BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1415

In the Matter of the **PUBLIC UTILITY COMMISSION OF OREGON** **Staff Investigation into Cost Methods for Use in Developing Electric Rate Spreads.**	**STAFF'S REPLY COMMENTS ON THE COMMISSION MEMORANDUM DATED SEPTEMBER 31, 2011, REGARDING THE DRAFT STRAW PROPOSAL**

Staff appreciates this opportunity to continue the dialogue regarding straw proposal factors and supporting utility directives that the Commission developed to assist it in "evaluating whether or not to approve a proposed mandatory time varying rate."[1] The following Staff's reply comments are organized to generally follow the same sequence of questions and issues contained in the September 30, 2011, Memorandum issued by the Commission following the September 27, 2011, workshop that was held on this subject.

Factors

1. **A number of parties proposed in their opening comments to add additional factors to the straw proposal. Please comment on whether the factors proposed by other parties should be added to the factors in the straw proposal. Why or why not? The parties are also invited [to] propose wording changes to the factors in the straw proposal. Please explain the rationale behind any substantive wording changes.**

Staff

Staff reaffirms its strong recommendation to add the following factor to the Commission's list:

F-8. The level of improvement in achieving rates that reflect cost causation.

Staff is not saying that this factor should over-ride all other factors, in particular the implementation cost factor (F-5).[2] But implicitly, if the relevant cost differentials (i.e., F-7) are well upheld and if the cost-based-rates achievement is high, and if, furthermore the implementation costs are minimal and the

[1] *See* page 1 of Appendix 1 of Order No. 11255.

[2] It should be noted that in the recent past Staff has advocated time varying rates (i.e., seasonal rates for all customers and "enhanced" time-of-day [TOD] rates for large, smart-meter-equipped industrial customers) only under circumstances where implementation costs would be minimal.

customer-impact factors (i.e., F-3, F-4, and F-6) are met with satisfaction, then the factors regarding conventional demand-side benefits (i.e., F-1 and F-2) can take on minimal relevance.[3]

A long-standing policy of the Commission is that rates should reflect costs. Clearly rates, per se, can't reflect costs unless the cost-allocation/rate-spread process also reflects costs. Our commission was one of the first to adopt marginal cost concepts to rate spread and rate design. (*See* Order No. 74-998, pages 26-30, and Order No. 78-521, in its entirety.) PGE and Idaho Power most notably factor in seasonal and diurnal cost factors in their rate spread studies. As a consequence, customers within a class whose loads are concentrated more on the peak periods cause their class to take on a greater revenue requirement burden.

As regards rate design more particularly, Order No. 78-521, page 4, reads as follows:

> With no change in usage patterns, typical customers will often pay the same annual total dollar amount under time-of-use pricing as under non-time-differentiated tariffs. Those who consume relatively more during peak periods will pay more and those who consume less during peak periods and more during off-peak periods will pay less. However, consumers are free to alter their patterns of demand to save themselves money at the same time they save the company money. *The purpose of marginal cost pricing is not necessarily to level the company's load or otherwise to shift it in time, but to charge prices which reflect cost differences at different times of use* (emphasis added). To the extent demand is responsive to price, shifts in time of demand may be expected.

That same order, 78-521, directed PGE to file seasonal residential rates to reflect cost differences and the same order approved the seasonal residential rate design filed by PacifiCorp.

With regard to the F-4 factor, and given the context of considering/evaluating *mandatory* time-varying rates, Staff recommends removing the clause, "opt-in and opt-out provisions." In its stead we would suggest the clause, "*promoting equal-pay provisions*.[4]" The inclusion of optionality in our context would create an internal inconsistency that would cloud the meaning of, or ability to evaluate, other factors. For example, how would "[t]he amount of. system benefits that can be tapped through a time-varying rate" (i.e., F-1) be evaluated if there were little or no apprehension regarding the customer load that would participate in the candidate optional time-varying rate. As we discuss below, Staff believes there can be

[3] This position is directly contrary to the following ICNU recommendation that would place great weight on factor F-1: "No time-varying schedule should be implemented without a rigorous review of the elasticity of [inter-temporal] substitution of each class of potentially effected [sic] customer." (*See* page 3 of Opening Comments of ICNU.)

[4] "Equal pay" refers to smoothing out the monthly bills over the course of the year. Such occurs without altering the prices that determine the various month's accrued payment *obligations,* which would also be clearly shown on each month's bill.

an important role played by selectively applied optionality in the realm of time-varying rates, but such would constitute quite a different context within which the Factors and Directives are evaluated.

With regard to the F-2 factor, Staff would simply recommend the substitution of the more general phrase, "those benefits," for the phrase, "that resource."

ICNU

ICNU proposes several additional factors. The first such factor is, "How will differently-situated customers be affected by the proposal?" Staff does not support adding this as a factor. This question is already covered by factors F-3 and F-4.

Another factor proposed by ICNU is, "What actual costs will the proposal attempt to recover?" ICNU seems to be arguing that resources presently used and useful and partially depreciated should be the costs included in the analysis–suggesting an embedded cost study instead of a marginal cost study for purposes of evaluating a time-varying rate proposal. Staff continues to support cost-allocation and rate design analyses based on marginal costs, meaning going-forward economic costs. Even assuming that current loads were met entirely with fully depreciated plant, the reduced loads induced by a rate proposal in the long run can enable the deferral of new plant additions due to what would otherwise have been future load growth; and in the short run can produce surplus off-system sales at market prices which ordinarily carry a marginal-cost basis. Having said all that, the reader should bear in mind that what are spread to the customer schedules are *embedded* costs, and it is each schedule's share of those costs that, in the aggregate, the rates must recover–be they time-varying or non-time-varying rates.

ICNU also suggested the factor, "Will the Proposal create revenue instability, leading to higher costs of capital?" The Commission could add a new factor F-9 to capture changes to near term utility costs and revenues that are incurred by the utility. F-9 then would read, "*The yearly effects on utility power costs and revenues arising from the time-varying rate*." The indicated ICNU wording is not recommended as it assumes that revenue instability must lead to higher costs of capital. This is not necessarily true. For example, consider power cost excursions that are ideally exactly matched by the time-varying rate excursions. In this case, the instability of power costs is neutralized and the resulting *net* revenues are changed from an unpredictable path to a smooth and level path. This might lead to a lower cost of capital.

