BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1460

In the Matter of an Investigation into Smart Grid Objectives and Action Items	STAFF CLOSING COMMENTS

Introduction

On November 16, 2010, Staff issued its Opening Comments. Those comments first summarized the options on a set of issues set forth in the Smart Grid Straw Proposal (SGSP). Then, Staff described its current positions on these same issues. While Staff modified some of its prior recommendations, primarily as a result of parties' comments at the workshop held on November 3, 2010 (Second Workshop), Staff's positions for the most part were unchanged from the proposals articulated in the SGSP.

These Staff Closing Comments (Closing Comments) respond to some of the issues raised by parties in their Opening Comments. For each issue that appears in these Closing Comments, Staff first summarizes comments received. Then, Staff discusses these comments. Finally, the Staff recommendation is described. Appendix A is a list of the Smart Grid Plan (SGP) guidelines.

1. Access, Control, and Use of Customer Information

A majority of the parties commented on Staff's proposal. Both the Citizens Utility Board (CUB) and the Northwest Energy Coalition (NWEC) argued that Staff's proposal is too restrictive. Idaho Power Company (IPC) supported Staff's proposal but argued that this docket is not the right place to establish this policy. Portland General Electric (PGE) proposed that a workshop be held on this issue early in 2011. PGE also proposed that the utility should have the flexibility to determine what steps need to be taken to meet existing law. PGE also proposed that the utility be allowed cost recovery for any costs associated with providing information privacy. Pacific Power and Light (PPL) supports addressing the issue of customer information privacy in this docket and proposed the following standard:

> "Utility companies will take reasonable steps to ensure the protection of customer data, including but not limited to name, address, and other personally-identifying information, and usage and other meter data, technical configuration, type and destination, as well as ensure that it is meeting all federal and state standards as it considers the deployment of smart grid technology."[1]

Staff's Opening Comments proposed that the Commission require utilities to employ privacy safeguards consistent with the Department of Homeland Security's Fair Information Practice Principles (FIPs).[2] Staff proposes that these standards be a minimum privacy standard until a comprehensive privacy policy is established.

Staff does not support calls to exclude this issue from this investigation. In part to address the concern expressed by IPC and PGE that this docket isn't the right place to address this issue, at the close of the UM 1460 investigation, Staff will propose that the Commission open an investigation

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[1] Pacific Power's Opening Comments on Straw Proposal, pg. 2

[2] *See* U.S. Department of Homeland Security, Privacy Policy Guidance Memorandum, and The Fair Information Practice Principles: Framework for Privacy Policy at the Department of Homeland Security (2008), available at http://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf

to consider the need for, and the substance of, a customer information privacy policy. Staff also requested that parties comment on what privacy issues should be included in such an investigation.

Staff does not support CUB's comment that it is premature to apply Direct Access Code of Conduct to Smart Grid activities. This is the time to address this issue in order to stay out in front of this rapidly expanding field. Staff's view is that utilities must not share confidential customer information with an unregulated subsidiary that could help give that affiliate a competitive advantage over existing or potential rivals. This is equally inappropriate in the provisions of Smart Grid services and products as it is with retail competition.

Staff understands PGE's request that the utility be allowed to determine what steps are required under current law. However, Staff is concerned that state law may not mandate adequate safeguards in this rapidly evolving area. In fact, PGE comments that the federal and state statutes on data security "…are lacking in detail on exactly how this security needs to be achieved."[3]   However, if PGE or other parties are able to allay our concern about the adequacy of existing laws, Staff will take that information into consideration. Regarding PGE's call for cost recovery, Staff will remain silent on that request in this forum, and leave that decision to the rate case process.

2. <u>Utility Energy Management in Customer's Home or Business</u>

Most parties commented on this issue and all but one disagreed with Staff's suggestion. CUB and NWEC both support allowing these costs to be rate based. IPC commented this docket is the wrong place for this

[3] PGE Opening Comments, pg. 6

issue. PGE and PPL both argued in favor of allowing rate basing of such costs. SGO was the sole commenter supporting Staff's suggestion.

Parties identified potential unintended consequences of such a blanket prohibition. As a result, Staff no longer supports a blanket prohibition against rate basing these costs.

Considering that adequate Commission precedent exists, Staff does oppose SGO's call to use this docket as a means to define who owns the meter as there exists Commission precedent in the rate case process. Precedent is that the utility owns at least the primary meter, and it is part of the utility's infrastructure.[4] The meter base is not owned by the utility; it is installed by the customer. The meter is a fixed expense that is a recoverable cost if those expenses are determined to be prudent in a rate case proceeding.[5]

After considering these comments, Staff proposes to retain the proposal made in Opening Comments.

3. <u>Systems Reliability</u>

Most parties wanted Staff to go further than what Staff described in the SGSP. Though, parties did not agree on just how Staff should go further.

IPC commented that discussions about reliability improvement should not occur in the SGP. Specifically, IPC argues that the part of the SGSP that

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[4] Oregon Administrative Rules (OAR) 860-038-0360 states "…The electric company must own/lease, install, test, read, remove, and maintain a customer meter for each retail electricity consumer receiving metered distribution services. (2) The electric company's meter reading must be the basis for the electric company charges billed to the retail electricity consumer."

[5] Oregon's requirement may be worth review since direct access customers in California are allowed to install their own meter. According to CPUC staff, "The decision to allow non-utility meters was opposed during that proceeding, but a Commission ruling in the late 1990s decided that Direct Access customer meters did not need to be owned by the utility."

calls for the SGP to provide sufficient detail to allow the Commission to conclude that it is reasonably likely that the Action Plan will improve system utilization and reliability goes beyond the stated scope of the SGP. CUB argued for exemptions to the interoperability standards. It believes that Staff has gone too far with its proposed policy requiring "…the utility should work assuring that any devices of software it is involved in installing allow for interoperability with third-party hardware and software."[6] NWEC suggests that utilities should be required to propose tariffs and interconnection standards to help customers and third parties sell ancillary services and storage to the utility.

The Oregon Department of Energy (ODOE) strongly supported what Staff laid out in the SGSP. It also adds a request that if the SGP includes actions that may affect resource management that the Commission ensures there will be "…a synchronicity between the SGPs and an investor-owned utility's Integrated Resource Plan, in conformance with Commission Orders: 07-002 and 07-047."[7] PGE also commented in support of the Staff proposal. In contrast, SGO advised that the SGP should identify the value of improved reliability and power quality. It also proposed that the SGP include valuation methods to measure these improvements.

Staff opposes IPC's call to summarily exclude reliability improvements as a topic in the SGP. Staff also disagrees with the comment the SGP is not the place to address reliability. Reliability improvements are an important element of SG. Under the proposal in Staff's Opening Comments, a discussion of reliability improvements may be excluded only if a utility (a) does not investigate, or (b) propose SGP actions that bear on reliability. In the situation where the utility does not even investigate reliability

[6] Staff Opening Comments, November 16, 2010
[7] ODOE Opening Comments, pg. 3

improvements, we expect the SGP to explain its rationale for not investigating potential actions.

Staff understands CUB's concern but it appears CUB overstates Staff's proposal. The SGSP contains the following language "…the utility should work to assure that any devices or software *it is involved in installing* [emphasis added] allow for interoperability with third-party hardware and software." Staff's proposal already provides flexibility, since it only applies to third-party hardware and software the utility is actively involved in installing. Therefore, Staff does not support CUB's call to further suspend the interoperability requirement.

Staff opposes NWEC's call for the SGP to include proposed tariffs and interconnection standards to help customers and third parties sell ancillary services and storage to the utility. Staff encourages NWEC to bring the proposal of interconnection standards and tariffs to the Integrated Resource Plan (IRP) process and appropriate rate case dockets.

Staff supports SGO's call that the SGP include the value of improved reliability and power quality *only* if the utility's SGP proposes actions that affect reliability or power quality. If there are no SGP actions proposed that bear on reliability or power quality, the valuation of improvements to reliability and power quality appear more appropriate for the IRP.

After considering these comments, Staff proposes to retain the proposal made in its Opening Comments.

