UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION 00 NOV 24 AM 9:56

Avista Corporation	)	**Docket No. RT01-15-000**
Montana Power Company	)	
Nevada Power Company	)	
Portland General Electric Company	)	
Puget Sound Energy, Inc.	)	
Sierra Pacific Power Company	)	
Avista Corporation	)	**Docket No. RT01-35-000**
Bonneville Power Administration	)	
Idaho Power Company	)	
Montana Power Company	)	
Nevada Power Company	)	
PacifiCorp	)	
Portland General Electric Co.	)	
Puget Sound Energy, Inc.	)	
Sierra Pacific Power Company	)	

(Not consolidated)

COMMENTS OF DYNEGY INC.

These Comments are filed by Dynegy Inc. (Dynegy) pursuant to Rule 211 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.211 (2000) and the Notices issued on October 20, 2000 in the above-referenced, unconsolidated proceedings. Dynegy filed a separate Motion to Intervene in each proceeding pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000) on November 1, 2000.

I. BACKGROUND

On October 23, 2000, Avista Corporation, the Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. and Sierra Pacific Power Company filed a

Supplemental Compliance Filing and Request for Declaratory Order Pursuant to Order No. 2000[1] and in accordance with 18 C.F.R. § 385.207(a)(2). Among other things, this filing describes the filing utilities' proposal to form a regional transmission organization (referred to as RTO West) that purports to comply with the requirements of the Commission's Order No. 2000.

The RTO West Applicants request that the Commission address and approve certain limited aspects of RTO West's "Stage 1" proposal by issuing a declaratory order on an expedited basis with respect to: (1) the form of the RTO West First Restated Articles of Incorporation and RTO West Bylaws; (2) the scope and configuration of RTO West; and (3) the form of Agreement Limiting Liability Among RTO West Participants. Furthermore, three of the RTO West Applicants request that the Commission issue a declaratory order "finding that the concepts as a package embodied in the Transmission Operating Agreement and Agreement to Suspend Provisions of Pre-Existing Transmission Agreements are acceptable to the Commission and consistent with the requirements of Order 2000."[2] RTO West Filing at p. 6.

The RTO West Applicants indicate that in spring 2001, they will make a "Stage 2" filing, which will include all documents and information needed to complete their proposal for RTO West. RTO West Filing at p. 5.

Separately, on October 16, 2000, Avista Corporation, the Montana Power Company, Nevada Power Company, Portland General Electric Company, Puget Sound Energy, Inc. and

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[1] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000).

[2] The remainder of the RTO West Applicants do not seek such a finding with regard to these agreements.

Sierra Pacific Power Company (TransConnect Applicants) tendered a filing in compliance with Order No. 2000[3] and a petition for declaratory order pursuant to section 35.34(d) of the Commission's regulations and Rule 207(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. 35.34(d) and 207(a)(2) (2000), in connection with plans to form an independent transmission company (ITC) to join RTO West.

The TransConnect Applicants request the Commission issue a declaratory order on or before December 15, 2000, finding that (1) TransConnect will meet or exceed the minimum requirements for independence; and (2) the functions that the ITC proposes to undertake – related to rate filings and transmission planning and expansion – are acceptable. TransConnect Filing at p. 2. The TransConnect Applicants note that further filings will be made pursuant to Sections 203 and 205 of the Federal Power Act once the remaining documents are finalized. TransConnect Filing at p. 4.

II.
COMMENTS

- **Introduction**

In issuing Order No. 2000, the Commission believed that "appropriate RTOs could successfully address the existing impediments to efficient grid operation and competition and could consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers."[4] The Applicants' filing in this proceeding and other RTO compliance filings made in October will challenge the Commission's beliefs. This is not to say that the Commission should despair and walk away from the many pro-competitive aspects

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[4] Order No. 2000 at 30,993.

of Order No. 2000; rather, the Commission must resolve to strictly apply the requirements of Order No. 2000 to the October filings, while acknowledging that other renovations to the electric industry are needed along with RTOs if consumers are to receive the benefits of competition.

The comments herein will address the Applicants' compliance with the functions and characteristics of Order No. 2000; prior to that, however, Dynegy offers the Commission the following preliminary comments and observations about the October filings.

Incompleteness of Filings. The fact is that many of these October filings are missing such significant pieces of their proposals that it is virtually impossible to judge whether the entity complies with Order No. 2000. In some cases, it is the OATT that is missing, or the list of grandfathered contracts, or the rate proposal, or the details of the governance structure, or a well-defined congestion management plan. Clearly, the Commission must take these shortfalls into account when evaluating the October filings, when reading the comments of the parties, and, most importantly, when considering what next steps to take. Is issuing guidance orders on partial filings the best avenue to perfecting these filings, or should the Commission instead hold technical conferences in Washington where the details can be discussed further, or even delay issuing any order until the filing is complete?

Collaborative Process. As the Commission considers what the next steps should be, it is imperative that the Commission recognize the source of many, if not all, of the October filings. The Commission believed that "the collaborative process that we are promoting in this Rule will provide an opportunity for all interested parties with their varied interests to resolve many of their differences, in advance, and reach consensus on the RTO solution that best fits the overall needs of their respective region."[5] Perhaps the Order No. 2000 was not clear enough in what was meant by the "collaborative process." In several regions, that process consisted of a small number of meetings where the transmission owners presented customers with their proposal and made only minor changes, if any, in response to their requests. Admittedly, the Commission's requirement to make the compliance filing was to the public utility; yet, if the Commission's expectation was that the filing would be representative of the desires in the region, these filings fall far short. The RTO filers will claim that there was too much to do in too short a time, and perhaps they have a point. The Commission however needs to take the lack of collaborative process into account when judging these filings: who has made the filing and whose interests do they serve?

The Commission is not without experience in evaluating regional filings made solely by the transmission owners. The Commission has on many occasions afforded a great deal of deference to a filing when it was satisfied that various stakeholders had meaningful input into the process.[6] The Commission has also recognized the overriding importance of independent governance of a regional transmission entity. As the users of the transmission grid in each region will have to live under the RTO's tariff and protocols, and changing that tariff and those protocols will be difficult and expensive, it is imperative that such independence be in place before a particular proposal is presented to the Commission. Only recently, in the *Order*

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[5] *Id.* at 31,226.

[6] *See, e.g., Pennsylvania-New Jersey-Maryland Interconnection, et al.*, 81 FERC ¶ 61,257 (1997). The Commission accepted the PJM proposal after having instructed the transmission owners in a previous order to allow all stakeholders to have meaningful input into the formation of the ISO. *Atlantic City Electric Co., et al.*, 77 FERC ¶ 61,148 at 61,584 (1996).

Proposing Remedies for California Wholesale Markets, the Commission required a revised congestion management proposal no later than 60 days after the independent ISO board is seated,[7] the clear implication being that such a proposal must come from an entity or group that will not be limited to the interests of one segment of the industry. The Commission should consider whether certain functions of the RTO should be submitted after a date that the approved governance structure has become effective. In the alternative, the Commission should consider taking a more active role in the development of the RTO to ensure that it represents all the interests of a particular region.

Comparability for All Transmission Customers. For all its laudable features, Order No. 2000 falls short of addressing the market disparities and the fundamental inequities resulting from the lack of comparable access to transmission service for all market participants.[8] As can be seen from many of the October filings, RTOs by themselves are doing little to remove the ability of the transmission owner to hide discriminatory behavior behind the cloak of native load.[9] Specifically, service for utility native load maintains a priority over service provided for competitive suppliers and the rules to enforce this priority, e.g., capacity benefit margin (CBM), can negatively impact reliability.

As recognized in the Commission's Staff Report on Bulk Power Markets (Staff Report), in order to improve incentives for open access transmission, the Commission can act to

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7 93 FERC ¶ 61,121, slip op. at 34 (hereinafter, California Order).

8 *See* Initial Comments of Dynegy Inc. at 21-22, filed August 23, 1999 in Docket No. RM99-2-000.

9 *See also*, Threshold Comments of the Coalition for a Competitive Electricity Market and the Electricity Consumers Resource Council, filed July 28, 1999 in Docket No. RM99-2-000.

> [r]educe the advantages of network service over point-to-point service by requiring that native load be served under the same tariff provisions as other transmission services. Given that all transactions serve load of one sort or another, all load would be treated in the same manner. This would eliminate the current incentives that vertically integrated transmission owners have to favor their native load through the manner and method of calculating ATC and handling interconnection requests. It would also restore confidence among market participants that transmission owners were not calling TLRs to favor native load, because they would no longer have the incentive to do so.[10]

The Commission must seize the opportunity to act now, in the context of the RTO proceedings, to implement Staff Report's recommendation.

Furthermore, as the Commission recognized so astutely in Order No. 636,[11] comparability is the lynchpin for overcoming both competitive and reliability challenges. While the Commission also addressed other issues in that landmark rule, such as pipeline rate design, flexible receipt and delivery points, secondary markets for transportation, and market hubs, it was comparability that provided the impetus for all industry participants to work together on all the other issues facing the gas industry. No such impetus exists in the power industry, and the result is painfully obvious – incomplete filings, delay, new incomplete filings, and more delay.

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10 Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States; Part II of the Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 2-49.

11 *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines after Wellhead Decontrol*, Order No. 636, [1991-96 Regs. Preambles] FERC Stats. & Regs. ¶ 30,939 [hereinafter cited as *Order No. 636*], *order on reh'g*, Order No. 636-A, [1991-96 Regs. Preambles] FERC Stats. & Regs. ¶ 30,950, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1991), *reh'g denied*, 62 FERC ¶ 61,007 (1993), *affirmed in part and vacated and remanded in part, sub nom. United Distribution Companies v. FERC*, 88 F.3d 1105 (D.C. Cir. July 16, 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

The Same Old *Pro Forma* Tariff. Not to disparage the Commission's *pro forma* tariff that was the product of Order No. 888,[12] but perhaps the time has come to reexamine whether it satisfies the needs of the market. This issue is, of course, closely tied to the comparability issue discussed above. But it is more than that. There are serious questions raised by the different treatment afforded point-to-point customers and network customers. The Commission itself recognized this in its order denying rehearing in Entergy's source and sink proposal.[13] And apart from the disparity in transmission services, there are many other instances where changes can and should be made to enhance the flexibility of the marketplace. The *pro forma* tariff was a positive event in 1996; but times have changed. The market has changed.

Gas pipeline tariffs, while still possessing many of the fundamental features of Order No. 636, have changed in many positive ways. They now offer shippers greater flexibility with pooling and hubbing services, ways for them to manage their imbalances, opportunities to park their gas, etc.

Below, Dynegy suggests changes that will improve the *pro forma* tariff. While the Commission may say that the Order No. 2000 does not require these changes; the questions then become, if not now, when? If later, at what costs? This is not simply a matter of making a change later, but of having the repercussions of "imperfect" markets in the meantime, the costs of

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12 Order No. 888, *Promoting Wholesale Competition Through Open Access Non Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21,540 (May 10, 1996), 1991-1996 FERC STATS. & REGS. PREAMBLES ¶ 31,036 (Apr. 24, 1996), *order on reh'g*, 62 Fed. Reg. 12,274 (March 14, 1997), 78 FERC ¶ 61,220 (March 4, 1997), *order on reh'g*, 62 Fed. Reg. 64,688 (December 9, 1997), 81 FERC ¶ 61,248 (November 25, 1997), *order on reh'g*, 82 FERC ¶ 61,046 (January 20, 1998) (Order No. 888).

13 *Entergy Services, Inc.*, 92 FERC ¶ 61,108 at 61,397-98 (2000).

reprogramming RTO and user software later.

Everyone in the industry knows that what is needed is to put every user on the same transmission tariff; the industry will get there some day. It is painfully obvious that we as an industry are not getting there without some Commission mandate to do so. Threatened with transmission and generation shortages at the same time demand for power and enhanced reliability is growing, the nation cannot risk its economic future waiting before it implements a simple, fair solution to these problems. The time for the "comparability mandate" is now. To that end, the Commission, as noted above, must act decisively, in the context of the RTO proceedings, to issue such a mandate as part of a conditioned acceptance of the RTO filings, as those proceedings are moved into the next level of detail, such as settlement and/or technical conferences.

As noted by the RTO West Applicants and the TransConnect Applicants, both proposals are works in progress, with future filings to be made next year. Dynegy's comments below are directed to the specific aspects of Applicants' proposals for which Applicants seek Commission approval, as well as to issues generally applicable to all RTOs, including Applicants, in terms of the functions and characteristics required by Order No. 2000. To the extent Dynegy's comments address generic RTO issues, Dynegy is hopeful that the Commission will consider the issues raised herein in the course of the Commission's analysis of Applicants' proposals and its issuance of orders providing guidance to the Applicants for any future proposals. Dynegy reserves its right to comment on all aspects of any future filings tendered by Applicants in compliance with Order No. 2000.

- **Independence**

Order No. 2000 requires that an RTO must be independent in both reality and perception.[14] Additional details are required with regard to the Applicants' proposals before it can be determined whether the Commission's independence requirement has been met. For example, the filings fail to clearly delineate which functions RTO West will perform and the functions TransConnect will perform and how the two organizations will interact. As the Commission found with regard to Commonwealth Edison Company's proposed ITC, and its relationship with the Midwest Independent System Operator, Inc., applicants seeking approval of a "binary" regional transmission entity/independent transmission company relationship must clearly set forth what functions are performed by the regional transmission entity and what functions will be performed by the independent transmission company.[15]

Until the functions of TransConnect are clarified, the Commission cannot rule on the independence of TransConnect. Absent such clarification, there will be insufficient information by which to determine whether TransConnect will be independent from market participants because it is not clear what transmission functions TransConnect will perform and thus what functions will be independent from market participants.

TransConnect proposes that individual market participants, including the Applicants, may have an active ownership interest in TransConnect. Market Participants and the Applicants to the extent they are market participants may hold up to five percent of the total Class A stock of

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[14] Order No. 2000 at 31,061.

[15] *Commonwealth Edison Company, et al.*, 90 FERC ¶ 61,192 at 61,618-19, *order on reh'g* 91 FERC ¶ 61,178 (2000).

