Transmission Services

Customer Comments on the 2008 Network Open Season Recommendation

Posted: February 13, 2009

This document contains the Transmission Customer comments for the 2008 Network Open Season Recommendation received during the period of January 15, 2009 to January 30, 2009. Responses to these comments have been included as Attachment B to the 2008 NOS Decision Letter posted to the NOS web site at http://www.transmission.bpa.gov/customer_forums/open_season/default.cfm.

Thank you for your comments.

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1 Northwest Requirements Utilities

Northwest Requirements Utilities (NRU) appreciates this opportunity to comment on BPA's 2008 Network Open Season (NOS) recommendations that were distributed on January 15, 2009. In general, we appreciate the work BPA has done in clearing out the queue and adhering to the evaluative criteria in determining which projects will go forward at an embedded rate.

One project which is of particular importance to NRU members is the LaGrande project. While BPA is proposing this project should not go forward at an embedded rate, it noted that the special circumstances of this project necessitate a special process. Such process would include a "rigorous needs assessment" that incorporates, among other factors, assessments of current and future NT obligations to network load growth and new network resources. BPA also noted in its presentation that it will develop alternatives to provide service as part of its assessment of the LaGrande project, such as participating in other transmission providers' construction projects or non-wires solutions.

It is imperative that BPA work expeditiously to develop solutions to improve this path's transmission availability. BPA has noted reliability concerns with the current path and existing loads in Idaho; this only highlights the need for focused attention and creative problem-solving on that path. Loads will continue to grow, and utilities need to have the ability to move non-federal resources under their post-2011 contracts. All of these point to the immediacy of resolving these issues. NRU staff is committed to working with other customers and BPA in finding ways to ease the constraints on this transmission path.

With regard to the proposed 2009 NOS timeline, NRU offers two general comments. First, we are pleased to see BPA attempting to continue the NOS process on a regular basis. Second, as we expressed in this month's Transmission Forum, we encourage BPA to extend the 2009 NOS close date until the end of June 2009 in order to accommodate for the fact that public power utilities will not receive their above high water mark loads for FY 2012-13 until approximately May 2009. Extending the deadline slightly would enable some public power utilities to participate in the 2009 NOS process, while still keeping BPA on its general timeframe.

2 Iberdrola Renewables

IRI supports BPA's recommendation to provide at embedded rates transmission service enabled by the following upgrades and reinforcements: West of McNary (McNary-John Day and Big Eddy-Station Z), Little Goose Area, West of Garrison (RAS) and I-5 Corridor.

3 Renewable Northwest Project

RNP encourages the Administration to move forward on the staff recommended embedded rate projects: McNary-John Day, Big Eddy-Station Z, I-5, Little Goose, and West of Garrison RAS ("embedded rate projects"). It is not the intent of our comments below to slow down the process for moving forward with these projects.

As the environmental work and technical specifications of the embedded rate projects are completed, RNP encourages the Administration to consider the demand for any additional long-term transmission capacity over the paths associated with these upgrades. For example, the costs and potential future benefits of acquiring additional right-of-way and/or sizing towers that more easily accommodate the addition of future capacity should be considered as the embedded rate projects move forward. The Administration should take advantage of economies of scale that can be financed without undue upward rate pressure.

The following sources of information may be useful in assessing future needs and mitigating the uncertainty and risk associated with optimally sizing lines for future uses:

a. Current LTF queue.
b. 2009-10 Open Season commitments.
c. WGA Western Renewable Resource Zone mapping efforts. [1]
d. Regional RPS targets.
e. Network Load growth.
f. Regional Load growth.

RNP supports the Administration's effort to coordinate with affected transmission providers and relevant PTSA customers to move the identified La Grande segment and any related upgrades forward in a timely manner. The Administration should explore all opportunities to coordinate with affected transmission providers for other incremental rate segments and consider alternative plans of service before ending the PTSAs.

RNP suggests that the deposits associated with PTSAs for incremental rate projects in NOS I be allowed to rollover to cover PTSAs signed by the same party in the 2009-10 Open Season.