4. <u>Utility SGP Activities and SGP Content</u>

IPC commented on the relationship between the SGP actions the utility investigates and the content of its SGP. IPC agrees with the recommendation that "…the SGP must include a discussion of …technology, programs, and protocols that utilities are investigating."[8] IPC then argues that "…the SGP should discuss only those programs the utility has actually considered, and specifically need not discus all possible activities that could be considered by the utility." [9] IPC's comments must be viewed in light of its conclusion that "it is important to note that many features of the Smart Grid are not yet mature or cannot appropriately be broadly implemented in Idaho Power's service territory."[10] PGE comments that "…the details of smart grid are not well understood and its meaning continues to evolve…we believe a significant part of the smart grid process should focus on education and on clearly defining objectives."[11]

While Staff supports IPC's observation that the SGP "…need not discuss all possible activities that could be considered by the utility," Staff is concerned that IPC may misunderstand the proposed substance of the SGP. In Opening Comments, Staff stated that the content of the first SGP "… will likely emphasize actions currently underway. However, it is our expectation that even this first SGP will include actions not currently implemented."[12] Staff clarified that the SGP must also include "…any and all SG related activities being pursued by all unregulated affiliates "[13] Turning to the proposed Goal 4, Staff further noted that "In future SG investment related cost recovery decisions, these conclusions will provide evidence to support or oppose cost recovery. This includes, but is not limited to, actions that are intended to improve reliability, quality of service, and compliance with statutory mandates (such as Renewable Portfolio Standard)."[14]

[8] IPC Opening Comments, pg. 2
[9] Ibid.
[10] Ibid.
[11] PGE Opening Comments, pg. 1
[12] Staff Opening Comments, pg. 3
[13] Ibid.
[14] Ibid., pg. 5

At a minimum, an SGP with little or no content will likely raise concerns about how thoroughly the utility has investigated SG actions. This is especially true considering the breath of potential SG actions, including, but not limited to, those that are intended to improve reliability, quality of service, and compliance with statutory mandates. Staff does expect the utility to explain what facts it relied on to conclude SG actions do not fit in its service area.

Staff does not agree with PGE's argument that smart grid is not well understood and the meaning of smart grid continues to evolve. Yes, it is true that SG applications, technologies, policies, regulatory structure and treatment do continue to evolve. However, a review of the voluminous literature indicates there is a very good understanding of SG fundamentals. For example, one definition is "…two-way flow of electricity and information to create an automated, widely distributed energy delivery network."[15] A report issued by the U. S. Department of Energy titled "The Smart Grid: An Introduction"[16] provides a good starting point on understanding SG. Section 1306(d) of the Energy Independence and Security Act (EISA) further characterizes nine key functions of a Smart Grid.[17] These sources are but a few of the significant amount of information that exists to define and explain SG.

PGE further comments that the limited understanding of SG implies that a good deal of this process should focus on education and clearly defining objectives. If by education, PGE means education activities on the utility's part focusing on SG and how its customers can be more involved in the SG arena, we agree. Since the SGSP identified five goals for the SGP,

[15] Electric Power Research Institute (EPRI), Report to NIST on the Smart Grid Interoperability Standards Roadmap (2009), available at http://www.nist.gov/smartgrid/InterimSmartGridRoadmapNISTRestructure.pdf

[16] The Smart Grid: An Introduction. Prepared for the U.S> Department of Energy by Litos Strategic Communications. *See* www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages(1).pdf

[17] The Energy Independence and Security Act of 2007 (PL110-140)

and those goals, for the most part have not been rejected by the parties, Staff assumes these five goals do provide a good starting point. Therefore, we do not agree that a significant part of this process needs to focus on objectives.

After considering both PGE's and IPC's comments, and reviewing Staff Opening Comments, it is important to emphasize that the SGP is intended to inform parties of the utility's SG-related thinking and actions. To reiterate, Staff has proposed that every section of the SGP must include a discussion of (a) what actions are being proposed in the SGP and (b) actions that were investigated and rejected. If the SGP contains neither any actions or a discussion of actions investigated and rejected for a section, that section must then explain the utility's rationale for not investigating potential SG actions

5. <u>Education and Information - Customer Energy Use Management</u>

PPL proposed this section be included if the utility is planning these types of actions. SGO commented that this is a very important section of the SGP. It also proposed the utility include a discussion of its approach to finding the right level of customer interaction. It also would require that the SGP address how the utility plans to engage the consumer to assure that "…customer education programs are optimally targeted and effective."[18]

Staff opposes SGO's call for the SGP to include details of how they plan to assure that customer education programs are "…optimally targeted and effective." This language could be construed to require an SGP not be acknowledged if some party argued that the utility's plan is not optimally targeted. In response to SGO's concern, Staff supports a requirement that the SGP include a discussion of how the utility chose its proposed

[18] SGO Opening Comments, pp. 8-9

education efforts, including how it concluded the proposed efforts will likely be effective.

Staff proposes that the approach described in its Opening Comments be retained, with one addition. The SGP must include a discussion of how the utility has arrived at the education efforts it is proposing, including a discussion of the expected effectiveness of those efforts. This is elaborated on in Appendix A.

6. **Distribution of SGP Benefits and Costs**

CUB argued that distribution should be considered when making a decision about whether to acknowledge an SGP. CUB's concern is succulently summarized in its closing observation "... telling a utility that the Commission's acknowledgement will not be dependent on a particular section of the Plan is like telling the utility that it does not have to make any real effort in that section."[19]

PPL advised that it will "…look to the comments and input from the groups representing various customer classes to help the Commission understand the impacts." In addition, the company proposed that the sentence stating that the utility "stay alert to, and advise the Commission of, potential or actual threats to any of its businesses that currently contribute revenue for cost recovery" is overly broad and vague and should be deleted.

Staff understands CUB's call that distribution be considered in the acknowledgement decision. In Staff Opening Comments, we proposed that distribution be considered during SGP review. The discussion of this issue in Opening Comments went to some length to describe some of the various dimensions of benefits and costs distribution.

[19] CUB Opening Comments, pg. 7

Staff encourages PPL to provide information on distribution in its SGP as well as relying on other parties to help identify potential impacts of its SGP actions. Staff opposes PPL's request to delete the requirement that the utility stay alert to potential threats to the businesses that contribute revenues for cost recovery. However, Staff does agree that this requirement is overly broad. Since the SGP focuses on SG-related changes to its business, Staff supports a re-wording of this requirement clarifying that it applies to revenue changes considered to arise from SG-related activities by the utility submitting the SGP or because of SG activities of other market participants. Staff is also open to hearing from parties about how this requirement may be better described. However, Staff expects that the utility will continue to monitor its businesses for revenue erosion as part of its on-going business management. Except for these two modifications, Staff otherwise supports retaining the proposal made in its Opening Comments.

7. SG-Enabled Pricing Options

PPL commented that this section of the SGSP should be rewritten to clearly convey its intent. PPL states it heard Staff make the following clarification at the Second Workshop that this section "…is intended for the utility to explain the status of the deploying advanced metering infrastructure and the capability of pricing options in conjunction with that infrastructure." [20]

Staff does not agree with PPL's characterization of Staff's comments at the Second Workshop. The SGSP stated the following:

[20] PPL Opening Comments, pg. 6

> "The SGP should assess the applicability of price-based demand response alternatives and plans for introducing them in the next five years. The SGP should also assess the potential benefits and costs of deploying AMI within the Action Plan timeframe. The SGP should include a discussion of whether AMI deployment will occur and if the conclusion is that Advanced Meter Infra-structure (AMI) will not be deployed, the SGP should articulate the basis for this conclusion. If the utility has not enacted dynamic pricing (DP) or price-based demand response in its service area, the SGP should discuss the utility's plan to implement it."[21]

PPL appears to misunderstand what Staff has proposed. Staff wants to draw attention to the first sentence in the excerpt above which states "The SGP should assess the applicability of price-based demand response alternatives and plans for introducing them in the next five years." Staff interprets this to mean the SGP must address what plan the utility has to introduce price-based demand response in the next five years. If the utility has no plan, it will not be sufficient to say no plan exists. Staff wants to know the utility's rationale for not proposing to implement price-based demand response alternatives. The SGSP language also states that Staff expects the SGP to "articulate the basis for…" the conclusion that it is not proposing to implement AMI. Finally, the SGSP also states, "…the SGP should discuss the utility's plan to implement…" DP and price-based demand response in its service area.