TransConnect for a period of five years.[16] While TransConnect asserts that it has met the safe harbor provisions of Order No. 2000, active ownership raises additional questions as to the independence from market participants, especially when the TransConnect/RTO West interrelationship is unclear.[17] Thus, the Commission should defer any conclusion that TransConnect has met the independence standard of Order No. 2000 until the functions of TransConnect and its relationship with RTO West have been sufficiently set forth in final form.

Since the TransConnect Applicants have not provided enough detail to determine if their proposed structure would actually meet each of the RTO requirements, the Commission should consider only whether the TransConnect Applicants' general framework falls within the options discussed in Order No. 2000.[18] Once the complete RTO West "package" is filed along with further clarifications regarding the functions of the ITC, the Commission and market participants can examine the proposals together for the proposals' interrelationships with respect to independence, scope and configuration and other specific characteristics and functions on which the Commission has deferred judgment.

- **Tariff Administration and Design**

Order No. 2000 requires that the RTO must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of

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16 TransConnect filing at p. 23.

17 ITC members can also own passive interests in the ITC, thereby obtaining a stream of revenue from the facilities. Thus, it is not clear why they also must have an active and voting interest in the ITC, particularly in the early days of the formation of the ITC and RTO West.

18 *See Commonwealth Edison Company, et al.*, 91 FERC at 61,639.

transmission and generation facilities.[19] Specifically, Order No. 2000 requires that the RTO must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own tariff. In addition, the RTO must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The RTO must also have the authority to review and approve requests for new interconnections.[20]

Although Applicants have not yet submitted an OATT for Commission review and approval, as noted above, Dynegy seeks herein to bring certain issues to the forefront with respect to the Commission's review and approval of RTO OATTs. Specifically, in view of the importance of these issues to the competitive market, Dynegy respectfully requests that the Commission require that Applicants' future OATT filings address the following issues with respect to *pro forma* OATT improvements and generator interconnections:

Pro Forma OATT Improvements

The Commission must take the opportunity during the course of reviewing the RTO filings to reevaluate whether the *pro forma* tariff satisfies the needs of today's bulk power market. As noted above, concerns relating to the sufficiency of the *pro forma* tariff as a vehicle for comparable transmission service are closely tied to the comparability issue, in that serious questions are raised by the divergent treatment of point-to-point customers and native load customers. Apart from the disparity in transmission services, there are many other instances where changes can and should be made to enhance the flexibility of the marketplace. As the product of Order No. 888, issued over four years ago, the issuance of the *pro forma* tariff was a

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19 Order No. 2000 at 31,108.

20 *Id.*

positive event in 1996. But, the market continues to evolve, and the *pro forma* tariff has failed to change with it.

Although the Commission indicated in Order No. 888 that it will consider proposals that differ from the pro forma tariff terms and conditions, based on the "consistent with or superior to" standard,[21] outside of the currently operating ISOs, only a limited few transmission providers over the past several years have taken the Commission up on its offer to allow such improvements to the *pro forma* tariff.[22]

The few suggestions below will improve the flexibility of service offered under the *pro forma* tariff as well as help to clarify transmission customers' existing rights. As such, the proposals meet the "consistent with or superior to" standard for *pro forma* tariff modifications. Dynegy respectfully urges the Commission, to the extent appropriate in the context of its examination of the RTO filings, to require RTOs to make the relatively simple, yet important, clarifications to the *pro forma* tariff requested below.

- Rollover Rights

Section 2.2 of the OATT provides that long-term firm service customers "have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. . . . This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms

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21 Order No. 888 at 31,770.

22 As noted above, interstate pipeline tariffs, while still possessing many of the fundamental features of Order No. 636, have changed in many positive ways. Pipelines now offer shippers greater flexibility with pooling and hubbing services, ways for shippers to manage their imbalances, opportunities to park their gas, etc.

of one-year or longer."

In order to clarify the timing requirements for exercising rollover rights under OATT Section 2.2, the Commission recently required transmission providers to update the business practices section of their OASIS to reflect the following clarification:

> Any existing long-term customer that wishes to exercise its reservation priority must make an application for its new service term following the usual pro forma tariff procedures and notify the transmission provider, no less than sixty days (60 days) prior to the date an existing long-term contract ends and the new service term commences, that the long-term transmission customer wishes to exercise its reservation priority (right of first refusal) under Section 2.2. of the pro forma tariff.

Entergy Power Marketing Corporation v. Southwest Power Pool, Inc., 91 FERC ¶ 61,276 at 61,937 (2000). In addition, the Commission approved a proposal by PJM to require an existing long-term transmission customer to respond, within 30 days of being informed of a competing request, as to whether the transmission customer intends to exercise its right of first refusal, regardless of when the competing request is submitted. *PJM Interconnection, L.L.C.*, 91 FERC ¶ 61,178 (2000).

The Commission should require RTOs to adopt procedures similar to those put into place by PJM in order to provide further clarity with respect to the procedures applicable to the exercise of rollover rights, while at the same time providing additional flexibility for customers under the *pro forma* tariff. By spelling out procedures that require an existing long-term transmission customer to respond within a designated period of time from a competing request as to whether the transmission customer intends to exercise its rollover rights, the Commission will improve the existing *pro forma* tariff service. However, the right of first refusal period for the existing customer should be at least 60 days, rather than the 30 days adopted by PJM, in order to allow an existing customer sufficient time to evaluate whether it desires to match a competing request that might impact the existing customer's transmission decisions years in advance.

- Firm Redirects

Section 22.2 of the *pro forma* tariff provides that

> [a]ny request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

Despite the simplicity of this provision, Dynegy has found that, due to the lack of specific Commission guidance on this section of the *pro forma* tariff, certain transmission providers have severely limited, or in some cases altogether denied, the ability of transmission customers to exercise their right to modify Receipt and Delivery Points on a firm basis, or "redirect," pursuant to the transmission provider's OATT.

If it were not for the real dollars at stake for market participants, some of the current transmission provider restrictions on the ability of customers to redirect transmission would be laughably absurd. For instance, the rules employed by AEP with respect to a transmission customer's exercise of its right to modify Receipt and Delivery Points on a firm basis[23] result in a

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[23] The following instructions appear in the business practices section of the AEP OASIS:

> Section 22.2 -- Changes in Service Specifications:
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> In accordance with AEP's OATT ["the Tariff"] and Business Practices, a change in POR and/or POD cannot take effect until the start of the next calendar month for monthly service or the start of the next calendar week for weekly service. An alternative is to allow displacement of the original reservation and require that the new request drop down to a lower service period. Accordingly, a monthly reservation could be replaced by either

transmission customer being limited to redesignating firm Receipt and Delivery Points *only in months that end on a Sunday.*

In order to ensure that RTO transmission customers are not subject to such restrictions on their ability to redirect firm transmission, the Commission must make clear that RTOs must permit transmission customers to modify firm Receipt and Delivery Points, including modifications on a daily basis, and that redirecting a request does not affect the transmission customer's rollover status pursuant to Section 2.2 of the OATT.

While considering this clarification, the Commission may also want to consider the policy justifications for having two quite different approaches in the natural gas and electric policies regarding flexible receipt and delivery points. Shippers on interstate pipelines do not need to submit new requests for service in order to change receipt or delivery points. Shippers can change their receipt and delivery points and still maintain their firm rights as long as the points do not exceed the firm capacity rights that they pay for. This flexibility was a hallmark of

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a weekly or a daily reservation and a weekly could be replaced by a daily, with some limitations. For all cases, the change must be for the remaining period of the original reservation. In addition, for:

a) Monthly Dropping Down to Weekly - this will only be allowed for up to four weeks and the last calendar day of the final week has to be on the last day of the calendar month;

b) Monthly Dropping Down to Daily or Weekly Dropping Down to Daily - this will only be allowed for up to five calendar days and the last day has to be the last day of the calendar period.

For example, a customer with a monthly reservation requests a change on the second Tuesday of the month. Since there are more than five days left in the month, the only change permitted (if ATC is available) would be weekly service with a starting time of the following Monday, if the last calendar week ends on the last calendar day of the month. If the end days do not match, the request will be classified INVALID.

Order No. 636. The Commission reasoned that allowing shippers full access to receipt and delivery points would promote efficient use of the transmission system; would continue the development of market centers; and would provide for a broad and meaningful capacity release program.[24] The Commission must ask whether these goals are any less important to bringing competition to the electric industry.

- Reassignment of Transmission

Section 23.1 of the *pro forma* tariff provides that a point-to-point transmission customer may reassign its transmission rights to another eligible customer under the OATT, subject to certain pricing restrictions. Compensation for reassigned transmission may not exceed the higher of: (1) the original transmission rate paid by the transmission reseller; (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (3) the transmission reseller's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of sale to the eligible customer.

In *Enron Power Marketing, Inc.*, 81 FERC ¶ 61,277 at 62,361 (1997), the Commission, among other things, concluded that transmission resellers may not recover opportunity costs in connection with the reassignments "without making a separate filing under Section 205." The *Enron* order, however, lacked any guidance with respect to how opportunity costs under the required 205 filing would be calculated.

This restriction seems to be one of the primary reasons (along with the Commission's order in the Entergy source-sink proposal) that a robust secondary market for transmission

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[24] Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,429.

capacity has failed to emerge.[25] Indeed, the Commission found that the restriction on capacity release prices in the natural gas industry "reduces shipper's options, decreases the operation of the market, and does not adequately protect captive customers."[26] The uncertainty surrounding what precisely constitutes opportunity costs in effect caps the resale price at the maximum rate of the transmission provider. The capacity holder is thus given no incentive to award the capacity to someone who would place a high value on that capacity. This is contrary to one of the important objectives the Commission has applied to the pipeline industry – capacity should be rationed during peak periods.[27] As the Commission recognized in Order No. 637, the maximum rate restriction prevents such allocations during constrained periods, with the result that shippers who place a lower value on the capacity will retain it, rather than selling it to someone who would place a greater value on it.[28] While some may argue that the gas model does not fit in this regard, the end result should nevertheless be the same: a robust secondary market for transmission.

It is unclear how the seller of such transmission in the secondary market would be able to obtain data sufficient to show that its opportunity costs are "capped at the applicable

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[25] As discussed above, the ability of shippers on interstate pipelines to access flexible receipt and delivery points is one of the principal reasons that the secondary market has flourished post-Order No. 636. See discussion in Order No. 637 *Regulation of Short-Term Natural Gas Transportation Services* and *Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, 65 Fed. Reg. 10,156 (February 25, 2000); III FERC Stats. & Regs. ¶ 31,091 at 31,304-06 (February 9, 2000) [hereinafter Order No. 637].

[26] Order No. 637, III FERC Stats. & Regs. at 31,275.

[27] 18 C.F.R. § 284.10(b)(1).

[28] Order No. 637, III FERC Stats. & Regs. at 31,276.

transmission provider's cost of expansion at the time of sale to the eligible customer" in accordance with Section 23.1 of the *pro forma* tariff. For those transmission resellers that are not transmission owners, such information would be difficult, at best, to obtain.

So that transmission customers may more readily realize the benefits of a robust secondary market for transmission, the Commission must clarify how resellers of transmission under Section 23.1 of the *pro forma* tariff would meet the Section 205 requirement with respect to opportunity costs. Alternatively, the Commission should, for those entities with market-based rate authority, permit such sales to be made at market-based rates, subject to the quarterly reporting requirements currently applicable to such entities.

Generator Interconnections

The importance of interconnection issues to the overall success of the competitive marketplace cannot be overstated. Merchant capacity, in the form of new and expanded generation projects, enhances competition, promotes diversity in products and services offered to the market, mitigates market power of incumbent utilities, and contributes to overall market liquidity. However, if this merchant generation is to be built, the Commission must ensure that it can be expeditiously and predictably interconnected to the grid. The entire industry now accepts that accelerated development of additional generation capacity in markets such as California and New York is probably the closest thing to a "silver bullet" solution to concerns about high energy prices. Given this situation, the resolution of interconnection issues cannot be delayed.

By clarifying that a developer's rights during the interconnection process are grounded in the OATT, the Commission's *Tennessee Power* order[29] was a step in the right direction.

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[29] *Tennessee Power Co.*, 90 FERC ¶ 61,238 (2000).

However, the Commission must attend to the unfinished business of further detailing the rights of interconnecting generators.

On numerous occasions over the past several months, the Commission has deflected generators' requests for a generic proceeding on interconnections by pointing to the upcoming RTO filings as a potential source of continuity and fairness with respect to interconnecting generators.[30] Now that the RTO proposals are before the Commission, it is imperative that the Commission's guidance with respect to interconnection issues result in interconnection procedures that are clear, fair, and consistent.

For developers of merchant generation, the process of obtaining interconnection studies and interconnection agreements is often inordinately complicated, and requires substantial commitment of resources to battle recalcitrant transmission owners that seek to unfairly shift costs and risks to developers. In this regard, Dynegy is no stranger to risk; starting last year, Dynegy has brought new merchant generation on line, or has announced plans to do so, in Georgia, Illinois, Kentucky, Louisiana, Michigan, and North Carolina.[31] In Dynegy's experience as a developer of power projects in control areas throughout the nation, more often than not it is the interconnection process that bogs down the plant's progress.

Unfortunately for developers of merchant generation, the same issues often crop up again

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[30] *See, e.g.*, *Commonwealth Edison Co.*, 91 FERC ¶ 61,083 at 61,296, *order on reh'g* 92 FERC ¶ 61,018 (2000); *Entergy Services, Inc.*, 91 FERC ¶ 61,149 at 61,560 (2000); *American Electric Power Service Corp.*, 91 FERC ¶ 61,308 at 62,053 (2000); *Southwest Power Pool, Inc.*, 92 FERC ¶ 61,109 at 61,406 (2000); *Sierra Pacific Power Co., et al.*, 92 FERC ¶ 61,179 at 61,629 (2000); and *Carolina Power & Light Co.*, 93 FERC ¶ 61,032, slip op. at 13 (2000).

