than that for comparable utilities. The figure shows a decline in awareness for residential customers and stable awareness for business customers. For the residential customers, the decline can be attributed to both a decrease in awareness for PGE customers and in increase in awareness for the benchmark utilities.

Figure 6.5.3: PGE Customer Awareness of EE and Conservation Relative to Average



Like JDP, MSI conducts surveys for business and residential customers separately. Each survey has a sample of approximately 400 customers and results are reported quarterly (every other quarter for business customers) from 2006 to 2012.[58] MSI asks customers to score their utility on a scale from 1 to 10 on a variety of topics. MSI then summarizes results for each question in terms of the percent of customers who "agree" or give "positive" responses (scores between 6 and 10). The following four measures of residential and business customer satisfaction are summarized in Figures 6.5.4 and 6.5.5:

- Overall Satisfaction
- Overall Favorability
- Showing Concern and Caring (towards customers)
- Value of Customer Service

Because MSI data are confidential, Figures 6.5.4 and 6.5.5 show PGE's scores relative to the average score for utilities in the PGE peer group (expressed as a ratio).[59] Again, in every case

[58] Only results from 4th quarter reports are summarized here.

[59] MSI defines the peer group to include eight or nine large western utilities. The peer group consists of varying combinations of the following utilities in each year: Pacific Gas & Electric, Pacific Power, Puget Sound Energy, Rocky Mountain Power, Southern California Edison Company, Seattle City Light, San Diego Gas & Electric, Sierra Pacific Power Company, NV Energy North, and NV Energy South.

the value of each ratio is above one indicating above average performance from PGE. With respect to business customers, each measure was stable or declining through 2009 but recovered in 2010. Overall satisfaction and overall favorability maintained or exceeded 2010 levels into 2012; however the two remaining factors related to customer service declined in both 2011 and 2012. With respect to residential customers, all four measures of satisfaction declined from 2008 to 2011 and saw large rebounds in 2012.

Figure 6.5.4: PGE Satisfaction Scores Relative to MSI Peer Group, *Business*

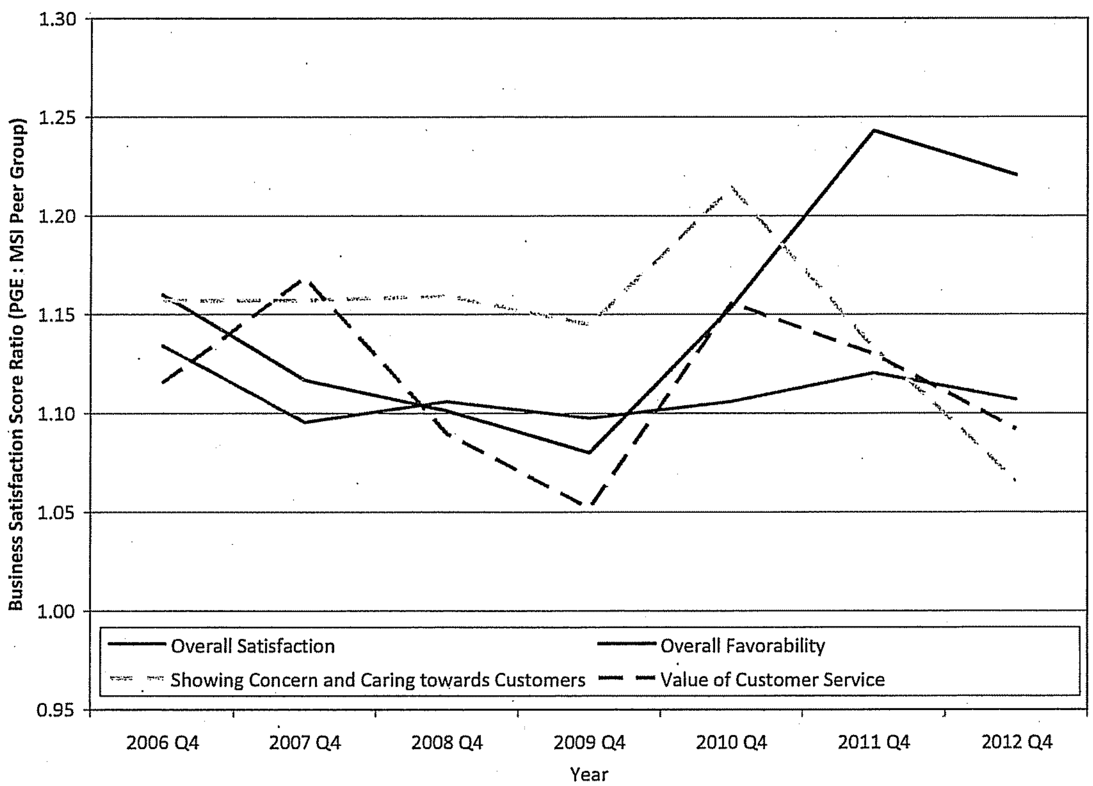
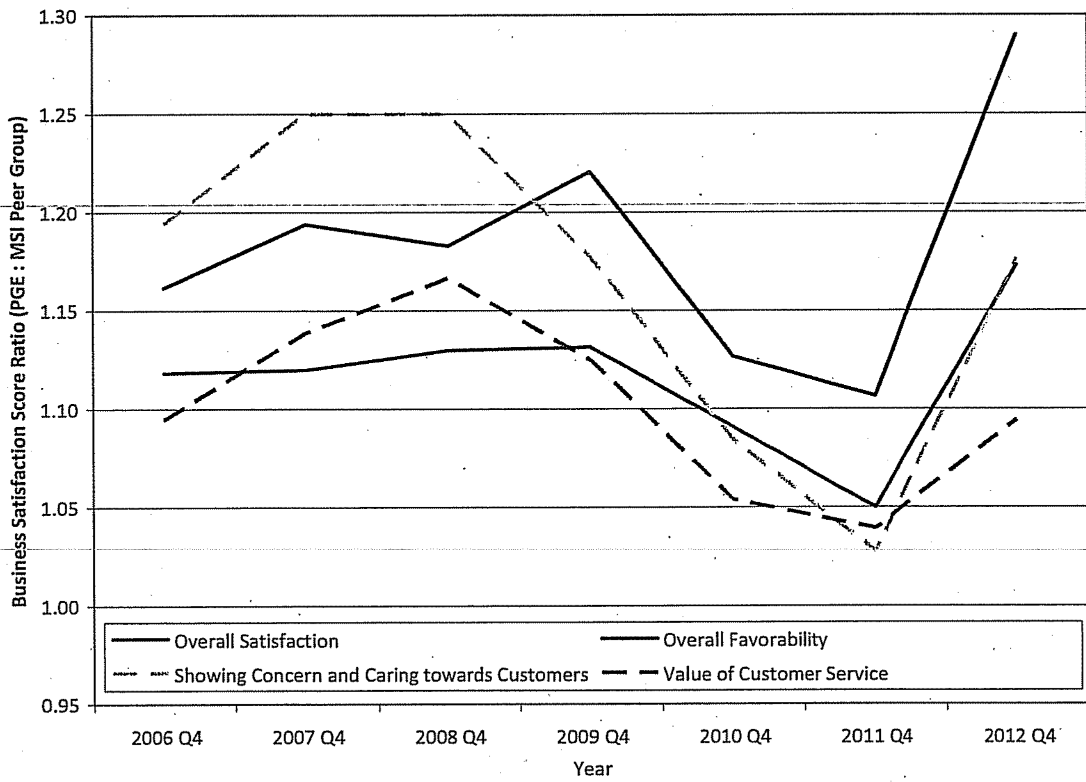


