Phase I Report

Northwest Transmission Restructuring

Evaluation and Description of Alternative Organizational Structures

PNUCC

(Pacific Northwest Utilities Conference Committee)

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1. Objectives of this Project and Report

The Pacific Northwest Utilities Conference Committee (PNUCC) began this project to review alternative organizational changes that might be required or necessary to respond to the changes that are occurring in the electric power industry. The changes in regulatory policy over generation and transmission have been changing slowly since the Public Utility Regulatory Policies Act (PURPA) was passed in the late 1970s. With the passage of the National Energy Policy Act of 1992, (NEPA-92) the Federal Energy Regulatory Commission (FERC) was authorized to encourage the formation of competitive bulk power markets. With the draft Mega-NOPR in 1995, the FERC proposed changes to its regulatory policies with respect to transmission access, terms, conditions and prices to facilitate the formation of competitive power markets.

By the summer of 1995, PNUCC members recognized that FERC's proposed fundamental changes in regulatory policies were likely to lead to a new structure for the electric power industry in the nation and the region. Because of the unique history and structure of the region's electric power industry, PNUCC decided to begin a collaborative evaluation of all feasible alternatives for restructuring the various functions of the utility industry to be compatible with FERC's policies and, more importantly, consistent with the formation of competitive electric power markets. The PNUCC membership includes public and private utilities and the large industrial customers that are served directly by the Bonneville Power Administration (BPA). The Industrial Customers of Northwest Utilities (ICNU) and the BPA were invited to join the PNUCC members in conducting this analysis and in preparing this report.

PNUCC established a Steering Committee involving principals of each of the major groups within the region's utility industry and industrial customers. The objectives of this project were to evaluate all reasonable alternatives that would achieve the project goals, as established by this Steering Committee. The project goals are described in Section 4 below. The Steering Committee formed a Working Group including a broad mix of experts with experience in the utility industry and transmission operation. The Working Group conducted the technical, legal, economic and policy analysis that is contained in this report.

In addition to the analysis documented in this report, several other alternatives were investigated during a screening level analysis. Because of problems, deficiencies or redundancy with specific alternatives that are included in this report, some alternatives were rejected from further consideration. The project has documented the reasons and rationale for screening out specific alternatives but these are not included in this report.

This report represents a Phase I analysis of the key features and the pros, cons and critical actions that are necessary to implement each alternative. No decisions have been made. This project was structured to provide information to the various utility, industry, customer and regulatory agencies that would serve to inform them of the characteristics of all reasonable alternatives. This information should help each of the parties to identify the "best" approaches from their perspective and to provide a structured analysis of the key features of the feasible alternatives.

The Northwest Governors have recently formed a Comprehensive Regional Review to address the larger question of the changes that may be necessary in the region's electric power industry. The Regional Review will discuss and evaluate changes that are needed in the region's electric power industry, giving special attention to the changes that may be required in BPA's role in the region as the competitive electric power marketplace emerges. In the next phase of this project, the questions and requirements of the Regional Review will be addressed by the Working Group. To accomplish the Regional Review's broader public involvement goals, the Working Group will be expanded to include other non-utility, non-industrial interests.

The objectives are twofold during the next phase of this project. The first objective is to provide information to the Comprehensive Review. They will use this information to determine necessary legislative and regulatory changes that they will recommend to the Governors, the Northwest's Congressional Delegation and regulators. The second objective of the next phase is to provide the necessary information for the current transmission owners and users to support their individual choices that will be required to align the transmission system with the needs of the competitive electric power marketplace.

2. Background and Problem Statement

Current transmission ownership is an artifact of the vertically integrated monopolies that are a component of the electric system's infrastructure. Utilities had an obligation to build generation or make purchases sufficient to meet their customers needs. They also had to build the necessary transmission to link generators to loads.

With the passage of National Energy Policy Act in 1992 (NEPA-92) the electric power world changed dramatically. Empowered by the policy changes in NEPA-92, FERC policy moved to allow competition in bulk power supply markets to determine electric power prices instead of regulatory command and control. To stimulate competition, FERC proposes to require transmission owners to operate as common carriers. This means that in FERC's jargon the golden rule is that transmission owners must treat competitors wishing to use a utility's transmission system comparably with how the utility treats itself. This means that transmission owners must provide open access to all qualifying customers with transmission prices, terms and conditions that are comparable to those the utility provides its own power marketing efforts. Transmission ownership has shifted from a strategic asset to a potential liability because FERC will scrutinize all power transactions by transmitting utilities.

The current multi-owner transmission system impedes the formation of competitive bulk power markets because, under current arrangements, transactions that cross several utility systems must negotiate multiple transmission contracts. The multiplicity of terms, conditions and prices for passing through each transmission system is called pancaking because each system's cost and overhead is layered on top of the basic cost of electricity. Pancaking causes administrative and contractual complexity because it requires transmission users to pay the average cost of the entire network of transmission facilities and administrative overhead for each system utilized. As a result, pancaking can significantly increase transaction costs. The higher the transaction costs the more limited the scope of the wholesale power market and the higher the price for both power and transmission.

Based on preliminary work, the region's transmission costs total approximately $1.3 billion per year, including costs of the Southern and Eastern interties. Of these costs, debt service (including returns on capital) is approximately 69 percent and operations and maintenance cost about 31 percent. The total annual costs can be broken down another way based on federal and non-federal ownership. The total regional costs of transmission are comprised of about 41 percent federal and 59 percent non-federal. The non-federal portion includes both public agencies and investor-owned utilities. Figures 1 and 2 illustrate these percentages of the total annual transmission costs.

The transmission system of the Northwest includes 12 control areas. Each control area is responsible for matching load and resources on a moment to moment basis. In order to move energy between control areas, both control areas must agree to the schedule for hourly interchange if the entire system is to remain in balance. These interchanges are scheduled over specific transmission paths, comprised of the set of lines interconnecting two control areas. This rating procedure takes into account the effects of scheduling over a given path on parallel facilities in other parts of the Western Interconnection. The rating method allocates the simultaneous transfer capability of parallel lines among their owners. While similar in concept to the "contract path" methods used in the Eastern United States, the "rated path" method is differentiated by its allocation of usage rights between owners of facilities which can be sold and resold by other parties under a reasonable commercial relationship.

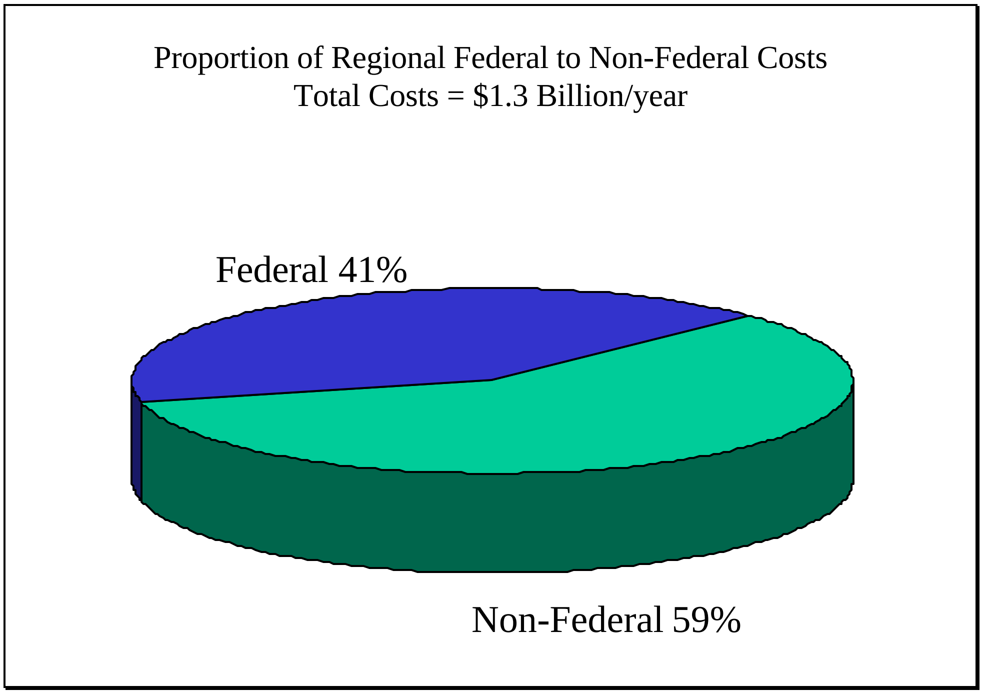

Figure 1 - Proportion of annual costs

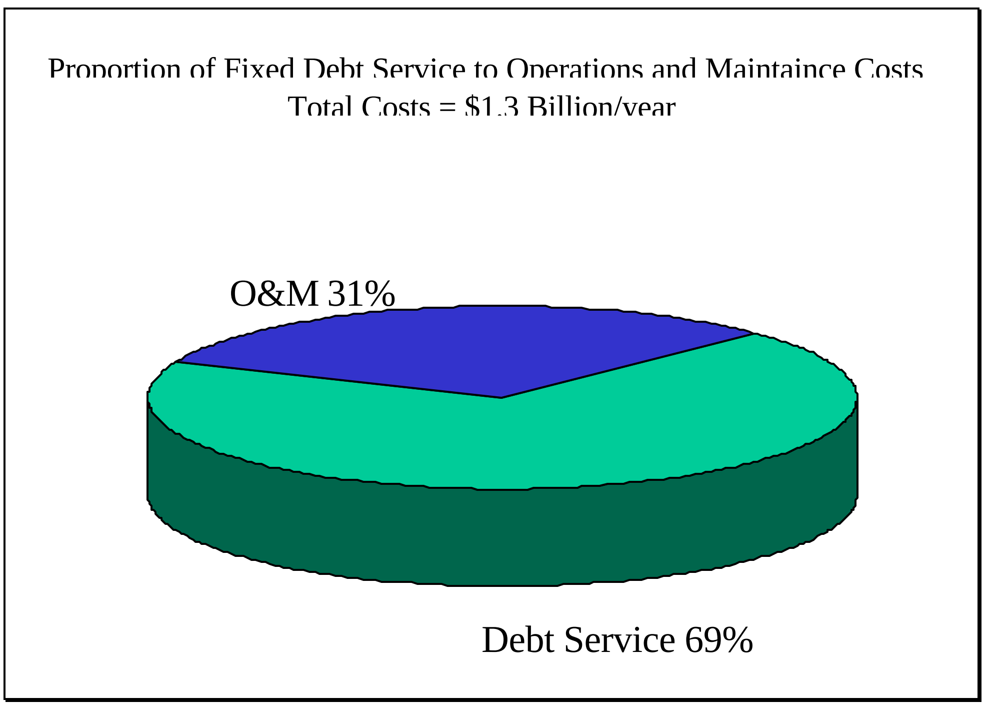

Figure 2 - Proportion of fixed and O&M costs

The rated path method, however, remains an approximation of effects done on the basis of planning studies. Under nominal conditions, it works reasonably well for management of system flows. There are times when inefficiencies can occur because there is no central control of the network to coordinate path usage that will simultaneously maximize the use of a set of parallel paths. In today's multi-owner and multi-operator system, the benefits of a given usage arrangement differ. This is especially true with regard to system upgrades. When an upgrade is needed on a utility's system to remove a bottleneck or to increase transfer capability on another utility's system, the benefits of the upgrade may accrue to parties other than the transmission owner.

Multiple owners make it difficult to know when there is excess transmission capability available. A prospective buyer or seller must investigate each transmission system that might be crossed to determine the availability of transmission capacity. This takes time and complicates transactions and it will continue to be difficult even after utilities are required to electronically post available capacity information.

Another complexity occurs because regulatory control and influence is not the same for all transmitting utilities in the Northwest. FERC's authority over BPA is limited by BPA's other statutes and unique federal status. FERC's legal authority under the Federal Power Act and NEPA-92 is focused primarily on investor- owned utilities. This results in differing legal requirements for FERC regulation of public, private and federal utilities that own transmission.

3. The Opportunity

FERC has determined that nondiscriminatory, low cost, common carrier electrical transmission is a fundamental requirement for the formation of competitive bulk power markets. However, the current transmission system in the region involves at least 12 control areas and the number is increasing. This makes it very difficult for buyers and sellers who wish to cross multiple transmission systems, and requires continual regulation by FERC to ensure that transmission owners are not using their transmission to exercise market power.

The transmission system was not developed, designed or structured to encourage competition. However, the system now in place can be used to enable such competition. For this reason, a changed organizational structure offers the opportunity to reorient the transmission system's planning and operations to facilitate competition in wholesale power markets.

Transmission is the highway system that allows commerce in bulk electric power commodities. Artificial limitations on access, terms, conditions or prices will serve to restrict competition unnecessarily. Transmission restrictions will increase both transmission and power prices by limiting competition. A look at the boundary conditions for transmission may be instructive.

If transmission access is blocked or transmission rates are prohibitively expensive, the only competition would be actions taken by customers, e.g., self-gen, co-gen, fuel switching or conservation. The transmission system can either be a barrier to competition or, if it is operated efficiently and priced appropriately, the transmission grid can provide the highway system needed to stimulate competition in electric power generation.

NEPA-92 set national energy policy on a course toward the formation of competitive bulk power markets. As a result, FERC's regulatory policies are forcing transmitting utilities to operate their transmission systems as nondiscriminatory common carriers that provide open access with terms, conditions and prices that are "comparable" to what they provide themselves. To implement this regulatory philosophy, FERC will have to scrutinize the power transactions of transmitting utilities to ensure that no unfair advantage is being achieved. This increased regulatory scrutiny could limit the utility's ability to compete with other generation.

