Supplement to the Rule 3627 Reports

The Colorado Public Utilities Commission asked Public Service to provide a portion of the 120-Day Report in the Electric Resource Plan (ERP) in Docket 11A-869E with our 3627 filings. So that the record is complete, we have attached the information requested by the Commission from 120-Day report in its entirety below.

The Company's reports and the parties' comments on them highlight the state of transmission investment and the slow course of the development of new transmission projects relative to the generation acquired to meet RES requirements.

Company General Comments: To adequately respond to the following Commission questions Public Service believes it is of value to provide background on the original purpose behind -- and the goals of -- SB 07-100 as well as the issues it was designed to address. Public Service also notes that as of the date of this 120-day report, and without consideration of the additional wind and solar PV resources proposed in this report, Public Service has already acquired sufficient renewable generation from wind and utility scale solar to meet the Non-DG requirements of the RES for the next twenty years and beyond.

Prior to the time SB07-100 was enacted, Colorado voters had passed Amendment 37 creating a new renewable energy standard ("RES") for Colorado. Unique challenges awaited Colorado jurisdictional utilities charged with meeting this new standard. These challenges were in large part due to the fact that transmission operation and planning in Colorado was and is unique in that 1) neither is performed by a Regional Transmission Organization ("RTO") with the aim of meeting a regional Renewable Portfolio Standard ("RPS") and 2) planning is done state-wide by individual transmission providers, many of whom are not jurisdictional utilities. Until recently, these non-jurisdictional utilities or cooperatives were not required to meet a RES.

Adding to these unique, Colorado-specific challenges was the overarching issue facing most utilities and renewable energy providers, i.e. "the chicken and the egg problem." Over the years, there has been a shift in timeframes associated with generation and transmission development. In the past it might take 7 years or more to develop and construct generation facilities while transmission was easier to site and permit such that it could be constructed in about a 3 year timeframe. Because new transmission was mostly built to accommodate new generation, utilities were often able to demonstrate the need for the new transmission by demonstrating the need to deliver the new generation to load. However, the paradigm has shifted: transmission now takes about 7 years to construct while generation can take as little as 18 to24 months to construct. Thus, after the RES was enacted, there was a concern that the unique challenges outlined above would hinder the ability of utilities to acquire the levels of renewable resources necessary to meet the RES. As a result, SB07-100 was enacted to facilitate the ability of jurisdictional utilities to focus first on the development new transmission facilities to access areas of the state where beneficial generation was expected to be sited.

As it turns out, many of the anticipated challenges and barriers to meeting the RES that SB07-100 was designed to avoid never materialized. Public Service is well ahead of compliance with the RES for the types of resources that require new transmission facilities and customer have benefited from the fact the Company was an early adopter of wind energy, taking advantage of tax incentives and market conditions that allowed the early acquisition of cost effective wind energy. As a result, the chicken and the egg problem has not hindered Public Services ability to meet and exceed the RES in the lowest cost manner for customers. Wind developers have been able to site projects in areas with good wind resources that are close to Public Services bulk transmission system and then build radial transmission lines (aka extension cords) to interconnect their projects to the existing grid. This approach has allowed developers to control the timing and construction of the transmission interconnection thereby ensuring that their projects ultimately qualify for the often short-lived tax incentives, incentives which have been shown to result in a 50% decrease in the price of wind to our customers

As a result, we have not been required to engage in the extensive long lead time permitting and construction of transmission facilities that might have been contemplated when SB07-100 was enacted. This fact has, in turn, permitted Public Service to focus our generation resource planning efforts on acquiring cost effective resources through competitive acquisition processes, and to focus our transmission planning efforts on smaller scale transmission projects that both facilitate the development of beneficial resources and that help us reliably operate the system.

1C. **How can the transmission planning and resource planning proceedings and processes integrate better with one another? For example, can generation forecasting in an ERP, such as forecasts of load growth and associated generation requirements beyond the resource acquisition period, better inform transmission planning? Can the transmission planning process be used to identify locations compatible for new generation and to inform policies for transmission cost assignment in bid evaluation?**

Company Response: The integration of the generation resource planning process and the transmission planning process has happened somewhat naturally over the last ten to twenty years. Since generation resource planning decisions tend to be on a shorter timeline, with some generation coming on line within 18 to 24 months after being selected, new generation resources have recently focused in areas where existing transmission capacity was available or where new transmission projects had been announced and possibly already under construction. The typical generation resource planning process includes identifying injection locations where possible transmission capacity exists and letting bidders know these locations and quantities in advance. A competitive all-source solicitation process for generation then follows from which resources offering the lowest overall cost to customers (including transmission related costs) that can be in-service when needed are selected. Through this process generation resource planning does lay out a general projection of need for new generation, as well as generation technologies that are likely to be a good fit for the system, both in the near term as well as for 40 years into the future. While the Company cannot commit to a given generation resource technology or location for more than ten years into the future, the transmission planning process can and does incorporate these general resource need forecasts in their planning process. As a result, the resource planning process and the transmission planning process are somewhat integrated today.