[31] Of these projects, the Rocky Road project in Illinois, Phase I of the Calcasieu project in Louisiana, and the Rockingham project in North Carolina are currently on line.

and again in the interconnection process. In order to ensure that the benefits of new merchant generation to the competitive market are realized as quickly as possible, the Commission must act decisively in the context of the RTO proceedings to provide the industry with guidance needed to resolve the issues set forth in the attached Appendix A to this filing, which addresses the following points:

- RTOs must be required to file interconnection procedures, which must provide, among other things, for i) standardized forms posted on the RTO's OASIS; ii) elimination of artificial procedural delays; iii) flexibility to allow for generator construction of facilities; and iv) filing of all criteria applicable to interconnecting generators.

- Interconnection studies must be undertaken pursuant to clear and consistent study timelines and a study model that represents a realistic portrayal of the RTO's system.

- RTOs must set forth clear and consistent rules applicable to the process of getting in, and staying in, the queue for interconnecting to the RTO's system.

- The Commission must reconsider cost responsibility rules for generation interconnection, including rolling-in upgrade costs instead of directly assigning these costs to generators in recognition of the system-wide benefits such upgrades can provide.

- Generator's rights under the Commission's current interconnection cost allocation policy must be clarified with respect to cost responsibility and crediting procedures for system upgrade costs.

- RTOs must not be permitted to unilaterally abrogate existing interconnection agreements.

- To the extent the RTO requires redispatch, VAR support, and other ancillary services, generator provision of such services must be voluntary, the generator must be compensated for providing such services, and such generator compensation must include opportunity costs.

- Information pertinent to interconnections must be posted on the RTO's OASIS, and must include information regarding locations where generation is needed to relieve congestion.

- **Congestion Management**

Order No. 2000 requires that an RTO ensure the development and operation of market mechanisms to manage transmission congestion.[32] The Commission further requires that market mechanisms accommodate broad participation by all market participants, and provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions. In general, the Commission concluded that a workable market approach to congestion management should establish clear and tradable rights for transmission usage; promote efficient regional dispatch; support the emergence of secondary markets for transmission rights; and provide market participants with the opportunity to hedge locational differences in energy prices.[33]

RTO West proposes a flow-based physical rights congestion management model to meet the requirements of Order No. 2000. 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, which are RTO grid facilities that are expected to have commercially significant amounts of congestion. Customers that wish to schedule across flowpaths will be required to have transmission rights, such as firm transmission rights (FTRs) or other transmission rights. RTO West Filing at p. 66-67.

RTO West describes how 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

[32] Order No. 2000 at 31,126.

[33] *Id.* at 31,126-28.

facilities. Any other residual congestion is managed by RTO West through the RTO's redispatch of resources, repurchase of rights, and, as a final resort, curtailment of schedules. *Id.*

While the model is still in the early stages of development, Dynegy supports the RTO West Applicants' congestion management proposal, with the exception of the treatment of FTRs (addressed below), as the best model for a competitive market. A great deal of work went into the development of a model that, unlike others, limits input of a centralized bureaucracy and allows the market to set the price for transmission uses based on real congestion. The model provides a means of addressing congestion in the region by providing transmission customers with efficient price signals regarding the consequences of their transmission usage decisions by establishing tradable rights for transmission usage. However, a number of details remain to be fleshed out, and market participants must have an opportunity to provide meaningful input into the process of further developing the proposal.

Although the flow-based physical rights congestion management model is clearly a step in the right direction, the RTO West Applicants' proposed allocation of FTRs to the incumbent utilities is not; the allocation will lock up nearly all the available capacity on congested paths, leaving little or none available to other market participants through the auction. Under the proposal, FTRs will be granted to each of the participating transmission owners: (1) to replace its firm rights under pre-existing long term transmission agreements; (2) to use its transmission facilities as needed to serve its load not covered by pre-existing agreements; and (3) to use its transmission facilities to serve its obligations under bundled power sale, exchange, coordination or other obligations not covered by a pre-existing transmission agreement. RTO West Application at p. 30. In addition, through December 14, 2011, additional FTRs will be made available without charge to each participating transmission owner as needed to meet that participating owner's annual load growth. RTO West Application at p. 31. RTO West would afford continuing rollover rights for all transmission agreements required to provide an adequate power supply for loads served from the electric systems of the participating transmission owners, and would provide all other transmission owners holding pre-existing long-term transmission agreements a one-time opportunity before the commencement of RTO West transmission service to extend the term of any pre-existing long-term transmission agreements, subject to available transmission capacity. RTO West Application at p. 32.

While the initial allocation of firm rights should reflect the previous use of the system, the allocation proposed by RTO West unfairly perpetuates that use and does not allow the market to set a price for such rights. As such, the RTO West's proposal to allocate FTRs for load growth and FTRs associated with a rollover must be rejected.

Moreover, the proposed treatment of FTRs fails to support the emergence of secondary markets for transmission rights, as required by Order No. 2000. The Commission has previously emphasized its intent to promote a liquid FTR secondary market.[34] Secondary markets for transmission capacity must be developed to foster robust, competitive wholesale and retail electricity markets. However, with the initial allocation of FTRs to pre-existing customers, allocation for future load growth and the rollover rights described above, there will be few or no FTRs to auction.

Without a liquid and transparent auction process, the valuable FTRs allocated by RTO West will be left in the hands of the incumbent utility to serve existing load or to engage in other

[34] *PJM Interconnection, LLC*, 87 FERC ¶ 61,054 at 61,221 (1999).

market transactions. As a result, ability of market participants to compete for existing load will be unfairly limited. The fact that under the RTO West proposal the incumbent utilities will have no obligation to make these valuable rights available to the market at any time in the future only exacerbates the problem. The limited availability of such rights in the day ahead market is not sufficient to allow new market participants to compete.

To address this shortcoming, there must be an annual auction for all FTRs. Existing transmission rights holders would have the option to set a reserve price below which they would not sell their rights in the auctions, thereby facilitating a market price for FTRs by establishing a value for the rights. The holders of those rights would receive any auction revenues received as part of the annual auction as set forth in the RTO West tariff. Finally, as noted above, Applicants' final congestion management proposal must be the product of an independent board, with stakeholder input from all segments of RTO West participants.

In general, the RTO West Applicants acknowledge that there is more work to be done and state that they are committed to continuing the collaborative process. That's the good news. The bad news is that as they themselves admit – this is a filing by the transmission owners. Real stakeholder involvement in developing congestion proposal is critical and the question is whether an independent structure should be in place before a proposal is submitted to the Commission. This was the conclusion of the Commission in its recent *California Order*, where it required the new governing structure to be in place before a congestion proposal is filed. The Commission should do the same here. And if, for some reason, it is not possible to have the independent structure in place timely, the Commission should alternately assume a very active role in the process. The industry has seen what happens when that is not the case. The incumbent utilities develop the plan, present it to the Commission in a section 205 filing, then the customers are left with the heavy burden of convincing the Commission to make changes (or to throw out entirely) a plan that may be so far down the road to implementation that the Commission is reluctant to send the applicants make to the drawing board. No one benefits from this process. Therefore, Dynegy urges the Commission to either insist on stakeholder involvement within the context of an independent governing structure or to guide the process itself.[35] This is just too important.

To help focus the debate on this issue, Dynegy is attaching as Appendix B to these comments a short paper on congestion pricing and RTOs. The paper makes these points:

- Congestion management proposals should be designed to satisfy the needs of the market, not created to "be the market."
- The industry's experience with structured markets has been that they are slow to adapt, unwieldy in their adoption and in large part due to the processes involved, always behind the curve.
- Any congestion model should be judged against whether it meets the needs of customers, which include: liquidity, certainty of price, certainty of delivery, and transmission flexibility.
- LMP, when judged against these standards, comes up far short.
- Other models, such as flowgate and zonal pricing, hold a great deal of promise in meeting the needs of customers.

The Commission has stated its willingness to accept different approaches to congestion pricing in Order No. 2000.[36] It is time for the Commission to reiterate its willingness and to send a clear, unmistakable signal to the industry – LMP is not the only method the Commission will

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35 There can be little argument that the industry benefited greatly from the Commission staff involvement in the Order No. 636 restructuring of the interstate pipelines.

36 Order No. 2000 at 31,127.

accept. It is critical to the groups of market participants across the country (and especially here in this region) that are working on various congestion proposals that the Commission be very clear about this.

- **Interregional Coordination**

The RTO West Applicants describe their efforts to as part of the Western Interconnection to form the Western Interconnection Organization to perform interconnection-wide reliability and market-interface functions and to coordinate between regional entities within the Western Interconnection. The RTO West Applicants also describe a proposed framework for coordination with Canadian entities, with the goal of providing standardized business practices and closely coordinated system operation. RTO West Filing at pp. 75-80.

Dynegy and others have been have been squarely focused on the issue of interregional coordination since the Commission issued its Notice of Proposed Rulemaking in RM99-2-000.[37] Thus, the Commission's action to add this as the Eighth Function for RTOs in Order No. 2000 was applauded from all corners. From the issuance date of Order No. 2000 to now, interregional coordination has been a recurring theme throughout the collaborative process. Even while some have argued that very large RTOs will solve the "seams" issues, the truth became evident that: (1) very large RTOs are not likely for the foreseeable future, and (2) unless there are three RTOs – East, West and ERCOT – there will continue to be seams issues.

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[37] Notice of Proposed Rulemaking, Docket No. RM99-2-000, *Regional Transmission Organizations*, 64 Fed. Reg. 31,389 (June 10, 1999); FERC STATS. AND REGS., Proposed Regulations ¶ 32,541 (May 13, 1999).

As the Commission is aware through comments filed with the Commission,[38] Dynegy and other industry participants have been engaged in a dialogue on how to best address two of the most significant issues facing the wholesale power industry today: (1) transfer capability/loop flows; and (2) seams issues between transmission providers.

Dynegy suggested a construct – the Interregional Transmission System Coordinator (ITSC) as an entity with the capacity to take a broad perspective on "flows and seams" issues as RTOs are forming, rather than waiting until after filings are made and decisions are cast in concrete. Dynegy and others felt strongly, though, that if there were ongoing efforts in the industry to do the same things, there was no need for duplication. What Dynegy and others did want, however, was a signal from the Commission that interregional coordination was so critical to achieving the benefits of wholesale competition that some entity – whether it was an ITSC or NERC or some other standards organization or the Commission itself – that someone was going to take control of this function.

Isn't this the job of the RTO? Yes and no. Yes, RTOs will indeed have the responsibility to ensure that coordination takes place, but who is going to ensure that this coordination is timely, efficient, makes sense for the *entire* region, and is customer-driven. One of the most promising developments since Order No. 2000 are the recent

[38] *See* Request for Clarification and/or Rehearing, and Motion for Expedited Implementation of Interregional Coordination Function of Dynegy Inc., filed January 19, 2000 in Docket No. RM99-2-000 and Comments of Dynegy Power Marketing, Inc., *et al.* Filed June 30, 2000 in Docket No. EL00-75-000.

Staff Reports to the Commission. The Staff Reports were the outgrowth of an investigation ordered by the Commission in late July.[39] FERC Staff interviewed and collected data from a variety of market participants to "determine any technical or operational factors, regulatory prohibitions or rules (federal or state), market or behavior rules, or other factors affecting competitive pricing of electric energy or reliability of service."[40] Much of the Staff Reports confirm what transmission customers already know. The lack of consistency of rules from one transmission owner to the next, and from one ISO to the next, are one of the single most important impediments to the creation of large, regional markets.

Indeed, on the subject on whether RTOs on their own can solve these problems, Staff found that:

> The problems of non-standardized protocols, discussed below, are not likely to be completely solved by RTOs if the RTOs retain multiple control areas and procedures. For example, it is not enough for an RTO to calculate ATC for its members if the members provide the data used by the RTO to calculate ATC. Otherwise, given that the control areas contain generation units of the transmission providers, the incentive for those providers to favor generation will continue.[41]

The Staff Report found that there are no consistent rules for calculating and posting ATC and CBM, *e.g.* some regions like SPP post ATC by flowgate while still others do it by control area. The reasons for this variance, they found, are the result of different assumptions about reliability,

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39 92 FERC ¶ 61,160 (2000).

40 Staff Report Introduction at ii.

41 *Id.* at 1-37.

dissimilar engineering approaches, as well as historical and operational parameters. (Staff Report at 2-37). This was the Staff conclusion:

> As a result of the lack of standardized procedures for calculating ATC and CBM, and the inaccurate posting of ATC, market participants cannot determine what transmission capacity is available so that they can make deals to provide energy to their customers. This has an effect on the amount of transactions and is a limit on liquidity.[42]

What does the Staff suggest as a solution?

> ...[t]o avoid uncertainty during the interim period before RTOs become effective, the Commission could undertake to standardize methodologies for calculating ATC and TTC. The Commission could do this by requesting proposed standards, either from industry participants or NERC. The Commission could also direct NERC to develop procedures to ensure industry-wide dissemination of TLR information to market participants.[43]

The picture the Staff Report paints of the wholesale power market is not rosy. But industries in transition rarely are. That is not to say that no progress is being made on these issues. For one, there is the Memorandum of Understanding Process underway in the Northeast among the three ISOs and the Ontario Independent Market Operator. However, this MOU process still has a long way to go towards resolving issues despite its 15-month life.[44] A number of the developing RTOs have been engaged in serious discussions about seams issues (the Inter-RTO Seams Collaborative). The Gas Industry Standards Board is considering an expansion of its duties to include wholesale and retail

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[42] *Id.* at 2-38.

[43] *Id.* at 2-49.

