NORTHERN TIER
TRANSMISSION GROUP

Description of Meeting:	**NTTG Stakeholder Meeting**
Meeting Date:	**January 28, 2009**
Meeting Notes Prepared By:	**Lynn Jesus-Olhausen**

Attendee List: Ravi Aggarwal, Brian Altman, Ali Amirali, Kathy Anderson, Jamie Austin, Rich Bayless, Adam Bless, Rebecca Berdahl, Dave Cory, Brian DeKiep, Dan Dettmer, Bjorn Doskeland, Jim Eden, Marshall Empey, Hilary Foote, Darrell Gerrard, Kurt Granat, Rick Haglund, Roger Hamilton, Randy Hardy, Derrick Harris, Sharon Helms, Raj Hundal, Shaun Jensen, Lynn Jesus-Olhausen, Shay LaBray, Marv Landauer, John Leland, Sam Liu, Jeff Miller, Matt Muldoon, Ryan Munson, Jeff Newby, Marci Norby, Carol Opatrny, Linda Pelagi, Jim Portouw, Matt Richard, Nate Sandvig, Aleka Scott, Kip Sikes, Berhanu Tesema, Jim Tucker, Steven Wallace, Kris Van Victor, Pat Weeres, Lou Ann Westerfield, Cameron Yourkowski, Joni Zenger, Darrel Zlomke

1. **Overview:** The NTTG Standard of Conduct and Antitrust policies were reviewed. Phone participants were directed to the NTTG website for meeting materials.

   Meeting Purpose: This will be a joint committee meeting with updates and presentations from the Northern Tier Planning, Cost Allocation and Transmission Use Committees.

2. **Agenda:**
   - Planning Committee Update
   - Economic Study Request Informational Session
   - Transmission Use Committee Update
   - Cost Allocation Committee Update

3. **Summary of Questions & Answers:**

   Planning Committee Update

   Q. What are stakeholders interested in seeing studied in the draft plan?

   A. Maybe this is something that can be can be done down the road when you are talking about third quarter coordination with Columbia Grid, but I think there would be some value in looking at the different stresses between the two regions, particularly between Idaho, Montana and the Northwest. You could look at cases that would look at maximum stress with production and see if any issues would pop up from that.

   A. So it would really be looking at path 8 coming across Montana to the Northwest, as well as the Idaho/Northwest cut plane, to see how we could load those up, whether they load up simultaneously or not, depending upon whether resources out of Montana are being dispatched relative to resources may be coming from Wyoming. So that sounds like a good scenario to consider – to ramp up resources in the East and export them into the Northwest.

   Q. Is there a preferred way to sink that into the Northwest, versus just backing off Mid-C or something like that? Is there a way we want to coordinate that?

   A. In the Northwest, winter is probably the more critical season. Maybe we could use a summer case and then we could view what might happen. But what we've been doing in a lot of cases where we are looking at stressing the Northwest system, is we take down the gas resources over on the West side of the system (in the Portland/Seattle area primarily), so I think that would be a good start given that the gas resources will probably be the swing resources for generation integration.

Q. So you're planning on integrating all the ColumbiaGrid, including Bonneville stuff, is that true?

A. The interchange that we're talking about here is in loading up the paths as far as import and export between regions.

Q. Bonneville has a lot of transmission, how is that going to get integrated?

A. I think at this point, from a Northern Tier standpoint, in what we do with our transmission plan and see how we get it there in the base case that we have, it may not have all of the included Bonneville transmission. We are not going to do an exhaustive study of what breaks in the ColumbiaGrid footprint, but coordinate with them so that they can help assess that too.

A. [ColumbiaGrid] I think we can start out with your [NTTG's] cases and see where the limitations are. Your cases have the Southern Crossing project in it, which is a good project, but it is probably likely to come after the Bonneville improvements, just because Bonneville is further along in the process – speaking particularly in the bussing area of the reinforcement project. So we could look at your projects, your cases, initially and see where the limitations are and then add, if necessary, to west of McNary for reinforcement.

Q. You mentioned something about – that this study work is about addressing WECC's phase 0 kind of a process. A lot of these projects are already entering into the WECC rating phase 2 process. What is the added value of going to a phase 0 process when the projects are already working through a TCWG forum in the phase 2 process?

