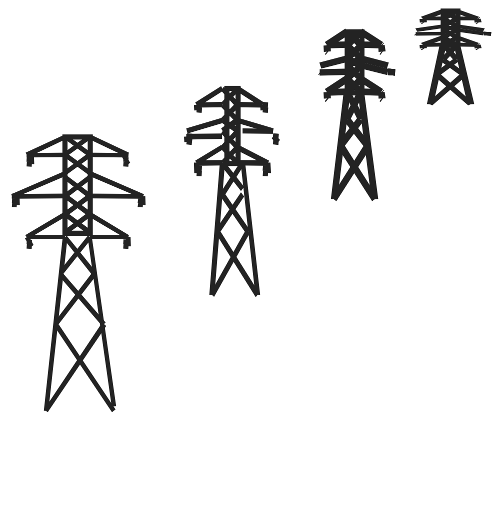
Financing Electricity Transmission Expansion in the West

A Report to the Western Governors

February 2002



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1 EXECUTIVE SUMMARY

In August 2001 the Western Governors' Association (WGA) issued its report, "Conceptual Plans for Electricity Transmission in the West", which explored alternative electricity futures for the West, with a focus on the need for large-scale transmission expansion in the Western Interconnection. The report recognized that future transmission expansion could raise unprecedented financing and cost recovery issues. In response to that recognition, the Transmission Finance Committee (TFC) has prepared this report exploring those financial issues and recommending to the Governors several specific steps they can take to help ensure that justifiable expansion of the Western grid can be financed. In its consideration of transmission financing and cost recovery alternatives, there has emerged among the TFC members a broad consensus on the following points.

- Confidence over cost recovery, including a reasonable return on investment is the key to financing transmission expansion.
- Uncertainty over the future structure of the industry and recovery of transmission investment costs has contributed to a lack of investment in recent years.
- Due to the long lead-time required for transmission construction, further investment to expand the transmission infrastructure in the western states may be needed now to bring economic and strategic benefits to customers in the future.
- The committee has identified two distinct models for identifying transmission expansion projects, securing the necessary capital investment and offering reasonable assurance of recovering the investment costs. These are the market-driven model and the total system cost model.
- The two models could co-exist and it is possible that some transmission projects could be financed through a combination of these models.
- The Western Governors have important contributions to make towards ensuring the appropriate level of investment in the transmission infrastructure during this transitional period.

Looking forward, the Regional Transmission Organizations (RTOs) will manage a planning and expansion process which, combined with regional cost recovery authority, is intended to overcome investment recovery uncertainty and make transmission expansion more financially feasible. Since the RTOs are not expected to be fully operational before 2004, the Committee has considered what actions would be appropriate in the immediate term, the period prior to the operation of the RTOs.

The TFC recommends the following actions.

1. The Governors should support the early formation of Regional Transmission Organizations (RTOs) in the West to identify and facilitate needed expansion of the transmission infrastructure.

2. The Governors should call on the RTOs to address at an early stage any factors that may inhibit investment in transmission expansion in the West. For market-financing expansions to occur, the RTOs must clearly define the property or financial rights that accrue to a market participant making a transmission infrastructure investment.

3. Prior to the formation of the RTOs, the Governors should support organizational arrangements that will permit suitable transmission expansion proposals to be identified and to receive the necessary state and Federal Energy Regulatory Commission (FERC) approvals.

    a. The Governors should recognize and encourage the recent initiative of the Seams Steering Group - Western Interconnection (SSG-WI) to develop a robust interconnection-wide "proactive" transmission planning process. This process, to be implemented in advance of the formation of RTOs, would identify problems that can be addressed by transmission (or alternative non-transmission) solutions. Information developed in such a planning process will be valuable to market participants regardless of which financing model is used for a particular project. Such a process is essential to garner the public and political support that would be needed to implement the total system cost model, especially in those cases where costs are to be recovered on a regional basis.

    b. The Governors should urge FERC and state Public Utility Commissions (PUCs) to form joint State/FERC panels to adopt appropriate mechanisms that will enable cost recovery of transmission investments made before the RTO structures are fully implemented. Working in conjunction with the SSG-WI, these panels could drive agreements between state and federal regulators, transmission developers and their investors that would provide cost recovery assurances sufficient to induce development of needed infrastructure. The panels should also explicitly consider risks and the need for financing incentives.

4. The Governors should jointly encourage the Internal Revenue Service to issue permanent regulations that clarify and extend the use of tax exempt bonds for investment to expand the transmission infrastructure. Specifically the IRS should be encouraged to make it clear that transfer of operational control of transmission assets financed with tax-exempt securities does not constitute a private business use or otherwise jeopardize the tax-exempt status of those securities.

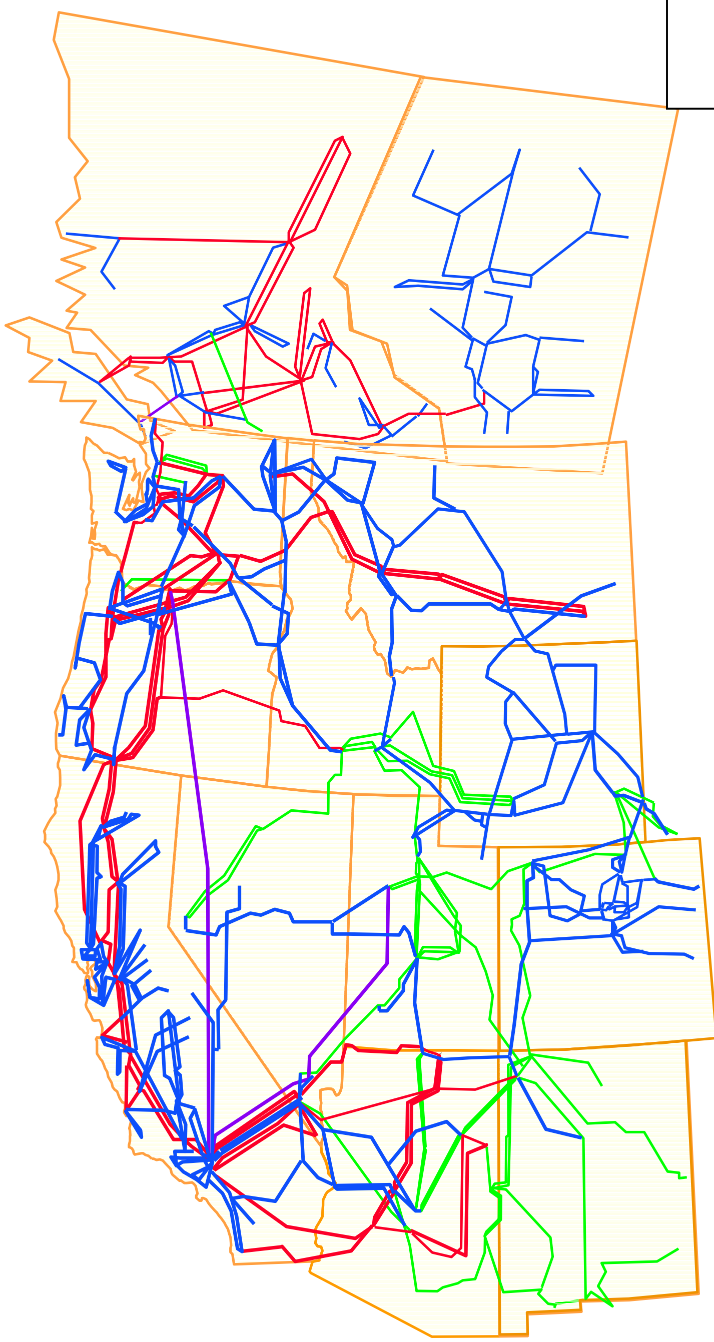
5. The Governors should urge the Administration and Congress to approve any reasonable requests by Federal Power Marketing Administrations: to increase their

borrowing authority; to allow Congressional appropriations; or to allow the use of revenue streams for needed transmission investment.