Finally, ICNU suggested the factor, "Does the proposal create a danger of windfall revenue for the utility at the expense of the customers?" Examples of "expense of the customers" included family-time disruption and greater night-time accident rates. The first part of this factor is captured sufficiently by the suggested new F-9 proposed factor. The latter part can be addressed by the addition of the following (italicized) language to factor F-3: "The impact on customers (*including secondary and/or non-price-related effects*) of the proposed rate (e.g. rate shock, bill impacts on vulnerable populations, the choice between direct access and standard cost of service, etc.) and the ability of customers to respond to those impacts."

<u>PacifiCorp</u>

PacifiCorp proposes an additional factor that addresses "the importance of acceptance by customers of time-varying rates, particularly if mandatory rates are proposed." Staff suggests that this consideration is already present in factor F-3, F-5, and F-6. However, factor F-6 could be revised to read, "The ability to explain and communicate the rate to customers, *as well as its general acceptance"* [new language in italics].[5] In addition, and in recognition of the additional costs involved in communicating and promoting time-varying rates, factor F-5 could be augmented to read, "The direct costs of implementing time-varying rates (e.g., IT costs, accounting, *call-center and outreach burdens,* etc) [new language in italics]."

<u>PGE</u>

PGE proposes several additional factors and each will be discussed in turn.

The first of several factors PGE proposes relates to customer acceptance. PGE notes that lack of customer acceptance could lead to higher call center costs. Staff's proposed revisions to factor F-5 and F-6 address this general concern.

The second PGE proposed factor relates to maintaining competitive neutrality of a time-varying rate with direct access. Staff supports PGE's concern. Factor F-3, could be revised to address this issue as follows: "The impact on customers of the proposed rate (e.g. rate

[5] The weight placed on the "acceptance" feature within this factor may be different from the weight given to communication and explanation.

shock, bill impacts on vulnerable populations, *choice between direct access and standard cost of service*, etc.)..."

The third PGE proposed factor deals with revenue impacts on the company. Staff views a *net* revenues concern as more appropriate insofar as a simultaneous reduction or increase in costs *and* revenues would maintain stability in the company's earnings. Staff's proposed new factor F-9 should address this issue.

The fourth factor proposed by PGE involves price elasticity of demand estimates. Staff believes this is adequately handled by factor F-1. In addition and as might be inferred from our earlier statements, Staff concurs with Idaho Power's comment of belief that "the weight given to these factors [i.e., F-1 and F-2] should be limited because at this time the underlying data that would be used to support either factor are estimates at best."[6]

The fifth factor or concern identified by PGE is the complexity of explaining the time-varying rate and the "ability to evaluate the results." Staff believes this is adequately addressed by factors F-3, F-5, and F-6.

The sixth factor proposed by PGE reads as follows: "The availability of cost effective alternatives such as direct load control or other use of technology to automate changes in consumption patterns to create system benefits." Staff believes this consideration is incorporated in factor F-2. Furthermore, in assembling their preferred production portfolios the electric utilities' IRP processes already give considerable heed to a panoply of demand-response and conservation resources as alternatives to conventional thermal and other generation facilities.

<u>CUB, AARP, CAPO, and Oregon HEAT</u>

The comments of these parties were generally dedicated to a categorical opposition to *mandatory* time varying rates, the expressed subject of this phase of the Docket. As a substitute, those parties suggest optional time varying rates (to be discussed later) and conventional demand-response programs.[7] Staff does not want to minimize the role that non-price-based DSM programs might play in fostering important, economizing system benefits. However, we believe the aspirations of this docket are

6 *See* page 3 of Idaho Power's Opening Comments.

7 "Conventional demand-response programs" means Class 1 (i.e., dispatchable load reduction) or Class 2 (i.e., conservation-based) demand-side-management (DSM) programs. The less conventional Class 3 DSM is the *price-based* category, and the subject of this docket.

ambitious enough without increasing the docket's scope by now involving more than a minimal reference to conventional demand-response programs.

<u>To encapsulate, Staff's proposed factors are as follows:</u>

F-l. The amount of demand-side resource and system benefits that can be tapped through a time-varying rate.

F-2. The extent to which an optional rate or alternative program can achieve those benefits.

F -3. The impact on customers (including secondary and/or non-price-related effects) of the proposed rate (e.g. rate shock, bill impacts on vulnerable populations, the choice between direct access and standard cost of service, etc.) and the ability of customers to respond to those impacts.

F-4. The means available to mitigate impacts on customers (e.g. phasing in of rate differentials, promoting equal-pay provisions, providing programmable equipment or software to enable customers to respond more easily, etc.).

F-5. The direct costs of implementing time-varying rates (e.g. IT costs, accounting, call-center and outreach burdens).

F-6. The ability to explain and communicate the rate to customers as well their general acceptance.

F -7. The cost differential between the relevant time periods, how robust the cost studies are, and whether customer response to the time-varying rate is expected to affect the cost differential over time.

F-8. The level of improvement in achieving rates that reflect cost causation.

F-9. The yearly effects on utility power costs and revenues arising from the time-varying rate.

2. **Some parties argued that seasonal rates are fundamentally different from other time-varying rates, and should therefore be analyzed differently. Do you agree? If so, should the Commission use a different set of criteria for evaluating seasonal rates, or should the factors under consideration simply be weighed differently?**

Staff has two principal recommendations in response to this question: First, the same factors the Commission adopts for evaluating mandatory time-varying rates can appropriately be used to evaluate seasonal rates. While the factors may be the same, the Commission acknowledged in its order No. 11-255,"We may weigh the factors differently depending on the type of time-varying rate." As regards seasonal rates and as discussed earlier, Staff would likely place substantial emphasis on our new factor F-8 (i.e., The level of improvement in achieving rates that reflect cost causation), and less emphasis on factor F-1 (i.e., The amount of demand-side resource and system benefits that can be tapped through a time-varying rate). It is also recognized that some factors are much less problematic with regard to seasonal rates than with other kinds of time-varying rates. For example, direct utility implementation costs are lower (i.e., F-5) and, based upon past experience in other jurisdictions, mandatory seasonal rates are easier to explain and achieve customer acceptance (i.e., F-6) than would be mandatory time-of-day rates–particularly on behalf of residential customers.

