

Transmission Pricing in the Western Interconnection

--A draft paper by the CREPC Transmission Pricing Work Group¹

Introduction and context of this paper

This paper is a work in progress designed to serve several ends. First, the paper is intended to aid the members of CREPC in formulating comments to FERC on the three western RTO proposals (RTO West, Desert STAR and the California ISO). Toward this end the paper will summarize and discuss the issues raised by the developing RTO proposals as they are embodied in working papers, RTO board decisions and FERC filings. An early goal is to have this information available to the states in time to help with the first round of comments due to FERC by November 16.

Second, the paper will serve as a vehicle for evaluating the effects of the RTO proposals on seams issues that are a subject of concern for commercial transactions across the West, and the focus of immediate attention at the Western Market Interface Committee (WMIC). We hope that the discussion here of seams issues will assist the WMIC in improving the transparency of the seams. WMIC is a vehicle for encouraging consistent practices among the three RTOs to ensure that commercial decisions made by an individual RTO do not inadvertently and unnecessarily impede the development of vigorously competitive west-wide wholesale power markets.

Finally, the paper will satisfy in part the obligations involved in DOE's RTO pricing and congestion management grant to CREPC. Under the grant proposal CREPC was to develop a "western pricing and congestion management proposal" that would foster efficient wholesale power markets and efficient use and expansion of the transmission grid.

This paper is organized into three sections:

- C. Potential Comments to FERC on RTO Filings**
- D. Discussion of Transmission Pricing Issues**
- E. Summary of RTO Transmission Pricing Proposals**

¹ The Work Group consists of Larry Nordell (MT), chair, Wally Gibson (NWPPC), Arne Olson (WA), Prasad Poturri (NM), Bill Eastlake (ID), and Jim McClusky (CA).

- C. **Potential Comments to FERC on RTO Filings**
- D. The purpose of this section of this section of the paper is to provide language individual states **may** want to use in making comments to FERC on various RTO filings. This section will evolve as additional RTO filings that clarify elements of the RTO proposals are made. Comments on DSTAR's October 16 filing are due to FERC on November ~~20~~¹⁶.
- E. Comments on RTO West's October 23 are due October 20.
- F. Comments on the FERC proposed Order Proposing Remedies for the California Wholesale Electric Markets (including congestion management redesign) are due November 22

In this section you will find (A) initial detailed comments on the October 23 RTO West filing and (B) generic comments applicable to all three RTOs.

Again, the intent of this section is to provide language that states may find useful as they respond to RTO filings at FERC.

A. Generic Language Potentially Useful in Commenting on DSTAR or RTO West Filings or FERC's November 1 "Order Proposing Remedies for California Wholesale Electric Markets"

The Commission noted in its in November 1 Order on the California market that:

California is physically integrated into an extensive interstate transmission grid and has therefore been part of a western electricity market for a long time. California's markets will never realize optimal performance until the impediments to efficient utilization of the regional transmission grid are eliminated and the regional interstate transmission system is designed in such a way that it supports transparent, competitive Western bulk power markets - - markets that support all of the wholesale products that California requires, markets that remove impediments to efficient imports and exports, markets that eliminate rate pancaking and allow California to access more distant markets at a lower cost, markets that undertake regional transmission planning to ensure that the needs of California are considered when transmission expansions in other states are considered, and markets that allow regional market hubs like Palo Verde to develop where new generation can be located to serve multi-state markets. . . . When fully implemented, RTOs will provide for operation and planning that will ensure consumer benefits for Californians and the citizens of other Western states. The problems being confronted in California can, in many ways, be traced to the continued balkanization of the Western grid and the absence of a true RTO with regional scope. . . . We expect that the matters addressed in this order will move the California market toward meeting the significant objectives

of Order No. 2000 and that these long-term market reforms will facilitate California's transformation into a properly sized and functioning RTO.

San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Docket No. EL00-95-000, et al. (November 1, 2000) at 46.

The policies of an RTO West, Desert STAR and California ISO should foster an efficient wholesale electricity market in the Western Interconnection. To enable this to occur, the Commission should review filings for these entities at the same time. This will enable to Commission to address important elements that will determine whether an efficient wholesale market develops in the Western Interconnection. Specifically, the Commission needs to strongly encourage consistency among western RTOs with regard to the following:

- G. Determination of the transmission paths in the Western Interconnection where FTRs will be offered;
- H. Determination of the amount of capacity on such paths that will be covered by FTRs;
- I. Flowgate methodologies;
- J. Definition of terms (Firm Transmission Rights, Recallable Transmission Rights, Non-firm Transmission Rights) to the extent such commonality is necessary to foster a competitive wholesale market; and
- K. The schedule for each of the RTOs to make filings with the Commission of documents governing important elements of their plans (e.g., TOAs, tariffs);

In addition, with regard to export fees the Commission should encourage RTOs to enter into reciprocal agreements that incorporate mechanisms to offset any undue cost shifting caused by the waiver of export and/or import fees. With regard to FTRs, the Commission should determine whether the depth of the FTR market is sufficient for a competitive market.

B. Potential Language Conveying Initial Detailed Comments on the October 23 RTO West Filing

0. General

We support the proposal to form RTO West, and applaud the filing utilities for their willingness to take this step towards a single management, open access transmission grid covering a significant portion of the Western Interconnection. We believe that the proposed filing meets most of the requirements set by FERC in Order 2000. We support the proposal for an independent Board of Directors, and we note that the governance proposal was developed with the participation of representatives of many stakeholder groups, including the regulatory and policy agencies of many of the western States. Nevertheless, we note that the proposal is the proposal of the filing utilities.

- 1. A well-functioning power market in the western interconnection requires that the three RTOs flesh out congestion management and pricing proposals on a common schedule and submit to a common evaluation by the Commission.**

The Western Interconnection has historically been a single wholesale market. California relies heavily on power supplies from the Northwest and Canada and the Desert Southwest; the Northwest relies seasonally on supplies from California. The integrated nature of this market was demonstrated this summer by the tracking of prices around the region.