Figure 6.5.5: PGE Satisfaction Scores Relative to MSI Peer Group, *Residential*



MSI also reports the percentage of customers who agree (scores between 6 and 10) that PGE "offers practical advice on how to save money on your electric bills," but does not provide a benchmark value from the peer group. Greater than 80 percent of customers agree with this statement in all years and in both customer groups. The scores are relatively stable, with a six percentage point spread between highest and lowest score for business customers and only a four percentage point spread for residential.

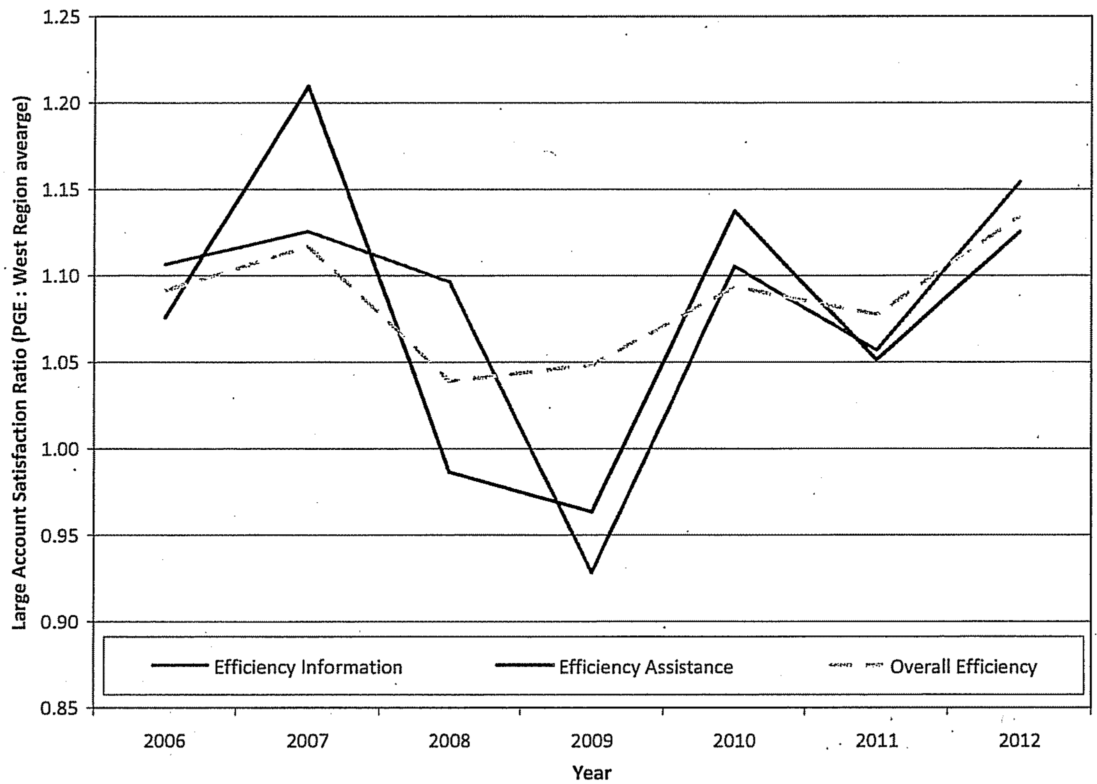
Finally, TQS conducts interviews and generates annual reports summarizing satisfaction of large accounts for PGE and an additional 65 or more large utilities.[60] TQS asks survey respondents to rate PGE from 1 to 10 (10 being "very satisfied") on several topics, in particular:

