BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
PORTLAND GENERAL ELECTRIC,	)
Request for a general rate revision.	)

TESTIMONY

OF BOB JENKS ON BEHALF OF THE CITIZENS' UTILITY BOARD

OF OREGON'S APPLICATION FOR RECONSIDERATION OF ORDER

NO. 09-020, SECTION III.B.12. PGE DECOUPLING PROPOSAL

March 23, 2009

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

In January 2009 the Commission entered Order No. 09-020, which contained a provision on decoupling.[1] The provision sets forth a two year decoupling mechanism whereby PGE would be reimbursed by its customers for monies it would have earned if its customers had not effected energy efficiency measures that reduced the company's load.[2] However, the current provision does not differentiate between load reductions that are the result of energy efficiency savings and those that are the result of declining economic conditions.

During the compilation of this docket in the summer and fall of 2008, economic analysts were predicting market corrections of limited proportions. The Commission therefore is unlikely to have given much consideration to the possibility of a massive reduction in customer load due to an economic downturn. Although there was some muted discussion of an impending recession and the associated effects of decoupling, it is

[1] UE 197 Order No. 09-020 Section III.B.12, PGE's Decoupling Proposal
[2] *Ibid.*

clear from the record that none of the parties envisioned the severity of the current economic collapse. Indeed, in its rebuttal testimony, PGE argued against drawing any conclusions from staff's hypothetical example of a recession, because "nothing short of the extraordinary events of 2000-2001 seems consistent with the staff scenario."[3]

Today, economic analysts predict that this recession will be the most severe in the postwar period.[4] and vast amounts of new information are available which evidence that this "recession", "economic downturn", "large scale market correction" – whatever you choose to call it – is having an enormous and devastating effect on PGE's residential, commercial and industrial customers. And now, on top of the already increasing economic burden faced by PGE's customers, Order No. 09-020 will result in additional customer costs. Customers will have to remit payments to PGE of monies related to load reduction due to the economic downturn, because there is no way to distinguish between that load reduction caused by the economic downturn and load reduction caused by customer efficiency measures.

Decoupling was implemented to create better incentives for PGE to improve energy efficiency programs. However, by focusing on the <u>average</u> level of fixed cost recovery per kWh rather than the <u>marginal</u> level of fixed cost recovery per kWh, this decoupling mechanism overcompensates PGE for reductions in load. The result is a bizarre incentive mechanism, whereby PGE's profits increase when customers lose their jobs, small businesses close up shop, and houses remain vacant for months on end. As PGE's customers' economic situation gets more dire, PGE's economic situation improves. This does not represent improved incentives.

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[3] UE 197/PGE/2100/Cavanagh/16
[4] UE 197/CUB/Jenks/303/1

In this testimony, I will address how the current view of the economy differs from the view that existed when this case was developed, how this recession will affect the decoupling mechanism, and how this decoupling mechanism will lead to several years of surcharges. Finally, I will address a series of issues I believe need to be clarified and a list of issues I believe need to be reconsidered in order to insure that customer rates are reasonable in the future.

II. The Implications of the Current Recession on this Decoupling Mechanism

There is little doubt that the state of the economy is very different than we expected when the record of this case was developed. The recession is much worse than expected. The load losses from this recession are much greater than the load losses that could be expected from energy efficiency programs. This situation will lead to large decoupling adjustments that may take years to collect from customers. The result could be similar to the experience of Maine, which abandoned its "failed" decoupling program after the recession in the early 90s.

A. The current recession is much worse than when the UE 197 record was compiled.

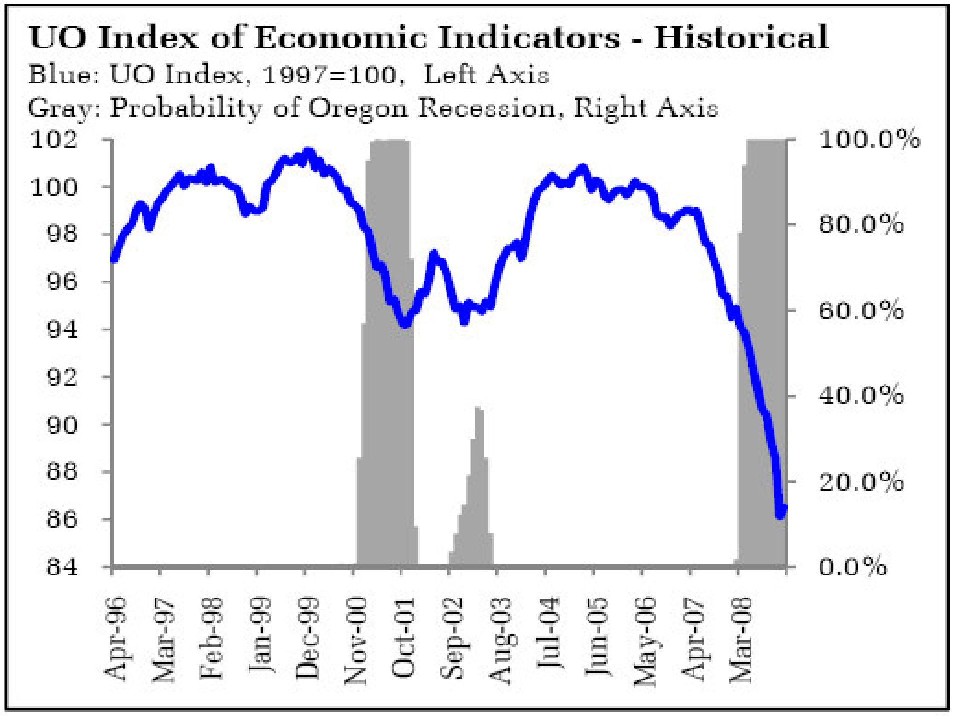
Today the events of 2000-2001 no longer look extraordinary. In fact, the current economic downturn is happening faster than the economic downturn of 2000-2001, is already significantly more severe, and is continuing to worsen.

The unemployment rate in February 2009 reached 11.9% in Oregon (10.8 % seasonally-adjusted). This is significantly higher than the 8.8% unemployment in January

2002, at the end of the last recession. Unemployment has more than doubled from 5.3% to 11.9% in this recession. In the last recession, unemployment started at 4.6% and went to 8.8%. In other words, so far 6.6% of Oregonians have lost their jobs since this recession began, whereas in the last recession, 4.2 % of Oregonians lost their jobs.[5] Furthermore, this recession has not reached it peak, and may well worsen before economic conditions improve.

The University of Oregon publishes an index of economic indicators for Oregon, which shows that the current decline is significantly worse that the "extraordinary" events of 2000-2001. It is clear that the economy is in the tank. Even though the risk of a recession was discussed in UE 197, this recession is already worse than was expected last fall (see State Economist below). The unexpected collapse of the economy requires the clarification of some issues and reconsideration of other issues related to decoupling in UE 197.

[5] Oregon Employment Dept., Oregon Labor Market Information System. http://www.qualityinfo.org/olmisj/AllRates



As we were putting evidence on the record last year, there were some signs of a recession, but few indications that the economy would fall so far or so fast. Even the State Economist of Oregon, Tom Potiowsky, did not predict this. CUB Exhibit 301 shows the forecast of the State Economist last August. This was after CUB placed our final testimony on the record:

> The downturn in Oregon's economy is not expected to grow worse but will continue into 2009, then begin a slow recovery in the second half of next year, state economists said Thursday...State Economist Tom Potiowsky continued to assure lawmakers that this appears to be a shallow recession, unlike earlier turbulence that reduced income taxes by 20 percent and required five special sessions in 2002 for legislators to make enough cuts in programs. Potiowsky also acknowledged, however, that this recession looks as if it will last longer than originally thought. The worst part would end in the first three months of 2009, followed by slow improvement. That means Oregon will see less than 1 percent growth in employment this year and next -- and possibly even overall job losses.

CUB Exhibit 301, Oregon Live, August 28, 2008

In its load forecast, PGE predicted that more than 7,700 new residential customers would be added in 2008 and more than 8,500 in 2009.[6] CUB Exhibit 302 lists the leading Oregon Economic Indicators as compiled by the University of Oregon's Department of Economics. This document shows that new home construction is falling rather than increasing. The number of new residential housing permits was above 2,600 per month in late 2005 and early 2006. This number fell below 1,000 last September and has stayed at that low level since. In January, the number of new residential housing permits was 947, just 36% of the average level three years prior.[7] PGE is unlikely to see the growth in residential load that it has forecast in this case.

In addition, homes currently placed on the market now take an average of 19 months to sell. Having this large of a supply of homes on the market means that we will not see building permits increase in the near future. According to the Portland Housing Blog,[8] homes sales have fallen from 2,600 per month in 2006 to 1,235 in January 2009, and the housing inventory has increased up to 19.2 months:

	Pending Sales	Pending Sales change	Inventory in months	Inventory in months change
Jan-2006	2,601	0%	3.20	0%
Jan-2007	2,544	-2%	6.20	94%
Jan-2008	1,671	-34%	12.80	106%
Jan-2009	1,235	-26%	19.20	50%

Portland Housing Blog[9]

[6] UE 197/PGE/1104/Nguyen/1
[7] UE 197/CUB/301/7
[8] http://oregonhousing.blogspot.com/
[9] http://portlandhousing.blogspot.com/2009/02/jps-market-analysis-january-2009.html

If 1,235 homes are sold per month and we have a 19.2 month supply of homes on the market, then simple arithmetic tells us that 23,712 homes are currently on the market today. Assuming that most of these houses are not occupied, the potential decoupling adjustment associated with these homes would be:

23,712 homes X 19.2 months on the market X $41.38/month decoupling adjustment = ***$18.8 million***

This figure represents the potential statewide decoupling adjustment caused by the collapse of the housing market; it is in no way related to energy efficiency. As the state's largest electric utility and the only one with a decoupling mechanism, it is PGE's residential customers who would bear the brunt of this amount.

B. PGE's 2009 load forecast is highly likely to overestimate demand.

The testimony of PGE's Senior Economist, Ham Nguyen, is presented in this case as Exhibit 1100 and describes the company's load forecast for the 2009 test year. This load forecast did not forecast the current recession. In his testimony, Mr. Nguyen offers the following response to describe the drivers of uncertainty in the model:

> Our model typically performs well over the *sample* period, the span over which we estimate the model, as it captures most, if not all, behaviors and relationships such as economic activities or customer response to price changes on energy use. We expect our model to perform equally well over the forecast period if these relationships remain unchanged or *stable*. If such relationships change in the test year period in response to significant events that were not anticipated or have never occurred over the historical period, our model will become outdated, or in statistical language mis-specified, leading to inaccurate forecasts.[10]

Given that economic conditions are specifically cited as a source of potential uncertainty in the model, CUB must assert that it is highly likely that the 2009 load

[10] UE 197/PGE/1100/Nguyen/11

forecast is mis-specified. First and foremost, this analysis was conducted prior to Mr. Nguyen's testimony on February 27, 2008. As such, PGE used baseline economic forecasts from December 2007 to develop its load forecast. Although these forecasts did provide a modicum of caution in their outlooks, the base cases PGE used provided what now appears to be an overly-optimistic economic outlook for 2009. Specifically, the 2008 Oregon Office of Economic Analysis forecast predicted statewide employment to decrease by only 0.2% in its worst-case scenario.[11] As unemployment in Oregon actually almost doubled in 2008, real-world conditions must certainly be far outside the considerations of any forecast modeling conducted over a year ago. The latest Oregon Office of Economic Analysis (OEA) forecast predicts an employment decline of 4.3% for 2009. This is on top of the employment losses of 2008. The latest OEA Executive Summary is included as Exhibit 303 and can be contrasted with the forecast PGE used to put together its load forecast.

Mr. Nguyen does acknowledge that the economic forecasts issued by Global Insight and OEA were revised downward in February 2008 in recognition of deteriorating economic conditions.[12] However, these forecasts only called for a recession in the first 6 months of 2008. This analysis can be contrasted with Global Insight's year-end review of its 2008 predictions, in which the firm admits its GDP growth estimates for the year were overly optimistic, and that its predictions for a housing rebound were premature.[13] Furthermore, Global Insight's 2009 analysis predicts the current recession being the

[11] UE 197/PGE/1100/Nguyen/12
[12] UE 197/PGE/1100/Nguyen/13
[13] UE 197/CUB/302/7

deepest in over sixty years.[14] Each of these factors indicates that the economic conditions contained in PGE's load forecast model are thoroughly outdated.

C. The current recession will create a decoupling adjustment that is greater than the energy efficiency adjustment discussed in this case.

In its opening brief, PGE summarized the way decoupling works:

> PGE's decoupling proposal is a simple balancing account and rate adjustment process that diminishes the disincentives PGE faces when seeking to support and encourage energy efficiency programs (PGE/100, Piro/20.) Like most utilities, PGE currently recovers most of its fixed costs through the rates it charges on a per-kilowatt-hour basis. (PGE/2100, Cavanagh/6.) A portion of the cost of every kwh represents PGE's fixed costs, while the rest of the charge per kwh reflects variable costs of producing that kilowatt hour. (*Id.*) The Commission sets rates based on load forecasts. If actual sales lag below the load forecasts, PGE will not recover its approved fixed cost revenue requirement. On the other hand, if loads are higher than expected, shareholders earn a windfall by recovering more than the approved revenue requirement amount. In either event, every reduction in energy sales from efficiency improvements results in a reduction in cost recovery, thereby reducing earnings. (*Id. at* 5-6.)

UE 197/PGE Brief, page 45

Order 09-020 agrees with PGE that the purpose of adopting decoupling is to create "appropriate incentives" for the company as it relates to energy efficiency and distributed generation. The problem is that decoupling is a blunt instrument that adjusts rates for changes in load as compared to the company's load forecast, without determining the cause of that reduction. So, while decoupling does compensate the utility for changes in load due to energy efficiency improvements, it also compensates the utility for changes in load due to reduced economic output (*i.e.*, a recession).

One problem with decoupling is that while it is designed to "fairly" compensate the company for reductions in load due to energy efficiency, changes in load due to a

[14] UE 197/CUB/303/1

recession can be much greater. A mechanism that is expected to cause small changes in rates to compensate for the small changes in load due to efficiency can cause significant changes in rates when a recession hits. This is what destroyed decoupling in Maine – the concept was so tarnished in the recession of the 1990s that it has never been utilized to deal with actual changes in loads resulting from energy efficiency.

i. PGE's testimony considered energy usage reductions of 0.5% to 1% of load.