It is essential that the three RTOs adopt consistent commercial methods and product definitions, and systems of pricing and congestion management, so that the seams between RTOs do not become barriers to the functioning of a westwide competitive wholesale market.

FERC should require that the three western RTOs flesh out their pricing and congestion management proposals and file with the Commission on a common schedule. FERC should also evaluate the three proposals together to determine whether proposed methods are consistent and whether they would foster or impede the development of a smoothly functioning competitive westwide wholesale power market.

- 2. The RTO-W proposal to make the Transmission Operating Agreement (TOA) contractually supercede other documents, including the tariff, violates FERC's requirement for open architecture.**

The TOA is a contract among the filing utilities that will determine how RTO-W will operate. We recognize the need for the filing utilities along with their customers and regulators, to ensure that they know what will happen to the assets and rights at stake. However, the filing utilities go too far in proposing to make the TOA the overriding document that will supercede all other documents, including the tariff, in all areas. We believe that there are legitimate areas in which the TOA can take priority: ratifying the company rate and transfer charge negotiations over the recovery of the costs of the existing system is one, and ensuring that the native loads and existing contract holders that pay the transfer charges that go into the company rates get the benefits of the FTRs is another. Protection of benefits should not, however, extend to allowing FTR holders to withhold them from the market at their sole discretion.

The RTO, once created and set in motion, must be the master of its own destiny. It must be able to respond to changed circumstances and to rectify problems that are uncovered in its methods and operations. For this reason, FERC properly required the RTOs to incorporate the principle of open architecture into their proposals. The effort by the filing utilities to control the actions of the RTO after it is created and set in motion would severely undercut this principle. Further, it could make it difficult to remedy market design flaws that may show up in the future, especially the potential failure of the secondary market in physical transmission rights described below.

FERC should require that the TOA be amended to recognize the independent ability of the RTO to propose, and FERC to regulate, changes in its operations and procedures as conditions dictate.

- 3. The RTO-W filing does not ensure a liquid market for FTRs, which is necessary for market-based congestion management. FERC should consider mandating auction participation by all FTRs and bar reservations of capacity in lieu of FTR assignments.**

RTO-W is proposing a system of physical rights to congested transmission paths. Only holders of rights to those paths will be able to schedule across them. RTO-W envisions an active secondary market for FTRs in which market participants will acquire the rights they need for desired transactions. Congestion would be self-managing through this market.

The physical rights system of congestion management can result in efficient, market-based congestion management only if there is a liquid and transparent market for the FTRs. Regardless of how rights are distributed initially, a liquid market will monetize them and provide incentives for all parties to incorporate the market value of FTRs into their comparisons of alternate sources of power or their evaluations of potential power market transactions. They will have incentives to retain or acquire only the rights they need for their best set of transactions.

However, the RTO-W proposal does not ensure a liquid market for FTRs. There is no requirement that existing owners of transmission and existing contract holders place their FTRs in the market; they may choose to retain any or all of the FTRs distributed to them. The RTO-W proposal would auction any unallocated FTRs, thereby placing them into the market. However, it is not clear whether significant unallocated FTRs would remain after assignments for load growth of transmission owners and preexisting contract holders, and given generous conditions for contract renewals into the future. Further, unused FTRs would be released only as non-firm or callable FTRs and only very late in the scheduling process, where they would not be of help to marketers trying to make long-term firm transactions. This system will protect existing rights holders at the expense of efficient market-based congestion management.

Under the current system of posting available transmission capability (ATC), key transmission paths that are not heavily loaded may show little or no ATC. This demonstrates that the rights holders can block competitors from access to their markets by withholding transmission capacity even though they are not using it. FERC's intent in requiring the establishment of RTOs is in part to eliminate the ability of transmission owners to strategically limit access to their systems. The RTO-W proposal fails to ensure this result.

Two possible changes could insure the development of liquid markets for transmission access. First, all existing rights could be monetized as rights to auction proceeds and all FTRs could be offered at auction. Equivalently, all rights holders could be required to offer the rights in an auction. Existing rights holders and native load would be protected because they would receive the proceeds from the auction enabling them to outbid any other bidders for the rights they need. A second change in the RTO-W proposal that would ensure liquid markets for transmission access would be a switch to a financial rights model instead of the physical rights model. In this model all transactions would be accepted, congestion would be managed by purchases of reverse flows through re-dispatch, and the marginal cost of congestion management would be charged to all parties affecting the congested path. FTR holders would submit coupons and non-FTR holders would pay the marginal congestion cost. In order to ensure liquidity in a financial rights model, the RTO might need the ability to require congestion re-dispatch bids from most not all generators.

(Alternative 1) FERC should require that the RTO-W proposal be modified to ensure that liquid markets for transmission access will develop. We would prefer that existing rights be translated into rights to auction proceeds rather than FTRs, so that all rights holders would have to monetize their rights and evaluate the optimal package of rights they need. However we recognize that this may be too big a step to take at once for many stakeholders. We suggest therefore that FERC require a phase-in over a five

year period from startup to a system where all rights must be offered in the auction. In the second year FTR holders would have to place 25 percent of FTRs for each hour and each path into the RTO's auction, in addition to unallocated FTRs placed in the auction by the RTO. In the third year this figure would rise to 50 percent, in the fourth year to 75 percent, and in the fifth year all rights would have to be placed in the auction. The right holders would not be at risk in this procedure as their right to the auction proceeds would make their ability unlimited to bid for rights they need. FERC should consider requiring that RTO revisit the issue every year to make sure that the secondary markets are working, with parties that wish to hold their FTRs out of the auction having the burden of proving to the RTO board that they would suffer irreparable harm.

(Alternative 2) FERC should evaluate whether the RTO-W provisions would result in a liquid market for FTRs and ensure that a competitive westwide regional market for power can develop. FERC should direct RTO-W to explain the following: (1) how the provisions of the TOA ensure that a liquid market for FTRs will exist; (2) how parties not granted FTRs can acquire them in a timely manner to facilitate firm transactions across the RTO-W system and the west and (3) and how right holders will be prevented from withholding the rights from the market to enhance their market power. If FERC is not satisfied with such assurances it should order the proposal to be modified in a way that provides them.