Second, because of the relative simplicity of seasonal rates and their limited applicability for achieving short-term peak load reductions, Staff appreciates the Commission's "clarification" that the process of "systematically evaluating promising time-varying rate designs…does not necessarily need to occur as part of the Integrated Resource Planning." Staff concludes that seasonal rates in particular can be proposed, analyzed and evaluated within the context of a general rate case, while fully incorporating a consideration of the nine factors.

A Note on the Role of Precedent in Rate Spread and Rate Design: Since direct implementation costs (i.e., F-5) and time-period cost differentials (i.e., F-7) may be quite different with respect to one utility versus another, time-varying rate "reforms" that are "ruled" by this Commission for one utility should not have presumptive precedential bearing on another utility. Staff clarified at the workshop that support for Idaho Power's proposal for seasonal rates did not, and in fact has not, implied support for seasonal rates for the other electric utilities. Staff noted that while supporting seasonal rates for Idaho Power, it did not advocate seasonal rates for the customers of PGE, in that company's most recent general rate case (UE 215).

3. Should the factors under consideration in the straw proposal also apply to voluntary time-varying rates? Demand-response programs? Please explain. Are there additional or different factors that should be applied to evaluate voluntary time-varying rates and demand-response programs?

With minor modifications,[8] the same factors should apply to voluntary time-varying rates programs as to mandatory programs. Also, some factors will be applied differently between the voluntary and the mandatory programs.[9] Finally, a number of the factors would be approached or evaluated differently if the voluntary program were opt-in versus opt-out. (Clearly, opt-out would better serve the F-8 objective of increasing the amount of load served under rates that reflect cost-causation.)

As regards conventional, non-price-based demand-response programs, the nine listed factors would seem, on the face of it, to apply–with the exception, that is, of the just-mentioned factor F-8, and the obvious substitution of "demand-response program" for "rate" or "time-varying rate."

[8] Example: F-2 would be modified to say, "The extent to which an ~~optional rate or~~ alternative program can achieve those objectives."

[9] Example: As regards communication and acceptance F-6), the primary focus would be on the marketing of the program to obtain the hoped-for participation.

Directives

1. **[Original d]irective 1 (D-1) asks the utilities to provide the Commission with detailed information on the cost of serving Oregon customers during different time periods. In essence, the Commission is seeking an overview of the cost differentials of serving customers during different time periods in each utility's service territory. If a party believes that D-1, in its current form, is imperfect or unachievable, please provide an alternative method for providing the Commission with the type of overview it is seeking.**

While these "directives" and accompanying instructions are primarily aimed at utilities, we as Staff would like to weigh in with some brief comments. One utility[10] stated that it "does not have hourly cost of service data at the requested level of detail." We find that curious insofar as that utility has a peak/shoulder/off-peak rate design for its large customers. Staff expects that sufficient granularity in the cost data is being brought to bear so as to appropriately construct the specifics in both price and duration of on-peak, shoulder, and off-peak rates. Presumably no utility is constrained in its pricing alternatives by what some publication or market says is on peak and off-peak. Utilities have their own load patterns, with peaks–based on their loads served–potentially different from the region's. The utilities should be directed to find methods by which to construct meaningful hourly marginal cost values given their load and dispatch-cost structures.

2. **To the extent a party believes that the IRP process is not the right place for the proposed "systematic look" at time-varying rates, please describe, in much detail as possible, an alternative venue and process for achieving the Commission's stated goals.**

Staff appreciates the desire to use a timely and thoughtful process by which to analyze time-varying rates. Staff is unable to identify any singular type of docket which best fits this need. For simpler rate designs such as seasonal rates, staff believes consideration within a general rate filing is sufficient. For more complex time-varying rate designs, a separate, dedicated docket may make sense for the purpose of analyzing their merits. But ultimately, and here Staff agrees with a comment offered by CUB's expert Barbara Alexander (i.e., as we interpret it), the final scrutiny of any rate proposal as it relates to a particular utility and its tariff filing must fall under an ORS 757.210 review.

3. **The Commission intends to require utilities to work with Staff and stakeholders to periodically evaluate time-varying rates and programs. Please identify four or five types of time-varying rates or demand-response programs that should be examined by the utilities. This list need not be limited to mandatory rates. It may also include voluntary programs, pilot programs, and demand-response programs that you believe to be promising and should be explored now. This list is not intended to be a final list.**

Staff Recommendations

The Broad Picture of Demand Response (DR)

[10] *See* pages 6 and 7 of the "Opening Comments of Idaho Power."

According to the *Implementation Proposal for The National Action Plan on Demand Response*, "...demand response and variable rate projects should offer insight into how customers react to different types of demand response offerings and how different offerings affect energy use levels."[11] USDOE has argued that "States should consider aggressive implementation of price-based demand response for retail customers as a high priority,,,"[12] That report argues that "Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers.

The transformation to time-varying retail rates will not happen quickly. Consequently, fostering DR through incentive-based programs will help improve efficiency and reliability while price-based DR grows.[13]

TABLE 1

Price-Based Options
•Time-of-use (TOU)
•Real-time pricing (RTP)
•Critical Peak Pricing (CPP)
Incentive-Based Programs
•Direct load control
•Interruptible/curtailable (I/C)
•Demand Bidding/Buyback Programs
•Emergency Demand Response Programs
•Capacity Market Programs
•Ancillary Services Market Programs

[11] "*Implementation Proposal for The National Action Plan on Demand Response,*" Report to Congress Prepared by staff of the Federal Energy Regulatory Commission and the U.S. Department of Energy, p. 18.

[12] "Benefits of Demand Response in Electric Markets and recommendations for Achieving them, A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005" USDOE, Feb., 2006 p. V.

[13] Ibid.