[44] The process has identified numerous areas of concern, and while this is surely progress, it is not closure. See for instance the charts of pending actions and accomplishments found at the IOS MOU website; http://www.isomou.com/working_groups/operations/Documents/Meeting%20Notes/ISO%20OWG%20Meeting%20Notes%20-%20Sept%2012,%202000.pdf Attachments 2 and 3.

electric business standards. NERC is involved in several efforts. The point is not that work is not being done, but rather that it is not being done in a coordinated effort, or being done fast enough, or being done with the proper focus. Thus, it is quite heartening to see that the Commission Staff is recommending such bold action for the Commission to undertake. In response to what Staff observed in the Northeast, this is Staff's recommendation:

> It might be more effective to devote the resources of all market segments and regulators to the potential for northeastern regional solutions to issues such as transmission planning or congestion management than to perfect separate ISO-administered markets. Synergies that will further the Commission's goal of broader regional coordination may be lost, at a minimum, in the near term and quite possibly longer term once NYISO and ISO-New England have made considerable investments in fixing or enhancing their separate markets. To prevent the possibility of continued internal changes by ISOs that do not also enhance, and may hinder, further trade across the Northeast, the *Commission may want to take a more active role in the coordination and standardization process begun with the MOU.*[45]

The Commission should seriously consider the findings of the Staff Report and, if it does, it will realize that without its active involvement in matters such as interregional coordination, the industry will make little or no progress. Rather than react piecemeal to each Applicant's proposal on interregional coordination, the Commission needs to take bold action in this endeavor.

What does Dynegy suggest that the Commission do? Before getting to our suggestions, how did the natural gas industry achieve success in this area? Unquestionably, the pivotal moment came during a Commission-sponsored conference that was held in September of 1995 to assess the progress that was being made towards standardization in the industry. The message

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45 Staff Report at 1-92 (emphasis added).

heard at that conference was "very little." As a result, the Commission took concrete steps to move things along. The Commission gave the industry deadlines and outlined what it wanted done.[46] (And the subtle message contained in the order was that if the industry didn't do it, the Commission would.) One advantage that the Commission had then was an industry group that was ready to take on this task and was on its way to having a governance structure in place that represented all segments of the industry.

Is this the model for the electric industry? Quite possibly. Indeed, as mentioned above, GISB itself is discussing expansion of its responsibilities to the power side. Also, it is obvious that the Commission used this very order as a model for its recent Advance Notice of Proposed Rulemaking in RM00-10.[47] There, it required the electric industry to develop proposals relating to communication protocols and associated business practices by February of next year. What will be presented to the Commission is an unclear at this point.

Again, the question - what should the Commission do? It seems apparent that the lack of progress shown in the October RTO filings and the critical nature of these problems demands that the Commission take action now. Dynegy offers the following "Ten Steps to Interregional Coordination":

1. Acknowledge that the problems identified in the Staff Reports are indeed problems that need to be solved expeditiously.

2. Based on the Staff Reports and on comments filed in the RTO proceedings, develop a comprehensive list of interregional issues that must be addressed.

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46 Standards for Business Practices of Interstate Natural Gas Pipelines, 73 FERC ¶ 61,104 (1995).

47 Open Access Same-Time Information System (Phase II), 92 FERC ¶ 61,124 (2000).

3. Recognize that RTOs will not solve these issues by themselves, but they must be part of the solution.

4. Recognize also that because RTOs will take time to become fully functional, solutions to these problems cannot wait.

5. Take a broad perspective with regard to these problems, and mandate interconnect-wide solutions.

6. Establish a process that looks first to the industry to fix these problems, but only in close collaboration with the Commission.

7. Establish deadlines and milestones that must be accomplished for these deadlines.

8. Ensure that whatever industry group is tasked with these issues, that the group is representative of *all* segments of the industry and that *fair* voting rules are in place.

9. Make a condition of full compliance with Order No. 2000, that each RTO adopt and implement the results of this process.

10. And, finally, if the industry fails to take this challenge on – the Commission must do so itself.

- **Agreement Limiting Liability**

The RTO West Applicants specifically request Commission approval of the Agreement Limiting Liability among RTO West participants. The Agreement Limiting Liability seeks to inappropriately limit recovery for a generator that has been wrongfully dispatched by the RTO. RTO West Filing, Attachment Y, Section 8. The Agreement Limiting Liability would deny reimbursement of opportunity costs for a transaction that has been adversely affected by an improper RTO action. This is contrary to the Commission's finding in its rehearing of Order No. 2000, where the Commission clarified that "generators that are redispatched . . . should be fully compensated and that the compensation would consider, among other things, lost opportunity costs."[48] Similarly, such costs should be considered when a transaction that has been adversely affected by an improper RTO action.

Moreover, Applicants' attempt to limit liability with respect to such costs is contrary to previous Commission rulings. In *Pacific Gas and Electric Co., et al.*,[49] the Commission reviewed and rejected a similar attempt to limit the liability, including the types of damages recoverable, of the California ISO (CAISO).[50] In that proceeding, the Commission reviewed proposed Section 14 of the CAISO tariff, which provided that the CAISO would not be liable for losses, damages, claims, etc. arising from the performance or non-performance of the CAISO's obligations under the tariff except to the extent that CAISO's breach of its tariff provisions resulted in damage to property or death or injury to any person. Proposed Section 14.2 of the CAISO tariff further provided that the CAISO would not be liable to any market participant under any circumstances for any financial loss resulting from physical damage to property.[51] The Commission found that the proposed limitations on CAISO liability to be overly broad. Specifically, the Commission concluded that, while it is appropriate to limit liability in instances where the CAISO is not negligent in the performance of its responsibilities under the tariff, the determination of liability in instances where the CAISO is found to have been negligent or to have engaged in intentional misconduct "is best left to appropriate court proceedings, in which

48 Order No. 2000-A at 31,373.

49 81 FERC ¶ 61,122 (1997).

50 In the same proceeding, the Commission rejected parallel provisions in the California Power Exchange tariff.

51 *Id.* at 61,517.

the parties will be free to advance any appropriate argument," and required the CAISO to modify its tariff accordingly.[52] The Commission has also rejected similar limitations on liability proposed by NYISO.[53]

III.

WHEREFORE, for the reasons set forth above, Dynegy respectfully requests that any approval of Applicants' proposals be conditioned upon Applicants bringing their proposals into full compliance as described above and in the Commission's orders, and that the Commission grant any further relief specifically requested above.

Respectfully submitted,

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I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C.: November 20, 2000

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52 *Id.* at 61,520.

53 *New York Independent System Operator, Inc., et al.*, 90 FERC ¶ 61,015 at 61,034-35, *order on reh'g*, 91 FERC ¶ 61,012 (2000).

APPENDİX A

INTERCONNECTION ISSUES IN RTO FILINGS

By clarifying that a developer's rights during the interconnection process are grounded in the OATT, the Commission's *Tennessee Power* order[1] was a step in the right direction. However, the Commission must attend to the unfinished business of further detailing the rights of interconnecting generators.

On numerous occasions over the past several months, the Commission has deflected generators' requests for a generic proceeding on interconnections by pointing to the upcoming RTO filings as a potential source of continuity and fairness with respect to interconnecting generators.[2] Now that the RTO proposals are before the Commission, it is imperative that the Commission's guidance with respect to interconnection issues result in interconnection procedures that are clear, fair, and consistent.

Unfortunately for developers of merchant generation, the same issues often crop up again and again in the interconnection process. In order to ensure that the benefits of new merchant generation to the competitive market are realized as quickly as possible, the Commission must act decisively in the context of the RTO proceedings to provide the industry with guidance needed to resolve the issues set forth below:

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1 *Tennessee Power Co.*, 90 FERC ¶ 61,238 (2000).

2 *See, e.g.*, *Commonwealth Edison Co.*, 91 FERC ¶ 61,083 at 61,296, *order on reh'g* 92 FERC ¶ 61,018 (2000); *Entergy Services, Inc.*, 91 FERC ¶ 61,149 at 61,560 (2000); *American Electric Power Service Corp.*, 91 FERC ¶ 61,308 at 62,053 (2000); *Southwest Power Pool, Inc.*, 92 FERC ¶ 61,109 at 61,406 (2000); *Sierra Pacific Power Co., et al.*, 92 FERC ¶ 61,179 at 61,629 (2000); and *Carolina Power & Light Co.*, 93 FERC ¶ 61,032, slip op. at 13 (2000).

Interconnection Procedures

In a number of recent proceedings, the Commission has encouraged transmission providers to revise their OATTs to include procedures for requesting interconnection services and the criteria for evaluating those requests.[3] As noted above, now is the time for the Commission to act in the context of the RTO proceedings to require all RTOs to file clear rules at the Commission (and to post those rules on their OASIS) detailing the procedures for interconnecting generation to the grid. As recognized in the Commission's Staff Report on Bulk Power Markets (Staff Report),

> [r]egardless of whether problems relating to system impact studies and interconnection requests are widespread, the lack of standard procedures for those studies in the current regulations appear to have created uncertainty in the market, as public power and other market participants are forced to deal with different standards and procedures for every transmission provider for which they seek an interconnection request. This appears to inhibit the free flow of transactions within the region. Moreover, the lack of specific standards and procedures makes it difficult to pursue allegations of discriminatory conduct in this area.[4]

In addition, the Commission should require RTO interconnection procedures, at a minimum, to provide for the following:

- Develop and Post Standard Forms on RTO OASIS

  In order to ensure that the interconnection process is as streamlined as possible, all forms and agreements relating to the interconnection process, such as interconnection request forms, study request forms, study agreements, etc., should

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3 *Commonwealth Edison Co.*, 91 FERC at 61,296; *Entergy Services, Inc.*, 91 FERC at 61,560; *American Electric Power Service Corp.*, 91 FERC at 62,053; *Southwest Power Pool, Inc.*, 92 FERC at 61,406; *Sierra Pacific Power Co., et al.*, 92 FERC at 61,629; and *Carolina Power & Light Co.*, 93 FERC ¶ 61,032, slip op. at 13.

4 Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States; Part II of the Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 2-45.

be standardized and posted on the RTO's OASIS. By posting such documents, the RTO will enable interested developers to become more fully informed about its interconnection requirements before even initiating formal contact with the RTO. Moreover, once the interconnection request is formally submitted, by having access to forms posted on the OASIS, the developer will be able to provide more complete and timely information to the RTO with respect to the specifics of the developer's request.[5]

By suggesting that such forms be standardized and posted on the RTO's OASIS, Dynegy is <u>not</u> advocating that RTOs unilaterally develop and file pro forma <u>interconnection agreements</u>. As noted above, interconnection agreements constitute the generator-specific contract that sets forth the unique rights and responsibilities of the parties. To the extent that some interconnection agreement terms and conditions can be standardized, the process of developing such a "model" interconnection agreement must be undertaken on a collaborative basis, with ample opportunity for input from generators – the RTO's interconnection customers.

- <u>Eliminate Artificial Procedural Delays</u>

The Commission should make clear that the RTO must not raise artificial barriers, such as requiring that study agreements be signed or certain studies be completed before the standard form of interconnection agreement used by the RTO is made available to the interconnecting customer for review. RTO interconnection

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5 *See, e.g.*, *Carolina Power & Light Co.*, 93 FERC ¶ 61,032, slip op. at 5 (where the Commission approved a proposal by CP&L to post technical data requirement on its OASIS as a means of expediting the interconnection process).

procedures must make clear that the RTO will seek to obtain long lead-time items and will commence construction on an interconnection prior to the filing of an interconnection agreement (whether executed or unexecuted) so long as the developer provides adequate financial assurance, such as a letter agreement.[6] Given the time-critical nature of the generation development process, developers on a tight construction schedule are often faced with the equally unpleasant choices of either i) agreeing to execute an interconnection agreement that contains unreasonable prices, terms and conditions; or ii) requesting that the transmission owner file an unexecuted interconnection agreement that contains many provisions still under dispute. Delays in the construction schedule can significantly impact the economics of a project (not all years/seasons are equal), and therefore can make the difference as to whether a project is feasible or not. By providing that the RTO may begin to obtain long lead time items and commence construction once it obtains adequate financial security from the developer, the interconnection process (such as finalization of studies or continuation of negotiations with respect to the terms and conditions of the interconnection agreement) can continue on a parallel track, without resulting in undue delay to the project.

- <u>Allow Generator Construction of Facilities</u>

RTO interconnection procedures must make clear that, in the event that the RTO is unable to commit to finishing construction of the interconnection on the

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6 *See, e.g.*, *Commonwealth Edison Company*, 91 FERC ¶ 61,083 at 61,300, *order on reh'g* 92 FERC ¶ 61,018 at 61,036 (2000); *Southwest Power Pool, Inc.*, 92 FERC ¶ 61,109 at 61,405 (2000).

schedule required by the project, the interconnecting customer has the right to construct or have constructed the interconnection facilities necessary to interconnect to the RTO's grid. This type of "self help" is a standard remedy in most commercial agreements, especially where timeliness of performance is an issue. Most utilities do not maintain employees on staff charged with construction of interconnection or transmission facilities, but instead contract with third parties to construct such facilities. Nevertheless, with some notable exceptions such as Entergy, most utilities will not allow an interconnecting customer to procure the construction of interconnecting facilities meeting the utility's requirements. Consequently, a project can be jeopardized by the "Catch-22" of a utility i) refusing to commit to meeting the required completion date for the facilities, and ii) refusing to allow the interconnecting customer to have such facilities built by a third party who will commit to meeting the required completion date. By providing that the RTO is required to allow the interconnecting customer to procure the construction of the required interconnection facilities to the RTO's reasonable specifications if the RTO is unable to commit to meeting the customer's project schedule, and then turning the facilities over to the RTO, the interconnection process can proceed efficiently, without jeopardizing the viability of, or resulting in undue delay to, the project. Of equal importance, by allowing the generator to procure third-party construction of such facilities pursuant to industry standards, as opposed to utility "gold plating," the ultimate costs of the interconnection can be reduced.