(Alternative 3) FERC should determine whether the RTO-W proposal will lead to a liquid market for FTRs and adequately satisfy FERC's goal of market-based congestion management.

3. Flow-based scheduling and congestion management by FTRs should extend to inter-RTO schedules across seams.

We applaud the intent of RTO-W to use flow-based, rather than contract path, scheduling for transactions within and across the RTO grid. The same approach should be used to schedule transactions that cross RTO boundaries. This will make possible a true market-based approach to parallel path flow. Efforts are underway at the Western Market Interface Committee to coordinate the three RTO approaches to scheduling across the seams. FERC should encourage the extension of flow-based scheduling to inter-RTO transactions.

4. We reserve the right to submit comments regarding the RTO West transmission operating agreement (TOA) during the current 30-day period beginning October 23, 2000 and the 30-day period following December 1, 2000 when the filing utilities plan to file revisions to the TOA.

L. Discussion of transmission pricing issues (including how the issue impacts seams among RTOs and whether there is consensus on the issue). This section of the paper is still being developed.

A. Westwide single commercial model

The western United States is served by a single, interconnected, synchronous transmission grid. Power sales take place across the western interconnection without regard to the ownership of the intervening transmission lines. Historic pricing methods have led to financial barriers that accumulate each time a transaction crosses another utility's transmission system, even though there may be no additional costs associated with carrying the transaction. A major goal of FERC in promoting the establishment of RTOs is to eliminate this "pancaking" of rates when multiple systems are crossed. Many parties in the west would go further and argue that the creation of RTOs should lead as much as possible to transparent boundaries between RTOs (or "seams"); i.e., it should

be no more difficult to make a transaction across a seam than within an RTO, and the charges for making transactions across seams should bear the same relation to the costs of carrying power as charges for transactions within an RTO.

Transparency also requires consistency of commercial product definitions, schedule timing, and FTR definitions and markets. Thus transactions should trade in the same units and time periods, and scheduling deadlines should be the same in all RTOs. A commercial transaction should not have to be repackaged to cross a boundary, and should not have to wait for multiple closing times to know whether it has firm access. Firm access across seams should be available on the same basis as access across flowgates within an RTO. Thus a transaction should require a single set of FTRs for crossing a congested seam, not one for each side of the seam. Flows should be scheduled consistently. Commercial transactions should be able to schedule from one RTO to another and expect the adjacent RTOs to use the same conventions about the resulting flow patterns. If the originating RTO were to use contract path scheduling while the receiving RTO used flow-based scheduling, the scheduling parties would face undue difficulty in assembling rights for the transaction.

This is the essence of the seams problem. In order for users of the western grid to be able to make firm transactions across the western grid in a single, competitive market, the seams must be transparent. The RTOs must coordinate their commercial practices and product definitions, their scheduling practices, and the time of locking in schedules.

B. Load-based access fees for sunk capital cost recovery

1) License plate rates

Traditional pricing for use of the transmission grid, by parties other than the owner or the owner's native load, consists of wheeling charges filed as FERC tariffs that are based on the recovery of a share of the total investment in the transmission grid. The cost charged to a transaction has no relation to the actual incremental costs associated with carrying it.

The true incremental costs of carrying a transaction are the congestion costs (which can be measured by a shadow price or by the value of the other transactions that would have to be displaced to make room for the transaction), incremental losses and incremental ancillary services. Congestion costs are zero if those portions of the grid that would carry the transaction are not fully loaded. Transaction charges that collect capital costs, independent of the true incremental costs of the transactions, will distort decisions of the economic viability of the transactions. Transactions that make good sense and provide benefits to all parties will be blocked if the capital cost recovery method makes them unprofitable.

Capital cost recovery is a key issue for the transmission-owning utilities in the formation of RTOs and it must be addressed. A number of proposals have been made for methods to assess capital cost responsibility (for example, the MW-mile method), that would continue to collect capital costs from transaction charges. However, economic efficiency objectives require that sunk capital costs not be collected from transaction fees. The alternative is to collect sunk capital costs from annual fees divorced from actual transactions. Annual fees can be load-based or generation-based. There is a general but not total consensus that load-based fees are preferable in that they can be set to mimic historic cost responsibility and avoid major problems with cost shifting. All three RTO proposals include at least an alternative that would collect capital costs through load-based annual fees.

Payment of the load-based annual fee entitles parties to make transactions at will across the RTO subject only to incremental cost responsibility - congestion costs, ancillary service costs, and incremental transmission losses. With the use of load-based fees, generators and marketers must be concerned only with incremental costs.

"License plate" fees allow for the collection of capital costs through load-based fees while recognizing that the historic capital costs are not uniform across the RTO. Historic cost differences may reflect geographic factors such as terrain or load density, or simply differing practices of the transmission-owning utilities. A license plate fee paid by a utility load would cover approximately its historic transmission cost responsibility, and once paid, would allow it free access to transactions across the system paying only the incremental costs of each transaction. The fee for each load area (or "license" area) would reflect the historic capital cost recovery plus wheeling charges paid to other areas, less wheeling revenues from other areas. Company rates are license plate fees that minimize cost shifting and eliminate pancaked rates within the RTO. No other capital cost-based charges need be paid to cross other utility systems within the RTO.

There has been considerable discussion dating back to the IndeGO negotiations over the extent to which FERC would allow the freezing of historic rate differentials among utilities after control of the transmission grid was put under common control. Immediate movement to uniform area rates or to uniform rates RTO-wide would clearly result in dramatic cost shifts that would benefit the customers of high-transmission-cost utilities and harm the customers of low-transmission-cost utilities. Freezing company rates would avoid these shifts initially. Over time, however, it is impossible to predict the path of company rates and of the distribution of benefits of RTO formation, and arguments about cost shifting become more problematic.