- Providing you with information to make energy efficiency decisions;
- Providing technical assistance to make your company more energy efficient; and
- Overall satisfaction with your utility's efforts to make your company energy efficient.

[60] TQS defines large accounts to be "manufacturing facilities with a demand of over 1,000 kW, plus large hospitals & universities." As many as 100 utilities are included in the 2012 TQS report and as few as 65 in 2006. Note that many of these customers may not be eligible for Schedule 123, which does not apply to customers with usage exceeding 1 aMW.

TQS summarizes responses based on the percentage of customers who are "very satisfied" (those who give scores between 8 and 10). Figure 6.5.6 summarizes PGE's share of very satisfied customers relative to that of the West Region average (expressed as a ratio) from 2006 to 2012 for each of the three energy efficiency topics. All three measures saw lower scores in 2008 and 2009 and rebounded in following years. With the exception of one data point (efficiency information in 2009), all ratios are greater than one indicating above average performance from PGE.

Figure 6.5.6: Large Account Satisfaction with Energy Efficiency Programs Relative to West Region Average



6.6 Customer Complaints

We asked OPUC Staff to provide us with customer complaints that can be attributed to Schedule 123. Their response consisted of three complaints. The first, from March 2009, contained a fairly common (in our experience) objection to decoupling on the grounds that customers "pay for energy that they did not use." We do not find this objection to be compelling, because decoupling relates only to fixed costs, not variable energy costs. Therefore, even under decoupling, customers will pay for less energy if they use less energy.

The second complaint, from April 2009, objected to decoupling based on a belief that the utility should not be able to apply a surcharge to rates when customers use less. The customer believed that it was unethical for PGE to propose such a charge with their history of financial waste, and urges the Commission to consider the history of decoupling in the Northeast United States.[61] The overall message of the complaint appears to relate to concerns about a shift in economic risk from PGE to its ratepayers. Our analysis in Section 4 indicates that this concern is not without merit, though the overall improvement in economic conditions during the period in which the SNA has been in effect has caused the SNA to benefit customers at the expense of PGE.

The third case record (from August 2011) was more of an inquiry than a complaint. The customer was confused by the fact that the SNA credit had changed to a charge across billing periods. The customer's question was answered and the case was closed.

6.7 Service Outages

In a December 2012 stakeholder meeting, a question regarding service quality was added to the evaluation requirements. Specifically, it reads "Did the partial decoupling mechanism affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality."[62]

From an incentive perspective, the mechanics of the SNA suggest that PGE could face a reduced incentive to resolve service outages. That is, under the SNA, PGE recovers fixed costs based on the number of customers served rather than on the sales to those customers. Therefore, the revenue associated with a reduction in sales that occurs because of a widespread outage would be recovered through the SNA deferral.

Realistically, we do not expect that the change in the financial incentive is large enough to affect PGE's behavior with respect to resolving outages. Even with the revenue assurance provided by the SNA, the cost savings the utility could achieve by allocating fewer resources to resolving outages seem small when compared to the safety issues, costs associated with dealing with an increase in customer complaints, and the adverse affects associated with a decrease in customer satisfaction that would likely result from allowing longer service outages.

Table 6.7.1 summarizes PGE's service outages from 1999 through 2011. The data are taken from PGE's 2011 Service Quality Measure Report. The rows containing 2009 through 2011 are italicized to indicate the years in which Schedule 123 was in place. Comparing the three years before and after Schedule 123 was implemented (as shown in the means at the bottom of the table), we find improvements in SAIDI, SAIFI, MAIFI, and the number of outages. CAIDI is the only measure that is worse when Schedule 123 was in effect.