The fundamental design of the 2008-09 NOS is a sound and should not be abandoned. The following suggestions are offered for improving future Open Seasons:

1. The Commercial Infrastructure Financial Policy ("CIFP") was an ambitious and positive start toward developing a quantitative analysis to inform infrastructure investment decisions. Unfortunately, the first round of NOS was not able to complete all of the analysis conceived of in the original CIFP. Prior to the 2009-10 Open Season, the Administration should reexamine the CIFP to clarify which transmission expansion benefits are important to the analysis. Those benefits that are measurable should be measured. Any benefits that are important, but not quantifiable, should be incorporated into the embedded rate test in a formal, consistent, and traceable manner.

a. RNP believes that the following benefits are important to making long-term infrastructure investment decisions:

i. Variable Generator diversity value.
ii. Reliability benefits.
iii. Economic benefits of accessing cheaper resource (including a sensitivity to CO_2 cost).
iv. Future uses.
v. Short-Term Firm and Non-Firm transmission revenue.

[1] http://www.westgov.org/wga/initiatives/wrez/technical/briefing1-13-09.htm.

RNP believes that a different policy should be considered for segments that fail the embedded rate test. Rather than automatically ending the PTSA commitment, customers should have the option to keep their commitment and “queue” position while other commercial interests and benefits associated with the same upgrade are analyzed. This could be done through the subsequent NOS round. Another possibility is to have an expedited Open Season specifically focused on a incremental rate upgrade to ensure that all long-term interests for that upgrade are accounted for.

RNP encourages the Administration to consider an Open Season for expanding the capacity on those interties that will facilitate the transfer of renewable energy among the four Northwest states.

There should be a process in future Open Seasons for customers to work with the Administration to design plans of service before moving on to the commercial infrastructure financial analysis and the rate test decision.

The 2009-10 Open Season should allow PTSA holders to redirect their PORs to the extent that the redirect has similar ATC impacts to the same flowgate. Prior to the opening of the 2009-10 Open Season, the Administration should identify and post the POR combinations that are deemed transferable. This policy will allow generation developers to mitigate the risk and uncertainty associated with not knowing which one of their similarly located projects will be developed first. This policy will ensure greater participation from generation developers.

RNP encourages the Administration to institute a “Simultaneous Window” after the close of the next Open Season so all Transmission Customers may have an equal chance of gaining favorable queue positions. Without a Simultaneous Window, parties that do not have an automated system for submitting TSRs are at a systematic disadvantage when entering the new queue. For example, all TSRs received during the same hour could be treated equally and then randomly assigned queue positions. TSRs received during the next hour would be treated in the same manner, with all requests queued strictly below those from the previous hour.

As RNP stated in their supporting comments to FERC, and the Commission supported, the embedded rate test methodology relies heavily on the presence of reliability benefits and thus systematically favors internal network upgrades over more radial upgrades.[2] RNP believes the Administration should consider a slightly revised Open Season process primarily focused on accessing location constrained renewable resources.

One of the primary benefits of the current NOS design is that it binds customers to long-term transmission commitments such that their individual demand for transmission capacity can be consolidated to sufficiently justify a “lumpy” transmission investment. Those commitments also decreased the transmission provider’s risk of overhanging capacity. The off-ramp provided to customers if incremental rates were deemed necessary was beneficial because customers were not asked to commit to contracts with unbounded rates.

These same design features could be made to apply to Open Seasons for more radial lines. Northwestern Energy is currently considering a similar concept (EL09-29-000). RNP believes the Administration should consider running an Open Season focused on location constrained renewables that commits customers to binding transmission contracts and gives an off-ramp if incremental rates are required and are calculated to be more than some previously agreed upon percentage above embedded rates.

4 PNGC Power

PNGC POWER appreciates the continuing effort that BPA is making to address its long-term transmission request queue and its transmission system additions through NOS. We also appreciate this opportunity to comment on BPA's 2008 Network Open Season (NOS) recommendations that were distributed on January 15, 2009.

We support BPA's recommendation that it move forward at embedded rates with the projects identified in the January 15, 2009 presentation: West of McNary Reinforcement, I-5 Corridor Reinforcement, West of Garrison (RAS), and the Little Goose Area Reinforcement. We believe that this combination of projects will greatly enhance the robustness of BPA's transmission grid and allow it to process current and future requests for long-term transmission service in a timely manner. Given the push for new renewable resources currently underway nationwide as well as in several Northwest states, and the opportunity public agencies have to diversify power supply under the new Regional Dialogue power contracts, a robust transmission system is critical to our member utilities success.