The need for open access transmission in the Northwest is not limited to the BPA transmission system. All transmitting utilities have some role to play in facilitating the formation of competitive bulk power markets. For this reason, the industry's leaders need to develop a shared vision of the best future structure for the region's transmission system.

There are large potential benefits for customers from reduced bulk power costs from increased competition in generation. As an example, for each 1 mill/kWh reduction in average power prices in the Northwest, customers save about $160 million per year. The benefits of competition will only be possible if the customers have and exercise choices. Without competition there is little incentive to make the hard decisions necessary to reduce power costs.

4. The Goals

The following goals were established by the PNUCC Steering Committee to guide the development and analysis of alternatives. The project was structured to evaluate all reasonably feasible alternatives from a variety of perspectives. These goals were designed to provide evaluation criteria that could be used to identify those alternatives that were likely to meet the requirements of a competitive marketplace.

4.1. Restructuring Goals

- Develop a new transmission structure that promotes competition in power markets.
- Facilitate the broadest possible competitive market for bulk power through non-discriminatory, open access.
- Improve management and coordination of transmission planning, maintenance and operations.

- Plan, upgrade and maintain the transmission system to achieve acceptable levels of system reliability consistent with keeping transmission rates as low as possible.
- Cause the least disruption possible for the Pacific Northwest.

4.2. Economic Goals

- Improve transmission efficiency through improved coordination in planning, maintenance and operations that will secure economies of scale and reduce costs.
- Through increased utilization, keep transmission rates as low as possible, consistent with reliability and meeting the needs of the competitive marketplace.
- Reduce transaction costs by simplifying transmission agreements including the terms, conditions and rates for use of the network.
- No radical cost shifts between areas with higher voltage transmission and areas at lower voltage transmission.

4.3. Transition Period and Policy Goals

- Maintain existing transmission contracts and arrangements through a voluntary transition.
- Provide for a smooth transition from today's industry structure with no significant adverse financial impact on participants.
- Develop a consistent common carrier approach to access, pricing, terms and conditions, including ancillary services.

4.4. Regulatory Goals

- Provide non-discriminatory, open access transmission as a common carrier.
- Separate the transmission system from financial interests in generation market transactions.
- Provide equitable treatment for all transmission users.
- Provide consistent and uniform regulation of transmission rates, terms, conditions, and review the appropriateness of planned upgrades.
- Enhance regulatory efficiency by centralizing regulatory accountability.
- Create regulatory incentives to provide efficient and economical transmission to all users.

5. Alternative Scenarios for Improving Transmission System Efficiency Through a Better Integration of Grid Operations

At the beginning of this project PNUCC reviewed the following alternatives for changing transmission system operations to be consistent with the needs of a competitive power marketplace. These alternatives were discussed and it was decided that additional analysis of each alternative was necessary to be able to determine the costs, benefits, risks and feasibility of any of the possible changes. The following descriptions provide a summary of the features of each alternative. Detailed descriptions are provided in Section 8.0 "Basic Characteristics of Alternatives."

5.1. Reliance on NRTA With No Additional Coordination of Transmission

This alternative implies that regional utilities continue to develop the mechanisms of the Northwest Regional Transmission Association (NRTA); and comply with the dictates of FERC, along the lines implied by the draft Notice of Proposed Rulemaking (NOPR). During this time, the NRTA would develop a mediation mechanism that would allow resolution of most transmission disputes within the region without having to appeal to FERC. The NRTA would also continue the laborious process of rating numerous regional transmission paths to develop estimates of available transmission capacity (ATC), and help resolve ownership rights (taxable property rights) to parallel paths and contract path problems. Although it would be difficult, NRTA would also attempt to develop a regional system of transmission tariffs to reduce the problems associated with pancaking as much as possible. During this time, as competitive power markets continue to develop, regional utilities owning transmission will get increasing numbers of third party wheeling requests under §211 of the Energy Policy Act.

The difficulty with this approach is that to be successful, it requires a high degree of ongoing regional cooperation on transmission issues which may be difficult to sustain as power markets become more competitive. Progress towards achieving increased efficiencies may be slower than under more comprehensive restructuring of the transmission system. Also, if California and other places on the West Coast move to a more centralized transmission structure without the Northwest, that more centralized structure may have spillover effects harmful to the Northwest.

The forces of competition are at play in the West and across the nation. Discussions are currently underway in California, the desert Southwest and in the Western Systems Coordinating Council (WSCC) on alternative solutions to the formation of competitive generation markets and the separation of the transmission function from the power marketing functions of vertically integrated utilities. The result of these discussions in other regions of the West could sweep the Northwest into a WSSC transmission restructuring that meets the requirements of power and transmission systems that have different technical, economic and political needs from those of this region.

5.2. Administrative Split

Transmitting utilities could recognize the changing regulatory and market realities by voluntarily separating their transmission business from the power marketing business. While organizational separation is not likely to divorce transmission decisions from the organization's overall strategy, it would mitigate the exercise of market power by transmission owners. This approach to common carrier operating policies and implementation of the concept of "comparability" is the course proposed by FERC in its Notice of Proposed Rule Making (NOPR) on Open Access Transmission and proposed standards of conduct.

New transmission tariffs and contracts are currently under development as a result of the FERC NOPR and could be used to implement new relationships between the utility's use of their transmission and the use by others. The terms and conditions would be the same for the utility's power marketing business and for all competitive power suppliers and users of the transmission system.

BPA has agreed to follow the full intent of FERC regulation even though there are legal arguments that some of FERC's regulations do not apply to BPA. BPA is also in the process of functionally unbundling its transmission services from its power marketing activities, as are other utilities in the region. This will provide some degree of separation between transmission and generation, however, there will continue to be concerns with the administrative wall between these two functions.

5.3. Transmission Coordination Agreement (TCA)

The transmission owners could negotiate a coordination contract that would attempt to operate and price transmission services in a way that is as close as possible to that which would be provided by a one-owner model. This is conceptually similar to the Pacific Northwest Coordination Agreement (PNCA) that is used to maximize firm power by coordinating hydropower operations.

The TCA negotiation could use the current NRTA as a negotiations forum. However, the current NRTA membership involves both parties that do not own transmission, while at the same time it does not involve all Northwest parties that have a stake in this issue (for example, all transmission users). It might also be difficult for NRTA to reach a consensus coordination contract among the transmission owners, given the diverse interests of NRTA membership since initiatives require a "super majority" for decisions (each member class must agree).

5.4. Independent Grid Operator without Ownership

A new organization could be formed called an Independent Grid Operator - Limited (IGO-L) that would operate the transmission system as if it were owned by a single entity. The IGO-L would be structured to ensure independence from power marketing by creating a new organization with a specific charter that did not allow the IGO-L to engage in power marketing activities. The IGO-L would need the ability to purchase specific power products and ancillary services to maintain the reliability and stability of the grid; but these power transactions would be limited in scope to avoid the IGO-L taking market positions to produce profits.

The IGO-L would plan and operate the collective transmission network to achieve maximum efficiency, maximum utilization and minimum rates. The IGO-L would establish access, terms, conditions and prices for all transmission services.

The existing and new transmission assets would continue to be owned by the original owners. Only the operation of the grid would be under the IGO-L's control. The IGO-L would assume full operational control of transmission facilities through contracts with each transmission owner. These contracts could establish something similar to a blind trust to ensure that the transmission operations are independent of power marketing and competition for power sales.

The IGO-L would be able to plan transmission expansions but would not be permitted to construct or own transmission facilities. For this reason, the IGO-L would have to rely on the existing transmission owners and their eminent domain rights to respond to §211 requests that required the construction of new facilities. If a transmission bottleneck occurs it may not be in the interest of the relevant transmission owner to remove the bottleneck. In this case the IGO-L would have limited ability to relieve the constraint and less than optimal operations may occur.

The IGO-L would be regulated by FERC to establish transmission access, terms, conditions and prices. The transmission system would be maintained by the current owners according to maintenance plans established through negotiations between the IGO-L and the owners. Only mutually approved O&M would be included in transmission rates.

5.5. Independent Grid Operator With Ownership

The Independent Grid Operator with Ownership (IGO-O) alternative would be similar to the IGO-L in terms of independence and operational control. However, the IGO-O would be able to own transmission facilities. This means that the IGO-O could be created by an existing owner of both generation and transmission legally separated into two organizations, one owning only transmission facilities and the other owning only generation. When the IGO-O identified a transmission bottleneck, they could either request the existing utility to construct the upgrade or they could finance and construct the necessary equipment themselves if no existing owners will take on the project at a reasonable cost. The IGO-O would be regulated by FERC to ensure that only necessary facilities be included in the transmission rates charged by the IGO-O.

The IGO could be governed as a public, private or federal organization. The IGO-O would need to be able to access capital markets to allow financing of system upgrades. The alternative governance options also include non-profit and an interstate compact agency which would operate as public agencies without profit incentives.

The IGO could be structured around a federal entity following a legislative separation of BPA into a transmission agency and a power marketing agency. A Federal IGO would require new legislation to establish the new entity and provide access to capital so that the transmission system could be expanded and maintained. While there are concerns with the possibility of political involvement in the federal IGO's actions, this type of involvement could be limited by establishing some degree of regional governance such as that being used for TVA. Through a legislative separation of BPA's transmission into a new agency that is accountable to FERC regulation, the new Bonneville Transmission Agency (BTA) could become the IGO. FERC could use incentive based regulation to encourage improved transmission system efficiency.

A private IGO-O could issue new debt and equity as necessary to maintain and upgrade the existing system. Incentive based regulation could be used under this model as well. Most forms of incentive regulation allow efficiency gains to be shared between transmission users and the shareholders, in this case the taxpayers. To the extent appropriate, and as necessary, a Private IGO could purchase existing transmission assets by issuing new stocks and bonds. New private debt and equity will cost more than the cost of the existing Federal and public debt. This increased cost would have to be offset by increased efficiency due to profit incentives.

5.6. Single Transmission System Ownership - Transco

The split transmission systems could be merged into a single entity that would assume all transmission responsibilities. The merged transmission system would be managed by a single entity that would make all planning, operational, control and contractual decisions. The objective of Transco would be to maximize the use of the transmission system and minimize transmission rates.

This alternative would merge all of the transmission system into a new organization that had ownership of the assets. This new transmission entity would have ultimate responsibility for managing and operating the transmission system as a separate business. This alternative is legally, technically and politically complex. Transfer of assets might require an reappraisal of transmission assets based on value and function. This could lead to increased transmission costs. However, the new organization would have a clear incentive to control costs and efficiencies in planning and operations. Thus, a profit incentive might actually reduce current transmission rates. Whether the efficiency gains will offset the cost increases would need to be analyzed and demonstrated.

5.7. Transition and Regulatory Oversight

In the alternatives listed above it is anticipated that new transmission entities will be accountable to NRTA's contractual and FERC's regulatory policies. It is anticipated that FERC will use incentive regulation wherever possible to encourage efficiency in the planning and operating of the transmission system. All transmission rates should be non-discriminatory and cost based. In advance of new legislation, transmission policy will be more uniform since BPA voluntarily agrees to comply with all of FERC's regulations on transmission for "public utilities" (IOUs).

Current transmission contracts, such as Formula Power Transmission (FPT), Integration of Resources (IR) and the General Transfer Agreements (GTAs), must be honored as the transmission system is integrated into a one owner operation. Either an IGO or a Transco would have to continue such contracts. Current transmission users may voluntarily agree to move to a new contractual relationship with the IGO but this must be a voluntary choice rather than a mandatory requirement. Implementation of an IGO must allow a transition period for all current users of transmission. During this transition period there should not be large shifts in costs or benefits.

There are numerous transition issues related to the conversion of vertically integrated monopolies to competitive deregulated generation markets. The issues related to potential stranded investments have been discussed in FERC proceedings and in FERC's Mega NOPR where it stated:

> "The recovery of legitimate and verifiable stranded costs is critical to the successful transition of the electric utility industry from a tightly regulated, cost-of-service industry to an open transmission access, competitively priced industry."

It would not be appropriate or acceptable to the current transmission owners to establish an IGO that would simply become a mechanism for avoiding stranded costs.

Any IGO that would be established for the Northwest would need to acknowledge this basic public policy issue and provide for ways of ensuring recovery of legitimate and verifiable stranded costs during a transition period. Any utility who might be adversely affected by an agreement with the IGO that would allow the IGO to wheel power from competitive power suppliers to the utility's existing loads will need to be able to seek recovery of stranded costs. The utility seeking to recover these stranded costs would need to comply with FERC policies with respect to the conditions and procedures for demonstrating that there are legitimate and verifiable stranded costs and that FERC will allow the recovery of the stranded costs through the appropriate tariffs.

The categorization of transmission assets into segments is treated differently by each transmitting utility. The current segmentation will need to be reviewed and a decision made on which physical facilities would be included in the IGO. Facilities that are not merged into the IGO could be transferred to the current users of the facilities, to new or existing distribution entities, or covered by tariffs of current owners. The decision as to which facilities are included in the IGO is a significant equity issue that must be resolved. The selection of facilities is a complex decision based on several attributes such as the use of the facilities in the network, the voltage, the current ownership, the degree of involvement of the facilities in facilitating a competitive bulk power market, the pricing structures adopted, etc.