A. I am using the phase 0 as an analogy in talking about the WECC TEPPC process as well as coordinating with PCC -- as what really is phase 0 planning? And phase 0 as defined by WECC was in existence prior to the development of the sub-regional planning group process. So in a sense, a lot of these projects that have already entered into the WECC rating process, being in phase 1 or about to enter or mid-phase 2, are ahead of the regional planning cycle. And so a lot of this is a little bit of catch up, if you will, from a planning process, but we also don't want to go back and reinvent the wheel. So what we are really doing here in the sub-regional planning process is, for ColumbiaGrid, Bonneville, as well as Northern Tier, is starting from the base plans that are already out there and examining with the full intent of what phase 0 was intended for is: are there opportunities combine projects, or are there any redundant projects, or are there some unfulfilled needs that exist out there that these projects don't address. And that's what we are really trying to uncover through this process now. It's not support of individual projects, but analysis more of a sub-regional plan and how projects work together.

Q. Where is the cost allocation? Is that on the other side of the coordination?

A. The cost allocation process in the Northern Tier Transmission Group occurs in Q3 of this year. So it's as we release the draft plan. So the projects are identified. Every one of the project sponsors submits that information on the individual transmission projects to the Cost Allocation Committee for them to review.

A. I don't think there is any coordination of cost allocation. NTTG has its own process for within its own footprint, and ColumbiaGrid has its own process. So as far as coordination, if there were some sort of agreement struck among parties where you have power crossing, or you have projects crossing from one footprint to the other, that could be arranged by private agreement. I don't think the Cost Allocation Committee would try to impose, or superimpose, its will on that situation.

A. If a project sponsor has a project that emanates in one footprint and terminates in another sub-regional planning footprint, as a Northern Tier project sponsor, they would submit that back to the Northern Tier Cost Allocation Committee for review, under the Northern Tier process. And understanding that the Northern Tier Cost Allocation process is not a rate-making process by any means, but it is designed to provide both the state regulators as well as the transmission providers input, feedback and understanding as to what the purpose, as well as the actual benefit, of the proposed projects are.

Q. You discussed, as part of a slide, that there had been the local studies looking at the interconnections – looking at resources as part of this biennial plan. Was the Populus Terminal upgrade included in that? And I don't know where to go to look for those local studies, are they listed as part of the NTTG project or a PacifiCorp project?

A. As far as local area studies, specifically to projects that are in the WECC phase rating process, those study reports are out on the WECC website in keeping with the PCC process.

PacifiCorp, as well as Idaho Power and other transmission providers, as part of the Attachment K process have been conducting in parallel with the Northern Tier process their local transmission planning exercises. They are on the transmission provider's OASIS site also.

A. For Idaho Power and the other transmission providers, if you have specific questions about where to get some of those reports go ahead and contact us directly and we can provide that.

Q. For the ATC charts, I don't see a path that utilizes the Populus Terminal. Is there going to be changes to the ATC descriptions that PAC is going to use for ATC use?

A. If you are referring to the ATC Summary Compilation data, which goes out to Summer of '09, as of yet we don't have that updated.

Q. At what point does the information on the integrated resource plans, as well as the information from your local process, roll up into the direct planning and plan that we see here? Or does it?

A. I think what you asked is how does the IRP in effect roll up into the Northern Tier process. What Idaho Power had started - our integrated resource plan is on cycle for submission in June of 2009 which is kind of coincident with the release of the Northern Tier, as well as Idaho Power's, final draft transmission plan. So the timing of these things have been synchronized as such that the transmission plan coming through Idaho Power's local transmission planning process should end up being the transmission plan that matches the selected or preferred portfolio in the integrated resource plan. So we are working with the people at Idaho Power on the IRP process to coordinate the portfolios back and forth and examine the required transmission for the resource portfolios being selected.

A. For PacifiCorp, if there is to be any economic study analysis in 2009, we will be reflecting our preferred portfolio currently under construction so that we have the latest data from IRP.

Q. Are we to contact you folks to make sure that what we are running right now is going to be consistent with the results that you have?

A. What I would point out is, coordination with your transmission provider and their local planning process fits best with the IRP analysis. If there is modeling information that is required for that type of analysis for your individual company studies for integrated resource planning, I would suggest checking back with your transmission provider for access to that.

Q. Will the project cost information be available?

A. The only cost information that we have, if it's not already deemed public, is back in the cost allocation process. What I would recommend is to go ahead and contact us directly and if that information is not public, or if it's sensitive, I am sure that through a non-disclosure agreement the information could be provided or if there is other public information available it could be provided.

Q. I am wondering what the nexus is between the NTTG biennial process and the TEPPC scenarios that are being run? Is that a completely parallel path or are you going to be considering in the NTTG process some of the scenarios and sensitivities being run in the TEPPC process?