PGE testified in this case that in the absence of decoupling the company could lose money if customers conserve energy. In PGE/100, Mr. Piro testified that if residential customers cut their loads by 0.5%, the company would lose $2 million in fixed cost recovery in the first year.[15] In rebuttal testimony, PGE's witness, Mr. Cavanagh, ups the ante and discusses the impact on PGE if customers reduce usage by 1% per year. The company would lose $4 million the first year, and the cumulative effect over 5 years would be $60 million.[16] Of course, even Mr. Cavanagh admits that the company can remedy much of this shortfall by filing a rate case and updating its load forecasts.[17]

While claiming the risk to the company was large, Mr. Cavanagh attempts to minimize the risk to customers by pointing out that the rate impacts from PacifiCorp's decoupling in the late 1990s was relatively small.[18] Of course, the small impacts on customers were because the changes in load were tiny. Just as importantly, PacifiCorp's experience with decoupling in the 1990s did not lead to any additional investment in energy efficiency.[19] While Mr. Cavanagh's point about small rate impacts is true, he is

[15] UE 197/PGE/Piro/100/19.
[16] UE 197/PGE/2100/Cavanagh/7.
[17] UE 197/PGE/2100/Cavanagh/8
[18] UE 197/PGE/2100/Cavanagh/9
[19] UE 197/CUB/100/Jenks/46 and UE 197/PGE/2100/Cavanagh/23

pointing at a decoupling experiment that, from an energy efficiency standpoint, must be considered a failure.

Even though the record in this case is filled with these exaggerated predictions of losses to the company if we fail to implement decoupling, there is very little on the record that analyzes the potential cost to customers if we have decoupling during a recession. In Maine, Central Maine Power – a utility that is smaller than PGE – ran up a $52 million decoupling charge to customers in 2 years.[20]

ii. The loss of load due to a recession is greater than 0.5% to 1.0%.

This is the big problem with decoupling: the effects of recessions on the mechanism are greater than those of energy efficiency. While PGE cites the potential of energy efficiency to reduce loads by 0.5% to 1.0%, we know from experience that the loss of load due to a recession is greater. According to PGE's 2002 Annual Report, "retail energy sales in 2002 were approximately 8% lower than levels used in the Company's general rate case implemented in the fourth quarter of 2001",[21] and according to PGE's 2003 Annual Report, "although Oregon's economy [was] improving, retail energy sales in 2003 remained approximately 8% lower than projected in the Company's rate case".[22]

From PGE Exhibit 1208, we can calculate the decoupling effect of a similar reduction in commercial load. From that exhibit we know that PGE forecasts 1.5 million MWh from Schedule 32 customers. An 8% reduction in load for two years would lead to a decoupling adjustment of $10 million for those two years. Because the 2% rate cap for

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[20] UE 197/CUB/305/Jenks/13
[21] PGE Annual Report, Form 10-K for year ending 12/31/2002
[22] PGE Annual Report, Form 10-K for year ending 12/31/2003

decoupling adjustments for schedule 32 customers is $3 million, the first two years of decoupling would result in more than 3 years worth of maximum charges to customers.[23]

Recessions have an outsized impact on decoupling adjustments because economic activity uses electricity, and when a recession causes economic activity to decline, use of electricity also declines. Thousands of Oregonians have lost their jobs during this recession. The electricity that they consumed at work will not be used, and PGE gets to charge other customers about 42% of the retail price of that "lost" sales.[24] If a business responds to the recession by reducing its retail hours, its electric usage will also be reduced, leaving other customers to be charged for about 42% its electric bill while it is closed. When business or government offices reduce their days of operation, other customers have to pay for 42% of the cost of PGE's "lost" sale. When a business property is vacant, except for lighting for security purposes, other customers will pay 42% of the electricity that would have been used if the property were fully occupied.

D. This recession will lead to a decoupling rate adjustment that could last several years.

According to PGE annual reports for the years 2002 and 2003, PGE's load declined by 8% for each of the two years during the 2001-02 recession.[25] We know that unemployment is already worse than the previous recession and continues to increase. Every economic indicator that we know of shows that this recession is going to be

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[23] UE 197/CUB/304/Jenks/1

[24] PGE/197/1208/1 shows 1494.25 kwh/month for average Sch. 32 customer. Based on PGE Schedule 32, this usage would translated into a bill of $151.24 for single phase service. Schedule 123 lists the decoupling fixed cost recovery amount as $63.47/month for Sch. 32. 63.47 is 42% of 151.24.

[25] PGE Annual Report, Form 10-K for year ending 12/31/2002 and PGE Annual Report, Form 10-K for year ending 12/31/2003

significantly worse than 2001-02. If the commercial load reduction caused by the recession is 10% instead of 8%, then the 2 year decoupling debt that customers will owe the utility will be $12.6 million. If the load reduction caused by the recession is 12%, then the debt that customers owe the utility will be more than $15 million.[26]

Under the decoupling mechanism approved by the Commission in Order No. 09-020, the money in excess of the 2% annual cap is allowed to roll over into future years, potentially leading to many years of surcharges. If Schedule 32 sees a decline in load of 12% (150% of the level of the most recent, less-severe recession), then those customers will incur 5 years of maximum surcharges.[27]

While residential load may not fall as sharply as commercial load, this recession has affected new home building permits and sales of existing homes. In addition, consumer spending has fallen sharply, which means that consumers are not buying plasma televisions and other new items that should have been reflected in PGE's load forecast. These factors should lead to residential load being less than forecast. If the load is down 5%, the decoupling adjustment would be $38 million for the two year decoupling period. With the residential 2% rate cap forecasted to be $17 million/year, a 5% reduction in residential load would lead to a rate hike that is in excess of the rate cap, and would therefore need to be rolled over into future years. Of course, if the residential load reduction is larger, the amount of the decoupling adjustment could also be greater.[28]

E. The Maine experience.

This recession is severe. It is worse than the 2001-02 recession. It is very plausible that Oregon, like Maine, will find that 2 years of decoupling will build up an

[26] UE 197/CUB/304/Jenks/1
[27] *Ibid.*
[28] UE 197/CUB/304/Jenks/1

adjustment that will take several years to pay off. In two years, Oregon may be in the same position as Maine in 1993: considering whether to renew decoupling while its ratepayers owe the decoupled utility millions of dollars associated with an economic downturn, not with energy efficiency. As in Maine, Oregon customers can be expected to oppose renewing decoupling when they owe the utility tens of millions of dollars. Also like Maine, Oregon may declare this decoupling experiment a failure and regulators, utilities and customers will lose decoupling as a mechanism that might help energy efficiency during normal economic conditions.

The experience of Maine with decoupling should give us pause to consider the implications of the current economic recession as it relates to decoupling. Maine implemented decoupling in the early 1990s on a three year trial basis.[29] At the end of the first two years of decoupling, customers owed Central Maine Power more than $52 million.[30] This experience suggests that it is unwise to simply wait and see what happens until the end of our two-year trial. Instead, we should consider the implications of the recession on decoupling today.

CUB Exhibit 305 is a recently-authored report on Maine's decoupling experiment. This report discussed the experience from the 1990s:

> **MAINE'S EXPERIENCE WITH REVENUE DECOUPLING**
>
> As mentioned above, Maine has experience with revenue decoupling that is generally considered a failure. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling mechanism for CMP (referred to as "Electric Revenue Adjustment Mechanism" or "ERAM"). The "allowed" revenue was determined in a traditional rate case proceeding and adjusted annually based on changes in the utility's number of customers (as a result the mechanism was also referred to as "ERAM per customer"). Analyses before the Commission at the time

[29] UE 197/CUB/305/Jenks/13
[30] *Ibid.*

> indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP's ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its "allowed" revenues.
>
> CMP's ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was experiencing the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October 1991 that would have increased rates at the time, and resulted in lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.
>
> By the end of 1992, CMP's ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.
>
> Maine's experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties.[31]

III. Issues that Need to Be Clarified.

The size of the loss of load due to the economic recession and the size of the likely surcharges due to decoupling are greater than was anticipated in this case and raise a number of new issues which should be clarified.

A. Definition of an "active customer".

The record in this docket as it pertains to decoupling is somewhat confusing. While PGE often theorized about "if actual sales fall below load forecast,"[32] and included an example based on a true up to the total Residential and Small Commercial load

[31] UE 197/CUB/305/Jenks/12-13
[32] UE 197, PGE Opening Brief, page 45.

forecast used in this case[33], this example is not how the decoupling mechanism will work. The mechanism is designed to identify the difference between forecasted load per customer and actual load per customer and use this difference to true up the forecasted fixed costs. The decoupling mechanism does not attempt to true up costs, but instead trues up load per customer and multiplies this figure by the forecasted fixed costs.

The mechanism is concerned with the forecasted versus actual load per customer. The Company continues to risk forecasting a higher number of customers than may exist in a given period.[34] In his PGE-sponsored testimony, Mr. Cavanagh notes that a recession "would be likely to affect customer growth along with usage per customer"[35] and that the customer growth risk remains with the Company. We therefore know that PGE assumes the risk that its actual number of customers is different than what was forecast. The decoupling adjustment schedule, Schedule 123, is consistent with this assumption. It is not based on a true-up to the forecasted number of customers, but instead is based on the number of "active customers." However, the schedule does not define this term, and we cannot find a definition in the record of this case.

i. Active residential customer.

PGE states in its load forecast that residential customers "are most households, but also include dwellings that PGE has connected for electrical service but are not yet occupied.[36] Given the current average 19.2 months that new homes are on the market before being occupied, defining new homes as active customers results in a $794.50

[33] UE 197/PGE/Exhibit 1208
[34] UE 197/PGE/100/
[35] UW 197/PGE/2100/16
[36] UE 197/PGE/1100/6

surcharge levied on other residential customers before each new home is occupied.[37] For every 1,250 unoccupied homes in PGE's service territory that the company has connected, PGE's residential customers will incur approximate $1 million in charges related to decoupling.[38] While realty companies might have the power turned on in order to show houses to prospective buyers, this usage is minimal, as the homes are not occupied by residential customers. As stated above, statewide the decoupling adjustment associated with homes that are on the market could be as high as $18 million. But are vacant homes that have reduced usage considered to be "active customers"? Further, is their reduced usage eligible for a decoupling adjustment even though the reduction is caused by the collapsed housing market leaving house unoccupied, not energy efficiency programs?

PGE defines residential customers in load forecast conflicts pursuant to the definition in ORS 757.600(28), which states:

> (28) "Residential electricity consumer" means an electricity consumer who resides at a dwelling primarily used for residential purposes. "Residential electricity consumer" does not include retail electricity consumers in a dwelling typically used for residency periods of less than 30 days, including hotels, motels, camps, lodges and clubs. As used in this subsection, "dwelling" includes but is not limited to single family dwellings, separately metered apartments, adult foster homes, manufactured dwellings, recreational vehicles and floating homes. [emphasis added]

While this statute is the direct access law that determines which customers are guaranteed cost-based rates (among other options), it does require that a consumer "reside" at the dwelling. Houses that are connected for electrical service but are not yet occupied are not residential customers; no one resides there.

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[37] 19.2 months times $41.38 surcharge per month.
[38] 1250 homes times $794.5/home

This is not a small issue. PGE projected 15,000 new residential customers in this docket. In a deepening recession, it is likely that customer growth will fall well short of this number. Due to the length of time that homes are on the market, it seems likely that new homes have been built in excess of the supply of new customers. In addition, as we cited above, Oregon currently has an inventory of 23,712 houses waiting to be sold and occupied. Both Mr. Piro and Mr. Cavanagh suggest that PGE continues to take the risk as to the number of customers, but because they do not define active customer, it is unclear whether they really mean the number of residential customers or the number of dwellings.

A similar issue exists on the on other side of the ledger. Are houses that have their electricity shut off counted as customers? Surely PGE does not count as an active customer someone who has had their electricity shut off for non-payment. Requiring other customers to subsidize 49% of the electricity to a house after it is shut off makes little sense.[39] If we are to subsidize people's electric bills, does it not make more sense to subsidize them before they are shut off?

ii. Active small business customer.

Defining who is considered an active customer is also important on the commercial side. We all know of local businesses that have recently closed their doors and stopped serving customers. Is a restaurant that is closed 24 hours per day, 7 days per week, an "active customer"? In many cases, commercial customers are renters and do not own their property. Property owners may well want to keep some level of power on in

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[39] PGE Exhibit 1208 shows residential month average usage of 897 kWh. PGE's residential tariff (Schedule 7) produces a bill of 85.4 for this usage. Schedule 123 has a residential decoupling charge of $41.38 customer/month which is 49% of this average bill.

order to show the property or for security purposes, but the usage at an unoccupied property is minimal.

If closed businesses are defined as "active customers", then decoupling adjustments will certainly be larger. Each business that is closed will require a decoupling adjustment amounting to approximately 42% of the bill that the customer would have paid if it had not gone out of business. This again raises the issue of appropriateness: wouldn't it make more sense to subsidize the bill of a customer before they closed down and laid off their workforce?

Even if decoupling adjustments are restricted to only those businesses that have not closed, customers are going to pay heavily for this economic downturn. When a business lays off an employee, the decrease in the demand for electricity associated with that employee will lead to a decoupling adjustment. Likewise, if a business reduces its hours, there will be a decoupling adjustment associated with this reduction.

In their testimony, PGE witnesses Jim Piro and Ralph Cavanagh both state that PGE assumes the risk related to its customer forecasts.[40] However, they did not say what mechanism was used to identify the number of active customers. This forecast mechanism is very important, as it will largely determine whether customers are assuming nearly all the risk of an economic downturn, or the risk is jointly assumed by customers and the Company.

B. ORS 757.355 (presently used) is implicated in decoupling

ORS 757.355 codifies the "used and useful" standard:

> a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs

[40] UE 197/PGE/2100/Cavanagh/16 and UE 197/PGE/100/23

> of construction, building, installation or real or personal property not presently used for providing utility service to the customer.

This statue was amended to deal with property that was retired in the public interest before its rate base was fully recovered. However, the law does apply to investment in utility rate base that have yet to be used for providing utility service to the customer.

PGE defines a new home as a customer when it is hooked up to the grid, even if the home is vacant. This definition is not consistent with this law. The rate base associated with the transformer, the line drop and other elements of the distribution system cannot be considered as "presently used to serve customers" if no customer dwells at the house.