Table 1 lists some of the alternative types of price-based (or economic) and Incentive-Based programs that can be implemented to capture DR energy savings.[14] Price-based DR programs generally do not allow the end-user to override a high price signal. Therefore, this DR resource is considered dispatchable, or in the terminology of the Pacific Northwest, a firm resource. However, it is not necessarily the case that end-users must be prohibited from not responding to the utility's dispatch signal. If the end-user is given the option to play that role, the DR has significantly less value to the utility because it is no longer a dispatchable resource. Again, in the language of the Pacific Northwest, that DR would be considered non-firm resource. One example is the pilot operated on the Olympic Peninsula by the Bonneville Power Administration with the cooperation of a retail utility. Homeowners could vary their preferences between greater comfort or lower bills and in so doing affect the point at which a price signal would result in reduced consumption.[15]

Risk is an additional issue to consider when designing a utility's approach to acquiring DR resources. A report by EnerNOC[16] on DR presented at the Northwest Power Planning and Conservation Council (Power Council), provides a good overview of the mix of approaches to achieving DR using a portfolio approach to risk management. While a full discussion of a portfolio approach is beyond the scope of this document, suffice it to say that a portfolio approach is designed to address both performance and cost risks of DR by 'spreading' a utility's DR resource across a variety of approaches to implementing DR. The table below, titled "Building a Portfolio of DR Programs," illustrates some of the alternatives designs available when crafting either price-based or incentive-based study options, using a portfolio approach.

[14] Ibid, p. 14.
[15] *See:* D. J. Hammerstrom, Principal Investigator , Pacific Northwest National Labs, "*Pacific Northwest GridWise™ Testbed Demonstration Projects Part I. Olympic Peninsula Project,*" PNNL-17167, October 2007.
[16] EnerNOC, "*Commercial & Industrial Demand Response: An Overview of the Utility/Aggregator Business Model,*" Presented at Pacific Northwest Demand Response Project Workshop, April 28, 2011.

Building a Portfolio of DR Programs

Utilities often diversify their implementation approaches in order to reach across all customer classes while maximizing impact and minimizing risk.

	DLC	Dynamic Pricing	TOU	Interruptible Tariff	C&I DR (Utility Managed)	C&I DR (Outsourced)
Customer Classes	Residential	Residential and C&I	Residential and C&I	C&I	C&I	C&I
Dispatchable	Yes	No	No	Yes	Yes	Yes
Customer Penalties	Sometimes	No	No	Yes	Yes	**No**
Performance Guarantee	No	No	No	No	No	**Yes**
AutoDR Capability	Yes	Yes	No	Yes	Yes	Yes
ENOC Offering	Consulting Services	Consulting Services	Consulting Services	Consulting Services	Implementation Services	Turnkey

Five Proposed Study Options

As a result of reviewing reports, studies, and comments made in UM1415, Staff is proposing the five study options listed in Table 2. These study options are not necessarily mutually exclusive; more than one may be selected for a given utility and features of several could be combined into a new study option. Turning to Table 2, study options 1-3 fall into the category of Incentive-Based Programs. These may be dispatchable or non-dispatchable depending on the ability of the end-user to overrule the utility's curtailment signal. Study options 4 and 5 fall into the category of Price-Based Options. These two study options can be designed in two different ways–either fully curtailable or allowing end-user ability to override.

TABLE 2

1. Incentive Based utility/customer load control pilot for the Residential Sector
2. Incentive Based utility/customer load control pilot for the Commercial and Industrial Sectors
3. Incentive Based utility/customer load control pilot for other end-uses (e.g., Irrigation)
4. Price-Based pilot using Hourly Pricing (HP) for the C & I sectors
5. Price-Based pilot using CPP, possibly with PTR for low-income, or a TOU pilot combined with CPP as an opt-out. Seasonal Rates could also be included.

At this point, staff is framing these study options at a conceptual level to seek comments to further refine staff recommendations. One reason for the Incentive Based utility/customer load control pilot study options is that staff anticipates a fairly slow adoption of time-varying rates. Second, for this particular set of study options are in response to comments made in this docket. Staff is also proposing two Price-Based DR study options. These two study options reflect comments made in UM1415, results from numerous pride-based DR studies across the country, and arguments made by USDOE.

This set of study options aren't 'written in stone.' Staff proposes a collaborative effort among the parties. Once utility-specific factors are taken into consideration, staff expects that each utility will have its unique mix of study options. There is also a rationale for combining features of several different study options when reaching a proposed approach for a given utility.

It's important to note that CUB has argued that DR programs can provide all the system benefits that would be achieved using load control programs[17]. Staff has not been able to locate a study that would substantiate that argument.[18] Consequently, staff remains uncertain about whether Incentive-Based DR pilots can provide savings at least equal to what can be accomplished using price-based DR pilots.[19] This uncertainty is echoed in a report from the Power Council. Quoting, "The region still lacks the experience with demand response to construct a detailed and comprehensive estimate of its potential. To make that estimate possible, the region will need to conduct a range of pilot programs involving demand response. These pilots should pursue two general objectives, research and development/demonstration."[20]

A short discussion of Staff's proposed study options follows:

1. *<u>Incentive Based Pilot for the Residential Sector</u>*

   This study option is intended to examine the amount of DR that may be achievable in the residential sector. It should also help identify logistical issues that need resolution, and also refine cost estimates for implementing a full program across a utility's Oregon service area.

   This study option is partly a response to the general view that pilots and programs for direct load control of appliances (e.g., air conditioners, water heaters, and pool pumps) have an established track record and should be maintained or expanded.[21] That USDOE report identified a number of possible features of this type of approach, including:

[17] Using staff's terminology, CUB wants Incentive-Based Programs to be used rather than Price-Based Programs.
[18] If a party knows of such a study, staff is very interested in hearing about it.
[19] Both the quantity of savings and the pattern of savings across hours of the day and/or months of the year should be compared. Savings on a cost per-kilo-watt hour basis should also be a part of any such evaluation. Finally, a portfolio approach should also be part of DR pilot design.
[20] Sixth Northwest Conservation and Electric Power Plan , "*Chapter 5: Demand Response*," p. 5-1, February 2010.
[21] U.S. Department of Energy, "*Benefits of Demand Response and Recommendations*," pp. 33-34.

- Administratively-determined floor payment that exceeds customers' transaction costs;
- "Pay-for-performance" approaches that include methods to measure and verify demand reductions;
- Low-entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and
- Multi-year commitments for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.