6. Features of Transmission Alternatives

The four basic transmission restructuring alternatives evaluated in this project are shown in Figure 3. This figure shows the basic characteristics of the transmission alternatives in the top part of the matrix. Here the characteristics of the TCA, IGO-L, IGO-O and Transco are compared and contrasted. The bottom portion of Figure 1 shows the five alternative governance structures for the IGO-L and IGO-O alternatives. This portion of the matrix shows the type of entity, the capital structure that would probably be used, the governance and the entity that would most likely appoint the board of directors for the new transmission operator.

Figure 3 - Matrix of Transmission Alternatives

Characteristics of Transmission Alternatives

Basic Characteristics	TCA	IGO-Limited	IGO/Owner	Transco
Transmission ownership	utilities	utilities	utilities/IGO-O	transco
Independence from power mrkts.	none	operational	complete	complete
Need to allocate contract paths	yes	some	no	no
Upgrades				
Who plans	utilities	IGO-L	IGO-O	transco
Who budgets & builds	utilities	utilities/others	utilities/IGO-O	transco
Who has eminent domain	utilities	utilities	utilities/IGO-O	transco
Maintenance				
Who sets standards	utilities	IGO-L	IGO-O	transco
Who sets budgets	utilities	utilities	utilities/IGO-O	transco
Who schedules	utilities	IGO-L	IGO-O	transco
Who performs system maintenance	utilities	utilities	utilities/IGO-O	transco
Operations				
Who schedules	utilities	IGO-L	IGO-O	transco
Who curtails	utilities	IGO-L	IGO-O	transco
Who maintains reliability	utilities	IGO-L	IGO-O	transco
Who back stops ancillary services	utilities	IGO-L	IGO-O	transco
Who has 211 responsibility	utilities	utilities/IGO-L	IGO-O	transco
Who do you ask for service	utilities	IGO/utilities	IGO-O	transco
Who regulates transmission	FERC/PUCs	FERC	FERC	FERC
Transmission compensation	utility tariffs	lump-sum	lump-sum	purchase

		Limited IGO - No Transmission Ownership					**IGO Owner/Operator**					
Issues	**TCA**	**Federal**	**Coop**	**Non-profit**	**Interstate**	**For Profit**	**Federal**	**Coop**	**Non-profit**	**Interstate**	**For Profit**	**Transco**
Type of Entity	Contract	Federal Corporation	Members of the cooperative	Non-profit corporation	Interstate Compact	Corporation	Federal Corporation	Members of the cooperative	Non-profit corporation	Interstate Compact	Corporation	Corporation
Investment capital	None	small capital needs	small capital needs	small capital needs	small capital needs	small capital needs	Private markets	Private markets	Private markets	State Revenues	Private markets	Private markets
Working capital	no change	Reserves & customers	Reserves & members	Reserves & customers	Reserves & customers	Reserves & shareholders	Reserves & customers	Reserves & members	Reserves & customers	Reserves & customers	Reserves & shareholders	
Governance	NRTA	DOE & Congress	Customer Board	Customer Board	Public Board	Private Board	DOE & Congress	Customer Board	Customer Board	Public Board	Private Board	Private Board
Who regulates	no change	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs	FERC/PUCs
Dispute resolution	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC	NRTA/FERC
Incentive Structure	no change	Management performance	Mgt/perf. + dividends	Management performance	Management performance	Mgt/perf. PBR & profit	Management performance	Mgt/perf. + dividends	Management performance	Management performance	Mgt/perf. PBR & profit	Mgt/perf. PBR & profit
Who bears risks	no change	Customers	Customers & members	Customers	Customers	Shareholders & customers	Customers	Customers & members	Customers	Customers	Shareholders & customers	Shareholders & customers
Who files tariffs	Owners	IGO/Owners	IGO/Owners	IGO/Owners	IGO/Owners	IGO/Owners	IGO	IGO	IGO	IGO	IGO	Transco
Who appoints Board?	Customers	President	Customers	Customers	Governors	Shareholders	President	Customers	Customers	Governors	Shareholders	Shareholders

Note: Transco could also be formed under the other forms of governance shown for the IGO.

7. Evaluation of Transmission Alternatives

Each of the transmission alternatives were evaluated to determine their pros, cons and critical actions necessary to implement the alternative. This evaluation is shown in the summary tables that follow. These tables provide a quick overview of the key features of each alternative and the limitations that will affect the ability of the alternative to achieve the goals of this project.

7.1. Base Case

Alternative	Pros	Cons	Critical Actions
Base Case - Administrative Separation + NRTA	1. No coordinated actions necessary	1. System remains fragmented 2. Inefficiencies in planning and operations 3. Pancaking of rates, terms and conditions 4. Transmission responsibility remains with owners of generation 5. Regulatory controls needed to constrain market power	1. None

7.2. Transmission Coordination Agreement (TCA)

Alternative	Pros	Cons	Critical Actions
Transmission Coordination Agreement (TCA)	1. Builds on NRTA agreement. 2. Could simplify tariffs 3. Would coordinate operations and maintenance 4. More transmission providers than under IGO or Transco alternatives so the level of competition in transmission that exists today will continue 5. Governance less of a concern because the TCA has less authority than other alternative entities	1. Transmission responsibility remains with owners of generation 2. Difficult to coordinate planning and no ability to force construction to remove bottlenecks 3. One stop shopping for transmission services will require complex inter-utility agreement. 4. Difficult and lengthy negotiations - Who signs TCA? Owners only or users and owners? 5. Regulatory controls needed to constrain market power 6. Owners may have less incentive to control costs if TCA produces joint tariffs and revenue/costs are shared 7. Transmission and generation functions are not fully separated 8. May be limits on private use of transmission financed with tax exempt funds 9. Obtaining a common tariff under the existing property right system is very difficult 10. Complex annual negotiations for prices and services to be shared 11. Not a very stable contract relationship over time 12. Not likely to be able to agree on a single pricing structure	1. Transmission owners and users reach agreement on who are the parties in the negotiations 2. NRTA has to add functions and be able to plan and order construction to remove bottlenecks

7.3. Independent Grid Operator Without Ownership of Transmission (IGO-L)

Alternative	Pros	Cons	Critical Actions
Independent Grid Operator without Ownership (IGO-Limited)	1. IGO-L would be a new entity with incentives to operate transmission efficiently 2. IGO-L activities focused on operations and tariffs while relying on NRTA/FERC for expansion decisions 3. Possible one stop shopping for transmission services 4. Incentives to maximize use subject to constraints 5. Able to solve problems in real time 6. Some level of transmission competition between parties wanting to construct new transmission 7. Provides operational separation between transmission and generation 8. Would be possible to operate the entire regional grid as a single control area to reduce costs and inefficiencies	1. IGO-L and owners may not agree on what transmission is to include and what price to pay for use of the existing system resulting in complex negotiations 2. IGO-L plans upgrades but cannot remove bottlenecks - must rely on owners to budget and construct 3. Complex contractual arrangements needed between owners and IGO-O with extensive regulatory reviews at start-up by PUCs and FERC 4. §211 Responsibility is with the IGO-L for use of existing and with the owners for new trans 5. Operations could be constrained by both maintenance and construction budgets of the owners 6. Inefficient owners may want to continue to construct new facilities 7. Concerns over market power of owners may remain because of continuing influence on construction decisions by generation owners 8. Prohibition from ownership limits IGO-L's capability to independently maximize system use and efficiency in the long run 9. Public transmission may have limits on private use to retain tax exempt status 10. Governance would be less of a concern than with the IGO-O or the Transco because there is less authority over the system 11. It may be difficult to create financial incentives to motivate the IGO-L to work to remove bottlenecks	1. Transmission owners would need to agree to negotiate transmission contracts with the IGO before formation 2. Regulatory review and approval by PUC 3. Agreement on pricing concepts and methods for addressing constraints

7.4. Independent Grid Operator With the Ability to Own Transmission (IGO-O)

Alternative	Pros	Cons	Critical Actions
Independent Grid Operator with Ownership (IGO-Owner)	1. Would allow IGO-O to form without ownership and gradually increase the amount of the transmission system that they owned 2. IGO-O could maximize use and efficiency by controlling operations, maintenance and construction of new facilities to remove bottlenecks 3. IGO-O would have the §211 responsibility 4. Current owners generation and transmission are separated so they would be free to compete in generation and distribution 5. IGO-O could control like a single owner and offer one-stop shopping 6. A single tariff could be used to provide efficient price signals 7. Some level of competition between parties bidding to construct new transmission 8. Provides a backup constructor for utilities on needed new transmission facilities 9. All operational risk is borne by the IGO-O 10. Can raise funds for construction and working capital. 11. Has the incentive to minimize trans. costs and maximize utilization	1. IGO-O and owners may not agree on what transmission to include and what price to pay for use of the existing system resulting in complex negotiations 2. IGO-O would be a horizontal monopoly and care should be taken to have sufficient incentives to be efficient 3. Complex contractual arrangements needed between owners and IGO-O with extensive regulatory reviews at start-up by PUCs and FERC 4. Public transmission may have limits on private use to retain tax exempt status 5. Incentive regulation's effects on a regional scale are not fully understood at this time	1. Transmission owners would need to agree to negotiate transmission contracts with the IGO before formation 2. Legislation would be needed to transfer control of BPA's assets to IGO-O and provide FERC oversight 3. Need to agree on governance structure. 4. Need regulatory incentives to increase efficiency. 5. Regulatory review and approval by PUC 6. IGO-O needs eminent domain authority 7. FERC approval. 8. Agreement on pricing concepts and methods for addressing constraints

7.5. Single Transmission Company - Transco

Alternative	Pros	Cons	Critical Actions
Transco	1. Provides maximum control over operations, maintenance and planning 2. Single owner makes it possible to maximize efficiency and provide one-stop shopping 3. Performance based incentives could encourage efficiency 4. Removes §211 responsibility from current owners 5. Clean separation of transmission and generation functions 6. Decisions are focused on the transmission function	1. Complex transaction to transfer ownership to a new entity 2. Publicly owned transmission may have limits on private use to retain tax exempt status making transfer difficult 3. Tax consequences of transfer of assets needs to be resolved with the IRS 4. Difficult negotiation required to select facilities for inclusion in Transco and there will be transfer price and cost allocation issues 5. Large scale and economic scope requires close regulatory oversight 6. PUCs and FERC may not agree on regulatory treatment of Transco and this could lead to financial and operational inefficiencies	1. Legislation would be needed to transfer BPA's assets to Transco 2. IRS ruling or letter would be needed to ensure tax consequences of Transco formation 3. Efficiency motivation based on new forms of regulation based on incentives for performance 4. Agreement on pricing concepts and methods for addressing constraints

7.6. Evaluation of Alternative Governance Structures

Alternative	Pros	Cons	Critical Actions
Federal Ownership	1. Make it easier to transfer control of BPA's transmission to the IGO 2. Provides federal powers to speed development 3. Access to capital markets 4. NEPA formalizes the environmental review process and requires a balance of costs and benefits of a proposed federal action	1. Concern over efficiency of federal Agency 2. NEPA requirements for major actions could be expensive and cause delay 3. Political entanglements possible 4. Governance determined by non-regional parties 5. Accountability to federal interests outside the region 6. Performance based incentives difficult 7. Performance risk borne by US Treasury	1. Federal legislation to establish new federal IGO and to transfer control of BPA transmission 2. Legislation to achieve independence and regional control 3. Legislation is needed to give FERC regulatory oversight identical to regulation of IOUs
Alternative	**Pros**	**Cons**	**Critical Actions**
Public - Not for Profit	1. Not motivated by maximizing profits 2. Could be governed by the public interests in the region 3. Might have access to lower cost of capital	1. No profit incentive makes it difficult to provide incentives for performance 2. Board appointments difficult 3. Accountability not clear 4. Performance risks borne by customers 5. Non-profit could be difficult to govern and organizational goals could be conflicting 6. Method for forming the organization and the board are uncertain	1. Need to form a not-for-profit corporation and determine governance and who appoints the board
Alternative	**Pros**	**Cons**	**Critical Actions**
Cooperative	1. All users control the organization 2. Some incentives could be given to management to increase efficiency 3. Members benefit from efficient operations	1. Governance by all users would be difficult and have less independence from power markets 2. Actions may be blocked by the members when it is not in their best interest 3. Performance risks would be borne by the users 4. Voting structure could be complex	1. Establishing a new coop and the governance and membership rules would need to be negotiated with the existing users and owners

Alternative	Pros	Cons	Critical Actions
Interstate Compact	1. Similar to the current system to maintain and construct highways or port facilities 2. Would provide an independent entity that has no interest in the competitive marketplace	1. Difficult to get the four or more state governments to agree on the need and the formation of a new interstate compact 2. Performance risks would be borne by the States 3. Regulatory oversight by both the PUCs and FERC likely	1. Need to pass legislation in each State to form the compact 2. May need both state and federal legislation to provide clear authority for FERC regulation
Alternative	**Pros**	**Cons**	**Critical Actions**
For Profit	1. With proper incentives profit can motivate efficiency. 2. Could issue debt and equity for needed facilities 3. Regulation could be focused on FERC after initial formation 4. Performance risks are borne by shareholders	1. Higher cost of debt and equity 2. Regulation would need to focus on the difficult task of establishing performance based regulations 3. Cost of service could be higher due to higher costs of capital for shareholders and bond holders	1. Investors would be needed to form the corporation before assets could be acquired

8. Basic Characteristics of Alternatives

8.1. Transmission Coordination Agreement (TCA)

8.1.1. Transmission ownership

The current ownership and operational control of existing and new facilities would continue with a TCA. The TCA would formalize an agreement between the current transmission owners as to how they will agree to coordinate operations, planning and maintenance. It may be possible to negotiate a single tariff for use of the combined network under the TCA. If this is possible, the transmission users would see a single set of transmission rates, terms and conditions and the existing owners will agree on the method for collection and allocation of revenues in accordance with the TCA.