2) Company rates at least initially

RTO-W plans to start with company rates and to maintain them for a period of 10 years, locking in current cost relationships. After the ten-year period, the RTO board will decide how to proceed. This decision may be more intended to postpone arguments over cost shifting and to punt the decision to the RTO-W board which will face a different set of political constraints and realities than do the filing utilities.

C. Flow-based congestion management

1) More accurate signaling of marginal congestion costs for operation, new construction of load and generation, new construction of transmission

Power flows in a transmission network travel on all available paths, following the laws of physics. This is difficult to turn into a commercial method for charging for access when portions of the grid are under the ownership of separate utilities. Therefore, utilities have developed a commercial system under which transactions that cross multiple utility transmission systems have been scheduled using a "contract path" system. Under the contract path method, a transaction only needs permission to follow a specific path through the intervening utilities to be an allowable schedule.

The use of the contract path has created difficulties in dealing with congestion. Transactions allowed on a contract path contribute to congestion of the other paths that they do not pay for, and they may appear to congest the path they do pay for even though it is not fully loaded. Since the prices seen by transacting parties are unrelated to the costs they actually impose on the grid, they do not receive accurate indications of the best pattern of operation of existing generation, the best places to build new generation, or the appropriate places and time to expand transmission capacity.

The movement to an RTO offers the opportunity to create an efficient system for managing access to the grid that is consistent with the physical reality of the transmission network. A market-based congestion management system would force transacting parties to pay the costs of the actual congestion caused by their transactions. Efficient price signals will provide incentives for new construction of transmission capacity and for properly located central station and distributed generation, and would send location-differentiated price signals for the value of load management programs.

Under a flow-based system, a transaction between two points on the transmission grid would be distributed across the "flow paths," or the links in the simplified model of the transmission system of the RTO. In order for the transaction to be accepted, under the physical rights model chosen by RTO-W,

it would have to have firm transmission rights (FTRs) on each of the flow paths. On uncongested paths the FTRs should have zero value. However, on paths that are congested competition for the FTRs will raise their value to the marginal value of congestion – the difference between the value of generation on the downstream side of the constraint and the value of generation on the upstream side of the constraint.

2) Proposal for continuation of rated path for one year - with FTRs implemented at startup

The RTO-W proposal calls for the use of a flow-based system of managing congestion, and will begin operation with FTRs assigned to preexisting rights holders according to the historic pattern of their transactions. However it has been proposed within the RTO-W discussions to operate for the first year with a flow-distribution matrix that assumes contract path flows. This fiction would simplify the task of beginning the operation of the RTO and postpone the task of calculating the flow matrix that would reflect the electronic topology of the transmission grid. However it will create problems for congestion management and impede the RTO's ability to make full use of the transmission system capacity. . The October 23 RTO-W filing does not specify any interim steps, but allows for them to be proposed in the Stage 2 filing in the spring.

3) Replace WSCC Loop Flow Mitigation Scheme with market-based loop flow mitigation

The western transmission grid is characterized by a large loop in which inadvertent flows move in different directions in different times of the year, depending on patterns of load and generation. Flows from the northwest to California are scheduled south on the AC and DC interties between Oregon and California. However, part of the flow travels in a large clockwise loop through Utah and Colorado, and enters California through Palo Verde and Mead at the Arizona/Nevada California border. Power flows from Arizona and Four Corners to California are deemed to flow directly through Palo Verde and Mead, but a portion flows north through Utah and Idaho into Oregon and down the N-S interties. When California sends power to the Northwest during Northwest winter peak it is deemed to flow north on the interties, but a portion travels through Arizona, Utah, New Mexico, Colorado, Wyoming and Idaho. In each of these cases, the portion of the flow that travels off the deemed contract path is called inadvertent flow or loop flow, and it is uncompensated in that no wheeling payments are made to compensate the owners of the transmission lines.

In order to deal with congestion caused by these major inadvertent and uncompensated power flows, the western utilities have developed a series of technological fixes and operation procedures, called the "WSCC Unscheduled Flow Mitigation Plan." These procedures call for the utilities whose lines are congested by inadvertent flow to absorb a certain amount of uncompensated congestion, and to operate the phase shifters on their own systems to change the system characteristics and block some portion of the loop flow. If congestion persists, the utilities can ask for phase shifters on other utilities' systems to be operated. Finally, there is a procedure for requiring curtailment of schedules according to a predetermined pattern.

The WSCC loop flow mitigation procedures have functioned effectively at minimizing the effects of loop flow on utility system operations. However, they are not market based. They result from a series of negotiations among the western utilities that tried to balance equities among the transmitting parties and the affected transmission owners. The formation of the RTOs and the development of market-based congestion management procedures within RTO boundaries offers the possibility of agreement on a market-based system for dealing with inadvertent flows.

Under a flow-based system, there are no inadvertent flows. All three RTOs propose to use some form of flow-based congestion management within their borders that will allow markets to operate. However, the three proposals envision continued use of contract path procedures for scheduling transactions across the borders between the RTOs and continued use of the WSCC loop flow mitigation plan. Extension of flow-based scheduling to inter-RTO transactions is a relatively straightforward issue that requires coordination, and mapping of existing rights to flow-distributed rights among the RTOs. It also requires agreement on the flow distribution factors across the western interconnection. It would probably not require the RTOs to use identical definitions and properties of FTRs. Rather a transaction that crossed RTO boundaries would simply need sufficient FTRs on each flow-path in each RTO. Even if one RTO were using a physical rights scheduling model and another a financial rights model, a transaction that crossed the boundaries would simply need FTRs on all affected flow paths in the first RTO, and could decide whether congestion risks needed to be hedged in the second. While not required, identical definitions and properties would considerably simplify commercial transactions in the West.

Under a flow-based system, the need for the WSCC loop flow mitigation plan would go away, simply because all flows would be accounted for and would come under the appropriate congestion management procedures, and no flows would be inadvertent. Congestion management would be appropriately market-based, as long as each RTO has adopted procedures ensuring a liquid market for FTRs.