Based on these data, we do not see any evidence that PGE's service quality was adversely affected by the introduction of Schedule 123.

[61] The customer is likely referring to the introduction and subsequent withdrawal of a decoupling mechanism for Central Maine Power.

[62] If one prefers to interpret "service quality" to mean customer service rather than addressing service outages, then this question is addressed in Section 6.5 (customer satisfaction).

Table 6.7.1: PGE Service Outage Data, *1999 – 2011*[63]

Year	SAIDI (minutes)	SAIFI (#/Customer)	MAIFI (#/Customer)	CAIDI (minutes)	# Outages
1999	83	0.78	3.30	106.4	4,216
2000	64	0.62	2.70	103.2	4,040
2001	67	0.65	2.20	103.1	4,558
2002	73	0.65	2.20	112.3	4,935
2003	82	0.80	2.10	102.5	5,366
2004	85	0.80	1.80	106.3	5,582
2005	86	0.83	1.60	103.6	5,560
2006	117	1.06	1.60	110.4	6,930
2007	77	0.71	1.30	108.5	5,994
2008	75	0.73	1.30	102.7	5,817
2009	*115*	*0.81*	*1.40*	*141.6*	*6,354*
2010	*77*	*0.65*	*1.10*	*118.3*	*5,454*
2011	*66*	*0.51*	*0.89*	*129.0*	*4,535*
Averages:					
w/ Schedule 123 (2009-11)	**86.0**	**0.66**	**1.13**	**129.6**	**5,448**
3 yrs. Prior (2006-08)	**89.7**	**0.83**	**1.40**	**107.2**	**6,247**
All prior years (1999-2008)	**80.9**	**0.76**	**2.01**	**105.9**	**5,300**

7. STAKEHOLDER INTERVIEWS

We contacted the key stakeholders (which include CUB, ETO, Kroger, Northwest Energy Coalition, OPUC Staff, and PGE) to provide them with the opportunity to provide feedback on the SNA and LRRA. PGE's feedback consisted of the responses to our data requests. We had some communication with OPUC Staff to discuss the project and desired areas of inquiry. Finally, we had detailed conservations with the ETO and Kroger, which are summarized in the following sub-sections. We did not receive responses from CUB or the Northwest Energy Coalition.

7.1 Energy Trust of Oregon

We spoke with Margie Harris, who is the Executive Director of the ETO. As the third-party provider of conservation and energy efficiency programs, the ETO has a unique perspective on the effects of Schedule 123. In our conversation, Ms. Harris was weakly supportive of Schedule 123. That is, she said that it helps make PGE neutral to the effects of conservation, but does not provide them with a direct incentive to advocate conservation. In addition, she believes that several other factors, such as funding provided under Senate Bill 838 and the least-cost planning required of PGE's Integrated Resource Plans, are more significant drivers of PGE's behavior with respect to conservation than Schedule 123. Ms. Harris did not believe that she

[63] SAIDI is the System Average Interruption Duration Index; SAIFI is the System Average Interruption Frequency Index; MAIFI is the Momentary Average Interruption Frequency Index; and CAIDI is the Customer Average Interruption Duration Index.

was in a position to determine the extent to which the adoption of Schedule 123 affected PGE's behavior, independent of these other factors.

However, she also stated that ETO's research indicates that utility cooperation in the promotion of conservation and energy efficiency programs improves program performance. That is, program performance is improved when PGE and the ETO work together (e.g., through joint messaging) rather than separately. This suggests a valuable role for PGE in promoting ETO's programs. She indicated that PGE has been very committed to working with the ETO.

The ETO provides conservation and energy efficiency programs for all customer classes. PGE has three different types of customers, from a conservation incentive perspective:

1. Those covered by the SNA (residential and small commercial);
2. Those covered by the LRRA (medium commercial and industrial); and
3. Those with no mechanism for the recovery of lost revenues.

We asked Ms. Harris whether she has observed any differences in PGE's efforts to work with ETO across these groups. She responded that she has not, though she suspects that in the future, the ETO will attempt to obtain an increasing share of its energy savings from the "group 3" customers. She believes that this may provide a test of PGE's willingness to promote conservation in the absence of any regulatory mitigation of lost revenues.

OPUC Staff conveyed to us additional information they received from Kim Crossman of the ETO. The specific feedback we received from Staff follows:

> [I]n conversation with Kim Crossman of the ETO, Staff has identified that PGE, in their function as a Program Delivery Contractor (PDC) for the ETO, aggressively targets smaller customers relative to other PDC contractors. This evidence suggests that the LRRA provides a conflict of interest for PGE. As a PDC, the Company should promote energy efficiency based on cost effectiveness. However, because the LRRA only decouples customers under one MWa, PGE has the incentive and opportunity to shift Senate Bill 1149 and Senate Bill 838 funding from large customers to small customers.