6. The Governors should continue to work with the Canadian provinces to find appropriate mechanisms to support new transmission investments that have mutual benefits.

Western Transmission

Main Grid System



2 INTRODUCTION

At the Western Governors' Association's (WGA) Transmission Roundtable on May 9, 2001 the Governors posed three questions:

1. What transmission enhancements are needed in the West to ensure adequate and affordable electricity supplies?
2. How can needed transmission enhancements be financed?
3. How can needed transmission enhancements be expeditiously sited and permitted?[1]

The Governors created a Transmission Working Group to produce a *Conceptual Transmission Plans* report to begin to address the first question. The report, which was presented to the Governors at the WGA annual meeting in August 2001, also included a brief outline of alternative approaches to financing needed transmission enhancements.

In August the Governors adopted WGA Resolution 01-001, "Western States Energy Policy Roadmap" (http://www.westgov.org/wga/policy/01/01_01.pdf) that directs the WGA "...to identify and evaluate options available for financing investments in new transmission capacity."

To address the second question, the Governors asked Jack Davis, President of Pinnacle West, and Marsha Smith, Commissioner of the Idaho Public Utilities Commission and Chair of the Committee on Regional Electric Power Cooperation, to continue as co-chairs of the WGA Transmission Working Group and to develop a white paper examining the advantages and disadvantages of the alternatives to finance new transmission investments. Jack Davis and Marsha Smith created a Transmission Financing Committee (TFC) to develop the white paper and asked John Carr of PacifiCorp to chair the committee.

A broad array of more than 50 stakeholders representing all segments of the electric power industry in the Western U.S. and Canada, the financial community, and states participated in the development of this white paper. The TFC met on December 13-14. Subsequently, committee members reviewed various drafts of the paper and a conference call was held to discuss recommendations. The paper reflects the deliberations of the TFC and does not reflect the views of any individual committee member. A list of members of the TFC is given in Appendix 2 at the end of this report.

[1] To answer the third question, the Governors are undertaking a separate effort to develop a protocol to enhance collaboration among states and other permitting agencies to improve the timeliness and quality of reviews of interstate transmission proposals. The Governors expect to sign such a protocol in June 2002.

3 BACKGROUND

3.1 Traditional Structure

The traditional structure of the power industry in the West consists of three types of organizations. First are the vertically integrated utilities owning and controlling the entire process of generation, transmission, distribution and supply of electricity. Each company plans and builds its system to meet reliably the annual peak day requirements of its own customers at least cost. Regulatory review (usually at the state level) of capital projects ensures that systems are appropriately sized to customer needs and that costs are prudent.

Second are the two Federal Power Marketing Administrations (PMAs), Bonneville Power Administration and Western Area Power Administration, which were formed to market the generation output from federally-owned hydro projects. They primarily market the output to municipals and rural electric cooperatives over their own transmission systems or through contracts with vertically integrated utilities. The two PMAs' transmission system comprises a significant part of the high-voltage transmission grid in the Western System Coordinating Council (WSCC) region. As government entities, they have limited regulatory oversight on their rates and capital projects, but depend on an open public process and Congressional oversight to guide their actions.

Third are municipal utilities, rural electric cooperatives and public utility districts. These are usually distribution utilities which by themselves or through joint action agencies or generation and transmission cooperatives have also built generation and transmission facilities. These entities are regulated by their governing bodies through a public process, determined by the respective state laws.

For vertically integrated utilities, expansions in this traditional business model are financed on the overall borrowing power of the entire vertically integrated utility. Attracting capital at reasonable cost is a consideration of traditional utility rate making and the financial community views the transmission function as integral to the utility business model. Further, the investment characteristics of transmission facilities are well suited to this process; they are long-lived assets with high up-front capital costs. Fixed costs are recovered with a high degree of certainty over the long term making them ideal candidates for long-term borrowings. Therefore, transmission financing and cost recovery have been reasonably integrated, straightforward and well understood in the past. The combination of the cost recovery/rate making authority of regulators, the understanding and acceptance of the utility business model by the financial community, and the borrowing capabilities of the utility are key to the traditional transmission investment process.

To appreciate the challenges now facing transmission expansion, it is important to understand the cost recovery aspects of the traditional regulatory framework. As noted above, state regulators review transmission expansion proposals by vertically integrated utilities for prudence. Before allowing the cost of transmission expansion to be included in the rates charged to customers, the state regulators must be satisfied that:

1. Ratepayers in the regulator's state need the proposed expansion; and
2. It is appropriately sized and located and the costs are reasonable.

Long-term benefits are matched against the cost of long-term assets and that cost, if found prudent, is recovered over the life of the assets in the rates under that state's jurisdiction.

The PMAs, municipal utilities, public utility districts and cooperatives face some of the same issues about acquiring capital investment money and cost recovery, but with their different corporate structures, need to have different solutions.

BPA's borrowing authority for capital projects is established and must be expanded by Congress. While WAPA does not have borrowing authority and must acquire appropriations from the Congress for any capital improvements, alternative financing mechanisms are being explored. Both entities' cost recovery processes are through public ratemaking hearings to set cost-based rates for their customers.

Municipals have generally financed transmission and generation facilities with tax-exempt debt that places restrictions on the use of those facilities (see Section 8 below). Their cost recovery processes are also through public ratemaking hearings to set cost-based rates for their customers.

Cooperatives have generally financed transmission and generation facilities with debt from the Rural Utilities Service, which also imposes restrictions on the use of those facilities by other entities.

3.2 Increased Wholesale Trading Activity

Against this traditional regulatory backdrop of one-for-one benefit identification and long term cost assignment, the Federal Energy Regulatory Commission (FERC) has been encouraging greater use of the transmission system for wholesale market activities. Wholesale electricity markets can be volatile, particularly where there are transmission constraints, with energy traders adjusting their positions to respond to changing market conditions. Wholesale prices, and consequently the demand for transmission services, may vary considerably in the short term, often within a single day due to changing demand or unit availability. Longer-term variables include fuel price movements, seasonal variations in supply and demand, transmission and generation maintenance requirements, commissioning of new generation and plant retirements. Consequently, the beneficiaries of transmission transactions in a dynamic wholesale market are not always apparent and may be several states away. Accordingly, the traditional state regulatory model is ill suited to match costs and benefits as wholesale activity grows and state regulators may be increasingly reluctant to allow transmission expansion expenditures into the rate base. Due to this uncertainty of cost recovery, transmission owners are less willing to invest.

3.3 Industry Restructuring

The industry is now in the midst of unprecedented regulatory and structural changes. The overall program of industry restructuring is designed to harness the power of competitive market forces across all sectors of the industry. Driven by regulators at both federal and state levels, these reforms envision a future in which wholesale power buyers, and in some states end-users, will be able to choose among alternative providers. A market structure that allows buyers to have meaningful choices regarding when and from whom they purchase, requires different considerations and reforms in the various sectors of the industry.

