INDUSTRIAL
CUSTOMERS OF
NORTHWEST
UTILITIES

MICHAEL B. EARLY
EXECUTIVE DIRECTOR

September 9, 2005

Stephen J. Wright
Administrator and Chief
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Attn: Communications – DM-7
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Submitted to: www.bpa.gov/comment

RE: Open Comment Period – Grid West Decision Point 2

Dear Steve:

Enclosed are the comments of Industrial Customers of Northwest Utilities ("ICNU") in response to your letter of August 4, 2005. As I understand your position, BPA's decision will be either to approve Decision Point 2 and go forward with development of Grid West or to oppose Decision Point 2 and go forward with development of the Transmission Improvements Group proposal. ICNU does not believe that either proposal is sufficiently complete at this time for such an either/or decision. However, if BPA intends to make this either/or choice at the September 29, 2005 Grid West meeting, which in our view would preclude a useful discussions of convergence of these two models, then ICNU's recommendation, for the reasons stated in our comments, is that BPA not approve Decision Point 2 but instead continue development of TIG.

Sincerely,

Michael B. Early

Enclosure

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ICNU Comments on BPA Grid West / TIG Paper
September 9, 2005

With its August 4, 2005, letter, the Bonneville Power Administration ("BPA") seeks comments on BPA's future stance toward Grid West and the Transmission Improvements Group ("TIG"). The letter incorporates 14 questions regarding transmission alternatives.

The BPA letter has been prompted by BPA's need to prepare for Decision Point 2, a September 29 deadline that Grid West has set as the date to decide on an expansion in the level of activity of Grid West—an expansion that includes the selection and seating of a Developmental Board of Trustees and a substantial budget increase.

Recommendation

The Bonneville Power Administration has requested comments regarding three potential paths forward on regional transmission:

1. Go forward with Decision Point No. 2 on Grid West, *i.e.* increase funding, seat a Development Board, hire key staff, negotiate Transmission Agreements with utilities and prepare a transmission tariff for filing at the Federal Energy Regulatory Commission;

2. Go forward with further development of the Transmission Improvements Group proposal; or

3. Continue separate transmission operations.

BPA believes that continuing separate operations (option 3) is unrealistic because current and approaching regional transmission problems require a significant change in the stand-alone approach to transmission. ". . . now is the time to apply the 'one utility' vision to transmission." BPA's August 4, 2005 letter at 2.

BPA also believes that "further delay in picking a path (between options 1 and 2) is not the preferred outcome;" *i.e.,* BPA would prefer to develop further either Grid West or TIG, but not both. Id at 4.

While further development of both Grid West (short of seating the Developmental Board) and TIG would be helpful in making a better choice, ICNU's recommendation is based on the constraints of BPA's August 4, 2005, letter.

Neither the Grid West nor TIG proposals as they stand today is sufficiently complete to merit full endorsement at this time. The principal concerns with Grid West are:

- Grid West creates a new FERC-jurisdictional non-profit entity to offer all new service over the regional transmission grid.
- Grid West has an independent board who is accountable to FERC and to a membership that will likely split on all major issues (*e.g.* loads pay nearly all costs, generators do not).
- The short-term risks and benefits of Grid West are not well established; *e.g.,* there is double counting of benefits, serious problems in the modeling of redispatch benefits, a minimization of cost-side risks, and little testing of potential unintended consequences.
- The long-term risks of Grid West are barely addressed, *e.g.,* potential cost-shifts after the Company rate period expires—shifts that caused IndeGO to fail—have not been resolved; unrealistic practicality of BPA later withdrawing from Grid West should BPA's customers be harmed, function creep, etc.

While additional development could clarify some of these concerns, others (a new FERC jurisdictional entity) are fundamental to the proposal and still others (long-term cost-shifts) remain unresolved after 10 years of discussions.

The principal concern with TIG is that the proposal is not fully developed. However, TIG does establish at least one bright-line difference from Grid West: TIG does <u>not</u> propose a new FERC-jurisdictional entity.

ICNU notes that neither proposal offers transmission access to retail customers beyond that access which is already available under current separate transmission operations.

ICNU notes, however, that BPA's question 13 suggests that "convergence" of Grid West and TIG may be the only answer that produces broad regional support. Any convergence discussion must recognize that certain elements of the Grid West proposal are inherently inconsistent with the TIG proposal: a new FERC jurisdictional entity and its associated governance structure. Any convergence discussion must begin with a decision of whether additional Grid West-like functions can be grafted onto the fundamental TIG model (*i.e.,* no new FERC jurisdictional entity) or the converse. ICNU believes such discussions could be useful, but this would require a delay in the Grid West process (*i.e.*, a no vote on Decision Point 2 on September 29th) and a commitment to begin convergence discussions with the TIG model as the starting point.

On balance, because ICNU is asked to decide today, ICNU recommends that BPA not approve Decision Point 2 for Grid West development, but instead continue development of TIG.

The risks of Grid West are too high to justify an exclusive commitment at this time to this path. FERC is no longer forcing RTO formation, and the FERC declaratory order on jurisdiction is not comforting. On the other hand, TIG is similar to successful regional power arrangements (*e.g.,* coordination agreement) and has the advantage of being incremental: (1) TIG could evolve into a Grid West-type model if regional parties agree to a new FERC-jurisdictional entity; and (2) the one-utility concept can be applied by TIG, as appropriate, function by function.

Discussion

The following provides elaborates on many of the considerations that underlies our recommendation above.

Both TIG and Grid West Overestimate the Effectiveness and, Therefore, Benefits of "One Utility" Planning

Both Grid West and TIG have placed a high emphasis on a regional transmission plan, and BPA's first item in its list of potential solutions is an "[e]ffective"one-utility planning with adequate backstop for reliability purposes. This goal has been echoed by regulators and state officials throughout the region. Supporters of DSM and generation alternatives have cited the intention to include alternatives to "wires" as a major advantage.

ICNU believes it is unlikely that an effective one-utility plan with an adequate backstop will provide the benefits promised 1) because of the nature of the power and transmission institutional structure that is developing the plan and 2) because of the difficulties of allocating costs and responsibilities of a plan's directives.

Despite Good Intentions to Include Generation and Demand-Side Alternatives in a Regional Transmission Plan, the Reality is that the Plan Is Likely to be Transmission-Centric.

There are two chief problems with developing the transmission plan envisioned in the Grid West and TIG documents. They relate to 1) the lead times for developing transmission, generation and DSM, respectively, and 2) the nature of the entity that builds the facilities.

Regarding lead times, it is generally agreed that the construction of transmission upgrades, particularly large upgrades, especially on new corridors, takes years to complete—perhaps as long as a decade. It is well known that a gas-fired generating station generally can be planned and constructed within two years, and a DSM program probably can be installed in less than a year.

The longer lead time for transmission projects requires approval decisions to be made long before they would have to be made for generation or DSM alternatives/substitutes. For example, a decision for a transmission line for service in 2015 might have to be made as early as 2006, where the decision on a generation station could wait until 2013, and a decision on DSM could wait, say, until 2014. There is a further consideration: If load patterns or growth change, the generation or DSM alternatives might never be needed at all; as a consequence the alternatives have a flexibility advantage over a transmission alternative.

The reality of transmission planning is that a decision on a transmission line needs to be made, in the example, in 2006; so, in 2006 the planners must assess the likelihood of the generation and DSM projects being completed in time to address the perceived need.[1]

The decision is further complicated by 1) the fact that generation alternatives are provided by a non-transmission entity, whether voluntarily developed market resources or independent decisions by load-serving entities (for both of these, Grid West does not plan directly), and 2) a commitment for generation or DSM <u>at the time of a transmission decision</u>, in 2006 in the example, probably makes no sense. Alternatively, the transmission plan could call for Grid West (or TIG) to provide "reservation" or stand-by payments to potential generators or DSM providers (for seven years in the example), but there are serious questions about whether it can or should do so.

In a vertically integrated utility world, this timing issue is not a problem, because the same entity is responsible for all three alternatives. Similarly, in a free-market world, price signals would bring about the construction of generation or the development of DSM alternatives as a market response if there was no prior decision to build transmission. <u>Furthermore, a transmission-construction decision will seriously reduce the incentives for generation or DSM alternatives, whether that construction decision is forced by Grid West or made by market participants.</u>

1 Some have noted that the commitment to transmission does not mean a commitment for the entire project at the outset, but only for preliminary studies and land acquisition. While there is merit in this observation, these preliminary transmission-project costs become "sunk" at the time of the next plan, and the relevant test becomes the <u>cost to complete</u> a transmission alternative versus the cost of generation or DSM. As a result, the remaining transmission alternative becomes less and less costly relative to generation and DSM alternatives. For, example, if transmission and generation alternatives had equal expected costs in the first plan, at the time of the second plan (without major cost changes for either) the transmission alternative would show an advantage due to the costs that had been incurred and sunk between the two plans.

As a consequence, the transmission decision will necessarily be suboptimal if generation or DSM were in the optimal plan.

It is ICNU's conclusion that it is highly unlikely that an "effective" transmission/ generation/DSM plan can be constructed given the timeline and the nature of potential alternative providers. Placing much stock in the large benefits of a regional transmission plan seriously overstates the possible outcomes. Because of the problems any transmission plan is likely to be a suboptimal transmission-only outlook on the region.

The Words, "Backstop Authority to Allocate Responsibility and Costs of Reliability Transmission Projects," Are Likely to Be Easier Put on Paper Than to Implement.

It is highly unlikely that Grid West can allocate responsibilities to build transmission alternatives to generation projects or to providers of DSM, because Grid West has no authority over those entities. A plan that includes generation or DSM measures is therefore not enforceable by Grid West. Allocation attempts will be limited to assignments to transmission owners (which, if the preceding observations are correct about transmission-centric plans, may be the only components of the plan in any case). The problem for Grid West comes when an allocation is to an intended recipient that contends that it will install generation or DSM, if needed. Is such an entity allowed to challenge the allocation on the grounds that it has a better market-driven substitute? If the plan allows for generation or DSM alternatives, it may be difficult for Grid West to contend that a reluctant transmission owner's alternative is infeasible.

The upshot of the discussion in this and the previous sections, ICNU believes, is that Grid West (or TIG) will create a transmission-centric plan for the region, try to enforce an allocation of transmission responsibility on those who may have a better alternative and be rebuffed by some. That is, the allocation assignment will almost certainly be contentious to some "beneficiaries," resulting in challenges and potentially litigation and potential cost-shifts towards end users.

The Inability to Allocate of Costs and Responsibilities to Beneficiaries Who Are Not Obligated to Pay Will Simply Increase 'Uplift' Costs and Stimulate 'Free Riders'

There is a further serious problem of allocation. While the intended consequence of an "effective" transmission plan and resulting allocation backstop is to force transmission upgrades, an unintended consequence is to create a serious "free rider" problem. Transmission owners who do not join Grid West do not face an allocation, but they will benefit from those who are forced to pay.

The argument is made that the situation exists today. However, today, although the incentive is to hold out support for a transmission project to extract as much benefit as possible, there is the prospect that such a project will not be built, or that when the holdout utility wants to sponsor transmission for itself in the future and requires others to help, it will receive no help. Today, as a consequence, there is an implicit quid pro quo to supporting transmission projects. Under an allocation process, there is no need for such a quid pro quo and "free rider" holdouts will be encouraged.

BPA and Other Hydro Utilities Must Have the Authority to Establish the Opportunity Costs of Their Hydro Power When Offered into Imbalance and Reserve Markets in the Consolidated Control Area

The intended consequence of the CCA reserves and imbalance markets is that entities would bid in their resources at cost or at what they think would be the market-clearing price.

With a hydro utility, the intended consequences are more difficult to accomplish. A hydro utility with storage will bid its resources in at what it considers to be its opportunity cost. That opportunity cost is the utility's best judgment of the value of hydro power stored in the reservoirs—whether for the next day, next week or next month. The level of the opportunity cost is clearly a judgment, based on expectations of precipitation, temperature, fish restrictions, other market opportunities, including the effect of the quantity sold on the price, and reservoir levels, among other factors. For BPA, of course, the judgments involve complex, interacting hydro systems and non-power constraints. Plus, because of its size, the quantities offered, in some markets, may have a large impact on price. Another serious aspect to consider is that, in BPA's case, BPA is a dominant market player on both the buyer and seller side at some constraints.

The intention of Grid West is that BPA will act in a responsible manner, and its offers will help set the imbalance or reserve-market price. However, when the BPA's determination is questioned, what happens? Does the market monitor determine what the "true" offer should have been? Does an arbiter do so? Does FERC set the "true" offer? Is BPA's offer considered the last and final word, or can the agency be second guessed by another entity? If FERC or the market monitor can establish the "true" offer of BPA, then BPA's rate payers are at serious risk of revenue shortfalls.

Some may say the situation under Grid West is no different from today's. However, there is no one arguing that these markets will be benefits of the CCA in the status quo, and, under the status quo the cost of Grid West (or TIG) and the risk of permanent FERC regulation over BPA's power sales offers are avoided. There is an assumption in the Grid West proposal that these imbalance and ancillary services markets will provide large benefits, but that assumption relies on the notion that BPA's pricing will be uncontested and unregulated.

<u>In the Alternative, Setting a Tariff Rate for BPA Sales Into Consolidated Control Area Markets Risks Significant Cost Shifts for BPA Customers</u>

If Grid West's or FERC's answer to the BPA dominance and hydro problems is to set require tariff rates for BPA's sales into the CCA reserve or imbalance markets, then much of the benefit of those markets as price-signal setting entities may not emerge.

For BPA power customers, these risks are not trivial. Currently, BPA depends on secondary sales revenues of nearly $500 million, which are then credited to rates. A serious erosion of those secondary sales revenues would have substantial power-rate impacts on BPA customers. Grid West has not evaluated the power-rate impacts of any of its actions.

In BPA's Summary to the Oregon PUC the Agency Implies Incorrectly That a Reliability Authority Can Only Be Achieved Through TIG or Grid West

It is clear from the Energy Policy Act of 2005 that a reliability authority is mandated irrespective of the formation of Grid West or TIG. This act changes the nature of the benefits and costs to be counted for either Grid West or TIG. The benefits will come irrespective of who ultimately becomes the reliability authority, and these benefits will roughly be the same for all alternatives. The differences will lie on the cost side—in how well one alternative can provide the benefits versus another alternative.

The Energy Policy Act of 2005 makes the reliability authority mandatory. As a consequence neither the costs nor the benefits of that authority from the Grid West and TIG calculations—only the cost savings versus the alternatives should be considered.

In Grid West, There is an Immediate Cost-Shift Impact when the Value of Real-Power Losses Must Be "Uplifted" to Existing Customers. These Losses Arise Upon the Offer of Transmission Rights Into the Reconfiguration Service Market. This Large Open Issue Must Be Resolved Prior to Approval of Decision Point 2 As Currently Conceived.

The intended consequence of the structure of Grid West with regard to existing transmission contracts is that existing users will continue to pay the Company rate/rates of their current contracts during the Company rate period. These existing contracts contain provisions for real power losses charged by the transmitting owner. According to Grid West documents, maintaining their existing rights is sufficient incentive for current contract holders to stay with their existing contracts. The number and impact of contracts that expire is insignificant and adds a small amount to the "lost revenues" that are anticipated from short-term sales.

There is a substantial risk, as yet unquantified, that the proposed structure will have unintended consequences that either 1) cause substantially more cost shifts than anticipated, or 2) make the Reconfiguration Service (RCS) much less beneficial than anticipated.

The risk arises if current transmission customers are able to offer injection/withdrawal pairs into the RCS market and avoid the loss provisions incorporated into their contracts. If these are the conditions, transmission users would take advantage of the RCS when it is profitable for them to do so by selling rights into the market and buying them back—directly or through an intermediary. Using this tactic during periods of acceptably small or no congestion would allow them to retain the most valuable rights during congested times while avoiding loss provisions when ample transmission exists. This is not a trivial problem. Saving 1% losses in a $50 market would result in a larger benefit than the anticipated grid management charge for Grid West.

Requiring existing contract holders to continue to pay Company losses as a condition of offering injection/withdrawal rights into the RCS could severely limit the usefulness of the RCS—leaving it largely, ICNU expects, to sales of rights of last-minute flexibility.

This potential unintended consequence of the Grid West structure has been mentioned, recorded by Grid West but deferred to later study. ICNU believes that the relationship between existing contracts and RCS offers must be resolved before the large additional expenditure proposed at Decision Point 2. This is not an issue requiring independent governance to resolve.

If the Standard for Grid West or TIG Expansion Is "Good Enough," the Risk of Cost Overruns and Scope Creep Becomes a Serious Risk

The RRG has established that "good enough" is the standard for the examination of costs and benefits of Grid West despite significant drawbacks to the PacifiCorp analysis. Indeed, BPA has recognized many of the drawbacks and removed (or moved to unquantifiable) many elements of the PacifiCorp analysis from its calculation of net benefits.