SGO proposed that the SGP study how rate structures relate to costs and incentives for SG planning. It also proposed that the SGP identify which rate structures are enabled by Advanced Meter Infrastructure (AMI).

[21] SGSP, pg. 9

Staff opposes SGO's call that the SGP should identify what rate structures are enabled by AMI. Given the amount of existing literature on AMI and dynamic pricing alternatives, there is little of a general nature that can be added.

Staff does not disagree with SGO's observation that the SGSP omits a discussion of "…a range of possible options enabled by AMI systems such as energy usage analysis, feed-in tariffs for solar or other alternative energy, monitoring and verification of energy efficiency investments, ancillary services etc."[22] Staff agrees that AMI can help implement a range of monitoring and rate options. However, it is unclear how feed-in tariffs are tied to AMI since Oregon already has feed-in tariffs that do not require AMI. Staff understands that AMI can help facilitate greater energy use analysis if it includes smart meters. Distributed sources of ancillary services are not presently economically viable. If that should substantively change in the timeframe of SGP filings, nothing would preclude Staff from taking this into account during the SGP review process.

Staff is uncertain how to distinguish between a "…SG-based rate structure"[23] and one that is not SG-based. For example, any rate design that contains different prices for different period of time falls into the category of dynamic pricing. Therefore, a two-period (e.g., diurnal) rate structure is an example of a dynamic pricing rate structure. Yet, such a rate structure does not require AMI.

Because of the reasons identified above, Staff proposes to retain the approach described in its Opening Comments. We also want to clarify that in keeping with the discussion of Demand Response (DR) in this section of the Opening Comments, and with PGE's comments that a DR

[22] SGO Opening Comments, pg. 8
[23] Ibid.

discussion is important,[24] the SGP must address DR as part a part of this section. This is elaborated on in the Guidelines.

8. Timeframes for the SGP

Both CUB and NWEC commented that 180 days is too short to complete a review of the SGP and for the Commission to issue its decision. They proposed keeping the 180 days review length but extend the time for the Commission decision. IPC agreed with the 180-days timeframe.

IPC, PPL, and PGE each proposed that the timeframe for the SGP should be 10 years rather than 20 years. IPC and PGE supported the five-year timeframe for the Action Plan, whereas PPL and SGO commented that five years is too long. PPL proposed a three-year Action Plan timeframe and SGO suggested that different timeframes be used for different types of SG investments. ODOE supports the timelines contained in the SGSP.

There are five timeframes contained in the SGSP: (1) a 20-year timeframe for all economic analyses in the SGP, (2) a 20-year timeframe for the utility to discuss various SG-related actions, (3) a 5-year timeframe for the Action Plan, and (4) a 180-day timeline for plan review. A fifth timeframe is the submission schedule, and that will be addressed in the next section.

Staff continues to support one 20-year timeframe for use in all economic analyses contained in the SGP. This length dovetails with the timeframe for economic analysis in the IRP. Staff understands the point SGO is making with its proposal that the timeframe be tailored to the technology. Using consistent assumptions, one of which is the timeframe for the economic analysis, will aid in helping to assure that competing

[24] PGE Opening Comments, pg. 10

investments are compared under comparable assumptions. Staff understands that different asset lives will need to be addressed.

Staff understands the concerns about the 20-year timeframe in the SGSP for identifying SG actions. While this is long, at the Second Workshop Staff clarified that the Action Plan will be the main focus for SGP review. Staff continues to support the utility reporting potential future actions after the Action Plan timeframe. There will be much less detail about these possible actions, yet it is important for all interested parties to have the benefit of the utility's thinking sooner in time. With that, Staff is willing to replace the 20-year timeframe for the reporting of SGP actions with a 10-year timeframe for the reporting of expected and possible SGP actions. However the 20-year timeframe for all economic analyses remains intact.

Turning to the issue of the Action Plan timeframe, Staff is reluctant to reduce it from five years since the Action Plan timeframe and the SGP submission schedule are interlinked. For example, if the Action Plan length is reduced to three years as PPL proposed, the second SGP must be *in place* no later than about June 2014, which means that it will likely need to be submitted by around September 2013 at the very latest. Given that the current deadline for the first SGP submission is about September 2011, with a 180-day review (plus time for the Commission's final decision), the first SGP acknowledgement would occur sometime in the early in 2012. This leaves scant time for learning before the second SGP will need to be submitted.

Regarding the 180-day timeframe for review and a Commission decision, Staff modified its position in its Opening Comments. In Opening Comments, Staff proposed "…holding a Prehearing Conference to adopt an SGP evaluation schedule within 30 days of receipt of the SGP…The schedule will include a public hearing before the Commission within 6 months of the Prehearing Conference."[25] Staff also proposed that any party may petition the Commission for additional time for the SGP review.

To summarize, Staff proposes to (1) retain the 20-year timeframe for the economic analysis, (2) shorten the timeframe for identifying planned and potential SGP action from 20 years to 10 years, (3) keep the Action Plan length at five years, and (4) retain the proposal for review timeframe stated in Staff's Opening Comments.

9. SGP Submission Schedule

Both CUB and NWEC support a staggered submission schedule with one utility being selected to go first with its SGP due in three months. The SGP for the second utility would be due six months after the first utility's SGP. The SGP of the third utility would be due 12 months after the due date for the first utility's SGP. ODOE supported the submission schedule in the SGSP. PGE proposed that each utility be required to submit their second and third SGP four years apart.

While Staff understands the concerns of CUB and NWEC about workload, Staff opposes imposing a staggered submission schedule. First, Staff does not see that much is gained with the CUB/NWEC proposed staggered schedule. CUB/ NWEC proposal allows for a six-month review frame for the first utility's SGP before the second utility submits its SGP. Then, it allows a three-month window for the second utility's SGP review before the third utility submits its SGP. Granted, this would allow for a full 180-day review of the first utility's SGP. However, the review of the SGPs of the remaining two utilities would have to overlap. Also, the other procedural requirements (e.g.: hearing, reconsideration and so forth) would certainly overlap between the second utility's submission and that of

[25] Staff Opening Comments, pg. 39

the third utility. Second, Staff believes it would be informative to have all three SGPs available for review at the same time for the first round of submittals. Third, any party may petition for more review time. For these reasons, Staff proposes to retain the submission schedule proposed in its Opening Comments.

10. SGP and Annual Update Review

Both IPC and PGE commented that it is premature to discuss acknowledgement. They argue the SGP should only be for information and discussion. PPL proposed a bi-annual update submission schedule. ODOE supports the approach described in the SGSP.

Staff continues to support its proposal that the SGP be subject to Commission acknowledgment. Filing an SGP that is only for information would be of little value to parties. Staff understands that SG is evolving and will continue to evolve for the foreseeable future. However, technological and institutional evolution is not an adequate reason to limit the role of the SGP in subsequent Commissions proceedings. In fact, that evolution can be argued to be a valid reason to seek acknowledgement of the SGP. In so doing, there is greater assurance about favorable rate treatment for actions included in the SGP.

Turning to updates of the SGP, Staff continues to support the requirement to file an Annual Update. While some commenter's argued that a five-year Action Plan is too long and the updates should be bi-annual, Staff views annual updates as the way to keep more closely abreast of developments within the five-year Action Plan timeframe. Staff also continues to support its proposal for the utility to have the option to request Commission acknowledgement of its Annual Update.

11. SGO Institutional Issues

SGO raises overarching issues about the institutional structure of the electric sector in Oregon. As a result of their all encompassing scope, these comments do not fit in any specific section of the proposed SGP structure.