D. Preservation of existing rights as FTRs.

A major issue in negotiations over the formation of RTOs is the question of how to translate the set of rights and contractual agreements that have developed under the existing system into a set of rights under the new regime. This issue has several aspects. First, the basic problem of figuring out who has what rights in the existing system, and how they add up and compare to the capacity of the relevant portions of the transmission system, is not a simple task. Indeed, there is some evidence that existing utility practices have led to an over-allocation of transmission rights. Second, there has been little agreement about the extent to which such existing rights should be protected after RTO formation. Some parties want to see as many rights as possible made available to the market, while others are greatly concerned about the potential effect on their continued obligation to provide bundled retail

service under state law. Third, those rights which are to be protected would need to be translated from contract path rights under the existing scheduling system into rights across multiple flow paths under a flow-based system.

The first issue involves looking at historic patterns of use for serving native load and disentangling contractual rights. Service of native load by a utility's own generation has always been handled implicitly by flow-based congestion management through redispatch, but the patterns of use have always varied with time of day and year. Contractual rights for wheeling across another party's system have in some cases been contract path rights, and in others, network rights. Some transmission-owning utilities have been providing re-dispatch free of charge to their own merchant function, to third parties with schedules across the transmission owner's system, and in some cases, to third parties that *do not* have schedules across the transmission owner's system. As a result, it is likely to be impossible to establish multiple feasible dispatches for each participating transmission owner that is also feasible for the entire RTO system.

The second issue involves decisions on whether and how preexisting contracts and load service obligations are to be protected. Setting aside a portion of the capacity of the transmission network for their exclusive use would result in maximum protection for existing uses, but would leave little in the way of available capacity for the market. Assigning FTRs that mimic the historic use they have made of the system would ensure that the maximum amount of transaction capacity is denominated in standardized, tradable instruments, but would entail some risks for those companies with continued contractual or regulatory obligations. Assigning rights to auction revenues instead of the FTRs themselves might result in still more risk for those companies, but would have additional liquidity benefits in providing a market test for historic uses of the system, while still enabling companies to fulfill their obligations by enabling them to outbid other uses through the revenue crediting mechanism. These issues are important because they relate to the likely degree of liquidity of the market for FTRs, discussed below.

The third issue involves the conversion of historic rights into flow-based rights. This requires agreement on a model of the transmission grid that is simple enough to be computable and to result in a manageable number of flow paths and FTRs. It requires decisions on the state of the system to be used for calculating flows (all transmission lines in service or some lines out for maintenance; settings on phase shifters; etc). It requires decisions on how many historic flow patterns to model (hourly vs. peak/off peak/shoulder vs. seasonal).

The final issue involves the disposition of the residual FTRs after calculation of the rights of native load and preexisting contracts. If residual rights are deemed to belong to transmission owners they must be placed in an auction and released to the market. Failure to do so would preserve the ability of transmission owners to withhold access of competitors to their markets, a situation that FERC has repeatedly concluded cannot be allowed to stand and one that has led FERC to issue Order 2000 on the formation of RTOs.

E. Liquid markets for FTRs

The congestion management scheme proposed by RTO West is based on physical rights to schedule power, embodied in a standardized product called a Firm Transmission Right or FTR. Generally this means that, because there will be only enough FTRs available on a path to match its capacity, the annual auction of FTRs and subsequent secondary trading in the forward markets will be the predominant mechanism for managing congestion. Market participants without FTRs will not be able to schedule on congested paths at all unless they can arrange independent bilateral redispatch arrangements with other market participants or are willing to wait until as little as two hours before real time to see if FTRs are not actually going to be used.

This can be contrasted with a financial rights scheme, like that proposed for IndeGO, where the key rights are rights to avoid the congestion charges caused by out-of-merit-order generation redispatch to relieve potential overloads. The congestion management mechanism is the generation redispatch market itself and congestion is managed by the willingness of market participants to pay the congestion charges. In this scheme, lack of the rights would not preclude scheduling entirely, but would merely mean that one would have to pay the congestion cost of the individual transaction. Access would not be limited to those with the rights. The financial rights are primarily a financial hedge mechanism rather than an access gate-keeper.

In principle, given adequate market liquidity, either a physical rights scheme or a financial rights scheme for managing congestion could result in liquid markets for transmission capacity. RTO West participants chose the physical rights scheme not to defeat market liquidity but out of a n unwillingness to assign authority to the RTO for the exceedingly complex, centralized dispatch mechanisms required for a financial rights models like locational marginal pricing.

However, in the absence of adequate market liquidity for the rights, a physical rights scheme may be more handicapped than a financial rights scheme and may offer very little in the way of market access for new market participants. This is precisely the outcome that RTO West is setting up by broad disposition of FTRs to incumbent rights holders with no restrictions on their ability to withhold them from the market (other than a use-or-lose provision that may leave non-incumbents with as little as two hours notice on their ability to pick up FTRs that will not be used).

Several factors contribute to the likelihood of this problem arising. First, the TOA provides for broad grants of FTRs by RTO West to the filing utilities, both to cover existing contracts, for “load service obligations,” (which are defined not by any legal obligation to serve load, but simply by being connected to the transmission facilities of one of the filing utilities) and for other specified and unspecified “obligations.” These FTR grants will also cover annual load growth out of otherwise unencumbered transmission capacity for the first ten years of the RTO’s existence.

Second, while any remaining available transmission capacity will be auctioned off in annual auctions, with the proceeds going to reduce the company rates paid by the utilities’ loads, the filing utilities will be under no obligation to place the capacity represented by the FTRs granted to them in the auction. Alternative proposals were made during the discussions that would have required the grantees to place

their FTRs in the auction, while allowing them to receive the proceeds of the auction. Some proposals limited this requirement to the large FTR holders only, while exempting small entities. All of these proposals would have allowed any entity that accurately bid its value (based on looking at its alternative means of meeting loads) to be held harmless even if outbid. They would also have allowed arbitrarily high bids by those who absolutely needed to retain the FTRs. Considering these alternatives that were considered and rejected, the ability to simply withhold FTRs from the auction appears excessively protective of incumbent interests.