8.1.2. Independence from power marketers

TCA defines the minimum acceptable separation between transmission and power for TCA signatories. The operational and planning control continues to be held by the current owners and they continue to receive §211 requests and FERC oversight and regulation. Questions of abuse of transmission market power will continue to arise and NRTA and FERC will be asked to resolve disputes concerning unfair competition.

8.1.3. Need to allocate contract path transmission use rights to owners

TCA continues the current relationships between transmission owners and therefore must define how parallel facilities are rated, how capacity is allocated among owners and how compensation will be distributed to the owners.

Even if a region-wide transmission tariff can be negotiated, the concept of “parallel path” will not be eliminated. Existing owners of transmission will continue to want to use their facilities to transmit their generation to markets. This will make it difficult to resolve disputes over transfer capacity of parallel facilities. Numerous transmission lines have not had a transfer capacity negotiated between parallel owners and these negotiations will need to happen to resolve disputes over rights and available transfer capability.

8.1.4. System upgrades

8.1.4.1. Who plans:

Individual utilities and NRTA. NRTA approval of utility initiated projects would be required before the cost of new facilities can be included in a utility's wheeling rates. Approval criteria would be related to consideration of regional needs, best plan of service, need justification (not contractual bypass), etc. NRTA Board would have authority to initiate a Project Study for a new "regional" project by approval of two out of three classes. It is expected that this type of planning and approval process involving NRTA is likely to continue and be used in the TCA.

8.1.4.2. Who budgets and builds:

Current owners of transmission build needed transmission facilities that are within their control areas. For projects NRTA might recommend for development that have regional benefits, there would need to be a negotiated agreement on how costs would be assessed to all members and how owners would be reimbursed through a regional tariff. The TCA would recognize the current NRTA Access Request Process which allows users to request a utility to either build new facilities or provide alternate access.

8.1.4.3. Who has eminent domain:

Current transmission owners will use their existing authority to acquire new right-of-ways for necessary transmission upgrades.

8.1.5. System operations

8.1.5.1. Who schedules:

Individual utilities. If a regional tariff and compensation methodology can be developed, such that the system can be operated as an integrated transmission system, individual utilities would schedule over paths according to total path capability, subject to reliability limitations rather than existing individual utility contract rights. A mechanism would be developed to compensate parallel owners whose capacity is being utilized. However, the existing owners will likely need to schedule and operate their transmission facilities and control power flows into and out of their control areas. While a TCA might encourage consolidation of control areas, this is not likely to happen unless experience with a regional tariff and compensation methodology indicates that system control can be effectively transferred under a TCA to another party without creating equity or reliability problems.

8.1.5.2. Who curtails:

TCA defines principles relating to curtailments, load dropping, generation redispatch and compensation. Individual utilities curtail in accordance with the TCA based upon the most efficient methods. Compensation schemes would need to be negotiated under the TCA that would compensate those who must curtail because of another party's operational problem.

8.1.5.3. Who maintains reliability:

Individual utilities in accordance with common Reliability Criteria approved by NRTA and defined in the TCA. Each transmission owner would need to (or arrange for the control area operator to) maintain and provide necessary ancillary services such as reserves, voltage control and reactive power such that their system remains within the NRTA approved guidelines. Remedies for failure to meet the NRTA criteria will need to be negotiated and included in the TCA.

8.1.5.4. Who is ultimately responsible for ancillary services:

The current transmission owners (or control area operators) will be responsible for their transmission system's stability and reliability. They will therefore be responsible for providing any ancillary services that are required to meet NRTA criteria and are approved by FERC. Some ancillary services may be purchased on the competitive market and could be provided by parties seeking transmission services. In this case the transmission provider would only need to assure that the necessary ancillary services are provided and that there are backup schemes should there be a problem with any of the ancillary service providers failing to perform.

8.1.5.5. What facilities are needed:

For the TCA to be effective at providing a system wide tariff with unified terms and conditions that will reduce pancaking of tariffs, there needs to be sufficient involvement of the key transmission providers in the region. Ideally, this would involve everyone who currently owns transmission facilities. But, in reality, only those transmission owners who control strategic transmission assets, the backbone of the regional grid, would have to be involved.

8.1.6. System maintenance

8.1.6.1. Who sets standards:

Current transmission owners would need to jointly develop common maintenance standards and practices for the bulk system. The TCA would create the process for establishing and reviewing these maintenance standards. While this is a desirable arrangement, it is not necessary for the TCA alternative because each owner could maintain separate maintenance standards.

8.1.6.2. Who sets budgets:

Individual owners would establish budgets for maintenance on their systems. For there to be a common tariff, the TCA would need to establish, through negotiations, the treatment of maintenance costs judged to be in excess of those required by the common maintenance standards. Also, the treatment of costs caused by reduced reliability from failure to conduct agreed upon maintenance would need to be negotiated.

8.1.6.3. Who schedules:

Individual utilities would continue to schedule their own maintenance but the TCA addresses the coordination of all maintenance schedules to ensure the highest level of transmission system performance. To the extent the TCA dictates maintenance schedules that are inconsistent with the owners wishes, there would need to be an agreed upon compensation scheme that would provide reasonable compensation for coordinated maintenance. NRTA could help to resolve these types of disputes with an efficient and effective procedure.

8.1.6.4. Who performs:

The current owners would perform required maintenance on their transmission facilities.

8.1.7. Transmission compensation to current owners

If it were possible to develop a common tariff the TCA would define how the transmission owners would secure FERC approval and how all signatory utilities to the TCA would implement the regional tariff. This tariff would be developed through and approved by NRTA, however, there may be antitrust concerns due to the fact that the transmission owners are members of NRTA. As members of NRTA the owners have some degree of control over NRTA policies and decisions.

The TCA negotiations will probably have to allow participation of all transmission users. The transmission users involve an even broader group than NRTA members. Retail customers of northwest utilities, including the Direct Service Industrial customers of BPA (DSIs), are not allowed to be members of NRTA. Because these parties have a very real interest in the terms and conditions contained in the TCA's tariffs as well as access terms and conditions, they will probably need to be involved in the TCA negotiations along with NRTA members and transmission owners.

8.1.8. Pricing of services

An option to pricing system-wide use of transmission facilities under the TCA is the "pay-to-get-on, pay-to-get-off" concept, with the system treated by the owners as a regional transmission pool. Revenues received would be allocated to the owners based on a fair and equitable formula to compensate them for their embedded and "NRTA approved" new facility costs and O&M. There are obviously numerous alternative rate designs that could be incorporated in the TCA and it is beyond the scope of this effort in this phase to recommend or predict the results of the TCA negotiations. Like any negotiation, the result will be a jointly determined solution that is acceptable to all parties. The idea that a region-wide transmission tariff be negotiated was an attempt to achieve, as much as possible, the benefits of increased transmission facilities coordination and reduce the transaction costs caused by pancaking of transmission systems.

8.1.9. Who do users go to for service

Individual utilities that own transmission will still be responsible for operating their transmission system. They will grant access and determine bottlenecks that restrict the amount of power transferred within or across their systems.

8.1.10. Who has ultimate FPA §211 responsibility

Individual utilities that own transmission facilities will be responsible for responding to §211 requests. NRTA members will use the NRTA Access Request Process to gain access to a regional system, or in the case of using the region-wide tariff, there will need to be a process for determining available transmission capacity. Since the owners of transmission retain ultimate control over their existing facilities and the upgrades to those facilities, they will continue to have responsibility for addressing all §211 requests for access.

8.1.11. Approvals/legislation

The TCA would be a contract among the transmission owners and other users of the transmission system. As such, the contract might not go beyond the current authority of any of the parties and no additional legislation would be required. Depending on how the region-wide tariff is negotiated, there may be a need for legislation that would clarify the authority of the BPA administrator to constrain transmission operations to the terms and conditions of a TCA. The terms and conditions of the TCA would be reviewed by the state PUCs. The PUCs would need to approve the terms of the contract so that the IOUs would be able to operate under a TCA without substantial regulatory risk. If a common tariff were put in place, both FERC and PUC approvals would be required as a separate matter from the TCA contract.

8.2. IGO Limited to Operation Only (IGO-L) - No Ownership of Transmission

8.2.1. Transmission ownership

Under this model the IGO-L would not be permitted to own existing or construct new transmission. This would focus the IGO-L on the operational and rate issues associated with the existing transmission system. Any necessary upgrades and all §211 requests which require new facilities would continue to be handled by the current transmission owners. All §211 requests that can be met by the existing system would be dealt with by the IGO-L.

8.2.2. Independence from power marketers

The IGO-L would be a separate entity from the utilities and have no interest in the buying and selling of energy as a commodity. The IGO-L would have the authority to purchase necessary ancillary services to be able to maintain transmission system reliability and stability. Except for these limited purchases of ancillary services the IGO-L is independent from the transactions that occur in competitive power markets. To the maximum extent possible, control of decision making processes of the IGO-L must be independent of owners of generation or distribution facilities.

There is also a possible need for the IGO-L to be able to purchase generation to relieve transmission constraints. To the extent the parties using the transmission system will not secure generation to relieve transmission constraints, the IGO-L may have to become a limited market player. This should be minimized through the use of nodal or congestion pricing on constrained transmission paths which should provide incentives for buyers and sellers to negotiate alternative supplies of generation to relieve the bottleneck.

8.2.3. Need to allocate contract path transmission use rights to owners

The IGO-L would be responsible for operation of all transmission within the region. While this would probably begin by continuing to use the current control areas, the IGO-L would reduce the number of control areas over time. Transfer capacity over parallel lines would not be an issue because the entire system would be operated by a single entity without regard to ownership of individual transmission facilities. This will not eliminate the need to rate the physical capacity of lines for operational control and system stability reasons, but this would obviate the need to allocate paths among multiple owners, assuming all owners are IGO participants.

8.2.4. System upgrades

8.2.4.1. Who plans:

IGO-L will perform the regional planning function. IGO-L will recommend those facilities that need to be upgraded and/or constructed. Because the IGO-L cannot own transmission the actual upgrades and construction budgets will continue to be the responsibility of the transmission owners. Only those facilities that are approved by the IGO-L will be included in the regional transmission grid. Facilities that are not approved by the IGO-L will remain the financial and regulatory responsibility of the owning utilities. NRTA would approve the plans developed by the IGO-L.

8.2.4.2. Who budgets and builds:

The owner will continue to be responsible for constructing new facilities within their service territory. The IGO-L will only have the authority to request new or upgraded transmission from the owners. If the IGO-L requested transmission facilities are constructed, the IGO-L will agree to pay for the annual costs including an agreed upon rate of return. The current owners of transmission will continue to have §211 responsibility. Facilities could be ordered by FERC that would have to be built and included in the regional grid.

8.2.4.3. Who has eminent domain:

The limited IGO-L model relies on the current owners of transmission to exercise their rights of eminent domain as necessary to build any new transmission that is needed.

8.2.5. System operations

The primary responsibility of the IGO-L is to manage all aspects of system operations. The IGO-L determines system transfer capability, manages system constraints and allocates curtailments. The IGO-L runs the Energy Information Network (EIN) and schedules available transmission. The IGO-L uses congestion pricing and generation redispatch or other methods to manage grid congestion while ensuring the highest possible utilization factor for the region's transmission grid.

The IGO-L will assure that necessary ancillary services are available to meet system reliability requirements. The IGO-L will establish technical criteria for generators that are, or want to be, connected to the grid and will also determine the contractual criteria that will be a prerequisite for access across the grid. All facilities used to wheel power would be included in the grid but the jurisdictional boundary for grid control by the IGO-L has not been determined. The IGO-L would have the ability to control all generation within the control area established by the regional grid when necessary to maintain reliability of the transmission system. The IGO-L would not be allowed to buy and sell generation as a market player in the bulk electricity commodity markets. Over time it is expected that the IGO-L would lead to a reduction in the number of control areas which could result in scheduling and operating efficiencies. The benefits of consolidation need to be determined and the appropriate number of control areas will be determined over time.

Power system control infrastructure and assets need to be assigned for operation purposes or otherwise made available to the IGO-L. A more complete description of IGO-L functions and services needs to be developed.

8.2.5.1. Who schedules:

IGO-L will dispatch and schedule transmission use. To the extent that users of the transmission system do not arrange sufficient ancillary services, IGO-L will purchase the services that are necessary to ensure reliability. Any ancillary services that the IGO-L purchases will be on a lowest cost competitive bid basis. Users of the system will be charged for the ancillary services that they need but do not provide themselves.

The IGO-L will run the EIN and establish the system constraints that limit physical power flows over specific paths. Each power transaction will be scheduled by the IGO-L to the extent that there is sufficient transfer capacity and the necessary ancillary services have been arranged or are available to the IGO-L.

8.2.5.2. Who curtails:

Constraints on the transmission system will be managed through the use of load curtailment (which IGO-L will either contract for or make the subject of transmission tariffs) or through generation redistribution. The IGO-L will be given some control over the region's generators for redistribution and for providing necessary ancillary services through contractual arrangements with owners of generation. The IGO-L will not be permitted to be a competitive player in the power marketplace. During emergency conditions the IGO-L has the authority to take all actions necessary to protect and recover the system. Suppliers of emergency services will be compensated under terms of a service contract with the IGO-L.