One area of particular interest to PNGC POWER members is La Grande. We agree that the presence of many NT loads and the immediacy of the reliability needs of those NT customers warrant a special process. Assessment of the needs of current and future NT obligations on this path is long overdue. PNGC POWER encourages BPA to creatively seek options to improve this path's transmission availability; the NOS process has highlighted the need for action on this path. We agree that BPA should look at all options for improving this path such as participating in other transmission providers' construction projects, alternate paths, operations driven solutions for the short-term, or non-wires solutions.

We are pleased to see BPA attempting to continue the NOS process on a regular basis. Customers need to know that their transmission requests will be answered in a timely manner if resources are to be developed. We do however encourage BPA to extend the 2009 NOS close date until the end of June 2009 in order to accommodate possible requests for long-term service from customers who just signed a Regional Dialogue power sales contract. These customers will receive from BPA Power their above high water mark obligations for FY 2012-13 in mid-May of 2009. Extending the deadline to the end of June would allow public power utilities who are ready to commit to resources to participate in the 2009 NOS process.

5 Powerex

BPA has provided its customers with information which, among other things, discusses the criteria it used when it evaluated projects to determine whether they should proceed on an embedded rate or incremental rate basis. Although this information is helpful, Powerex believes that BPA should provide additional information so that the rationale for determining which projects proceed on an embedded rates basis is clear and transparent. This is especially important given that the process used for the 2008 Network Open Season will serve as the template for the network open seasons BPA proposes to hold in the future. In particular, Powerex believes that it is critical that BPA provide a "scorecard" which sets out the criteria which were evaluated for each project, and the relative weight given to each criteria. It is important that customers understand what weight or importance BPA is assigning to the various criteria it uses to determine whether infrastructure upgrades are made – or not made – at embedded cost rates.

1. Powerex also has the following comments about the information that was provided:

   - BPA provides the net present value of the projects that it recommends move forward at customer expense, but does not provide the net present value of the projects that it recommends move forward at embedded cost rates. Powerex would appreciate it if BPA would provide this information.
   - Page 6 of the materials posted for the January 15, 2009 customer meeting states that one of the criteria BPA applied was that there be no more than a 2-3% rate impact over 35 years for the recommended combined expansion facilities. However, page 8 of the materials discuses the rate impact of the projects that will move forward at customer expense and refers to the 20 year average impact. Similarly, the chart on page 10 refers to 1, 5, 10 and 20 year average embedded rate impacts. Powerex would appreciate it if BPA would provide information which shows the rate impacts over a 35 year period for the projects.
   - Page 6 of the materials also states that providing capacity for future load growth and "future commercial sales" is one of the business/finance criteria that was used to evaluate the projects. Please clarify whether BPA is referring to potential future commercial sales made by Power Services.

2. Powerex understands that BPA may not have considered that proceeding with the Northern Intertie upgrade may help to alleviate constraints in the Puget Sound area. Transmission constraints in this area have been a significant source of concern to the region for some time. In addition, we note that "reliability benefits" and providing "regional benefits" to customers in BPA's balancing authority are listed as being criteria that BPA applied when it evaluated the projects. As a result, Powerex believes that BPA's evaluation of the Northern Intertie project should consider whether or not proceeding with the project will alleviate constraints. If this has not occurred, Powerex believes that BPA should re-assess the project to take this factor into account.

3. From discussions at the customer meeting, it appears there may be a lack of clarity as to how decisions made under the 2008 Network Open Season may be impacted by subsequent open seasons. It appears from page 18 of the materials that, if during NEPA or during subsequent open seasons, there are additional requests that can be enabled by new facilities, BPA will re-evaluate whether service can be provided at embedded costs rates, and may return NEPA costs to the funding customer. Given the long time-frame that can occur between the time a customer agrees to proceed on an incremental cost basis and the time the project is actually constructed, Powerex believes that it is important that BPA provide more detail regarding what will occur in these circumstances. Among other things, Powerex believes BPA should provide more information regarding:

   - Whether and how BPA will re-evaluate a project to determine whether it can proceed on an embedded rate basis, and the time-frame for doing this;
   - Whether BPA will reimburse the original customer(s) for any study monies they may have submitted;
   - What the process will be if the project still proceeds on an incremental rate basis but there are more subscribers (e.g. how will the rate be re-evaluated and will

those subscribers be obliged to reimburse the original subscriber(s) for any studies monies).