While the above information does not fully align with the feedback we received from Ms. Harris, we believe that it may provide the strongest evidence we have found thus far that PGE responds to the disincentive to promote conservation that is inherent in its rates, without Schedule 123. Above, Staff expresses the view that PGE "should promote energy efficiency based on cost effectiveness." However, this obligation exists in the absence of Schedule 123, and despite this the Commission ruled that "a properly constructed decoupling mechanism would promote behavior by the Company that would be publicly beneficial."[64]

[64] Order No. 09-020, page 28.

If the information provided by the ETO indicates that PGE is diverting its promotions of energy efficiency away from classes unaffected by Schedule 123, we suggest that a potential remedy is to expand the eligibility of the LRRA rather than remove it entirely.

7.2 Kroger

Denis George and Kevin Higgins provided us with feedback regarding Kroger's view of Schedule 123. The main points they expressed can be summarized as follows:

- Kroger believes that the utility disincentive to promote conservation and energy efficiency is overstated as a general matter. In Oregon, the presence of the ETO as a third-party provider of conservation and energy efficiency programs further reduces the effect of the incentive issue in Kroger's view.
- Kroger opposes the SNA because they believe it transfers risk from PGE to its customers.
- The LRRA is less objectionable to Kroger than the SNA because it is limited to the effects of energy efficiency measures. However, Kroger opposes the LRRA as well. If the LRRA is retained, Kroger would like it to be modified to address the following perceived flaws (quotation marks are used to indicate statements provided directly from Kroger):
    - The LRRA "provides for adjustments to the rates paid by Direct Access customers that include recovery of PGE's fixed generation revenues that are alleged to be lost as a result of energy efficiency measures. PGE's fixed generation costs should be excluded from any LRRA rates applicable to Direct Access customers that are participating in multi-year opt-outs."
    - "The LRRA is asymmetrical in that it does not take account of 'found revenues' that could accrue to PGE as a consequence of new load. Specifically, the LRRA focuses on the sales impact of energy efficiency measures in isolation and neglects to consider the effects of overall load growth on fixed cost recovery. In practice, the implementation of energy efficiency programs does not imply that a utility will be unable to fully recover its fixed costs. In general, when load grows above the level of the billing determinants used in setting rates, the fixed-cost recovery that occurs as a function of volumetric sales increases. This inures to the benefit of the utility. In traditional ratemaking, utilities are <u>not</u> required to return this incremental fixed-cost recovery to customers. This incremental fixed-cost recovery can be thought of as 'found' margins. If a 'lost margins' approach is adopted, then 'lost margins' should be netted against 'found margins.' Specifically, the kilowatt-hours used for measuring going-forward lost revenue recovery should be limited to the <u>lesser</u> of energy efficiency improvements attributable to energy efficiency measures or actual net reductions in retail kilowatt-hours sold relative to the retail kilowatt-hours used in setting base rates."
- Kroger believes "that 'lost' fixed cost recovery attributable to energy efficiency measures can be mitigated through rate design for demand-billed customers. For example, Arizona Public Service Company ('APS') negotiated a Lost Fixed Recovery Mechanism ('LFCR') with stakeholders as part of its last general rate case. APS's LFCR is similar to the LRRA, except that it excludes customers with billing demands greater than 400 kW because the lost revenue concerns for these customers are addressed by

aligning demand-related costs with demand charges, which are typically a more stable source of revenue than energy charges."

- Denis George pointed out that Kroger is self-motivated to conserve. There is a general frustration that they are required to participate in energy efficiency funding mechanisms and programs that they would likely pursue without the costs associated with regulatory intervention. He stated his belief that it is more difficult to make the case for energy efficiency projects in the presence of decoupling (and presumably the LRRA).

8. AREAS OF POTENTIAL HARM NOT INVESTIGATED IN THE STUDY

After reviewing a draft of this study, OPUC Staff requested that we "[i]dentify potential sources of harm from the decoupling mechanisms that were not fully investigated in the Report." Staff provided the example that "the social cost due to the shift in economic risk from the Company to the customer was not identified," including and investigation of "whether the Company, investors in the company, or the individual customer is best able to deal with the risk."

Addressing Staff's specific suggestion first, we do not see a straightforward means of identifying which party is best positioned to deal with economic risk, though we provide some thoughts on the matter.

First, the shift in economic risk does not seem large. Assuming that the SNA covers approximately 50 percent of Schedule 7 revenue, even the recent severe decline in economic conditions would have only produced approximately a 0.9 percent increase in customer bills. For Schedule 32 customers, the SNA-induced bill increase may have approached the 2 percent rate adjustment cap (these figures are based on results presented in Table 4.4.4).

Second, the economic risk shift is not distributed equally across customers within a rate class. That is, it seems likely that in comparatively dire economic circumstances, some customers are forced to dramatically reduce their usage while others do not need to make any adjustment at all. Extending the "peak-to-trough" example from above, a particular customer who reduced usage by 10 percent in response to a reduction in income would receive an SNA-rate increase in the following year based on the smaller 1.8 percent decrease in UPC that occurred for the entire class. Therefore, while the risk is shifted from the Company to the *class* of customers, the effect on *individual* customers varies.