A. What you are speaking to gets to the heart of the categorization of what the studies or scenarios are. For Northern Tier and most of the sub-regional planning groups we have three levels of planning – local, regional and sub-regional. What you are describing is more of a regional case. For example, if Idaho Power is the transmission provider and if we're looking at a POR-POD combination entirely within Idaho Power's transmission service, that would be considered a local study or a local scenario. If it goes from NorthWestern Energy's system in Montana into Idaho, it would be crossing footprints between two transmission providers, but it's entirely within the Northern Tier footprint, [so] that would be a sub-regional analysis. If it starts within the Northern Tier footprint, but goes into ColumbiaGrid's footprint, or Arizona's or California's, that's really a regional or WECC TEPPC level type of analysis. And that is why we want to have that discussion today. If there are resources looking at exporting to other areas that cross those boundaries, let's all get together on the same page so we can get with the WECC.

Q. TEPPC is more of an economic/production cost type of study. I am assuming that what you are doing here is more of a reliability/physical needs type of study. So there is a difference here. The study you are doing here is more about how does the transmission system perform with all the resource and load portfolio that you have put in and how is it involved in the NERC and WECC sub-regional reliability criteria? Is that correct?

A. The studies that we've got going on right now are the capacity planning studies. They are power flow studies, not production cost simulation studies. Going back to the Q1 data submittal that occurred in 2008, that was when people had the opportunity to modify the Northern Tier study plan to put in those specific study requests. So, to the extent that we have those, we are considering them in the study plan. Given the latitude that we have, we are wanting to accommodate as much interest as we can through the work we are doing in the next three months.

To the coordination issue, in WECC, base cases for power flows are developed under PCC and TEPPC. Sub-regional planning groups report up to boards on economic studies. But sub-regional groups also worry about capacity. So there is an activity going at TEPPC, PCC and WECC to try to get those two better matched so that the area of coordination process lines up better with what the sub-regional groups are trying to see in the base cases. Right now we have to sort of manually put our own stuff in there, but we are hoping to get that fixed.

Q. To the extent that we can balance loads and resources by ramping up and taking generation down some place then that would give us a stress factor on the system. In some of these areas there is enough resource potential to more than serve the existing footprint load for the conditions we are looking at. So at what point do we say we've brought the resource up enough, recognizing that not all of the proposed projects necessarily will go commercial? Is there some rule of thumb that the stakeholders and we can agree on? Or just take it up until the existing transmission line is full? Then say that it looks like we can accommodate this many thousands of megawatts of resources in this area without changing the transmission plan. What answer are we looking for?

A. The Path C upgrade – in regard to the ATC chart for the paths that PacifiCorp describes as ATC paths – it seems more can be done there. So we can see what the impacts are to resources on the eastside and get a better idea or feel for the ATC implications.

The network allocation for Path C is also published on the web, so you can look at that to see what's been allocated for network service and what's available.

Q. What is your left-over inventory that is available for the market?

A. That analysis will happen later this year when we look at the whole system, not just in isolation.

Q. Do the current ATC descriptions include Populus Terminal ATC accounting?

A. Since the project is not in service yet, I don't think the existing ATC includes the upgrade. The projects are being designed towards a TTC or incremental capacity increase above the existing system capabilities. What's missing then from a use committee standpoint is: what are the likely committed uses that would show up and use that project? Part of that information flows back into the submittal to the Cost Allocation committee of who are the users and benefactors of the proposed projects? The projects have a targeted TTC for the project, whether realized in the planning process or not. So through the planning process, increment the resources enough – plan to reach that flow level – and see what happens. And then the outcome of that would be to ensure the remaining resource proposed or potential resources would fit. We are not making choices about winners or losers, but saying at 10,000 megawatts of potential resources in this area another 2,000 would fit on the line so there would be potentially 8,000 stranded. That is the type of information we'd be looking for.

Q. When does ATC get adjusted with these projects?

A. It's not about existing transmission commitments, it's about when do you apply that planned TTC to the calculation of ATC.

Q. How was the ATC associated with these proposed projects incorporated in the planning process?

A. As these projects move into the rating process, if we weren't already far along in the rating process on a number of these projects in the traditional planning process, we would be looking at coming back to the expected committed uses, and then identifying resources to serve the load centers and saying "How much transmission do we need?" And then we would be sizing transmission for those expected uses. Where these projects are at this point and overt studies have been done for the IRP processes to say how much capacity do we need through this cut plane, and that's what these projects have been targeted for to the extent there is excess ATC because transmission is so lumpy and incremental and you can't size it down to the megawatt, then what happens is the projects move forward, they are large enough to fulfill the needs, the excess capacity coming through the project may be committed or subscribed as load growth over time and what is reserved for network uses. That information goes forward in public release for that capacity, whether it's on an interim basis or it's full firm ATC that is available.

Economic Study Request & TEPPC Report Presentation

Q. What about Bonneville? What categorization would it be for anything that comes in or goes out from Bonneville's system?