Under normal ratemaking rules, this is not an issue. While the utility may forecast an investment into ratebase, it also forecasts customer growth into its revenue. If the home remains unoccupied, while the utility may have added it to its forecasted rate base, there is no customer at that house being charged for that rate base. Decoupling can change this situation if we define an empty dwelling as a customer. The rate base associated with the vacant house would then be folded into the decoupling adjustment, and other customers would be charged for this ratebase even though Oregon law prohibits charging for rate base not presently used to serve customers.

C. How decoupling adjustments should be spread across customer classes.

PGE does not seem to address how the decoupling adjustments will be spread across customer classes. Mr. Cavanagh uses the PacifiCorp example from the 1990s to show that the rate impact will be minimal on each class of customers, but does not state whether PGE is proposing the same approach.

Because the bulk of the fixed costs relate to the distribution system that is assigned and dedicated to particular customer classes, we assume that the decoupling adjustments will be assigned to the customer class that causes the adjustment.[41] This particularly makes sense if the adjustment is caused by energy efficiency. If the utility collects its fixed costs through fixed cost charges, then the cost will be recovered from the class to which it is assigned. If the customer class reduces its usage, the fixed costs do not change and continue to be collected from that class. Decoupling should maintain this class assignment of costs.

This is exactly how the PacifiCorp decoupling that PGE cites worked.[42] Usage per customer was tracked for several customer classes, and the costs were then recovered from the customer class whose load was different than the forecast. We know of no good reason why this practice should be changed. Residential customers are obviously the largest class that is decoupled, and we do not want residential ratepayers to become the deep pockets who bail out other classes of customers when their loads are lower than forecast. To do so would place an addition risk on residential customers and make it less likely that CUB will support decoupling in the future.

D. How the ROE reduction implicates PGE's PCAM.

In Order No 09-020, the Commission required PGE to reduce its ROE by 10 basis points or $1.9 million.[43] The order directed PGE to defer this reduction until it could be placed into permanent rates. PGE's application to defer the $1.9 million listed the

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[41] UE 197/PGE/1208.
[42] PUC Order 98-191
[43] UE 197 Order No. 09-020 entered January 22, 2009 at Section III., Subsection 12 PGE's Decoupling Proposal, Resolution subsection (c), page 29; and PGE's Application for Deferral of Revenues Associated With ROE Refund and Sales Normalization Adjustment and Lost Revenue Recovery at page 3, filed January 30, 2009. .

deferral as commencing on February 1, 2009. However, neither that application nor Order No. 09-020 states whether the ROE used for the PCAM adjustment is the ROE that is currently in base rates or a combination of the ROE in base rates adjusted by this deferral. With decoupling in place during 2009 and the Company set to receive a tremendous benefit from the associated shift in risk caused by decoupling, PGE's ROE for the 2009 PCAM should reflect the ROE adjustment from Order No 09-020. The PUC should clarify this so PGE does not later claim that the PCAM is based on the ROE in base rates.

IV. Issues that Need Reconsideration

A. Consider whether the 2% cap should be a hard or soft cap on decoupling adjustments.

Decoupling died in Maine because after 2 years of decoupling during a recession customers owed the utility $52 million.[44] Oregon seems to be heading down the same path as Maine by implementing decoupling during a recession. The only protection customers have is the 2% cap, which PGE compares to a circuit breaker.[45] But of course, the 2% cap does not act as a circuit breaker. A real circuit breaker trips and stops the flow of electricity, while this decoupling "circuit breaker" does nothing to stop the flow of dollars. Instead, this "circuit breaker" allows customers to pay decoupling debt over time, but does nothing to stop the flow of dollars that customers owe PGE. Rather than see this as a circuit breaker, it is more accurate to view it as an installment loan.

The cap for Schedule 32 is approximately $3 million/year. The cap for Schedule 7 is approximately $16 million/year, bringing the total cap to $19 million/year, or $38

[44] UE 197/CUB/307/Jenks/13
[45] UE 197/Kuns-Cody/1200/29

million dollars for the two year decoupling period.[46] But if the decoupling adjustment is larger than these amounts, we simply roll over the additional amounts with interest to future years. CUB is concerned that we will go over these amounts. Consider that:

- A smaller utility in Maine accumulated $52 million in 2 years.[47]
- If commercial load falls in a manner that is similar to the 2001-02 recession, then that will exceed the Schedule 32 cap.[48]
- If residential load falls by 5%, the decoupling adjustmet will exceed the cap.[49]
- Statewide vacant housing due to the collapse of the housing market would require an $18.8 million adjustment.[50]

When decoupling comes up for review two years from now, there is a good likelihood that customers will owe the utility more in a decoupling adjustment than the cap will allow in a single year, requiring that the excess amount be rolled over for an additional year or years. This situation will complicate the review of decoupling. Customers will likely oppose renewal until the debt from the first decoupling period has been paid off.

An easy way to improve the decoupling proposal is to implement a hard cap, which would act as a real circuit breaker. Under a hard cap, PGE could earn a decoupling adjustment of up to 2%, with no additional costs placed on customers. Under such a cap, PGE would still have the potential to collect $38 million from customers, in exchange for

[46] UE 197/CUB/304/Jenks/1
[47] UE 197/CUB/307/Jenks/13
[48] UE 197/CUB/304/Jenks/1
[49] UE 197/CUB/304/Jenks/1
[50] UE 197/CUB/301/Jenks/9

a reduction in ROE of $ 3.8 million with this 2 year decoupling pilot. This nets out to a $34 million benefit to the company, which could be considered a very generous windfall.

Of course, PGE will oppose making this cap a hard cap. The Company will argue that customers are unlikely to go over the cap and that this is just allowing them to recover their actual fixed costs (which they could do by filing a rate case with an updated load forecast). However, if the adjustment is less than the cap, then there is no danger in making the caps real and hard. By opposing hard caps, PGE demonstrates that there is a significant risk that the amount of charges to customers could be greater than the caps. PGE would rather get its money, even if this practice threatens the viability of decoupling over time.

As to the other argument that these are fixed costs that the company is allowed to recover, we must disagree. First, as we will show below, by using the average fixed cost per kWh rather than the marginal fixed cost per kWh, customers are overpaying PGE for its fixed costs. Second, while rate regulation provides PGE with the opportunity to recover its costs, regulation does not guarantee such recovery. PGE is paid a healthy ROE (10%) on its investment in fixed capital assets. This amount is to compensate the Company for the risks associated with this recovery. For the distribution assets which make up most of this decoupling mechanism, the primary risks to recovery are the effects of weather and the economy on the Company's load forecast. Removing the economic risk moves the Company a long way towards guaranteed full recovery of its capital investment. Of course, under those circumstances, a 10% ROE is not appropriate.

CUB believes that the risk reduction to PGE associated with decoupling is much greater (especially during a recession) than the 10 basis points reduction in ROE that the

Commission ordered. This notion should become clearer as customers are facing tens of millions of dollars in decoupling adjustments, while the Company is facing less than $4 million in reduced ROE.

Even with a hard cap, this decoupling mechanism is out-of-whack. With a hard cap, the net cost to customers could approach $34 million. The fact that CUB is asking the Commission to make the cap hard and limit customers' liability to $34 million reflects our view of how this recession will affect decoupling. Making customers – many of who have lost their jobs and seen their retirement savings plummet – pay an additional $34 million with no guarantee of improved energy efficiency (beyond the elasticity of demand associated with higher rates) is unfair. However, a hard cap would implement a firm limit, and paying $34 million does beat having to pay $50 million, $60 million or some higher amount.

B. Consider whether decoupling should be based on average fixed costs per kWh or marginal fixed cost per kWh.

For residential customers, PGE's decoupling mechanism compares two figures: the amount of fixed costs (distribution, transmission and fixed generation) forecasted to be recovered from a customer at a rate of 4.646 cents/kWh, with a monthly fixed cost forecasted to be $41.38/month per customer. The problem with this structure is that 4.646 cents/kWh represents the average amount of forecasted fixed costs recovered per kWh, but does not necessarily reflect actual fixed costs recovered for any particular load reduction or load increase.

This structure assumes that PGE recovers its fixed costs equally across all kWh of electricity purchased by a customer; that assumption is false. PGE has a stack of resources with widely varying costs, and these are dispatched hierarchically, using the lowest-cost resource first. Hydro and wind resources have little variable cost, so when these resources are consumed, nearly all of the customer revenue goes to fixed cost recovery. Market purchases can be priced near the retail rate, in which case very little of the revenue from these sales goes to fixed costs. If all kWh of demand were met with a blend of all the company's resources, PGE's approach would be reasonable, but this is not the way PGE runs its system.

i. What effect does a 1% loss of residential load have on costs?

A 1% loss of residential load would reduce PGE's variable costs. As we have said, hydro and wind have little variable costs, but hydro and wind would not be affected by a loss in load. The production of hydro, wind, coal and any other resource whose variable cost is less than the market price would be unaffected by a loss of load. Even when customers do not need base load power, its variable cost is less than the market price, meaning that PGE would continue to operate the plant and sell the power on the market. For example, assume that the market price is 7 cents/kWh, and the variable cost of a gas CCT is 6 cents/kWh. If PGE was able to respond to the loss of load entirely through reducing market purchases, it would reduce its costs by 7 cents/kWh. If the Company was able to respond to the loss of load by the use of its gas CCT, production at that plant would not stop because the excess power can be sold on the market. Therefore, PGE's costs do not fall, but the Company receives an additional 7 cents/kWh for selling that power to the market. If this expense is netted against variable power costs, the effect is the same as if the Company's costs decline by 7 cents/kWh.

Because decoupling is based on forecasted costs, we could use confidential information from PGE's power cost filing to calculate the market price that the Company forecast it would save if customers reduce their usage. However, using confidential information will make it difficult to discuss the problems with this decoupling mechanism with members of the public. We have therefore decided to use more generic data to demonstrate our concerns. For the purposes of this example, we will assume an average market price of 7 cents/kWh. At this price, a 1% reduction in residential load would cause PGE's costs to decline by 77 million kWh times 7 cents/kWh, or $5.39 million. Using Schedule 7[51], we can calculate the lost revenues resulting from a 1% residential load reduction to be $7.7 million,[52] so the net loss to PGE from a 1% residential load reduction is $2.31 million.

Under the decoupling implemented in Schedule 123, PGE's decoupling adjustment would be 77 million kWh times 4.646 cents/kWh, or $3.58 million. In this example, reduced load due to energy efficiency would reduce PGE's net income by $2.31 million, but the Company would be allowed to surcharge customers $3.58 million. PGE would recover 155% of its losses in this scenario.

PGE will likely argue that we are inflating this by using 7 cents/kWh to calculate the market price of power, when today the price is lower than that amount. But the decoupling mechanism is dealing with forecasted costs, not actual costs. While market prices are less than PGE forecasted in this case, the PCAM is the mechanism that is designed to deal with the difference between forecasted and actual power costs. The decoupling mechanism uses forecasted costs and updates for actual load/customer.

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[51] UE 197/PGE/1208
[52] 77 million kwh times 10.008 cents/kwh.

In UE 115 PGE forecasted market prices that were as high as or higher than their retail rates.[53] If market prices are greater than retail rates, and customers conserve energy, then PGE can sell the power that it would have sold to retail customers to the higher-price wholesale market, increasing the return to its shareholders. Under the decoupling mechanism approved in Order 09-020, in addition to profits from the wholesale sales, the Company would charge customers an additional surcharge as a decoupling adjustment.

ii. PGE should be required to model what a 1% loss of load will cost.

We believe it is poor policy to assume that a loss of load will affect fixed cost recovery at 4.646 cents/kWh. This assumption is based on using the average forecasted fixed cost revenue per kWh. But as we have shown here, the amount of forecasted fixed cost revenue varies depending on the cost of the power that is being purchased or sold. We believe that a better approach is to assume that the fixed cost revenue recovery is what is left after the variable component of the lost load is valued at forecasted market prices.

There is a good way to test this assumption. PGE should forecast a reduction in its residential load of 1%. This reduced load would be run through PGE's load shape model and then Monet to determine how much its costs would decline with this load reduction, employing all the same assumptions for power costs that were used in this filing. The amount of fixed cost revenue that the Company loses can then be determined by calculating the revenue reduction due to the lost load and comparing that to the cost reduction that comes out of Monet. The net of these two numbers represents the projected loss of fixed cost revenue.

[53] UE 115/PGE/302/Pollock-Huntsinger/22

iii. PGE will likely argue that the PCA deals with power costs changes, so we don't have to address them here.

PGE will likely argue that CUB is proposing to bring changes in power costs into decoupling, and that these changes would be more appropriately addressed in the PCA. That is not what we are attempting to do. For the purposes of decoupling, we do not care whether power costs are higher, lower or the same as forecast. The PCA is set up to compare actual costs to projected power costs.

What we are concerned with here is the change in fixed cost recovery due to changes in load. To determine this we have to identify the fixed cost revenue per kWh on the margin that is built into our rates. In the most recent rate case, PGE did not actually forecast that it would collect 4.646 cents/kWh of fixed cost recovery for the first kWh it sold and for the last kWh it sold; the Company projected an average of 4.646 cents/kWh. This tells us little about fixed cost recovery on the margin. Even if power costs stay exactly where they were, the forecast marginal fixed cost recovery is not the same as the average fixed cost recovery.

iv. The consequences of miscalculating.

The consequence of getting these calculations wrong and not using marginal fixed cost recovery is that customers will be overpaying PGE. Customers pay the Company more than its net loss. The decoupling mechanism was supposed to get rid of a disincentive to improve energy efficiency, but has gone far beyond simply removing this disincentive.

This, in itself, creates some other incentives. If PGE gets overpaid for load reductions, then the Company will find a closed business to be a more profitable source of revenue than an open business. When an employee of a PGE customer gets laid off, PGE's profits will increase because the electricity that employee is no longer using will show up to PGE as conservation. If the Commission allows decoupling to apply to vacant houses, then a house that is vacant will be more profitable to the Company than a house that is occupied. In other words, PGE's incentives now run counter to the overall good of Oregon and our economy. This is not the right incentive.

C. Consider the benefits of implementing decoupling in the current economic circumstances or whether it will eliminate a potential tool for the Commission.