Possible end-uses for DR are water heating, space heating, air conditioning, pool pumps, and hot tub heaters. This study option would provide data to assess how well this Incentive-Based program may meet both the timing and quantity of load reduction requirements and their costs. If it's possible to have two study groups, one with the ability to override a dispatch signal and a second group that does not have that option, that will also help determine the impact that option has on total savings and costs and the pattern of savings across time,.

Incentive-Based DR pilots that use a signal to dispatch an end-use will help determine what issues need resolution when those signals are sent downstream from the utility to the end-use. There are various ways to send that signal, including but not limited to, using Advanced Meter Infrastructure (AMI). Such a program can also be designed to help identify more effective marketing strategies, recruitment and education programs, and participation persistence.

2. *Incentive Based pilots for the Commercial Sector and Industrial Sectors*

For purposes of brevity, the commercial and industrial sectors are combined since they are often reported together as C&I. However, staff is not limiting this study option to necessarily require that programs and/or pilots occur in only both sectors or none at all, or that the same pilot design be used in both sectors.

This study option is intended to measure customer response to utility dispatch signals in order to help assess DR potential. In combination with one or more of the other study options, data would then be available to assess the effectiveness of this approach to acquiring DR as compared to rates approaches. Ideally, there would be one group of customers that have no ability to overrule the dispatch signal and another group of customers who have the ability to overrule the dispatch signal.

Smith[22] argues that commercial programs must be designed considering three dimensions: cost-effectiveness, control, and convenience. He argues that for each of these factors, technology in the building will play an important role. For example, he sees technology as playing the central role in helping to achieve DR by providing "instantaneous information and communication, quick and automated load shed, and built-in measurement systems." It appears that displays and dashboards,

[22] Kelly Smith, "Scaling Demand Response through Interoperability in Commercial Buildings," Johnson Controls.

and communication systems will be especially important to achieve automated demand response (ADR) in commercial buildings. Pilot design should consider the type of information the utility wants from the pilot(s).

For example, Seattle City Light (SCL) has identified the following goals,[23]

- Integrating metering with internet access to the data,
- Identifying effective education program,
- Training a workforce that understands the technology,
- Working to integrate DR programs into building design and renovation,
- How much DR is available not only during winter and summer peaks but also during swing seasons.

Incentive-Based DR pilots that use a signal to dispatch an end-use will help determine what issues need resolution when those signals are sent downstream from the utility to the end-use. Such a program can also be designed to help identify more effective marketing strategies, recruitment and education programs, and participation persistence. Finally, it will be useful to determine what types of C&I DR help address various system problems from emergencies, reducing peak loads, and providing contingency reserves as well as regulation and load following services.

SCL pursued this pilot even though DR was not cost-effective. They viewed the pilots helping to learning more about its use in a winter peaking system, demonstrate and evaluate openADR communications architecture, and learning more about which commercial end-uses in what types of buildings may be eligible for dispatch at different times of the year.[24] Finally, some possible DR end-uses include: air handlers, anti-sweat heaters, chiller control, chilled water systems, defrost elements, elevators, escalators, external lighting, external water features, HVAC systems, internal lighting, irrigation pumps, motors, outside signage, parking lot lighting, production equipment, processing lines, pool pumps / heaters, refrigeration systems, and water heating.[25]

Returning to the EnerNOC report, it provides insight into the broad range of facilities and approaches that may be used to achieve DR in these types of facilities.[26] The table below provides a glimpse at the range of C&I DR designs and end-use applications.

[23] *See: "Northwest Open Automated Demand Response Technology Demonstration Project,"* (LBNL 2573E-Final), http://drrc.lbl.gov/pubs/lbnl-2573e.pdf, Appendix J, pp. 5-6.
[24] Ibid, Appendix J, p. 1-2.
[25] EnerNOC, "*Demand Response: A Multi-Purpose Resource For Utilities and Grid Operators*,2009*,* p. 2.
[26] "*Commercial & Industrial Demand Response: An Overview of the Utility/Aggregator Business Model,"* slide 24.

C&I Curtailment Plans Vary Widely by Facility

Type of Facility	Demand Response Plan	Capacity
Bowling alley / ice rink	Shut off one-half of the building's lighting and reduce HVAC temp by 10 degrees, while raising the set point on the ice rink cooling equipment	150 kW
Commercial office building	Use BMS to setback A/C temp by 4 degrees; turn off water feature pumps	250 kW
Dairy manufacturer	Shut down cooler equipment and a 350 HP compressor	250 kW
Farm supply company	Shut down pellet and hammer mill; turn off 50% of the facility's 400-watt lights	350 kW
Foil processing plant	Shut down etching machines and rectifier lines	500 kW
Graphics and printing company	Shut down air handler units in the press room and raise temperature set points in the office area	250 kW
Grocery store chain	Shut off one-third of in-store lighting across over 100 locations	50 kW per store (avg.)
Public school system, four locations	Shut off rooftop package units, 30 HP heat pump, and wall mount classroom units	500 kW
Retail office supply store	Use BMS to develop custom curtailment plans across over 400 locations	30 kW per store (avg.)
Shopping mall	Shut off one-half of the roof top units through its BMS system	350 kW
Thread manufacturer	Shut down chiller and 50% of its spinners and twisters	300 kW

EnerNOC reports that they currently have DR pilots with IPC aimed at achieving 65MW. That program is called FlexPeak Management.

It is worth noting that PGE has several existing pilots in this area. One pilot, Automated Demand Response (ADR), is a dispatchable DSM with a 6-10 minutes response time and is most applicable for large commercial customers. Another PGE project, the Firm Load Reduction Program (Schedule 77), provides for advance notification of four or twenty-four hours prior to the customer's having to reduce its load by the contracted amount. The inventive price is higher with the shorter notification period. This pilot is limited to very large industrial customers and it does provide for a limited number of times the customer may opt out–but with a penalty

It may also be useful to expand existing investigations into the use of third-party DR aggregator for C&I DR. EnerNOC notes a variety of advantages of this approach, including, but not limited to,

- Guaranteed performance to utility, while shielding businesses from under-performance penalties,
- Utilities contribute employee knowledge and customer relationships, EnerNOC manages and maintains the resource,
- No new tariff required; utility signs one contract with aggregator.[27]

[27] EnerNOC Report, slide 14.