Regarding the various parties' ability bear risk, the issue seems quite complex. Looking only within the residential customer class, there are a range of entities: low-income customers who could experience harm from even relatively small rate increases; and comparatively well-off customers for whom the electric bill is small part of their overall finances. Utility investors may also include a wide range of parties, including small individual investors, pension funds, or large institutional investors. The utility itself may have tools to mitigate cash flow risks (e.g., through a line of credit or cash reserves) or mitigate longer-term recovery issues (e.g., by filing a rate case). However, PGE is not very diversified in its operations, such that deterioration in its electricity sales can have a significant effect on its overall financial health. Devising a means of evaluating the ability these parties to bear risk is not within the scope of this study.

Given the thorough list of evaluation requirements, we do not believe there are many other areas of potential harm from Schedule 123 that have remained uninvestigated. We can only think of one area at this time: the distributional effects of SNA deferrals. That is, consider an example in which half of the customers reduce usage by 4 percent by pursuing conservation and energy efficiency, while the remaining half takes no action at all. Suppose that the net effect of this is a 1 percent bill increase through the SNA deferral mechanism (under the assumption that 50 percent of the total bill is covered by the SNA). The conserving customers in this example experience a net reduction in their bill, but some of the fixed cost recovery has been shifted from these customers to the non-conserving customers.

We have not investigated the effect of these potential intra-class allocation/subsidy issues. One can imagine a circumstance in which wealthier customers are more able to engage in conservation than low-income customers, with the result being an SNA-induced shift in cost recovery from high- to low-income customers. While we have not explored the existence or size of such an effect, we note that an alternative to decoupling in which all fixed costs are recovered through fixed charges (SFV pricing, described in footnote 67) has much more potential to shift cost recovery to low-income customers.

9. CONCLUSIONS AND RECOMMENDATIONS

Summary of the Study

In this study, we evaluated the Sales Normalization Adjustment and Lost Revenue Recovery Adjustment mechanisms approved for use by PGE in 2009 as Schedule 123. A primary motivation for implementing these mechanisms is to remove the disincentive to promote conservation and energy efficiency that PGE faces because fixed costs are recovered, at least in part, through volumetric rates.

The study consists of an examination of each mechanism to determine whether it functions as intended; an evaluation of whether PGE's behavior changed in a manner consistent with a change in its incentives to promote conservation and energy efficiency; an evaluation of whether Schedule 123 reduced PGE's risk; development of a statistical model to determine whether changes in use per customer (which affect SNA deferrals) are related to changes in economic conditions or energy prices; and an examination of PGE customer satisfaction and service quality to determine whether either suffered under Schedule 123.

A summary of findings follows:

1. The design of the SNA is effective in eliminating PGE's disincentive to promote conservation and energy efficiency to residential (Schedule 7) and small commercial (Schedule 32) customers.
2. The design of the LRRA is effective in reducing PGE's disincentive to support the ETO's conservation programs for the applicable rate schedules. (However, some disincentive may continue exist if PGE expects a mismatch between actual and estimated conservation from ETO programs.)
3. We do not find compelling evidence that the change in incentives led to significant changes in PGE's corporate behavior, though some actions were reported.
    a. PGE reports no change to its labor compensation practices and policies.
    b. PGE hired several employees to provide customer outreach regarding conservation programs.
    c. PGE introduced the Energy Tracker, which is an on-line tool that helps customers identify opportunities to conserve.
    d. PGE did not appear to alter its retail rate structures because of the incentive effects of Schedule 123 (this is understandable given that the SNA does not cover weather effects on sales and revenues).
    e. The ETO reports that PGE has been a valuable and effective partner in promoting its programs, but it is difficult for them to attribute this behavior to Schedule 123. The ETO cited other factors, such as funding provided under SB 838 or least-cost planning required by the Integrated Resource Plan as likely drivers of PGE's behavior.
    f. It is difficult to identify a change in PGE's marketing activities that was directly in response to the introduction of Schedule 123.
    g. Neither PGE's service quality nor its customer satisfaction appears to have been adversely affected by Schedule 123.
4. Based on our own empirical study, a review of other studies, and information provided in credit agency ratings reports, we do not find any evidence that the introduction of Schedule 123 reduced PGE's capital risks by a material amount. We therefore do not find a justification for adjusting PGE's allowed return on equity because of Schedule 123.
5. Our statistical analysis indicates that some economic risk may be shifted from PGE to its Schedule 7 and 32 customers.[65] The experience to date indicates that this has benefitted those customers, as economic conditions have improved since early 2009. The same analysis indicates that the SNA does *not* shift price risk to customers (i.e., there is no statistically significant relationship between the real electricity price and use per customer).

[65] This is not necessarily inconsistent with the finding that Schedule 123 did not materially reduce PGE's overall risk, as the amount of economic risk may be small in comparison to the combination of all of the other risks to which PGE is exposed.