Broad Issue #1: This Docket should begin to Investigate Regulatory Change and Institutional Impediments to Smart Grid Adoption

SGO argues, "Smart grid technology presents challenges to the way the State of Oregon regulates electric utilities." [26] It proposes that the need for regulatory change "…should start to be addressed in this docket."[27] SGO continues arguing, "…the Commission [should] lead or participate in a state-wide collaborative effort aimed at developing public goals and policy for the future of the electric business and structure in the state."[28] It goes on to argue that one key issue that needs attention is identifying and discussing how current legal and regulatory policies affect adoption rates and cost-effectiveness of smart grid technologies.[29]

This line of reasoning continues where SGO proposes that the SGP should include a "…discussion of what public and regulatory policies are needed to evolve for full implementation of the smart grid."[30] Later, SGO reiterates its call for the SGP to include "A discussion of regulatory and legal barriers or impediments to smart grid investments by utilities…"[31] Continuing, it argues that one of the major smart grid issues is the "…potential for misalignment of traditional legal and regulatory policies and the incentive structures that are needed…"[32] At the very end of its

[26] SGO Opening Comments., pg. 1
[27] Ibid., pg. 1
[28] Ibid., pg. 2
[29] Ibid.
[30] Ibid., pg. 3
[31] Ibid., pg. 9
[32] Ibid.

comments, SGO proposes that the SGP "…should address whether competitive markets at the customer level for energy management, energy efficiency, distributed renewable net-metering or feed-in tariffs, demand-response programs and ancillary services should be established."[33]

Staff understands SGO's concerns that the existing regulatory regime may present barriers to faster SG adoption. However, Staff is concerned that this docket could easily become overwhelmed by such an undertaking. Staff does not support SGO's call for the SGP to include a discussion of whether competitive markets should be established in "…[at the] customer level for energy management, energy efficiency, distributed renewable net-metering or feed-in tariffs, demand-response programs and ancillary services…." Staff's views on this issue reflect the perspective that the SGP is the utility's SG roadmap. Discussing how to establish competitive markets in segments of the electric service industry in Oregon will need to involve many parties beyond those involved in this docket, will likely be protracted, and will likely extend beyond the Commission's current jurisdiction.

Staff is not passing judgment on the merits of these proposals. Staff is focusing solely on the scope of this docket. Staff is likewise making no determination about what, if any, role the Commission may choose to play in such efforts. Making a decision about Commission participation or leadership on this issue lies outside the scope of this docket. Because of these reasons, Staff is not persuaded by SGO's request.

Broad Issue #2: *A 'visioning' process should be undertaken and the timeline for SGP submittal should begin at the close of that visioning process.*[34]

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[33] Ibid., pg. 10

[34] Appendix B summarizes correspondence and conversations with relevant Staff at the following state commissions: California, Colorado, D.C., Illinois, New York, and Texas on their respective approaches to establishing requirements for SG

SGO argues "Many commenter's have suggested that moving into a smart grid planning process is premature without the PUC first stating its vision for the smart grid."[35] SGO was the only party to raise this issue in its Opening Comments. Staff opposes SGO's proposal that a visioning process similar to that undertaken in California or Illinois ought to be undertaken and completed prior to any SGP submission deadline.

There are several reasons for Staff's opposition to this proposal. First, the resources available to devote to SG planning, developing an SGP, and reviewing the SGP are limited. All three utilities expressed concerns about resources available to devote to these efforts. These concerns were echoed by both CUB and NWEC. Staff prefers moving forward with actual implementation of SG planning rather than spending scarce resources on a visioning process that may very well produce dubious results. Second, Staff wants to go through at least one round of SGP submittal, review, and Commission decisions prior to when the ARRA-funded Staff departs. Third, Staff's perspective of the potential benefits of a visioning exercise is informed by consultations with relevant staff at Commissions across the country. In particular, the staffs at both the Illinois and California Commissions were reluctant to characterize their processes as visioning exercises. In particular, in Illinois, the staff pointed out that their process began in 2008 and had the scope it did because they could not have anticipated federal government actions that began with the new federal Administration.

Turning to spending time to define SG, Staff is aware of at least some of the ways SG has been defined.[36] A review of the multiplicity of SG definitions is evidence of an adequate amount of guidance existing in the

[35] SGO Opening Comments, pg. 3
[36] Several definitions were offered on pp. 8-9 of this document

SG literature. Also, Staff was persuaded by comments made by Illinois Commission staff who pointed out that they chose to use existing federal definitions as guidelines and avoid developing an Illinois-specific SG definition.

Staff provided the following broad definition of SG at the First Workshop: "The Smart Grid is the integration of digital communication technology with the electrical system." Staff noted that this definition did not capture all aspects of SG, but it went fairly far down the road. Staff also noted that the SGSP contains illustration of SG technologies in its discussion of System Reliability and Communications and IT Infrastructure. Staff also directed parties to Order 09-501[37] for additional guidance about what the Commission considers advanced versus non-advanced grid technologies.

In the Second Workshop, Staff noted the challenge in focusing on technologies as a way of defining SG. For example, broadband deployment by the utility may, or may not, qualify as an SG investment. If that deployment is in support of enhanced video surveillance, it would not likely be an SG action. On the other hand, broadband deployment to facilitate remote monitoring and sub-station control would likely be an SG action. As a result, what is and is not an SG-related investment can depend on the functions performed by the assets. This is why Staff has proposed that the SGP provide adequate information for Staff and other parties to reach a conclusion about whether a particular action is an SG action.

For the reasons mentioned above, Staff proposes that the submission schedule described in Opening Comments be retained.

[37] On 12/18/09, the Commission adopted ORDER NO. 09-501 that mandates utilities file a report describing the rationale for making a non-advanced grid investment. This report is to be filed prior to making such an investment. The Order includes a definition of a non-advanced grid technology and what demonstrations the utility is required to make in that report. Submitting a Smart Grid Plan does not meet the filing requirements in that Order.

Broad Issue 3: *Elaborate on how the PUC and the utility will help facilitate coordination between all the various stakeholders that are important to a successful SG strategy*[38]

SGO argues that this docket primarily addresses the utility's SG planning process and avoids much, if any, discussion of how the utility will "…plan to encourage and interact with assets owned by others."[39] It continues by noting that "The integration of activities of government, utilities, regulators, third-party investors, and consumers is key…and a fuller discussion of the utility role with regard to other parties should be a key part of the SGPs."[40]

Staff agrees with SGO that full SG implementation will require coordination between regulators, the regulated utility, customers, third-party suppliers, legislatures, to name but a few key stakeholders. Staff also agrees with SGO's observation that UM1460 "…speaks primarily to how the utility should plan for its assets alone…" This reflects the Commission's limited scope of authority with economic jurisdiction only extending to the Investor Owned Utilities (IOU) with customers in Oregon. This scope of authority does not extend to investment decision-making on assets purchases or operation by any other party. However, Staff has proposed that the utility's SGP contain details about "…activities working with retailers and vendors aimed at educating customers about other information, equipment, and software that may help them better manage their electricity use." [41]

For these reasons, Staff proposes to retain the coordination requirements set forth in its Opening Comments.

[38] The NWEC also proposed that the Commission has a role to play in enabling 3rd party SG activities
[39] SGO Opening Comments, pg. 4
[40] Ibid.
[41] SGSP, pp. 21-22

12. **Opt in, Opt Out, or Mandatory Program Participation**

PPL is the only party who commented on this issue. The company asserts it is premature to address this except in the case of pilot programs. Specifically, PPL commented that "It is premature to develop a guideline on how customer participation in smart grid-related programs should be managed."[42]

Staff's proposal only requires the utility to identify which of these three options it is selecting for each action (to which they apply) in the utility's SGP. This would require the utility to make this declaration for all actions, including but not limited to, pilot programs. Therefore, given the limited scope of this proposed requirement, Staff proposes to retain this approach (which was also articulated in Staff Opening Comments).

13. **Treatment of Obsolescence Risk**

Four parties submitted comments on this issue. ODOE supports Staff's proposal. PPL argued that it is premature to address this issue overall, but the company supports it for specific actions contained in the SGP. PGE also supports this section and suggested it might be appropriate to include it in the depreciation study. It also suggested that other risks be added. SGO went further, proposing this section address who should bear obsolescence risk and identify alternative risk management strategies.