What concerns ICNU is that the estimate of benefits provided by PacifiCorp was accepted unquestioningly by the RRG.

Applied more broadly, if the Good Enough Standard, wherein a rushed-out, PowerPoint presentation devoid of full peer review is sufficient in part for the determination that the region should spend $20 million, is the region's protection against Grid West spending, then ICNU customers have serious concerns of expanding the level of effort of Grid West.

If an RCS is designed that overlooks potential gaming of losses under the Good Enough Standard, then ICNU members are further discomfited.

The Company Rate Period Is a Short Time for Customers of Those Utilities That Have Traditionally Received Substantial Revenues from Customers Wheeling Across Their Systems—in particular, BPA and Idaho Power.

Eight years out is the end of the Company Rate period. Under the Company Rate, ICNU enjoys the benefit of transmission payments by others for whom the size of BPA's (and Idaho Power's) transmission systems was intended. Approximately 40 percent of the cost of BPA's transmission system (and Idaho Power's) is not paid by loads within the BPA service area. It is paid by wheeling transmission users who wheel through and out of the BPA system. The prospect of a 66% rate increase even eight years out concerns us. ICNU suspects that there will be intense regional fighting over the future of the Company Rate that may result in significant cost increases for BPA and Idaho Power Customers. This is not an issue with TIG because it is not moving to a regional transmission rate.

Having Loads Responsible for All Costs Will Distort Incentives for Those Who Are Exempt from Paying for the Grid West Services

The basic design of Grid West is that loads ultimately would pay all costs except congestion costs. The reason apparently is that <u>any</u> costs charged to generation, whether fixed annually or variable per MWh scheduled, affects economic dispatch and therefore efficiency. Another reason cited is that because loads ultimately pay the costs of generation, it doesn't matter that loads are charged.

It is true from an economic theory point of view, all else equal, that including fixed costs in variable-cost effects does affect economic dispatch. All else is not equal, however. There are other costs than tariff rates or the costs of facilities needed to carry generation. For example, there are system reliability effects from loads and resources transactions that rely on longer distance transmission. To the extent that loads in one area rely on transmission of resources that are hundreds or thousands of miles away, transmission problems can cause serious outages. The recent rolling outages in Southern California as a consequence of problems on the SW-NW Intertie is just such an example.

All else is not equal also, because, at the margin, incremental facilities and services are avoidable whether "caused" by load or generation. Because of the joint nature of reliability and market-opening transmission facilities, reliability investments benefit both loads and generation, but loads pay—a distortion of economic efficiency. The problem comes when those who are not required to pay the full cost demand incremental transmission services for which they see only part of the cost.

For example, suppose a reliability investment west of the Cascades improves throughput East of the Cascades for sellers of power down the intertie into California—a not unlikely scenario. Power sellers have the incentive to support increased reliability on the west side of the Cascades, because it is to their benefit, and because they face no costs: The cost allocation under the Grid West proposal affects only transmission owners and their loads. That is, the external benefits going to the power sellers, in this example, cannot be internalized; the result from an economic point of view is a misallocation of resources—a cost not reckoned in the benefit/cost analysis.

The argument has been made that because loads ultimately pay the costs, it doesn't matter that they pay directly or indirectly. The true question to ask, though, is not whether loads pay, but which loads pay? In region or out of region or one utility's versus another's. An analogy would be that it doesn't matter how business taxes are collected—whether based on income, revenues, value added, property owned or retail sales—because they all ultimately are paid by consumers.

The Minimization-of-Cost-Shifts Criterion Continues to Consider Only Transmission Rate Impacts and Ignores Power Cost Shifts, Shifts From Generators to Loads or the Impact of Different Loss Provisions on Revenue Collections.

At this time, the cost shifts between regions, among utilities and between generators and loads from Grid West have not been estimated. Estimation of these cost shifts is not dependent on an independent body, but they are key to whether or not ICNU is willing to support a go-ahead of Grid West. Many cost shifts arise because of the elimination of inter-regional charges and moving the Northwest power market levels closer to those of California.

These shifts are not transmission cost shifts for which Grid West has offered some remedy. These shifts are power cost shifts that no one has yet estimated.

The Benefits That BPA Has Estimated Are Probably Closer to Reality, But Are Still Too High

To date there have been effectively three Grid West oriented estimates of the net benefits of Grid West. The first was through the Grid West Risk and Reward group. The second was through a group of utilities involved in the Consolidated Control Area. Their work, largely performed by PacifiCorp, ultimately was brought before the Grid West Risk and Reward Committee, but in ICNU's view there was insufficient time to test the results, and many questions are pending at this writing. The third was done by BPA, which assessed the efforts of PacifiCorp and adjusted them (downward) to reflect what BPA called a more conservative look at the net benefits.

The benefit/cost calculations measure "quantifiable benefits," and identify non-quantifiable benefits. In addition, the written document (but not the public Power Point documents) identify non-quantifiable costs and risks. Many of the quantifiable benefits and costs/risks have been discussed earlier in this paper.

In ICNU's view, the PacifiCorp work for the CCA is replete with double counting, dubious assumptions about the use of the hydro system, highly dependent on inappropriately used "opportunity costs" and reliance on a few artificial conditions to represent the entire year. Furthermore, from early looks at the PowerWorld model, which estimated some of the benefits, it appears that many of the thermal redispatch benefits derive from PacifiCorp's ill-designed power system—with too many combined-cycle plants in the PAC West and too many combustion turbines in PAC East. These mismatches are being quickly corrected with the construction of two combined cycle facilities in PAC East, which means that many of the benefits may simply disappear. These changes need to be modeled, but to date, have not.

As a consequence, the more conservative approach taken by BPA makes more sense, though we have problems with their work, as noted in Appendix 2 and 5 to this document.

It is ICNU's view that the net of quantifiable costs and benefits of Grid West, properly calculated, would be close to zero. The results for TIG are not yet developed.

Thus, the determination of overall value of Grid West will come from the unquantifiable benefits, costs and risks. Because of the major unknowns, listed in the questions in Appendix 4, it is unclear what the bottom line might be.

Appendix 1 – Direct Answers to BPA Questions

The answers will apply primarily to Grid West because of the fuller development of its proposal.

1. Do you agree with BPA's goal of applying the "one utility" vision to the region's transmission system?

   Only in part. A one-utility vision has many dimensions, from reliability to regional planning to subregional planning, to OASIS provision, for example. Whether or not a one-utility vision is required for all potential functions of Grid West (or TIG) is not clear. There is probably some limit where the disadvantages or costs of large scale operations outweigh the one-utility benefit on <u>each</u> major function. Increasingly larger does not always result in better outcomes. It is not necessary to have a one-utility vision for all aspects of transmission services. A one-utility view might be fruitful for maintenance of reliability, but not for the policing of utilities' tree trimming programs (which has been suggested as a function of Grid West). Furthermore, it is not clear how suboptimal, on balance, a smaller version of a transmission entity is, perhaps one that has fewer functions and incorporates only the BPA area as defined by the Regional Act.

2. Please describe how well you think each alternative achieves the six benefits described on pages 2-3 of this letter (planning and expansion, reliability, ATC, congestion management, market monitoring, and "one stop" stopping).

   a. As indicated above, the planning and expansion goal is probably not able to be implemented because of the dilemma of the timelines among construction of transmission and its alternatives and because of the cited problems of allocations after a plan is chosen.
   b. Both Grid West and TIG can achieve reliability benefits, as can a number of other institutional structures. Because FERC is mandating reliability improvements, the benefits of having only Grid West or TIG provide them not a cost or benefit of either. It is outside the scope, because it will be done.
   c. Both the Grid West and TIG proposals incorporate the notion of flow-based analysis when determining Available Transmission Capacity. While Grid West is ahead in using flow-basis planning for ATC, TIG is not far behind.
   d. Grid West probably achieves better short-term congestion clearing within the CCA, but both alternatives apparently plan

to increase the availability of trading information. Within the CCA, Grid West introduces to the region the notion of centralized short-term operation of generation, while TIG relies on centralization of transmission information.

e. Neither Grid West nor TIG can solve the market-monitoring problem posed by the operators of hydro that have substantial storage and therefore a substantial time dimension in determining the opportunity cost of their product. How will a market monitor be able to second guess the decision of, for example, a BPA hydro operator who looks at his or her vision of future hydro prices, precipitation patterns, reservoir levels and other opportunities and constraints to develop a bid or an offer of transmission rights? In short, ICNU doubts that the overly optimistic benefits ascribed to the market monitor can, in practice, be fully obtained in a system dominated by hydro.
f. One stop shopping is a large convenience offered by Grid West and TIG. Whether the entirety of the scope of Grid West or TIG is necessary to achieve this goal is problematical.

3. How well do you believe the Grid West and TIG proposals meet the goal of effective decision-making that is not unduly influenced by market participants?

   Independent decision making is at the core of Grid West and has a much lesser role in the TIG proposal. Because those market participants with strong financial interests are likely to expend the effort to influence the Grid West deliberations, the practical effect of independence will be less than the theoretical effect. Moreover, because Grid West and TIG are transmission entities, it is likely that transmission solutions will be favored over market-oriented generation and utility or market-oriented DSM solutions to problems. TIG's ad hoc independence, as presented in early efforts, needs to be strengthened (such as, forcing the transmission owners to respond to independent groups' proposals and comment).

4. If BPA supports the TIG proposal, are you committed to all of the elements of the TIG proposal? If not, which ones are troubling? And why?

   The TIG effort is not formed well enough to answer this question.

5. If the TIG proposal were to be chosen, how likely would it be that the proposal would be successfully implemented?

   Probably as likely as Grid West.

6. If BPA supports Grid West, are you committed to all of the elements of the Grid West proposal? If not, which ones are troubling? And why?

   There are a large number of major gaps in the proposal that need to be filled before this can be answered. The discussion above outlines some of the gaps that we see at this time.

7. If the Grid West proposal were to be chosen, how likely would it be that the proposal would be successfully implemented?

   Opposition to Grid West by BPA's public utility customers is unlikely to diminish. Moreover "successful" implementation of Grid West is also an economic question. Grid West may well be implemented, if BPA chooses to participate, but cost overruns, cost shifts, etc., would make it unsuccessful.

8. If you are a supporter of the TIG alternative, please explain why adopting the TIG alternative will be in the collective best interests of all of BPA's customers who depend on the Northwest transmission grid and of other stakeholders who have an interest in regional transmission issues.

   We believe there is less likelihood of TIG moving in a direction that is opposed by end users in the region than is Grid West. If a majority <u>as represented by the diverse Members of Grid West</u> finds the justification of a particular expansion of Grid West "good enough," the entity could expand its scope. We recognize that certain scope expansions require a super majority, but many do not. The Good Enough Standard to approve Grid West actions causes significant concern to ICNU

9. If you are a supporter of the Grid West alternative, please explain why adopting the Grid West alternative will be in the collective best interests of all of BPA's customers who depend on the Northwest transmission grid and of other stakeholders who have an interest in regional transmission issues.

   While not endorsing a yes vote at Decision Point 2, there are aspects that are likely to improve the region's transmission market—but at a cost—and there may be other ways to achieve increased reliability, one-stop shopping, more localized power markets and flow-based analysis.

10. The RRG recently completed an examination of the benefits of the Grid West proposal. Do you have additional views on the benefits of the Grid West proposal that you have not already brought to our attention?

There has been insufficient review of the Grid West models. Our comments on the BPA analysis are included as Appendix 2. Our comments of the Grid West risk/reward effort as of this writing are included as Appendix 3..

11. Do you have additional views on the estimated costs of the TIG and Grid West proposals.

    While the costs may have been competently calculated, the problem is managing to those cost levels and avoiding "good enough" scope-increase proposals within the by-law constraints. The substantially lower figure for the estimated costs of TIG are always a positive, though they are for a lesser product. If, as BPA has indicated in its regional discussions, most of the TIG and Grid West offerings are very similar, then the cost of an independent entity and a more robust congestion market is, by subtraction, approximately $50 million a year at the outset. Given the uncertain status of Grid West's initial features, the potential inability to avoid heavy FERC regulation and the long-term risks at the expiration of the Company Rate, ICNU believes that an independent entity and some other Grid West advantages do not merit a $50 million a year expenditure.

12. What 2-3 improvements might you suggest for each alternative?

    TIG needs more definition. Grid West needs to solve/define/answer the issues assembled as Appendix 4.

13. The Grid West and TIG alternatives seem to be quite similar. Please suggest how these alternatives may converge?

    They could converge further in many respects except for the issues surrounding independence (including governance), establishment of a new entity and FERC jurisdiction.

14. Where do you think the region will be in ten years under each alternative?

    a. For ICNU, ten years out is the end of the Company Rate period. Under the Company Rate, ICNU enjoys the benefit of transmission payments by others for whom the size of BPA's (and Idaho Power's) transmission systems was intended. Approximately 40 percent of the cost of BPA's transmission system (and Idaho Power's) is not paid by loads within the BPA service area. It is paid by wheeling transmission users who wheel through and out of the BPA system. The prospect of a

66% rate increase even ten years out concerns us. ICNU suspects that there will be intense regional fighting over the future of the Company Rate. This is not an issue with TIG because it is not moving to a regional transmission rate.

b. We suspect also that the Good Enough Standard for increases in Grid West scope will cause significant cost increases that may or may not cross the by-laws threshold. TIG will be more constrained because of its more limiting acceptance rules.

c. With Grid West, we expect that there will be significant cost and responsibility allocation issues outstanding at Grid West and FERC. TIG will be more restrained because of its unanimity rules. .

Appendix 2 – Comments on BPA Risk Reward Analysis

ICNU's comments and observations are included as red-line changes to BPA's document, which is below.

BPA has taken the analysis performed by PacifiCorp ("PacifiCorp Analysis") and modified it—to reflect some of the criticisms that have been leveled against it and to make it more "conservative." There remain problems even with the BPA analysis—problems that stem from the original Pacificorp Analysis, particularly with respect to the PowerWorld results and double-counting.

In our view, one issue has become largely mute: the benefits of reliability. Because of the Energy Policy Act of 2005, the reliability benefits essentially are off the table. They will arise regardless of the alternatives chosen, so they are not an advantage to Grid West, TIG, or less extensive changes to the status quo. Rather, the reliability issue for the benefit/cost analysis becomes one of which alternative can provide what the act mandated at the lowest cost. The reliability benefits are not an exclusive result of any of the alternatives.

The comments to the BPA analysis of risk and rewards are included as Appendix 5, as comments to each of the sections.

Appendix 3 – Preliminary Comments on Grid West Risk Analysis

The Grid West Risk/Reward—that is, benefit/cost analysis—is not a definitive examination of the value of Grid West. ICNU anticipated a substantially more comprehensive analysis of the regional net benefits of Grid West before Decision Point 2, but such a study is not available. For ICNU, the analysis is not "Good Enough Standard" for the substantially increased expenditures sought at Decision Point 2.

The Grid West preliminary assessment of the benefits and costs of Grid West significantly overstates the net benefits of the proposed organization. There appears to be double-counting of benefits, the PowerWorld analysis of redispatch benefits is severely flawed, and the Energy Policy Act of 2005 changes how the reliability benefits should be counted: The benefits of reliability will arise independent of Grid West; they are not an exclusive result of Grid West formation and, along with the costs of reliability, need to be largely removed from the calculations.

Unfortunately, the analysis and any critiques of it suffer from the lack of documentation. ICNU recognizes the short time that was required by the (overly) aggressive Grid West decision schedule. As a result, however, there is insufficient documentation of much of the work done. The critique below is necessarily dependent on what has been produced.

The Risk/Reward group was not included in the original design of the Consolidated Control Area analyses and only reviewed largely undocumented results in a few meetings just prior to the release of the West Preliminary Report on the Estimated Benefits of Grid West, July 19. Subsequent to that report, several members have sought additional information that has not yet been completed.

Contingency Reserves

The savings in contingency reserves come from the possibility that a short-term market for reserves would enable utilities to serve their reserve needs more efficiently. Currently, no organized market for reserves exists in the Northwest, though utilities buy reserves on a short-term basis from one another.

There are three concerns with the Grid West estimates. First, there has been no estimate of how many short-term market transactions take place today to provide additional reserves. Second, there has been no explanation of the transmission requirements (and reserves for transmission failures) necessary to carry such reserves, particularly into constrained areas. To the extent that transmission must be reserved for contingency reserves or that there is a reduction in reliability from dependence on distant versus load-area contingency reserves, there is an opportunity cost that needs to be taken into consideration. Third, the high estimate of benefits derives from a model effort that otherwise is disparaged—particularly in the dispatch benefits. That is, there is a cherry picking of model results throughout the PacifiCorp analysis that balloons the results.