It should be noted that decoupling an electric utility is different than decoupling a gas utility. The impact of decoupling during an economic recession is much more severe for an electric utility. As cited earlier, tens of thousands of Oregonians have lost their jobs in the last few months. Nearly every one of these people used electricity as part of their job, in the form of lighting, computing, heating, etc. The falling electric consumption of employers results in a decoupling adjustment. On the natural gas side, many employees have no incremental impact on their business's use of natural gas, and therefore their job losses do not translate into automatic decoupling adjustments.

For this reason, Oregon should recognize that electricity decoupling requires a different approach. The PUC should consider a policy that allows the Commission to suspend decoupling for electric utilities when there is a severe economic recession. The purpose of decoupling is to make it easier for utilities to implement energy efficiency under more normal circumstances. Decoupling could be preserved during "normal" circumstances, while at the same time recognizing that electric decoupling should be suspended when energy efficiency benefits are overwhelmed by economic troubles.

i. Decoupling itself should be subject to a cost-effectiveness test.

It is clear from PGE's testimony and from the PUC order adopting it that decoupling serves a single purpose: removing the disincentive that PGE has to improve energy efficiency and conservation:

> PGE currently recovers most of its fixed costs through rate charged on a per-kilowatt-hour (kWh) basis. PGE asserts that reduced energy sales from efficiency and conservation result in reduced fixed cost recovery and earnings and therefore that there is a disincentive for the Company to promote demand-side management programs.

Order 09-020, page 26.

As a program that is designed to encourage conservation, decoupling should be subject to a cost-effectiveness test similar to other conservation programs. When PGE requested the ability to hire new employees to encourage customers to take advantage of Energy Trust programs, CUB and the Commission Staff demanded that the company demonstrate that the cost of these employees be lower than the energy efficiency savings they produced.[54] The cost of decoupling should also be subject to a similar test. According to PGE witness, Mr. Cavanagh,

> CUB makes the point forcefully that decoupling should result in demonstrated benefits to customers in the form of cost-effective energy efficiency results, and I agree.

PGE/2100/13

While Mr. Cavanagh refers to "cost-effective" energy efficiency, it is not clear whether he thinks that the costs of implementing decoupling should be included in this cost effectiveness evaluation. Because the energy efficiency he cites is both the purpose for decoupling and the "result" of decoupling, implementation costs of decoupling should also be included in this evaluation.

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[54] PGE Schedule 109 and 110.

As we have discussed above, this decoupling mechanism may cost residential and small commercial customers tens of millions of dollars. Customers and regulators should care whether the benefits of decoupling are worth the costs. This can best be determined by including the cost of decoupling into the cost-effectiveness evaluation of the energy efficiency gains that are the objective of the decoupling program.

D. Consider suspending decoupling if it is not expected to be cost-effective.

We suspect that PGE, Mr. Cavanagh, and other decoupling proponents will oppose the idea of requiring a cost-effectiveness test for this two year decoupling period. Proponents know that the decoupling adjustment associated with the recession will be too much to overcome, and decoupling will therefore not result in enough energy efficiency savings to justify its cost. If that is the case, however, the solution is simple: decoupling should be suspended until the economy has improved to the point that it can be cost-effective again. This is a reasonable expectation, and one that merits a reconsideration of the Commission's decision.

V. Conclusion.

Based upon all of the evidence and examples above, CUB respectfully makes Application for Reconsideration of Order No. 09-020, Section III.B.12, PGE's Decoupling Proposal, pursuant to ORS 756.561 and OAR 860-014-0095(3)(a) and (d), upon the grounds that new evidence that was unavailable and not reasonably discoverable before issuance of the order has come to light. There is good cause for further examination of this evidence, which was essential to the original decision.[55] CUB

[55] OAR 860-014-0095(3)(a) and (d).

respectfully requests that the Commission reverse, change or modify[56] Order No. 09-020 so as to prevent PGE from receiving a massive financial windfall at the expense of residential and small business customers under the decoupling mechanism contained in the Order. As explained above, this request is made because PGE is experiencing a significant reduction in its demand load due to the current economic downturn, rather than due to any voluntary efficiency measures taken by residential and other customers of the utility. As currently set up, the decoupling mechanism cannot distinguish between load reductions due to the economic downturn as opposed to load reductions actually due to customer voluntary efficiencies.

We make this request as a party that has historically supported decoupling and other programs designed to promote energy efficiency. However, the decoupling we supported in the 1990s did not achieve any results with regards to increasing energy efficiency. The decoupling we supported with Oregon's natural gas utilities did achieve energy efficiency savings, but the programs were directly tied to commitments from the utilities to invest in energy efficiency.

In this case, we have the following concerns that the harm caused to customers by decoupling will outweighs the benefits:

i. The decoupling adjustment is not tied to new energy efficiency programs.
ii. The adjustment is expected to result in a massive cost to customers due to the current economic decline.
iii. The program it is designed to overpay PGE by using average fixed costs rather than marginal fixed costs.

[56] ORS 756.561(3)

We would like to support a decoupling plan for PGE in the future. We would like to see a mechanism that is well-designed, does not overcharge customers, and is tied to new energy efficiency programs. These safeguards should be guaranteed parts of the decopuling mechanism, not something that we hope the utility will propose. We would like to see such a program operate in normal circumstances, rather than in a severe recession. However, unless the current program is suspended or revised, we doubt that we will ever see a decoupling proposal that we can support. We suspect that Oregon's experience will be similar to Maine's, and decoupling will be considered such a failure that we will permanently lose it as a tool to actually promote energy efficiency programs.

Finally, we would like to conclude by quoting the conclusion from the Maine Public Utilities Commission's recent report:

> As discussed above, decoupling, like all ratemaking approaches, has both positive and negative attributes. In addition, the development of any new ratemaking approach comes with the possibility of serious unintended consequences (as occurred with Maine's experiment with ERAM in the early 1990s). Although we can learn from our mistakes, we can never predict all future scenarios and thus there will always be a risk that despite all the best intentions, ratepayers can be seriously harmed by the unforeseen impacts of alternative ratemaking approaches.

UE 197/CUB/305/Jenks/17

EXECUTIVE SUMMARY

March 2009
Oregon Economic Forecast

The fourth quarter of 2008 posted the fourth consecutive quarter of job losses. The preliminary estimate of fourth quarter job loss in Oregon is negative 6.8 percent at an annualized rate. Under the newer North American Industrial Classification System which goes back to 1990, this is the largest single quarterly job decline. On a year-over-year (Y/Y) basis, jobs decreased by 2.5 percent in the fourth quarter.

Most sectors were hit hard in the fourth quarter. Manufacturing and construction continued to lose jobs at a high rate. Joining in heavy job losses were retail and wholesale trades, transportation services, warehousing and utilities, professional and business services, financial activities, and local government education. The only sectors not experiencing declines were food processors, private education and health services, and state government.

This forecast incorporates the Oregon Employment Department benchmarked job numbers released in early February. The revised numbers show more job losses in 2008 than previous estimates. Previous estimates had Oregon employment peaking in February of 2008. New estimates now place that employment peak in January 2008. The first quarter of 2008 was showing a 1.4 percent job growth but this has been revised to job losses of 0.1 percent. Every quarter of 2008 now reports job losses. The revised numbers paint a deeper recession for 2008 with job losses considerably higher in the service sector of the economy.

The direction of the forecast for job losses was correct, but job losses in the fourth quarter were much greater than projected. The forecast for the fourth quarter was in error by 1.4 percent. As with the national economy, the fourth quarter was brutal to the Oregon economy. Of all the jobs lost in the US economy in 2008, around 73 percent were lost in the fourth quarter. For Oregon, the corresponding number is about 70 percent. The fourth quarter downturn has been swift with the unemployment rate in Oregon moving from 6.5 percent in August 2008 to 9.0 percent in December 2008. The Federal Reserve Bank of Philadelphia's Coincident Index of economic activity for Oregon shows the state down 2.0 percent for both the 1-month and 3-month change going into November 2008. That is the largest decline for any state, with North Carolina being the closest at down 1.2 percent for 1-month and 1.4 percent for the 3-month change. More striking for this measure is the 12-month change with Oregon down 8.9 percent. This also is the largest decline of any state with Nevada the closest at 6.5 percent.

Ian Mcfarlane, the Governor of the Bank of Australia made the following comment concerning the problems facing the world financial system: "When everyone feels that risks are at their minimum, over-confidence can take over and elementary precautions start to get watered down." We have moved from "over-confidence" to "no confidence". Banks have dramatically reduced their loans and households have taken a bunker mentality to the economic future of our country.

There is a huge amount of funds infused into our financial systems along with help to industries such as the automotive manufacturers. A federal stimulus package of $789 billion consists of around 2/3's of spending and 1/3 of tax cuts. Estimates place Oregon's share at around $550 million from now until June 30 of this year and $2 to $3 billion in total over three years. All this effort will not go far enough if "confidence" is not revived. Banks need to lend once again with a reasonable level of risk. Households need to believe that the recession will pass and jobs will feel a bit more secure. The daunting question is "when" and how much suffering do we endure before the seas are calm once again.

OEA projects the year average for 2009 is an employment decline of 4.3 percent. Job growth is positive but very weak with job gains of 0.04 percent in 2010. The Oregon economy does not start to recover until the second half of 2010.

The wood products sector lost 9.8 percent of its workforce in 2008. The industry is projected to lose jobs at a rate of 17.3 percent in 2009 with a further decline of 5.3 percent in 2010 as the prolonged housing market correction continues to unfold. Looking forward, as the housing market improves through late 2010 and into 2011, employment is expected to regain some of these lost jobs.

The computer and electronic equipment sector lost jobs at a 4.5 percent rate in 2008. Given the economic conditions, this industry will see further job declines of 10.9 percent in 2009. Mild improvement is projected for 2010 and into 2011, when job growth rebounds to 4.3 percent.

Employment in the transportation equipment industry declined 14.7 percent in 2008. Employment is projected to decline 23.6 percent in 2009, 5.6 percent in 2010 before positive growth in 2011.

Other nondurables, which includes paper and allied products, is projected to have job declines of 13.7 percent in 2009 before adding jobs in 2010 at 1.6 percent.

Construction employment fell 9.2 percent in 2008 and is projected to decline by 16.0 percent in 2009 and 7.5 percent in 2010. As the housing market begins to recover, employment should turn positive in 2011, with strong growth in 2012 of 4.4 percent. Both the federal stimulus package and state capital projects should provide some relieve to this sector.

Trade, transportation, and utilities sector lost jobs in 2008 at a rate of 1.4 percent and is projected to lose a further 4.1 percent in 2009. Moderate growth is expected for the industry starting in 2010. Retail employment declined in 2008 at 2.0 percent and will decrease sharply in 2009 at a 4.4 percent rate before rebounding in 2010 with positive 2.8 percent. Wholesale trade jobs were down slightly in 2008, and are expected to fall a further 3.8 percent in 2009 and 0.4 percent in 2010. Growth of 1.8 percent in projected for 2011.

The information sector, which includes traditional publishers such as newspapers and publishers of software, is expected to contract by -6.2 percent in 2009 and -2.1 percent in 2010.

The financial sector lost 4.3 percent of jobs in 2008 and is projected to decline at a 4.6 percent rate in 2009. A mild rebound is expected in 2010 when jobs will increase at a rate of 1.2 percent and stronger growth of 2.7 percent in 2011.

Professional and business services lost employment by 0.8 percent in 2008. This sector is expected to be hit especially hard in 2009 with projected losses of 8.2 percent. Beginning in

2010, the industry will begin to recover with 0.8 percent job growth, followed by 8.0 percent growth in 2011.

Education and health services job growth was 3.9 percent in 2008 and is expected to be 3.0 percent in 2009, 3.1 percent in 2010, and 2.7 percent in 2011.

Leisure and hospitality employment increased slowly in 2008 at a 1.1 percent rate and is projected to decline in 2009 at a 3.0 percent pace. Jobs will decline slightly in 2010 before mild job growth in 2011.

The government sector employment increased by 3.2 percent in 2008 and is expected to decline by 0.2 percent in 2009. Mild job growth is projected for 2010 and a slight job loss for 2011.

Population growth will slow to 1.1 percent in 2009 with slightly faster growth of 1.2 percent in 2010 and 2011.

Forecast Risks

The world is in the grips of a steep recession. Japan recently reported that their fourth quarter GDP fell 12.7 percent at an annualized rate, the biggest quarterly drop since 1974. Even China is pursuing a stimulus package to jump start its economy. Exports have come to a screeching halt as 2008 came to a close. We now more than ever realize that we operate in a world financial system. Even with all the fiscal and central bank plans underway, uncertainty still looms as the success of these programs.

The recession in the US and Oregon economies will come to an end. The looming questions are how much deeper and how much longer. The dollar amount of programs is staggering. The Federal Reserve alone is estimated to have added $1.2 trillion of new programs with more to come. The Treasury's TARP program has $800 billion. The US federal stimulus package placed into law in February tops off at $789 billion. Oregon has added its own state stimulus package of $175 million. Economic policy commentators still question if more needs to be done and what proposed remedies will work best.

With uncertainty, you have both negative and positive risks. The recession could be more protracted and deeper than presently projected or the rescue packages in place may kick in earlier and bring a more rapid end to this recession.

We will continue to monitor and recognize the potential impacts of risk factors on the Oregon economy. We have identified the major risks now facing the Oregon economy in the list below:

Contagion of the credit crunch and financial market instability. With the freezing up of credit markets, broad based borrowing and lending is very expensive or non-existent. Consumer spending has been greatly curtailed and the stock market has lost 40 percent of its value in 2008. If the credit markets do not return soon to some sort of state of normalcy, the current recession could be much deeper and longer than presently projected. Oregon will suffer the consequences along with the rest of the nation.

Prolonged housing market instability. Generally, analysts believe that the housing market has yet to hit bottom, at least in terms of price declines. Though Oregon has been hit hard through this downturn, Oregon's housing market is relatively better off compared to California, Nevada, Florida, and Arizona. Coupled with the recessionary state of the economy, the rise in mortgage rates and heightened credit standards will keep demand for housing relatively low. Rather than the correction of the housing bubble further hurting the Oregon housing market, it will be the deepening recession that causes further home price declines and rising foreclosures. Unlike many parts of the economy, there is an upside risk here as well. If the recession is over sooner than forecasted, Oregon's housing market should revive better than the states who experienced the greater housing market bubbles.