3.3.1 Competition in Generation

Competition has developed strongly among generators. In many market areas the generation sector is characterized by numerous new entrants, generating and marketing power to end-users, as well as to traditional utilities. These "merchant" power plants rely on their ability to generate, sell and deliver power at competitive prices. The opportunity to earn unregulated rates in a competitive market has attracted generators who have been willing to accept normal market risks. It is accepted that, in the extreme, the merchant generator may be unable to meet debt payments and could therefore fail. Although the transition of the generation sector is incomplete, it has been successful in attracting new entrants who have brought on line significant new generation capacity. However to finance such investments, most generators need firm, multi-year contracts for the sale of the electricity generated. Most importantly for the purposes of this paper, the competitive generation model, including its regulatory interface, has been sufficiently clear as to risk and rewards, that generation developers feel they can manage these factors and attract reasonably priced financing.

3.3.2 The Role of Transmission

The transition of the transmission sector is not nearly as far advanced as generation. The broad role of transmission in the new industry structure is reasonably well understood, but the details are not. The integrated and interdependent nature of the transmission system means that the provision of transmission capacity is largely viewed as a natural monopoly function, a neutral enabler of the competitive generation sector. Federal regulators recognized that open access to the transmission grid over wide regions is a necessary condition for a competitive market. This led to the FERC ordering the formation of Regional Transmission Organizations (RTOs).

In addition to operational control across broad geographic regions, these organizations are to undertake regional transmission facility planning which, in conjunction with the tariff administration, should add needed certainty to the expansion and cost recovery framework. The RTOs will also perform region-wide congestion management, which should result in more efficient use of existing transmission facilities. However, RTOs are just in their formative stages and transmission planning, expansion and cost recovery procedures will not be approved for some considerable time. RTO-West, for example, is not expected to be operational before 2004. The California ISO (Cal-ISO) on the other hand has approved over $1.0 billion in transmission expansion and replacement since it began operation in March 1998.

3.4 Regulation of the Transmission Sector

Adding to the uncertainties over the financing of transmission expansion is the lack of clarity surrounding FERC's plan for transition to competitive wholesale markets. In its Order 2000 issued on December 20, 1999 the FERC called upon transmission owners to cede control of operation, coordination and planning functions to RTOs. FERC has made it clear that it has a strong preference that ownership of transmission should be completely separate from other electricity supply interests. To encourage a complete separation of the transmission sector, the FERC has, in Order 2000, identified various financial incentives that may be available only to transmission entities that are fully independent. In response, many traditional integrated utilities have undertaken or are considering the separation of their transmission functions from the rest of their business. Options to accomplish separation include the formation of a separate, wholly owned transmission company, contributing assets to a joint venture with other transmission owners, and outright sale of transmission assets. In the West, a number of utilities have announced the formation of such independent transmission-only companies (ITCs). There is however no detail available at this time about the incentives that FERC may allow or how independence would be measured.

3.5 Wholesale versus Retail Restructuring.

It is important to distinguish between the restructuring of wholesale power markets and the various initiatives aimed at promoting retail choice. Retail choice programs entail the selection of a power supplier by the retail energy end-user. These are state-designed and regulated programs that push energy choice down to the ultimate consumer. In other words, these programs aim to introduce market forces into the retail side of the energy market.

Wholesale market restructuring, which includes greater separation of transmission and generation functions is intended to encourage competition in the generation side of the market. While in some states utilities have been encouraged to divest their generation, the separation of the transmission function and restructuring of previously integrated utilities is largely a Federal initiative.

3.6 Current Practice in Alberta and California and the RTO West proposal

Alberta and California are two regions in which restructuring of the industry and the introduction of an independent transmission function are relatively well advanced. In both examples the transmission authorities (ESBI Alberta and the Cal-ISO) undertake a coordinated grid planning process to identify and secure funding for economically justified transmission expansion projects. The process adopted by each of these transmission authorities can be described as following the total system cost model described later in this paper. An outline of the transmission expansion process and the cost allocation approach in both Alberta and California is provided in Appendix 1.

RTO West, like Alberta and the Cal-ISO, proposes a strong public planning process. However RTO West proposes primary reliance on market-driven solutions, with a role

for the RTO to ensure construction and to allocate costs only where market-driven investment is not forthcoming.

4 THE VIEW FROM THE FERC

The importance of the transmission infrastructure to the successful development of competitive wholesale markets is well recognized and has gained visibility at the FERC in recent months. Although the Commission has not detailed its preferences with regard to transmission expansion planning, financing and cost recovery, the broad outlines of its approach are beginning to emerge.

- On May 16, 2001 the Commission issued its "Further Order on Removing Obstacles… in the Western United States". This recognized the role of transmission constraints in destabilizing markets in California and elsewhere in the West. To encourage rapid construction of transmission capacity and generator interconnection with the grid, the FERC authorized a program of temporary financial incentives. This first use of financial incentives for transmission infrastructure allowed premiums on equity returns and accelerated depreciation on certain projects as detailed in the following table:

Project Type	In-Service Date	ROE Premium	Depreciation Life
Transmission Capacity at existing constraints	July 1, 2001 Nov. 1, 2001	2.0% 1.5%	10 years 10 years
System Upgrades using new rights of way	Nov. 1, 2002	1.0%	15 years
Interconnection Facilities for new entrants	Nov. 1, 2001 Nov. 1, 2002	1.5% 1.0%	- -

  While these incentives are of limited duration and geographic applicability, they do signal the Commission's recognition that rate of return and cost recovery are significant hindrances to transmission investment and the Commission's willingness to do something about it. It is, however, unclear if these kind of incentives will be renewed by FERC.

- As part of their investigation into energy infrastructure adequacy (Docket AD01-2), the Commission is conducting a series of regional meetings that began in Seattle on November 2, 2001. While the expressed purpose of the meeting was information gathering, the Commissioners who attended the Seattle meeting (Chairman Wood and Commissioner Brownell) committed to work with regional parties to develop solutions that respond to the unique needs of the West.

- On December 17, 2001 the FERC Staff released their "Concept Discussion Paper" on standard market design, including the transmission functions and expansion. The paper looks ahead to the markets five to ten years from now when "market-driven price signals will exist to support well-planned investment in … new transmission…" Planning and expansion of transmission is presented as a function to be performed regionally and would include both privately and publicly-owned facilities. An annual plan looking out five years would identify transmission constraints and determine desirability of various options including generation, transmission and demand-side management. System expansion cost recovery is less explicit. The Staff paper states that costs "would be borne by all parties who benefit from expansion". The paper goes on to say that "the Commission should prescribe by rule whether expansion pricing will be based on a rolled-in or incremental cost basis (or a combination), but in either case, regional costs that benefit multiple regional parties must be shared regionally".

- In mid-December, several FERC Staff members participated by conference call in the WGA Transmission Finance Committee meeting. While unable to commit to specific actions, their insights as to current Commission thinking and their reaction to Western issues and ideas were very helpful in framing the problems and identifying potential obstacles. For example, the debate continues within the Commission between a pure market-driven approach as opposed to a more regional, total system cost model for transmission expansion. Therefore, to be effective, any expansion and cost recovery proposals for the West, prior to the operation of the RTOs, would have to have broad support, including industry, public agencies and state PUCs.