6 Seattle City Light

Summary

Seattle City Light (SCL) submits these comments to BPA Transmission Services (BPA) in response to its proposed 2008 Network Open Season Recommendation (NOS Recommendation). SCL believes that BPA should reevaluate its estimate of the Northern Intertie Reinforcement project to include reliability and congestion benefits that were not quantified in the BPA model results presented in December 2008. In addition to incremental revenue from additional PTP subscriptions, the value of the project should include reliability benefits of $12 to $24 million per year, plus potential reduced congestion costs of a similar magnitude. If these additional benefits are included, the Net Present Value calculation should indicate more favorable consideration under BPA's Commercial Infrastructure Financing Proposal (CIFP).

Background

In a BPA 1991-2000 Transmission System Facilities Ten Year Development plan, a second Echo Lake – Monroe 500 kV circuit was proposed with an estimated cost of $25 million. This project was never built, but the plan notes that the "reinforcement is required to eliminate heavy loading on the underlying 230-kV system during an outage of the existing Monroe-Echo Lake line." During recent years, Northern Intertie nomogram studies have consistently indicated that heavy loading of the underlying 115-kV and 230-kV system will occur during outage of the existing Monroe-Echo Lake line (which is now tapped for load service to SnoKing). Many other outages in the Puget Sound Area now result in heavy pre-contingency loadings of the underlying system with post-contingency impacts that adversely affect load service and transfer limits.

In June 2007, SCL submitted comments to BPA on it proposed policy for financing Commercial Infrastructure. These comments stressed the need to consider reliability-related benefits as well as other quantifiable economic benefits resulting from new infrastructure. BPA adopted its CIFP in late summer 2007 with provisions to include: "(a) the measurable reliability-related benefits from the project to BPA and to the customers, (b) an allowance for the measurable value of expected future uses, and (c) recognition of the value of other relatively certain and quantifiable economic benefits resulting from the new infrastructure." [2] Under the CIFP proposal, BPA initiated its first Network Open Season process for evaluating queued transmission service requests (TSRs). In April 30, 2008, SCL filed comments with FERC supporting BPA's proposed Network Open Season.

On January 15, 2009, BPA posted its 2008 Network Open Season Recommendation for customer comments. In the NOS Recommendation, BPA concluded that the Northern Intertie reinforcement project would be placed in a group of projects that could "move forward at customer expense." Presumably this means that these projects

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[2] Issued August 2007, Proposal for a New Approach for Allocating Transmission Expansion Costs and Financing Commercial Infrastructure.
http://www.transmission.bpa.gov/customer_forums/open_season/docs/CIFP_Policy.pdf.

would be funded at incremental rates if they are to "move forward." The primary reasons for this determination appear to be: the negative Net Present Value of the Northern Intertie Reinforcement; rate impacts; and low confidence in the cost estimate. No recognition of potential reliability-related benefits or other quantifiable economic benefits appears to be considered in the BPA analysis. Without such recognition, the Northern Intertie Reinforcement project exceeded BPA's threshold for consideration under the CIFP criteria for rolled-in, embedded-cost rates.

The next section provides SCL's perspective on the Northern Intertie Reinforcement project and its value to reliability and congestion relief – both economic benefits that are more difficult to estimate than subscription revenues. Nevertheless, these benefits are vital to SCL's interests as an existing transmission customer and a load serving entity dependent on reliable transmission service to the Puget Sound region.

Analysis

A. Reliability

Damage functions can be used to estimate the value of improving the reliability of transmission within a region. For these comments, the damage function represents the probability of losing service to 25 to 50% of the customers in the Seattle-Tacoma-Bellevue Metropolitan Area for 1 day.[3] The daily Gross Domestic Product (GDP) of approximately $673 million is multiplied by a loss load percentage (25% - 50%) and the change in probability (%) resulting from implementation of a transmission reinforcement project. Distinction is made between weekday and weekend GDP values.