8.2.5.3. Who maintains reliability:

IGO-L will follow reliability criteria established by NERC, WSCC and NWPP or NRTA. The reliability criteria may change under the various restructuring alternatives. (This area needs more thought. There may be some difference between what occurs with a TCA and what occurs with a Transco.)

8.2.5.4. Who is ultimately responsible for ancillary services:

IGO-L will be the party to ensure that necessary ancillary services are provided for each transaction and maintain system reliability for the system as a whole. If the users of the transmission grid do not purchase sufficient ancillary services, the IGO-L will provide the necessary services and charge for these services on a cost basis. In this way the IGO-L will “back stop” the ancillary services that should be arranged by the parties using the transmission system.

8.2.5.5. What facilities are needed:

At a minimum the IGO-L will need to have the power system control infrastructure and key strategic assets necessary for operation as an integrated transmission grid.

8.2.6. System maintenance

8.2.6.1. Who sets standards:

The IGO-L would be the entity responsible for assuring a reliable transmission system. Reliability is a function of both operations and maintenance. The IGO-L will need to set maintenance standards to ensure that key transmission facilities are available when needed. The IGO-L will work with the transmission owners to develop maintenance plans that are consistent with the IGO-L's maintenance standards. The IGO-L will compensate the transmission owners for the costs of maintenance that is conducted in accordance with the IGO-L approved maintenance plan.

8.2.6.2. Who sets budgets:

The transmission owners will set budget levels for the maintenance of their transmission system based upon the maintenance plans approved by the IGO-L. The owner's maintenance budgets will reflect a maintenance plan that, at a minimum, is consistent with the IGO-L required and compensated maintenance. Any owner may conduct additional desired maintenance but it will not be compensated by the IGO-L unless it is consistent with the maintenance plan.

8.2.6.3. Who schedules:

The IGO-L is the party responsible for the assurance of a reliable transmission system. The maintenance schedules must be integrated with transmission system operations to ensure that the availability and efficiency of the integrated grid is maximized. This will require the IGO-L to establish all maintenance schedules and to coordinate maintenance activities so that it has the minimum impact on firm power transactions.

8.2.6.4. Who performs maintenance:

The transmission owners will perform the actual maintenance of their facilities. To the extent it is appropriate and more efficient, the owner and the IGO-L may agree to coordinate maintenance activities through a maintenance contractor.

8.2.7. Transmission compensation to current owners

Owners of transmission facilities would receive an annual lump sum payment from the IGO-L for the use of their facilities. This annual payment would be based on the capital costs of the transmission facilities placed in the IGO-L's control. The annual payment would also include the cost of maintenance performed as required in the approved maintenance plan. The IGO-L's responsibility is to optimize the use of the grid without regard to ownership. From the IGO-L's perspective the costs of using the transmission system are largely fixed. For this reason it will be unnecessary for the IGO-L to determine the capacity of each scheduling path because the IGO-L will not have to allocate transmission costs and revenues based on usage of particular lines. The IGO-L will determine appropriate pricing and compensation methods to assure that the transmission revenues are sufficient to pay the lump sum payments to transmission owners and to cover the IGO-L's other costs.

8.2.8. Pricing of services

Transmission rate making principles will be cost based with a FERC approved rate of return on investment for the owners. The specifics of rate design go beyond the scope of this paper, but it is anticipated that the IGO-L will select the appropriate rate design with FERC approval. To streamline transmission services and eliminate unnecessary pancaking, there will be one rate structure for all transmission within the IGO-L's control rather than additive rates collected by each owner. Ancillary service rates will follow the appropriate FERC transmission rate guidelines. Costs of economic redispatch to alleviate transmission constraints may be allocated based on a formula between the original seller and the actual generator or collected by some other pricing mechanism. Standards for pricing and rate design need to be further developed but will ultimately be the purview of the IGO-L.

8.2.9. Who do users go to for service

The IGO-L will control operation of the existing transmission system but to the extent there are bottlenecks, the requester may need to ask the appropriate owners to build or upgrade facilities. If this request is unsuccessful, the requester may need to file a §211 request with FERC.

8.2.10. Who has ultimate FPA §211 responsibility

The IGO-L is subject to FERC and state PUC regulation. The IGO-L and the utilities have a joint responsibility to process FERC §211 requests. The IGO-L and the utilities will both be subject to §211 requests because they both continue to maintain some degree of control over existing and new transmission facilities. Because the IGO-L does not have the capability to build transmission facilities, the existing owners will continue to have to respond to §211 requests. This means the owners of transmission will continue to be regulated by FERC and there will continue to be concerns that owners will use their control over transmission construction to enhance their competitive position.

8.2.11. Approvals/legislation

To the extent the IGO-L is federal, there will need to be legislation to create a new federal corporation and to restructure BPA. The federal transmission function should be corporately separated from the remainder of BPA's functions. Legislation will be necessary to determine which BPA transmission functions would be included in a federal IGO-L. The state PUCs will need to approve the transfer of some transmission control facilities from utilities to the IGO-L but the cost of these assets are expected to be relatively small.

8.3. IGO Plus Ownership Option (IGO-O)

8.3.1. Transmission ownership

Initially, utilities would retain ownership of most of their transmission facilities. If an existing utility's transmission becomes the IGO, the IGO would retain ownership of the initiating utility's transmission facilities. The utility that began an IGO would have to legally separate transmission from power marketing and distribution functions. The IGO-O would be empowered to construct and own future transmission facilities. Some of the possible events which might trigger future ownership are:

- A new transmission facility is needed but no existing transmission owner is interested in constructing and owning the facility;
- an upgrade of an existing facility is needed such as reconductoring or conversion to a higher voltage class and an ownership transfer is needed to disentangle borrowing for the upgrade from the original owner's mortgage;
- a transmission owner wishes to divest itself of ownership as a part of merger activity or restructuring and needs to transfer assets to a party independent of generation ownership; or
- a new facility is needed within the IGO's system if the IGO was formed from an existing utility.

8.3.2. Independence from power markets

To the maximum extent possible, control of the decision-making process by the IGO-O should be independent of owners of generation or distribution facilities. By having the option to own facilities, the IGO-O can build facilities that are needed to serve regional demands but which an existing owner would prefer not be built because of the effect it may have on the owner's position as a buyer or seller of energy.

8.3.3. Need to allocate contract path transmission use rights to owners

The IGO-O provides network service within its area of operations so no contract path usage rights (i.e., capacity property rights for owners) are needed within the network. However, there will still be a need for such rights to be determined for connections to facilities outside of the IGO-O's operational area and the capacity of IGO-O lines will continue to be rated for system reliability and stability reasons.

8.3.4. System upgrades

8.3.4.1. Who plans:

The IGO-O would do the operational and system expansion planning for all transmission facilities over which it has operational control.

8.3.4.2. Who budgets and builds:

The IGO-O will develop system-wide transmission expansion plans. When additional facilities are needed the IGO-O would invite current owners to build new facilities within their transmission system. If the transmission owner chooses not to build the necessary transmission or the proposed costs of the existing transmission owner are unacceptable to the IGO-O, the IGO-O could finance and build the needed facilities itself.

8.3.4.3. Who has eminent domain:

The IGO-O would need to be recognized as a public utility operating in all of the various states in the region. This would provide the IGO-O with eminent domain so that it could build new facilities.

8.3.5. System operations

All aspects of system operations are the responsibility of the IGO-O. The IGO-O determines system transfer capability, manages system constraints and allocates curtailments. The IGO-O runs the EIN and schedules transmission use. The IGO-O uses generation redispatch, congestion pricing and other methods to manage grid constraints.

The IGO-O assures that all ancillary service and system reliability requirements are met. The IGO-O would be responsible for all facilities used to control transmission of power over the grid. The IGO-O obtains a degree of control over all generation within the regional control area boundary that will be established through negotiations with the existing transmission owners. Such control is used for maintaining reliability and managing system power flows. To the extent feasible, the IGO-O could reduce the number of control areas which would result in scheduling and operating efficiencies. The right number of control areas and the benefits of consolidation need to be determined. The existing transmission system control infrastructure needs to be transferred or otherwise made available to the IGO-O.

8.3.5.1. Who schedules:

The primary responsibility of the IGO-O is the dispatch and scheduling of transmission usage. The IGO-O will run the EIN and provide other information necessary for buyers and sellers of electric power to know transmission availability and where constrained paths are possible.

8.3.5.2. Who curtails:

Constraints on the transmission system will be managed through the use of load curtailment (which IGO-O will either contract for or make the subject of transmission tariffs) or through generation redistribution. The IGO-O will be given the ability to redistribute generation only to relieve transmission constraints and not as a party to any particular power sale. During emergency conditions IGO-O has the authority to use all available generation and load curtailment to protect and recover the system. Suppliers of emergency services will be compensated under terms of a service contract with the IGO-O.

8.3.5.3. Who maintains reliability:

IGO-O will follow reliability criteria established by NERC, WSCC and NWPP or IGO-O with FERC oversight.

8.3.5.4. Who is ultimately responsible for ancillary services:

IGO-O has primary responsibility to ensure that necessary ancillary services are provided for each transaction. IGO-O will be responsible for providing those ancillary services not purchased by users of the transmission system in the competitive market for ancillary services.

The IGO-O will obtain the necessary ancillary services through either its terms and conditions under its transmission contracts or through contracts with those who can provide ancillary services at competitive prices. If the users of the transmission grid do not purchase sufficient ancillary services, the IGO-O will provide the necessary services and charge those parties on a cost of service basis. In this way the IGO-O will "back stop" the ancillary services that should be arranged by the parties using the transmission system.

8.3.5.5. What facilities are needed:

At a minimum the IGO-O will need to control the transmission system infrastructure and key transmission assets that define the regional transmission grid. The specific facilities that are included in the grid will have to be negotiated between the IGO-O and the current owners.

8.3.6. System maintenance

8.3.6.1. Who sets standards:

The IGO-O, as the party responsible for reliability of delivery, would set standards for system maintenance. These standards would be in general agreement with industry standards of maintenance of specific equipment and the unique conditions present in the region's grid.

8.3.6.2. Who sets budgets:

Based on meeting the IGO-O's required maintenance standards, the owner would propose an annual budget for all system maintenance. The IGO-O would approve the budget submitted or negotiate a different budget in line with efforts to control costs consistent with insuring adequate reliability. If the owner does maintenance not approved by the IGO-O, there would be no obligation for the IGO-O to reimburse these costs.

8.3.6.3. Who schedules:

The IGO-O would schedule all maintenance so that outages could be integrated with operational needs by the IGO-O. This will allow the IGO-O to minimize the operational costs of maintenance outages by moving maintenance into periods of low transmission line loadings.

8.3.6.4. Who performs:

Maintenance would be performed by the transmission owner or its agents or under an agreement with the owner. The IGO-O could arrange for maintenance to be performed on those transmission facilities that are owned by utilities. The IGO-O would be responsible for maintenance of those transmission facilities that it owns.

8.3.7. Transmission compensation to current owners

Owners of facilities would receive an annual lump sum payment for the use of their facilities by the IGO-O based on capital costs of the facility and the cost of actual maintenance performed as approved by IGO-O. The IGO-O optimizes the use of the grid without regard to ownership. Existing scheduling path methodology would be unnecessary within the IGO-O's area of control, because the IGO-O would not need to allocate out contractual rights to power flows over particular lines nor would the IGO-O have to allocate transmission revenues to specific transmission owners. Other pricing and compensation methods may be employed to assure the owners of facilities a lump sum payment to cover their costs plus a reasonable rate of return.

8.3.8. Pricing of services

Transmission rate making principles will be cost based with a FERC approved rate of return on investment for the owners. The use of performance based regulation that uses rate caps and incentives will encourage IGO-O to capture efficiency gains. The specifics of rate design go beyond the scope of this paper, but it is anticipated that the IGO-O will select the appropriate rate design with FERC approval. To streamline transmission services and eliminate unnecessary pancaking of transmission there will be one rate structure for all of the transmission within the IGO-O's control, rather than additive charges collected by each owner. Ancillary service rates will follow the appropriate FERC transmission rate guidelines. Costs of economic redispatch to alleviate transmission constraints will be allocated based on a formula between the original seller and the actual generator or they may be handled under some other pricing mechanism. Standards for pricing and rate design need to be further developed but will ultimately be the purview of the IGO-O.

8.3.9. Who do users go to for service

Parties would approach the IGO-O to obtain transmission service under FERC approved tariffs and service agreements. Existing transmission service contracts would be transferred to the IGO-O and contracts would be written between the IGO-O and the transmission owners for service to their wholesale and retail customers. Such contracts would also be filed at FERC. Because the IGO-O has the capability to build new transmission to remove bottlenecks, all requests for transmission service should be the IGO-O's responsibility.

8.3.10. Who has ultimate FPA §211 responsibility

Since the IGO-O can build transmission, it becomes subject to FPA §211 requests directly. This differs from the §211 responsibility under the IGO-L model where the transmission owners must address all requests that require construction because the IGO-L lacks the authority to own transmission facilities. This would replace the current owners of transmission with the IGO-O as the entity with complete control of both existing and new transmission facilities.