The relative effectiveness of nearly-global government stimulus. The level of government response to the current recession has never been greater. Furthermore, the coordination of central bank actions throughout the world was similarly unprecedented. While the intent was for significant stabilization and growth, it is unknown if these will come to pass. Federal Reserve, US Treasury, and the federal stimulus package may lift this economy out of recession sooner than projected.

The return of federal timber payments to Oregon counties. Included in the federal bailout was a provision to reinstate federal timber payments for four years. Oregon counties will receive $254 million, down from the previous $282 million level and will be phased out over the four year window. While this temporary reinstatement helps cover short term budgets for Oregon counties, finding or replacing this dwindling revenue source will be imperative as any loss of public services could have adverse impacts on economic activity.

The extent of the global downturn triggered by the U.S. slowdown. The U.S. economy has been an important engine of growth for the global economy. As the U.S. economic woes continue, the whole world is beginning to feel the impact. First, European economic growth slowed considerably, even contracting in places. Then Asian economies began slowing due to their large exposure, via trade, to the U.S. economy. China is a top importer of Oregon products and any slowing of the Chinese economy will adversely impact Oregon exports. How long and how deep the impacts of the downturn will remain open ended questions.

Appreciation of the U.S. dollar. Along with slowing foreign economies, the recent appreciation of the U.S. dollar is expected to slow exports from U.S. producers. This will also be true for Oregon exports. The extent of the impact from the U.S. dollar may not be as great for Oregon given the expected appreciation of the Chinese Yuan, one of Oregon's major trading partners. Still, the risk is present for a slowing of exports.

National and regional energy prices. The over 60 percent drop in oil prices is bringing relieve to both businesses and households. The near term outlook is also for lower regional prices for natural gas and electricity. This comes at a welcomed time when businesses are looking for cost savings. The benefit from lower energy prices is most likely short-lived as the underlying demand drivers will return once the world economies rebound from this recession.

Geopolitical risks. Uncertainty still abounds in Iraq. Tensions with Iran and heightened security risks weigh on businesses and consumers. Disruptions in travel, oil supplies, and consumer confidence could be severe. The drop in business activity could deepen if this uncertainty persists or if the transition out of the Iraq war goes badly for the U.S. The eventual winding down of military expenses will not greatly impact Oregon. There is also an upside risk that the transition will go more smoothly than anticipated, and stability in the Mideast will provide a stronger than forecasted stimulus to the economy.

Initiatives, referendums, and referrals. Generally, the ballot box brings a number of unknowns that could have sweeping impacts on the Oregon economy.

Demographic Forecast

Oregon's estimated population on July 1, 2008 reached 3,791,075. That was an increase of 1.2 percent over the 2007 population. The growth has slowed down since the highs of 2005 through 2007 when it approached or exceeded 1.5 percent. Overall, population change since 2000 is much lower than the rate of growth of well over 2.0 percent during the early 1990s.

As a result of recent economic downturn, Oregon's population is expected to grow at a slower pace in the near future. Based on the current forecast, Oregon's population will reach 4.117 million in the year 2015 with an annual rate of growth of 1.2 percent between 2008 and 2015.

Oregon's economic condition heavily influences the state's population growth. Its economy determines the ability to retain local work force as well as attract job seekers from other states and beyond. As Oregon's total fertility rate remains below the replacement level and deaths continue to rise due to ageing population, long-term growth comes from net in-migration. Working-age adults come to Oregon as long as we have good economic and employment situations. During the 1980s that included a major recession and a net loss of population, net migration contributed to 22 percent of the population change. On the other extreme, net migration accounted for 73 percent of the population change during the booming 1990s. This share of migration declined to 57 percent in 2002. As a sign of slow to modest economic gain, the net migration will account for 58 to 63 percent of the population change in the near future. Although economy and employment situation in Oregon look bleak, migration situation is not expected to replicate the early 1980s pattern. Potential Oregon out-migrants have no better place to go since other states are also in the same boat in terms of economy and employment.

Growth in all age groups will show the effects of the baby-boom and their echo generations during the period of 2008-2015. It will also reflect demographics impacted by the depression era birth cohort combined with diminished migration of the working age population and elderly retirees. After a period of slow growth in the past, the elderly population (65+) growth has picked up in pace and will surge as the baby-boom generation starts to enter this age group. The annual growth of the elderly population will be nearly 3.8 percent during the forecast horizon as the boomers continue to enter retirement age. The youngest elderly (aged 65-74) will grow at an extremely fast pace due to the direct impact of the baby-boom generation entering retirement age. The elderly aged 75-84 will continue to shrink in numbers until 2009, as the depression era birth-cohort will dominate this group. The oldest elderly (aged 85+) will continue to grow at a moderately high rate due to the combination of cohort change, continued positive net migration, and improving longevity. However, the annual growth rate will continue to taper off as the depression era small birth cohort transitions from the younger age group.

As the baby-boom generation matures, the once fast-paced growth of population aged 45-64 will gradually taper to near 0 percent rate by 2012. The young adult population (aged 18-24) will grow at an average of 0.1 percent annually, considerably slower than the rate averaging 1.1

percent experienced between 2000 and 2008. Although the slow growth of college-age population tend to ease the pressure on public spending on college education, college enrollment typically goes up during the time of high unemployment and scarcity of well paying jobs when even the older population flock back to college to better position themselves in a tough job market. Compared to other non-elderly age groups, children under the age of five show a higher rate of growth after a slow growth period in the recent past. The K-12 population (aged 5-17) will show very slow growth which will translate into slow growth in school enrollments. The 25-44 age group population has reversed the several year trend of decline. The decline was mainly due to the exiting baby-boom cohort. This age group has seen positive growth starting in the year 2003 and will approach 1.2 percent annual growth by the year 2011.

Revenue Forecast

The forecast for General Fund revenues for the 2007-09 biennium is $12,018.4 million, a decrease of $713.1 million from the December 2008 forecast. The decrease is concentrated in personal income taxes, as expectations for income tax receipts related to both capital gains and retirement income continue to diminish. Corporate income tax receipts have weathered the storm a little longer than expected, but have begun to show some significant signs of weakness, resulting in a corresponding decrease in the forecast.

Total structural General Fund revenues will decrease 0.4 percent to $13,050 million in 2009-11. This represents a $1.7 billion decrease relative to the December forecast. Personal income tax growth of 10.4 percent, which will raise collections to $11,429.8 million, is due largely to the $1.084 billion kicker rebate distributed in the prior biennium. Corporate income taxes will decline 2.9 percent to $727.1 million, as the economic slowdown in 2008 and 2009 filters through to corporate income tax receipts.

General Fund revenues will total $16,955.7 million in 2011-13, an increase of 15 percent from the prior period. The growth is fueled primarily by a 15.2 percent increase in personal income tax collections to $15,099.8 million. Corporate income taxes will reach $981.1 million, while all other revenues will total $874.7 million.

Projected lottery earnings will total $1,317.2 million, a decrease of $6.8 million from the prior forecast. Recent lottery sales have been subjected to a perfect storm of circumstances. Continued slowing in consumer spending has stalled, winter weather over the holidays, the implementation of smoking restrictions, and decreased gas prices making driving to a casino more likely, have all contributed to driving down expectations for lottery sales through the remainder of this biennium. The most recent weeks have seen year-over-year decreases of close to 20 percent.

Lottery earnings are expected to fall more than 14 percent to $1,128.5 million for the 2009-11 biennium. In addition to the expected impact of the smoking restrictions and slow economic growth, the weak growth is the result of an absence of administrative savings for the biennium, compared with $97 million in the current biennium. In spite of the increased transfer rate, video lottery earnings will decrease 7.5 percent, while traditional products will decline eight percent.

IHS GLOBALINSIGHT

Top-10 ECONOMIC PREDICTIONS FOR 2008 — HOW ACCURATE WERE WE?

NARIMAN BEHRAVESH, IHS GLOBAL INSIGHT CHIEF ECONOMIST

Here is what IHS Global Insight said in December 2007 as we introduced our Top-10 Predictions for 2008:

The U.S. economy is now in the danger zone. GDP growth in the fourth quarter of 2007 (0.0%) and first half of 2008 (0.8% in the first quarter and 1.8% in the second quarter) is expected to be very weak. This will make the United States extremely vulnerable to another shock. Furthermore, it is unlikely that the rest of the world will be able to shrug off the expected sharp deceleration in spending by American households. IHS Global Insight currently predicts that world growth will be 3.3% in 2008, compared with 3.7% this year. With the potential for housing crunches in some European economies and a post-Olympics slowdown (or even bust) in China, the risks for the global economy are now overwhelmingly on the downside.

Eight of the top-10 IHS Global Insight predictions for 2008 were right on the mark. The U.S. and world economies did slow down dramatically. Global GDP growth downshifted from 3.9% in 2007 to 2.7% in 2008.

1 **IHS GLOBAL INSIGHT PREDICTION:**

U.S. GROWTH WILL BE THE WEAKEST SINCE 2002, AND POSSIBLY SINCE THE LAST RECESSION.

Growth in 2002 was a meager 1.6%, as the economy struggled to recover from the twin shocks of the high-tech bust and the 9/11 terrorist attacks. Growth next year will be almost as low (1.9%), and there is a mounting risk that it could be lower. The main culprit is housing, which will cut real GDP growth by 1.0 percentage point during the year. However, consumer spending growth is also predicted to decelerate from 2.8% in 2007 to 1.7% in 2008. Moreover, capital spending is expected to increase a lackluster 2.6%. The only saving grace will be net exports, which will add 0.9 percentage point to growth. IHS Global Insight forecasts that the U.S. economy will rebound in the second half, expanding 2.7%, compared with 1.3% in the first half.

WHAT ACTUALLY HAPPENED:

U.S. economic growth in 2008 — at 1.2% — was the slowest since the recession of 2001.

2 **IHS GLOBAL INSIGHT PREDICTION:**

MOST OTHER REGIONS OF THE WORLD WILL ALSO DECELERATE.

Except for commodity-exporting countries and regions, world growth is expected to "re-couple" with the United States and slow down. For Canada and Mexico, weak U.S. growth will be offset by strong oil prices. However, Europe will be hit by multiple headwinds, including the global slowdown, a stronger currency, the continuing credit crunch, housing problems in some countries, and high oil prices. Japan will be similarly afflicted, although there is little evidence of fallout from the subprime and housing-related problems in the United States — so far. The fate of emerging markets will depend on if and when growth in China and the rest of Asia falters.

WHAT ACTUALLY HAPPENED:

With the exception of the Middle East and Africa, all the regions of the world did slow down over the past year, as the world economy "re-coupled" with the United States.

3 IHS GLOBAL INSIGHT PREDICTION:

THERE WILL BE NO SIGNIFICANT COOLING IN CHINA AND THE REST OF ASIA UNTIL LATE 2008.

A mild global slowdown will only put a small dent in China's rapid rate of growth in 2008 — 10.8%, compared with 11.5% this year. Credit growth is still very strong and the Chinese government's modest tightening efforts have had little impact, with fixed-asset investment growing at about a 30% rate in 2007. In the first half of 2008, there are likely to be further gradual interest-rate hikes and currency appreciation. After the Beijing Olympics next August, however, the government may have no choice but to tighten credit conditions more dramatically. This will further slow China's growth, but there is a significant risk (at least 33%) that the landing could be hard. Such a scenario would hurt the rest of Asia. However, since India's growth is predominantly domestic-led, this vibrant economy should be able to sustain a growth rate around 8.5%.

WHAT ACTUALLY HAPPENED:

China's and India's GDP growth rates did slow from 2007 to 2008 (respectively, from 11.9% to 9.4% and from 9.0% to 6.5%)—although in both cases, more than predicted by IHS Global Insight.

4 IHS GLOBAL INSIGHT PREDICTION:

OIL PRICES WILL EASE, BUT REMAIN AT HIGH LEVELS.

Weaker global growth will dampen oil prices and bring them more into line with supply/demand fundamentals. These fundamentals support a price between $75 and $80 per barrel. IHS Global Insight expects that, on average, a barrel of WTI will cost $75.67 next year, compared with $72.13 in 2007. However, with markets still tight, any type of supply disruption (actual or expected) could send prices back up again — probably just temporarily. An unknown factor in oil and other commodity markets is the role of speculation. Some have referred to the recent spike in commodity prices (especially oil) as the "next bubble." If so, the recent drop in oil prices suggests that some of these speculative positions many be unwinding.

WHAT ACTUALLY HAPPENED:

Oil prices did eventually fall—precipitously—but not before approaching $150 last summer. Over the past year, oil prices averaged a little over $100 per barrel.

5 IHS GLOBAL INSIGHT PREDICTION:

CORE INFLATION WILL EDGE DOWN.

The U.S. economy is now operating well below potential. This will begin to gradually push up the unemployment rate. This extra slack in the economy will put further downward pressure on core inflation, which IHS Global Insight expects to fall from 2.0% this year to 1.8% in 2008 for the core personal consumption deflator and from 2.3% to 2.1% for the core CPI. The good news, so far, is that high energy prices have had very little impact on other prices and on wage inflation. This benign state of affairs can be expected to continue for at least another year.

WHAT ACTUALLY HAPPENED:

While on a calendar-year (average) basis, core inflation was unchanged between 2007 and 2008, by the fourth quarter of 2008, it had fallen to 1.0% for the core CPI and 0.8% for the core PCE deflator.

6 IHS GLOBAL INSIGHT PREDICTION:

THE FEDERAL RESERVE WILL KEEP CUTTING INTEREST RATES.

With inflation not a serious threat, and the risks predominantly on the downside, the Fed will keep lowering rates. IHS Global Insight now expects cuts of 25 basis points at the December 11 Federal Open Market Committee Meeting, 50 basis points at the January 29-30 meeting, and another 25 basis points at the March 18 meeting. Meanwhile, if the credit crunch and housing problems get worse, the Fed may have no choice but to inject more liquidity into the financial system, and support the subprime mortgage relief/freeze plan devised by the Bush administration.

WHAT ACTUALLY HAPPENED:

The Fed did keep cutting interest rates throughout 2008, even more than predicted by IHS Global Insight.

7 IHS GLOBAL INSIGHT PREDICTION:

HOUSING SECTOR ACTIVITY WILL BOTTOM OUT IN MID-2008.

Housing activity will continue to slide in the first half of next year. IHS Global Insight now expects that total starts will fall below 1 million units during 2008—less than half their level in 2005. During the second half of the year, we expect housing activity to stabilize and begin recovering gradually. The same cannot be said about home prices, which are likely to keep sliding, at least through 2009. The peak-to-trough drop in home prices (as measured by the OFHEO price index) will probably end up being more than 10%.