Table 1. GDP by Metropolitan Area (millions of current dollars)

Seattle-Tacoma-Bellevue, WA (MSA) [42660]

Line	Industry	2001	2002	2003	2004	2005	2006
[001]	All industry total	155,695	158,031	163,224	171,025	184,419	197,686

SCL is assuming that a major reinforcement to the Northern Intertie could change the probability of losing 25% to 50% of the load from 1 day-in-10 years to 1 day-in-20 years. For this example, the resulting value of that improvement is approximately $12 to $24 million per year.

B. Congestion Relief

Congestion occurs when transmission rights are curtailed to amounts less than the face value of the reservation used for scheduling power deliveries. Sometimes curtailments are implemented by the Transmission Provider setting a scheduling limit that is less than the transmission reservation. In the most severe implementations, a reliability limit is used to adjust a tagged schedule within the hour. The cause of these limits being placed on reserved transmission service is typically the incidence of forced and scheduled outages that result in transmission path capacity reductions. Congestion

[3] It is assumed that an outage lasting any number of hours within a single day will nominally result in a loss of 1-day of productivity.

causes Transmission Customers to change their operating plans and generally incur costs for replacement energy from sources unaffected by the curtailment. In recent years, these incidents have become more frequent, longer in duration and more severe in impact. SCL must develop forward operating plans, including sunk costs for hedging against such curtailments.

For example, on January 23, 2009, BPA issued an Initial Outage Plan for March 2009 that includes an outage that significantly affects transmission in the Puget Sound Area – an outage of the three-terminal Monroe-Echo Lake-SnoKing 500 kV line for a period of 5 days. Given the capacity estimates provided in this outage plan, SCL receipts of energy from resources in Eastern Washington may be reduced by as much as 50%. In order to provide uninterrupted load service, SCL's normal operating plan estimates that it needs to schedule at least 800 MW from these resources, therefore, approximately 400 MW may be at risk during this single outage. The estimated cost to purchase replacement energy during these 5 days is approximately $640,000.[4] Additional outages in late-March and April are estimated to have similar impacts. SCL presumes that other Puget Sound Area utilities will have similar or greater replacement energy cost risks.

A forced outage of the Chief Joseph-Monroe 500 kV line on January 22 – 25, 2009, resulted in sudden changes to established operating plans, including the necessity to hold back capacity offered to BPA for reliability redispatch. The congestion costs for this event have not been estimated, but include uncertain disposition of energy costs associated with curtailed deliveries of BPA Power. A sustained incident of this type would also result in substantial replacement power costs. A second 500-kV transmission circuit connecting Monroe and Echo Lake would have mitigated the curtailment risk associated with this forced outage.

7 Snohomish County PUD

The Transmission Service Requests (TSR) term was limited to a ten year period. BPA's current business practice for TSR limits the term to a ten year period, but provides the NOS with the ability to do long term cluster studies with a focus upon reliability and future load growth, as well as commercial requests. A longer project term might provide for a more favorable benefit analysis.

The contract language included in the Deposit of Escrow accounts needs to be modified to permit Washington PUDs that have issued bonds to be able to participate in these types of Security Deposits. The other two alternatives cause additional costs to a utility that is unable to legally accept the language as it is currently written. Snohomish PUD requests that BPA revisit the language with a creative look.

Snohomish PUD would like to offer the following comments on the recommendation:

BPA should review the Monroe Echo Lake (Northern Intertie) again. The transmission curtailments that were implemented in the Puget Sound Region during the week of January 19th and the probability of further curtailment situations during March 2009 indicates that reliability benefits associated with the project may have been missed

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[4] This estimate is based on 50% pro-rata curtailment of 800 MW in firm schedules and a cost spread of $20 per MWh during HLH only.

during the initial review. The PUD acknowledges that there is a considerable amount of financial risk related to this project's costs. Are there ways to break this project into smaller pieces to give relief to the area in segments?

How will BPA review projects if there are more requests in the 2009 NOS that would build on the initial 2008 NOS requests? Will BPA re-evaluate the outcome of the Echo Lake/Monroe II project and consider the changed economics?

8 Columbia Energy Partners LLC

Columbia Energy Partners LLC (CEP) generally supports the work the Bonneville Power Administration (BPA) undertook in its first 'ground breaking' Network Open (NOS) with the goal of clearing out its transmission service queue. CEP congratulates the both the founders and the implementers of the NOS on the significant success of the program. CEP is happy to see additional transmission infrastructure being built in the region to facilitate interconnection and transmitting new wind project to market, incremental capacity added by virtue of the synergies between projects, etc. With that said, CEP has many observations, reservations and recommendations about how NOS #1 was conducted, the conclusion and transition to NOS #2, how BPA's NOS #2 should be handled and next steps for projects subject to incremental rate treatment.