Staff agrees with PPL that this is not the forum to discuss obsolescence risk overall. The utility's SGP is not intended to be the forum for a thorough discussion of the utility's approach to managing this risk. Rather, it is intended to be the forum to discuss risk associated with measures

[42] PPL's Opening Comments, pg. 2

contained in its SGP.[43] At the Second Workshop, Staff elaborated that actions in the utility's SGP might reduce, increase, or have no impact on the utility's overall obsolescence risk.

Regarding PGE's suggestion to include obsolescence risk as part of the depreciation study, Staff is not prepared to use this docket to make decisions related to rate cases.

Staff opposes SGO's suggestion that the scope of this docket be expanded to discuss who should bear obsolescence risks. That is better left to rate proceedings. Staff supports SGO's request that the SGP include a discussion of risk management strategies. This proposal is consistent with SGSP language proposing a discussion of mitigation measures. In conclusion, Staff proposes to retain the proposal made in its Opening Comments.

14. SGP Estimated Benefits and Costs

NWEC argued that the SGP should include a definition of services and benefits including reserves, ramping, storage, etc.[44] ODOE suggested that the Commission should consider cost-effectiveness as part of reviewing a utility's SGP. PPL proposed that the timeline used for benefit and cost estimation be tailored to the relevant technology.[45] PGE generally supported Staff's suggestion in the SGSP. SGO requested that a discussion and estimation of environmental benefits and costs be required in the SGP.[46]

[43] This may also include a discussion of how existing risk(s) are changed due to actions in the SGP
[44] NWEC Opening Comments, pg. 1
[45] PPL Opening Comments, pg. 4
[46] SGO Opening Comments, pg. 6

Staff opposes NWECs request that the benefits and costs of ramping, reserves, storage, etc. be included in the SGP if a utility's SGP is not proposing actions that affect these services. If the utility's SGP includes such services, the existing language requires benefits and costs to be addressed. Further, Staff has proposed in the Electric Vehicle (EV) proceeding (PUC Docket that the utility study the demand and supply of such services as part of its IRP process.

ODOE's proposal that the Commission consider cost-effectiveness as part of its plan review process raises a question about SGP-review criteria. Staff expects that cost-effectiveness will be among the criteria considered as part of SGP review. However, cost-effectiveness is not a condition that must always be met. An action may not be cost-effective, but may have other attributes that are compelling that counter-balance a strict numerical benefit – cost analysis.

Staff is aware of SGO's concern about the treatment of environmental costs. At both workshops, SGO raised the issue of including a discussion of environmental costs in the SGP. Staff replied that this docket will not change the Commission's statutory direction generally prohibiting accounting for environmental benefits and costs. What can be included are risks associated with changes in the current environmental laws that would change resource costs and other such costs that are likely to be incurred. Staff's Opening Comments address this very issue and contain language on this point. Staff supports the proposal made in its Opening Comments.

15. <u>Goals of the utility's SGP</u>

In the SGSP, Staff identified five possible goals for the utility's SGP. IPC supports the identified goals. ODOE also supports the goals as drafted.

PPL agreed with the goals with one modification. It proposed that Goal 5 be deleted. In contrast, SGO commented that the SGSP lacks substance about the goals of the SG planning process.

Turning to SGO's comments about the lack of specificity in the goals of the SG planning process, SGO remarks that:[47]

> The straw proposal lacks a substantive statement of the objectives of the smart grid planning process. For example, integrated resource planning is expected to produce a least-cost, robust resource plan for meeting a range of demand scenarios over time. There is no similar statement of objectives for the smart grid planning process. The goal stated in I. A. of the straw proposal is primarily procedural. The staff statement in its ARRA Smart Grid Docket was far more specific about what was expected to result from smart grid planning (*See ARRA Smart Grid Docket*, P.3).

Staff disagrees that "The staff statement in its ARRA Smart grid Docket was far more specific about what was expected to result from smart grid planning." Rather, on page 3 of that document there is a list of six potential issues for investigation. However, that list of potential issues for investigation is neither a list of expected results from smart grid planning nor a list of topics that must be addressed in the SGP.

Considering the broad-based support for the five SGP goals in the SGSP (and reiterated in Staff Opening Comments), Staff proposes to retain those goals.

16. <u>Communications and IT Infrastructure</u>

All three utilities acknowledged the importance of ensuring adequate safeguards for this information. PGE also called for a separate workshop on this topic to clarify what information should be in the SGP.

[47] SGO Opening Comments, pg. 3

Staff supports the concerns about the need for sufficient safeguards for this information. At this time, Staff does not support PGE's suggestion that a separate workshop be held. There will be future opportunities to convene one or more workshops on this and other related issues after this investigation is completed and before the first SGP filing. Staff supports retaining the proposal made in its Opening Comments.

17. <u>Cyber and Physical Security</u>

PPL agrees that the SGP should include a section to discuss CIP requirements. PPL also commented that "As utilities progress towards the smart grid, enhanced security measures and more stringent requirements will be necessary."[48] It also proposed that the costs of increased security should be reflected in smart grid costs, if those costs are known. PGE proposed that this topic also be addressed in a workshop to define what to include in the SGP.

Staff supports the concerns expressed about safeguarding this important information. At this time, Staff does not support PGE's suggestion that a separate workshop be held. There will be future opportunities to convene one or more workshops on this and other related issues after this investigation is completed and before the first SGP filing. The approach discussed in the SGSP and Opening Comments goes beyond CIP requirements. Therefore, Staff opposes PPLs proposal that a section should be included to discuss CIP requirements. Concerning PPL's call for cost recovery, all cost recovery decisions will continue to be made as part of the contested rate proceeding. For the reasons stated above, Staff supports retaining the proposal made in Opening Comments.

[48] PPL Opening Comments, pg. 5

18. Risk and its Mitigation

PPL filed comments supporting this section and suggesting that obsolescence risk should be included in this section.

This section should include a discussion of all risks associated with action in the SGP, if those risks have not already been addressed in some other SGP section. For example, cyber and physical security risks from SGP actions may be addressed in that section. Staff supports retaining the proposal made in its Opening Comments with the following clarification: this section may contain all risks associated with SGP actions or it may address risks associated with SGP actions not addressed in some other section. The risk discussion is limited to (a) changes in existing risks attributable to SGP actions, and (b) new risks associated with SGP actions.

Dated at Salem, Oregon this 17th day of December, 2010

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Electric Rates & Planning
Oregon Public Utility Commission

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1460

In the Matter of an Investigation into Smart Grid Objectives and Action Items	STAFF CLOSING COMMENTS

APPENDIX A

GUIDELINES FOR THE UTILITY SMART GRID PLAN (SGP)

1. ***Guidance that applies to the entire SGP and all Annual Updates***

   A. For each section, the utility must (1) identify all Smart Grid (SG) related proposed actions for that section both by the utility itself and all unregulated affiliates, and (2) identify all actions that were investigated and rejected, including a substantive explanation for the rejection.

   B. For any section in which the utility provides no information in response to either requirement in section A above, the utility must provide a compelling rationale for its decision to not investigate possible SG actions.

   A. Since the SGP focuses on changes in each section of the SGP, these changes are limited to those arising from actions[1] proposed in the SGP unless otherwise noted.

   B. Section 5(I) identifies compliance requirements that apply to various sections in the SGP.

   C. For all economic analysis, as applicable, use the assumptions used in your most recent or next Integrated Resource Plan (IRP), and explain any differences from the IRP.

[1] The term 'action' is used throughout these guidelines. An action is any step that leads to a smarter grid than what exists. Some examples of SG-related action are: investing in SG-related hardware or software; adopting or changing a SG-related guideline, policy, procedure, or rule; acquiring a business or establishing an SG-related enterprise. These are illustrative examples and should be understood as such.