WHAT ACTUALLY HAPPENED:

The U.S. housing market did not bottom out in 2008. Instead, as the financial crisis worsened, housing activity and prices continued to plummet through year-end.

8 IHS GLOBAL INSIGHT PREDICTION:

THE U.S. CURRENT-ACCOUNT DEFICIT WILL CONTINUE TO IMPROVE.

The long-awaited correction of the gaping global imbalances is finally happening. The deceleration in the U.S. economy is likely to be much more pronounced than that across the rest of the world. Moreover, the dollar has fallen more than 20% (on a real trade-weighted basis) in the past five years and should fall a little more, before stabilizing. These developments are supercharging exports and dampening imports. During the course of the next year, the positive contribution by trade will make all the difference whether the U.S. economy suffers through a recession or not. IHS Global Insight forecasts that the current-account deficit will fall from $755 billion in 2007 to $659 billion in 2008.

WHAT ACTUALLY HAPPENED:

The U.S. current-account deficit did improve to $660 billion in 2008—to within $1billion of the valued predicted by IHS Global Insight!

9 IHS GLOBAL INSIGHT PREDICTION:

THE DOLLAR WILL REACH A TROUGH AGAINST SOME CURRENCIES IN 2008.

While the dollar has been on a downward trend since 2002 (mostly because of the huge current-account deficit), the recent weakness is a function of fears over the subprime crisis and a U.S. recession, combined with expectations that the Fed will cut interest rates more than other central banks. As the economy begins to recover in the second half of 2008 and early 2009, though, sentiments on the dollar will turn more positive, at least against some currencies. We expect that the euro will top out around $1.55 next summer and fall to $1.49 by year-end. The Canadian dollar may have peaked already, if oil prices keep falling. However, both the Japanese yen and the Chinese renminbi should keep appreciating vis-à-vis the dollar, given the large current-account surpluses in both economies.

WHAT ACTUALLY HAPPENED:

The U.S. dollar did bottom out against most currencies, although even more dramatically than predicted by IHS Global Insight. By year-end, the dollar-euro rate was around $1.25.

10 IHS GLOBAL INSIGHT PREDICTION:

WITH U.S. GROWTH BARELY POSITIVE THROUGH MID-2008, EVEN A SMALL SHOCK WILL PUSH THE ECONOMY OVER THE EDGE.

For the past two years, IHS Global Insight has been saying that it would take two or more shocks to trigger a U.S. recession. There is a growing risk that such a scenario may be about to unfold. The combination of the housing/subprime crisis and higher oil prices could be enough to push growth into negative territory. If oil prices continue to fall, and end up in the $75–80/barrel range early in 2008, the U.S. economy will probably be able to escape recession. However, either another rise in oil prices or some other shock (even a small one) could be the straw that breaks the camel's back. IHS Global Insight has raised the probability of a U.S. recession from 35% to 40%.

WHAT ACTUALLY HAPPENED:

The twin shocks of oil reaching nearly $150/barrel and the financial crisis getting much worse were enough to push the U.S. economy into recession.

IHS

GLOBAL INSIGHT

Top-10 ECONOMIC PREDICTIONS FOR 2009

NARIMAN BEHRAVESH, IHS GLOBAL INSIGHT CHIEF ECONOMIST

The U.S. and world economies are about to suffer through some of the worst recessions in the postwar period. **Most measures of economic and financial activity look like they fell off a cliff in September and October, and have been deteriorating at an alarming rate ever since. The United States is now officially in a recession that started in December 2007. Japan and many European countries are in the same boat. At the same time, growth in most emerging markets is faltering. IHS Global Insight now believes that global growth will be in the 0.0–0.5% range during 2009, compared with 2.7% in 2008.**

1 THE U.S. RECESSION WILL BE ONE OF THE DEEPEST – IF NOT *THE* DEEPEST – IN THE POSTWAR PERIOD.

The current downturn is well on its way to becoming the longest in the past six decades. Based on the December IHS Global Insight baseline forecast for the U.S. economy, it will be the fourth deepest in the postwar period (the 1957 recession was the deepest, followed by the contractions of 1973–75 and 1981–82). Nevertheless, given the very negative tone of the incoming data (including the 533,000 drop in November payrolls), the recession could well be the worst in the postwar period. At the same time, the large back-to-back declines in real GDP predicted for the fourth quarter of 2008 and the first quarter of 2009 (down 5.0% and 3.8%, respectively) are the worst since the 1982 recession, and may easily be the worst in more than six decades. Overall, we expect the U.S. economy to shrink at least 1.8% in 2009.

2 THE DOWNTURN WILL BE THE WORST IN EUROPE OVER A COUPLE OF DECADES AND THE WORST IN JAPAN SINCE 1998.

Japan and some European countries (Ireland, Italy, and Germany) are already officially in a recession. The other economies of the European Union will follow them down. For Europe, this will be the biggest economic contraction since the early 1990s—and the first for the Eurozone. For Japan, it will be the nastiest recession since the depths of the Asian crisis in 1998, when its economy contracted 2.1%. In 2009, IHS Global Insight expects respective GDP declines of 1.0%, 1.3%, and 2.0% for the Eurozone, Japan, and the United Kingdom.

3 GROWTH IN EMERGING MARKETS WILL DECELERATE DRAMATICALLY.

The global scope of the current economic crisis has put to rest the notion that emerging markets have "de-coupled" from the economies of the developed world (something to which IHS Global Insight never subscribed). There are at least three transmission mechanisms to the emerging world: 1) the collapse in commodity prices, which is already hurting the oil- and commodity-exporting countries (e.g., Russia, Iran, Venezuela, and South Africa); 2) the drying-up of capital flows, which is harming economies with large current-account deficits (e.g., many countries in Emerging Europe, some of which have already sought help from the IMF); and 3) the precipitous decline in world trade, which will damage growth prospects for the major exporting countries (almost all of which are in Asia). As a result, GDP growth in most emerging markets during 2009 will be roughly half the rate of 2007 and early 2008. For example, the Chinese economy, which enjoyed 11.9% growth in 2007, is likely to expand only 6.9% in 2009.

4 THE FEDERAL RESERVE AND OTHER CENTRAL BANKS WILL KEEP CUTTING RATES.

The race to zero is on! The Fed has already cut the federal funds rate to 1% and is likely to take it all the way to zero by the end of January. Once the overnight rate is at zero, the Fed may have to engage in "quantitative easing" (direct purchases of long-term Treasuries). It is already engaging (massively) in unorthodox measures such as buying commercial paper, mortgage-backed securities, credit card debt, and loans to small businesses, students, and car buyers. On December 4, the European Central bank joined the fray by cutting the overnight rate by 75 basis points (to 2.5%), while the Bank of England cut by 100 basis points (to 2.0%). IHS Global Insight now believes that the ECB and BoE will push rates all the way to 1.0% and 0.5%, respectively—and could cut all the way to zero. Most central banks around the world have followed suit. Notably, on November 26, the People's Bank of China lowered rates by 108 basis points, the largest cut in 11 years and the fourth cut since mid-September.

5 MORE FISCAL STIMULUS IN THE PIPELINE.

The incoming Obama administration has been talking about a fiscal-stimulus package of between $500 billion and $700 billion (or between 3% and 5% of GDP). Our December baseline forecast assumes a package of $550 billion, which consists of tax cuts, infrastructure spending, and other provisions. Given how quickly the economy is deteriorating, the fiscal package is likely to end up much bigger than current estimates. The only other country that is considering a big stimulus program is China, which has announced a two-year program worth about $586 billion (or 16% of GDP). Even if only half of this is "real," it would add substantially to growth. Without it, we estimate that Chinese GDP growth would only be 5%. The fiscal-stimulus plans announced for other major economies are much smaller. In particular, the plans being discussed for the United Kingdom and the Eurozone are only between 1.0% and 1.5% of GDP.

6 COMMODITY PRICES WILL REMAIN AT DEPRESSED LEVELS FOR MUCH OF NEXT YEAR.

The steep collapse of commodity prices over the past few months (60–80%) has been unprecedented—and the worst is probably yet to come. With the economic outlook deteriorating by the day, futures markets for commodities have not priced in the full extent of the "demand destruction" taking place. IHS Global Insight now believes that oil prices will (easily) fall below $40 per barrel in the next year, and could tumble all the way to $30. The good news is that the drop in energy prices is like a tax cut for households and businesses. In the United States, the drop in gasoline prices is, so far, the equivalent of a $230-billion tax cut.

7 INFLATIONARY FEARS WILL BE REPLACED BY CONCERNS ABOUT DEFLATION.

Only a few months ago, there was a lot of hand wringing over inflation. Such fears have evaporated, and concerns about deflation are on the rise. IHS Global Insight now expects that headline consumer and producer price inflation will remain in negative territory through next summer. For calendar-year 2009, headline CPI and PPI will fall 1.5% and 6.3%, respectively. At the same time, core inflation will fall from a little over 2% to just over 1%. A similar, though perhaps less-pronounced, pattern will be evident in Europe. Japan, which barely shrugged off deflation, is likely to suffer a relapse. At the same time, fears about overheating in China have given way to the possibility that deflation will rear its ugly head again.

8 GLOBAL IMBALANCES WILL IMPROVE MARKEDLY.

The long-awaited correction of the gaping global imbalances is happening with a vengeance. The U.S. current-account deficit, which was $731 billion in 2007 and likely to come in at $660 billion this year, will plummet to $282 billion in 2009. The large deficits in the past two years belie a significant improvement in the non-oil deficit—which was, nevertheless, overwhelmed by the sharp rise in the oil import bill. With the collapse in oil prices, the current-account deficit will plummet about 50%, both in absolute terms and as a share of GDP. The big drop in commodity prices also signals a major shift in the terms of trade, in favor of the developed economies, and represents a "re-balancing" of growth and current-account deficits, with commodity-importing countries being the major beneficiaries.

9 THE DOLLAR WILL REMAIN RELATIVELY STRONG AS LONG AS THE FINANCIAL CRISIS CONTINUES.

The joke is that the dollar is the "best-looking horse in the glue factory." This means that in the midst of the ongoing crisis, the safe-haven/principal-reserve-currency status of the U.S. dollar has trumped all other fears. As long as the crisis continues, the dollar is likely to remain strong. Moreover, the markets seem to have a little more confidence that the United States may be able to pull out of its recession sooner and faster than other parts of the world. That said, once the crisis is over, the downward pressures on the dollar are likely to return. For example, the euro/dollar rate will probably stay at its early-December levels of $1.26 – 1.28 for some time (and may even strengthen a little), before very gradually appreciating to the low $1.30s by the end of next year.

10 THE SINGLE-BIGGEST RISK FACING THE U.S. AND WORLD ECONOMIES IS A TIMID RESPONSE TO THE CRISIS.

The policy response to this crisis needs to be big, bold, and rapid. The good news is that both the United States and China are taking the crisis very seriously. The not-so-good news is that the policy responses in other large economies, especially Japan and Eurozone, seem to be much more timid. This could well mean deeper and longer recessions in those countries, which could mean even weaker world growth in 2009.

CUB's Calculation of Rate Impacts due to Decoupling

fixed cost adjustment adjustment level	per kwh	per month
residential sch. 7 (from Schedule 123)	0.04646	41.38
sch 32 and 532 (from Schedule 123)	0.04221	63.47
total rev/kwh residential (from PGE/1202 andPGE	0.108547395	
variable cost	0.062087395	
commercial load 2009 (kwh) (from PGE/1208)	1,500,066,000	
8% reduction	**120,005,280**	
decoupling adjustment 8% reduction	5,065,423	0
2% cap (from PGE/1202)	***3,050,471***	
decoupling adjustment 10% reduction	**6,331,779**	
decoupling adjustment 12% reduction	**7,598,134**	
residential load (from PGE/1208)	7,712,700,000	
5% reduction	**385,635,000**	
decoupling adjustment	17,916,602	
2% cap (from PGE/1202)	***16,743,870***	

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Report on Revenue Decoupling for Transmission & Distribution Utilities

Presented to the Utilities & Energy Committee by the MPUC, OPA and OEIS

January 31, 2008

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Attachments

Attachment A – Summary of September 14, 2007 Stakeholder Group Meeting.

Attachment B – Stakeholder Comments and Recommendations.

Attachment C - *Decoupling for Electric and Gas Utilities Frequently Asked Questions (FAQ),* NARUC, (Sept. 2007).

Attachment D – *NASUCA Energy Conservation and Decoupling Resolution* National Association of State Utility Consumer Advocates (NASUCA) (June 2007).

Attachment E – *A Response to the NASUCA "Decoupling" Resolution*, Alliance to Save Energy, American Council for an Energy Efficient Economy, Conservation Law Foundation, Environment Northeast, Izaak Walton League of America, Natural Resources Defense Council, Northwest Energy Coalition, Orion Energy, Pace Energy Project, Rocky Mountain Institute and Western Resource Advocates, (Aug. 2007).

Attachment F - *Energy Efficiency and Utility Profits: Aligning Incentives with Public Policy*, Presentation in the Rhode Island GHG Process by Rick Weston of the Regulatory Assistance Project, (April 26, 2007).

Attachment G - *Revenue Decoupling: A Policy Brief prepared of the Electricity Consumers Resource* Council, ELCON, (January 2007).

Attachment H – Excerpts from *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives*, American Council for an Energy-Efficient Economy (ACEEE), (October 2006).

I. INTRODUCTION

In the 1st Regular Session of the 123rd Legislature, the Utilities and Energy Committee (Committee) considered LD 1836, An Act to Save Money for Maine Energy Consumers through Enhanced Energy Efficiency. The Committee voted "Ought Not to Pass" on the bill. However, during the work session on LD 1836, some Committee members indicated that they remain concerned about the financial incentives for Maine's transmission and distribution (T&D) utilities to encourage increased electricity consumption over energy efficiency and conservation.

In separate letters to the Office of Energy Independence and Security (OEIS), Office of the Public Advocate (OPA) and Public Utilities Commission (Commission) (collectively, the Agencies) dated June 14, 2007, the Committee Chairs requested the Agencies to jointly convene a stakeholder group to discuss the Committee's ongoing concern and to explore rate design options, including decoupling mechanisms, to reduce current regulatory incentives to T&D utilities to promote consumption. The June 14th letters requested the Agencies to report back to the Committee by January 15, 2008 on the results of the stakeholder discussions.