Current Commission planning rules which favor all-source competitive solicitation processes as opposed to targeted solicitation processes further complicate the issue of generation and transmission planning. Electric Resource Plans are filed every four years and are limited by rule to considering generation needs no more than ten years from the date the plan is filed with the Commission. The Phase I litigated process usually takes 13-15 months. Phase II immediately follows which takes another 300 days or 10 months. By the time the Company receives the final Commission Phase II decision on the generation resources to pursue, approximately two years of the ten year window have passed. Add to this the time required for the Company to prepare, file and gain approval for any CPCN for new transmission facilities that might be needed as a result of the Commissions final Phase II order and it is conceivable that another year or more of the remaining eight year window could be lost and the remaining time for permitting and constructing any needed transmission facilities may not be adequate. Further complicating these timing challenges is the fact that it has been Public Services experience that developers of wind and solar projects are not interested in offering the type of firm bid pricing required in the ERP process for projects that will be constructed and placed in-service 7 to 8 years after the Commissions Phase II decision. Instead, developers typically offer in-service dates 2 to 3 years beyond the date when the Commission would render its final Phase II decision on selected resources, a time period in which they have more certainty and control over the costs of their projects. While a 2 to 3 year timeframe is sufficient for a developer to construct a radial line from a wind or solar project to a point on the existing grid or, a point where upgrades have previously been announced and possibly already under construction, 2 to 3 years is not sufficient time to complete the development of larger-scale transmission projects.

While the integration of these two major processes has occurred over time, it appears the real question being asked is whether there are advantages to making the integration of these two processes more formal. To analyze the benefit of making this planning process more deliberate and formal, one must take into account how the lead-times for generation development have shortened while those for transmission development have lengthened discussed above. In addition, due to rapidly changing technology and fuel costs on the generation side of the equation, the generation planning has a difficult time committing to new resources until the need for the resource is nearly upon us. Likewise and in addition to, the transmission planning process must take into account the needs of a larger group of possible customers, not just the need of a single utility, and therefore its planning process can be stymied by the inability to get a firm commitment from potential new customers.

Whether transmission should take the "build and they will come" approach or worry about the traditional rate issues associated with cost causation, cost minimization and cost responsibility is a major issue. In the case of Public Service, where the Company has acquired enough renewable resources to satisfy the requirements of the Renewable Energy Standard (RES) well past 2030, it is fair to ask how much of a need remains for new transmission. On the flip side, a valid question is whether the Company will continue getting the best priced generation when taking into account the possible limited transmission availability. While these types of concerns have not appeared to be an issue in the past (based on the bids received over the last 15 years) they should not be discounted when looking into the future. Balancing these difficult issues and possible benefits related to the two planning processes is what raises the question of whether we should forge forward and pre-build possibly millions of dollars in transmission that may never be used, or at least not fully used for a long time. Certainly some new transmission projects may present benefits that outweigh these concerns (such benefits may include reliability and market access), and therefore should be pursued regardless of a committed generation project.

Public Service believes that an important issue that factors into this equation is whether generation developers would be willing to commit to the price and timing of a generation project at a certain transmission location before a transmission expansion to that location is approved. If the developer has the option of waiting until after a transmission project is approved before committing to a specific project and price, the developer may get an artificial windfall due to the fact he may have a competitive advantage relative to a developer who needs to include a project owned transmission radial, to access available transmission. Certainly if a developer does not have to include the cost for a radial transmission line to the grid in his bid price, they may be able to raise their bid price to the level of a competing developer who does need such a radial line. This exact circumstance has occurred on numerous occasions. In this situation, by pre-building transmission projects, the Company could unintentionally transfer the value of that transmission project to the developer and the customer ends up paying both the cost of the new transmission project and a higher cost for generation that utilizes that transmission. The ideal situation for customers is for a developer to commit to a price for the generation without the support of the transmission expansion and then have all bids evaluated based on the inclusion of both the transmission expansion costs and the generation bid price. Alternatively, having the developer include the cost of any necessary transmission expansion in its bid price would also provide a more competitive environment and a better situation for customers.

2C. If it is appropriate to improve the integration of new transmission and generation investment, how does this ERP highlight the challenges of such integration, what role should Public Service play to resolve these challenges, and what steps should the Commission take to advance such integration?

Company Response: See response to the questions above. On the surface, it would appear that a more deliberate integration of transmission and generation planning could make sense, but beneath the surface there are hundreds of millions of dollars at stake in this process. One possibility for addressing some of these issues would be to require the generation resource planning process to establish the identified resource need, possible resource costs and locations, and available transmission capacity for a period of 15 to 20 years into the future. In addition, the resource plan, utilizing the results of a competitive bidding process, could identify the general difference in cost between generation plans along with their associated transmission expansion plans. Likewise, the transmission plan would be informed by the projected generation need identified in the latest resource plan filing in an effort to develop alternative transmission expansion scenarios that could provide the necessary transmission access for the identified generation. This process would allow the two planning processes to be more integrated but still allowed them to proceed on their own time schedule.