5 THE VIEW FROM THE FINANCIAL COMMUNITY

5.1 Overall Observations on Transmission Financing

The lack of regulatory clarity in rate recovery is the primary obstacle to transmission investment.

Generation was the first electricity market function to move away from traditional utility financing concepts. Project finance, an existing capital markets mechanism, fits well with the characteristics of competitive independent power projects (IPPs). For this reason it has been both popular and successful with project sponsors. IPP projects are reasonably discrete. The responsibilities of the parties involved can be clearly defined and the risks can be managed or hedged.

Transmission services are different. There is normally no intention on the part of existing transmission owners to operate these as "unregulated" assets. Transmission is regarded as a natural monopoly service, similar to pipelines, and cost-of-service rates have been and could continue to be applicable. Other funding and cost recovery mechanisms, including bilateral contracts and secondary markets for capacity may also be applicable for transmission in certain circumstances. However, the inability to restrict power flows over AC (alternating current) transmission lines to only those parties who have paid for

the use of the lines, makes it difficult for a rights owner to capture the value of his investment or contract. Further, changes in the distribution of generation and demand in one part of the network can have a significant impact on power flows, and thus on line loadings in another part of the network.

Currently, there are few entities seeking capital to fund exclusively transmission-oriented upgrades. Integrated utilities are still funding transmission investments as part of an overall capital expenditure plan. The transmission component of such packages is predominantly maintenance, and replacement of existing, locally-oriented transmission or hookup of new generators to serve local markets. Currently transmission investment does not appear to be focused on increasing regional accessibility to generation supplies.

Analyses performed by the FERC, the Edison Electric Institute, as well as other individual industry participants agree that there is a "need" to build more transmission infrastructure. There are, however, differing views on the scale of the transmission investment required to overcome actual and potential constraints, to facilitate wider regional power markets and to make more competitive generation available to a wider range of consumers. Even though that "need" is well documented, Wall Street is not seeing companies seeking funds for substantive transmission expansions.

5.2 Regulatory Uncertainty

The core of the transmission investment problem is the incomplete restructuring of the industry and the regulatory uncertainty associated with recovery of investment in transmission assets. In the early stages of deregulation, the primary concern was the fate and valuation of generation assets. Little attention was paid to transmission until congestion became newsworthy with the price spikes in the Midwest in summer of 1998. Transmission shortcomings also played a role in the California crisis of 2000/01, and to a lesser extent in a high price episode in the Northeast in May 2000. It is only fairly recently that transmission has demanded more attention from industry participants, regulators and customers.

Under some RTO structures, investment in transmission would be recovered through an RTO-wide tariff. This looks to be completely workable from the perspective of the capital markets. The problem is that no RTOs have yet been approved in the West to provide this surety of return. The RTO structure as planned by the FERC would contribute the following to the calculation of capital costs for new transmission projects with regional benefits:

- Regional political and regulatory support for a specified transmission project or projects to assure collection in rates and facilitate permitting;
- A mechanism through which revenues would be collected and distributed to the transmission owner; and
- Charging provisions that would either guarantee an agreed-upon rate of return or a performance-based rate providing a potential return on investment that is appropriate to the risks taken.

Without RTOs in place, there is little incentive to develop transmission projects that would have primarily a West-wide regional benefit, as the three criteria noted above are absent. There does not yet appear to be any significant problem funding locally oriented transmission projects.

5.3 Pre-RTO Transmission Financing

From the perspective of the financial community, there are several actions and conditions that would facilitate financing of regional transmission projects. These include:

Political and regulatory support. Until RTOs are fully established, it is going to be difficult for states to play the role of regional planners. Unless a transmission project has overwhelming consensus behind it, including cost recovery agreements, it will probably not be realized before RTO operation. Project-by-project endorsement by state and local authorities would need to be secured in order to assure the capital markets that a project does not face high regulatory risk. A memorandum of understanding between PUCs and/or Governors might serve this purpose on an interim basis.

Revenue collection and distribution. This is a serious obstacle to financing regional transmission expansion prior to RTO operation. There appear to be few alternative methods that would allow recovery of these costs other than through a rate hike on the transmission owner's existing rate base.

- **Deferment**: The cost of a major regional transmission expansion could be capitalized and carried on the balance sheet as a regulatory asset with recovery deferred until the planned RTOs are in operation. The rates covering this service would then be added to the rolled in rates as existing transmission. This permits cost matching when revenues finally flow. Revenue recovery would be sought from all benefiting consumers, and would be deferred and socialized as appropriate. Such an approach would face the risk that the RTO would not start up on time. This risk on RTO startup could impact the cost of financing but could be mitigated by agreement among RTO stakeholders on the cost allocations of each upgrade ahead of the actual formal obligations of the RTO.

- "**But For" interconnection charges**. Generators would fund both the direct physical interconnection <u>and</u> network upgrades that would not be undertaken "but for" the addition of the new generation capacity. This would free the transmission owner from financing and push the costs of expansion to the generators benefiting from the expansion. FERC is unlikely to approve this approach since it would mean reversal of several recent interconnection orders and the direction of its current interconnection rulemaking.

6 MARKET-DRIVEN FINANCING MODEL

In the market-driven financing model, the financial support for a transmission expansion is derived from those who obtain transmission service. Its key assumption is that the financial commitment of market participants, each acting in his own best interests (in this case the combined decisions of project sponsors and their subscribers or customers), will

be sufficient to ensure that new transmission is constructed. Transmission would be built to alleviate congestion when economically warranted, to improve reliability or to serve load growth while isolating financial impacts to the project developers and the project's subscribers. A similar model has been used successfully by the gas pipelines for over a decade. While differences in regulatory history, industry structure and physics could make its application to electric transmission somewhat different, its advocates argue that, with creative adaptation, the market-financing model is most appropriate for a competitive transmission sector. The market-driven model does not preclude, and in fact would benefit from, a centralized forward looking analysis that would identify potential transmission bottlenecks based on forecast load and generation patterns.

6.1 Description

The market-driven financing alternative relies on the financial interests of market participants (generators, load serving entities, large end-users or independent third parties acting as agents on behalf of the others) to get appropriate transmission built. Examples of such participants would include a load serving entity contracting for distant, lower cost generation, a generator gaining access to higher value markets or a marketer seeking to gain competitive advantage in a trading position.

Typically, a project sponsor would subscribe a larger project with a number of participants, each of whom had concluded that they could gain economic benefits that exceeded their financial commitment and risks. Those who have subscribed (contracted for service) on an expansion project would be contractually committed to support the expansion through the payment of rates as negotiated with the project sponsor or as established through an open season process. Subscribers would typically bear the risk that the market conditions that currently support their benefits would endure or even improve over the duration of their commitment. Benefits (firm service rights or financial hedges) would be contractually defined and protected. The open season subscription process, successfully used in the gas pipeline industry, is frequently cited as a model for subscribing such market participant financing of transmission.

Philosophically, this model relies on the traditional regulatory precept that cost recovery should follow cost causation. That is, those who benefit from and cause the expenditure should pay for it. It presupposes that those benefits can be contractually specified and protected. From a regulatory perspective, the capacities created and the rates or other payments made by the customers would be held separate from the rest of the transmission system.

6.2 Issues and Discussion

The market-financing alternative depends on clear identification and estimation of the future costs and benefits for participants. A potential subscriber must fully understand the risks and benefits of participation and must have full confidence in the security and stability of the benefits. Therefore there must be an economic/market and regulatory environment in which those forecasts can be relied and acted upon. As described below, the incentives and the environment to act on those incentives should improve when the RTOs are in place.