EnerNOC suggests that DR in C&I can be either manual or automated, and that a customized curtailment plan is usually required. They also note that while businesses in these two sectors have some energy sophistication, most will require guidance, and that metering and control technology results in this being a highly reliable source of DR.[28]

3. *Incentive Based pilot for other end-uses (e.g., Irrigation)*

Based on reports filed by Idaho Power (IPC), Portland General Electric (PGE), and PacifiCorp (PAC), in docket UM1460, DR potential in other rate classes and end-uses should also be evaluated. One example is irrigation DR.

The Power Council's 6th power Plan assumes that 200MWs of irrigation DR available by 2030 in the Pacific Northwest at a fixed cost of $60/kW-year and be available for 100 hours/year.[29] They also note that PacifiCorp and Idaho Power currently are reducing irrigation load by about 100 megawatts through scheduling controls at an assumed cost of $60 per kilowatt a year, limited to 100 hours per summer.[30]

Turning to IPC, they currently have an Irrigation Load Control project for the purpose of turning off irrigation pumps during times of peak power usage.[31] They also have what they call an Irrigation Peak Rewards program, which according to IPC, is voluntary, available to all Idaho and Oregon agricultural irrigation customers, and applies to the season June 15 through August 15. Participants chose between three options: 1) the electric timer option; 2) an automatic dispatch option that allows IPC to remotely turn participants' pumps off, or 3) a manual dispatch option designed for large-service locations.[32] Lastly, according to EnerNOC, they are working with PAC to acquire about 400MW of irrigation DR.[33]

4. *Price-Based pilot using Hourly Pricing (HP) for the C & I sectors*

These two sectors provide an opportunity to assess the success, impediments, and costs associated with an hourly pricing program to reduce peak use. Generally, studies reviewed showed that RTP provided the greatest change in peak use.

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[28] "*Demand Response: A Multi-Purpose Resource For Utilities and Grid Operators,* 2009, p. 9.
[29] Chapter 5 of the 6th power Plan, table 5-2.
[30] Ibid, p. 5-9.
[31] Idaho Power Company, "*Smart Grid Plan for the Public Utility Commission of Oregon,"* October 2011, p. 6.
[32] Ibid.
[33] EnerNOC presentation, slide 9.

The Brattle Group reports that the average medium-sized commercial customer could produce a peak reduction of 5% to 10% with dynamic pricing.[34] They also report the following forecast of average change in peak usage by rate design per medium C&I customer: RTP -1.40 to 4.5 percent, TOU -1.78 to 5.9 percent, and CPP/TOU -3.00 to 9.9 percent.[35] While these results suggest that CPP/TOU pricing pilot results exceed those for this study option, they also report that this study option resulted in a smaller upside exposure bill impacts for a medium size commercial customer. The bill impacts as -7.03 to 0.4 percent from RTP, -49.05 to 1.9 percent from TOU, and -57.40 to 2.2 percent CPP/TOU rates.[36]

It's important to note that these estimates of peak reduction for various rate designs are based on results in California's statewide pricing pilot. Therefore, these estimates likely exceed what we could expect in Oregon given the differences in rate levels and design between Oregon and California.

Connecticut Light and Power (CL&P) ran a pilot called The Plan-It Wise Energy Pilot[37]. C&I customers on the Peak-Time price tariff reduced peak demand 7.2 percent with enabling technology (such as a smart thermostat, energy orb or appliance smart switch) and 2.8 percent without that technology. On average, Plan-it Wise C&I customers averaged monthly savings of $15.45. In an exit survey, 74 percent of the C&I participants said they would be open to further programs.

5. *Price-based pilot using CPP, possibly with PTR for low-income, or a TOU pilot combined with CPP as an opt-out. Seasonal Rates could also be included.*

This study option would provide information on a number of factors including the impacts of this type of rate design on both customers and on the utility. Existing opt-in TOU rates in the residential sector have not received many customers, probably for a variety of reasons. However, studies in other states have shown that TOU rates can lead to reductions in peak usage, and in some cases, reduction in total energy usage.[38] However, opt-in rates create greater revenue recovery risk for utilities compared to opt-out rates due to adverse selection. That is, with opt-in, we expect that people who opt-in expect to reduce their bills. In contrast, there is less revenue recovery risk under opt-out for several reasons. First, only a small number of customers will choose to opt-out. Second, some customers that remain in the program will reduce their bills while other will experience higher bills. These two reasons tend to result in lower revenue recovery risk for the utility.

[34] Ryan Hledik, The Brattle Group, "*The Coming Wave of Price-Based Demand Response,*" DR Expo, Santa Clara, May 22, 2008, slide 9.
[35] Ibid.
[36] Ibid, slide 10.
[37] Refer to the appendix for other conclusion of this study and citations.
[38] A summary of some of the existing studies is presented in the appendix.

One of the price-based programs summarized in the appendix that staff finds especially interesting was conducted in Washington D.C. and is called the PowerCentsDC project.[39] In that project, three pricing plans were studied, Critical Peak Pricing (CPP), Critical Peak Rebates (CPR), and Real-Time Pricing (HP for Hourly Pricing) that followed the wholesale electric price. Customers with limited income participated only in the CPR option. It should be noted that summer peak reduction under CPR for the low-income group was 11 percent while it was 13 percent for 'regular' income customers. Among other conclusions, they note that CPP led to the greatest reductions in peak demand while CPR was the most popular option. Regarding low-income participants, participation rates were higher than for the regular income group, and the low-income group's peak reduction was only slightly less than that for the regular group.

Referring again to the CL&P pilot, consumers who participated received a smart meter, along with an enabling technology such as a smart thermostat, energy orb or appliance smart switch. Residential customers enrolled in the Peak-Time Price (PTP) rate plan reduced peak demand by 23.3 percent if supplied with an efficiency enabling device, and 16.1 percent without such a device. On average, Plan-it Wise residential participants saved $15.21 over the three-month pilot span. In an exit survey, 92 percent of the residential participants said they would be open to further programs.

CPP pilot (possibly with a PTR option for low-income customers) would test customer degree of responsiveness. Customers may be in a position to mitigate any negative impacts from higher rates by adjusting their usage and by the way this study option is designed. For example, one way to design this study option is to randomly selected customers and offer them the option to enroll in this study option or them the option to opt-out.