8.3.11. Approvals/legislation

To the extent the IGO-O is a federal entity, there will need to be legislation to create a new federal corporation that is separated from BPA power marketing responsibilities. The federal transmission function must be legally and physically separated from the vertically integrated BPA. Federal legislation will determine whether the BPA transmission system is moved to federal IGO or to a new entity, perhaps the Bonneville Transmission Administration (BTA). The state PUCs will need to approve the transfer of some transmission assets from utilities to the IGO-O.

8.4. Transco (System Owner/Operator)

8.4.1. Transmission ownership

The Transco concept is to put as much of the transmission control and management responsibility as possible in the hands of a new entity. The Transco model would probably be a private corporation which would own and operate major transmission facilities that are turned over to it by the current owners, although other governance structures might be possible such as a federal corporation. In some cases legal transfer of assets may not be feasible or cost-effective. The Transco could utilize a contractual relationship with current owners to gain operational control and responsibility for making necessary upgrades similar to the IGO alternatives.

8.4.2. Independence from power marketers

The Transco would be a new corporation that is fully independent of owners of generation or distribution facilities. It is anticipated that part of Transco's charter would prohibit ownership of either generation or distribution aspects of the industry.

8.4.3. Need to allocate contract path transmission use rights to owners

The Transco is an owner of the facilities it operates, so no scheduling path usage rights are needed within its network. However, there will still be a need for such rights to be determined for connections to facilities outside of the Transco's operational area.

8.4.4. System Upgrades

8.4.4.1. Who plans:

Transco plans facilities to meet its customer's needs.

8.4.4.2. Who budgets and builds:

Transco budgets for and builds facilities necessary to meet its customer's needs and recovers the costs of new facilities through FERC's regulatory oversight.

8.4.4.3. Who has eminent domain:

Transco is a regional transmission utility with eminent domain to enable construction of facilities needed to meet its public utility obligations in the states served by the grid.

8.4.5. System operations

8.4.5.1. Who schedules:

Transco will dispatch and schedule transmission use. The Transco will run the EIN.

8.4.5.2. Who curtails:

Constraints on the transmission system will be managed through the use of load curtailment (which Transco will either contract for or make the subject of transmission tariffs) or through generation redistribution. Transco will be given control over part of the region's generators through contracts with generation owners for redistribution and for providing necessary ancillary services to reduce constrained paths and to provide a reliable and stable transmission grid. Transco will not be permitted to be a party to any bulk power sale. During emergency conditions Transco has the authority to protect and recover the system. Suppliers of emergency services will be compensated under terms of a service contract with the Transco.

8.4.5.3. Who maintains reliability:

Transco will follow reliability criteria established by NERC, WSCC and NWPP or Transco. The financial consequences of investments to maintain acceptable levels of reliability will be reviewed and approved by FERC.

8.4.5.4. Who is ultimately responsible for ancillary services:

Transco will be responsible for providing those ancillary services that are necessary to maintain acceptable levels of system reliability. Users of the transmission system will be required to arrange for adequate ancillary services, either securing them from a competitive ancillary service market or through Transco. Transco will arrange for ancillary service by competitive bid and will provide them at cost if the transmission users fail to meet their obligations.

8.4.5.5. What facilities are needed:

At a minimum the Transco will need to have the transmission system control infrastructure and key transmission assets.

8.4.6. System maintenance

8.4.6.1. Who sets standards:

Transco sets its own standards subject to regulation of service quantity by FERC.

8.4.6.2. Who sets budgets:

Transco budgets for maintenance subject to any limitations on cost recovery imposed by the price regulation of the FERC.

8.4.6.3. Who schedules:

Transco schedules maintenance to maximize reliability and minimize cost.

8.4.6.4. Who performs:

Transco or its contract agents perform maintenance on its facilities.

8.4.7. Transmission compensation to current owners

Transco could purchase or alternatively acquire facilities in exchange for common stock distributed to the original owner's individual shareholders, who thus become shareholders of Transco. The former approach might be preferred for acquiring ownership by governmental agencies, while the latter approach could be used for investor owned utilities or cooperatives.

8.4.8. Pricing of services

Transmission rates will be regulated and approved by FERC based on transmission cost. The use of performance based regulation that uses rate caps and incentives will encourage the Transco to capture efficiency gains. Rate design will be proposed by the Transco and approved by FERC. There will be one rate structure for use of all regional transmission that is within Transco's control rather than additive rates collected by each owner as in the past. Rates for ancillary services will follow the appropriate transmission rate guidelines established by FERC. Dollars for redispatch will be allocated based on a formula between the original seller and the actual generator or through another appropriate congestion pricing methodology.

8.4.9. Who do users go to for service

Transco contracts with current transmission owners directly for use of their transmission facilities. All parties seeking use of the transmission system would then see one-stop-shopping with Transco.

8.4.10. Who has ultimate FPA §211 responsibility

As a transmission provider, Transco is subject to FPA §211. Former owners of facilities are no longer transmission providers.

8.4.11. Approvals/legislation

The federal transmission function must be separated from BPA. Legislation will determine whether the BPA transmission system is transferred to Transco or whether it remains in federal ownership under a new entity, Bonneville Transmission Administration (BTA). Transco secures the use of the federal facilities through an exclusive lease or use permit. The state PUCs and utility boards will need to approve the transfer of assets from utilities to the Transco.

9. Organizational Structure

9.1. Transmission Coordination Agreement (TCA)

9.1.1. Contract Between Existing Parties - (TCA)

Contractual arrangement among Northwest transmission owners, users and non-utility suppliers.

9.1.1.1. Capital structure:

Individual utilities provide own capital for new facility construction. The TCA does not form a new entity therefore there is no change in the current transmission owners and their capital structures would remain unchanged under a TCA.

9.1.1.2. Governance:

NRTA Board would provide executive level, equal class oversight of the TCA. Provisions of the TCA would be coordinated, developed and implemented through the NRTA Committee structure.

9.1.1.3. Who appoints board:

Board members would be elected by their class in accordance with NRTA Bylaws.

9.1.1.4. Who regulates:

FERC and state PUCs.

9.1.1.5. Who resolves disputes:

Disputes would be resolved under the current NRTA guidelines that call for facilitation and arbitration before FERC review and resolution.

9.2. Independent Grid Operator (IGO-L or IGO-O)

9.2.1. Federal Corporation (FIGO)

A federal corporation that operates the transmission systems of various transmission owners in the Northwest, including any facilities constructed through FIGO funding.

9.2.1.1. Capital structure:

FIGO will have direct access to the capital markets. FIGO funding ability will be completely separate from BPA and Congressional appropriations.

9.2.1.2. Governance:

FIGO will be headed by an administrator reporting to DOE and Congress.

9.2.1.3. Who appoints board:

The administrator is selected by the President.

9.2.1.4. Who regulates:

FERC will need to have regulatory control over the FIGO with authorities identical to what FERC currently has over public utilities (Investor Owned Utilities). FERC will regulate price, terms and conditions of service provided by the FIGO. FERC will also regulate the payment by the FIGO to the existing transmission owners. The state regulatory agencies will have regulatory oversight on the siting of new transmission facilities.

9.2.1.5. Who resolves disputes:

The FIGO will rely on NRTA/FERC Dispute Resolution. Appeals will go to FERC to make sure that the FIGO is responsive to the Dispute Resolution mechanism.

9.2.2. Cooperative IGO

A cooperative IGO membership could be limited to those entities who transact business on the transmission grid operated by the IGO. Over time, this might even be expanded to include end-users as retail wheeling becomes a reality. However, membership would not have to be a requirement for use of the grid. Membership would instead confer on its members some control over governance, including operations, capital investment decision making, and allocation and use of margins.

9.2.2.1. Capital structure:

The cooperative could be nominally non-profit but could establish financial goals which would cause margins, i.e., an excess of revenue over expenses, to be generated. A cooperative's capital structure would not be limited by its cooperative nature. Cooperatives have access to capital markets, as well as the ability to use margins for capital projects. The distinguishing feature of a cooperative is the use of those margins. Margins are allocated to members in some manner and can be paid out to members within the current year time frame or at a later date. For example, in rural electric cooperatives, members agree to give the cooperative interest free use of margins for a given period of time. Another model is the REI model, or mutual insurance model, where excesses are returned immediately following the closing of the year in question. This ability to retain all or some portion of the margins generated by the IGO for upgrades or expansion of the transmission system could be a benefit to an IGO. All members of the cooperative would benefit from any excess revenue over expenses to the extent these excesses were reinvested in the cooperative.

The cooperative model also has some built in regulation features. Members are users and so have an incentive to keep rates as low as possible. However, they also have the ability to decide on their financial objectives (stated as TIER, DSC, or return on investment). Therefore, because members are both users and stakeholders, a tension exists which tends to result in self -regulation. Passing the incentive for both efficiency and performance down into the management of a cooperative can be done with all the tools available to any other type of organization.

9.2.2.2.Governance:

Governance in a cooperative is usually by board directive to a compensated CEO or general manager. Voting can be one-man-one vote, proportional based on some investment, or within membership classifications such as the RTA's. This is one of the significant advantages and at the same time a disadvantage of the cooperative structure. The advantage of governance by the users of transmission is that there is a direct feedback mechanism to management based on performance as seen by the users. This will provide management incentives for efficient operations. The users are the decision makers as well as the stakeholders; the structure provides for self-regulation. A problem might arise to the extent that users of the transmission system can influence IGO decisions in a way that is perceived to provide advantages to themselves.

When members sit on the IGO cooperative board, especially if representing a class of members, they should be acting in the best interest of that class first and of the IGO second. The members of the board of directors should not directly advocate alternatives that are in their parent organization’s competitive interest but this is difficult to regulate and control. This is often a source of conflict within cooperatives (parent company vs. board), but also its source of strength.

Cooperatives often employ committees which report directly to the board. The committees are made up of employees of the members and staff of the cooperative. The committee structure is an excellent way for members to insure that their needs are reflected in cooperative decision making and to insure efficient operation of the cooperative.

Issues tend to arise around how the board interacts with the paid management of the cooperative; i.e., how much day to day control will be vested with management, and what remains as the boards responsibility. This is a governance issue which will need to be addressed in any IGO structure and is not limited by a cooperative structure.

9.2.2.3. Who appoints board:

In a cooperative, the board is made up of member representatives. If all members of the cooperative cannot be on the board due to sheer numbers, elections are held. Board seats could be allocated on type of entity, similar to the RTA's, by sub-region, or by type of organization (IOU, PA, IPP, regardless of transmission status). There does not appear to be a limitation on how the seats on the board are allocated (this needs a legal review).

9.2.2.4. Who regulates:

FERC would obviously provide regulator oversight over the co-op’s decisions. In a cooperative structure many of the questions of serving two masters (ratepayers and stockholders) would be mitigated because the ratepayers are stock- or stake-holders. This could give the cooperative IGO more latitude to do what is in the best interest of the cooperative members who are users of the region’s transmission system.

9.2.2.5. Who resolves disputes:

Rely on NRTA Dispute Resolution. Appeals will go to FERC.

9.2.3. Non-Profit or Publicly Owned Corporation

9.2.3.1. Capital structure:

The public entity would have access to conventional capital markets. However, to the extent that substantial use of the transmission network is by non-tax exempt parties, tax free financing will probably not be available. There is a remaining tax issue with respect to existing publicly-owned transmission facilities and their use by non-tax exempt parties that needs to be reviewed further.

9.2.3.2. Governance:

Public IGO will be headed by an administrator reporting to a board of directors.

9.2.3.3. Who appoints board:

A variety of stakeholders could have authority to appoint the board. This is a difficult decision because there does not appear to be any focus as to who the appropriate parties might be to involve in the selection of board members.

9.2.3.4. Who regulates:

A publicly-owned IGO may not be subject to FERC regulation in the same fashion that a privately-owned IGO would be. However, since both the IGO and participating utilities would be subject to §211 requests, it is unclear that there is practical import to this difference. But, it remains an issue with respect to regulatory accountability for an entity that would have significant involvement in facilitating competitive power markets.

9.2.3.5. Who resolves disputes:

To the extent a publicly-owned IGO can be made to be subject to the same FERC regulations, FERC and NRTA would continue to resolve disputes. If FERC jurisdiction over publicly-owned utilities is limited, then there may not be a set process for dispute resolution. A public corporation could be held accountable through binding arbitration or through court review of the IGO's decisions and the charter of the public corporation.

9.2.4. Interstate Compact

An Interstate Compact Agency would create a four state compact including at least Washington, Oregon, Idaho and Montana. It might be necessary to include Wyoming and Utah in the compact to provide control over critical transmission facilities. The Interstate Compact could be a new entity or an expansion of the role of the current NWPPC.

9.2.4.1. Capital structure:

Funding - The IGO financial resources come from the financial resources of the states in the compact. The IGO capital resources are small if the IGO does not own or fund construction of facilities. If the IGO does own and fund facilities, then the capital requirements could be large and the credit of the states may be necessary to generate the necessary capital.

Planning - Planning is coordinated by the IGO planning staff with input from the utilities, or alternatively, the RTA could provide for planning services. The IGO planning staff would be a relatively small staff if the RTA continues its planning role. The IGO planning staff becomes larger if duties are consolidated under the IGO. A small IGO planning staff working with the RTA would develop a Regional Transmission Plan. The IGO staff would make the final decision if agreement could not be reached through NRTA.