6.2.1 Problems in the Period Before RTO's Are Created

The environment for market-driven transmission investment is currently not very supportive. Pending the creation of RTOs in much of the West, the future institutional framework for assuring value for the investment is not yet clear. For example, currently in most of the West, congestion is not clearly priced. With the implementation of congestion management by the RTOs, pricing information will improve significantly. Unfortunately, expectations of improved access to transmission once RTOs are operational may make parties unwilling to invest in the interim.

6.2.2 Impact of RTO Creation

RTO regimes should provide refined congestion prices and standard mechanisms for their calculation, as well as standard processes for expanding the system in response to market demands. The prompt creation and operation of RTOs across the West should put in place a system where congestion costs and hence the value available to justify investment will be transparent. RTOs should also provide the institutional framework to support implementation of this model.

However, even in an RTO environment, market participants may not undertake some desirable transmission investments. There might be various market failures or a lack of direct incentives that preclude effective responses by market participants. RTO West, for instance, has addressed this issue by providing for a market incentive-based approach to future investment, using an open season process, that is backed up by RTO action to cause transmission investment in cases of demonstrable market failure.

6.2.3 Need for a Clear Definition of Property Rights

Electricity market participants will require clarity with regard to the transmission rights that they will receive in exchange for any investment they may make in transmission expansion. The capability of an interconnected AC transmission grid to transfer energy across various constrained paths may be affected by changes in load and generation in parts of the network that are physically remote from the constraint. For these reasons determination of physical rights that investors in AC transmission should receive is not always simple. It would however be possible to assign financial rights relating to the increased capacity created by the expansion at the time the investment is made. These rights could be valued by market participants based on their view of future energy costs on either side of the existing system constraint. To date, examples of the market financing model for electricity transmission are confined to DC (direct current) interconnections where the flow across the line can be directly controlled in the same way as the output from a generating station may be controlled.

7 TOTAL SYSTEM COST MODEL

The total system cost approach relies on a coordinated regional planning and expansion process. In many ways it represents an extension of the traditional process used by state regulators for individual utilities. Transmission expansion projects would be proposed and approved on the basis of a system-wide, total cost analysis. The transmission

investment would be approved, provided it contributed to a reduction in the overall cost of meeting future demand across the system. The assurance of cost recovery by a regional authority (eventually the RTO) would allow those constructing the facilities to obtain financing on reasonable terms.

7.1 Description

Advocates of this model argue that the construction of an efficient interstate transmission grid for the West can best be accomplished through coordinated planning. This approach is essentially the same as the traditional state review process, but extended to the regional level. Proposed projects would be evaluated in a coordinated planning process to meet the demands of the region (instead of those of a single utility's service territory) at the least overall cost. Prudently incurred costs of approved projects would be recovered through regional transmission rates over the long term.

7.2 Issues and Discussion

7.2.1 Recovery of Approved Costs

Proponents of the total system cost model generally favor cost recovery arrangements whereby the costs of approved projects would be recovered from all users of the transmission grid via a region-wide tariff. Although system-wide cost recovery is not the only option that could be used with this model, it has been assumed here that it would apply to major interstate transmission expansions with widespread benefits for many market participants. The underlying assumption is that such increased transmission capacity would ultimately benefit many different power users in the region and therefore it would be appropriate to allocate expansion costs across all users. This model is similar to the model currently being used in California an Alberta.

Implementation of this model could occur at the RTO level or, with agreements among all RTOs, across the West. In either case it will require an institutional mechanism to add a transmission surcharge to every electric bill in the applicable region. Prior to the formation of RTOs, there would be the need to consolidate collections and make payments back to the entities building the new transmission. Alternatively the investment cost could be held on the balance sheet of the investors with recovery deferred until the RTO is operational (see 5.3 above). To spread the cost to all users would require the agreement of state PUCs, FERC and non-jurisdictional utilities. Once RTOs are in place, they could provide the mechanism to collect and dispense money. The RTOs have already formed the Seams Steering Group – Western Interconnection (SSG-WI) to begin to develop structures and procedures to deal with those issues that will need cooperation among the RTOs. Specifically, the SSG-WI Planning Group has been formed to examine what needs to be done to develop transmission expansion planning both before and after the RTOs become operational.

7.2.2 Relative Cost of Transmission

The cost of bulk electric transmission service represents around 5% of a residential consumer's electric bill and typically around 10% of an industrial user's bill. Therefore, the potential impact of contemplated transmission expansions on West-wide end users would be relatively small. Advocates of the total cost model argue that the penalty of not building enough transmission capacity can be many times the cost of building too much. Hence even if, as opponents of this approach contend, the total cost model did tend to err on the side of building too much transmission, this approach would be preferable to one that resulted in too little transmission.

8 COMPARISON OF THE TOTAL SYSTEM COST AND MARKET DRIVEN MODELS

The total system cost model would require broad agreement by parties on the need for a particular transmission investment. Such agreement is most likely to emerge from a robust, open regional transmission planning process. The market financing model would not require the equivalent degree of consensus on the need for a specific transmission investment since agreement among all PUCs, FERC and non-jurisdictional utilities would not be required to spread project costs.

With the total system cost model, the combination of coordinated system-wide planning and widely spread costs overcomes the problem of identifying, protecting and pricing transmission service rights. Each change in system load, generation or transmission capability has the potential to alter existing flow patterns. In the market driven model this could present difficulties in defining firm physical rights for investors and could result in radically different pricing for equivalent but sequential expansions. If the cost of transmission expansion were spread across all users, such anomalies would be absorbed into the overall cost structure of the system.

The market-driven model relies on the expectations of a project developer, or the project subscribers, that there will be continued price differentials between supply and market areas. While this concept has allowed success of market financing for gas pipelines, it would be a less certain proposition in power markets. A gas pipeline developer has greater locational certainty of both market and gas supply. The developer knows it is highly unlikely that gas will be discovered in his target market area, a development that would lessen dramatically the value of the pipeline. A transmission developer or his customers cannot be as sure that another developer will not put new generation in the target market area after the transmission capacity is built. The developer could shift some of this risk to his customers through long term contracts. However, this lack of durability of market signals for transmission investment increases the risk, regardless of which party bears that risk. For similar reasons a market-financed transmission project may have a bias towards under-sizing the transmission expansion since an expansion that completely removes a constraint would also remove the scarcity value of transmission access across that constraint.

Advocates of the market-driven approach argue that the total system cost model has the potential to over build transmission. They believe that it is not good policy to ignore the

fact that market participants may not have sufficient confidence in the economic advantages of the proposed expansion to invest themselves in creating the increased transmission capacity. Moreover those who favor the market-driven approach point out that so long as the beneficiaries of projects hope that a future RTO may socialize the cost of expanding the transmission system, they will not come forward to sponsor projects themselves. Finally, they would argue that substituting a planning process for a market-based expansion process will not send price signals to generation developers regarding the optimal location for new generating resources. As a result, consumers will pay for new transmission that could have been avoided if new generation had been optimally located.

Finally, if a political consensus were reached to promote a specific generation or fuel diversity policy, the total system cost model could be adapted to take account of such a policy more easily than the market-driven model.