- Filing of Criteria Applicable to Interconnecting Generators

Any applicable standards, procedures, rules, or other documents to be utilized by the RTO to determine the rights and responsibilities of the parties under the interconnection agreement must be filed with the Commission as part of the RTO's interconnection procedures or as part of an individual interconnection agreement. The Commission has made clear that, to the extent that such material is intended to further dictate and/or delineate the rights and obligations of the parties to the interconnection, the material should be included as part of the interconnection agreement to be filed with the Commission and subject to review and comment.[7]

Interconnection Studies

In order to enable developers and the Commission to gain a clear understanding of the standards applicable to interconnecting generators, interconnection procedures must include, among other things, a precise explanation of the applicable timelines, scope and methodology used for interconnection studies. Moreover, consistent with Commission precedent, RTO interconnection procedures must not blur the line between

[7] *See, e.g.*, *Entergy Services, Inc.*, 91 FERC ¶ 61,234 at 61,856 (2000) (where the Commission ordered Entergy to file its "Non-Utility Generator Standards" referenced in a previously-filed interconnection agreement); *Duke Energy Corp.*, 91 FERC ¶ 61,128 at 61,485 (2000) (where the Commission concluded that a switchyard lease was subject to filing with the Commission to the extent the terms and conditions in the lease "in any manner affect or relate to the jurisdictional service, i.e., the interconnection service"). *See also*, *Atlantic City Electric Co., et. al.*, 91 FERC ¶ 61,063, slip op. at pp. 6-7 (wherein the Commission ordered PJM to file revisions to PJM's description of its operating reserve energy credit, previously contained only in the PJM Manuals, which are not on file with the Commission); *Coalition Against Private Tariffs, et al.*, 83 FERC ¶ 61,015 at 61,039, 61,043-44 (1998), *order on reh'g*, 84 FERC ¶ 61,059 (1998) (wherein the Commission found that, when changes in operating practices affect, for example, reservation, scheduling, and curtailment provisions of the Commission's *pro forma* tariff, the changes need to be filed).

interconnection service under the OATT and transmission service under the OATT;[8] to that end, interconnection studies should not automatically include an assessment of deliverability, or assume that the generator desires to be a network resource or receive network service.

Study Timelines

In terms of timeliness, to the maximum extent practical, the interconnection studies should be "compressed" so as to ensure that study delays are kept to a minimum. RTO interconnection procedures should provide a process for interconnecting customers to accelerate the study process by overlapping or combining, to the extent possible, the various studies relating to the interconnection request, so long as the RTO is provided with adequate security, *i.e.*, an interconnecting customer may be willing to make any deposit set forth in the study requirements when the customer submits its initial request.[9] Virtually all transmission owners that Dynegy has worked with complain of being overwhelmed by the large volume of interconnection requests. Dynegy is sympathetic to their plight, but only to a point. Many of the transmission owners continue to be integrated utilities that are not very enthusiastic about interconnecting competing generators.[10] As recognized in the Commission's Staff Report,

[8] *See, e.g.*, *Tennessee Power*, 90 FERC at 61,761-62; *Entergy Services, Inc.*, 91 FERC at 61,559.

[9] Interconnection procedures filed by Southwest Power Pool, Inc. provide for expedited studies. *Southwest Power Pool, Inc.*, 92 FERC at 61,401.

[10] For example, despite this "overwhelming volume" of interconnection requests, and the availability of well qualified outside consulting firms that could perform some or all of the required studies, many utilities refuse to engage such consulting firms to help process interconnection requests. The Commission must ensure that RTO procedures will permit qualified firms to perform the necessary studies.

> transmission providers, as vertically integrated utilities, have no economic incentive to provide transmission access to a competitor, and in fact have incentives to discourage transmission access to competitors, particularly if such access would conflict with the transmission provider's service of its native load. The engineers and other technical staff who perform system impact studies on interconnection and transmission requests are the same personnel that perform such studies for native load. RTOs could provide the solution to this problem by handling all interconnection requests and system impact studies for their member transmission providers. On the other hand, if existing control areas are maintained, the disincentive for processing third party interconnection and transmission requests would remain.[11]

Similarly, the Commission must ensure that RTO interconnection procedures do not allow a neighboring RTO's study of the project to delay completion of an interconnection study.[12]

Study Model

The question of which projects to include in an interconnection study has been a source of continuing controversy among generation developers and transmission providers. In the past the Commission has approved interconnection procedures that would include only those projects that have signed an interconnection agreement.[13]

Rather than including only those projects that have signed an interconnection agreement or that have requested the filing of an unexecuted interconnection agreement, which may portray an inaccurate picture of the system, projects that exist or are reasonably certain to exist during the study time frame should be included in interconnection study models. One way to ensure that such projects are included in interconnection study models is to determine whether the project has met certain

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11 Staff Report, p. 2-44; see also, p. 3-36.

12 *See, American Electric Power Service Corp.*, 93 FERC ¶ 61,151 (2000).

13 *See, e.g., Entergy Services, Inc.*, 91 FERC at 61,561.

objective development milestones, which should be mutually agreed to by the developer and the RTO at the beginning of the interconnection process.[14] Objective milestones for gauging project viability will ensure that "bench-warmer" projects do not stand in the way of proactive developers.[15] This holds especially true for utility placeholder projects that may or may not be completed in the distant future.

At the very minimum, RTO interconnection study procedures must present developers the option of specifying that such facilities – *i.e.*, facilities for which an interconnection agreement has not been executed or filed, but which otherwise are reasonably certain to be interconnected to the grid – be included in the RTO's interconnection study model for the developer's plant, subject to reimbursement by the developer for any additional RTO study costs that result from the inclusion.

Queuing Rules

Developers are often faced with a bewildering array of shifting and ill-defined queues in the interconnection process. For example, there is the queue that consists of interconnection requests waiting to be studied by the transmission provider. A developer's priority in this study queue is often based on when the interconnection request is submitted to the transmission provider.

In addition to the study queue, however, there may be a queue – a "cost queue" – for locking in priority for a particular location in the transmission provider's control area, which, depending on the extent that the transmission provider includes competing

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[14] Attached to this Appendix A is a proposed listing of various milestones that could be used to gauge a project's continued viability.

[15] *See, e.g.*, *Commonwealth Edison Company*, 91 FERC at 61,299; *Carolina Power & Light, Inc.*, 93 FERC ¶ 61,032, slip op. at 9-10.

projects in its studies, can have a tremendous impact on the developer's ultimate costs for interconnecting to the grid. Often, inclusion in this queue is based upon the date a generator "signs" an interconnection agreement, and only those projects with executed interconnection agreements are included in the transmission provider's study model, regardless of why a particular developer might not be ready to execute a proffered agreement.[16]

The Commission should require RTOs to set forth clear and consistent rules applicable to the process of getting in, and staying in, the queue for interconnecting to the RTO's grid. To that end, RTOs should be required to make clear that a generator's rights are determined by when the original request for an interconnection is submitted to the RTO, on a first-come, first-served basis, so long as the generator continues to meet or exceed objective milestones designed to gauge the project's continued viability. In this manner, a developer does not get "leapfrogged" in the queue, in terms of study priority or interconnection costs, by a competing facility simply because the competing developer signed an interconnection agreement. As noted above, current procedures requiring executed interconnection agreements put at a disadvantage those developers who have viable projects well under way, but who have not yet executed an interconnection agreement – often due to protracted negotiations with the transmission provider.[17]

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[16] *See, e.g., Entergy Services, Inc.*, 91 FERC at 61,561. As noted above, each project has different characteristics, any of which might give rise to the need to alter the utility's version of the document.

[17] The advantage goes to competitors who will sign any proffered form of agreement (and whose project may not ultimately get built), and not to experienced developers/operators who get projects built, yet who in evaluating a given project's viability, assess carefully the costs buried in the interconnection agreements proffered by the utility.

Interconnection Costs

The Need for an Alternative

Dynegy is increasingly concerned about how to convert the nation's transmission system from one designed to connect local generation to local loads, to a system that allows the efficient transfer of large amounts of power from regions with excess capacity (temporary or otherwise) to those that are experiencing temporary shortages of capacity. Virtually all industry observers agree that substantial investments in transmission assets are needed to achieve the robust wholesale markets envisioned by the Commission. In addition, virtually all industry observers also agree that current rate structures are not motivating transmission owners to make the substantial investments necessary to move the industry forward in this increasingly critical area.

The "transmission upgrade problem" frequently confronts generation developers in the form of required or optional upgrades identified in interconnect studies. Generators are being told that they must pay upgrade costs that are ranging from $30 to $80 million in order to interconnect their plants. These extra costs are negatively affecting the economics of many projects with the result that the developer often terminates the project. Providing future transmission credits does not adequately address the problem due to the time value of money for such sizable dollars and the uncertainty over exactly what transmission service the generator may eventually need.[18]

There can be little debate that all of the new generation capacity being developed today will be used to serve load. The generation will not sit idle and the energy certainly

[18] Two common examples exist where the generator will never buy any transmission service: 1) the generator sells all of its output to a wholesale entity that has procured its own transmission service; and 2) the generator sells all of its output to the local utility that designates the generator as a network resource.

won't be shipped to Mars. As noted above, most transmission owners are requiring generators to pay for all upgrades. The transmission owners' rationale is that if the generator wants to move its power out of the local control area, then the generator should pay for the cost to do so. This explanation oversimplifies the issue, but is very appealing to regulators, particularly state regulators who do not want their state's consumers to pay more "so generators can sell their power somewhere else." What is missing from the debate is acknowledgement that the nation's interstate transmission system is seriously underbuilt – this must be changed. An important step towards that end is a change in policy on interconnection costs.

The issue must be viewed from a broader perspective. Reinforcement of the nation's transmission grid will benefit consumers by allowing generation to be transferred from regions that have surpluses to regions that are short. And a region that is long generation one week may find itself short the next week due to unplanned outages and shifting weather patterns – exactly the scenario that has been repeated summer after summer and yet continues to "surprise" people. Transmission upgrades are not "one-way streets;" the same transmission upgrade that may allow power to flow from Louisiana to Missouri, through Arkansas during a period of high demand in the Midwest will also allow power to flow from Missouri to Louisiana when Louisiana is short of power. And, as discussed below, interconnection costs charged to the developer often fail to factor in consideration that the presence of a generator at a particular location may actually <u>relieve</u> congestion on the grid.

The relative investment in generation versus transmission is also a factor that must be considered. While actual percentages vary, the transmission component of the nation's electrical system is estimated to be approximately 8-10% of total delivered energy costs. The generation component is estimated to be in the 45-55% range, dwarfing the investment in transmission. A major investment in transmission will actually be a fairly modest overall investment when compared to the dollars invested in generation. Yet the investment in transmission will yield considerable benefits on the generation side – lower overall generation prices due to the ability to more efficiently utilize the nation's existing and future generation fleet. On a macro level, less generation will be needed because of the increased transfer capability.[19] Therefore, a substantial investment in transmission that increases consumers' prices by 1-2 % can be expected to reduce consumers' generation prices by 4-8% or possibly more. At the end of the day, consumers will be better off if they pay for most system upgrades associated with new generation. As consumers will benefit from the generation, it is entirely reasonable that they should pay for the transmission upgrades.[20]

The Public Utility Commission of Texas (PUCT) has adopted precisely such a model for new generation developed in ERCOT.[21] The PUCT recognized that ERCOT needed additional generation to serve load growth. The PUCT also realized that requiring new generators to pay for all transmission system upgrades would constitute a major barrier to entry for competitive generators resulting in many desirable projects

19 Less generation will also yield considerable environmental benefits.

20 The Commission should also consider how cost responsibility for transmission upgrades associated with new utility rate base generation are handled. There is no question that transmission costs associated with a utility's own plants are rolled into utility rates. Why should transmission costs for generation developed by a non-affiliated entity be treated differently?

21 Tex. P.U.C. Subst. R. 25.195(d)(2).

being abandoned due to the increased costs. Recognizing that such a path would lead to a shortage of generation and higher prices, not to mention reliability concerns, the PUCT adopted a presumption that the cost of transmission upgrades be rolled into the overall cost of transmission service and recovered from load. One result of this policy is that ERCOT is projected to have a generation reserve margin in excess of 25%, due in large part to the presumption of rolled-in rate treatment. There can be little doubt that consumers will ultimately benefit from this policy. Indeed, the Commission' Staff Report appears to recognize the potential benefits of such a pricing policy, in recommending that the Commission "reconsider cost responsibility rules for generation interconnection, including rolling-in upgrade costs instead of directly assigning these costs to generators."[22]

Current Approach to Interconnection Costs

In the alternative, and at the very least, in the event the Commission finds that it is appropriate to continue the current policy of permitting transmission providers to require interconnection customers to pay for system upgrades subject to receiving a credit for transmission service, the Commission must ensure that RTO procedures adequately address the following issues with respect to cost responsibility for such upgrades:

- Transmission Planning

While the developer should be responsible for costs related to "plugging-in" to the grid, RTO interconnection procedures must make clear that the interconnection customer will not be responsible for upgrading an already obsolete or inadequate grid.[23] More

22 Staff Report, p. 1-96.

23 *See, e.g., Carolina Power & Light Co.*, 93 FERC ¶ 61,032, slip op. at 10-11 (where the Commission noted CP&L's agreement with Dynegy's comments that a

often than not, transmission expansion plans are treated as closely-guarded secrets by traditional investor-owned utilities. However, as an independent entity, an RTO's transmission planning studies and data must be available for inspection and regularly updated by the RTO pursuant to published and verifiable criteria, so as to ensure that new generators are not subsidizing or accelerating the upgrade of the grid without compensation. If upgrades required due to the interconnection of the customer result simply in the correction of existing inadequacies in the grid, or acceleration of previously planned upgrades to the grid, the costs of such upgrades should be equitably allocated between the interconnecting customer and the RTO.

- Congestion Relief

In a similar vein, interconnection costs charged to the developer must factor in consideration of the potential that the presence of a generator at a particular location may actually relieve congestion on the grid.[24] By providing for an open and transparent transmission planning process, RTOs can encourage generators to site projects in areas that can relieve congestion. At a minimum, the Commission must require RTOs to post information on their OASIS regarding locations where generation is needed to relieve congestion.

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generator should not be required to pay the entire cost of system upgrades that are simply accelerated as a result of an interconnection request, and noted further that transmission providers must provide interconnection service pursuant to the comparability requirement).

[24] Such projects should, at a minimum, be eligible for a transmission credit, as discussed below.