Construction - Construction additions and upgrades would be done by the utility owners under the IGO-L model. In this model funding of capital additions is provided by the owning utilities. In the event that utilities can not or will not build, the IGO-O would have eminent domain and would build upgrades if necessary to facilitate transmission access and remove constraints. The IGO-O is the first level for resolution of access issues. Furthermore, the IGO-O conducts the planning and decides what gets built. If a utility that owns transmission proceeds with construction that is not within the IGO's Regional Transmission Plan, the facility would not be allowed to be included in regional transmission rates. If the utility does not proceed with construction of facilities identified in the regional transmission plan, the IGO-O can issue bonds or otherwise finance the project, take bids for construction, own the facility and collect costs by adjusting transmission rates.

9.2.4.2.Governance:

Under the Interstate Compact IGO model, governance is accomplished through state government appointed officials. State appointed officials could also establish a separate utility/user group board for the purpose of overseeing the IGO.

The span of control is to operate the regional transmission grid and to adopt a Regional Transmission Plan and maintenance plan. The IGO is a state agency that is employed by the states or the federal government to operate transmission and achieve publicly stated goals. Under an expanded NWPPC role the council would not only be responsible for a Regional Power Plan, but would also be responsible for developing a Regional Transmission Plan and operating the regional grid. The IGO sets common reliability criteria and standards with the objective of optimizing the use of the grid and producing the lowest possible transmission rates.

O&M crews continue to be employed by the owning utilities. The IGO sets standards, approves budgets and schedules maintenance outages.

9.2.4.3. Who appoints board:

The Governors of the states involved in the regional grid would appoint the board of directors in a fashion similar to that used to appoint council members.

9.2.4.4. Who regulates:

This is a difficult question because of the roles of the state and federal government. Ideally, FERC would regulate the Interstate Compact in the same manner as they regulate public utilities. However, it is unclear whether the states could or would allow the FERC to regulate the states operation of a regional grid. This issue needs more analysis.

9.2.4.5. Who resolves disputes:

Disputes could be resolved by NRTA and FERC if the Interstate Compact was accountable to FERC. If the states choose to regulate the compact, there would need to be an independent regulatory body like the PUCs that had regulatory jurisdiction over the compact.

9.2.5. For-Profit Corporation

9.2.5.1. Capital structure:

Capital would be raised by the sale of publicly traded common stock and of public bond offerings. Stock would not be held by any owner of capital Needs would vary:

- For an IGO, initial capital requirements would be low to cover cost of control centers and communications;
- if an IGO exercises the ownership option (IGO-O), the capital requirements would be substantially greater; and
- for a Transco, capital needs would be immediate to facilitate ownership transfer.

9.2.5.2. Governance:

The IGO or Transco would be governed by a board of directors. Board members would have to be independent of any generation and distribution system owners or of the other system users which take service from the IGO or Transco.

9.2.5.3. Who appoints board:

Board members would be elected by the shareholders of the corporation.

9.2.5.4. Who regulates:

Price, terms and conditions of service would be regulated by the FERC. Siting of transmission lines would continue to be regulated by state statute unless federal legislation were passed giving the FERC authority for siting, similar to what FERC holds for natural gas and oil pipelines.

9.2.5.5. Who resolves disputes:

Disputes would be subject to local alternative dispute resolution mechanisms under the NRTA Governing Agreement with appeal rights to the FERC.

10. Definition of Transmission Facilities to Include in Grid

10.1. Geographic Area and Specific Transmission Facilities to be Included in the Definition of the Transmission System

One of the major unresolved issues in this restructuring study is the extent of facilities to be included in the IGO/Transco structures described in the previous sections. Resolution of this issue is difficult, if not impossible, without the more detailed evaluations of pricing and operations that will occur in Phase II of this study. However, the discussion devoted to this issue in Phase I has thrown light on two different questions to be addressed:

10.1.1. System access

What facilities should fall under the contractual arrangements of an independent operator's regional tariff in order to provide all wholesale customer's access to power markets and to effectively transfer to the IGO/Transco the responsibility of responding to Section 211 transmission service requests?

10.1.2. System control

What facilities should be under the physical control of an independent operator in order to obtain the advantages and efficiencies of a regional transmission system?

10.2. Geographic Area Under Consideration

For the purposes of the discussion that follows, it is assumed that the IGO/Transco would operate the transmission system of the existing operators whose control areas fall within the portion of the Northwest Power Pool within the United States. The geographic area under consideration, therefore, is defined by transmission facilities within Oregon, Washington and Idaho and the major portions of the transmission facilities in Montana, Wyoming and Utah whose owners are members of the Northwest Power Pool.

10.3. Transmission Facilities Needed for Wholesale Access and to Insure IGO/Transco Section 211 Responsibility

In order for an IGO/Transco to meet the needs of all the users of the system, facilities which connect wholesale electric utilities to the transmission system need to be included under the contractual arrangements of the regional tariff, whether or not they fall under the physical control of the IGO/Transco. A second customer access concern is the extent of the facilities which need to be under the contractual control of an independent operator if transmission owners are not to have continuing obligations under §211 of the Federal Power Act. The treatment of these contractual arrangements in pricing under a regional tariff is part of the much larger pricing question to be addressed in Phase II. Whether a facility is needed for physical control or for access/§211 considerations, should in no way impact the rate design decisions that an IGO/Transco will eventually need to make.

A precise definition of facilities that are needed for access to the power market is difficult. The issue of transmission access is related to the pricing and control of lower voltage delivery facilities for specific customers. Many of BPA's customers are served through lower voltage transmission facilities that have historically been segmented as "delivery" facilities. These delivery facilities are critical for these customers to have meaningful choices. For this reason, the treatment of these delivery facilities is an important decision. There are several alternatives for treatment of delivery facilities. First, the facilities could be transferred to the local utility to own and operate as appropriate for their customers. Second, the physical facilities would not be included in the transmission system per se but could be included in access, terms, conditions and prices on a case by case basis into the transmission tariffs. This issue will continue to be analyzed and discussed to identify an equitable and effective definition of the transmission network from the customer's perspective.

In general, facilities needed for wholesale access are those lines and substations which interconnect a wholesale utility's load center with the network, including any radial lines or substations in the path. For example, a 69 kV radial line which connects a wholesale utility to the grid may be included under the IGO's contractual control but switching of the facilities would remain with the local utility. In most other cases, however, the 69 kV facilities which provide subtransmission within to a wholesale utility's system will not be included in the IGO/Transco for either control or access purposes.

This approach will guarantee every wholesale utility access to the bulk power market. It also recognizes that certain facilities are provided for internal reliability and it is not appropriate for these facilities to fall under the IGO/Transco's control, either physically or financially. Take for example any number of 115 kV lines and stations inside a utility's service area which serve no current wholesale purpose.

10.4. Transmission Facilities Needed For System Control.

If an independent operator is to achieve the advantages and efficiencies of regional system operation, it must be able to manage system flows on the facilities used for cross regional transactions and also the interconnections from the regional system to other parts of the Western Interconnection. The following proposal was developed to provide a general guide to which facilities in each voltage class would be candidates for transfer to the physical control of an IGO or Transco.

Facilities not included in the IGO/Transco's physical control would continue to be operated by their existing owners. In order to accomplish the contractual access described above, the IGO/Transco would contract with the owner for use of the facilities necessary for the IGO/Transco to provide its customers with access to the wholesale power market. Under such an arrangement, the IGO/Transco would include such facilities in its pricing structure, but leave management of local reliability with the facility owner.

10.4.1. High voltage

All lines and substations at 500 kV, 345 kV and 230 kV would be included, beginning at the point of interconnection. The point of interconnection is defined as the point in the system where the transmission system operator and a plant operator must coordinate their operations. The switching of facilities which alter flows in parallel lines in the regional system should be under the IGO/Transco's control. Lines serving purely radial loads would not generally be included for control purposes unless load status is critical to network control, e.g., where the system operator needs to control line operation to make use of interruptible load for system control.

10.4.2. Medium voltage

Only those 161 kV, 138 kV and 115 kV facilities would be included which are either operated in parallel with high voltage facilities and which are part of the definition of a rated system path, i.e., a known constraint on the regional system. Other specific lines in this class could be included only where they are needed for other control purposes.

10.4.3. Low voltage

69 kV, 46 kV and lower voltage facilities would not be included under the physical control of the IGO/Transco, unless a specific impact could be shown on higher voltage facilities.

11. Transmission Restructuring Legal Issues

11.1. Legislation

11.1.1. Transmission Coordination Agreement ("TCA")

ISSUE: *Is legislation necessary for TCA?*

No necessary legislation identified.

11.1.2. Independent Grid Operator ("IGO") or Transco

ISSUE 1: *Is legislation necessary for the sale of federal assets?*

ISSUE 2*:* *Is legislation required for BPA's transmission system to be subject to a long term operating agreement?*

ISSUE 3: *Is legislation required for transfer of operating control over BPA transmission facilities?*

Response to Issues 1-3: Federal legislation would be necessary for BPA to sell, lease or transfer its transmission system. Although the Administrator has broad authority to dispose of surplus property, Congress has exercised specific control in the Urgent Supplemental Appropriations Act of 1986 over any transfer of ownership, management or control of major assets of the federal power marketing administrations. (S. Larson).

ISSUE 4: *Is state legislation required for IGO/Transco to exercise condemnation rights?*

In some states legislation probably will be required to afford a non-federal IGO or Transco the power to condemn transmission rights-of-way. In other states the applicable statutes as currently drafted would permit an IGO or Transco to condemn such rights-of-way. (M. Wood)

ISSUE 5: *Is legislation necessary for BPA or a new federal entity, such as the IGO, to accept a shift of the financial risks to be borne by the U.S. Treasury?*

ISSUE 6: *Is enabling legislation required for a new federal entity as IGO?*

Response to Issues 5-6 : Legislation would be necessary to create a new federal entity to act as a Federal IGO e.g., FERC jurisdiction over a new federal IGO. (S. Larson).

Legislation would be necessary to modify BPA's statutes to better enable BPA to act as a federal IGO. (S. Larson).

Bonneville is currently unable to permanently shift to the Treasury financial losses suffered as a federal IGO. Legislation would be required to shift such losses to the Treasury. (S. Larson).

ISSUE 7: *Is enabling legislation required for interstate compact IGO?*

Interstate compacts are usually ratified by state legislatures through statute and then approved by Congress. Express Congressional approval would be required if the state compact IGO will exercise powers within the purview of the federal government. There is some risk that an interstate compact whose governing body is appointed by state officials is unconstitutional if it exercises traditionally federal authority (or authority over federal assets). (M. Early).

ISSUE 8: *Are there legal constraints on Public Utility Districts ("PUDs"), municipal utilities or cooperatively owned utilities from participating in an IGO or Transco?*

Under current state statutes, Washington and Oregon PUDs and municipal utilities could not participate in a cooperative-model IGO if the IGO-members included entities which are not regulated by the WUTC or OPUC.

<u>Cooperative utility participation in IGO/Transco</u>. Unless otherwise limited by its articles of incorporation, bylaws or membership agreement, a cooperative corporation organized under the laws of Oregon, Washington or Montana would be free to participate as a member of an entity formed to be an IGO of a consolidated Pacific Northwest power grid. (R. Moore).

But an IGO established in certain northwest states would require changes in current state laws. For example, a Montana cooperative corporation could have no more than seven members and an Idaho cooperative association needs to be nonprofit. (R. Moore).

<u>PUDs and municipal utilities participation in IGO/Transco</u>. Washington PUDs and municipal utilities are permitted to participate in the <u>joint development and ownership</u> of generating and transmission facilities with other PUDs, municipal utilities, cooperatives, joint operating agencies and IOUs <u>regulated by the Washington or Oregon utility commissions</u>. Any such joint participation would have to comply with the liability and debt limitations set out in the statute. Washington PUDs and municipal utilities may form joint operating agencies in order to take action, acquire any facilities and enter into any contracts to generate and deliver power, including transmission facilities.

Washington PUDs and municipal utilities are prohibited from directly or indirectly owning any stocks or bonds of any corporation, association or company. However, joint ownership of facilities does not constitute the ownership of stock or bonds. (T. Mundorf).

ISSUE 9: *Does the Public Utility Holding Company Act (PUHCA) limit the cooperative - IGO model?*

The Public Utility Holding Company Act (PUHCA) presents a problem in the cooperative-model IGO for any cooperative-member owning 10 percent or more of the IGO (or that otherwise is deemed to have a controlling interest in the IGO). (M. Wood).

11.2. Regulatory Approvals

11.2.1. Transmission Coordination Agreement

ISSUE 1: *Will state regulatory approval be required for TCA?*

No

ISSUE 2: *Will FERC approval be required for TCA?*

Yes

ISSUE 3: *Is a BPA public process required for approval of TCA?*

Yes. Requirements of the Administrative Procedures Act and the Northwest Power Act either expressly or implicitly call for public process attendant to BPA's participation in a TCA.

ISSUE 4: *Do National Environmental Policy Act ("NEPA") requirements need be met to support a TCA?*

Unless a statutory exemption is obtained, BPA’s participation in the TCA would be a major regional policy decision and would be subject to the applicable NEPA process. Additionally, an Appointments Clause issue may exist with regard to the authority of NRTA to prohibit facility costs from being recovered. Because BPA has no other source of revenues to cover costs excluded by NRTA from TCA-based rates, NRTA authority would be tantamount to plenary authority over BPA's construction decisions. (S. Larson).