9 TAX TREATMENT OF TRANSMISSION INVESTMENTS

9.1 Present Law.

Under present law, two different categories of tax-exempt bonds can be issued to finance electric transmission facilities, "government use" bonds and "exempt facility" private activity bonds. Tax-exempt "government use" bonds can be issued to finance a transmission facility that is owned and used by a state or a political subdivision of a state. A state or local government may also issue tax-exempt "government use" bonds to finance its ownership interest in a transmission facility that it jointly owns with others, including non-governmental utilities.

The "private business use" of a transmission facility (*i.e.*, the portion of the facility that is used by an entity that is not a state or a political subdivision) that is financed with "government use" bonds cannot exceed the lesser of 10% of its capability or $15 million. Private business use includes use by federal agencies (such as BPA and WAPA), investor-owned utilities, marketers, non-profit cooperatives and any other non-governmental entity. The applicable U.S. Treasury Regulations contain highly technical provisions that must be used to measure the private business use of transmission facilities.

"Exempt facility" private activity bonds may be issued to finance facilities for the local furnishing of electricity, regardless of whether these facilities are owned or used by non-governmental utilities. These bonds are of very limited usefulness because of the requirement in present law that the financed facility and its owners and users provide electric service to an area that is no larger than two adjacent counties.

9.1.1 Current Treasury Regulations

Under present law, these rules limit the extent to which state and local governmental units that own transmission facilities financed by tax-exempt bonds are allowed to

permit non-governmental entities to use those facilities. Nationally, 8% of transmission is owned by public power. In some states, the percentage is much higher. For example, in California about 25% of the transmission is owned by municipal utilities or governmental entities.

Prior to 1998, the private use rules essentially barred public power from committing to provide full open access transmission and from joining RTO's. Temporary regulations issued by Treasury in 1998 and reissued in 2001, provided partial temporary relief from these rules. But because the rules are only temporary, they do not permit public power entities to make long-term commitments to provide open access transmission service and to join RTO's when they are formed. More importantly, under the temporary regulations, no real relief is available for new transmission facilities financed by recently issued tax-exempt bonds. If the transmission facilities are reasonably expected to be used to provide open access transmission service, tax-exempt bonds cannot be used. So for the needed transmission infrastructure that will benefit all transmission users in an open access or RTO structure, the current Treasury regulations restrict a significant segment of possible transmission developers and their source of capital. Therefore, the current temporary regulations deter rather than encourage expansion of the grid. Congressional action or action by the IRS to make the temporary rules permanent is needed to cure this problem.

9.2 Extended Use of Tax Exempt Bonds

The Internal Revenue Code could be amended to create a new category of "exempt facility" bond that can be issued on a tax-exempt basis to finance transmission facilities. These bonds could be issued under the following conditions:

- The transmission facilities to be financed would be approved by the applicable regional transmission organization as necessary.
- The financed facilities would be available to users on a non-discriminatory basis under applicable open-access requirements.
- The total dollar amount of exempt facility bonds for transmission facilities would be subject to a separate annual state-by-state volume cap limit that could be combined by states participating in regional transmission projects and/or combined over a period of years to provide sufficient financing for large projects.

The requirement that the financed facilities be approved by an RTO or other regional authority would ensure that only those projects that are truly necessary from a regional perspective would benefit from tax exempt financing. The requirements that the financed transmission facilities should be available to subscribers and others under non-discriminatory open access terms ensure that special benefits would not be passed through to any party.

The benefits of tax exempt financing would be available to those willing to invest in transmission, including investor owned, co-operative and government utilities and builders of merchant transmission lines, provided access was made available to all parties on a non-discriminatory basis. The special volume cap requirements could be used to

limit the total dollar amount of tax-exempt debt that is issued for transmission projects and to quantify the costs to the U.S. Treasury.

10 CROSS BORDER ISSUES

As a result of the meeting between Western Governors and Western Canadian Premiers during 2001, there is a clear understanding that the Canadian provinces, especially British Columbia and Alberta, are integral to a well functioning Western grid and electricity market. The Governors and Premiers expressed a desire to work together on energy issues that had the potential for cross border impacts. It is acknowledged that there may be differences between the States and the Canadian Provinces in terms of regulatory requirements and the pace of market transformation.

In general, however, the models and issues discussed in this paper have parallels in British Columbia and Alberta. The TFC recognizes the importance of continued cooperation between the Western States and Canadian Provinces to find appropriate mechanisms to support new transmission investments that have mutual benefits.

11 CONCLUSIONS

The TFC has identified two distinct models through which expansion of the transmission infrastructure of the West could be financed. While there are different views among Committee members on the relative merits of these models, there is agreement that uncertainty over cost recovery arising from restructuring and changes to the way the industry is regulated, has created difficulties for investment in transmission expansion projects.

There is a strong argument that major transmission expansions that cover a number of states and provide widespread and diffuse benefits for a large number of customers may be more effectively identified and implemented through the total system cost model. Where a transmission expansion is primarily targeted at providing increased access from existing or new lower cost generation to a higher priced market then the market-driven model may be the more appropriate way forward. It is also possible that some transmission projects could be financed via a combination of these models with part of the expansion being funded by market participants in exchange for clearly defined transmission rights.

It is possible to improve the prospects for investment in the transmission infrastructure by establishing organizational and regulatory arrangements to implement a system-wide total cost model while at the same time creating the conditions that would permit and encourage market driven investment in transmission expansion. There is a broad consensus that the climate for transmission expansion investment is likely to improve when the uncertainties over the structure and regulation of the industry are removed and the functions, scope and operating rules for RTOs have been clarified. The recommendations outlined in this report address actions that the Governors can take to improve the prospects for investment in transmission infrastructure both before and after the RTOs are fully operational.

12 RECOMMENDATIONS

12.1 Regional Transmission Organizations

There is consensus among the TFC members that the formation of RTOs with clearly defined functions and operating rules will help to remove at least some of the uncertainties that are hindering investment in transmission expansion. The TFC therefore recommends the following.

1. The Governors should support the timely formation of Regional Transmission Organizations (RTOs) in the West to identify and facilitate expansion of the transmission infrastructure.

2. The Governors should call on the RTOs to address at an early stage any factors that may inhibit investment in transmission expansion in the West. For market-financing expansions to occur, the RTOs must clearly define the property or financial rights that accrue to a market participant making a transmission infrastructure investment.

12.2 Pre-RTO Actions

Given the long lead-time involved in transmission construction the TFC felt it was important to consider what actions could be taken in the period prior to the implementation of RTOs. Information regarding current and future transmission loading and the cost of possible transmission expansion projects would be valuable inputs for either of the transmission expansion models identified in this paper. It is also important for the total system cost model that planned expansions obtain the necessary regulatory approval to give investors greater confidence that they will be able to recover their investment costs from the rates charged to users of the transmission system. The FERC has indicated that it would be willing to consider financial incentives to help encourage investment in transmission. While these incentives could help to mitigate the increased risk that potential investors perceive in transmission investment at this time, the extent to which such incentives will be available for future investments is not clear. The Committee therefore makes recommendations to address these issues in the period before the RTOs are fully operational.