2. ***Access, Control, and Use of Customer Information***
The utility must:

A. Indicate how it plans to manage access, control, and use of customer information;
B. Explain how it plans to maintain the security of its network from unauthorized access to consumers' information;[2] and. by anyone not having authorized access to that information;[3]
C. Identify steps being taken to assure that the utility does not share confidential customer information with an unregulated subsidiary that could help give that affiliate a competitive advantage over existing or potential rivals.

3. ***Opt in, Opt out, or Mandatory Program Participation***
The utility must identify:

A. When it is proposing to use opt in or opt out customer participation choices;
B. If and when it intends to make customer participation mandatory and the reason(s) for this requirement;
C. When it is proposing to use opt in or opt out customer participation choices;
D. If the utility plans to ultimately seek to make a program mandatory; and
E. What requirements exist for equipment installation on the customer's side of the meter required to implement an SGP action, the expected installation and annual maintenance costs, and the proposed cost allocation between the customer and the utility.

[2] Data may be aggregated and released without customer prior approval only if there is no way to associate data with a particular customer.
[3] Data may be aggregated and released without customer prior approval only if there is no way to associate data with a particular customer.

4. ***Treatment of Obsolescence Risk***[4]

The utility must:

A. Identify and qualitatively discuss potential new, and changes to, pre-existing obsolescence risks;[5] The discussion should include (1) the cause of the risk, (2) its impacts on customers by group, (3) steps taken to reduce its impacts, and (4) any residual risks;[6]

B. Quantify[7] obsolescence risks identifying its magnitude, important economic assumptions, and (2) any residual risk and (2) any residual risks, and any other dimension of the risk that helps to convey its significance.

5. ***Utility Energy Management in Customer's Home or Business***

The utility must:

A. Assure that any devices or software it is involved in installing will allow for interoperability with third-party hardware and software; and;

B. Examine and report on (1) the steps required, (2) the cost, (3) important issues to be resolved, and (4) timeline for implementing customer's ability to retrieve their usage data. Also explain how this information changes between opt in, opt out, or mandatory program participation.

6. ***SGP[8] Content***

A. *Estimated Benefits and Costs of Actions in SGP*[9]

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[4] Obsolescence risk arises only when a durable asset is being replaced and a portion of the capital cost of the asset being replaced has not yet been fully recovered through rates.

[5] The explanation should provide the reader with a complete picture of the utility's overall approach to managing this risk.

[6] The explanation should provide the reader with a complete picture of the utility's overall approach to managing this risk.

[7] Include an explanation of quantification efforts, including but not necessarily limited to, methods and data used, problems, and key assumptions.

[8] Unless otherwise expressly stated, throughout this document "SGP" means the utility's initial filing as well as the Annual Updates.

[9] For purposes of the SGP, costs include, but need not be limited to, capital, operating, and depreciation costs of all hardware and software for SGP actions.

The utility must:

a. Present and discuss quantified (where possible) benefits and costs.[10] [11] These benefits and costs should be identified in total by year, and for the timeframe of the analysis using typical present value methods. In addition, identify all key economic, financial, and program assumptions; [12] [13]

b. Group benefits and costs in the following categories (to the extent possible):

    a. Economic – e.g. reduced costs that result from improved utility system efficiency and asset utilization;

    b. Reliability and Power Quality – e.g. reduction in interruptions and power quality events;

    c. Environmental – e.g. identify changes in the cost of meeting climate change risks; and

    d. Security and Safety – e.g. improved energy security and increased cyber security.

c. Distinguish between intermediate outcomes and end-user benefits.[14]

d. Discuss non-quantifiable benefits in sufficient detail so as to adequately describe their significance; and.

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[10] While it is not a requirement, utilities are encouraged to separate benefit and cost detail into logical groupings, such as along functional lines (generation, transmission, distribution, customer level). Utilities are also encouraged to separate costs within a category in a logical way, such as between capital and ongoing expenses.

[11] The detailed benefit and cost analyses provided should provide the business basis for actions in the SGP. This includes, but is not limited to, actions that are intended to improve reliability, quality of service, and compliance with statutory mandates (such as the Oregon Renewable Portfolio Standard).

[12]Utilities are encouraged to separate benefit and cost detail and reliability discussions into logical groupings, such as along functional lines (generation, transmission, distribution, customer level). Utilities are also encouraged to separate costs within a category between capital and ongoing expenses.

[13] The detailed benefit and cost analyses should provide the business basis for actions in the SGP. This includes, but is not limited to, actions that are intended to improve reliability, quality of service, and compliance with statutory mandates (such as the Oregon Renewable Portfolio Standard).

[14] For example, enhanced distribution system monitoring that improves capacity utilization is an intermediate result. This may then contribute to an end-user benefit in the form of avoiding costly generation and/or distribution investments.

e. Separate benefit and cost detail into logical groupings, such as along functional lines (generation, transmission, distribution, customer level). Note: This item is not a strict requirement. The Commission encourages the above-grouping along with separating costs within a category in a logical way, such as between capital and ongoing expenses.

B. *Systems Reliability*[15] [16]

As appropriate, information related to this section may be incorporated in the section on Communications and Information Technology (IT) infrastructure.

The utility must:

1. Explain[17] actions designed to improve generation and distribution reliability and end-user power quality. This explanation should include, at a minimum, (a) a description of the action, (b) the goal(s), (c) how success will be determined, (d) the cost, and (e) expected benefits. If for an action, there is the option of opt in, opt out, or mandatory participation, identify how the results may vary between these three program participation options;
2. Identify reliability and power quality investments that were considered and rejected and discuss the rationale for the rejection.

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[15] "Systems reliability" includes the electric system components and all the communications and data components required to assure and improve both continued power deliveries and power quality. Systems reliability means, at a minimum, assuring no degradation in power delivery or power quality, or the ability of the system to react to potential problems before they occur and recover from problems after they occur.

[16] See footnote 8.

[17] The explanation should identify the action, its anticipated benefits, its costs, and any other information needed to understand the rationale for its selection.

3. Identify and explain any standards it is considering adopting that bear on the issue of systems reliability;
4. Discuss its assessment of actions (along with any actions investigated and rejected) to increase ancillary services including, but not limited to, those designed to enhance customer distributed resource interconnection, coordinated management of distributed resources, optimized electric vehicle charging, and dispatch from electric vehicles or other storage; and.
5. Identify and explain reliability and system awareness enhancements at the transmission level...

C. *Education and Information - Customer Energy Use Management*[18]

The utility must:

1. Explain why the utility expects its plans for customer education and improved interaction will be effective relative to alternatives that were considered and rejected;
2. Identify and describe customer[19] education efforts focused on helping the customer to: (a) Better understand and benefit from SG technologies, including systems on the customer side of the meter; (b) Understand SG and how it can lead to improved reliability, security, economics, efficiency, environmental friendliness, and safety; (c) Understand the broad SG framework; (d) Understand and influence approaches to assuring usage data are secure; and, (e) Influence the direction of plans for retrieving use data directly and in near real-time from an in-premises device;

[18] SG related education and outreach should include those intended to conform with education and outreach requirements for Electric Vehicle (EV) established UM 1461.
[19] The utility should discuss it plans to collaborate with customers, customer groups and stakeholders on the design of consumer education programs and in the development, targeting, and delivery of program-specific information or tools.

3. Identify and explain the utility's efforts to coordinate with retailers and vendors to help educate customers about equipment and software that is available to manage their electricity use.
4. Discuss how it plans to enhance interactivity with customers to help the power system and its users react to each other's needs; and,
5. Summarize (and discuss your reaction to) the comments received from customers, customer groups, retailers, and any other key group, on these education and information efforts.[20]

D. *Communications and IT Infrastructure*

1. This section of the SGP will include sufficient detail (including estimates of costs) to allow the Commission to determine the adequacy of the utility's communications and IT planning to support actions in the SGP.[21]
2. The utility must address each of the following design issues as they relate to its proposed communications and IT actions:
   a. Capacity (bandwidth);[22]
   b. Openness and "standardization;"[23] [24]
   c. Reliability;
   d. Manageability;[25]

[20] That is, what considerations and factors influenced your choice? What experience by you or others influenced your choice? How did you conclude these actions will likely be effective?
[21] See footnote 8.
[22] This refers to the ability of a communications link to carry data described by such factors as latency, data volume, and event rate.
[23] "Standardization" is the degree to which the technologies used to implement the application are recognized by official organizations and the user community.
[24] This refers to the degree to which systems associated with the application can automatically recover from power, communications and component failures, in order to minimize the impact on the customer and the systems.
[25] This refers to the degree to which devices, systems, and data must be configured, synchronized, tracked, diagnosed or maintained in order to implement the application. "Manageability" includes the ability to measure the health and the performance of the system.

e. Upgradeability;[26] and,

f. Scalability.[27]

E. *Cyber and Physical Security*[28] [29] [30]

The utility must identify:

1. Steps it has or is taking to ensure an adequate level of system security. Security means the system's ability to withstand both physical and electronic attacks; and,
2. Physical security actions necessary to maintain cyber security.