Regulating Reserves

The benefits of regulating reserves derive from the insurance concept that an increased diversity in loads increases the chances that positive and negative deviations from forecasts will offset one another. At the margin, the incremental need for reserves to cover a set of loads is lower than the average need.

BPA has analyzed this issue for several years and has made a reasonable estimate of benefits.

Two issue remain. First, when regulating reserves are transmitted long distances, say from the Mid-Columbia to Utah, they are affected by transmission constraints and reliability as more and more transmission lines come into play. These factors are particularly important when the machines providing the regulation also provide load following. Second, the benefits from regulating reserves exist today and BPA has tariff rates for such reserves, so it is possible that the tariff rate is simply set too high.

Redispatch Efficiencies

The PacifiCorp analysis with PowerWorld is seriously flawed, based on the model assumptions and two simulations that were done with the model. (More simulations have been requested, but, at this writing, were not available)

1) when the ability to store hydro in reservoirs is eliminated from the model in certain seasons, there is no benefit.
2) The benefit in one other season without the hydro storage shows savings from reductions in PacifiCorp's combustion turbines in PacifiCorp East (PACE) and increases in combined-cycle operations in the West. However, PacifiCorp is already altering the way it operates by constructing two major combined-cycle facilities in PACE, which will reduce the need for redispatch. Those changes have not been included in the analysis;
3) Using 5 hours of "typical" results to represent 8760 hours of conditions is a serious stretch, particularly in the use of spring results (with highly loaded interties) for fall operations;
4) While the WECC studies used are "typical," there is no assurance that the end-product represents and equilibrium market solution for the West;
5) The estimated high redispatch benefits for the 10-CCA area of over $400 million (for about 1% of generation and compared to $900 million in total

operations costs for load service and contracts) calls into question the benefits for the 4-CCA area. A savings of $400 million for 2.6 million MWh implies a redispatch benefit of over $150 a MWh averaged over a "typical" 8760 hours a year;

6) Because of the basic assumptions of the model construct, assumed changes in "opportunity cost" of power have no market-response consequences; that is, all benefits are attributable to redispatch, when market responses to changed prices may preclude redispatch transactions.
7) Opportunity costs are entered incorrectly. The opportunity cost of off-peak usage should be equal to or higher than on-peak usage, particularly when preserving power in off-peak hours for sale in the next on-peak period.

Reliability

With the reliability requirement of the Energy Policy Act of 2005, reliability measures will be taken with TIG, Grid West or any other entity. As a consequence, the incremental benefits of Grid West should replace the benefits provided in the Grid West documents and costs developed by the Structure Group. As a consequence, the flaws in PacifiCorp's analysis noted by BPA become irrelevant, as are the additional problems we see with the short-term reliability benefits.

The incremental benefits, if any, would come from more efficient provision of the Energy Policy Act requirements by Grid West rather than TIG or a change in the status quo.

Rate Pancakes

The rate-pancake benefits include high, medium and low estimates. The high estimates, from a study by Tabors Caramanis and Associates, was performed for RTO West. It is outdated and inappropriately designed. It is outdated in the sense that there have been significant changes in natural-gas spreads throughout the West as a result of the pipeline connecting Western Canada with the Central United States. As a result, the gas-price advantage of the Northwest has been reduced or eliminated and the benefit of generating electricity in the Northwest for sale to California has been reduced. Second, TCA assumed that all transmission was exposed to wheeling expense, when most Northwest transmission is under contracts that have no impact on incremental generation costs. Thus, TCA significantly overstates the pancaking issue.

The medium case relies on PacifiCorp analyses that assumed additional transmission utilization stemming from Grid West operation of the system. In addition, the PacifiCorp analysis assumes that all transactions face pancakes, which is untrue. BPA has rightly discounted the PacifiCorp results in its report, but, without further analysis, it is unclear whether or not the amount of discounting is appropriate.

The low case probably overstates the amount of power that is carried under fixed-transmission-price contracts, but is probably far closer to the actual figure than the very flawed TCA and PacifiCorp studies.

Reconfiguration-Transmission Utilization

The reconfiguration-transmission utilization benefit overlaps with other benefits, as the Grid West benefits document acknowledges. Until the overlap is sorted out, reliance on estimated benefits should be discounted.

Improved Transmission Planning

There is doubt that an optimal regional plan, which would include unplanned generation and demand-side options, can be formulated, and there is further doubt that the backstop assurance works when non-TA-signers are allocated costs or responsibilities and when non-wires options are a valid alternative.

Grid West has placed a high emphasis on a regional transmission plan, and BPA's first item in its list of potential solutions is an "[e]ffective "one-utility" planning with adequate backstop for reliability purposes. This goal has been echoed by regulators and state officials throughout the region. Supporters of DSM and generation alternatives have cited the intention to include alternatives to "wires" as a major advantage.

ICNU believes it is unlikely that an effective one-utility plan with an adequate backstop will provide the benefits promised 1) because of the nature of the power and transmission institutional structure that is developing the plan and 2) because of the difficulties of allocating costs and responsibilities of a plan's directives.

Despite Good Intentions to Include Generation and Demand-Side Alternatives in a Regional Transmission Plan, the Reality is that the Plan Is Likely to be Transmission-Centric.

There are two chief problems with developing the transmission plan envisioned in the Grid West documents. They relate to 1) the lead times for developing transmission, generation and DSM, respectively, and 2) the nature of the entity that builds the facilities.

Regarding lead times, it is generally agreed that the construction of transmission upgrades, particularly large upgrades, especially on new corridors, takes years to complete—perhaps as long as a decade. It is well known that a gas-fired generating station generally can be planned and constructed within two years, and a DSM program probably can be installed in less than a year.

The longer lead time for transmission projects requires approval decisions to be made long before they would have to be made for generation or DSM alternatives/substitutes. For example, a decision for a transmission line for service in 2015 might have to be made as early as 2006, where the decision on a generation station could wait until 2013, and a decision on DSM could wait, say, till 2014. There is a further consideration: If load patterns or growth change, the generation or DSM alternatives might never be needed at all; as a consequence the alternatives have a flexibility advantage over a transmission alternative.

The reality of transmission planning is that a decision on a transmission line needs to be made long before the market would make a decision on an alternative. In the example, a transmission decision would have to be made in 2006; therefore, in 2006 the planners must assess the likelihood of the generation and DSM projects being completed in time to address the perceived need.[2]

The decision is further complicated by 1) the fact that generation alternatives are provided by a non-transmission entity, whether voluntarily developed by market participants or by independent decisions of load-serving entities—in other words, by entities for which Grid West does not plan directly, and 2) a commitment for generation or DSM <u>at the time of a transmission decision</u>, in 2006 in the example, probably makes no sense. [Alternatively, the transmission plan could call for Grid West (or TIG) to provide "reservation" or stand-by payments to potential generators or DSM providers (for seven years in the example), but there are serious questions about whether it can or should do so.]

[In a vertically integrated utility world, this timing issue is not a problem, because the same entity is responsible for all three alternatives. Similarly, in a free-market world, price signals would bring about the construction of generation or the development of DSM alternatives as a market response if there was no prior decision to build transmission. <u>Furthermore, a transmission-construction decision will seriously reduce the incentives for generation or DSM alternatives, whether that construction decision is forced by Grid West or made by market participants.</u>

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2 Some have noted that the commitment to transmission does not mean a commitment for the entire project at the outset, but only for preliminary studies and land acquisition. While there is merit in this observation, these preliminary transmission-project costs become "sunk" at the time of the next plan, and the relevant test becomes the <u>cost to complete</u> a transmission alternative versus the cost of generation or DSM. As a result, the remaining transmission alternative becomes less and less costly relative to generation and DSM alternatives. For, example, if transmission and generation alternatives had equal expected costs in the first plan, at the time of the second plan (without major cost changes for either) the transmission alternative would show an advantage due to the costs that had been incurred and sunk between the two plans.

As a consequence, the transmission decision will necessarily be suboptimal if generation or DSM were in the optimal plan.]

It is ICNU's conclusion that it is highly unlikely that an "effective" transmission/ generation/DSM plan can be constructed given the timeline and the nature of potential alternative providers. Placing much stock in the large benefits of a regional transmission plan seriously overstates the possible outcomes. Because of the problems any transmission plan is likely to be a suboptimal transmission-only outlook on the region.

The Words, "Backstop Authority to Allocate Responsibility and Costs of Reliability Transmission Projects," Are Likely to Be Easier Put on Paper Than to Implement.

It is highly unlikely that Grid West can allocate responsibilities to build transmission alternatives to generation projects or to providers of DSM, because Grid West has no authority over those entities. A plan that includes generation or DSM measures is therefore not enforceable by Grid West. Allocation attempts will be limited to assignments to transmission owners (which, if the preceding observations are correct about transmission-centric plans, may be the only components of the plan in any case). The problem for Grid West comes when an allocation is to an intended recipient that contends that it will install generation or DSM, if needed. Is such an entity allowed to challenge the allocation on the grounds that it has a better market-driven substitute? [If the plan allows for generation or DSM alternatives, it may be difficult for Grid West to contend that a reluctant transmission owner's alternative is infeasible.]

The upshot of the discussion in this and the previous sections, ICNU believes, is that Grid West will create a transmission-centric plan for the region, try to enforce an allocation of transmission responsibility on those who may have a better alternative and be rebuffed by some. That is, the allocation assignment will almost certainly be contentious to some "beneficiaries," resulting in challenges and potentially litigation and potential cost-shifts towards end users.

The Inability to Allocate of Costs and Responsibilities to Beneficiaries Who Are Not Obligated to Pay Will Simply Increase 'Uplift' Costs and Stimulate 'Free Riders'

There is a further serious problem of allocation. While the intended consequence of an "effective" transmission plan and resulting allocation backstop is to force transmission upgrades, an unintended consequence is to create a serious "free rider" problem. Transmission owners who do not join Grid West avoid an allocation, but they will benefit from those who are forced to pay.

The argument is made that the situation exists today. However, today, although the incentive is to hold out support for a transmission project to extract as much benefit as possible, there is the prospect that such a project will not be built, or that when the holdout utility wants to sponsor transmission for itself in the future and requires others to help, it will receive no help. Today, as a consequence, there is an implicit quid pro quo to supporting transmission projects. Under an allocation process, there is no need for such a quid pro quo and "free rider" holdouts will be encouraged.

Long Term Siting Efficiencies

It is not true that there presently exists no price signals for siting of plants. A developer today who wants to construct a power plant, particularly one distant from load, must take into account the costs of transmitting that power to load areas. The costs of upgrading the transmission system for a new resource's generation is a true marginal cost of development that should be included in that developer's calculation.

Two issues arise: 1) Is the estimate to the developer the true cost of transmission upgrades (or does it meet the Good Enough Standard)?; and 2) is a Grid West estimate of the costs to be assigned to a developer that much better than the status quo?

In today's world, upgrades that developer pays for are contained within the control areas through which the power flows as determined by contract-path calculations, and there may be no allowance for benefits received by other users on that path, including the utility control-area's customers. Grid West proposes to allocate costs to other beneficiaries, and, as a result, reduce the cost to the developer. However, if Grid West is unable to allocate such costs (because of potential market-driven substitutes, for example) and the cost obligations are returned to the developer, the benefit of Grid West's siting efficiency effort is lessened. If, on the other hand, the costs are spread as "uplift" to all users of the transmission system, the societal benefit is distorted, and society is made worse off to that extent. If we operate under a Good Enough Standard, it may be that the existing system or a Grid West system meet that criterion.

The issue is complicated further by the fact the planning process may not adequately treat alternatives and likely will not consider natural-gas-pipeline construction or rail transport in the analysis. If, for example, building plants closer to load and transporting natural gas is cheaper than a "perfect" Grid West allocation to a developer, there is a societal cost to choosing a Grid West solution.

Assigning a very large benefit to location of new resources is not warranted.

Construction Deferral

Converting the measurement of available transmission capacity to a flow basis will have the impact of more efficient utilization of the existing system. One result is the deferral of construction. Another result is the use of that capacity for redispatch. The same transmission capacity cannot do both, but the modeling assumes so--in the Redispatch Analysis, in the Reconfiguration-Transmission Utilization Analysis and in the qualitative benefits.

Clearly, there is double counting. The highest valued use should be calculated as a benefit, but not the highest-valued and the second-highest valued, plus the qualitative.

Conservation and Demand Side Management

Cost effective conservation for *energy* purposes has been a regional goal for decades, and there are likely savings to transmission as energy loads are reduced. These savings are not the issue here, however, because they do not rely upon the formation of Grid West to achieve the conservation goals.

What is of importance for transmission-only purposes is how DSM and conservation fit within the institutional structure. Grid West does not control conservation or DSM program offerings, just as it does not control generation. In general, the market or the load-serving entity does. As pointed out in the planning section, it is unlikely that a transmission plan will contain non-transmission alternatives when a decision to implement one under Grid West's purview or another that relies on the load-serving entity or market has to be made.

It is easy enough to include conservation and DSM alternatives in the abstract. In reality, implementing a non-transmission alternative is likely to be far more difficult.

Accordingly, estimates of large benefits from DSM or conservation as a result of Grid West are of dubious value.

Coordinated Generation and Transmission Maintenance

The Grid West proposal is to take over existing coordination of maintenance of utility systems. No coordination of generation outages is in the Grid West proposal; in fact, just the opposite is true. Generators are not obligated to provide outage data to Grid West, for obvious competitive reasons.

As planned, Grid West has no enforcement authority on outages.

As a result, it appears that the additional Qualitative Benefit from Grid West coordinated generation and transmission maintenance is slight.

Load Following

There has been an assertion of a large load-following benefit, but there has been no documentation of the benefit and therefore no ability to see what the assertion is based on, nor to test it.

The load-following issue is complicated in the BPA control area and perhaps in control areas of some other utilities with large hydro facilities by the fact that the load-regulation facilities may already be providing load following. In thermal systems, load following is a significant cost issue. In hydro systems, it may be a very small issue.

Given that there has not been any information provided on the asserted benefit, the standard for benefit measurement surely has not been met.

Market Innovation

Market innovation, of course, is a major benefit to society. Innovation and invention occurs throughout the world. However, it is difficult to imagine that the existence of Grid West *per se* would provide a significant additional benefit.

Relying on market innovation as a significant benefit of Grid West is not warranted.

Market Monitoring

Market monitoring is another area that sounds good on paper, but in practice in a hydro dominated system must face enormous difficulties of placing a value on hydro power or on transmission facilities that carry such power.

It is well recognized that a hydro utility's bid to sell or purchase hydro energy or the transmission facilities that enable hydro wheeling should be based on the opportunity cost of those bids. The opportunity cost is a judgment of a seller or buyer of power that is subject to a wide range of valid interpretations—of future markets, of reservoir and salmon-preservation constraints, of future loads, and so forth. The wide range of potential judgments makes it difficult for a market monitor to challenge a hydro operator's bids and renders that monitoring function fairly ineffective for many Northwest transactions.

In the Northwest, the issue is doubly compounded by the fact that BPA and some other utilities are major players on both sides of a market.

Unquantified Risks

The Grid West report identified a number of unquantifiable risks that ICNU felt were needed to balance the unquantifiable benefits list. The areas identified were:

- Costs of a New Organization
- Uncertainty of the Efficacy of the Planning Process
- Potential for Unaccounted-for Costs
- FERC Engagement (or Non-engagement)
- Governance and Lack of True Independence
- Prospects for Cost Shifts
- Uneconomic Real Power Loss Provisions
- Short-term Time Horizon
- Conservatism in Operation
- Market Power
- Erosion or Extension of Rights under Existing Contracts
- Loads Pay
- Market Mismanagement and RTO/Customer Relationships

Responses to those risks were included in the report. However, there was no discussion of the responses by the Risk/Reward group, so the report may give the impression that there was agreement on the responses. There was not.

Some of these have been discussed above—the planning process, real power losses, market power, loads pay. Others rely on a judgment as to whether the Grid West Bylaws provisions provide enough security to End Users. There obviously will be differences of opinion on the protections provided, and ICNU does not concur that the protections are adequate for end user interests. Still others rely on some pessimism about an assumption that Grid West will not follow the path of other RTOs. Again, reasonable people can differ.

The Grid West report, in ICNU's view, does not adequately reflect the less-optimistic position.

Appendix 4 – Questions for Grid West

1. Consider the following:
    - The Reconfiguration Service is set up so that offers of existing PTP (I/W) transmission rights can be made on a short-term basis;
    - Grid West scaled marginal losses replace Company Losses on, perhaps, multiple systems;
    - There is no congestion on most, if not all, hours

   What is to prevent transmission users from offering those rights in uncongested hours (or hours of low congestion costs) and transferring perhaps significant costs of real power losses to the remaining users.