This report is being submitted jointly by the Commission, OPA and OEIS and is intended to respond to the Committee Chairs' June 14th letters.

II. BACKGROUND

Representatives of the Agencies met in June and July to discuss the stakeholder group process and potential participants. During our preliminary meetings, the Agencies agreed to a four-part stakeholder group process and tentative schedule for completing the required report. By letter dated July 27, 2007, the Commission provided a summary of the proposed process to the Committee Chairs. That proposed process and schedule was ultimately implemented and is outlined below.

- **Pre-Meeting (August 1st through September 13th)**. During the pre-meeting phase, the Agencies contacted potentially interested persons and identified people who wanted to participate in the stakeholder group process. During this phase, the Agencies solicited relevant documents from interested persons and distributed those documents to the evolving stakeholder group.

- **Stakeholder Group Meeting (September 14th).**

- **Post-Meeting (September 15th through October 15th).** During this part of the process, the Agencies distributed, and invited comments on, the meeting notes that were prepared by the OPA.

During this phase, the Agencies also distributed additional decoupling documents.

- **Report Drafting (October 15th through January 15th).** During the final phase of the process, the Agencies distributed a draft outline of the report and solicited input. The Agencies then issued a draft report, invited and incorporated comments and recommendations, finalized the report and submitted the final report to the Committee.

A. Composition of Stakeholder Group

On August 13th, the State Planning Office (SPO), on behalf of OEIS, sent a letter to prospective participants notifying them of the formation of the stakeholder group and inviting them to participate. Shortly thereafter, SPO sent a second letter to participants notifying them that the stakeholder group would meet on September 14th and inviting them to attend.

The following people indicated that they would like to be members of the stakeholder group. The people/organizations underlined in the following list attended the September 14th stakeholder group meeting.

<u>David Allen - Central Maine Power Company</u>
Newell Augur – Bangor Hydro Electric Company
Senator Phil Bartlett
<u>Representative Seth Berry</u>
Representative Larry Bliss
<u>Brent Boyles - Maine Public Service Company</u>
<u>David Bragdon – Energy Matters to Maine</u>
Tony Buxton – Industrial Energy Consumer Group
<u>Representative Stacey Fitts</u>
<u>Representative Jon Hinck</u>
Senator Barry Hobbins
<u>Jeff Jones - Bangor Hydro-Electric Company</u>
Linda Lockhart - Industrial Energy Consumer Group
<u>Calvin Luther – Bangor Hydro-Electric Company</u>
<u>Sharon Staz – Kennebunk Light and Power District and Dirigo</u>
<u>Michael Stoddard - Environment Northeast</u>
<u>Dylan Voorhees - Natural Resources Council of Maine</u>

In addition to the stakeholders listed above, representatives from several state agencies participated in the process. The Agencies also invited the Regulatory Assistance Project (RAP) to participate in the process. The following people participated on behalf of state agencies and RAP. Those underlined in the following list attended the September 14th stakeholder group meeting.

Dick Davies – OPA
Sue Inches – State Planning Office
John Kerry – OEIS
Lucia Nixon - Office of Policy and Legal Analysis
Chris Simpson – PUC
Mitch Tannenbaum - PUC
Vendean Vafiades – PUC
Suzanne Watson - Department of Environmental Protection
Rick Weston – RAP

B. Document Exchange

The Agencies determined that two of the primary objectives of the stakeholder group process are to (1) conduct a search of current literature on decoupling and related issues and (2) facilitate the exchange of relevant documents among the stakeholders. To accomplish these objectives, the Agencies actively solicited relevant documents from stakeholders. In our initial memo to stakeholders, the Agencies noted that:

> In our report to the Committee, the Agencies need to identify current trends regarding decoupling and summarize what other states are doing regarding decoupling. We invite stakeholders to share with the Agencies and the group any other documents that they think may be worthy of discussion by the group and/or useful to the Agencies in drafting the report to the Committee.

Several stakeholders submitted a variety of useful and informative documents to the Agencies that were, in turn, distributed to the full stakeholder group by memos dated September 5, 2007, September 12, 2007, and October 2, 2007. Relevant documents were also exchanged during the September 14th stakeholder group meeting. Some of these documents are discussed in this report and are included as attachments to the report.

C. September 14th Meeting

The Agencies agreed that the meeting should include an educational component. To help satisfy this objective and to expand the scope of the discussion, the Agencies invited Rick Weston of RAP to attend the September 14th meeting and provide the group with a description of various decoupling mechanisms and a summary of decoupling activities in other jurisdictions.

To help stakeholders prepare for the meeting, the Agencies emailed a draft agenda to stakeholders two days before the meeting. To provide a status report to interested persons who were not able to attend the September 14th meeting, the Agencies emailed a summary of the meeting to all persons on the stakeholder group distribution list. A copy of the September 14th meeting summary is included as Attachment A to this report.

D. Report Drafting Process

On October 22, 2007, the Commission emailed an outline of the draft report to stakeholders and invited comments. We received comments from seven stakeholders and attempted to incorporate the suggestions into the draft report.

On November 21st, the Commission emailed the draft report to all stakeholders and invited comments and suggested edits by December 10th. In addition, the Commission invited stakeholders to submit specific comments and recommendations regarding the implementation of a decoupling mechanism in Maine and noted that we would attach a compilation of stakeholder comments/recommendations to the report. We received comments/recommendations from three[1] stakeholders and have included those comments/recommendations as Attachment B to this report.[2]

E. Scope of the Report

During the September 14th meeting, the group briefly discussed the scope of this report. Commission representatives noted there are a variety of regulatory mechanisms that are designed to promote energy efficiency.[3] The group agreed that the primary focus of the report should be on revenue decoupling mechanisms. However, there was some discussion during the September 14th meeting about fixed charge rate design as a way to eliminate a

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[1] The Agencies received comments on the draft report from RAP, the Natural Resources Council of Maine and Environment Northeast.

[2] We thank the stakeholders for their comments and have incorporated many of their suggestions in the text of the final report. We have attached stakeholder comments in their entirety because (1) in early process discussions we indicated to stakeholders that we would do so and (2) we wanted to make sure the Committee had the opportunity to see the comments in their entirety. We note, however, that some of the comments in Attachment B include references to page and paragraph numbers from an earlier draft of the report. In some instances, this makes it difficult to compare the comments with the final report.

[3] Some of these mechanisms are discussed in the Commission's February 1, 2004 report to the Committee titled *Report on Utility Incentive Mechanisms for the Promotion of Energy Efficiency and System Reliability,* Maine Public Utilities Commission (*MPUC 2004 Incentives Report*). (See pages 27-36.) The MPUC 2004 Incentives Report can be viewed on the Commission's webpage at http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/Eff-Rel%20Report-final.htm.

T&D utility's incentive to promote sales.[4] In post-meeting comments, Sharon Staz provided information to the Agencies about the Fox Island Electric Cooperative's (FIEC) ongoing consideration of a fixed charge rate design. While the Agencies consider a detailed discussion of fixed charge rate design beyond the scope of this report, we wanted to remind the Committee that there are a variety of alternative regulatory mechanisms that can be used to remove a utility's incentive to promote sales and that FIEC is currently considering the merits of a fixed charge rate design.

F. Decoupling Mechanism Design Considerations

During the September 14th meeting, the Agencies noted that there is significant disagreement about the relative merits of revenue decoupling and that they were not attempting to reach consensus through the stakeholder process. The Agencies did note that they would identify some decoupling mechanism design considerations in this report to highlight key issues for the Committee. These design considerations are included in section VII of this report.

The Agencies further noted that they did not intend to include specific recommendations about the whether a decoupling mechanism should or should not be adopted in Maine. They further noted that stakeholders would be invited to submit written recommendations regarding the implementation of revenue decoupling and that stakeholders' written recommendations would be appended to the report for the Committee's consideration. As noted above, stakeholder recommendations are contained in Attachment B to this report.

III. DESCRIPTION OF REVENUE DECOUPLING

Revenue decoupling is a form of utility[5] ratemaking in which the corporate earnings of a utility are made independent of its level of sales.[6] The purpose of

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[4] The more a utility's costs are recovered through fixed charges (as opposed to usage sensitive charges) the less financial incentive the utility will have to promote sales or discourage energy efficiency. See pages 32- 35 of the *MPUC 2004 Incentives Report* for a discussion of fixed charge rate design.

[5] This report focuses on the application of decoupling mechanisms to T&D utility ratemaking. The Agencies adopted this focus because the June 14th letters from the Committee Chairs indicated that the Committee's concerns related specifically to the financial incentives of T&D utilities. We note that much of the discussion regarding revenue decoupling applies with equal force to gas utilities as is reflected in several of the attached documents.

[6] This does not mean that decoupling "guarantees" a specified amount of earnings for the utility. Under decoupling, only the level of revenues is predetermined. The utility's ultimate earnings will continue to be a function of the utilities managerial and operational performance.

this form of ratemaking is to remove the financial incentive that utilities have to discourage energy efficiency and conservation activities, and to promote electricity sales.[7] This financial incentive is inherent in both traditional ratemaking and multi-year rate cap plans.[8] Under such regulatory paradigms, a utility's revenues (and therefore earnings) are linked directly to sales volumes. Thus, any activity that lowers sales volumes, such as energy efficiency or conservation, will have a negative impact on the utility's bottom line. Conversely, any activity that increases sales will have a positive impact on the utility's earnings.

Revenue decoupling works by severing the link between a utility's sales and its earnings. This is accomplished by pre-establishing a utility's "allowed" revenues, which would typically occur in a traditional rate case proceeding. These allowed revenues are periodically compared to the utility's actual revenues and the difference is tracked for ratemaking purposes in a deferred account. In the event actual revenues are greater than allowed revenues, the difference is returned to ratepayers through a rate reduction. Conversely, if actual revenues are below allowed revenues, the difference is collected by the utility through a surcharge on rates. By establishing a ratemaking process in which the revenue a utility ultimately obtains is independent of sales levels, the financial disincentive that exists under traditional and rate cap regulation to promote energy efficiency and conservation, as well as the incentive to promote increased consumption, is removed because profits are no longer a function of sales volume.

Revenue decoupling does not, however, provide any positive incentive for utilities to promote or support energy efficiency or conservation programs. The mechanism only makes a utility financially neutral to such activities.[9]

The concept of revenue decoupling is not new. It was developed in the late 1980s and early 1990s to address the utility financial incentive problem. During this time, T&D utilities generally were required to take an expanded role with respect to designing and delivering energy efficiency and demand-side management programs. Because of this expanded role, it became important to attempt to align the financial interests of utilities with their obligations to conduct efficiency programs. Without a change in ratemaking approach, utilities would

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[7] Decoupling would also remove a utility's financial incentive to discourage on-site generation.

[8] Over the past 15 years, Maine's T&D utilities have operated under both traditional regulation and multi-year rate cap plans.

[9] There are mechanisms that would create a positive incentive for a utility to engage in efficiency and conservation activities. In effect, all such mechanisms involve ratepayer payments to utilities associated with efficiency programs that enhance their earnings. Such mechanisms are beyond the scope of this report.

have the incentive to design programs that appeared to conserve electricity, but were actually ineffective in doing so.

Maine attempted to address the incentive problem in the early 1990s by adopting a revenue decoupling mechanism known as "ERAM per customer." As discussed in section V, below, Maine quickly abandoned its experiment with decoupling. Other states also adopted decoupling mechanisms that were later discontinued.[10] In section VI below, we note the recent renewed interest in revenue decoupling and the various states that have either adopted a decoupling mechanism or are considering the adoption of such a mechanism.

With the restructuring of the State's electric industry, Maine greatly diminished the financial incentive problem by eliminating the utility obligation to conduct efficiency and conservation programs and placing that obligation first with the State Planning Office and later with the Commission. As a result, Maine utilities no longer have an obligation to conduct programs whose success would be contrary to their financial interest. Thus, the need to address the financial incentives of utilities through changes in the ratemaking structure is significantly less in Maine than in other states in which utilities are required to conduct efficiency programs.

However, Maine's utilities continue to have an incentive to promote sales and act in ways that can be viewed as contrary to State policies regarding energy efficiency and conservation. This continuing financial incentive has lead to utility efforts to enhance sales (or reduce the erosion of sales) through such activities as use of bill inserts to encourage usage by promoting air conditioners, space heaters or increased lighting,[11] opposing legislation that would increase efficiency spending through increases in electricity rates, and resisting the installation of on-site generation (generally on the grounds that purchases from the grid are more cost-effective).

IV. ATTRIBUTES OF REVENUE DECOUPLING

All utility ratemaking paradigms have both positive and negative attributes. The same is true for revenue decoupling. Revenue decoupling mechanisms can be designed to effectively sever the link between utility sales and utility earnings. However, the impact of revenue decoupling is not specific to revenue losses from efficiency or conservation activities. Revenue decoupling results in utilities being

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[10] The *MPUC 2004 Incentives Report* contains a table (page 38) that lists states that had adopted decoupling mechanism in the past, but were no longer operating under the mechanism. At the time of that report, no state was utilizing a decoupling mechanism.

[11] Although Central Maine Power Company (CMP) uses bill inserts in this manner, the inserts do promote the use of energy efficient appliances.

financially neutral to the impact on sales levels (either sales decreases or increases) from any cause, most notably economic conditions and the weather. Revenue decoupling would also reimburse a utility for revenue loses that result from price-induced conservation that does not result from any type of conservation program. Although decoupling does render a utility financially neutral to sales volume, it does not guarantee that the utility will earn its allowed return on equity. Thus, a utility retains its financial incentive to minimize its costs under decoupling.

By severing the link between utility sales and earnings, revenue decoupling has the effect of eliminating a utility's risks of revenue fluctuations deriving from economic cycles and weather variation. Under a decoupling regime, a utility would automatically be kept financially neutral (through future ratepayer surcharges) if an economic downturn or an unexpectedly warm winter results in decreased revenues. Conversely, ratepayers would automatically benefit (through ratepayer refunds) in the event there is higher than expected revenues from economic expansion or colder winter weather. The elimination of a utility's sales level risk that occurs with revenue decoupling should be offset to some degree by a lower cost of capital for the utility that could translate into some level of lower rates.