F. *Distribution of SGP Benefits and Costs*

Note that while the Commission's acknowledgement of an SGP may consider the content of this section, decisions on actual cost allocations and incentive amounts will continue to be made in general rate cases, tariff filings, or similar proceedings.

The utility must:

1. Discuss impacts[31] on the customer and stakeholder groups below:
   a. Retailers of products and services that give consumers greater choice and flexibility in energy consumption[32];
   b. Residential customers;

[26] This refers to how easy it is for the system to adapt to future conditions.
[27] This refers to how the design permits future expansion.
[28] This section is not intended to substitute for CIP compliance reporting requirements.
[29] "System" means the electric delivery components (e.g. generation, sub-stations, etc.) as well as all the supporting communications and IT technologies, including those systems involved in customer data collection, management, billing, etc.
[30] Staff will work with the utilities in order to determine the best way to balance the need for some disclosure while avoiding identifying the details of its security plans.
[31] Focus on impacts on their expected class revenue requirements, end-user reliability, the ability of customers to control their energy use and bills, and any other known impact you consider important.
[32] For this element the utility should discuss how its plan will encourage cooperation from retailers.

c. Small commercial customers;

d. Low income customers and elderly customers on fixed incomes;

e. Large customers; and

f. Local governments.

2. Identify (including cost estimates) SGP actions that require customer investments to fully realize any benefits identified in the SGP.

G. *SG-Enabled Pricing Options*

The utility must:

1. Evaluate the applicability of selected dynamic pricing (DP), price-based demand response (PBDR), to all customers under (a) opt in, (b) opt out, and (c) mandatory participation. This evaluation should include the amount of expected program participation, program cost, the distribution of benefits and costs, and the expected impact on consumption;
2. Discuss and explain its plan for enacting DP, PBDR, to all customers under (a) opt in, (b) opt out, and (c) mandatory participation within the Action Plan timeframe, and if none will be implemented, the basis for this decision;
3. Evaluate the potential benefits and costs of deploying Advanced Meter Infrastructure (AMI) to all customers within the Action Plan timeframe (including a discussion of whether, and when, AMI deployment will occur);
4. Provide a compelling rationale if you do not plan to deploy AMI; and
5. Evaluate automated load dispatch to all customers assuming (a) opt in, (b) opt out, and (c) mandatory participation. This evaluation should examine (1) the amount of expected program

participation, (2) program cost, (3) distribution of benefits and costs, (4) expected impact on consumption, and (5) any other significant factors.

H. *Risk and its Mitigation*[33]

The utility must:

1. Identify any financial and operational risks that have not already been previously discussed that arise from actions set forth in the SGP and plans to reduce these risks. This discussion must include such issues as (a) the potential for and cost of risk mitigation, (b) risk exposure absent mitigation, and (c) how the SGP affects existing risk. The discussion will include steps the utility plans to take in an effort to reduce these risks.
2. Advise the Commission of, potential or actual threats to any of its businesses that currently contribute revenue for cost recovery.[34] As with other parts of the SGP, monitoring of revenues used to set rates are limited to revenue changes that may arise from its own SG-related activities or SG actions of other parties.

I. *Compliance with National, Regional or Other Standards*

The utility must:

1. Discuss how its plans are consistent with guidelines, protocols or standards adopted by the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the NERC or the WECC that relate to communication, IT, or privacy;

[33] The Commission encourages the utility to separate these risks sub-sections: Generation; Transmission; Distribution; Customer Level.

[34] At this time, the Commission does not have a list of such threats. These issues arose with direct access legislation and rules concerning retail de-regulation. They have also occurred in other regulated industries, such as telecommunications as its industry structure changed. With that said, one example would be a high-efficiency low-cost natural-gas fuel cell that generated electricity and provided space heat and water heat at a lower overall cost than traditional utility service.

2. Explain how its privacy safeguards relate to the then-current Department of Homeland Security's Fair Information Practice Principles or related principles;
3. Identify how it plans to protect Critical Energy Infrastructure Information (CEII);
4. Discuss how its system could incorporate, in a timely manner, protocols, standards or guidelines proposed by the NERC, the WECC, the NIST or other leading organizations relating to communication, IT, or privacy;
5. Discuss how its plans are consistent with protocols, guidelines, or standards adopted by the FERC, the NERC or the WECC that relate to systems reliability, interoperability and cyber and physical security;
6. Explain its reasoning if it does not plan to incorporate or adopt standards or technologies recommended by the NIST Smart Grid Framework; and
7. Explain its reasoning if it does not plan to be consistent with a planned or adopted standard, protocol or guideline. The compliance discussion should include planned or current applications for exceptions and possible consequences of non-compliance.

7. *SGP Submission Schedule and SGP Timeframes*

Pacific Power, Idaho Power, and Portland General Electric must submit their first SGP no later than six months from the effective date of the Commission's Order in this docket.

The utility must:

A. Use a 20-year period of analysis for the economic analysis of costs and benefits;
B. Design the first SGP to cover the ten-year period 2011 – 2021;

C. Split the 10-year SGP timeframe into two periods as follows:

   1. A five-year Action Plan that will identify actions the utility intends to take during the first five years of the SGP (i.e.2011 – 2015, inclusive, for the first SGP). For the second and third SGP, the five-year Action Plan will begin on the SGP submission date;
   2. The remaining five-year period SGP will also identify potential actions, measures, and programs in less detail than in the Action Plan;

D. If pilot projects are proposed, discuss (a) their rationale, (b) selection of length, (c) how participation will be determined, (d) the pilot's purpose(s), and (e) estimated cost;

E. Submit a second SGP no later than June 30, 2014. Utilities may submit this second plan at any time during the 2012-2014 timeframe. Also, parties (including Commission staff) may agree to a different submission schedule. Absent an agreement between the utilities and parties (including Commission staff), each utility will file its second SGP on or before June 30, 2014 with a beginning date no later than June 30, 2015; and

F. Submit a third SGP no later than June 30, 2019. Utilities may submit this third plan at any time during the 2017-2019 timeframe. Also, parties (including Commission staff) may agree to a different submission schedule. Absent an agreement between the utilities and parties (including Commission staff), each utility will file its third SGP on or before June 30, 2019 with a beginning date no later than June 30, 2020.

Before the end of the Action Plan for the third SGP, Staff will submit a report to the Commission on the SG planning effort, including its recommendations for next steps.

8. Annual Updates

The utility must:

A. Submit an Annual Update during each year of the Action Plan;

B. Submit its first Annual Update no later than the 12-month anniversary of the submission of its initial SGP; and

C. Include in the Annual Update:

   a. Changes to the SGP and a discussion of reasons for the changes; and,

   b. Progress on Action Plan implementation.

9. SGP and Annual Update Review

Commission Staff must:

A. Within 30 days of receipt of the SGP, or of an Annual Update that requests acknowledgement, request Administrative Hearings to convene a Prehearing Conference to adopt a schedule for processing the submitted filing).