- Upgrade Credits

Transmission credits should be available for any upgrades paid for by generators that provide a benefit to the grid, regardless of whether those upgrades were triggered by the interconnection of the customer. For example, some utilities have taken the position that certain types of upgrades (such as those that added transmission lines/capacity to overcome thermal overloading) are entitled to transmission credits, while other types of upgrades (such as those that added transmission lines/capacity to ensure stability) are not.[25] Yet in the case of adding transmission lines/capacity, there is no difference in the benefit to the grid from the addition to overcome thermal overload and the addition to ensure stability. Indeed, in the case of a peaking generator that is required to add transmission lines/capacity to ensure stability, the generator "uses" such lines/capacity only occasionally, while such lines/capacity remain available to the grid even when the peaking generator is not on line. At a minimum, if upgrades to the grid provide a benefit to the grid, and not just the generator, the costs of such upgrades should be equitably allocated between the interconnecting customer and the RTO.

- Crediting Procedures

Any transmission service credits that result from a generator paying for system upgrades must be transferable by the generator to another entity. Often it is not the generation owner that arranges for the transmission of power produced at the facility being interconnected. Instead, a marketer or other customer purchasing the power would typically reserve and schedule transmission service for power generated by the facility. Therefore, to the extent an RTO provides for transmission service credits equivalent to

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25 *See* American Electric Power Service Corp. OATT, Attachment P, Section 3.2 in FERC Docket No. ER00-2413-000.

the cost of system upgrades, the RTO must recognize the commercial reality of the market by making clear that such credits are transferable by the developer that originally paid for the upgrades.

- Tax Gross-Up

To the extent a developer is required to pay a tax gross-up, RTO procedures must provide that such payment will be refunded to the developer with interest in the event the Internal Revenue Service (IRS) issues a favorable ruling on such gross-ups. While the IRS has indicated that it has suspended the issuance of private letter rulings on the issue, IRS Notice 88-129 ruled in the context of a Qualifying Facility that a transfer of property by a power producer to a utility to construct an intertie is not treated as a contribution in aid of construction (and is thus not taxable) when the principal purpose of the construction is to enable the power producer to sell the power it produces, either to the utility, or to third-party buyers, with the power being transported to those buyers across the utility's transmission facilities. Additionally, as evidenced by the IRS position in Private Letter Ruling 9327019, there is no reasonable basis for distinguishing the situation of Qualifying Facilities from other independent power producers or the transfer of property from a transfer of money to pay for construction of the property in applying the principles established by IRS Notice 88-129.

Existing Interconnection Agreements

The Commission must make clear that existing interconnection agreements will remain intact as RTOs are formed. The Commission's RTO Final Rule noted that "it is not appropriate to order generic abrogation of existing transmission contracts" recognizing that "existing contracts represent negotiated rights and obligations achieved through mutual negotiation."[26] Instead, the Commission expressed its intent to address the issue of existing transmission contracts on an RTO-by-RTO basis, and encouraged "each RTO to address how and when it might convert existing contracts and submit a contract transition plan that contains specific details about the procedures to be utilized involving the conversion from existing contracts to RTO service."[27]

Although it may be permissible for existing interconnection agreements to be assigned to an RTO by the transmission owner that originally entered into the agreement with the generator, the existing interconnection agreement should otherwise remain intact, unless the generator opts to either renegotiate an existing interconnection agreement or negotiate a new interconnection agreement directly with the RTO.

There are a number of well-grounded policy reasons for leaving existing interconnection agreements intact. Neither of the Commission's stated policy reasons for opening the door to reviewing existing transmission contracts – "the need for a uniform approach for transmission pricing and the elimination of pancaked rates" – are implicated in existing interconnection agreements. The Commission's statements in the RTO Final Rule with regard to the potential for reexamining existing *transmission agreements* are clearly directed to agreements for wheeling power across the grid. Moreover, interconnection service is provided pursuant to a generator-specific contract that sets forth the unique rights and responsibilities of the parties to the interconnection agreement. Each agreement differs, depending upon the location and type of facility

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26 *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 810 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,205 (Dec. 20, 1999), *order on reh'g* Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (Feb. 25, 2000).

27 *Id.*

being interconnected to the grid, and is often the product of protracted and intense negotiations between the parties. Finally, while *Tennessee Power* made clear that a generator's rights with respect to interconnections stem from the OATT, the Commission has also clarified that the interconnection service and transmission service components of the OATT are separable.[28]

Therefore, in order to provide the parties to existing interconnection agreements with the continuity and certainty reached in the agreements through arm's-length negotiations, the Commission should make clear that such agreements may not be unilaterally abrogated by an RTO that takes control of the original transmission owner's system.

On a related issue, to the extent the RTO requires additional services from the generator that may not be covered by an existing interconnection agreement, *e.g.*, redispatch authority, the Commission must make clear that those agreements must be separately negotiated with the generator. As the Commission clarified in its rehearing of Order No. 2000-A, "generators that are redispatched . . . should be fully compensated and that the compensation would consider, among other things, lost opportunity costs."[29]

<u>Requirements to Provide Services to RTOs</u>

To the extent the RTO requires redispatch, VAR support, and other ancillary services, generator provision of such services must be voluntary, the generator must be compensated for providing such services, and such generator compensation must include opportunity costs. Requirements relating to the provision of such services to the RTO

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[28] *See, e.g.*, *Entergy Services, Inc.*, 91 FERC ¶ 61,149 at 61,559 (2000).

[29] Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 at 31,373.

must be set forth in clear, nondiscriminatory and commercially reasonable terms. Moreover, as noted above, if the RTO requires additional services from the generator, such as authority to redispatch the plant, the Commission must make clear that the providing generator must be fully compensated and that the compensation would consider, among other things, lost opportunity costs.[30]

Information Posted on OASIS

Access to timely and accurate information is critical to the success of any interconnection process. In order to enable interested developers to become more fully informed about an RTO's interconnection requirements and the status of interconnection requests, the Commission must require that certain limited information be posted on the RTO's OASIS. As referenced above, this information must include, at a minimum i) the RTO's interconnection procedures for requesting interconnection services and the criteria for evaluating those requests; ii) standardized interconnection forms, such as interconnection requests, interconnection study agreements; iii) RTO transmission planning criteria and conclusions; and iv) information regarding locations where generation is needed to relieve congestion.

In addition, in order to allow interested developers to remain informed about the status of their own and others' interconnection requests, the RTO must be required to post on its OASIS information relating to general location, size and status of interconnection requests, along with regular updates of such information.

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[30] *Id.*

VIABILITY MILESTONES
ELECTRIC POWER PROJECTS

- ___ Plant Location Determined/Land Availability Confirmed?
- ___ Site Controlled: Purchased/Leased/Optioned?
- ___ Board Of Directors Approval for Capital Expenditure?
- ___ If Financed, Debt Agreements Executed?
- ___ Firm Order Placed for Generation Equipment (turbines)?
- ___ Engineering Procurement Construction Contractor Identified and Contract Executed?
- ___ Environmental Permits (air, water, operating, etc.) Requested?
- ___ Environmental Permits (air, water, operating, etc.) Obtained?
- ___ Electric Transmission Interconnection Requested?
- ___ Electric Transmission Interconnection Agreement Executed?
- ___ Fuel Commodity Contract Executed?
- ___ Fuel Interconnect and Transportation Contract Executed?
- ___ If Qualified Facility (QF):-Power and Steam Purchase Agreements Executed With Thermal Host?

APPENDİX B

CONGESTION PRICING ISSUES IN RTO FILINGS

Congestion Management: What "Customers" Really Want.

In Order No. 2000, the Commission stated that congestion management solutions should be "market-driven."[1] A simple statement, perhaps, but one subject to interpretation.

- **The Choice of Paradigms: Congestion Management as (1) a Vehicle to Deal With Congestion or (2) a Means to Drive Market Structure.**

The Commission's statement that congestion management solutions be "market driven" could mean that congestion management solutions should be developed to satisfy the needs of the market, as decided by the market. Or, it could mean that a congestion management system is created to ***be*** a market, perhaps for the sake of recognizing some inherent value in having a structured congestion management market.[2] These are two very different paradigms.

- **Highly Structured Markets Have Been Problematic**

Experience has shown that structured, rigid, formulaic approaches will result in a multitude of rules - rules created to address every situation that could possibly arise, rules that must constantly be changed to address new twists, and rules that become increasingly cumbersome and complicated. And with each rule and subsequent change comes a new set of unintended consequences. In the end, the rules inevitably fail to fully accomplish their intentions,[3] even assuming that there are clearly stated intentions.[4] Or, the rules are established

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1 *Regional Transmisson Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 30,993 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000) at 31,126.

2 *See also* discussion in EPSA position paper, "RTOs Must Manage Transmission, Not Power Markets" ("*Congestion management is just a backstop to be used to assure reliable transmission service.*") filed in Docket No. EL00-75-000, June 30, 2000.

3 We need only look at the experience in California and the 30-plus amendments to the ISO's tariff.

in a manner that allows their strongest proponents to accomplish their goals, while the rest of the market figures out how to live within those rules, and, perhaps, to profit. But, at the end of the day, the rules become the game, and the game does not forward the original purposes, but instead, the playing of the game itself.[5]

In creating RTOs, the Commission must recognize that any successful market is fluid and must be allowed to change and adapt to the needs of customers. And as the industry has found, that is not how centrally structured, government-regulated markets really work. Rather, as we have found in California and to a lesser but not insignificant extent elsewhere, centrally structured markets are slow to adapt, unwieldy in their adoption, and in large part, due to the processes involved, always "behind the curve."

California's travails are legend, so we will instead focus on the "golden child" of RTOs, PJM. PJM's version of LMP was adopted in 1997[6] and implemented on April 1, 1998. At that time, it did not have a means to provide protection from after-the-fact transmission pricing. The

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4 One of the problems with the development of centralized, structured congestion management systems is that they are products of compromise, and as a result, their intentions are the embodiment of many different interpretations of different sponsors, each reading into the structure their own favored interpretation, and, likely, few being satisfied that the reality of implementation matches their expectations.

5 The classic example here is PJM's locational marginal pricing (LMP). The proponents of LMP in PJM were the transmission owners, who also owned the generation. In adopting LMP, they killed two birds with one stone. First, they established a mechanism with which to dispatch generation using someone else's checkbook – the transmission customers pay for congestion relief, and the transmission owners have no financial downside for failure to optimize their system. And, second, they established a market that paid the highest prices possible for their generation. In turn, some traders were able to find ways to profit from the system, usually by not actually doing the business of the power industry – i.e., generating and physically delivering power - but rather, by trading paper that became a necessary protective corollary to performing the physical obligations of the system.

6 *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 (1997).

financial transmission right (FTR) auction did not come about until May 1999.[7] And, even then, the FTRs that were offered were offered only once per month and for monthly periods only. A liquid secondary market is yet to develop a year and a half later, much less a liquid secondary market in derivatives of the monthly product. Similarly, the two-settlement system, recently added to create some price certainty, had been originally proposed by PJM Supporting Companies in a 1997 filing. Hubs have been added in an attempt to create liquidity.

Notably, all these changes are indicative of trying to overcome a market flaw – transmission pricing uncertainty – that was known even as the market structure was being approved in 1997. In the meantime, those with locational market power have been able to exercise it, and the consumer has been the victim.[8]

We do not mean to chide the PJM staff here, they are by virtually all accounts very professional and responsive. But when the responsive golden child cannot respond quickly in dealing with embedded market problems, what hope is there for the others?[9] This would not be so problematic if the customer had a choice of congestion management methods, *e.g.* (1) managing congestion by purchasing firm rights in the first instance and then submitting balanced schedules, or (2) taking a chance on having to buy through congestion. Rather, the LMP system, by pricing transmission after the fact using basis differentials between thousands of nodes, impacts every transmission user's use of the system. In order to protect themselves against transmission pricing uncertainty, transmission customers must buy an FTR, which in PJM is not

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7 *PJM Interconnection, L.L.C.*, 87 FERC ¶ 61,054 (1999).

8 *See, e.g., Old Dominion Electric Cooperative v. PJM Interconnection, L.L.C. and Conectiv*, 92 FERC ¶ 61,278 (2000).

9 We have noted California's difficulties. The two other ISOs with highly structured markets - New York and New England - also have had difficulties with their markets. Notably, every one of these markets now has price caps, a telltale sign of market structure problems.

simply an option, but also an obligation that in certain circumstances requires the payment of congestion charges, something that FTRs are supposed to protect against.

One can legitimately ask: "Why does life have to be so complicated?" To take a well-used example, LMP is akin to filling up at the gas station and having no choice but to purchase an imperfect financial instrument to protect against receiving a higher bill later. And to use the financial instrument, you must agree to use your gasoline at a certain time. [10]

- **Room at the Inn for Other Models**

Fortunately, the Commission has indicated a willingness to consider other paradigms. Indeed, the Commission recognized this when it allowed different regions of the country to have the flexibility to decide on a congestion management scheme that suits its particular circumstances.[11] As we see in the various RTO filings received by the Commission to date, some regions have taken the Commission up on this invitation.

Notably, a number of proposals are "hybrids" - combinations of flowgate and/or physical rights models for forward contracting and LMP for balancing markets. Dynegy is optimistic that these hybrids will make the best of both models available to transmission customers. The Commission should indicate its support for these efforts.[12]

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10 The only way to protect oneself from having to pay congestion in the circumstances alluded to above is to have a set generation source and sink and to utilize both.

11 Order No. 2000 at 31,127.

12 We note in this regard that there has been a concerted effort of late to propagate the LMP model everywhere. The usual "sell" involves two pitches: (1) that LMP "works," and (2) that anything the proponents of non-LMP models want to accomplish can be accomplished by "decomposing" elements of LMP. As to the first claim, if LMP works so well, one must ask why it constantly has to be changed in order to approach satisfying the basic consumer goal of price certainty. One can also legitimately ask why the tool for achieving price certainty – the FTR - has not achieved liquid status in the secondary market, something long ago predicted by the proponents of LMP. As to the second claim, there are two responses: First, one must question why the market must be burdened with decomposing a tool that is necessary to fix a

We suggest that, in reviewing congestion management proposals, the Commission frame what is "market-driven" in a manner that asks: "What does the customer (who is the one in the market) really want?" Rather than trying to find or to create the perfect market – something that even if found or created would only last for a fleeting instant – we as an industry need to focus on meeting overall customers needs, which will involve dealing with congestion, but not having congestion management drive all other aspects of transmission.