Finally, PGE will soon be billing customers who are part of its residential CPP pilot. The details of that pilot may be found in Schedule 12.

Overview of Pricing Pilots Summarized in the Appendix

One comment staff has heard in this and other dockets is that the pilots and studies summarized in the appendix were all conducted in summer peaking utilities and therefore have limited applicability to IOU customers in Oregon.[40] Performing price-based DR pilot(s) here in Oregon would provide information on issues raised by the parties.

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[39] Refer to the appendix for citation to the final report of this study.

[40] Preliminary discussions between staff and program management at Sierra Pacific Power CO, a subsidiary of NV Energy, indicate that they have several pilots underway and that they are a winter peaking utility.

IOU customers in Oregon.[40] Performing price-based DR pilot(s) here in Oregon would provide information on issues raised by the parties.

A second issue of concern to staff is the comparison between rate structures and rate levels here compared to those found in other states. Conducting a one or more pilots with a seasonal; rate structure and a wider peak-off peak difference would also help to answer the question of how applicable the study results from other parts of the country are to ratepayers of Oregon three IOUs.

Finally, staff is aware of Price-based DR pilot just underway in winter-peaking service NV Energy. In March 2011, NV Energy issued a new rate schedule titled "NEVADA DYNAMIC PRICING TRIAL: RESIDENTIAL SINGLE-FAMILY SERVICE TIME-OF-USE ENHANCED." [41] According to that tariff, its primary purpose of the Nevada Dynamic Pricing Trial (NPDT) is to collect data from a sufficient number of residential and small commercial customers who will then receive different pricing structures and rates, technology and education. This pilot will test two advanced pricing structures (a TOU or CPP offering) and possibly an enhanced education package, and/or a technology package relative to the control group.

Dated at Salem, Oregon, this 20th day of October, 2011.

Marc Hellman
Administrator
Economic Research & Financial Analysis Division

[40] Preliminary discussions between staff and program management at Sierra Pacific Power CO, a subsidiary of NV Energy, indicate that they have several pilots underway and that they are a winter peaking utility.
[41] *See:* NEVADA POWER COMPANY dba NV Energy *"Schedule RS-TOU-E (N) NEVADA DYNAMIC PRICING TRIAL: RESIDENTIAL SINGLE-FAMILY SERVICE 0TIME-OF-USE ENHANCED." See:* http://www.nvenergy.com/company/rates/snv/schedules/images/RS_TOU_E_South.pdf for further pilot details including TOU rates, opt-out ability and the like.

Attachment

Overview of Selected Pricing Pilots

Understanding the context for the price-based study options proposed by staff partly rests on the finding of the various price-based pilot/studies performed by other utilities in other states. This appendix provides a quick overview of a selected cross-section of those studies. The studies summarized below reflect what staff has had an opportunity to review. There was no intentional effort to select successful studies and ignore unsuccessful ones. Additionally, staff has made no effort to 'cherry pick' results. Hopefully, one of the results of including this appendix is that other parties will bring yet other studies to staff's attention.

A. Faruqui and Sergici Report[42]

The report by Faruqui and Sergici referenced in the above provides a survey of seventeen U.S. pricing experiments. The report provides an excellent, and concise, overview of a variety of pricing experiments in the U.S. and other countries. Those seventeen experiments used different pricing strategies (TOU and CPP), were conducted for varying lengths of time, with different number of participants, with and without enabling technology. The overarching conclusion is that these pricing schemes can substantially reduce consumption at critical periods. People do respond to the price signals.

B. PowerCentsDC

One interesting pilot was PowerCentsDC[43]. This pilot is unique for several reasons. These are,

1. It was conceived in part by the official consumer advocate organization for D.C.
2. It tested three different price structures and various information formats, and
3. Limited income customers were recruited to test their price responsiveness.

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ir entire report here, you will find the details in their report. What is included here is a table summarizing the experiments studied and the percentage reduction in peak load of each experiment.
PCDC Final Report - FINAL.pdf

Three pricing plans were studied, Critical Peak Pricing (CPP), Critical Peak rebates (CPR), and Real-Time Pricing (HP for Hourly Pricing) that followed the wholesale electric price. Customers with limited income participated only in the CPR option. It should be noted that summer peak reduction under CPR for the low-income group was 11 percent while it was 13 percent for 'regular' income customers.[44] Among other conclusions, they note that CPP led to the greatest reductions in peak demand while CPR was the most popular option.[45] Regarding low-income participants, participation rates were higher than for the regular income group, and the low-income group's peak reduction was only slightly less than that for the regular group.[46]

C. MyPower Pricing Pilot Program[47]

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two programs, myPower Sense and myPower Connection.

myPower Sense educated participants about the TOU/CPP tariff and they were notified of a CPP event on a day-ahead basis. myPower Connection participants received a free programmable communicating thermostat (PCT) that received price signals from PSE&G and adjusted their air conditioning settings based on previously programmed set points on critical days.

There were 1,148 participants in the pilot program; 450 in the control group, 379 in myPower Sense, and 319 in myPower Connection. The TOU/CPP tariff consisted of a base rate of $0.09 per kWh. There were three adjustments to this base rate, (1) a night discount of $0.05 per kWh in both summers, (2) an on-peak adder of $0.08 per kWh and $0.15 per kWh respectively in the summers of 2006 and 2007, and (3) a critical peak adder for the summer months that resulted in a critical peak prices of $0.78 per kWh and $1.46 per kWh, respectively, in the summers of 2006 and 2007.

[44] Ibid, p. 11.
[45] Ibid, p. 5.
[46] Ibid.
[47] IEE Whitepaper, pp. 17-18.

The results from this experiment were as follows,[48]

- myPower Sense customers with Central A/C reduced peak load
    - by three percent on TOU only days.
    - by 17 percent on peak days.
- myPower Sense customers without Central A/C reduced peak load
    - by six percent on TOU-only days, and
    - by 20 percent on CPP days.
- myPower Connection customers (those with the PCT) reduced their peak demand
    - by 21 percent due to TOU-only pricing
    - by 47 percent on CPP days

D. Power Smart Pricing Program

According to discussions with ICC staff, the current ComEd and Ameren Power Smart Pricing program (PSPP) were legislatively created and are optional rates open to anyone.[49] According to the company web-site for Ameren, the Power Smart Pricing program is an hourly pricing program for residential customers. In this case, the electricity prices are set a day ahead by the hourly wholesale electricity market run by the Midwest Independent System Operator (MISO).