B. Either recommend (1) acknowledgement of the SGP as submitted, or (2) withholding acknowledgement and make recommendations to the utility that, if adopted, will achieve Commission acknowledgment of the SGP;[35]

C. Review the Annual Update to assess whether material changes have occurred in either the utility's proposed actions or its implementation of its Action Plan; and

D. If any party asserts that the Annual Update includes a material change, Staff's comments, and those of other parties, will be presented at the same Commission public meeting where the utility summarizes its Annual Update. Comments on the Annual Update, and the utility's response, if any, will become part of the record for the Annual Update filing.

[35] Acknowledgement" of a SGP has the same meaning and effect as it does for an Integrated Resource Plan.

APPENDIX B
SUMMARY OF CONVERSATION AND CORRESPONDENCE WITH OTHER STATES COMMISSION STAFF

Staff has also consulted with Commission Staff at the California (CA), Colorado (CO), District of Columbia (DC), Illinois (IL), New York (NY), and Texas (TX) to be informed about other state Commissions approached these issues. What follows is a summary of those correspondences and conversations.

CA began its SG rulemaking in response to Energy Independence and Security Act (EISA), which directed the states to consider a couple of Smart Grid-related PURPA amendments.[1] During that process, the state legislature passed a bill (SB 17) directing the California Public Utilities Commission (CPUC) to create requirements for a "Smart Grid Deployment Plan" that would be filed by the utilities.

As part of the CPUC process defined by statute, the CPUC continued their proceeding (begun in response to EISA) and developed eight issues that the utility's Smart Grid Deployment Plan must address: Vision, Strategy, Roadmap, Baseline, Cost Estimates, Benefits Estimates, Metrics, and Cyber-Security.   The "Vision" section of the utility's Smart Grid Deployment Plan should be based around the concept of a Smart Market, Smart Consumer and Smart Utility. The deployment plans are due to the Commission by July 1, 2011.

Rather than think of the CPUC process as one of 'visioning," Commission staff led that process, with legislative direction, to formulate requirements for a Smart Grid Deployment Plan. Over the past two years, the CPUC held over 10 workshops, had numerous rounds of filings and comments, and issued 3 decisions. It should also be noted that SG-related issues continue to be addressed in other dockets. Regarding a definition of SG, they used both the

[1] Based on email correspondence with CPUC Staff

EISA definition and the state legislation's version (virtually the same except for eight references to cost-effective in the state law).

Turning to IL[2], in 2007, the utilities (notably ComEd) requested riders to begin grid modernization investments. The Illinois Commerce Commission (ICC) "…more or less turned those down"[3] It did approve a limited-scope and scale smart meter pilot for ComEd which the courts have just ruled violated single issue rate making rules for its rider Recovery. In the fall of 2008, the ICC ordered a two-year long Collaborative to look at smart grid issues. .

The ICC ordered the two IOUs in to work together and a 3rd party was hired to facilitate these discussions. The Commissioners were not involved, but Commission staff was involved as one of the parties. Concurrently, Prior to the Collaborative, The Center for Neighborhood Technology had partnered with the Galvin Institute to run a series of workshops in summer of 2008 under the name the Illinois Smart Grid Initiative (see: http://www.ilsmartgrid.org/). Those workshops served the purpose of warming up stakeholders in Illinois to smart grid issues, as this was prior to the federal efforts under the current administration. At the time, there was a very low level of understanding and awareness, and a high degree of skepticism.

At least initially, parties accustomed to Commission proceedings were not always comfortable with this collaborative process. Parties at times seemed to hold back from being constructive in the collaborative because they seemed to want to did reserve the right to litigate issue in the future. Nothing in the Collaborative was binding and the final report did not ascribe positions to specific parties.[4]

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[2] Based on email correspondence and phone conversations with ICC Staff
[3] Ibid.
[4] ICC had a bad experience a few years ago where a similar collaborative on restructuring was supposed to be done without attribution and later the utilities cited specific comments made in that collaborative in litigation which appeared to violate the ground rules people had agreed on.

The Commission-ordered Collaborative delved into more detail than that first collaborative. In this second initiative, a definition of what constitutes smart grid was omitted. A decision was made to not spend time developing Illinois-specific definitions but rather to use existing federal definitions as guidelines.

ICC Staff report that this second initiative did help parties reach consensus on a set of issues, but some key difficult ones were not resolved such as default pricing and remote disconnection policies. Consensus tended to form on more technical issues. While there was consensus on the nature of smart grid filing requirements there was no consensus on whether or not they were mandatory, or merely guidelines. Overall the process was effective in narrowing the issues that need to be resolved, but it hit its limitations and a contested proceeding will be needed to hash out the remainder of issues.

At this point in time, the Commission is still considering how the Collaborative conclusions become Commission policy. A docket will be opened soon to adopt consensus items and has just begun to resolve the contested issues.

Turning now to CO[5], The CO Commission's current definition of SG technologies is as follow: "Technologies designed to result in utility, consumer, societal, environmental, and economic benefits derived from eight distinct value streams: Improved operational efficiency; Improved end-use efficiency; Demand response enabled load management; Improved power quality; Reduced outages; Facilitated integration of renewable resources (central and distributed); Facilitated integration of plug-in hybrid electric vehicles and/or electric vehicles (PH/EVs); and Improved customer service and the ability to provide customers with near real-time information about the price and environmental attributes of the electricity they are consuming[6]

[5] Based on email correspondence with CO PUC Staff
[6] CO Commissions Staff developed this definition from a synthesis of reports – of notable mention is EPRI's Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects and Nibler & Masiello's Handbook for Assessing Smart Grid Projects.

CO Commission Staff solicited comments on a host of issues, including but not limited to, rate design, targeting AMI installations based on usage, new incentives to allow for recovery of lost margins, issues for low-income customers, Smart Grid Cost/Benefit Analysis methodologies, components for a utility smart grid application, and PH/EV rate design. Also, they report having a separate docket open to address data privacy issues[7]

The Colorado Smart Grid Task Force (SGTF) was convened in response to Senate Bill 10-180 to examine key issues and make recommendations regarding Smart Grid development and implementation to the CO Commission, the CO Governor's Energy Office, and the CO General Assembly. This Task Force has been meeting since July.[8] A synthesis report of key issues and recommendations is expected by the end of January 2011.

Turning to the District of Columbia[9] (D.C.), they too did not use a "visioning" process. In the District of Columbia, the following definitions were established by the legislature: "(1) "Advanced Metering Infrastructure" or "AMI" means a system capable of providing 2-way communication with metering equipment to gather at least hourly energy consumption data on a daily basis for all customers. (8) "Smart Grid" means the installation of advanced technology to enhance the operation of the electric distribution and transmission system. AMI was approved by DC Code 34-1562"[10]

The New York Commission also did not use a "visioning" process. Several months ago they asked utilities and other stakeholders to file answers to a series of questions posed by the NY Commission. Thirty-two parties filed comments.

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[7]Docket No. 10R-799E
[8] Information on members along with meeting agendas and summaries are available here: rechargecolorado.com/index.php/programs_overview/smart_grid_task_force
[9] Based on email excerpts from relevant DC Commission Staff
[10] Ibid.

There was a utility consensus that they want to increase Transmission & Distribution reliability first and then implement AMI in a few years[11].

Texas has not used a "visioning" process. SG deployment in TX has centered on AMI. Legislation was passed in 2005 that provided the framework for the Commission work in this area. The Texas"…Commission then adopted a rulemaking (controversial at the time) for AMI deployment. That rulemaking included standards for minimum functionality, deployment plans, cost-recovery, utility compliance reporting, customer and provider access to data, 15-minute IDR requirements and settlement timeline for ERCOT ISO, and security requirements." [12]

TX Commission Staff identified the main paragraph from the legislation as "In recognition that …new metering and meter information technologies, have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of transmission and generation assets, and provide more choices for consumers, the legislature encourages the adoption of these technologies by electric utilities in this state."[13]

[11] Comments excerpted from email correspondence with relevant NY Commission Staff.
[12] Excerpt form email correspondence with Texas Commission Staff.
[13] HB 2129 (79th Regular Session)

CERTIFICATE OF SERVICE

UM 1460
CLOSING COMMENTS

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 17th day of December, 2010, at Salem, Oregon.

Kay Barnes

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UM 1460

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