Recommendations
For our recommendations, we provide answers to two required analysis questions that were not addressed in the body of the report.

11. How often should the fixed costs and use-per-customer parameters be updated?
Our findings do not provide a conclusive answer to this question. Our view is that there is no need to deviate from status quo, in which the mechanisms are updated as a part of rate cases initiated in the usual way (which is typically for the utility to file of its own accord, but the Commission also has the authority to compel the utility to undergo a rate case). The deviations that the SNA and LRRA cause relative to the outcomes that would have occurred under standard rates seem likely to be small enough such there is no need to require the utility to file more frequently than it otherwise would have. That said, if the stakeholders would be more comfortable with the long-term effects of Schedule 123 if the Commission were to impose something like a maximum five-year rate case window (i.e., there can be no more than five years in between PGE rate cases while Schedule 123 is in effect), the only harm that would be incurred would be the costs associated with the ratemaking process.

12. What would you recommend as improvements to the current PGE decoupling mechanism? Should it continue beyond 2013? Should it be terminated? Should it be modified? If so, what specific modifications should be made?
As described in the summary of our findings above, our evaluation has provided no overwhelmingly compelling reason to support the continuation or termination of Schedule 123. Little harm seems to have been incurred at this point: customer satisfaction and service quality are fine; total deferrals to date have been relatively small (a total net effect of approximately $500,000 across 2009-2012); and the ETO is generally pleased with the effort that PGE is giving in support of its programs.

Still, it is difficult to find evidence that Schedule 123 has caused PGE to behave differently than it would have in the absence of the mechanisms. However, some pro-conservation behaviors have been observed, including the introduction of the Energy Tracker; the hiring of additional staff to increase awareness of conservation and energy efficiency programs; and continued support for the ETO. We are not in a position to know whether these actions would have occurred in the absence of Schedule 123.

Taking all of this into consideration, we recommend the continuation of Schedule 123. While the evidence is not conclusive, we are swayed by the presence of some good (e.g., the ETO reporting that PGE is a good partner in promoting its programs) and very little evidence of harm. Since the ETO's conservation goals are no less ambitious in the future, it would be beneficial to ensure PGE's cooperation going forward.

We suggest some modifications to each mechanism, as follows.

For the LRRA:

- Remove the generation component from the charge paid by Schedules 485 and 489. There is no lost revenue toward generation costs for these customers, because it is not part of their standard rates.
- If it is administratively feasible, use schedule-specific Lost Revenue Rates, with the total ETO conservation spread across rate schedules in proportion to test-year sales levels. This method seems like a feasible method of reducing (but not eliminating) cross-subsidies due to LRRA adjustments without being unduly burdensome administratively.

For the SNA:

- Consider removing the weather normalization of "actual" sales (and therefore revenues) from the calculation. This has the following potential benefits.
    - It would enable PGE to implement rate structures that may provide customers with higher incentives to conserve, such as lower customer charges (and higher volumetric rates) or more steeply inclining block rates. Under the current SNA, these rate structures would be unappealing to PGE because of the weather-induced variability in revenues toward fixed costs that they could produce.[66]
    - It would allow for the reduction of weather risk for both PGE and its ratepayers. Some progress would be made in this regard by simply removing the weather adjustment to sales. However, it would be an even more effective risk mitigating measure if the SNA design change was accompanied by the introduction of a monthly weather adjustment. This would allow the weather risk mitigation to benefit customers in the current month rather than waiting for the effects of the modified SNA deferrals.[67] We acknowledge that the administrative cost associated with introducing the separate weather adjustment may more than offset the benefits of the additional risk mitigation that it would provide.
- Consider a bifurcation of the SNA so that separate calculations are conducted for the generation and transmission cost components (with the remaining cost components

[66] Note that the proposed changes to rate structure tend to go against marginal-cost-based pricing principles, in which fixed costs are recovered with fixed charges and variable costs are recovered with unit rates that closely approximate the unit costs. Such pricing, called Straight Fixed Variable ("SFV") pricing in natural gas (in which all fixed costs are recovered through the monthly customer charge), is another effective means of removing the utility's disincentive to promote conservation and energy efficiency. However, the increase in fixed charges tends to result in a shift in cost recovery from high-use to low-use customers. This raises potential distributional concerns, which are valid to the extent that low-use customers are more likely to be low-income customers. In addition, while SFV pricing removes the utility's disincentive to promote conservation, it also reduces the customer-level incentive to conserve because of the reduced volumetric rates. In contrast, revenue decoupling has small distributional effects and does not affect the customer-level incentive to conserve (as the Commission rightly pointed out in Order 09-020).