3. Prior to the formation of the RTOs, the Governors should support organizational arrangements that will permit suitable transmission expansion proposals to be identified and to receive the necessary state and FERC approvals.

   a. The Governors should recognize and encourage the recent initiative of the Seams Steering Group - Western Interconnection (SSG-WI) to develop a robust interconnection-wide "proactive" transmission planning process. This process, to be implemented in advance of the formation of RTOs would identify problems that can be addressed by transmission (or alternative non-transmission) solutions. Information developed in such a planning process will be valuable to market participants regardless of which financing model is used for a particular project. Such a process is essential to garner the public and political support that would be

needed to implement the total system cost model, especially in those cases where costs are to be recovered on a regional basis.

b. The Governors should urge FERC and state Public Utility Commissions (PUCs) to form joint State/FERC panels to adopt appropriate mechanisms that will enable cost recovery of transmission investments made before the RTO structures are fully implemented. Working in conjunction with the SSG-WI, these panels could drive agreements between state and federal regulators, transmission developers and their investors that would provide cost recovery assurances sufficient to induce development of needed infrastructure. The panels should also explicitly consider the risks and need for financing incentives.

12.3 Tax Treatment of Transmission Investments

It would be helpful to remove current uncertainty regarding the tax treatment of transmission investments. Bonds issued to finance transmission investments have been granted tax-exempt status in the past. However these arrangements have been very restricted and currently potential investors cannot be sure that this policy will continue over the period in which they may be required to make investments for a major expansion project. The Committee therefore recommends that this issue should be addressed to provide investors with greater certainty regarding the tax position of such investments and to permit increased use of tax exempt bonds to finance essential transmission expansions.

4. The Governors should jointly encourage the Internal Revenue Service to issue permanent regulations that clarify and extend the use of tax exempt bonds for investment to expand the transmission infrastructure. Specifically the IRS should be encouraged to make it clear that transfer of operational control of transmission assets financed with tax-exempt securities does not constitute a private business use or otherwise jeopardize the tax-exempt status of those securities.

12.4 Investment by Federal Power Marketing Authorities

It is recognized that federal power marketing administrations such as Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) have been important investors in transmission expansion in the West. If these bodies do not have continued access to investment funds, then future transmission expansion investment could be unduly constrained.

5. The Governors should urge the Administration and Congress to approve any reasonable requests by federal power marketing administrations to increase their borrowing authority, to allow Congressional appropriations, or to allow the use of revenue streams for needed transmission investment.

12.5 Cross Border Issues

The final recommendation recognizes the importance of developing solutions that will enable and encourage the appropriate level of transmission investment across the entire western interconnection.

6. The Governors should continue to work with the Canadian provinces to find appropriate mechanisms to support new transmission investments that have mutual benefits.

Appendix 1

Transmission Expansion Process and Transmission Cost Allocation in Alberta and California

A Paper by the Alberta Transmission Administrator and the California Independent System Operator Corporation

INTRODUCTION

This paper addresses the transmission expansion process and cost allocation methodologies that exist today in Alberta and California. Both areas have restructured their electric utility industry and have been operating under a competitive structure for a number of years.

THE ALBERTA PROCESS

Alberta was the first jurisdiction in North America to restructure its power markets and introduce wholesale competition in 1996 and retail competition in 2001. Alberta ranks first of all jurisdictions in North America on the Retail Electric Deregulation Index.

> ESBI Alberta Ltd. {"EAL") is the for-profit Transmission Administrator ("TA") of the province of Alberta and has a number of statutory duties, including the provision of open access and engendering reliability of the overall power system. One of the roles EAL carries out is planning the transmission system and procuring solutions to transmission needs for the entire geographic scope of the province. The process which has been developed with stakeholders over the past 5 years since de-regulation was introduced is described below.
>
> EAL in consultation with its transmission customers and service providers develops a demand forecast for the province.
>
> EAL then undertakes system-planning studies and identifies transmission needs over a 10 year planning horizon with the assistance of the Transmission Wire Owners through a consultative process. This process culminates in the publication of the rolling 10 year Transmission Development Plan which identifies the needs and contains some discussion on the possible solutions, such as transmission wires or generation substitutes. This plan is a benchmark document for the industry and allows it to anticipate future evolution of the industry.
>
> Once the timeframe begins to encroach on the lead-time for solutions, EAL decides based on consultation with stakeholders, the procurement mode appropriate to the likely general class of solutions. If local generation is the preferred solution, EAL administers an open competitive process – approximately 500 MW of local generation has been procured in this manner to date. If transmission wires are the preferred solution, a competitive process or a direct assignment process is undertaken – the latter is adopted for situations where the costs of the competition are considered to outweigh the benefits. The generation substitute procurement has been tested extensively in regulatory proceedings before the provincial regulator, the Alberta Energy and Utilities Board ("EUB"), who have emphasized the requirement that any 'must-run' contracts should not distort the competitive market.
>
> The competitive process is open, and the standard *pro forma* procurement documents and contracts have evolved over time and have the approval of the provincial regulator. The contracts

generally have a lifetime of 40 years; EAL pays particular attention to the ability of the proponents to perform the contract over that period.

After a winning proposal is selected and final negotiations are completed, the actual contract is submitted to the EUB for permitting of the facilities and for approval of the contract – which should be the *pro forma* modified to reflect the particulars of the project.

The EUB may hold a public hearing on the application and eventually, if it is found to be in the public interest, the project can be included in EAL's revenue requirement and a certificate of public convenience is issued.

Once this contract has been approved by the EUB the project developer can readily obtain financing. The funding of the contractual obligations by EAL is through the revenue requirement and hence recovered through general rates, and is transparent through each subsequent General Tariff Application.

A unique feature of the Alberta transmission tariff is that generators pay 50% of the costs on the 'sender pays' principle. The existing Alberta transmission tariff is based on a postage stamp design, with system costs shared equally between generation and load through the tariff. Some local costs directly attributable to a single customer are paid for by that customer.

In November 2001 EAL submitted an Application to the EUB for approval of congestion management principles and recommendations. A Decision by the EUB is not expected until after Q1 2002. A summary of the major recommendations made in the Application is provided below:

EAL's obligation as the TA is to relieve transmission congestion by expanding the system through building infrastructure to provide reasonable transmission access to Alberta customers. The expansion costs incurred based on a zero export assumption will be rolled into the tariff under the existing rules, and recovered on a postage stamp basis from Alberta customers.

The incremental costs identified as necessary to support export or import transactions, will be allocated directly to those parties contracting for exports or imports. Such incremental costs will include the advancement costs of facilities required by Alberta customers at a later date. The TA will not construct such facilities in advance of payment commitments.

It is not the TA's responsibility to procure point-to-point transmission extending beyond the Province. The expectation is that merchant developers will build such facilities. Merchant developers will recover the incremental costs of their own facilities and the incremental costs of the Alberta transmission system allocated to them, through their own pricing mechanism to exporters.

The policy recommendation includes the principle that Alberta customers will not be put at financial risk for the recovery of transmission investments made to accommodate export transactions.

THE CALIFORNIA PROCESS

The California Independent System Operator Corporation ("ISO") is a non-profit public benefit corporation organized under the laws of the State of California. The ISO is responsible for the reliable operation of a grid that initially comprised the transmission systems of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, as well as for the coordination of the competitive electricity market in California. The ISO began operation of the first competitive market structure for electricity in the United States on March 31, 1998. Effective January 1, 2001, the grid was expanded when the City of Vernon, California also became a Participating Transmission Owner

("Participating TO") by turning over operational control of its transmission facilities to the ISO. The transmission systems turned over to the ISO for operational control from the Participating TOs is known as the ISO Controlled Grid.