2. Will Grid West (or TIG) accept a regional transmission plan in which future unplanned generation or DSM is a major component?

3. If it can be shown by judicious location of market-responding generating resources or DSM that no significant transmission is needed, would that be acceptable to Grid West?

4. If an allocation of responsibility for a transmission project by Grid West is rejected by the entity to which it might be assigned because that entity has a "better" plan after arbitration or a FERC challenge, what happens to the allocation? Is it simply 'uplifted?'

5. If the allocation of benefits of a reliability transmission project is to an entity that has no agreement to pay, how is the shortfall handled?

6. Suppose a transmission owner is unable to finance a transmission project and an alternative provider is chosen to raise the funds and construct the transmission in exchange for a stream of payments from Grid West. What happens to that payment stream if BPA or another utility exercises its rights to withdraw from Grid West?

7. If BPA bids its opportunity costs into CCA reserves or imbalance-energy markets and those bids are challenged by a market participant or market monitor, how will the issue be resolved?

8. Is a withdrawal from Grid West past Decision Point 4 a realistic alternative?

9. Has Grid West quantified the probability of significant changes in network topology over time due to transmission line outages or outages of major generators? Put another way, how stable are network topologies over time?

10. What are the implications for revenue adequacy of long-term financial. transmission rights? How significant is the role of changes in generation dispatch over time to the feasibility of long-term financial rights?

11. For new service from Grid West is there or is there not an export fee?

12. What is the methodology for determining lost revenues for each utility, especially later in the Company rate period?

13. How are lost revenues determined for non-jurisdictional entities who sign a transmission agreement? What is the mechanism for resolving disputes over the level of lost revenues for a non-jurisdictional entity? How are such determinations challenged—particularly after any dispute-resolution alternatives have been exhausted?

14. What are the power-cost impacts of Grid West during the Company Rate period and after that period under the assumption of melded regional transmission rates and no intertie export charges?

Appendix 5 – Detailed Comments on BPA's Risk Reward Paper

BPA Grid West Benefit Assessment for Decision Point 2

August 4, 2005

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Appendices

Introduction

BPA committed to evaluating the expected costs and benefits of Grid West prior to its September 2005 decision as to whether or not to continue supporting the development of the Grid West structure/institution - also known as "Decision Point 2" (DP2). This paper documents the results of that effort. For Decision Point 2, we have evaluated benefits from a regional perspective. If BPA decides to pursue TIG or Grid West after Decision Point 2, we will begin the more difficult and detailed tasks of assessing the *distribution* of costs and benefits disaggregated to at least a state-by-state level.

As part of its efforts to meet this commitment, BPA has participated in the Regional Review Group's (RRG) Risk Reward Group (RnR) and the Consolidated Control Area (CCA) benefit assessment exercise. The RnR group has been meeting since spring of 2004. Initially it was charged with assessing the costs, benefits and risks associated with the proposed Grid West design. Eventually, the Transmission Service Liaison Group (TSLG) and its consultant, the Structure Group, took on the task of developing a detailed cost estimate, leaving the benefit and risk assessment in the hands of the RnR group. The RnR accomplished its tasks by 1) conducting a detailed survey of regional transmission owners, marketers, public utilities, and private utilities to ascertain and better understand the transmission problems that Grid West is charged with resolving. 2) reviewing existing RTO/Grid West benefit studies to glean relevant data, and 3) incorporating new analyses, as appropriate, to assess potential Grid West benefits. In addition, the Consolidated Control Area benefit assessment group ran models and conducted analyses to determine the potential benefits of the consolidation proposal. [These have not been fully reviewed by some members of the RnR group who were not involved in the CCA discussions.]

BPA also convened an internal group of analysts to follow and provide input to the external work, and to conduct its own analysis as needed – this group has been meeting since the inception of Grid West.

On July 20th, the external RnR group presented its estimate of benefits to the region. The estimates did not represent a consensus of the RnR group. These estimates were provided in a "menu" format, so that participants might select the estimates and benefit sources that best fit their vision and understanding of Grid West. BPA has taken that menu, selected benefit estimates we think most accurately capture the expected benefits of Grid West, added some of our own analysis, and derived a BPA estimate of regional benefits associated with Grid West.

Overview of Grid West Benefit Sources

Grid West's design is a response to specific problems with regional transmission transactions, as defined by the Regional Representatives Group in 2003 and further delineated in the RRG's 2005 Risk Reward Survey [3]. It is anticipated that Grid West's provision of solutions to these problems will yield benefits to the region. This study will examine the anticipated *regional* benefits of consolidation. The study of state-by-state impacts of costs and benefits will be conducted if the region votes to seat a Grid West developmental board and prior to Decision Point 4 (whether or not to sign a transmission operating agreement with Grid West).

Single Available Flowgate Capacity Calculations For All GW Participants:

A. The global view of schedules on at least a day ahead basis allows for a more *reliable operation of the NW transmission system* than does today's balkanized scheduling protocol. The global view of schedules allows foresight into dispatch problems and loop flow prior to real time. This, in turn, allows for better anticipation of transmission flows than does today's multi-CA scheduling protocol. It is important to note that the Pacific Northwest Security Coordinator (PNSC) currently provides and will continue to provide real time oversight & security for the GW transmission system – thus the increment of security expected from Grid West is associated with the day ahead view.

B. Single system view of schedules increases ATC/AFC – akin to TBL's efforts, only on a broader scale. The result will be the ability to net some loads and to more accurately anticipate physical flows. An increase in AFC will, in turn, leads to more efficient dispatch due to the increase in dispatch options.

C. Outage information, as coordinated by Grid West, is likely to be more transparent than it is today. [This may be an overstatement, because Grid West will be merely taking over the existing task currently performed by other regional entities; there does not appear to be anything new that Grid West adds.] That information will be incorporated into and influenced by the centralized calculation of AFC – giving Grid West the ability to minimize the lost opportunity costs associated with outages.

[3] For survey description and results, see *http://www.gridwest.org/Doc/RnRCompilation_RRGPres_Feb2405.pdf* and *http://www.gridwest.org/Doc/RRSurvey_preliminaryresults_031105.pdf*

D. Transmission construction deferral: To the extent that AFC is released due to the single operator AFC calculations, it will delay the need for construction of new facilities to meet load growth.

Reconfiguration Market:

A. Improves *liquidity of transmission markets* by providing a new mechanism for reconfiguring existing rights and issuing new rights on an injection withdrawal basis.

B. Allows for *more efficient dispatch of generating resources* by opening up transmission options.

C. Allows for more efficient dispatch of generating resources by eliminating the false price signals conveyed by short term pancaked transmission rates. *Note: we do not anticipate a decrease in the fixed cost of transmission, merely a re-assignment of that cost recovery to a more appropriate fixed-cost recovery mechanism.*

D. *Increases AFC by providing for more transmission trading options*. This, in turn, provides opportunities for more efficient dispatch.

Consolidation of Control Areas (CCA)

A. *Reliability benefits* – CCA gives more direct control of generating resources in emergency situations and more effective response/response time. This has the effect of giving operators control over generation in the face of an emergency, providing a more effective means for addressing problems than does the current mechanism of curtailment of transmission schedules. Thus, it is anticipated that the GW CCA will reduce the probability of cascading outages. [This benefit needs to be weighed against the possibility that Grid West would *cause* problems, similar to what has been reported (but not yet verified) in the recent Southern California outages.]

To substantiate this claim, we will provide reference to TBL expertise as to the extent of the problem and the degree to which it will be solved by Grid West.

B. *Regulation benefits* – The CCA's pooled load following and regulation reduce the amount of capacity that must be held out for meeting these needs.

C. *Economic Redispatch* – Consolidators can voluntarily make incremental ("incs") and decremental ("decs") bids into a real time redispatch pool . These incs and decs can be used to efficiently meet regulation and load following needs, and to economically redispatch consolidator's schedules based on physical transmission limits (as opposed to the contractual limits upon which their transmission schedule was based). These instruments lead to more efficient, more flexible redispatch options than those faced by separate control area operation. They also provide real time detailed price signals which can assist in market monitoring efforts, provide clearer incentives for transmission and generation construction, and [There is an assumption here that the BPA opportunity-cost problem—in which BPA is allowed to determine, in its sole discretion, what its opportunity cost is and that the resulting clearing price, should it be based on a BPA bid, is a valid price signal.]

B. *Contingency Reserves* - The CCA will allow for day ahead trading of resources to meet its contingency (i.e., spinning) reserve requirement. A more liquid market for such reserves can lead to more efficient assignment of units to meet those reserves and ultimately a cheaper cost of real time dispatch of generation.

Planning/Coordination

Grid West's planning responsibilities will include:

- Determining the capability of the Grid West grid.
- Assessing the transmission adequacy of the Grid West grid
- Developing and enforcing interconnection standards. [This is still a local utility responsibility.]
- Providing planning information to the AFC market.
- Coordinating transmission expansion activities.
- Providing backstop assurance for investment in reliability if needed.

There is doubt that an optimal regional plan, which would include unplanned generation and demand-side options, can be formulated, and there is further doubt that the backstop assurance works when non-TA-signers are allocated costs or responsibilities and when non-wires options are a valid alternative.

These measures should provide the following regional benefits:

A. Consistent assessments of capacity, adequacy and security of the regional grid.

B. Clear authority for main grid planning should ensure the integrity of the grid over time and reduce the probability of region-wide outages. [It is unclear how a market-induced generation project fits into "main grid planning," so the benefit here is probably overstated.]

Deleted:

C. Provides a one-stop transmission planning information source for market participants and project sponsors.

D. Provides independent planning from a one-utility regional perspective that will help identify least cost solutions without regard to existing control area boundaries. [Whether or not a one-utility solution would include wires and non-wires alternatives is problematic, given that Grid West cannot plan for non-wires alternatives.]

E. Backstop authority should serve to improve long term reliability by ensuring that transmission reliability investments are made. [There is a question as to whether Grid West will be able to allocate responsibility or the costs of reliability improvements: 1) some beneficiaries may not be signatories to the Grid West transmission operations agreements and would not be subject to allocation—e.g., generators, public agencies; 2) those to whom responsibilities and/or costs are assigned may contend and show that non-wires alternatives are better for them, causing delays while arbitration and FERC appeals are exhausted.]

F. Provides a better mechanism for distributing regional transmission costs. [See the response to E. above.]

Grid West Benefits: Summary of Quantitative Estimates

BPA's quantitative estimates of Grid West benefits are primarily drawn from work of the external RRG sponsored Risk Reward workgroup (RnR), but not a consensus of that group. BPA staff participated in all of this external work, and an internal Cost Benefit team was engaged to review the results internally (for internal and external participation information, see Appendix 1 – "BPA Grid West Cost Benefit Activities for Decision Point 2"). This group began meeting in the spring of 2004 and presented its preliminary results in an RRG seminar on July 20/21st of 2005. The RnR results (non-consensus) were presented as a menu of expected benefits with high, medium, and low benefit quantities (in US Dollars/year) derived for each of 7 categories. BPA has selected from this menu the estimates it deems most reasonable from a conservative perspective. Appendix 2 presents the RnR menu from which BPA selected its estimated benefits. A primary difference between the BPA estimate and the RRG estimate is that BPA chose to only adopt the quantified benefits associated with the consolidation of 3 control areas, not those associated with the consolidation of all filing utilities (10 CCA case). BPA has put the potential benefits associated with the consolidation of more than the 3 control areas who are currently exploring consolidation into our unquantified benefit category.

Benefit Summary

The expected benefits, and methods used to derive those benefits, are summarized below. Complete detail is provided on a benefit-by-benefit basis further on in this report.

BPA ESTIMATE: Quantified Regional Benefits of Grid West			$ Million/year	
Item	Potential Benefit	Facilitating GW Policies	High	Low
1	Reliability: Cascading Outage Prevention	1. GW DA Scheduling 2. Planning 3. Outage Coordination 4. Consolidation of CA's 5. CCA Redispatch 6. CCA Reliability Authority	$62	$27
2	Increased Transmission capacity.	Reconfiguration Service & Single Scheduling Entity	$15	$9
3	Regulating Reserves	CCA regulating pool	$8	$5
4	RT Redispatch Efficiencies	CCA RT redispatch market	$56	$41

5	Contingency Reserves	CCA AS Market	$30	$20
6	De-pancaking	Reconfiguration Service	$10	$4
		TOTAL	***$181***	***$106***

Method Summary:

Item 1: Reliability (Cascading Outages)

Benefits that could result from avoiding catastrophic outages were derived from the 2004 Gross Product for Grid West. Based upon US Census Bureau wage and earning data, it was assumed that 85% of total production occurs during weekdays and 15% on the weekends. The existence of Grid West was assumed to enable avoidance of 1 catastrophic outage every 20 years or 1 catastrophic outage of 1 productive day every 15 years. An outage is assumed to result in 50% loss of a pro-rated daily GDP (the remaining 50% would be recovered or protected by back-up generation). The high estimate reflects results of 1 avoided weekday outage every 15 years, the low estimate reflects results of 1 avoided weekend outage every 20 years. [Presumably, these are avoided outages net of outages possibly caused by Grid West.]

These estimates are supported by the work of Bill Mittelstadt, BPA transmission engineer and reliability expert who assisted in analyzing the causes of the East Coast outage. Mittelstadt reviewed NERC records of large disturbances in the WECC over the last 12 years and found that 45% of the causes of these outages would be likely mitigated by Grid West. See the BPA Grid West Benefit analysis for details.

Item 2: Increased Transmission Capacity

Benefits derive from increased access to existing transmission capacity as a result of more liquid and transparent transmission markets and as a result of Grid West's charge to merge regional schedules through before-real-time single area scheduling. This estimates what the benefits would be if the these features yield 3% or 5%, more available flow capacity (AFC). Grid View was run to estimate the least cost dispatch to meet loads over 1 year in the Grid West footprint with different transmission availability numbers. The measured benefit derives from the less expensive generation dispatch that occurs when more transmission is available. The high estimate assumes a 5% improvement over the baseline, the low assumes a 3% improvement.
(*Note: These figures were derated by 50% as compared with the RRG results, to account for the potential overlap between measurements of the benefits of increased*

transmission capacity and those accruing as a result of a real time balancing market).

Item 3: Regulation Reserves

These benefits accrue when regulating reserves are pooled and the magnitude of expected variation in load is reduced, resulting in a reduced need for regulating reserves. Studies were performed by TBL's Bart McManus in 2005 - he examined the actual variation in loads for BPA, PacifiCorp and Idaho Power over 3 years and 4 seasons. The benefits cited are based on a 60-minute rolling average deviation from average load. The high estimate values the resulting capacity savings, 109 MWs, at $6 per kW month, the low was valued at $4 per kW month (based on PBL trader estimates of the value of capacity). [1) This conclusion assumes no transmission limitations to get regulation reserves to anywhere in the region; 2) this conclusion would be modified if current regulating-reserve facilities also serve a role as load-following reserves as well (as has been claimed) .]

Item 4: Real Time Redispatch Efficiencies

PowerWorld optimal power flow analyses were used to calculate potential production cost savings resulting from the CCA Real Time Balancing service. PowerWorld was run using generator data from SSG-WI and transmission, load, and unit commitment data from WECC operating cases. The model was used to simulate a base case where least cost real time dispatch would be achieved with each GW control area minimizing operating costs independently. The future allows Idaho Power Company, PacifiCorp, and BPA (the consolidators) to minimize real time control area costs amongst themselves without regard to scheduling constraints. The difference in production costs between the base and future case is the anticipated Grid West benefit. Benefits for 8 representative hours in a year were estimated (heavy load and light load hours for each of the 4 seasons) and multiplied up to represent a full year's savings. .

The sensitivity of the resulting dispatch efficiencies to the price of hydroelectric surplus sales (which are a function of the value of power in California into the storable future) was tested. Five different cases were run: $20/MW-hour, $30/MWh; $40/MW-hour; $50/MW-hour; and, $65/MW-hour, as well as a run using Dow Jones average prices at the Mid-C trading hub. BPA's low estimate of benefits is a summation of the lowest benefits for each season of the year. The high estimate is based upon the Dow Jones runs.