[67] The weather adjustment would have the general form of (using summer as an example):
SNA FCER x {*Weather Sensitivity* (in kWh / CDD) x (*Normal CDD – Actual CDD*)}
In a hot month, the customer's bill would be reduced by the SNA Fixed Charge Energy Rate multiplied by an assumed (or estimated) weather sensitivity parameter, which is the amount by which the customer's sales are expected to change with CDDs, and further multiplied by the difference between normal and actual cooling degree days (CDDs). A key administrative difficulty is determining an appropriate weather sensitivity parameter, which ideally would be specific to each customer.

treated in the current manner). However, we believe that this is best conducted in conjunction with an indexing of the allowed generation and transmission revenue to an index of industry input costs. In our view, status quo is superior to a bifurcation in which allowed generation and transmission revenue is set at a fixed nominal value in between rate cases.

- Do not adjust PGE's allowed return on equity for the presence of decoupling. We do not find evidence that decoupling materially affected PGE's capital risks.[68]

[68] Note that our sample of decoupled utilities included mechanisms that do not remove the effects of weather. Therefore, it is not clear that PGE's allowed ROE ought to be adjusted downward even if our recommendation to remove the weather adjustment from the SNA is adopted. It is possible that an investigation of the Credit Agency Ratings reports for a sample of utilities with "full" decoupling mechanisms would be enlightening in this regard.

CASE: UE 262
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

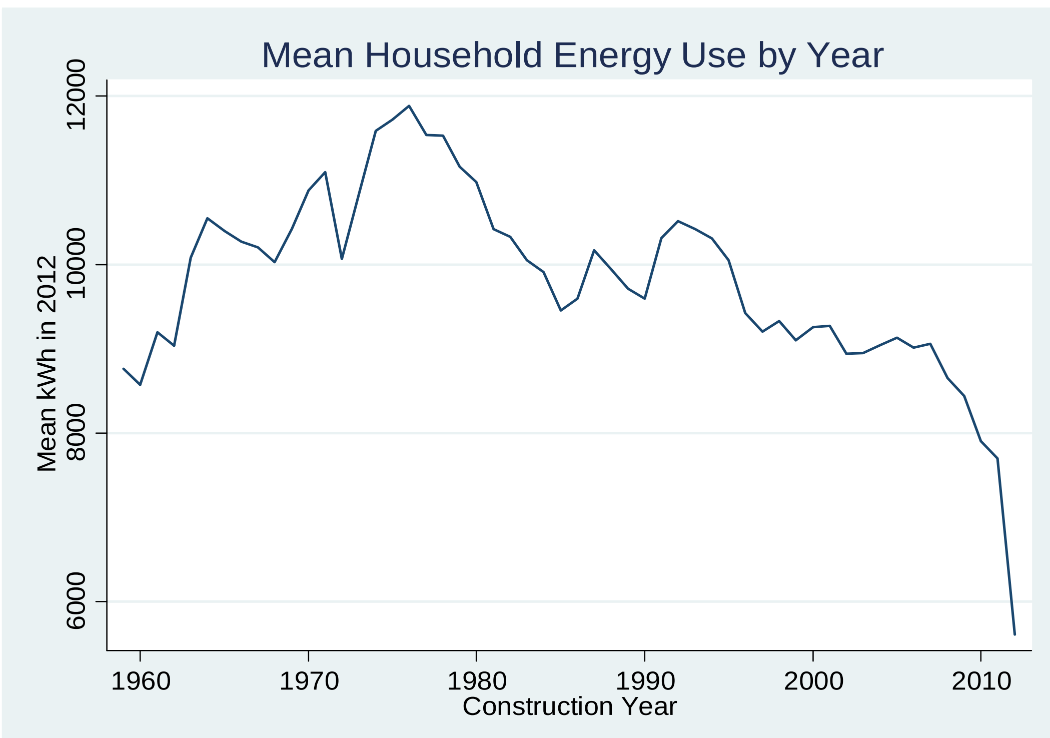
STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 14, 2013

Year of initial connection	Average annualized energy use per account
1959	8765.279
1960	8575.307
1961	9197.233
1962	9037.533
1963	10084.19
1964	10550.33
1965	10400.13
1966	10273.69
1967	10207.51
1968	10028.87
1969	10424.45
1970	10881.42
1971	11099.56
1972	10069.2
1973	10845.91
1974	11591.83
1975	11718.84
1976	11884.59
1977	11539.94
1978	11533.05
1979	11164.48
1980	10978.54
1981	10416.78
1982	10334.24
1983	10051.31
1984	9911.399
1985	9453.327
1986	9593.744
1987	10168.31
1988	9947.373
1989	9712.564
1990	9598.046
1991	10320.52
1992	10517.86
1993	10418.38
1994	10310.32
1995	10052.9
1996	9428.313
1997	9207.797
1998	9330.319
1999	9103.902
2000	9258.722
2001	9273.33

2002	8945.338
2003	8948.561
2004	9047.508
2005	9132.872
2006	9017.908
2007	9056.785
2008	8654.705
2009	8442.755
2010	7903.711
2011	7702.085
2012	5612.185



CERTIFICATE OF SERVICE

UE 262

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 14th day of June, 2013 at Salem, Oregon.

Kay Barnes

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UE 262
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