We find that electricity customers want four things:

1. Liquidity (many products and sellers to choose from);
2. Certainty of price;
3. Certainty of delivery; and
4. Transmission flexibility.

Liquidity: What do we mean by liquidity? For customers, it means being able to buy when they need to, but *only* when they need to, and being able to buy what is needed. That may mean standard products, or ones tailored to peak or off-peak periods, or it may mean allowing the customers to tailor precisely what it is they need. Liquidity also means having a multitude of sellers from whom to purchase these products. Having a vibrant secondary market can dramatically increase those choices.

Certainty of price: The customer needs to know *in advance* what the price is going to be. Who goes into the store and buys a pair of shoes only to find out at the end of the month the real price of the shoes when the credit card bill arrives? That would be risky buying for sure (unless of course the buyer

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fundamental market flaw, rather than the flaw itself being fixed. Second, if this was so simple to accomplish, why has the market not already accomplished it?

An even more interesting question is why has LMP inspired what some refer to as religious devotion from its advocates? The simple answer here is that LMP's advocates are mainly transmission owners and operators, who quite naturally like to have a system that allows them to redispatch the system using someone else's money. And for those who also own strategically located generation, there is an additional bonus; they get paid the highest market clearing price, regardless of the price at which they might have been willing to sell their power, all in the name of "efficiency," which, as discussed later, may not be all it's cracked up to be.

had a captive customer to pass the shoes along to – captive customers are the real "perfect hedge").

Along these same lines, the Commission made this pronouncement in Order No. 2000:

> "[W]e will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions. We are convinced that efficient congestion management requires that transmission customers *be made aware of the cost consequences of their actions in an accurate and timely manner*, and we believe that this is best accomplished through such a market mechanism."[13]

That is what price certainty is all about and the Commission must use this yardstick to judge congestion management proposals offered by the RTOs.

Certainty of delivery: Certainty of delivery is also a very simple concept. If you buy firm power, you want some assurance that it is going to get to where it is going. Absent *force majeure* conditions, that should be just part of the deal. There is no getting around this simple fact: Reliability is paramount.

In this regard, Transmission Loading Relief (TLR) curtailments must be eliminated, except in emergencies. Unfortunately, today, TLRs are standard operating procedure in many parts of the country; indeed, no one argues that the current state of affairs is woefully lacking. Transmission capacity is currently sold on a contract-path basis pursuant to the rules of Orders No. 888 and No. 889, and, rather than anticipating congestion and avoiding it, congestion management is handled primarily through after-the-fact methods, either with TLR procedures or redispatch with after-the-fact billing of the associated costs. The two main drawbacks with the TLR approach are: (1) TLR procedures handle excess demand for scarce resources through a quantity rationing process where users are not allowed to express the value of a transaction over a scarce resource; and (2) contract path-based trading ignores the physical realities of power flow, and does not efficiently prevent congestion in forward markets, often

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13 Order No. 2000 at 31,126 (emphasis added).

even causing congestion due to loop flows. Market participants have little certainty of delivery with this scheme.[14]

In a recent report to the Commission on the electric bulk power markets, the Commission Staff acknowledged the havoc that TLRs create in the market:

> TLRs inhibit optimal functioning of the transmission system, and thereby the market, because load is not served by the least cost supplier. However, quantifying the effect of this is difficult...The TLR procedure is an inefficient instrument to use in mitigating transmission constraints. When an overload occurs on a flowgate, the Security Coordinator orders curtailment by fiat, and scarce resources are allocated by command and control instead of the market. *TLR curtailment does not allow the transmission customers who value the scarce resource the most (i.e., the overloaded flowgate) to compensate others who might voluntarily cut back their transactions.* Instead, all transactions that have 5 percent or more of their flow on that affected flowgate will be curtailed.

Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States, Part II at 2-33 (Emphasis added).[15]

Flexibility: Customers also want flexibility. They want to be able to shop in the market for power from a variety of sources and to use the transmission rights they have acquired either in the primary or the secondary market. They may want to "park" the power now, later move it to a hub and then still later decide where to sink it.[16] In any event, they want to be able to react to market situations. They may not want to do this for their entire portfolio, but they want at least the opportunity to take advantage of the efficiencies of the market.

In addition to what the customer needs, any congestion management scheme should also recognize the following points:

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[14] The main defect with the LMP paradigm, of course, is the inability of the customer to gauge in advance what its transmission cost will be and react to that price signal.

[15] This can be contrasted with "flowgate" models, where congestion is avoided by requiring those scheduling transmission to actually have transmission rights for the flowgates they impact.

[16] These are terms of art. In reality, transmission customers want to be able to schedule power in a manner that tracks their acquisition and sale of power, *i.e.*, to be able to aggregate supply and customers

- ***Bilateral Trading:*** Every congestion management scheme will change, to varying degrees and in different ways, the characteristics of bilateral trading. Bilateral trading is an integral and vital component of any well-functioning commodity market. As has been vividly shown in California, any new congestion management scheme should not only allow a bilateral market to thrive, it should facilitate that market's development.
- ***Development of Retail Competition:*** Retail competition is an inevitable next step in many parts of the country. Thus, any new congestion management scheme needs not only to anticipate and plan for changes that may result from retail competition in its design, but also to ensure that the resulting system is *simple and practicable* enough to permit full-scale retail choice. By definition, retail competition will demand increased trading, since it will introduce a new set of buyers to the market, a large number of whom will lack sophistication. Thus, in addition to simplicity, *price certainty* (and therefore reduced market risk) will also benefit the development of retail choice.

A Question of Balance. Economic efficiency considerations always need to be checked by considerations of social equity. Congestion management schemes may internalize some equity considerations, such as allocating congestion costs to the users of scarce resources, rather than to all consumers. However, other less obvious equity considerations also arise with locational congestion management schemes. For example, prices in locational congestion management schemes are designed to reflect properties of the physical grid. Is it equitable to require consumers to pay different prices due to grid properties that are independent of their usage patterns or out of their control?

A Question of Perspective: Is It Worth It? The industry has heard much about the cost of congestion. It has come to light recently that perhaps this cost is assumed by many to be much higher

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separately, and later match up the aggregated wholes.

than it really is, at least when measured against the total cost of energy. To understand this, it is helpful to look at the magnitude of congestion costs relative to the energy market.

PJM. The total congestion costs in PJM in 1999 were $65 million. This represents about **1 percent** of the total energy market in PJM, and only **0.3 percent** of retail electricity sales in PJM (including T&D costs).[17] Of this, the potential socialized costs would be on the order of **0.1 percent** of energy demand value and **0.03 percent** of retail electricity sales in PJM.

California. Similarly low levels of congestion occur in California. During the past 12 months total congestion costs (only a fraction of which are being uplifted, or "socialized") in California were just $211 million[18] in a $26 billion market (about **.8 percent**).[19] Again, the amount socialized is much less. And, in California, the FTR auction reaped $41 million.

On the other hand, the gains of an LMP system (the avoidance of this 0.03 percent of "socialized costs") represent very small societal benefits. These benefits are accompanied by a very hefty sacrifice to bear in the form of a virtually inactive forward market.[20] It is useful to consider the trade-off between: (a) defining under 30 transmission products for commercial trade versus (b) an LMP system

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17 This energy demand value is shown in "Case Study - Congestion Pricing Mechanisms in PJM," presented by Stu Bresler, PJM, at the Congestion Forecasting and Pricing Conference in Chicago, June 2000. Retail electricity sales from Table A13, Energy Information Administration, Form 826, 1998. The retail percentages would be even smaller if measured against 1999 retail electricity sales.

18 Source: California Independent System Operator.

19 This is based on forecasted demand for 2000 of 266,380 GWH. Source: California Energy Demand: Staff Report - California Energy Commission, June 2000; Table B-9 (Net Energy For Load. Average delivered cost to all sectors is approximately 10 cents/kwh. Using revenue requirement calculations of three IOUs as proxies, this gives a total cost of over $26 billion dollars.

20 This is assuming that one can even consider the LMP prices to be reliable, which is highly debatable - this is an issue for a separate discussion.

with thousands of transmission products. A congestion management system with less than 30 products has a significant likelihood of improving liquidity in the forward market and improving the efficiency of the entire **$6 billion** wholesale energy market, but may cause uplift payments in the amount of **0.1 percent** of this market value. An LMP congestion management system provides little likelihood of any forward contracts for delivery in a $6 billion market, but provides the benefit of correctly allocating 0.1 percent of this market value. The price paid by society for an inefficient, inactive forward market in the long run will likely be significantly higher than the potential uplift costs, because it will stymie all the efforts of deregulation to lower electricity prices and increase innovation through market efficiency and competition. As discussed further below, the forward market in PJM is virtually inactive, because there are no contracts *for delivery*.[21]

The Various Proposals: Do They Meet the Customers Needs?

In the attempt to develop market-based congestion management mechanisms, several models have come to the fore. Some have been already implemented; others are still in the development stage.

Before listing the different models, it may be instructive to the Commission and to other market participants to acknowledge the success of the natural gas model and its salient characteristics.

Natural Gas Model. Transportation providers (pipelines) determine their available capacity and sell customers firm physical rights to that capacity. "Firm" is known to be reliable, is a relatively standardized product and as a result, a relatively liquid secondary market has developed in the firm transportation product. The gas market's trading hubs and flexible receipt and delivery points give customers a variety of options for getting the gas to market. Liquidity is high – parties can trade services with confidence at many common locations. Price signals are sent where the gas is produced, traded and consumed, without having the transportation provider and

[21] Much of the foregoing should be attributed to Dr. Richard Tabors, Tabors, Caramanis & Associates.

a complex, expensive, centralized pipeline-controlled market structure in the middle. Gas pipeline transportation rate design, with its volumetric component, provides incentives for transportation service to be provided, rather than withheld in order to drive up generation prices. The more gas a pipeline moves – or for that matter, appears to move in the case of offsetting forward hauls and backhauls – the more money the pipeline makes. It's that simple.

Now to electricity models -

- *Nodal Pricing or Location-based Marginal Pricing (LMP).* This method resolves congestion by pricing energy at every node on the system based on the marginal price of energy at that node. Market participants bid into a centralized pool at distinct time increments (day-ahead, hour-ahead), and the RTO calculates these nodal prices based on an optimal power flow model that takes as inputs participant bids and the state of the transmission system. Participants may attempt to hedge their congestion risk by purchasing FTRs between any two points within the RTO's system. These financial rights can vary in their characteristics. For instance, in PJM, the FTR is not only a right to congestion revenues, but may also become an obligation to pay them. In New York, the transmission congestion contract (TCC) is a right to those revenues, but does not become an obligation. Prices under each model are calculated ex-post, so that participants have no knowledge of their transaction value until after-the-fact.[22] LMP has been implemented in New York and PJM. LMP is under development in ISO New England and has also been implemented in Argentina, Chile, Peru and other countries.
- *Zonal Pricing.* This model is most appropriate for radial systems, which do not exhibit significant loop flows. It is characterized by physical property rights defined for select interfaces

[22] Recently, PJM has introduced a "two-settlement" system, which prices congestion first on a day-ahead basis and then in real time. Under both, there is no knowledge of the price of congestion until after schedules have been submitted.

between zones and aggregate locational prices within zones. Dispatch may or may not be centralized. In the presence of loop flows, this approach requires hybridization with the flow-based approach described below. A variation of this model has been implemented in California, and was proposed in the Mountain West ISA. This approach involves some approximations in overlaying a simple commercial model over the physical system. This results in some intra-zonal congestion being passed as an "uplift" to customers.

- *Flow-based/Zonal with PTRs.* The premise of this approach is that congestion can be managed in forward markets without RTO intervention. This is accomplished by selecting a set of commercially significant flowgates (CSFs), and marketing rights to the capacities of those flowgates to market participants in the form of physical transmission rights (PTRs). These PTRs involve a right to use the system, but no obligation to do so.[23] The RTO runs a real-time balancing market and coordinates dispatch with control areas. The RTO may be divided into zones based on a clustering of nodes that have similar flow impacts on the CSFs. The RTO may calculate zonal prices in the balancing market. If so, these zones provide price simplicity to market participants.
- *Flow-based/Zonal without PTRs.* A variation of this approach has also been developed within ERCOT. In this model as developed in ERCOT the flowgate rights are not physical rights. Rather, physical certainty is accomplished via other means. The Transmission Congestion Rights (TCR) to be sold in ERCOT provide financial hedges. There are no "obligations" associated with ownership of the TCRs.

Do any of these proposals meet the needs of the customer? With little dispute, the gas model does. Price signals are sent every day in natural gas markets, where hub pricing reports –based on

23 The obligation can arise, however, by mutual agreement, for example in the case of the creation of a counterflow.

bilateral transactions where buyers and sellers have agreed on price in advance – abound. Indeed, 106 pricing points are published in *Gas Daily* each day. In gas markets, the pipeline signals "congestion" when it declines to schedule service. Those who cannot purchase gas at a select location and have it delivered to a select market must go out into the marketplace, locate alternative supplies, and if necessary, transportation. This, in turn, drives up the cost of gas at the alternative supply location, thus sending a price signal. This is the functional equivalent of "redispatch," yet it is conducted by many players, each searching out and correcting inefficiencies in the market, not just the RTO.

Dynegy and others have long been critical of LMP and the deficiencies in that model.[24] The key drawbacks associated with this system are its complexity, the lack of price certainty, high cost, and low liquidity in the forward market. Rather than reiterating these criticisms, Dynegy brings to the Commission's attention and includes an excellent article that encapsulates the shortcomings of this model. The article, "Congestion Pricing or Monopoly Pricing?" by Alan Rosenberg,[25] discusses other flaws in LMP besides the usual lack of transparency and complexity. The author focuses on these flaws in particular:

- LMP is very much like value-of-service pricing for a monopoly service;
- LMP has little to do with either the embedded or incremental facility costs of providing transmission;
- LMP exceeds the costs necessary to redispatch to relieve congestion;
- LMP is not necessarily sensitive to changes in the magnitude of the congestion problems; and
- LMP can provide perverse incentives to retain congestion, especially if vertically integrated utilities are involved.