Transmission Expansion

The ISO has a coordinated grid planning process wherein each year the ISO and Participating TOs develop a five-year integrated transmission plan for the ISO Controlled Grid. Under that process, each Participating TO annually develops a five-year expansion plan for its portion of the ISO Controlled Grid; the expansion plan identifies the transmission projects necessary to satisfy the ISO's Grid Planning Criteria and incorporates any transmission projects, sponsored either by the Participating TO or another Market Participant, which may be requested and supported on economic grounds. The ISO then assesses the plans developed by the Participating TOs, determines which projects are needed, and develops an ISO Controlled Grid-wide integrated transmission plan. Upon approval of the ISO's integrated plan by its Governing Board, the Participating TOs are authorized to proceed with the development of the individual projects included in the plan. To date, the ISO has approved approximately $1 billion of transmission projects.

Cost Allocation

The law organizing the ISO - AB1890 - established that the initial Access Charge for the use of the ISO Controlled Grid would be based on the utility-specific rate of each Participating TO. The rolled-in embedded costs of the transmission facilities are recovered primarily through Access Charges levied on Market Participants withdrawing Energy from the ISO Controlled Grid.[2] Originally, each Participating TO determined the Access Charge applicable to Market Participants withdrawing Energy from the ISO Controlled Grid in its service area, based on the costs of its transmission facilities and Entitlements, in accordance with its Transmission Owner's Tariff.[3]

AB1890 also required the ISO to recommend for adoption by the Federal Energy Regulatory Commission a rate methodology for the subsequent Access Charge no later than two years after the initial operation of the ISO. Thus on March 31, 2000, the ISO filed Amendment No. 27 to the ISO Tariff proposing a two-tiered Access Charge. The Transmission Revenue Requirement of local or "low voltage" transmission facilities (below 200 kV) is recovered by the individual Participating TOs from the customers served in their service area. Costs associated with and allocated to regional or "high voltage" transmission facilities (200 kV and above) included in the ISO Controlled Grid, are initially based on the Transmission Revenue Requirements of all Participating TOs in each of three "TAC Areas," corresponding to each of the former control areas that were combined to form the ISO Control Area. Over ten years, the high voltage Access Charges for these TAC Areas will be combined to form a single ISO Grid-wide high voltage Access Charge.

In addition, capital investments by any Participating TO in new high voltage transmission facilities, and in additions to existing high voltage transmission facilities that are placed into service after January 1, 2001, would immediately be included in the ISO Grid-wide component of the high voltage Access Charge. This increases the pace at which the high voltages Access Charges converge into a single charge. At the end of the ten-year transition period, a single high voltage Access Charge will apply to the withdrawal of Energy at any point on the ISO Controlled Grid.

The transmission facilities that are in the ISO Control Area, some of which comprise the ISO Controlled Grid, vary considerably in: voltage size as compared to use; age of facilities and equipment; and, financing structure (tax-exempt vs. taxable). The costs for transmission based on transmission revenue requirement divided by transmission owners total load range from approximately $0.75/MWH to $11.00/MWH. The rate structure filed by the ISO has been in place since January 1, 2001 but is pending settlement proceedings that are currently ongoing at FERC. Because of the cost diversity, the cost shift between the various Participating TOs is limited for the 10-year transition period.

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[2] Market Participants using the ISO Controlled Grid for the transmission of Energy to serve a Load located outside the ISO Controlled Grid pay the Wheeling Access Charge.

[3] For the transmission of Energy out of or through the ISO Controlled Grid, a Wheeling Access Charge is imposed, based on Transmission Revenue Requirement of the Participating TO or TOs that own the facilities at the Scheduling Point where the Energy is scheduled to exit the ISO Controlled Grid.

SUMMARY AND CONCLUSIONS

Both similarities and important differences exist in the transmission expansion processes and cost allocation approaches currently implemented by Alberta's for-profit TA and the not-for-profit California ISO. The separate approaches have evolved with the restructuring and re-regulation of the electricity markets within which they operate. Differences in approaches reflect differences in the size and structure of the respective markets and industries these entities serve, as well as their unique regulatory and competitive environments.

While the timeframe over which the annual transmission plan is developed is longer in Alberta (ten years versus five years in California), both entities rely on a consultative process involving transmission wire owners in the development of the plan. The relatively more extensive role of transmission owners in developing and implementing the California ISO plan partially reflects the larger market and more complex nature of the California ISO controlled transmission system.

Alberta's existing postage stamp tariff, with system costs shared equally between generation and load, is expected to be modified in the future; new transmission facilities required for export or import transactions will be allocated directly to those parties contracting for such services, if the congestion management approach proposed by EAL is approved by the regulator. While different (load-based) access charges currently apply in California - reflecting differences in the costs of the ISO Controlled Grid in each Participating TO's service area - this will move toward a postage stamp design over the next ten years, as the separate high voltage Access Charges converge into a single charge.

REFERENCES

The various documents cited in this paper and other material relevant to transmission expansion and cost allocation can be found at the EAL and California ISO websites:

WWW.EAL.AB.CA
www.caiso.com

APPENDIX 2

LIST OF PARTICIPANTS IN THE TRANSMISSION FINANCE COMMITTEE

C. William Arrington	Transmission Technology Corporation
Ken Beeson	Eugene Water and Electric Board
Steve Begay	Dine Power Authority
Neil Brausen	TransAlta Corporation
Alex Brennan	PacifiCorp
Lewis Campbell	Lundberg, Marshall & Associates Ltd
John Carr	PacifiCorp
Philip Carter	ESBI Alberta Ltd
Phil Carver	Oregon Office of Energy
Ed Chang	Western Area Power Administration
Jim Charters	Western Area Power Administration
Mike Coleman	FERC
Alan Davis	Enventure
Joe Durham	Williams Energy Marketing & Trading Company
Chuck Durick	Idaho Power Company
Marshall Empey	Utah Associated Municipal Power Systems
Stephen Fausett	Tri-State Generation & Transmission Association, Inc
Wally Gibson	Northwest Power Planning Council
Jim Hicks	PacifiCorp
Steve Huhman	Mirant Corporation
Ted Humann	Basin Electric Power Cooperative
Tony Karr	Sierra Pacific Resources
Curtis Kebler	Reliant Energy
Jason B. Kreizenbeck	Micron Technology, Inc
Marv Landauer	Bonneville Power Administration
Doug Larson	Western Interstate Energy Board
Ronald Lehr	National Wind Coordinating Committee
Debi LeVine	California ISO
Carl Linvill	State of Nevada
Duane Marti	Bureau of Land Management
Fergal McNamara	ESBI Alberta Ltd
Denise Mullen-Dalmer	Energy and Mines, British Columbia

Phillip Muller	SCD Energy Solutions
Larry Nordell	Montana Dept. of Environmental Quality
Beatriz Rivera	Energy Resource Associates, LLC
David Schiada	Southern California Edison
Brian Silverstein	Bonneville Power Administration
Grant Siwinski	Nevada Public Utilities Commission
Mark Smith	FPL Energy
Marsha Smith	Idaho Public Utilities Commission
Scott Smith	Mirant Americas, Inc.
Dejan Sobajic	EPRI
Jim Souby	Western Governor's Association
Steve Stout	Micron Technology, Inc
Joe Taylor	Tri-State Generation & Transmission Association, Inc
Christine Tezak Uspenski	Schwab Capital Markets, LP
Steve Waddington	PacifiCorp
Lisa Wayne	Council of Energy Resource Tribes
Jacob Williams	Peabody Energy
Bruce Zimmerman	Umatilla Indian Reservation