Third, the proposal to allow utilities to be granted time-variant FTRs for up to 48 feasible dispatches in a single year means that incumbents would be largely immune to the need for seasonal and hourly shaping of transmission rights. Incumbents would essentially get network-like transmission rights for historic uses, leaving competitors to attempt to assemble the necessary rights from whatever is left over. Competitors wishing to make long-term block sales may find that FTRs are readily available and inexpensive during some months, but not available at all during other months.

Fourth, the fact that these features are built into the TOA, which would have precedence over other documents, including the tariff, makes it likely that any proposals to fix the problem, as it appears likely to develop, would be very difficult and essentially out of the control of RTO West. Any attempts to rectify the problem would require the re-negotiation of nine TOAs, subject to approval by seven state commissions and the federal Department of Energy, in addition to FERC.

In addition to limiting the entry of new market participants, the ability of the incumbent utilities to withhold FTRs from the auction is likely to have a further effect on the efficiency of the markets. The auction price and the subsequent secondary market prices of the FTRs are the price of transmission congestion in a market-based congestion management system. The price of congestion is a key element in a market participant's decision on how to allocated resources. To arrive at the most efficient outcome the price of congestion must be weighed against the cost of transmission expansion, the cost of different generation locations that will relieve or exacerbate congestion and the cost of local demand reduction or distributed generation. Inadequate liquidity in the congestion market will tend to seriously distort not just access to the transmission system but also the evaluation by various market participants of the value of transmission in comparison with other alternatives.

There are, however, some mitigating factors in this proposal. The conversion process will require the potential FTR grantee to demonstrate a feasible dispatch pattern, by month and for each of the on-peak and off-peak periods, based on monthly noncoincidental historical loads. This will tend to free up FTRs from capacity that may have been obligated in some way but not actually used historically. Nonetheless, overall the FTR allocation in the TOA looks likely to seriously constrain liquidity and access in the congestion management market.

III. Summary of RTO transmission pricing proposals as of the October 16 filings

The summaries of each of the filings are being organized into eight sections according to the eight minimum functions established for RTOs in Order 2000. Particular attention will be paid to pricing-related functions.

A. RTO West Functions:

Function 1. Tariff Administration and Design

RTO West will administer its own tariff as required by Order 2000. Although the filing utilities will submit a proposed tariff for RTO West as part of their Stage 2 filing, RTO West will have the right to change its tariff provisions as it sees fit (with the exception of the company rate design, which RTO West cannot unilaterally change until after the end of the company rate period). RTO West will have absolute discretion to set its own rate with respect to uplift charges, congestion management fees, and losses. A complete description of RTO West's initial tariff design, along with a proposed form of transmission tariff, will be submitted to the Commission as part of the filing utilities' Stage 2 filing.

Function 2. Congestion Management

To meet the requirements of Order 2000, RTO West proposes a "flow-based physical rights" congestion management model. RTO West will manage congestion on flowpaths, which are RTO grid facilities that are expected to have commercially significant amounts of congestion. On these flowpaths, RTO West will manage congestion primarily by issuing transmission rights. The filing utilities have identified an initial candidate list of flowpaths. The initial flowpaths will be listed in the documents submitted with the filing utilities' Stage 2 filing, along with initial transmission rights allocations and procedures for adding or removing flowpaths as changes are warranted.

RTO West will determine the total transfer capability for each flowpath and the amount of transmission rights to issue. Customers that wish to schedule across flowpaths will be required to have transmission rights (primarily firm transmission rights (FTRs) or other transmission rights such as recallable transmission rights (RTRs), non firm transmission rights (NTRs), and non-converted rights set-aside described in Attachment M, *Description of RTO West Congestion Management Model*) before the schedule is accepted. Congestion is therefore mostly self-limited by the need to acquire such transmission rights.

Most of the congestion costs associated with a flowpath are borne by the path users through the costs to purchase transmission rights and through the curtailment of these rights under certain circumstances, such as extended outages of RTO grid facilities. Any other congestion ("residual congestion") is managed by the RTO through the RTO's redispatch of resources, repurchase of rights, and, as a final resort, curtailment of schedules.

RTO West proposes a "flow-based" model in which flow distribution factors will be used to determine how schedules are deemed to flow between congestion zone sources and sinks on flowpaths (thereby requiring transmission rights). Many preexisting ownership and contract rights are defined on a contract

path basis. Before the tariff filing, these rights will be translated (mapped) from their now existing contract paths onto flowpaths. If the filing utilities find that translation to flowpaths seriously impairs the ability of rights holders to utilize or be compensated for their existing transmission rights, the provisions on the Stage 2 filing will include a transition period to move from the contract path to the flow-based congestion management model.

This congestion management system is intended to align well with those operating or proposed in other ISOs and RTOs in the Western Interconnection. Any residual difference will be addressed through RTO West's joint activities with other RTOs and control areas.

Function 3. Parallel Path Flow

WSCC members have developed tailored regional path rating methods and operating procedures that require schedules on rated paths be limited to the path's rating. There is also a WSCC Unscheduled Flow Mitigation Plan that uses coordinated phase shifter operation. When it becomes operational, RTO West will participate in these programs as the filing utilities have in the past.

To further satisfy Commission requirements regarding parallel path flows, RTO West will adopt uniform flow-based scheduling procedures. RTO West will accept incremental flow-based schedules over flowpaths above a specified threshold only if the schedules include FTRs on all flowpaths over which the power incrementally flows between the schedule's source and sink. The RTO will manage and schedule the entire RTO West grid system. Competing parallel transaction paths therefore will not be a factor.

RTO West will therefore comply not only with the WSCC Unscheduled Flow Mitigation Plan, but will also carry out interregional coordination at the RTO seams relative to phase shifter operation and scheduling protocols and procedures. RTO West intends to implement a flow-based model upon initial operation as well as the other measures discussed above affecting parallel path flow. This implementation may involve several steps as the physical model (flowpaths, congestion zones, flow distribution factors, FTR allocations, and mapping) evolves and is refined.