A. Anything going in or out from Bonneville and crossing Northern Tier's footprint would be a regional request.

Q. Is there somebody working constantly with DOE on their study or is it just going to be once they have come to some point then they will go to TEPPC?

A. There are people working full time with them on the study. They have come and talked to TEPPC and WECC. There's no direct linkage. They want to see what the western transmission plan is. It used to be that WECC put out an annual plan which was an aggregation of everybody's plan, but they haven't [put] one out in the last several years. The Portal should have information available.

Q. Back to the planning roadmap, where you are trying to coordinate with TEPPC to see if TEPPC can actually come up with a coordinated base case, do you have a timeline for that?

A. There was a timeline for that. There were supposed to be some drafts back by the end of the year, but then the seminar came along and it sort of booted priorities so we haven't heard of a revision of that. But that will be discussed at the next coordination call.

Q. So the plan still is to get something in place so it can be utilized in the next cycle?

A. Yes.

Q. What types of study requests would be of interest to the stakeholders here to make of TEPPC? What would be meaningful results for us to examine?

Do we want to submit more than just region simply because when TEPPC starts looking at requests and clustering there might be opportunities to also consider sub-regional items where it might be meaningful if you cluster?

A. What types if analysis would be meaningful to the regional is a better way to say it. Whether it exists primarily within the Northern Tier footprint or expands beyond.

A. Just some ideas: With the vast potential for renewable resources in the NTTG footprint, something of that nature would be appropriate. Obviously, it could be coming out of Montana to the Northwest or Montana to someplace like Phoenix or California, but coming out of the NTTG footprint. Those are broader studies that that might provide opportunity.

Q. How much of those renewable-type studies are being covered by the Western REZ, or the Renewable Energy Zones, or in the Northwest altogether?

A. Requesting something that someone else is requesting is OK. It helps add priority to it for TEPPC. But also, if something has recently been studied in the current study program, then we need to ask where it can be studied again.

A. The WREZ studies are not the same. They're more for capital costs for alternatives and options and they are very high level. They are not the same economic studies that TEPPC would be doing.

Q. So, specifically what we've heard, is that there are some resource rich areas in Montana to Wyoming. What about [the] Eastern Oregon area as far as renewable? Is that something that we package together?

A. I would advocate for the addition of the Eastern Oregon resource area. We've [Horizon Wind] provided Northern Tier with the comprehensive look at what our plans are. And in addition to the Wyoming and Montana portfolios, the Eastern Oregon portfolio is a unique and valuable resource area.

A. The resources that we are talking about do have different profiles and I am not sure how you want to look at considering the diversity benefits of these areas in the study process, but, for example, looking at the Eastern Oregon area, which is a heavy winter resource rich area, it might have a lot of diversity benefit for bringing resource to the Columbia area.

Q. Is there some target level of export of resources to be considered – like how much resource do we put in play? Back into the TEPPC model, do they have the appropriate level of potential development within the regions or are they doing it more from an L&R balance perspective? If we have 40,000 megawatts of wind potential in Wyoming, is all of that available in the TEPPC model?

A. Not thus far. Not in the PC1 and PC4 [cases]. PC1 just has the existing RPS, which is on average about 8%. The PC4 series has 15%. So if you want to look at bookends that is something they have not looked at.

Q. I understand that [the] ProMod model groups control areas/balance areas five at a time. Rather than selecting an individual one and promote a wind perspective, it might be interesting to expand that to ten to capture the diversity that was referred to earlier. Is there some flexibility in the modeling approach in terms of encompassing more balancing authorities?

A. You can set up various areas, but to actually have it work like a control system you would actually need to have hourly interchange. I think the capability might be there, but the data is not there yet.

A. It depends on the program. In GridView you can model as many control areas as you want with different reserve profiles, etc.

Q. How would we formulate a storage request?

A. It may be back to the turn-around efficiency of the storage technology, comparing that to an LMP that would trigger dispatch of storage in an area, that any LMP in the entire western interconnect that exceeds this price margin would justify storage at that location, so in effect you would increase the price gap to the economic dispatch.

Transmission Use Committee Presentation

Q. On the [Northwest to IPCO] graph on the green line those are TTC adjustments for CBM, is that correct?

A. It is for both CBM and TRM. We keep both on this graph.

Q. And do you sell that non-firm?

A. Yes. It is non-firm. And Attachment C in our tariff has the calculation for that.

Q. The TTC minus TRM – is that minus NT or just TRM that you've set aside for NT? Does it mean you are subtracting NT?

A. Not all network use gets scheduled. So you won't necessarily see your network in schedules on an internal path. Below that pink line is the point to point reservations that we have across this path. Those are the only scheduled part.

Q. So everything between the green line and the pink line is your network use?

A. Right it represents network and third party reservations.

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