The PacifiCorp analysis with PowerWorld is seriously flawed, based on the model assumptions and two simulations that were done with the model. (More simulations have been requested, but, at this writing, were not available)

8) when the ability to store hydro in reservoirs is eliminated from the model in certain seasons, there is no benefit.
9) The benefit in one other season without the hydro storage shows savings from reductions in PacifiCorp's combustion turbines in PacifiCorp East (PACE) and increases in combined-cycle operations in the West. However, PacifiCorp is already altering the way it operates by constructing two major combined-cycle facilities in PACE, which will reduce the need for redispatch. Those changes have not been included in the analysis;
10) Using 5 hours of "typical" results to represent 8760 hours of conditions is a serious stretch, particularly in the use of spring results (with highly loaded interties) for fall operations;
11) While the WECC studies used are "typical," there is no assurance that the end-product represents and equilibrium market solution for the West;
12) The estimated high redispatch benefits for the 10-CCA area of over $400 million (for about 1% of generation and compared to $900 million in total operations costs for load service and contracts) calls into question the benefits for the 4-CCA area. A savings of $400 million for 2.6 million MWh implies a redispatch benefit of over $150 a MWh averaged over a "typical" 8760 hours a year;
13) Because of the basic assumptions of the model construct, assumed changes in "opportunity cost" of power have no market-response consequences; that is, all benefits are attributable to redispatch, when market responses to changed prices may preclude redispatch transactions.
14) Opportunity costs are entered incorrectly. The opportunity cost of off-peak usage should be equal to or higher than on-peak usage, particularly when preserving power in off-peak hours for sale in the next on-peak period.

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Item 5: Contingency Reserves (Spinning and Supplemental)

The NWPP already pools contingency reserves – but they do not meet those reserves on a *regional* least-cost basis (each control area meets its reduced reserve requirement on an internal least cost basis). Consolidating Control Areas will meet their reserve requirement through a reserves market that combines resources and allows for a more optimal commitment of generating units. This more optimal commitment translates into a more optimal dispatch of generation in real time.

Henwood Energy Services conducted a study of these benefits on behalf of Snohomish PUD in September of 2004. BPA's high estimate de-rates their results ($73 million in benefits for the Grid West Region) by 44% as only 56% of Grid West load is assumed to participate in the CCA. This estimate is de-rated again to reflect the fact that short term reserves trades occur to a small degree today. We assumed a 25% to reduction in our high estimate and a 50% in our low case. [Again, the delivery of such reserves may require firm transmission, particularly into Utah and Sierra/Nevada Power, in the 10 CCA case.]

Item 6: Pricing Pancakes

BPA's estimated benefits of eliminating price pancakes were derived from two different studies. The high estimate is based on the PacifiCorp's runs of its GridView model wherein they simulated an optimal security constrained dispatch in the Grid West region with and without wheeling rates. The PacifiCorp results were de-rated by 50% to reflect potential overlap with the Real Time Balancing service analysis. The previously mentioned Henwood study also looked at the effects pancaking under extremely conservative assumptions and found there to be about $4 million in potential benefits – this figure comprises our low estimate.

Quantitative Estimate: Reliability

BPA staff and management spent a good deal of time exploring, developing and understanding the potential reliability benefits associated with Grid West. This level of effort was warranted as the need for improving BPA's ability to maintain existing reliability standards is one of the primary reasons that BPA is exploring Grid West and TIG.

BPA is anticipating that, without new ways of managing transmission, the likelihood and frequency of disturbances in its service territory is going to increase over time. [Is this true if generation is developed at load centers?] The reasons for this concern have not changed significantly since the October 2000 report developed for RTO West, "RTO West Potential Benefits And Costs – Final Draft", October, 2000[4]. That report listed the following reasons for changes in the reliability "playing field".

Previous Conditions	Emerging Conditions
Relatively large resources	Smaller, more numerous resources
Long term firm contracts	Contracts shorter in duration [This may now be a questionable assumption.] More non firm transactions [The quantity of surplus hydro power has not changed.]
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable [This is probably an outdated conclusion given

[4] http://www.nwrto.com/Doc/Benefit_Cost_Study_FinalDraft_Oct232000.PDF)

	the problems of California and at other RTOs around the country and the structure proposed for Grid West—i.e., the effort to avoid short-term trade reliance.]
Assessment of system security is made from a stable base (narrower, more predictable range of potential operating states)	Assessment of system security made from a more variable base (wider, less predictable range of potential operating states). [Probably an overstatement of the variability of future transactions given the nature of the California experiment.]
Limited and knowledgeable set of utility players	More players with divergent interests, less experience, making more transactions. [Again, is this still true?]
Hydro system resource flexibility readily dispatched to support the transmission system	Environmental constraints limiting resource operation in support of the transmission system
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition – little incentive for reducing reliability investments	Utilities less willing to make transmission reliability investments as many do not produce increased revenues [This simply is not true. Such investments become part of the revenue requirements of the utility.]`
Market rules and reliability rules developed together	Market rules changing – reliability rules not keeping pace
	More system through-put (except if Grid West limits throughput to make sure there are no transmission-caused problems.]

These concerns were reiterated in BPA's March 2005 "Keeping Current" publication: "Wanted: One-utility transmission for the Pacific Northwest"[5] That document spells out the reason that a regional transmission solution is needed as we move into the future. Among other things, it points out that:

[5] http://www.bpa.gov/corporate/pubs/Keeping/05kc/kc0305.pdf

- More than 20 generating and transmitting utilities rely on a single Northwest grid that is managed by 17 control area operators.
- BPA built no new major transmission lines from 1988-2000, and has recently added just over 150 miles of new 500 kV line, expanding the grid by 1%. [However, BPA has put nearly $1 billion investment into the transmission system.]
- We are experiencing too many "near misses" with respect to system outages. The document cites a particular near miss which started with birds in Arizona disturbing a 230 kV line and backup system failures – the event tripped out eight 230 kV lines and ten 500-kV lines, resulting in a loss of over 400 MWs of generation. Had this same event happened on a hotter day, it could have disturbed generation in the Northwest. Another disturbance was cited in which a minor event in Alberta caused dramatic power swings at the California Oregon border. A third case was overloads on Path 18 between Montana and Idaho that was very difficult to manage. Operators were close to dropping load
- Cut planes (points where the grid gets congested) have proliferated in the last few years – in 1998 we had 5, in 2004 the Northwest had had 15. [Aren't additional cutplanes a natural outcome of increased transmission system utilization? Is it optimal to have 5 cutplanes instead of 15? Is a higher number optimal, even under current conditions?]

Reliability Impact Analysis

BPA has had these concerns, and their solutions, in mind as it has participated in the development of the Grid West design. TBL's Bill Mittelstadt[6] and Don Watkins joined with BPA's Industry Restructuring staff to analyze the anticipated reliability effects of Grid West. The full output of this analysis is attached in Appendix 3. A summary of its results is provided below.

The proposed Grid West design was evaluated from a reliability perspective and found to have the following features that will likely enhance reliability:

A. Independent, centralized state estimator

Grid West will (perfectly?) implement a State Estimator, which will enable operators to evaluate the impact of transmission rights and schedules well

[6] Mr. Mittelstadt has served as the Principal Engineer at the Bonneville Power Administration in the area of transmission system planning. He is a registered professional engineer in the State of Oregon and a Fellow of the Institute of Electrical and Electronic Engineers ('93). Bill has worked extensively on reliability and planning issues and has served as chair of various Western Electricity Coordinating Council committees. He was also on the U.S. – Canada Power System Outage Task Force that examined the causes of the August 14 East Coast outage.

in advance of the hour of delivery, as well as in real-time. This should provide for an improved ability to manage the system and anticipate transmission problems before they occur. SE features include:

- Performs analyses automatically every few minutes based on real-time conditions.
- Able to perform analyses in study mode using preschedules, or planned load/generation patterns and planned outages as input.
- Performs power flow, contingency, and voltage stability analyses.
- Model uses approved flow limits, relaying standards, planning standards, planning and operating margins, system characteristics, Remedial Action Schemes, etc.

B. Centralized Planning/Backstop authority

Grid West will have backstop authority for transmission construction. In the long run this will provide for true one-region planning, assurance that needed construction will get built, and a more reliable system. It will also help ensure that enhancements address the needs of maintaining main grid reliability – including stability controls. Features include:

- A single planning standard will be applied to the Grid West Managed Transmission System (GWMT) using a flow-based approach.
- Develop and maintain transmission and resource models, methodologies and tools to evaluate system performance and resource adequacy.
- Define, collect or develop and share information required for planning, including:
  - Transmission facility characteristics and ratings
  - Demand resource forecasts (capacity and energy)
  - Generator unit performance characteristics and capabilities
  - Potential new generation performance characteristics and capabilities
  - Long term capacity purchases and sales
- Evaluate plans for customer service – transmission purchases and integration requests.
- Review and determine TTC, IROL, and SOL values.
- Assess, develop, document and report on resource and transmission expansion plans and their implementation. [How will it address future market-response (i.e. unplannable) issues, such as new generation in load-sink areas?]
- Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
- Evaluate the impact of revised transmission and generator in-service dates.

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- Work with adjacent areas so that system models and resource and transmission expansion plans take into account modifications in adjacent areas.
- Prepare regional power flow and stability data bases

C. Outage Coordination.

Grid West participants will conduct outage planning amongst themselves. This could provide for outages that more directly support reliability [the TSLG has included market value as well as reliability as criteria] from a region-wide perspective. Features include:

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- Outage coordination is based on the current NWPP process.
- All Grid West participants will coordinate outages through Grid West.
- Facility owners will submit generation (if voluntarily provided by the generator and agreed to be made public) and transmission outages to Grid West (the same as it does today?).
- Grid West will evaluate transmission outage requests against reliability criteria and known generation outages and approve requests, or propose changes [need market criterion] (detailed Grid West authority will be spelled out in the Transmission Agreement).

D. Consolidated Control Area: Single operation of consolidated control area.

The single control area operation of at least BPA, PACE, PACW and ID PWR provides for more direct communication with PNSC and more direct control over generators (as opposed to schedules) in the face of a transmission problem. Also helps to manage all consolidated flow paths in real time. Also provides a better tool, redispatch, for managing transmission overloads than does TLR. CCA features include:

- Primary & Backup control centers, with dual redundancy for all critical control systems.
- Participants are required to provide balanced load and generation schedules, including offers of IOS necessary to support those schedules. Load forecasts and schedules will be validated for accuracy and feasibility by Grid West.
- Central calculation of Area Control Error and dispatch of generation from the IOS resource stack using a Security Constrained Economic Dispatch (SCED) algorithm.
- Re-dispatch generation from the balancing stack to clear congestion.
- Curtail schedules, generation and load as required to maintain reliability.

- Uniform application of WECC/NERC Reliability Standards including all Category A-C Performance levels in both planning and operations.

E. Consolidated Control Area: Balancing Market

The CCA's balancing market provides a clear mechanism for compensating for real time changes to scheduled and unscheduled flows – this may make participants more willing to redispatch for reliability and will give a more direct and coordinated response to congestion. Features include:

- Balancing offers can be made by CCA resources and resources outside the CCA.
- Offers do not need transmission rights attached, except to get the resources to the CCA area of need if the offered resource is outside the CCA.
- Offers are priced by the generation owner, subject to a cap that will be set by Grid West. [What are the economic benefits of a cap that has an impact on transactions? How does a cap work in an opportunity-cost world? These are serious shortfalls for BPA customers in the proposal.]
- Resources are dispatched in merit (price) order, subject to congestion, using the SCED algorithm.

F. Flow-Based ATC & Scheduling

Grid West will estimate ATC/AFC using a flow-based methodology. This is expected to produce a more accurate estimate of available flow capacity on constrained paths than we currently have. Injection/withdrawal scheduling, coupled with flow-based analysis tools and prior actions by TOs will enable Grid West to anticipate congestion based on preschedules and to prepare for or take corrective action in advance of the hour of delivery, reducing rushed decisions in real time. It will also give a better indication of loop flow impacts on congested paths. The benefits of Grid West accomplishing this extend beyond those associated with a TBL-only implementation.

The BPA team used these features to analyze the expected effect of Grid West on reliability. The method used was as follows:

1. NERC disturbance reports for 20 outages over the last 12 years (18 of which wereWest Coast outages) were reviewed to determine the causes of outages.
2. The causes that would likely have been mitigated were Grid West in place were identified.
3. The percentage of causes that would have been mitigated by Grid West was determined.

Following is a summary of the results of this Impact Analysis:

Grid West Reliability Impact Analysis: Causal Review of 18 West Coast Outages

Disturbance Issue*	Mitigated by GW?	Occurrences
Not Ready for N-1	N	0
Insufficient time to readjust	Y	*0*
Not Ready for N-1, N-1	Y	*0*
Not Ready for N-2 (common corridor)	N	4
Not Ready for N-2 (different corridor)	N	2
ROW Maintenance Issue	N	4
Bus Configuration Problem	Y	*1*
Zone 3 or overcurrent relay line tripping	Y	*1*
Sympathetic or improper relay operation	N	11
RAS unavailable or improper operation	Y	*2*
Substandard voltage limits	Y	*0*
Reactive reserve margin not adequate or not monitored	Y	*2*
Tower collapse	N	1
Line(s) falling into underbuild	N	1
EMS System Failure	Y	*0*
Taking risk under weakened system condition	Y	*1*
No means to achieve rapid loading change	Y	*1*
No or poor visibility of system outage conditions	Y	*1*
Equipment tripping off under stress conditions	N	1
Operators not aware of relay setpoint	N	0
Lines tripping on overload (>20 minutes time to readjust)	Y	*2*
Successive lightning strikes	N	0
Lack of Coordination	Y	*1*
Load Shedding Miscoordination	N	3
Equipment Maintenance Error	N	0
Fire	N	4
Operator Error	N	2
Operators not aware of insecure state	Y	*2*
Total Causes		47
Number of causes that might be mitigated by Grid West		21
% of causes that might be mitigated by Grid West.		45%

Note: Causes in bold italicized font are thought to be mitigated by Grid West

Value of Grid West Reliability Improvements:

Given that:

A. There are increasing threats to the security of the transmission system (reviewed above), an

B. A historical review of widespread disturbances revealed that Grid West is likely to provide significant tools for minimizing such disturbances. [except when, if CAISO reports by Car Talk are to be believed, Grid West itself causes the disturbanced.]

BPA has estimated that Grid West reliability enhancements would be likely to reduce the likelihood of widespread cascading outages. More specifically, we believe that Grid West will facilitate the prevention of at least 1 widespread outage every 20 years as compared with business as usual.

Widespread outages are very expensive to society – as was demonstrated by the August 14 East Coast outage which cost an estimated $6.4 billion[7]. The majority of these costs derive from the losses experienced when a whole economy is shut down – losses in production opportunities, the cost of idle labor, lost sales, spoilage, damage to machinery, etc. When summed across a whole swath of society, these costs can be significant. There are also human health risks that rise in the absence of electricity, as well as a risk of social unrest (as was experienced in New York in 1977).

In order to put a dollar value on the anticipated Grid West benefit of increased reliability, BPA applied a modified (more conservative) version of the method used to in the August 14 Outage Report to assess the cost of the East Coast outage[8]. This method references the gross annual economic production for the areas affected by the outage, de-rates this production to a daily figure, then assumes that that production is lost in the face of an outage. BPA's analysis further de-rated lost production (beyond the method used for the East Coast Outage) by 50% to reflect the fact that not all production opportunities are lost when the lights go out – some are not electricity dependent and others will make up for lost production in future time periods. BPA's analysis also excludes utility level costs and the cost of spoilage. BPA also believes GW will help the region avoid more common but less widespread outages, but has excluded those benefits from the analysis.

Our analysis and results are as follows:

Step 1: Determine 2004 Gross Production for the Grid West Region (the states of MT, ID, UT, OR, WA, WY, and the province of British Columbia): US$761,208 million (based on 2004 data from U.S. Bureau of Economic Analysis and Statistics Canada).

Step 2: Determine ratio of weekday to weekend production:

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[7] See "U.S.-Canada Power System Outage Task Force: Final Report on the August 14th Blackout in the United States and Canada", April, 2004 at https://reports.energy.gov/

[8] "*Northeast Outage Likely to Reduce U.S. Earnings By $6.4 Billion*", Anderson, Patrick L and Geckil, Ilhan K, Anderson Economic Group Working Paper 2003-2.

About 85% of wages are earned on weekdays, 15% on weekends (based on US Census Bureau wage/earnings data).

Step 3: Determine daily Gross Production for Grid West Region:
Weekday Production: $2,489,000,000
Weekend Production: $1,098,000,000

Step 4: Determine cost of 1 productive day's electricity outage (reduce daily GP by 50%)
Weekday Outage Cost: $1,244,283,000
Weekend Outage Cost: $548,948,000

Step 5: Divide the avoided cost of one outage by the assumed frequency of avoided outage – 20 years. This yields the expected annual benefit of reliability improvements:

Annual Benefit of avoiding 1 weekday outage every 20 years: $62 million
Annual Benefit of avoiding 1 weekend-day outage every 20 years: $ 27 million

Quantitative Estimate: Increased Transmission Capacity

Grid West will provide new mechanisms for managing transmission. It will serve as a single regional scheduling entity developing and implementing flow-based transmission rights. In this capacity, it will be able to net some schedules and find new transmission capacity due to the flow based analysis. BPA's TBL has begun the process of flow-based transmission rights sales, but it can only go so far in the absence of participation by other regional transmission owners.