Function 4. Ancillary Services

RTO West will serve as the provider-of-last-resort of all ancillary services required under Order 888 . Ancillary services will be provided on up to a day-ahead basis except as described below, and except for black start and voltage support services, which may be contracted for with participating transmission owners or others on a longer term basis.

To allow the greatest degree of flexibility and cost exposure management, RTO West will have procedures in place to allow those transmission customers that elect to do so to either (1) provide electric generation capacity for use by RTO West to meet all or part of its ancillary services requirements, which provision will exempt the provider from paying the RTO West charges for ancillary services in the amount of electric generation capacity so provided (referred to as "self-provision"), or (2) use electric generation resources it controls to meet its

own ancillary services requirements, including the matching of electric generation to load within an RTO West defined time period (referred to as “self-tracking”). One exception is that RTO West will be the sole provider of scheduling, system control, and dispatch services.

RTO West will actively work to foster external competitive markets through which RTO West and RTO West transmission customers can procure ancillary services on a bilateral transaction basis, on both long- and short-term bases.

Function 5. OASIS, Total Transfer Capability, Available Transfer Capability

As required by Order 2000, RTO West will maintain and administer its own its own OASIS site and will be responsible for calculation of total transfer capability and available transfer capability.

Function 6. Market Monitoring

The RTO West Market Monitoring Unit (the “MMU”) will objectively monitor RTO West markets, specifically markets relating to congestion management, ancillary services, and FTRs. If the MMU detects market performance that is inconsistent with a competitive market, it will investigate further to determine the cause of such performance. With respect to market performance that appears to be inconsistent with a competitive market, the MMU will report the results of its monitoring and investigation to the RTO West Board. The Board will decide whether to report such market performance to the Commission or other appropriate regulatory or enforcement agencies.

Function 7. Planning and Expansion

RTO West is responsible for the planning of all facilities under RTO West control and expects that operational planning will be in place at the commencement of RTO service. RTO West is also responsible for the long-range planning for the facilities it controls and will develop a non-discriminatory process that allows for significant input from all users and owners of the system and considers non-transmission solutions. RTO West has the discretion to determine how to fulfill its planning responsibilities. RTO West will determine what information it needs from a participating transmission owner, what use to make of such input, and whether RTO West or the participating transmission owners (or some combination thereof) will perform studies. The filing utilities anticipate that RTO West’s approach will evolve over time.

C. Expansion for Reliability of Service to Load

Participating transmission owners are obligated to maintain the transfer capability of the facilities they have turned over to RTO West as directed by RTO West (with certain exceptions). Participating transmission owners are further obligated to expand and modify their systems in order for RTO West to provide the services requested under its open-access tariff. Should a participating transmission owner fail to satisfy its obligations, RTO West has the backstop authority to cause the construction of

transmission facilities that ensure that the participating transmission owner's transfer capability is maintained at an appropriate level and that the facilities under RTO West's control are adequate for load service purposes.

D. Expansion to Relieve Congestion

RTO West is committed to implementing a market-driven expansion mechanism for purposes of congestion relief expansion. The RTO West congestion management system is designed to provide accurate pricing signals to market participants. Based upon these pricing signals, a market participant will be able to make prudent economic decisions regarding transmission expansion for congestion relief. Such participants will sponsor the costs of new facilities in exchange for FTRs.

E. Relationship of RTO West and Siting Authorities

The RTO West planning and expansion framework does not alter the existing relationship of the participating transmission owners with siting authorities, with the exception that it is assumed that the RTO will participate, in some capacity, in siting and approval decisions. The filing utilities anticipate that RTO West will assist the state regulatory commissions and siting authorities in developing multistate agreements for review and approval of new transmission facilities.

Function 8. Interregional Coordination

In 1999, the Western Market Interface Committee (the "WMIC") cosponsored by the three regional transmission associations and the WSCC was established to ensure that the business practices adopted by transmission providers in the Western Interconnection do not negatively impact the market and that the market practices do not negatively impact the reliability of the grid. RTO West formed a work group to address seams issues with other RTOs, control areas, and transmission-owning utilities that are within the RTO West service area but not part of it. The work group coordinated its activities with those of the WMIC. The work group addressed, among other issues, reciprocal elimination of pancaked transmission charges between RTO West, California ISO, Desert STAR, and other RTOs that may operate in the Western Interconnection, and operational compatibility with respect to scheduling, congestion management, and other processes.

The filing utilities anticipate that RTO West will supplement the bilateral discussion already under way with neighboring transmission organizations by participating in the WIO when it forms. The WIO could serve to facilitate and coordinate the integration of reliability and market interface practices as appropriate.

B. DSTAR

Desert STAR Functions:

Function 1. Tariff Administration and Design

In accordance with FERC Order No. 2000, Desert STAR will be the sole provider of transmission service for the RTO using the transmission facilities of the members owning transmission within the Desert STAR Grid. These transmission owners will have transferred Operational Authority of their transmission facilities to Desert STAR under the TCA. Similarly, Desert STAR will be the sole administrator of its own tariff.

Desert STAR has yet to develop a suitable transmission access charge to equitably recover the respective Participating TOs' revenue requirement. This issue remains the most difficult issue facing Desert STAR. From the beginning of the Stakeholder negotiations, Members agreed on five goals: (1) honor existing contracts; (2) recover revenue requirements; (3) avoid cost shifting; (4) eliminate pancaking; and (5) facilitate retail competition.

Function 2. Congestion Management

The discussion of congestion management is divided into two parts in the Desert STAR filing: Appendix A that deals with firm transmission rights and Appendix B that describes the treatment of existing contracts.

Appendix A

Appendix A provides the details on how Eligible Customers² and their Scheduling Coordinators ("SCs") gain scheduling rights on potentially constrained transmission interfaces (known as FTR Interfaces), which is the way DSTAR will manage Inter-Zonal Congestion, and on interfaces (known as Scheduling Points) with adjoining non-DSTAR Control Areas, which is the way DSTAR will manage flows to and from non-DSTAR Control Areas. This is a physical transmission rights model, with the FTR Interfaces defining the boundaries of DSTAR Congestion Zones. Appendix A also provides details on the management of Congestion within a Congestion Zone, called Intra-Zonal Congestion. Desert STAR plans to include the market mechanism for managing congestion when it commences operations no later than December 15, 2001.