I think it bears noting that the interconnected western energy markets have exchanged power for many years during summer and winter seasons and that energy projects built in each region (i.e., Northwest, California or Southwest) are built to serve both the regional and super-regional needs. If projects were built and operated in isolation or specific to one region or another many too many inefficiencies would result. A protectionist approach to energy markets is simply not realistic and is not the way the energy markets have worked since inception. With that said, transmission systems must be planned and built on a "one utility" basis to optimize both short and long term needs within and between regions and utility / Balancing Authority / Transmission Provider systems. If we do not become more proactive in planning our transmission systems in a joint and bi-partisan manner inefficiencies will result, reliability will be impaired and energy independence will be stifled.

Conduct of NOS #1

a. Selection of embedded cost projects was based mostly on subjective metrics rather than purely objective metrics not transparent to CEP. The Net Present Value (NPV) cut-off line between embedded and incremental cost determination is arbitrary and subject much too significantly to one customer segment's preferences. Initial indications were that the NPV cut-off would be 4% based on TEPPC recommendation but the level was subsequently pushed down to 2% without any NOS transmission customer involvement to my knowledge. This must be a transparent process.

b. BPA was not transparent, did not fully understand and / or explain the Commercial Infrastructure Financial Policy process, the analysis associated with the rate determination and the underlying metrics associated with overall project cost and associated projects benefits including reliability, future beneficial uses, economic benefits, etc. The point here is that CEP continually sought opportunity to both understand and influence this process but was not provided any detail on BPA's proposed and final thinking in this area which influenced both overall project costs, benefits and NPV treatment.

c. BPA's 'one size fits all' approach is simply unacceptable. On several levels including plan of service determination and financial treatment, BPA was incapable of recognizing the unique attributes of various projects. BPA geared the entire NOS #1 toward how it would select, manage and process embedded cost projects. Those projects subject to incremental rate treatment were given proper "thought treatment" until the end of the process via an incremental rate process. BPA's thinking on incremental rate projects seems headed in the right direction; however, much time has been lost in the process. AT the outset, BPA should have had clear metrics regarding the parameters to be applied to embedded versus incremental rate projects. Early in the process BPA should have made the determination both on a quantitative and qualitative basis what an embedded cost project looked like versus an incremental rate project and allowed an off ramp much earlier in the process for incremental rate projects to begin a process to structure alternative plan(s) of service to better fit the customer's needs whether ultimately treated on an embedded or incremental rate basis.

d. New projects or projects which did not have much history with BPA and the region were at a significant disadvantage and were treated in a discriminatory manner.

Rather than find ways to make projects work that have significant merit and benefits to the BPA grid and customers BPA chose not to explore new projects in more depth to openly discover and understand the merits of such projects and associated benefits.

It was clear BPA saw these projects in a different light.

e. BPA's timeline for NOS #1 was much too lengthy and the required elements can be accomplished in much less than ten (10) months. BPA can cut the time in half at east and it is recommended that BPA conduct NOS #2 in three (3) months.

f. BPA must proactively manage and plan its transmission system process to meet transmission service requests recognizing: (1) Renewable Energy Zone development,

(2) integrating diverse wind resources into the grid, (3) other Transmission Provider's

planning processes to jointly meet complementary transmission service requests

which could be met via integrated planning efforts, (4) utilizing techniques such as

Dynamic Power Flow Versus Wind Speed, etc.

g. The list of embedded cost projects are generally understandable except the I-5 project. The merits of the I-5 project as an embedded cost project are simply unexplainable and unacceptable given that the NPV of ~6% is well above what appears to be the embedded cost level of 2%. The tenor and amount of TSRs for the I-5 project do not justify this as an embedded cost project in addition to the significant NEPA concerns it will raise. The claim that it reduces congestion South of Allston and and Paul-Allston flow gates is not apparent in the public realm. Building facilities to enable non-firm and lower curtailments is a worthy goal but not a standard long term firm planning goal. Finally, the synergies specific to I-5 with WOMR and Little Goose to enable PTSA grants and ATC is a non-transparent process which needs to be supported by power flow studies posted on BPA's website.