Some in the region have said that BPA owns 70-80% of transmission in the Grid West region and should be able to accomplish an efficient AFC market itself. In fact, BPA is much more vulnerable to the effects of other system's management than that figure would suggest. The 70-80% figure is a figure that applies to the "BPA region" which is only a subset of the Grid West footprint. If one cuts the figure another way, say the percent of BPA transmission by line miles in the Grid West footprint, BPA owns only 25%. Following is a table reflecting different measures of BPA's transmission ownership as a percentage of the whole.

BPA Transmission Ownership as a Percent of the Northwest Transmission System

Definition of the "Northwest Transmission System"	BPA percentage by mileage	BPA percentage by capacity**
All Grid West Defined Transmission Facilities	25%	41%
All Grid West Transmission Facilities in for Control and/or Pricing	26%	41%
All Grid West Controlled Facilities	37%	43%
All Grid West Controlled Facilities in US	49%	59%
All Grid West Controlled Facilities in ~~BPA~~ Region*	66%	73%

*removed PacifiCorp Utah and Wyoming facilities, removed 75% of NWE facilities

**using average thermal capability of facilities

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While there is no denying that BPA is a significant presence in NW transmission ownership, these figures illustrate that there is more to be gained from consolidated determination of AFC than can be gained from BPA's actions alone.

Grid West will also provide a market for reconfiguring then selling transmission services on an injection withdrawal basis. This market is expected to expand transmission markets and allow more fluid access to a broader variety of re-sold transmission rights.

Together, these Grid West policies are expected to have the effect of making more transmission available than is presently the case. If more transmission is available, it can be used to expand and make more efficient generation dispatch options.

Method of Analysis

To determine the benefits associated with more abundant transmission, BPA has relied on a study conducted by PacifiCorp on behalf of the RRG's Risk Reward Workgroup[9]. This study used the GridView model to determine what effect more transmission availability might have on generation production costs using 2004 data. This is the same model that has been used to develop estimates of the benefits of eliminating pancakes. The ABB GridView model is a chronological, hourly production cost model incorporating a decoupled (DC) transmission powerflow. GridView uses linear programming optimization to minimize system production costs and for this study use powerflow and production cost data for the entire Western Interconnection (with loads, generation and transmission defined by SSG-WI planning studies[10]). Both the base case and the "with Grid West" cases are highly optimized in the model.

The steps of analysis were as follows:

Step 1:	Run a baseline GridView case which dispatches all Grid West generation on a least cost basis to meet load. Calculate production costs.
Step 2:	Run future cases with only 95% and 90% of transmission capacity available. Calculate production costs. [What is the basis for the assumption of 95% and 90% except PacifiCorp's staff assertion?.]
Step 3:	For a 10% improvement in AFC, subtract the results of the 90% run from the 100% run.[11]
Step 4:	For a 5% improvement in AFC, subtract the results of the 90% run from the 95% run.[12]
Step 5:	For a 3% improvement, pro-rate the benefits calculated in step 3 and 4.

The results of this work were as follows:

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[9] Full text of report, which is integrated with the Depancaking report, is available at the Grid West RnR workgroup website: http://rtowest.com/DP2Info.htm.

[10] The SSG-WI 2003 Planning Report and data description are available at the SSG-WI web site http://www.ssg-wi.com/

[11] The 10% improvement came from subtracting the benefits in the following GridView cases: "Base90% TTC less GW 100% TTC" less "Base 100% TTC less GW 100% TTC"

[12] The 5% improvement derived from subtracting the benefits in the following GridView cases: "base 90% TTC less GW 95% TTC" less "Base 90% TTC less GW 90% TTC."

10% transmission access improvement	$52 million/year in production cost savings.
5% transmission access improvement	$30 million/year in production cost savings.
3% improvement	$18 million/year in production cost savings.

[These assumptions and methodology have only been cursorily reviewed by the RnR group.]

BPA Benefit Estimate:

BPA feels it is reasonable to assume that Grid West could provide between 3% and 5% more transmission availability than is available today. Accordingly, we adopted the $30 million and $18 million figure of expected savings.

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However, we recognize that some of these savings have already been calculated in the "redispatch efficiencies" calculations (below). That is to say, the redispatch benefits assess the benefits of moving from a flawed dispatch - a dispatch born of imperfect market information, pancaked transmission price signals, inaccurate scheduling constraints. It calculates an optimal power flow having removed all these imperfections. In effect, the PowerWorld redispatch analysis already "cleaned up" the dispatch inefficiencies that are borne of imperfect and unnecessarily limited transmission markets. Thus to add these transmission market efficiencies to the redispatch efficiencies would be to double count benefits.

We correct for this potential double counting by reducing the expected transmission capacity related savings by 50%. This is for two reasons: 1) Redispatch efficiencies are only calculated for expected consolidators – BPA, PacifiCorp and Idaho Power. These consolidators constitute about 56% of Grid West load. The remaining unconsolidated load can still stand to add benefits from the redispatch market and single AFC calculation. 2) The ahead-of-real–time redispatch and AFC market will provide for a more efficient unit commitment, which will in turn provide more efficient resources available for redispatch in real time markets. This is a benefit that would go above and beyond the calculated redispatch benefit. [Within the BPA area, the hydro-thermal program already allows for optimal operation of thermal units—that is, commitment—with the hydro resource filling in to serve the remaining load. The commitment benefit would have to be on top of resources that were optimally operated within that area; outside that area there may be some benefit.]

Therefore the BPA estimates of benefits from increased transmission capacity due to Grid West are as follows:

High Estimate (50% of the 5% improvement in AFC benefits):	$15 million/year
Low Estimate (50% of the 3% improvement in AFC benefits):	$9 million/year.

Quantitative Estimate: Regulating Reserves Savings

These benefits accrue when regulating reserves are pooled and the magnitude of expected variation in load is reduced, resulting in a reduced need for regulating reserves. Studies were performed by TBL's Bart McManus in 2005 - he examined the actual variation in loads for BPA, PacifiCorp and Idaho Power over 3 years and 4 seasons. The benefits cited are based on a 60 minute rolling average deviation from average load. The high estimate values the resulting capacity savings, 109 MWs, at $6 per kW month, the low was valued at $4 per kW month (based on PBL trader estimates of the value of capacity). [Is there transmission capacity to deliver regulation from mid-C, say, to Utah?]

Grid West will pool the regulating reserve requirements of those who choose to consolidate control areas. This will allow the variation in load across the consolidating systems to balance out a bit more than they do today which, in turn, will reduce the regulating response capability that the consolidated control areas will need to place under automatic generation control (AGC). Reduced regulating requirements translate into reduced system capacity requirements.

Method of Analysis

In order to measure these benefits, TBL's Bart McManus replicated a study performed by Warren McReynolds for the October 2000 study of RTO West [13]. He collected actual data on load variation for BPA, PacifiCorp and Idaho Power Company for simultaneous time periods in 2004. One week of load data for each season was analyzed.

In order to estimate potential savings in regulation, McManus used 10 second area load data. Area load is a calculated number, total generation minus total interchange. He then calculated the regulation needed using three time frames, 60 minute, 30 minute and 10 minute. For all of these he used the same methodology: calculate a rolling average using 60, 30 or 10 minutes and compare the average to the instantaneous area load

The 10 minute rolling average is more of a traditional regulation benefit, while the 60 minute average represents capacity savings associated with lower requirements for regulation *and* load following. For Grid West regulating reserve benefit we chose to use the 60 minute rolling average, both because it is consistent with the McReynold's study, and because the capacity benefit savings that Grid West is expected to yield should also include those associated with load following.

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[13] "RTO West Potential Benefits and Costs: Final Draft" October 23, 2000, pp. 19-21 at http://www.nwrto.com/Doc/Benefit_Cost_Study_FinalDraft_Oct232000.PDF)

In his work, McManus noted a caveat to his results: the base numbers are much lower than are actually set aside for regulation in the BPA control area – they reflect what the reserve requirement would be (in both the base and change case) were the region to adopt a NERC-approved relaxed approach to meeting the CPS1 regulating requirement. If one were to assume that Grid West would allow the region (and BPA in particular) to reliably shift to this relaxed standard, then the estimated benefits would be higher yet. The calculated thus represent the minimum benefits that would be associated with regulating savings. Indeed, the final output of the RRG's Risk Reward group cited the benefits of relaxing control standards in its high estimate of regulating reserve benefits.

After calculating the estimated reduction in regulation reserve requirements, we assigned a market value to the avoided capacity requirement. The market values used were $4-$6/kW month, as advised by PBL staff. [Because the units on regulation also do load following, the savings may have to include the combined amounts, and deliveries into Utah may be constrained.]

Results of Analysis

The results of these efforts are presented below:

Estimated Benefits of CCA Regulating Reserve Savings
Based on Bart McManus' Analysis of Load Variances in ID,Pac and BPA

	No CCA	CCA	Delta	Low Value	High Value
10 minute moving average					
July 5-11 '04	176.7	102.4	74.3	$3,566,400	$5,349,600
April 12-18, '04	184.8	109.8	75	$3,600,000	$5,400,000
Jan 27 - Feb. 2, '04	182.7	108	74.7	$3,585,600	$5,378,400
July 7-13, '03	181.7	106.2	75.5	$3,624,000	$5,436,000
30 minute moving average					
July 5-11 '04	230.5	140.3	90.2	$4,329,600	$6,494,400
April 12-18, '04	238.9	148.9	90	$4,320,000	$6,480,000
Jan 27 - Feb. 2, '04	241.8	149.7	92.1	$4,420,800	$6,631,200
July 7-13, '03	236.3	146.4	89.9	$4,315,200	$6,472,800
60 min moving average					
July 5-11 '04	275.4	168	107.4	$5,155,200	$7,732,800
April 12-18, '04	287.1	180.8	106.3	$5,102,400	$7,653,600

Jan 27 - Feb. 2, '04	297.1	186.4	110.7	$5,313,600	$7,970,400
July 7-13, '03	287.3	176.6	110.7	$5,313,600	$7,970,400
	Assumed Value:			**$/MW Yr. Low**	**$/MW Yr. High**
	$4-$6 KW/Month			$48,000	$72,000

"Regulation Requirement" calculated as 99% bandwidth of the absolute value of MW deviations between 10-second instantaneous loads and X minute moving average loads at every 10 second interval during sample week.

BPA Benefit Estimate

For the reasons explained above, BPA adopted the benefits associated with the 60 minute moving average analysis.

High Estimate: $8 million/year
Low Estimate: $5 million/year

Quantitative Estimate: Real Time Redispatch Efficiencies

Grid West will operate an important new mechanism for balancing energy amongst those who choose to consolidate. The Real Time Balancing Service (RBS) will allow consolidators to define the source of their balancing energy and, if they wish, make incremental or decremental bids for redispatching scheduled generation to assist other consolidators in meeting their balancing needs at a price that is acceptable to the bidder. Consolidators can also elect to have Grid West redispatch their schedules for economic reasons – in other words, based on the individual consolidators' voluntary bid, Grid West can identify real time trades that would make the system more efficient. [As designed, this is only for balancing energy.]

This differs from today's practices in several ways:

1) There is no real time redispatch market today. As transmission operators (TO's) move into real time, they meet their load requirements (net of commitments borne of external sales) by minimizing the cost of running the generating resources within their control area. Those participating in the CCA can meet their commitments by minimizing the cost of generation amongst all participants in the CCA (via the inc/dec mechanism).

2) Close to real time trades today are hampered by the need to secure transmission rights (a process that takes time). However, as we move close to real time, transmission operators know what the actual transmission limits are. In the Grid West world, an independent transmission coordinator can coordinate inc/dec bids subject only to the physical and security constraints of the transmission system. This allows for more liquid real time markets and provides an opportunity to eke a bit more efficiency out of an already efficient system.

3) Grid West will provide for within-hour trades, a market which doesn't exist today and which will allow the region to eke a bit more efficiency out of an already efficient system.

Thus, Grid West will provide an opportunity to make Northwest generation more efficient. The Consolidated Control Area provides this benefit for those who consolidate by providing an inc/dec based real time balancing service that will allow for voluntary economic redispatch. This inc/dec market will also provide more transparent price signals for more delivery points than is provided today.

Method of Analysis: Detail

These benefits were measured by the Consolidated Control Area modeling group for Decision Point 2. After consideration of various modeling options, the group decided to use the PowerWorld OPF model to get at consolidation benefits. PowerWorld's

Simulator OPF(TM) (Optimal Power Flow) provides simulation of high voltage power system operations in an AC or DC mode, giving analysts a comprehensive view of issues surrounding electric power flows in a transmission grid. PowerWorld has been used by TBL for years to conduct transmission studies. Its OPF capability provides analysis for the optimal dispatch of generation in an area or group of areas while enforcing the transmission line and interface limits. PowerWorld was well suited to this work as most production cost models essentially assume preschedule matches real-time and cannot see sub-hourly movements in loads and resources. In addition, the optimization routines of these other models tend to produce a one owner optimal dispatch for the system, which does not allow for the modeling of the existing business as usual case, as we optimize for multiple owners over multiple system. The price paid for PowerWorld's specificity is twofold: time and data requirements. The model is run in 1 hour increments and requires a great deal of information about existing schedules, transmission ownership, transmission configuration, generator costs and commitment.

As PowerWorld solves one hour at a time the CCA group looked for a number of powerflow cases to build a crude Load Duration Curve model – a model of exemplary operating hours from which one can extrapolate benefits for the whole year. [The sample operating hours have no economic equilibrium component, so it is not clear from running the model if the results come from moving from a suboptimal economic model, which the market would correct, or a suboptimal dispatch.] The key to this task lies is in finding power flow cases where the loads, resources and schedules that are typical for a number of operating hours. [The cases for the spring have very different power flows than those for the fall, because of spring-flush runoff, so the "exemplary" effects are not so exemplary as claimed.]WECC produces operating cases by season and load conditions with the express purpose of illustrating "typical" operating conditions. These cases are coordinated through the WECC process by areas and reconciled. This coordination process allows and indeed forces the parties to enter feasible hydro schedules that respect current operating requirements. [As noted, if hydro is not allowed to vary—that is, only thermal varies—the results are drastically different.] The result is the best estimate of typical patterns of load, resources and schedules across the Western Interconnection that the CCA group could think of. Unfortunately, WECC only produces a few of these each year. Given the changes in hydro operation, the CCA group looked to use the most recent operating cases plus the disturbance case from June 14, 2004. This gave the CCA group 6 different powerflow cases, fewer than ideal, but enough to be indicative. [A judgment with which we do not agree at all.]

WECC power flow data does not include cost information. The heat rate, fuel type, and non-gas fuel cost were entered from the SSG-WI 2003 study work. The gas prices were adjusted to reflect more recent conditions.

The group struggled in deciding how to portray the value of hydro-power. Most resources have a value equivalent to their marginal cost of operations in these super-optimized models – this value is born of basic economic theory that suggests that in the short run, producers bid prices into a market at their marginal cost of operation: If the market clears at a higher price, they are able to cover their fixed cost. If it clears at a price equal to their marginal cost, then at least they haven't lost money (as the fixed cost have to be paid regardless of production levels). If it clears at a price below that which is bid, then that bidder does not sell into the market. Over the long run, if resources don't clear enough money over their marginal costs to cover fixed costs, they are deemed uncompetitive and close down. This theory can be reviewed in any basic economic text. Hydro resources, however, don't fit into the classic model for one primary reason – their fuel supply is limited – if power is sold in one hour, it prevents the sale of electricity from that particular unit of fuel in the next. Thus, hydro must be priced in these models at an opportunity cost not equal to its marginal cost – especially in the Northwest where we have access to California markets where the price tends to be higher. BPA's PBL staff suggested that the right price to use would be the opportunity cost of selling into California in the storable future. [However, this suggestion violates the optimality of the WECC interchange power results, because with different opportunity costs, market prices would change (or the higher or lower opportunity costs might reflect market changes) but there is no change in market transactions—a dubious assumption at best.]