ICC staff has also indicated that the ComEd RTP uses DAP for advisory purposes but bills used the RTPs. The Ameren program started that way but reverted to using the day ahead prices for billing. ICC staff noted that Ameren now has about the same number of participants as ComEd despite having a customer base one third the size. Follow the link to learn more about Midwest ISO prices compared to flat rate prices.[50] [51]

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[48] Ibid, p. 18.
[49] The ICC will be opening a docket soon to review the programs and the net benefits they may or may not be creating for non-participants
[50] *See:* http://www.powersmartpricing.org/about-hourly-prices/
[51] ICC staff has indicated that in May both ComEd and Ameren will be filing a variety of reports including four year program evaluations that will contain a significant amount of new information and will be the basis for a docketed proceeding to review the programs.

According to the T&D World column, a survey of 600 residential homes "Nearly 60% of residential energy consumers are willing to change their electricity-use patterns to save money, though many seek savings in return for signing on to a demand-response program." One study performed by Frost & Sullivan titled "U.S. Smart Grid Market – A Customer Perspective on Demand Side Management,"[52] In that study, they noted a significant percent of those surveyed (78 percent) said they would be interested in adjusting their power usage with a one-day notice of prices. A smaller fraction (60 percent) expressed an interest in allowing the utility to cycle their air-conditioner if that resulted in a lower utility bill.

E. Texas[53]

The Public Utilities Commission of Texas (PUCT) staff wrote a report to the Texas legislature last year covering AMS deployment in Texas and efforts, to include DP pilots, outside the state. Among the points made are the following,

- Demand response programs that rely on dynamic pricing or TOU rates are only just beginning to be offered in Texas. Currently, Nations Power offers prepaid service with RTP. This service is only available to customers with smart meters installed on their premises. The smart meters provide consumption data in fifteen minute intervals, enabling the company to provide customers RTP. Customers can see their historical and current consumption and current prices.

- TXU Energy offers a TOU rate that encourages their residential customers to save money by shifting demand to off-peak hours. Under this plan, customers pay a higher peak rate during summer afternoons (1-6pm, M-F, May-October) when demand is highest and a lower rate at all other times of the year. The lower rate applies to 93% of the hours of the year.

[52] This report is quite expensive. I've relied on a separate 15 slide presentation for these comments.
[53] Comments are based on correspondence and phone calls with PUCT staff.

- Reliant Energy also offers a TOU plan that rewards the customer for shifting demand to lower priced off peak periods. Reliant's plan divides pricing periods into three categories, off peak, standard and summer peak. The higher summer peak hours account for only 3% of the total hours in the year (4-6pm, M-F, April-October). Standard pricing applies to the other periods of high demand and varies by season. Reliant's TOU plan is available to customers with smart meters.

- Reliant is also piloting the implementation of in-home displays with consumers in Texas. This product offers consumers the ability to see real time consumption and projected bill amounts. In addition, Reliant Energy offers email alerts that utilize the 15-minute interval consumption data to provide weekly insights into consumption and projected bill amounts.

- Gateway Energy Services recently launched the Lifestyle Energy Plan, a three month pilot program to test two different TOU rates. Under the pilot, customers will continue to be billed on their current flat rate structure but will be able to see their monthly bill based on a TOU rate. Customers will have online access to reports detailing their usage and a side-by-side billing analysis of the TOU rate plan versus their flat rate plan. At the end of the pilot, customers who would have saved money with the TOU rate plan will receive a credit on their monthly bill equal to that savings. Criteria for customer participation included having a smart meter installed and enrollment in Gateway's variable rate plan.

F. <u>Baltimore Gas & Electric Company (BGE)</u>

BGE recently tested customer price responsiveness to different dynamic pricing options through a Smart Energy Pricing (SEP) pilot. The rates were tested in combination with two enabling technologies: an IHD known as the energy orb, a sphere that emits different colors to signal off-peak, peak, and critical peak hours, and a switch for cycling central air conditioners. Without enabling technologies, the reduction in critical peak period usage ranged from 18 to 21%. When the energy orb was paired with dynamic prices, critical peak period load reduction impacts ranged from 23 to 27%. The ORB boosted DR approximately by 5%. BGE repeated the SEP pilot for the second time in the summer of 2009. Results revealed that the customers were persistent in their price responsiveness across the period. The average customer reduced peak demand by 23% due to dynamic prices only. When the ORB was paired with dynamic prices, the impact was 27%.[54]

G. The Connecticut Light and Power Company/ Plan-It Wise Pilot

Another full scale pilot taking advantage of smart meters and three types of dynamic pricing was recently carried out by Connecticut Light and Power (CL&P). The Plan-It Wise Energy Pilot was designed as both a smart metering and rate plan pilot before the further deployment of smart meters to the 1.2 million metered electric customers in the CL&P service territory.[55] Consumers who participated received a smart meter, along with an enabling technology such as a smart thermostat, energy orb or appliance smart switch. Residential customers enrolled in the Peak-Time Price (PTP) rate plan reduced peak demand by 23.3% if supplied with an efficiency enabling device, and 16.1% without such a device. Commercial and industrial (C&I) PTP customers reduced peak demand 7.2% with a device and 2.8% without. On average, Plan-it Wise residential participants saved $15.21 over the three-month pilot span, while C&I customers averaged $15.45 in savings.99 In an exit survey, 92% of the residential and 74% of the C&I participants said they would be open to further programs.[56]

[54] Faruqui, Ahmad, Sanem Sergichi, Effects of In-Home Displays on Energy Consumption: A Summary of Pilot Results, Peak Load Management Alliance Webinar, April 6, 2010.

[55] Connecticut Department of Public Utility Control's Docket No. 05-10-03RE01 Compliance Order No. 4, Results of CL&P Plan-It Wise Energy Pilot, available at http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Planit%20Wise%20Pilot%20Results.pdf.

[56] Ibid.

UM 1415
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CERTIFICATE OF SERVICE

UM 1415

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

Dated this 20th day of October, 2011 at Salem, Oregon

Kay Barnes

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