The amounts of FTRs to be auctioned are based on the Operating Transfer Capability ("OTC") of the FTR Interface or Scheduling Point, less any amount of transfer capacity that must be reserved to allow DSTAR to honor Existing Contracts ("ECs") that have not been converted to DSTAR Transmission Service. The FTR auctions are single round clearing price auctions, and there will be provision for Eligible Customers to bid to be a "Price Taker" in the FTR auctions (i.e., willing to pay

² Attachment 1 to the Desert STAR filing is called "Master Definitions" and is intended to provide a definition for each of the terms that are capitalized in the filing. As consensus has not yet been reached on the master definitions list, there are no definitions for the capitalized terms in the filing.

whatever the market price is). The Jurisdictional Utilities' proposed default price in the event that there are more Price Taker bids than there are FTRs is \$1.00/FTR or \$1.00/MW/Hour.

FTRs can be traded in secondary markets. While DSTAR does not require notification of each FTR transfer in the secondary markets, the final owner of each FTR must be reported to DSTAR so that DSTAR can validate Schedules that utilize FTR Interfaces and/or Scheduling Points.

If the current owner of record of an FTR does not inform DSTAR early on the day before a Trading Day that it intends to actually use the FTR, DSTAR will conduct an auction to sell the FTR as a recallable transmission right (RTR). The RTR auctions are single round and the price paid is the price bid. Such an RTR can be recalled by the owner of record at any time up to two (2) hours prior to the start of a particular Settlement Period (clock hour).

RTRs will be recalled on the basis of price paid, with those paying the lowest price being recalled first. If not recalled by two (2) hours prior to the start of a Settlement Period, RTRs are treated just like the underlying FTRs. If recalled, the SC losing the RTRs has until one (1) hour prior to the start of the Settlement Period to submit a new Balanced Schedule that does not use the RTRs that were recalled.

Once the Day-Ahead Balanced Schedules have been submitted, DSTAR will determine if it can make available non firm transmission rights (NTRs) based on counterflow schedules and transmission capacity that has been used to schedule delivery of Ancillary Services. NTRs will be made available on a first come, first serve basis and will be interruptible upon cancellation of the counterflow or activation of the Ancillary Service.

Appendix E

Details on the treatment of non-converted ECs, and the resulting NCRs, are covered in Appendix E. Under the provisions of Appendix E, the Scheduling Coordinators ("SCs") that represent ECs that are converted to DSTAR Transmission Service will be entitled to a share of the revenues produced from the auction of Firm Transmission Rights ("FTRs") for use of the FTR Interfaces and Scheduling Points over which transmission service was provided under the EC. As proposed, these rights to auction revenues will continue for the longer of the specified term of the EC or ten (10) years.

Existing Contracts that are not converted to DSTAR Transmission Service will be honored by granting Non-Converted Rights ("NCRs") to the SCs for such ECs. In order for DSTAR to manage the rights under these ECs, the Participating TO that is a party to the EC has the primary responsibility for providing DSTAR with a set of NCR Instructions. NCR Instructions are all the rules and instructions that are pertinent to transmission service allocation, scheduling and curtailment of the transmission service in compliance with the non-converted EC.

Function 3. Parallel Path Flow

The discussion of parallel path flow is limited in the DSTAR filing. According to the filing, the effects of parallel path flows within the Desert STAR region will be handled as a result of the implementation of the Congestion Management system in Appendix A to the DSTAR Tariff, both for inter-zonal and intra-zonal congestion. Major path loop flows within the Western Interconnection currently are managed through the use of the Commission-approved WSCC Unscheduled Flow Reduction Procedure. Any additional mitigation that might be required in the future will be one of the responsibilities of the WIO.

Function 4. Ancillary Services

Appendix D to the draft DSTAR Tariff provides the details on how Desert STAR expects to address Ancillary Services. As required by the Commission, Desert STAR would serve as the provider of last resort. Market Participants would have the option of self-supplying Ancillary Services with the exception of Balancing Energy, Voltage Support, Scheduling and Dispatch, Black Start, Congestion Redispatch, and Local Generation Resource services consistent with NERC and WSCC criteria. Desert STAR would provide transmission customers with access to a real-time Balancing Energy market.

Function 5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

Desert STAR will be the single OASIS site administrator for all transmission facilities under its Operational Authority. Desert STAR would calculate all transmission capabilities of all Firm Transmission Right ("FTR") interfaces in the congestion management program as set forth in Appendix A.

Function 6. Market Monitoring

A draft of Appendix H dealing with market monitoring has been prepared, but has not received detailed scrutiny. A number of issues remain to be resolved as described in Attachment III-A and Attachment III-B hereto. Appendix H is designed to ensure that Desert STAR provides reliable, efficient and not unduly discriminatory transmission service. Toward that end, the Market Monitoring Unit would monitor the behavior of Market Participants and Desert STAR itself, reporting directly to the Board of Directors. Desert STAR will not operate an energy market except to the extent necessary to provide Ancillary Services in general and Balancing Energy, in particular. The Market Monitoring Unit would report on opportunities for efficiency improvements, market power abuses and market design flaws.

Function 7. Planning and Expansion

Attachment 4 to the draft DSTAR Tariff of both the Jurisdictional Utilities and the DSTAR consultants is a draft Regional Transmission Expansion Planning Protocol. At the time of the December

29, 2000 filing, Desert STAR will provide the milestones for the plan to complete Attachment 4, although all parts of this Protocol may not be operational by December 15, 2001.

Function 8. Interregional Coordination

Desert STAR will become a member of the WIO. WIO is expected to provide a comprehensive forum for addressing reliability issues and other interface issues within the Western Interconnection. Desert STAR is exploring other mechanisms to deal with other interregional issues and will provide the milestones for satisfying this function as a part of its December 29, 2000 filing.

C. California ISO – To Be Added

D. Alberta TA/Power Pool – To Be Added