In the end, given the limitations of PowerWorld's linear approximations and the difficulty of predicting hydro value in any particular season, the group decided to enter a variety of opportunity costs for each season in an attempt to capture a range of possible outcomes. High values for hydro opportunity costs would tend to correspond to good storage capability with high market prices (drought with high gas prices where power can be easily stored for sale tomorrow or next week), whereas low hydro opportunity prices would reflect difficult storage or a poor market (e.g. spill). An attempt was also made to limit the quantity of hydro that was available for redispatch in any particular hour by freezing dispatch on all but a few dams – however, it turned out that the model couldn't solve without being able to move all generating units at least a bit. [This statement is not true. The model solved when there were thermal opportunities and hydro was fixed. The hydro assumption is necessary to produce any result, but it is unrealistic at times and certainly over long periods of time. That is, reservoirs cannot be drawn down or added to for up to 1600 hours in a season without affecting hydro constraints. It is also not appropriate to assume that purchases for reservoirs can be disposed of without violating the interchange constraints, and it is not appropriate to violate those constraints for one purpose and not for other purposes, such as market participants taking advantage of market opportunities.] In the end, the unit commitment and generation max and min points from the WECC cases were used to limit the hydro production.

When the areas are consolidated, PowerWorld looks to see if plants that are currently carrying operating reserves (held back below capacity) in one area can be run up to back down expensive generation in another area (moving the reserves to that area). This "balancing energy/redispatch market" is all done respecting transmission limits and the net external schedules. For each case, the model was run with no consolidation of control areas (the base case), for a 4 CCA case (BPA, IPC, PacE, and PacW), and finally for all 10 areas consolidating. The cases were run with hydro opportunity costs of $20, $30, $40, $50, and $65/MWh covering a range of hydro storage and market conditions. The savings were viewed as indicative of the cost savings that could occur each hour, not the specific actions that would be repeated each hour. For example an off peak and on peak 4 CCA run stored 300 MWhs of hydro on BPA's system. The assumption was that BPA could increase its schedule, say to California, at its opportunity cost and sell the extra energy. A rerun of the 4 CCA on peak case with the extra 300 MWh schedule resulted in a net change to BPA's hydro of less than 1 MWh. [This means, of course, that after the first hour, BPA is both buying and selling 300 MW in the same time period.]

Method of Analysis: Summary

To summarize the above discussion, the methods used by the CCA modeling group to estimate redispatch savings were as follows.

For one heavy load hour and one light load hour case, in each season, and for each hydro price assumption ($20 - $65), proceed as follows:

Step 1: Collect data:

Loads: WECC Data
Transmission Configuration: WECC Data
Generating Units: SSGWI Data
Baseline Interchange Schedules: WECC Data

Step 2: Determine baseline production costs:

Run PowerWorld such that, for each separate control area, it minimizes the cost of meeting load net of interchange schedules with each control area's own resources. Calculate baseline production costs (sum the cost of running all dispatched generators for 1 hour).

Step 3: Run PowerWorld such that, for the combined control area, it minimizes the cost of meeting load net of interchange schedules with the consolidated control area's own resources. Non consolidator's costs are minimized as in Step 2. Calculate with/CCA production costs. (sum the cost of running all dispatched generators for 1 hour).

Step 4: Calculate dispatch benefits: Subtract baseline production costs from with/CCA production costs.

Step 5: Multiply results by the number of hours in a year that the case represents.

Results of Analysis:

Below is a brief summary of the results of the PowerWorld runs for the "4 CCA" case – which includes BPA, IPC, PAC East, and PAC West. Complete data sets from the runs (including detailed generator data) will be available on the Grid West website in mid-August[14].

Production Cost Savings Between No CCA and CCA (4 control areas)
Results expressed in $ per hour

Case	**Hydro Base Price ($/MWh)**				
	$20	**$30**	**$40**	**$50**	**$65**
Heavy					
Spring	$12,927	$10,574	$7,670	$5,862	$8,697
Summer	$10,108	$8,702	$6,552	$9,357	$3,218
Autumn	$12,927	$10,574	$7,670	$5,862	$8,697
Winter	$14,618	$13,645	$13,574	$13,531	$19,758
Light					
Spring	$266	$659	$53	$119	$27
Summer	$12,505	$7,975	$3,850	$775	$194
Autumn	$266	$659	$53	$119	$27
Winter	$7,406	$8,030	$8,534	$8,018	$14,312

Seasonal Tabulation

Heavy	**Seasonal Production Cost Savings ($)**				
Spring (1240 hrs)	$16,029,480	$13,111,760	$9,510,800	$7,268,880	$10,784,280
Summer (1648 hrs)	$16,657,984	$14,340,896	$10,797,696	$15,420,336	$5,303,264
Autumn (816 hrs)	$10,548,432	$8,628,384	$6,258,720	$4,783,392	$7,096,752
Winter (1216 hrs)	$17,775,488	$16,592,320	$16,505,984	$16,453,696	$24,025,728
Light					
Spring (968 hrs)	$257,488	$637,912	$51,304	$115,192	$26,136

[14] http://www.gridwest.org/RRG_GridWest_RiskandReward.htm

Summer (1280 hrs)	$16,006,400	$10,208,000	$4,928,000	$992,000	$248,141
Autumn (680 hrs)	$172,368	$427,032	$34,344	$77,112	$17,496
Winter (956 hrs)	$7,080,136	$7,676,680	$8,158,504	$7,665,208	$13,682,272

Annual Totals

Low	$41,181,141
Dow Jones*	$56,416,193
High	$65,457,195

* Weighted by historical price frequency data from Dow Jones

BPA Estimate

BPA staff, in addition to contributing to the exercises that lead to these results, spent time considering the implications of the results and submitting them to a "reality check". The detailed results of these kinds of models can be voluminous, and fairly vulnerable to changes in assumptions. Comparing the production costs in the base case PowerWorld runs to the production costs in the consolidated case, we found that the results showed a reduction in cost of less than 1%. This result is in keeping with and to some degree confirms our belief that the changes proposed are ones that will shift but not revolutionize the way that business is done today.

In order to maintain a conservative estimate of benefits, BPA chose to cite the low estimate as its own low estimate of regional redispatch benefits, and the "Dow Jones" result for its high estimate.

Accordingly, BPA's estimate of annual redispatch benefits associated with the CCA RBS is:

High: $56 million
Low: $41 million

Total power production costs are $600 million for Idaho and Pacific, including that needed for all interchange schedules. So the "savings" are far higher than 1%.

Quantitative Estimate: Contingency Reserve Benefits

Unlike regulating reserves, the Northwest has already pooled its contingency reserves to capture the capacity savings associated with a reduced reserve requirement. The Northwest Power Pool's reserve sharing agreement provides this benefit. NERC requires that transmission operators carry reserves in an amount equal to the greater of the largest single contingency in its control area or 5% of hydro generation and 7% of thermal generation. The Power Pool makes it so that the largest single contingency in the region is far smaller than the 5%/7% rule – allowing all participants to carry the lower figure in reserves. Contingencies are covered (through the end of the hour) via an automated computer program that belongs to the NWPP but resides at the PNSC. A settlement system is already in place for this type of reserve sharing.

However, today almost all participants meet that requirement with their own resources – there is no common close to real-time market for contingency reserves. One of the reasons that there is not an active market for such reserves is related to restrictions that FERC places on affiliates of non-independent transmission providers. We anticipate that the independence of Grid West and the broad information that the CCA will have, together with its provision of a day-ahead contingency reserve market for consolidators (subject to deliverability), will enable more liquid and efficient reserve markets. We believe these more liquid markets will, in turn, lead to a more efficient commitment of generation units ahead of time and a less expensive real time dispatch of generation . [Of course, the hydro-thermal program provides for efficient commitment of generation units ahead of time as well, so those utilities that have access to hydro—probably everybody but PACE have already optimized.] Thus we believe there are benefits to be gained through Grid West's day ahead contingency reserve market – benefits that derive from the ability to meet the existing commitment at a least cost amongst the consolidators, instead of a least cost for each control area. [assuming transmission capacity is available.]

Method of Analysis

This is the only category for which the RRG's Risk Reward Workgroup relied exclusively on existing studies. We did not, among ourselves, have a model and requisite information that could adequately simulate unit commitment. Thus we relied upon the most recent piece of research on contingency reserve benefits in the

Northwest – the Henwood Energy Services study of Grid West benefits commissioned by Snohomish PUD and completed in the fall of 2004[15].

Henwood used their EnterPrise Market Analytics Module, MARKETSYM to estimate the production costs associated with having each control area meet its reserve requirement with its own resources vs. meeting its requirement with a shared pool of generating resources.

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15 "Final Report: Study of Costs, Benefits and Alternatives to Grid West", prepared for Snohomish County PUD by Henwood Energy Services, October 15, 2004. Can be found at: http://www.snopud.com/AboutthePUD/CustomerNews/SpecialReports/gridwest/reference.ashx?p=2680#

Results

Henwood found that a total of $73 million in benefits might be gleaned in the Grid West region from a more efficient operating reserves market. They warned that they had not derated this benefit to reflect the trades that happen in today's system.

BPA Estimate

We de-rated the Henwood Estimates by 44% to reflect the fact that the anticipated consolidators (BPA, PAC and IPC) only represent 56% of the Grid West load. We further derated Henwood's estimate by 25% (in the high case) and 50% (in the low case) to reflect the fact that some efficient trading does happen today.

The results are as follows:

High:	$30 million/year
Low:	$20 million/year

Quantitative Estimate: De-pancaking Benefits

Pancaking refers to the practice of recovering the embedded costs of transmission on a control area by control area basis. This practice can unnecessarily increase the cost of delivered power by creating the appearance of incremental costs where there are virtually none (transmission investments to carry load have already been made). This, in turn, can bias the system against lower cost resources whose output must cross multiple control area boundaries, but whose delivery causes no new fixed transmission costs.

Transmission pancaking can also have a deleterious effect on resource siting – generation resource developers must sometimes work with several transmission owners to secure access to load. As such, they must often perform multiple transmission impact studies, negotiate multiple long term transmission contracts, and anticipate pancaked short term rates for any surplus sales they wish to make. It is possible that this might prevent construction that would be reasonable were price signals more reflective of the incremental costs they would be imposing on the system.

In addition to transmission rate pancaking, there is the potential problem of *transactional* pancaking. This occurs when buyers of transmission must contact multiple transmission owners to coordinate the delivery of power. The time requirements, information barriers, and administrative burdens created by this practice may limit efficient trade across multiple control areas.

It is anticipated that Grid West will eliminate pancaking for all new transactions selling rights on an injection/withdrawal rather than control area by control area basis. This result is partially dependent on the final design of long term transmission service, which won't be complete until after decision-point 2. Thus, these benefits will need to be revisited prior to decision point 4 (whether to sign a Grid West Transmission Agreement).

For its decision point 2 analysis, BPA has only included estimates of the benefits of eliminating the pancaked transmission rate itself – not the benefits of unpancaked loss charges. [Losses, of course, are not fixed costs; they vary with output.] We believe that the depancaking will lead to a slightly more efficient dispatch of generation.

Method of Analysis

Modeling the benefits of pancaking is a challenging exercise. One of the difficult issues to deal with is the idea that transmission that is committed through existing long term contracts is, to some degree, already depancaked – the user has already sunk the cost of using that transmission and will only consider the marginal costs of generation in dispatch. That beneficial effect is, however, mitigated when the contract is in the form of a point to point right which can be resold – then the opportunity cost of using the contract is determined by its value in the market which is, in turn, influenced by the existence of pancakes in short term markets.

To precisely model the effects of pancaking, one would need to catalogue all transmission rights and somehow represent their variable uses (through sheltering, etc.) in an OPF type model that also models the demand for short term and non-firm transmission. The effort required to produce this type of analysis would likely far outweigh the benefits of the estimate.

For decision point 2, BPA has referenced two different modeling efforts that we believe provides bookend depancaking benefits.

The GridView modeling run:

The first effort, a PacifiCorp study using its GridView model, is part and parcel of the modeling conducted for estimating the benefits of increased transmission capacity, described above. This effort assumes the following:

A. Perfectly competitive markets
B. Perfectly optimized transmission usage (excepting the pancaking charge)
C. All transactions face a transmission pancake [which grossly overstates current reality.]

It is this final assumption that makes this BPA's upward bound on the effect of pricing pancakes, as one cannot say that all transmission is currently pancaked. However, some postulate that it is the low cost resources (hydro) that are secured with long term transmission contracts, and that these would be dispatched in a similar way with or without pancakes – so their dispatch shouldn't change in this model. It is the high cost resources whose dispatch is shifted, and these are the resources that are more likely to be traded in short term, pancaked transmission markets. If one accepts this argument, [a big if in many hours and conditions] it leads to the conclusion that it is reasonable to model the system as if all transactions face transmission pancakes.

The ABB GridView model used in this analysis is a chronological, hourly production cost model incorporating a decoupled (DC) transmission powerflow. GridView uses linear programming optimization to minimize system production costs and for this study use powerflow and production cost data for the entire Western Interconnection (with loads, generation and transmission defined by SSG-WI planning studies[16]). Both the base case and the "with Grid West" cases are highly optimized in the model.

An averaged result of the GridView runs shows $20 million in annual savings from depancaking. More information about this study is attached as Appendix 4.

It is also interesting to note that the 2002 TCA Cost Benefit study[17] was conducted with similar methods and found a benefit in the range of $61 million/year [although the TCA study used very different inter-regional natural gas costs—that is, higher differences than exist after completion of the pipeline connecting BC and Alberta to the Middle West—and therefore very different potential benefits. In short, the TCA result would have to be re-run under current natural gas price conditions.]

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[16] The SSG-WI 2003 Planning Report and data description are available at the SSG-WI web site http://www.ssg-wi.com/

[17] " RTO West Benefit Cost Study: Final Report to RTO West Filing Utilities" March 11, 2002, at http://www.rtowest.com/Doc/BenCost_031102_RTOWestBCFinalRevised.pdf Report critique and response at :

The Henwood modeling run:

The Henwood study[18], commissioned by Snohomish PUD and referenced for our contingency reserve benefits also measured the benefits of pancaking. They took the other end of the assumption spectrum by modeling a case where "for the majority of transactions, there are no incremental transmission rate charges"(Page ES3). Only in certain conditions (when BPA paths are full and other non-BPA facilities must be used) does the Henwood analysis reflect pancaked transmission rates. Henwood used their EnterPrise Market Analytics Module, MARKETSYM to make this estimate.

Using these very conservative assumptions Henwood found an annual savings of $4 million resulting from the elimination of the few pancakes that were modeled.

BPA Estimate

BPA used the GridView runs as our high estimate of depancaking benefits, and the Henwood runs for the low benefit. We determined that the benefits counted in the GridView runs may overlap with those accounted for in the PowerWorld estimate of real time redispatch efficiencies (as those runs ''clean up'' the effects of inefficient before-real time market results). However, the Real Time Redispatch efficiencies were only run for the consolidating control areas (BPA, PAC and IPC) – which only represent about 56% of load. Furthermore, the elimination of pancakes allows for a more efficient unit commitment that can lead to more savings than those measured in the PowerWorld runs (the units it was given to redispatch were a function of pancaked transmission rates). Therefore, we reduce the GridView estimate by 50%.

Accordingly, BPA's estimates of benefits due to de-pancaking are as follows:

High:	$10 million/year
Low:	$4 million/year

[18] "Final Report: Study of Costs, Benefits and Alternatives to Grid West", prepared for Snohomish County PUD by Henwood Energy Services, October 15, 2004. Can be found at: http://www.snopud.com/AbouttthePUD/CustomerNews/SpecialReports/gridwest/reference.ashx?p=2680#

Qualitative Benefit Description

Improved Transmission Planning

[See transmission planning discussion above]

One of BPA's primary motivations in pursuing restructuring options is to solve ongoing problems in transmission planning. These problems have arisen in a world where markets have become more competitive and utilities have become more reluctant to accept small individual costs in order to promote the greater transmission good. [Where is the proof of this?] In this new world, the number and composition of market participants have increased and changed - the spirit of cooperation and coordination that existed among the planners in the regulated world is being replaced by competition and confidentiality. In this new world some transmission owners may not have sufficient incentives to accommodate unavoidable adverse consequences of their actions, such as parallel path flow. In this new world, it has been very difficult to get transmission built on a cooperative basis. [except BPA has invested well over $1 billion in the past few years, and generation can moot the need for transmission.]

Having Grid West responsible for transmission planning for the regional grid should provide a more transparent and effective planning process than the coordinated, yet fragmented, planning process it is envisioned to replace.

Grid West is expected to have the following planning responsibilities and processes:

1. Planning for the Grid West Managed Transmission (GWMT) system will be done on a single-system basis to address overall system reliability, transmission service adequacy, requests for longterm transmission service and integration of proposed transmission expansion projects.

2. The planning process will be open to all stakeholders, with participation anticipated from other federal, state, provincial, local and tribal regulatory authorities and siting agencies.