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3C. How will this ERP proceeding inform the Company's transmission planning process (e.g., bids received and bids not received)? For instance, will the bids to the solicitations help identify primary transmission corridors that need to be expanded (e.g., Missile Site)?

Company Response: See response to the questions above. Public Service perceives in the Commissions questions an inherent assumption that a wind bid from SE Colorado may offer lower per MWh pricing as compared to other bids in, for example, the Missile Site area. This perception is not unreasonable if one assumes that, all other things being equal, the bid pricing offered by a SE Colorado developer would have to be lower in order to accommodate the cost of new transmission facilities needed to deliver their output to customers that a developer in the Missile Site area does not need to account for since such facilities are already in place. The table below provides a comparison of bid pricing from all three SE Colorado PTC Wind Bids with a subset of PTC Wind Bids proposing to interconnect in the Pawnee/Missile Site area.

South Eastern Colorado Wind Bids (Lamar)

Bid ID	Facility Name	MW	Bid Energy LEC ($/MWh)	Pro-rata Share of Transmission Upgrade Costs ($/MWh)	Total LEC ($/MWh)
W022					
W009					
W012					

North Eastern Colorado Wind Bids (Pawnee/Missile)

Bid ID	Facility Name	MW	Bid Energy LEC ($/MWh)	Pro-rata Share of Transmission Upgrade Costs ($/MWh)	Total LEC ($/MWh)
W013					
W021					
W018					
W026					
W008					
W025					
W006					
W005					

This information indicates that SE Colorado bid pricing was not substantially different than that for NE Colorado injecting at Pawnee/Missile and SE Colorado bid pricing is nowhere near low enough to warrant the construction of large-scale transmission facilities which would burden customers with $13-$15/MWh in added costs to deliver the power from SE Colorado to load. Furthermore, there is no evidence that if large-scale transmission was constructed in SE Colorado that bid prices received from developers in this area would even hold at the levels offered in the PTC Wind Bid process. Indeed, were wind developers in SE Colorado to have access to transmission they might be just as likely to try and capture the economic benefit of having such access for themselves through increased bid pricing.

4C. **Can targeted system improvements (e.g., further expansion of the Missile Site) or the development of an energy imbalance market allow for additional acquisitions of cost effective renewables without significant new transmission investment?**

Company Response: PSCo believes that broad regional dispatch coordination, such as could develop through an Energy Imbalance Market would provide for more efficient renewable integration than current stand-alone balancing area operations permit. The efficiency benefits associated with pooled regional market dispatch can defer the point of "saturation", at which a balancing area has exhausted its internal capability to match generation and load. The pooled market can also reduce aggregate net ramping, through geographic diversity of wind and solar resources. These attributes of a market can facilitate additional renewable resource interconnection.

It has also been shown that regional market dispatch generally permits higher utilization of transmission assets through coordinated re-dispatch when grid constraints occur. However it would be incorrect to assume that the potential for increased utilization would defer significant transmission investment for new renewable resources as the question infers. The reason is that resource siting decisions and load growth remain the fundamental drivers for transmission investment. Sitting any new generators (renewable or not) in areas with insufficient transmission capability to accommodate the output would require transmission upgrades. The regional market, however, could mitigate operating conditions where a resource with grid constraints may otherwise have to experience curtailments, when the output could potentially be accommodated through coordinated redispatch.

5C. **How should the various constraints on the acquisition of additional intermittent renewable resources be taken into account in planning future transmission needs for such resources? For example, are limits in flexible generation reserves now constraining the development of additional intermittent renewable resources and is it necessary to examine flexible generation reserves before proceeding with transmission investment for intermittent renewable resources?**

Company Response: Public Service does not agree with the premise of the question suggesting that there currently exists a constraint in flexible generation that is impeding the acquisition of additional cost-effective intermittent resources. Public Service has stated that we feel our current level of flexible generation is sufficient to properly manage not only the existing wind on our system but an additional 550 MW of wind generation. The analysis supporting this position was provided in Appendix C of the *PSCo 2013 PTC Wind Evaluation Report*. That report concluded that the Company will have sufficient flexible resources to reliably manage the addition of 550 MW of wind resources. Factor in that Public Service's preferred portfolio contains an additional 276 MW of flexible generation, the Company believes that we have more than enough of such resources to manage the levels of wind and solar PV being recommended in this ERP and beyond.

6C. **Should the Commission establish overarching goals to drive coordinated, long-term generation and transmission development and, if goals are necessary, upon what should they be based?**

Company Response: The Commission has just recently put in place new transmission planning rules that require not just a 10 year transmission plan but a 20 year scenario plan. The first of these plans is not due until February 1, 2014. The Commission should wait and see whether the planning that takes place under those new rules addresses its concerns before developing new overarching goals and rules. The Commission should defer this question until after that filing has been made and has had the opportunity to consider the materials presented.