The operation of the revenue accounting deferrals inherent in revenue decoupling results in periodic surcharges or refunds. This tends to increase rate volatility and uncertainty relative to traditional or rate cap regulation.[12] There are, however, adjustments that can be made to a revenue decoupling mechanism to reduce rate volatility. For example, the allowed revenue under a revenue cap could be adjusted for weather or economic conditions. The implementation of these types of adjustments, however, is complicated and may not work as intended.

Revenue decoupling does remove the impact of sale levels on utility earnings, but may not result in the utility becoming entirely indifferent to the overall level of sales. As a general matter, the loss of utility sales results in higher electricity rates regardless of whether there is a decoupling mechanism in place.[13] Even if its earnings are unaffected, a utility should still have an interest in minimizing its overall rate levels. Utility efforts to increase rates often result in customer acceptance issues and controversy that could entail expensive litigation. Moreover, the more that rates increase, the greater the likelihood that additional customers would seek to leave the grid, resulting in upward pressure

[12] The level of volatility would be less in a restructured environment in which only distribution revenue would be subject to refund or surcharge compared to utilities that have fixed cost generation assets.

[13] To the extent that lower utility sales result from cost-effective energy efficiency, price increases will be offset by bill decreases.

on rates. Therefore, decoupling may not completely neutralize a utility's efforts to maximize sales or avoid significant decreases in load.

In the event that a decoupling mechanism does completely neutralize a utility's interest in sale levels as intended, there are a variety of implications outside the context of energy efficiency and conservation. A utility that is completely neutral to sales would have less interest in promoting economic development within its service territory.[14] Similarly, a utility would have little interest in offering a larger customer a special discount rate as an incentive to remain on the grid (as opposed to self-generation) or to otherwise act to ensure that customer decisions to leave the grid are based on sound economic analysis. The result could be higher than necessary electricity rates and uneconomic decisions by individual customers to cease or reduce purchases through the electricity grid.

For the reader who would like additional information about the attributes of revenue decoupling, we have attached several documents to this report. Attachment C was published by the National Association of Regulatory Utility Commissions (NARUC) in September 2007 and titled *Decoupling for Electric and Gas Utilities: Frequently Asked Questions (NARUC FAQ document)*, provides useful background information and includes a detailed bibliography of current resources on the subject. Attachment D, which was adopted by the National Association of State Utility Consumer Advocates (NASUCA) in June 2007, is captioned *NASUCA Energy Conservation and Decoupling Resolution*. Attachment E is *A Response to the NASUCA "Decoupling" Resolution*, which was published in August 2007 by 11 separately named organizations. Attachment F is a PowerPoint presentation made by RAP in April 2007 and titled *Energy Efficiency and Utility Profits: Aligning Incentives with Public Policy*. Attachment G, a document titled *Revenue Decoupling*, is a policy brief prepared by the Electricity Consumers Resource Council (ELCON) in January 2007.

V. MAINE'S EXPERIENCE WITH REVENUE DECOUPLING

As mentioned above, Maine has experience with revenue decoupling that is generally considered a failure. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling mechanism for CMP (referred to as "Electric Revenue Adjustment Mechanism" or "ERAM").[15] The "allowed" revenue was determined in a traditional rate case proceeding and adjusted annually

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[14] If a "per-customer" decoupling mechanism is in place (see section VII, below), a utility would have the financial incentive to encourage new business to enter the State, but would not have the incentive to encourage increased production.

[15] *Investigation of Chapter 382 Filing of Central Maine Power Company, Order,* Docket No. 90-085 (May 7, 1991).

based on changes in the utility's number of customers (as a result the mechanism was also referred to as "ERAM per customer"). Analyses before the Commission at the time indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP's ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its "allowed" revenues.

CMP's ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was experiencing the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October 1991 that would have increased rates at the time, and resulted in lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.[16]

By the end of 1992, CMP's ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.

Maine's experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties.[17]

VI. ACTIVITIES IN OTHER STATES

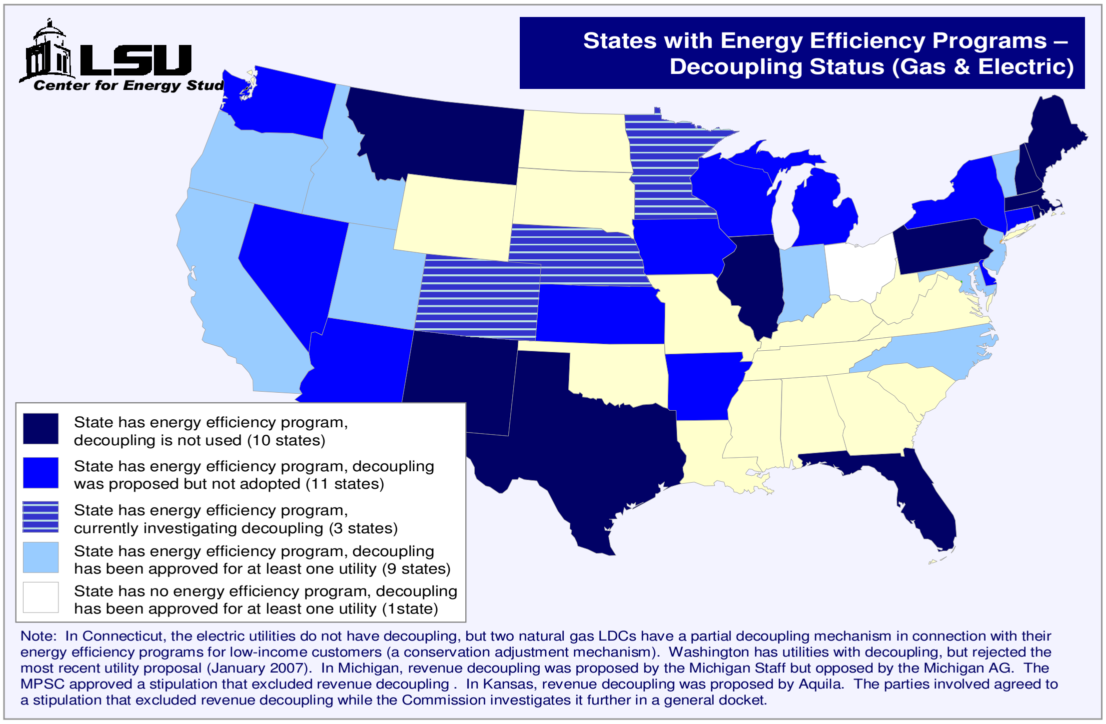
As discussed above, decoupling is not a new concept. It was developed over 15 years ago and was implemented in Maine and in other states in the 1990s. However, there has been a renewed interest in revenue decoupling in recent years. In the last few years, several states have adopted decoupling mechanisms, including Maryland, Delaware, California, New York and Idaho.

[16] *Proposed Increase in Rates, Order Granting Motion to Withdraw Proceeding,* Docket No. 91-174 (Jan. 10, 1992).

[17] *Consideration of Issues Concerning ERAM-Per-Customer for Central Maine Power Company, Order Approving Stipulation,* Docket No. 90-085-A (February 5, 1993). After the termination of ERAM, the Commission's efforts regarding incentive regulation moved to the development of rate cap regulation.

Within New England, Connecticut,[18] Massachusetts,[19] and New Hampshire[20] are at various stages of considering the adoption of a decoupling mechanism.

As the following map shows, 10 states have currently adopted a decoupling mechanism for at least one of their utilities.[21]



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[18] The Connecticut Legislature enacted a law in 2007 requiring decoupling, P.L. 07-242, and the mechanism is being considered in a Connecticut Light and Power rate proceeding, *Application of the Connecticut Light and Power to Amend its Rate Schedules*, Docket No. 07-07-01. In that proceeding, the utility has proposed a revenue per customer approach with an annual true-up of weather normalized revenues.

[19] The Massachusetts Department of Public Utilities initiated a proceeding in June 2007 to consider decoupling, *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources,* DPU 07-50 (June 22, 2007). The Department presented a proposal to adjust revenue based on the number of customers served through an annual reconciliation of allowed revenues and actual revenues.

[20] The New Hampshire Commission has opened a proceeding to consider revenue decoupling. *Investigation into Energy Efficiency Rate Mechanisms,* DE 07-064 (May 14, 2007).

[21] The map was prepared in 2007 by the Louisiana State University Center for Energy Studies.

In addition, Attachment H to this report contains a summary of decoupling activities in other states. Attachment H includes excerpts from a document prepared by the American Council for an Energy-Efficient Economy (ACEEE) in October 2006 titled *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives*. Due to the length of the document, we have not included it in its entirety, but we have included a four-page table and a 15-page written summary of the regulatory mechanisms in other states intended to promote energy efficiency including decoupling mechanisms.

A review of the states that have implemented decoupling or that are considering adoption of the mechanism shows that in almost all of these states, utilities have some responsibility to design and conduct energy efficiency and conservation programs. This is in contrast to Maine in which utilities do not have such responsibilities and, as a result, the financial incentives are of less concern.

VII. DESIGN CONSIDERATIONS FOR A DECOUPLING MECHANISM

As noted above, the Agencies have not attempted to achieve consensus through this stakeholder group process and do not include in this report any specific recommendations[22] about whether a decoupling mechanism should be adopted in Maine. However, there are several basic design considerations for a decoupling mechanism that the Committee should keep in mind as it considers the relative merits of revenue decoupling. These design considerations are summarized below.

In the event Maine pursues a decoupling mechanism, the Agencies believe that the mechanism should be designed in a way that maximizes its effectiveness and chances of success. Maine has experience with decoupling that is generally considered a failure. Any attempt to design a new decoupling mechanism should seek to avoid the pitfalls of Maine's prior efforts.

A per-customer revenue decoupling mechanism is widely regarded as the best approach and is the approach currently used in most of the states that have implemented decoupling. This is essentially the approach that Maine adopted in the early 1990s. To improve the operation of the mechanism and enhance its prospects of success, several adjustments should be seriously considered. These include adjustments for weather and economic trends designed to avoid substantial revenue deferrals based weather or economic fluctuations, rather than energy efficiency or conservation. A weather adjustment is not likely to be difficult because such a mechanism is common in utility ratemaking (e.g. revenue

[22] The Agencies did invite stakeholders to submit written recommendations regarding the implementation of decoupling mechanisms and the recommendations we received are appended to this report in Attachment B.

forecasts). However, an economic adjustment mechanism is uncommon and likely to be complex and extremely difficult to design.

The Agencies believe that a decoupling mechanism should have an annual reconciliation process, but there should also be quarterly rate adjustments if the cumulative difference between actual and allowed revenues is outside a pre-determined percentage range. This should help mitigate the possibility of large rate fluctuations as a consequence of the decoupling mechanism.

The Agencies believe that the decoupling mechanism should only be applied to distribution rates. This is because stranded costs are already reconciled to a large degree, transmission rates are set by FERC, and the energy portion of the rates are determined by the market. There should also be a return on equity (ROE) adjustment to account for any reduced risk faced by the utilities as a result of the adoption of revenue decoupling. The determination of any ROE adjustment is likely to be very complex and controversial.

Finally, the Agencies believe that the adoption of any decoupling mechanism should be accompanied by periodic reviews to determine, to the extent possible, if the mechanism is actually working to change the behavior of the applicable utilities.

VIII. RELATIONSHIP OF REVENUE DECOUPLING TO OTHER ISSUES CURRENTLY BEING CONSIDERED BY THE COMMITTEE

During the September 14th stakeholder group meeting, Representative Hinck asked how the issue of revenue decoupling in Maine would be affected by other issues that are currently being considered by the Committee such as T&D utility participation in the energy supply business. Representative Hinck noted that the Commission is currently drafting a report on this latter topic and requested the Agencies to list other pending reports that cover topics which relate directly to revenue decoupling.

The importance and desirability of revenue decoupling can be affected by significant changes in the regulatory structure that alter the role of T&D utilities in the State. Thus, revenue decoupling should not be considered in a vacuum but in a larger context that includes possible changes to the overall regulatory paradigm. There are several pending legislative reports that discuss the possibility of substantial changes to the current regulatory structure. These include the Commission's reports on the T&D utilities re-entering the energy supply business and alternatives to participation in the ISO-NE. Other relevant reports include the OPA's reports on the relationship of Efficiency Maine and the soon-to-be-created Carbon Trust and the impact that RGGI may have on Maine's ratepayers.

IX. CONCLUSION

As discussed above, decoupling, like all ratemaking approaches, has both positive and negative attributes. In addition, the development of any new ratemaking approach comes with the possibility of serious unintended consequences (as occurred with Maine's experiment with ERAM in the early 1990s). Although we can learn from our mistakes, we can never predict all future scenarios and thus there will always be a risk that despite all the best intentions, ratepayers can be seriously harmed by the unforeseen impacts of alternative ratemaking approaches.

Accordingly, the Agencies believe that policy makers should carefully consider the problem that a new regulatory scheme is intended to address, and weigh the importance of addressing that problem with negative aspects and the prospects for unforeseen difficulties. For example, as stated in *MPUC 2004 Incentives Report* (see pages 40 and 43), there was evidence at that time that utility promotion of usage through bill inserts had limited effect on electricity usage. Moreover, serious consideration of potential benefits should occur before adopting a ratemaking approach that could substantially diminish the desire of utilities to minimize their rate levels. This consideration should take into account that Maine's utilities are no longer obligated to engage in energy efficiency activities thus reducing the need for and potential benefits of a decoupling regulatory structure.

Finally, the *NARUC FAQ document* notes that no major study has been undertaken that actually links decoupling directly to increased utility efficiency activities. That document, which is included as Attachment C to this report, states that some efficiency advocates have anecdotally pointed to strong increases in efficiency activities for some utilities concurrent with the adoption of decoupling, while all New York utilities (between 1993-1997) increased efficiency spending regardless of whether they were operating under a decoupling mechanism. [23]

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[23] *Decoupling for Electric and Gas Utilities Frequently Asked Questions (FAQ),* NARUC (page 4) (Sept. 2007).

UE 197 – CERTIFICATE OF SERVICE

I hereby certify that, on this 23rd day of March 2009, I served the foregoing **AFFIDAVIT OF BOB JENKS ON BEHALF OF THE CITIZENS' UTILITY BOARD OF OREGON'S APPLICATION FOR RECONSIDERATION OF ORDER NO. 09-020, SECTION III.B.12., PGE'S DECOUPLING PROPOSAL** upon all parties of record in docket UE 197, as listed in the PUC Service List, by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending an original and 5 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

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(C) denotes service of confidential material authorized

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UE 197 – CERTIFICATE OF SERVICE

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