11.2.2. Independent Grid Operator ("IGO") or Transco

ISSUE 1: *What state approvals are necessary for formation and operation the IGO/Transco?*

State PUCs throughout the Northwest have clear jurisdiction to regulate “acts” or “practices” of public utilities which affect the rates of that utility, and they can also investigate “practices” in the public interest even if there is not a clear rate impact. The PUCs also have express jurisdiction to review transfers or leases of public utility property, if an element of creating an IGO or Transco. (R. Neate).

Under its authority to regulate all practices and services of public utilities, the Public Service Commission of Nevada would have to approve any transfer of transmission assets of an electric utility under its jurisdiction to the control of an independent grid operator ("IGO"). Such approval would be required whether the transfer involved a sale of those assets or transfer via an Operating Agreement (which would allow the IGO to schedule and to operate the transmission facilities for an agreed fee). (D. Norris).

ISSUE 2: *Will state and FERC approvals be necessary for the sale of transmission facilities to an IGO/Transco?*

ISSUE 3: *Will state and FERC approvals be necessary for the transfer of transmission assets to an IGO/Transco through an Operating Agreement?*

ISSUE 4: *Will FERC approval be required for the grant of operating control to an IGO/Transco?*

Response to Issues 2-4: Yes

ISSUE 5*:* *What state siting requirements apply to IGO?*

In the cooperative, not-for-profit and private IGO model, state siting approvals will apply. Each relevant statute by its terms applies to all "persons" who propose to construct or enlarge a covered energy facility. Person is defined in a manner that would not exclude cooperative, not-for-profit or private corporations under the Oregon, Washington or Montana acts. A comparable statute has not been enacted in Idaho. (R. Moore).

A federal IGO must comply with substantive state siting statutes only when the IGO constructs on certain federal private land. A federal IGO otherwise would be subject to state permitting and siting requirements only if Congress clearly and unambiguously so directs in applicable legislation. (S. Larson).

ISSUE 6: *Do National Environmental Policy Act ("NEPA") requirements need to be met to form an IGO/Transco?*

Unless a statutory exemption is obtained, BPA’s participation in an IGO or Transco would be a major regional policy decision and would be subject to the applicable NEPA process. (S. Larson).

ISSUE 7: *Would state antipiracy or nonduplication of service statutes apply to formation or operation of an IGO or Transco?*

Amendments to the Idaho Electric Supplier Stabilization Act and the Montana Territorial Integrity Act would likely be required to enable an IGO or Transco. This is because both of those acts presently resolve retail territorial service disputes on the basis of measured distances from transmission lines of competing utilities and cooperatives. While under an IGO or Transco, retail utilities and cooperatives would no longer own, or would no longer control, bulk transmission lines. (B. Strong)

ISSUE 8: *Is FERC approval necessary for agreements to interconnect?*

FERC approval probably will be required for agreements providing for interconnection of the transmission facilities of an IGO or a Transco with the transmission facilities of another transmitting utility. (M. Wood)

ISSUE 9: *Is FERC approval necessary for rates set by an IGO?*

Yes. For a new federal entity such as IGO, legislation would also be required to make the IGO subject to FERC regulation.

ISSUE 10: *Is FERC approval necessary for the terms and conditions offered by an IGO/Transco?*

Private IGO: Yes

Non profit IGO: Yes

New federal entity IGO: Probably requires legislation to compel FERC review and approval; otherwise, it depends on the enabling legislation of the new federal entity IGO.

Cooperative IGO: Not clear under current law

Interstate Compact IGO: Probably requires legislation to compel FERC review and approval; otherwise, it depends on the enabling legislation of the new federal entity IGO.

ISSUE 11: *Does FERC review and approve of section 211 wheeling requests made of an IGO?*

Private IGO: Yes

Non profit IGO: Yes

New federal entity IGO: Yes

Cooperative IGO: Yes

Interstate Compact IGO: Yes

ISSUE 12: *Is FERC approval required for an IGO to issue securities?*

For a for-profit, non-profit and possibly a cooperative IGO, FERC approval would be required for the issuance of securities. For the other forms of IGO, legislation would be needed in order for FERC to have jurisdiction over their securities issuance.

ISSUE 13: *Will FERC regulate the sale of ancillary services by the IGO?*

The preliminary question is whether, for FERC jurisdictions purposes, ancillary services are power services or transmission services. FERC regulates all transmission in interstate commerce but only sales-for-resale of power.

<u>Private IGO</u>: Yes, if transmission service; yes, if power service and provided for resale;

<u>New federal entity IGO</u>: Possibly; depends on the enabling legislation of the new federal entity IGO.

<u>Cooperative IGO</u>: No, if power service; yes, if transmission service (at least under FPA § 211 and 212).

<u>Interstate Compact IGO</u>: Possibly; depends on the enabling legislation of the new federal entity IGO.

11.3. Taxes

Taxes are addressed in terms of taxes associated with formation of the IGO and taxes associated with on-going operations of the IGO.

11.3.1. Formation

<u>Washington - Sale</u>. A transfer of IOU transmission assets to a Transco could be accomplished through a corporate reorganization with only relatively minor payments of sales, use or Business and Occupation ("B&O") taxes. In a sale of federal or publicly-owned transmission assets, sales, use, or B&O taxes will be minimized only if the assets are deemed "real property" assets not personal property assets. (M. Wood, M. Early).

<u>Transfer through Operating Agreement</u>. If transmission assets are transferred via an Operating Agreement to a non-federal IGO, to the extent that the property were deemed personal property, the Operating Agreement payments would be subject to sales and B&O taxes. Most of the assets probably would be considered real property rather than personal property, but state-by-state tax determinations would be required. If the Operating Agreements were treated for tax purposes as installment sales, <u>all</u> of the Operating Agreement payments would be subject to

various state sales and B&O taxes and the Operating Agreement payments in one or more states also would be subject to real estate excise taxes. (M. Wood).

We have not investigated whether and to what extent the transfer or related taxes may be applicable to a new federal entity such as IGO or Transco; however, taxes normally are paid by the seller and are not related to the tax status of the buyer.

11.3.2. Operation

Oregon - Tax on Gross Earnings. Cooperative, non-profit associations operating transmission systems for the benefit of their members pay a gross earnings tax. The rate is determined by reference to a formula provided in the statute and is the lesser of (a) 4 percent of all gross revenues of the association minus the cost of power to the association or (b) an amount derived by reference to the value of the property of the association. (R. Moore).

Idaho - Tax on Gross Earnings. A tax on gross earnings of cooperative electrical associations is levied in Idaho at the rate of 3.5 percent after reduction for certain WPPSS costs. "Gross earnings" include "gross receipts of a cooperative electrical association from the distribution, delivery and sale of electric power within the state of Idaho." Every cooperative electrical association in Idaho must file an operator's statement with the state tax commission. The tax becomes a lien on property of the association until paid. (R. Moore).

Washington. Public service businesses in Washington are exempt from the state business and occupation tax but are subject to a public utility tax. "Public service business" includes "light and power," which itself includes "the business of operating * * * a system for the generation, production, *or distribution* of electrical energy." RCW 82.16.010(5). In the case of electric transmission companies, the tax is imposed on gross revenues, calculated as provided by statute and regulations, at the rate of 3.6 percent. In addition, utilities that are subject to regulation by the Utilities and Transportation Commission must pay an additional administrative expense assessment (0.1 percent of first $50,000 and 0.2 percent of excess). City utilities taxes may also be levied at a rate not to exceed 6 percent." (R. Moore).

Federal. A state cooperative corporation used as the legal form of an IGO would be exempt from federal income taxation under Internal Revenue Code 501(a) and 501(c)(12) if it did not receive more than 15 percent of its income from non-members. Thus, users of the power grid would need to become members of the cooperative. (R. Moore).

11.3.3. Property Tax

If transmission assets are transferred from an exempt entity to a non-exempt entity (e.g., from BPA to a private IGO), new property taxes will apply.

Oregon Ad Valorem Tax. The Oregon Department of Revenue also assesses an ad valorem tax on all of the real and personal property of cooperative, non-profit associations operating transmission systems for the benefit of their members, which is not part of the "transmission and distribution lines" of the association. The Department of Revenue has asserted in the case of an electric cooperative that an interest in a contract providing for the use of the capacity of a transmission facility is personal property subject to the ad valorem tax; the ad valorem tax provision thus could be broadly construed by the Oregon Department of Revenue. (R. Moore).

Idaho Tax on Property. The Idaho tax code also provides for a property tax on assets of an electric cooperative:

> "The nonoperating property of any cooperative electrical association shall be assessed by the county assessor of the county wherein such property is situate, and taxes levied against the same shall be a lien, and shall be due and payable, in the same manner as are any other taxes on property."

Montana Property Assessment. The Montana Department of Revenue by statute must "centrally assess * * * property owned by a corporation or other person operating a single and continuous property operated in more than one county or more than one state, including * * * electric power or transmission lines." The tax is applied at a prescribed rate on the assessed value of the property. A different rate of tax is applied for property of cooperative rural electrical cooperatives. (R. Moore).

Washington Personal Property Tax. Easements and the personal property constructed or located on the easements owned by public service corporations are taxed as personal property. "Personal property" is defined as both tangible and intangible personal property. Specific provisions cover the assessment of the value of operating and nonoperating assets of a utility. (R. Moore).

11.3.4. Private Use Issue

General restrictions apply to the private use of facilities financed with tax-exempt bonds or other tax-exempt debt instruments. Typically, the benefit of a tax-exempt financed facility cannot be transferred to a private person or entity to any "substantial extent" during the amortization of the tax-exempt debt attendant to the facility. However, tax-exempt constructed facilities may form part of an IGO or Transco (in a joint use or exchange arrangement) if the contract implementing the transfer of the debt-financed facility contemplates such issues as:

- joint publicly and privately financed facilities;
- arrangements that provide only incidental and necessary private use of the publicly financed facility;
- use of facilities that have been debt-amortized;
- exchanges of usage rights;
- pricing mechanisms such that any substantial private use is not the basis for security behind the tax exempt debt.

The joint venture will encounter problems under tax-exempt laws and regulations if it intends to use tax-exempt financing to build regional transmission facilities that will be used on an equal basis by public and private users. It is unclear whether tax-exempt status can be maintained if such facilities are controlled by the IGO or Transco. The affected parties should consider obtaining a letter ruling from the IRS. (L. Cable, S. Richardson).

11.4. Investor Owned Utility Mortgage Indenture

11.4.1. Transmission Coordination Agreement

No specific problems are raised by the investor owned utility mortgage indentures. (M. Wood).

11.4.2. Independent Grid Operator - Limited (IGO-L)

No specific problems are raised by the investor owned utility mortgage indentures. (M. Wood).

11.4.3. Independent Grid Operator - Owner (IGO-O)

Each participating investor owned utility must agree 1) to retire property when requested by the IGO-O as necessary to accommodate IGO-O upgrades, additions or replacements; 2) to permit the necessary interconnection and otherwise to cooperate with the activities of the IGO-O; 3) to freeze its bond mortgage, so that the mortgage would not attach to new properties constructed by the IGO-O; and 4) to make available to the IGO-O the rights-of-way needed for the replacements, upgrades and additions or to obtain a release of the rights-of-way from the lien of the applicable mortgages. These actions all appear feasible and not unduly burdensome. (M. Wood).

11.4.4. Transco

In order to create a Transco, the participating investor owned utilities would need to obtain releases of their transmission facilities from the liens of applicable mortgages. For most such utilities the trustee would require substitution of properties, cash deposits or bond rollovers in an amount equal to the fair value of the released properties. Dividend covenants in some mortgages also must be analyzed carefully. Obtaining the necessary mortgage releases appears to be feasible, but may restrict the future financial flexibility of various investor owned utility participants. (M. Wood).

11.4.5. Operating Agreements

Investor owned utilities may be unable to transfer their transmission assets to an IGO through a lease without obtaining mortgage releases. These companies, however, should be able to enter into Operating Agreements. (M. Wood).

11.5. Cooperatively-Owned Utility Mortgage Indenture

It is likely that assets subject to a mortgage indenture containing the normal commercial terms could not be transferred, leased, or control there over transferred to an independent grid operator without the consent of the mortgagee. (R. Moore).

11.6. Antitrust

ISSUE 1: *What if any antitrust issues arise if generation owning and controlling entities are board members of, or collectively nominate directors of, a cooperative IGO*?

Creation of IGO: If the IGO is set up as a legitimate joint venture its creation may escape liability under Sections 1 and 2 of the Sherman Act and Section 5 of the F.T.C. Act. Assuming the IGO is structured as a single enterprise pursuing a procompetitive common goal, it probably could be created without liability under Section 1. In determining whether Section 2 has been violated, the joint venture's procompetitive features will be weighed against potential anticompetitive effects of the venture's market power. (P. Raskin).

Operation of IGO: If transmission-owning utilities (which are also sellers of energy) are board members of a cooperative IGO or Transco, or elect such board members, a court might hold that the IGO or Transco constituted a "horizontal agreement" among such competing utilities. As such, any action taken by the IGO that worked to the detriment of a competing power supplier might expose both the IGO and the utilities to antitrust claims. (M. Wood).

ISSUE 2*:* *Is notification of the United States Department of Justice required for purposes of compliance with Hart Scott Rodino?*

Notification to and antitrust review by the United States Department of Justice probably would be required for a cooperative form of IGO. Such notification and review might be required for a Transco. Such notification and review would not be required for a publicly held IGO unless a single person held voting securities or assets of such IGO in excess of $15 million.

11.7. Legal Analysis Contributors

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