3. Grid West is envisioned to have specific authority for transmission planning and expansion. The full extent of this authority as it relates to the facilities of Transmission Owners will be specified in the Transmission Agreements to be negotiated between Grid West and the transmission owners prior to Decision Point #3, while the connection between planning and requests for transmission rights and participation of other parties in the planning process will likely be identified in Grid West's tariff. The provisions of the Transmission Agreements will be the same for all Transmission Providers,

and they will make Grid West the transmission planning authority for Grid West Managed Transmission.

4. It is anticipated that Grid West's initial backstop authority will be limited to protecting transmission adequacy, responding to transmission service requests for long-term transmission rights and maintaining the transfer capability.

The benefits of Grid West planning include:

A. Consistent assessments of capacity, adequacy and security of the regional grid.

B. Clear authority for main grid planning should ensure the integrity of the grid over time and reduce the probability of region-wide outages. (this benefit has been partially measured in the Grid West reliability benefit estimate)

C. Provides a one-stop transmission planning information source for market participants and project sponsors.

D. Provides independent planning from a one-utility regional perspective that will help identify least cost solutions without regard to existing control area boundaries. (This is probably the most significant unmeasured economic benefit of improved planning, but it assumes that generation and other non-wires alternatives, which cannot be planned in the same timeframe as transmission, are included within the plan "on the come." Because future non-wires solutions are not under the control of the transmission planners, it is unlikely that a plan will include such facilities.)

E. Backstop authority should serve to improve long term reliability by ensuring that transmission reliability investments are made, assuming backstop authority can be implemented..

F. Provides a better mechanism for distributing regional transmission costs., assuming there are no allocation disputes in favor of the disputing parties.

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Long Term Generation Siting Efficiencies

To the extent that the real time redispatch market creates clearer locational price signals, those signals can lead to more rational generation siting decisions in the long run. This improved price signal effect is augmented by the depancaking of transmission rates.

The question to be answered in order to assess this benefit is as follows:

After a builder has taken into consideration the cost of construction, the cost of fuel, the cost of labor and O&M, and the cost of any needed transmission reinforcements/new construction, and the cost of congestion, - is the anticipated cost of rate pancakes across existing and available transmission lines high enough to discourage construction that would otherwise be financially viable? Similarly, is the expected income from a real time balancing service (into which non-consolidators may bid) enough to encourage construction that would otherwise not be deemed economic? [remember, real time balancing is not a generalized market]

Many economists believe that the effect of more rational price signals could be significant over long time horizons, and that this benefit should be one of the most significant reasons to pursue restructuring (together with reliability benefits). [To an extent, these price signals already exist to the extent that new generation needs to pay for and construct new transmission to reach markets for long-term sales.]

We did not have the tools to measure this benefit as of Decision Point 2.

Improved Ability to Monitor Markets

Market monitoring is a function that is essential to Grid West's operation and acceptance – it will help ensure that Grid West's markets and market rules are fair and reasonable. A good market monitor enables an organization like Grid West to learn and adjust to new information and business environments. Thus, to a large degree, BPA sees the market monitor as an essential piece of the Grid West package. It is also important to note that it is likely that a West Coast market monitor will take form in the near future with or without Grid West (development negotiations are underway through the Seams Steering Group – Western Interconnection, or SSG-WI, group). However, Grid West's real time balancing service and centralized reconfiguration auction should provide more specific price information than we currently have access to – this price information will allow the market monitor to perform its job with more accuracy. The value of the pricing information to a market monitor is the incremental value that Grid West brings to the region. [The market monitor faces a considerable challenge, however, with utilities that price based upon opportunity costs, thus limiting its effectiveness. The opportunity cost is a judgment of a seller or buyer of power that is subject to a wide range of valid interpretation. The wide range makes it difficult for a market monitor to challenge and renders that function fairly ineffective for many Northwest transactions.]

Transmission Construction Deferral

We anticipate that Grid West's ability to produce a region-wide calculation of available flow gate capacity, together with its reconfiguration service, will provide new transmission capacity. This was reviewed in the quantitative benefit category of Increased Transmission Capacity. This increased transmission capacity (which allows for more efficient trades of generation) should also enable the deferral of transmission construction. It is possible that there is some overlap between these two benefit categories.

The quantitative benefits associated with construction deferral are derived from decreased and delayed capital carrying costs. Construction benefits, were they calculated, would be based on the time value of deferring capital expenditures and carrying charges.

[This is another case of potential double counting. Space is made available by a CCA or by netting schedules, but to the extent it is used for short-term redispatch purposes, it cannot simultaneously be used for long-term power movements. It needs to be one or the other, but not both.]

More Efficiently Coordinated Maintenance

Maintenance outages may have a significant commercial impact on power suppliers, and the economic impact on customers may be reflected in purchased power adjustment charges or increased risk premiums charged to their utility. Generation and transmission outages can cause purchase of replacement power on short-term contracts, and depending on market conditions, significant costs may be incurred. Transmission outages can potentially form an unnecessary barrier to delivery of low-cost energy to consumers.

The Northwest does have already have a system for coordinating outages, the Northwest Power Pool's Coordinated Outage System. It is not, however, clear that this coordination is sufficient to support economic maintenance schedules. The RRG's Risk Reward Survey revealed that some in the region believe that transmission providers did not provide adequate justification for reductions in transmission capacity during outages. This is illustrated in the BPA-TBL Transmission Capacity E-mail Forum where subscribers receive a steady stream of concerns about the impacts of maintenance outages on the cost transmission maintenance outages.[19] While it is clear that the region actively discusses the occurrence and scheduling of transmission maintenance outages, the workgroup was unable to identify what systematic methods are used to evaluate the economic impacts of transmission outages on transmission customers or the consumers that they serve. [Rational power market players have the incentive to schedule their

[19] Subscribe to capacity-l-bounces@list.transmission.bpa.gov.

outages to maximize the value of their sales. This is another example of how the "unplanned" market may actually produce a beneficial result. The implication of BPA's discussion is that an "unsystematic" method produces an inferior result, a statement that ignores market forces.]

Grid West will improve the outage coordination of participating transmission owners by providing a forum for submission, discussion, evaluation, and coordination of outages that is more detailed than, and happens in advance of, current maintenance practices. [As I understand the TSLG proposal, Grid West simply will take over the existing outage coordination role.] It will provide an advocate for a regional perspective on outage impacts that is not currently possible. As an independent entity, Grid West would not have inherent conflicts of interest or commercial bias in its assessments of maintenance outage schedules. More specifically:

- Grid West will continue to participate in NWPP Coordinated Outage System
- Grid West will ultimately be responsible for maintaining a reliable and coordinated system operation for its managed transmission.
- Grid West will require information on planned and/or forced outages of key transmission and generation facilities [the latter has been specifically forbidden]
- Grid West will review outage requests, considering the following factors:
  - Forecasted peak demand conditions
  - Other known generation and transmission facility outages
  - Impacts on Grid West's ability to honor the awarded Injection/Withdrawal Rights (IWR) and any flexibility of the existing transmission agreements
  - Violation of pre and post-contingent rating of transmission facilities
  - Potential load curtailments
  - Outage plans of adjacent control areas.
- Grid West will publish the initial outage plan 30 days before operating day. Grid West will publish the final outage plan 15 days before operating day. [Grid West will not be developing an outage plan.]

More Efficient Load Following

The real-time balancing and re-dispatch market will not only provide for more efficient use of transmission and the combined generation stack on generation control within the consolidated control area and Grid West footprint, it will allow for more economic load following. Load following is the provision of in-operating-hour generation and interchange capability changes needed to meet in-operating-hour load increases or decreases due to daily variations not covered by regulation service. Consolidation of control areas enables the establishment of balancing markets within the operating hour that include a larger selection of generation available to provide load following and regulation than would otherwise be available. This larger selection and opportunity to capture load diversity allows for access to the most economic units to provide both load following and regulation. It is not theoretically clear whether or not these benefits were measured in the Real Time Redispatch Efficiencies study – that study focused on efficiency benefits associated with redispatch that corrected for inefficient scheduled energy. It may be that further benefits would be measured if they were measured off of actual energy rather than scheduled energy. This subject will require further analysis after decision point 2. [Note the previous comment that load regulation and load following may be accomplished in the Northwest by the same facilities.]

Unmeasured Reliability Benefits

BPA has not included a number of potential reliability benefits in its quantitative estimates. These include:

- The spoilage of stock on hand
- The restoration of industrial facilities (which may take longer than the blackout, and involve investment in equipment repair)
- Utility level costs of a blackstart: lost income for resources/facilities that take time to restore, cost of restoring operations.
- Potential costs of unrest (riots, looting,etc.)

In the previously mentioned NE blackout cost estimate[20], only 55% of the $6.4 billion derived from the loss of GDP – the remainder derived from spoilage, utility level costs, government costs, and indirect lost earnings. If a similar ration were applied to the GDP –alone analysis we used for our benefit estimate, the total would rise to from the adopted $27-$62 million in annual benefits to $60-$138 in benefits – an increase of $33-$75 million in benefits annually.

Also, benefits of avoiding an outage were measured based on 2004 GDP – a base figure that is likely to grow over time.

Additionally, we have not included measurements of potential improvements in non-cascading, less catastrophic outages that may result from Grid West's improvements (particularly those associated with planning).

If these elements were added into the cost benefit equation, they could increase the valuation significantly.

Demand Side Management Benefits

The current Grid West design includes provisions for allowing DSM to participate in markets. These provisions have not been described in any detail for Decision Point 2. If DSM is allowed to fully participate, it could

1) Reduce the cost of generation production by offering more and cheaper resources into Grid West ancillary service markets and real time balancing markets
2) Prevent monopoly pricing in load pockets by creating more competition regardless of transmission availability.
3) Augment transmission construction deferral benefits, as DSM resources do not require more transmission.

[20] "*Northeast Outage Likely to Reduce U.S. Earnings By $6.4 Billion*", Anderson, Patrick L and Geckil, Ilhan K, Anderson Economic Group Working Paper 2003-2.

In turn, allowing DSM to participate in Grid West markets will provide incentives for DSM innovation and product development. [As noted, because of institutional bias toward transmission, it is unlikely that DSM can be planned, because the transmission planners have no control over DSM offers and must commit to transmission or take a chance on the market providing DSM.]

Broader Consolidation of Control Areas

This analysis has been conducted under the assumption that three transmission owners would participate in Grid West: Idaho Power Company, BPA, and PacifiCorp. If more of the Grid West filers were to join the consolidation (a likely scenario, as most of the filers have participated in the development of the CCA and would stand to gain by joining), the benefits would be commensurately higher.

More specifically, the benefits *might* increase as follows (expressed in $millions/year of benefits):

10 CCA benefits:		**High**	**Low**
Regulating Reserves	Based on McReynold's 2000 estimate	13	9
Redispatch	Based on a load-based pro-rata increase in the 3 CCA redispatch benefits	55	40
Reliability	Based on a higher probability of avoided outages	21	10
Contingency Reserves	Based on full Henwood results (which had been de-rated for 3 CCA analysis)	25	17
	TOTAL	**114**	**76**

Unquantified Risks

The risks cited below are arranged into common groupings. They derive from several sources, including risks identified in the RRG's Risk Reward report.

Potential for Transmission-centric Planning.

Risk: This is the risk that Grid West, as a transmission entity, will bias the region towards transmission solutions to problems that may be better addressed by generation solutions.

Response / GW Controls:

- The GW planning/expansion model proposes an economic framework for investment decisions. However, the "good enough" standard for decision-making may cause uneconomic decisions to be made.
- GW will have no interest in financing transmission assets to increase its rate base. [Institutionally, however, it is a transmission organization.]This reduces the risk of transmission-centrism as compared with the status quo.
- GW planning tools will model the entire electrical system – generation, load and transmission, giving it the capability for a holistic look at problems.
- The real time balancing service will reveal clearer congestion relief values than today – aiding in understanding the trade-offs between redispatch costs, generation construction costs, DSM costs, and transmission costs.
- This is an existing risk today, not incremental. [Of course, that is the point; Grid West doesn't necessarily offer an incremental benefit.]

Bias toward Short-Term Solutions

Risk: Potential that Grid West might encourage increased reliance on short term markets –
leading to greater volatility in power costs and rates.

Response / Grid West Controls:

- GW design provisions preserve and bolster existing long term bilateral markets [but it is encouraging short-term balancing market behavior.].
- Participation in ST markets is voluntary.

Conservatism in Operation

Risk: Incentives to ensure reliability might result in Grid West operating the transmission system based on conservatively estimated limits. The flowgate methodology may encourage conservative grid management that protects TO's and minimizes complications for GW at the expense of customers.

Response / GW Controls:

- This is no more a risk than it is today. [Not true. Today, a transmission owner must serve load at minimum cost. Grid West is not likely to care if power costs go up, because it is not directly responsible for power costs, but it does care about a transmission problem, which is its responsibility.] TO's already operate conservatively due to the high priority placed on reliability, and due to a lack of information about the system as a whole. That information problem should actually be solved by GW.

  [Of course, the benefits of today do not rely upon an increase in throughput.]

Lack of True Independence

Risk: That "focused economic interests", large utilities, will capture the Grid West process at the expense of smaller, financially limited parties such as consumers and small utilities (as per theories by Stiegler and Peltzman).

Response / Grid West Controls:

- PNW has a long tradition of public involvement and advocacy organizations. [like those that have produced an expensive salmon program and the nuclear program.]
- A 2004 BPA commissioned report by National Association of Public Administration concluded that the GW bylaws "establish accountability to regional interests while maintaining independence of the governance structure from special interests." [Grid West's accountability is a compromise between independence and regional interests over which people can differ. Because the end user pays all the costs under the ideal Grid West plan, it should have the largest say in what Grid West does. End users do not.]
- See Appendix 5 for further discussion.

Cost Shifts

Risk: Structural changes in power and transmission markets are likely to shift wealth due to:

- Changes in transmission cost recovery
- Shifts from region to region due to increased market access

- New and different incentives for generation transactions
- Changes in transmission rate design, e.g. segmentation.

Response / Grid West Controls:

- Every effort has been made in market design process to minimize cost shifts. An ongoing mantra has been "honor all existing contracts" No effort has been taken to recognize "power" cost shifts.
- De-pancaking is limited to new contracts. [Not true, the reconfiguration market may allow users to dodge real-power losses costs.]
- Voluntary participation in balancing markets means that participants will have control over the impact of the new markets on themselves – if they stand to loose, they won't participate.
- The Decision Point 4 analysis will address the issue of cost shift impacts in detail.

Erosion or Extension of Existing Transmission Rights

Risk: Grid West might cause the reinterpretation, or even abrogation, of existing contracts.

Response / Grid West Controls:

- GW developers have focused on preserving existing contracts and have taken every precaution to assure the continuation of existing rights.
- A recent FERC declaratory order stated that it will honor the region's intention to preserve existing rights and will not attempt to abrogate any existing contracts.

Market Power

Risk: Competitive real time markets might create or exacerbate market power abuse.

Response / Grid West Controls:
This risk is well hedged in the Grid West design. It provides the following protections or improvements over existing systems:

- The real time markets are limited in scope – they only serve the balancing needs of voluntary control area consolidators – so opportunities to exploit the markets are limited. [This statement contradicts the intent to develop inc and dec markets under the CCA.]
- The design supports the continuation of existing dependence on long term bilateral contracts, leaving little to be manipulated in real time markets.
- The more transparent real time markets provided by Grid West reveal prices and make market monitoring easier to accomplish.
- The GW design includes a market monitor independent from any commercial interest.

Market Mismanagement

Risk: GW might take actions that impede efficient operation of the market place and lead to generation that is more expensive than it is today.

Response / Grid West Controls:

- GW Market and Operational Design is substantially different from the retail access models adopted by CA or the East Coast.
- GW is independent of any commercial interest.
- And there is no mismanagement in other areas that are "independent"

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New Opportunities for Inappropriate Gaming.

Risk: That the absence of a physical rights requirement in real time coupled with the requirement for physical rights in day-ahead markets will lead to arbitrage between the two markets – customers may attempt to circumvent the advance rights requirements by gaming the real time market.

Response / Grid West Controls:

- Balanced Schedule Requirement
- Intent to insert detailed provisions that will prevent this

Lags in Market Participation due to Transition Risks:

Risk: That many customers will take a 'wait and see' attitude before actively participating in new markets. They might wait for a year or two or three until the success of the Grid West operations is clearly established .

Response / Grid West Controls:
Grid West's incremental approach to development should hedge against this risk.

Increased Likelihood of Outage During Transition:

Risk: During the transition period, as Grid West brings new systems and people on line, there will be a higher probability of system failure.

Response / Grid West Controls:

- GW and TO operations will remain redundant initially – if not far into the future (BPA's utility level cost estimate reflects this in estimate a net increase, not decrease, in staff) [No cost estmate for the redundancy]
- GW will phase in new operations.
- To the extent possible, existing facilities, people, and systems will be used for Grid West operations.