Conclusion of NOS #1 and Transition to NOS #2

a. The process for projects subject to incremental rate treatment is an after thought in the NOS #1 process and is not being treated with the same priority as embedded cost projects. As stated above and as a part of NOS #1, BPA did not think ahead and proactively account for how it will process and treat projects subject to incremental rate treatment causing significant commercial delays and risk for such projects. Both during and at the conclusion of NOS #1, BPA's sense of urgency needs to be reconciled with the commercial realities of the market place that developers face.

BPA significantly padded the NOS #1 timeline and did not think through the commercial impacts to projects, especially incremental rate projects, up to and beyond the February 16, 2009 date when it will formally announce and execute agreements for embedded cost projects. Equal consideration and resource dedication to incremental rate projects must be instituted.

b. In order to accommodate Transmission Customer's posting of financial security in NOS #1 to continue into NOS #2, BPA must allow, at the customer's option, for the NOS #1 PTSAs to continue on a "hibernated" basis into NOS #2. On a parallel track, BPA must process TSRs through the OATT process to clear the queue prior to NOS #2 and rationalize, optimize and refine a customer's plan of service as either an incremental or eventually an embedded rate project. It should be BPA's goal to not stall or delay the OATT process.

BPA's NOS #2

a. BPA must allow customers to roll over their security posted in NOS #1 into NOS #2 by virtue of some form of parallel PTSA and OATT queue process.

b. BPA must allow for a more flexible plan of service determination process in NOS #2 than was allowed in NOS #1 such that alternate plans of service may be structured to better reflect the needs of the customer to fit within either an embedded or incremental process at the customer's option. Such flexibility in plan of service planning must also be facilitated in between NOS'es and under the standard OATT process. Clustering whether in a NOS process or a standard OATT process must not be a unilateral action by BPA not noticed to the customer. This must be a joint decision as stated in the OATT.

c. BPA must significantly shorten the NOS #2 timeline in general and especially for projects that carry-over from NOS #1 to NOS #2 with associated plans of service that have been partially or fully scoped.

d. BPA must allow for early rate determinations in the NOS allowing incremental rate projects to proceed on a parallel path to embedded cost projects with the goal of structuring an efficient and mutually acceptable plan of service on a commercially acceptable timeline. This will allow incremental rate projects to begin procuring long lead time equipment and begin construction at the customer's risk.

Next steps in BPA NOS #1 for incremental rate projects must follow the steps below:

a. BPA must make both full and partial offers under the PTSAs in consultation with Transmission Customers while working with the TC to structure an alternate plan of service.

b. Dedicate the necessary BPA resources to projects subject to incremental rate treatment such that these projects proceed in 'lock-step' with embedded cost projects without a resource disadvantage. BPA must allow for customers to supply the necessary resources if BPA faces constraints. BPA must treat incremental rate projects on the same paying field as embedded cost projects.

c. Immediately begin a process to structure alternate plans of service for incremental rate projects on February 17th or sooner.

d. Immediately and upon identification of an acceptable plan of service begin the NEPA and rate making process.

e. Allow for incremental rate projects to expedite certain E&P, LGIA, NEPA, etc. aspects in parallel with the plan of service. Identify those aspects which must wait for the plan of service to be complete.

f. BPA must open its books to how it determined total project cost and allocated underlying system benefits (FBU, reliability, economic benefits, etc) to the customer.

BPA must provide all workpapers, power flows and other analysis associated with the system impact study cluster studies and reports performed in conjunction and underlying the NOS #1 (should also apply to NOS #2, etc.).

g. The rate case / rate setting process for an incremental rate project must be project tailored, efficient and not last longer than 3 months. This must not be a regional and public process rather this is akin to a private line build which could be performed via a privately solicited open season process operated by the project sponsor.

h. BPA must factor into its planning, CIFP and rate treatment process the unique attributes of a project deemed 'subject to incremental rate treatment' such as wind profile diversity (seasonal and diurnal), effect on line rating versus wind speed, geographic diversity, capacity factor, etc. BPA must factor in benefits of geographically constrained renewable projects with beneficial attributes which will meet RPS and regional power needs more efficiently than other projects.