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24 *See, for example,* Initial Comments of Dynegy Inc., filed August 23, 1999 in Docket No. RM99-2-000.

25 *The Electricity Journal*, Vol. 13, No. 3, April 2000.

And notably, the attached article demonstrates that **centralized LMP dispatch does not necessarily guarantee least cost dispatch of the system and may indeed increase consumer costs.**

As for the other models – zonal and flowgate – they hold a great deal of promise. The auction of firm physical rights would value scarcity just as an auction of financial rights (FTRs in the LMP model) would, sending long-term price signals, signals that will be quantified and received in advance, thereby allowing customers to take actions based on those signals. And, just like the gas model, short-term price signals would be sent by delivered prices – if there is insufficient capacity across the necessary flowgates to accomplish the movement of electrons from Point A to Point B, the power will not be scheduled and the buyer (or seller, as the circumstances warrant) will have to replace the power with power bought nearer the point of delivery or capable of being transmitted there through other flowgates. The increased cost of generation at the sink or secondary market flowgate capacity as a result of increased demand will send short-term market signals. As noted, these signals will be sent *before* the power flows, not after, making them more useful signals.

Importantly, and in contrast to FTRs in an LMP model, the auction of firm physical rights will give capacity holders a *right*, as opposed to an *obligation* to use the grid. Thus, the holder can use any of a variety of sources that might impact a given set of flowgates, increasing flexibility and fostering efficient use of the grid.

As envisioned, the physical flow construct would involve constant, real-time scheduling. There would be a continuous auction in the secondary transmission rights market. Thus, a customer wanting to buy capacity now would be able to do so now. This contrasts with the FTRs associated with pure nodal LMP, for which we have yet to see a liquid secondary rights market evolve, due, surely, to the multiplicity of node to node compositions of the rights.

The flowgate theory is capable of solving pricing, delivery certainty, quantity, and timing issues. Product definition would be left to sellers and buyers, as the model would not require large, centrally-dispatched spot markets to be operated by the RTO. And, as with any industry, the more the products reflect the demands of the market, the more satisfied the customers would be.

SUMMARY CHART:

Characteristic	LMP	Zonal	Flowgates
Transmission Product Liquidity (many products and sellers to choose from)	No	Yes	Yes
Certainty of transmission price	No	Yes	Yes
Certainty of delivery	Yes	Yes	Yes
Transmission Flexibility	No	Yes	Yes
Bilateral Trading	Limited	Yes	Yes

Congestion Pricing or Monopoly Pricing?

Locational marginal pricing, though it has ardent proponents, suffers from numerous flaws: It is divorced from the actual cost of providing transmission, it can far exceed the redispatch costs necessary to relieve congestion, and it may even provide perverse incentives to retain congestion.

Alan E. Rosenberg

Alan E. Rosenberg, *principal at Brubaker & Associates, St. Louis, has been engaged in utility consulting since 1982. He holds a B.S. from City College of New York and a Ph.D. in mathematics from Brown University, and served as an Assistant Professor of Mathematics at Wesleyan University from 1969 to 1975 before moving to the position of Assistant Controller of a subsidiary of National Steel Corp., where he worked until 1981. Dr. Rosenberg has testified on a broad range of regulatory issues on behalf of large energy consumers. He has appeared before the Federal Energy Regulatory Commission as well as public service commissions in more than 20 states and provinces.*

Transmission congestion pricing is a controversial issue that has arisen in the transition to competitive power markets across the country. The emergence of competition and increasingly decentralized decision making in the generation sector has led to increased emphasis on transmission congestion pricing mechanisms. Such mechanisms are ostensibly designed to provide incentives for the short-term expansion of transmission capacity through generation redispatch, the efficient expansion of regional transmission grids through the construction of appropriate upgrades, and the efficient siting of new generation facilities in a manner that minimizes transmission constraints.

The Federal Energy Regulatory Commission (FERC) has emphasized the need to address the issue of transmission congestion through appropriate pricing mechanisms.[1] However, FERC has not endorsed any single approach to this issue.[2] In fact, alternative approaches to transmission congestion pricing are currently in effect or under development. California has addressed the issue through a zonal transmission pricing scheme that establishes congestion prices at defined interfaces between specified zones.[3] In

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withdrawal, and the RTO is left with the difference. In most scenarios, the RTO pays this difference to holders of what are called transmission congestion contracts (TCC) or fixed transmission rights (FTR).[9]

The first thing that may strike the reader is that the LMP makes no reference to the cost of the transmission facilities. LMP is totally a function of generation costs and not transmission facility costs. In fact, under the Hogan model, if the RTO that administers transmission system is completely independent of the market, it would be impossible to determine LMP in the first place.[10] It would also be difficult to administer LMP if all transactions were bilateral because in that case no bureaucrat or central planner would be privy to presumably confidential transactional prices.[11]

The second notion that should strike the reader is that LMP is a form of value-of-service pricing for what in many cases may be a natural monopoly service. Value of service is an economist's euphemism for "all the traffic will bear." Consider a simple analogy. You live downtown and buy widgets from uptown where they cost $20 apiece. You also pay the trucker $5 per widget to transport the widgets from uptown to downtown. Now, however, the trucker tells you that he is booked up and cannot make the delivery without going to a lot of extra expense, but if you are willing to pay a little extra, it can be arranged. You look for a widget supplier downtown and find that the cheapest you can buy them for is $50 apiece. How much are you willing to pay the trucker to transport the widgets from uptown? The answer of course, is $30—exactly the LMP price. The difference between our little analogy and electric transmission is that if the trucker tried to charge you $30 instead of $5, you might be able to find another trucker. In the electricity sector, building alternative transmission lines is often not a viable alternative due to the difficulties associated with the siting of new transmission facilities. Thus, transmission remains a natural monopoly.[12]

LMP is a form of value-of-service pricing—an economist's euphemism for "all the traffic will bear."

The third notion that may strike the reader is the apparent contradiction between the revenues collected under value-of-service pricing and the actual cost of service. After all, if transmission owners are only entitled to collect their actual costs, including the cost of capital and a fair return, what happens if LMP collects more than the actual cost? The ostensible solution is the transmission congestion contracts, devised by Professor Hogan.[13] The congestion rents go to the holders of the TCCs. The TCCs are theoretically able to be traded on some form of market basis. We will examine in this article whether that mechanism can really alleviate the monopoly aspects of LMP pricing.

Prior to examining two examples of LMP, we caution the reader of the simplifications we have assumed.

- All physical losses are ignored.
- All voltage magnitudes are equal.
- We assume that all prices are nodal, thus avoiding the added controversy of defining zones.
- We focus on a single settlement, thus finessing the problems associated with multiple prices for a single time period.
- We assume all generators are authorized to bid into the RTO's power exchange at market-based rates.

These simplifications are not made to reinforce the conclusions of this paper, but rather to focus on the crux of the LMP theory. Consideration of the above practical realities, and undoubtedly dozens of others, may serve only to deepen the problems with LMP that are evident in these illustrations.

Let us examine a simple one-line network with two nodes to see how LMP works. Consider the example given in **Figure 1**. First, let us assume that there is no congestion. Then clearly the total load on the system is 300 MW which is met most economically by 200 MW from Generator A, and 100 MW from Generator D. Any additional load, regardless of which node it was manifested, would be met from D (since that generator is

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congestion by blocking transmission construction.

Another item of interest is the calculation of the LMP. The above two-node, one-line, example was rather simple to analyze. In real life, LMP can only be calculated by a computer and users are confronted with a "black box" situation. Is your black box as good as my black box? This raises two additional concerns with LMP. LMP prices are only known after the fact (*ex post*). How can marketers and/or consumers intelligently enter into contractual arrangements when it is impossible to know in advance (*ex ante*) the total cost of transporting the commodity from source to sink?[22] Yet another problem is the sheer complexity of the LMP rate. Regulators and experts alike, from Bonbright on, have recognized that a good tariff must be simple and easy to understand.[23] This means congestion pricing must be transparent to customers. LMP is anything but.

To show how complex things might get, let us make two slight adjustments to our simple example. First, we will assume that the limit on the interface is only 49 MW so that Generator C must be run. Second, we will assume that Generator C has a minimum output of 20 MW. In this case the dispatch during the hour in question is:

- Generator A, 149 MWh
- Generator D, 131 MWh
- Generator C, 20 MWh

Now the next increment of load at Node 2 is only $25 per MWh since Generator D is below its maximum. Nevertheless, it is the understanding of the author that the New York ISO program will still utilize $50 per MWh as the LMP for Node 1.

As you might imagine, things can get even more complicated as the nodes and interfaces increase. Consider the example shown in **Figure 2**, which was inspired by an illustration appearing in an article in this Journal by Steven Stoft.[24] Here we have a three-line grid and we assume that each of the lines has equal impedance.

In Mr. Stoft's hypothetical, there is no limit (at least of any consequence) on the capacity at Node 1, nor on the capacity at Node 2, nor on the lines between those source nodes and the sink at Node 3. The only limit is the 100 MW line between Nodes 1 and 2. Under least-price dispatch, Node 1 would generate the entire 900 MWh. Thus, the "no congestion" cost of generation is 900 MW times $20, or $18,000. However, given the assumptions about equal impedance on each line, physical laws would have one-third of the output from Node 1 flowing across the interface between Nodes 1 and 2. This, of course, exceeds the assumed limit since 300 MW, one-third of the 900 MW, would flow from Node 1 to Node 2 on its way to Node 3. Consequently, the generation at Node 1 must be brought down to 600 MW, as can be derived as follows:

Let X = generation at Node 1 and Y = generation at Node 2. Since the load must be met, we of course must have

$$X + Y = 900. \qquad (1)$$

On the other hand, by the physical assumptions, one-third of the generation at Node 1 will flow from Node 1 to Node 2. By the same laws, one-third of the generation at Node 2 will flow in the opposite direction. Since we want to maximize X but still have the net flow between Nodes 1 and 2 no greater than 100, we can say

$$\tfrac{1}{3}X - \tfrac{1}{3}Y = 100. \qquad (2)$$

Solving the above two simultaneous equations, we get $X = 600$ and $Y = 300$. The LMP at Node 1 is thus $20 per MWh, at Node 2 it is $40 per MWh, and at Node 3 it is

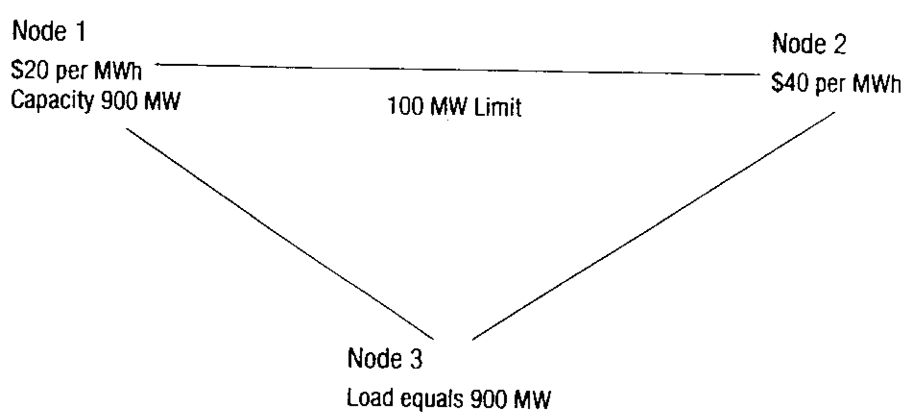

Figure 2: Example of a Three-Line Grid

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PTP service to support the transaction. Of course this transaction must pay the PTP rate based on embedded costs and we will ignore this because we are focusing only on congestion transmission pricing. If the LMP at Point A is M_A and the LMP at Point B is M_B then the producer must *pay* the congestion price of M_A minus M_B. On the other hand, as the automatic holder of the FTR, it will *receive* M_A minus M_B as a congestion rent. The net result is that the transmission cost is limited to the embedded OATT rate and the TCC is a perfect hedge against LMP. Thus, the issue of congestion pricing has essentially been excused from the long-term free market.[26]

The New York ISO is taking a somewhat different approach. In that state, there will be grandfathered TCCs, native-load TCCs, and residual transmission TCCs—the latter two FERC has stated must be treated the same.[27] While it is not clear exactly how all this will work, the transmission providers will conduct direct sales, the proceeds of which will reduce the embedded transmission revenue requirement. There will also be a centralized auction of TCCs as well as a secondary market. The author has some concerns with the TCC process.

- Who will prevent holders of the TCCs from exercising market power?
- How will bidders be able to make intelligent bids for the TCCs?
- Since the cost of the TCCs will ultimately be recouped from end users, consumers may end up paying more than the sum of the congestion rents.

In any case, TCCs are financial instruments that generators or marketers will use to either speculate or hedge. This author does not foresee consumers as players in the TCC market. Thus, it does not appear to me that TCCs will recoup the economic loss engendered by LMP pricing.

Some of the problems with TCCs were noted in a recent FERC decision conditionally accepting the California ISO proposal to implement firm transmission rights (FTRs), the California nomenclature for a TCC:

> We agree that the ISO's FTR proposal must be revised to include long-term FTRs. As we noted in our July 30, 1997 Order, a mechanism to obtain long-term transmission rights is important for the development of a competitive and efficient electricity market. . . . We expressed our concern that the absence of firm transmission service of any significant term "impermissibly disadvantages the bilateral transmission market". . . Because the instant proposal limits FTRs to a maximum one-year term, it does not address our concerns about long-term commitments.[28]

But this puts us on the horns of a dilemma. On the one hand, long-term FTRs are desirable. On the other hand, the longer the FTR, the more problematic it is for users (or arbitragers) to intelligently and confidently bid for these long-term TCCs. FERC noted another problem with the FTR:

> Finally, we agree with CalEnergy that the FTR proposal does not fully address the issue of how to provide incentives for timely and efficient expansion.[29]

In its Notice of Proposed Rulemaking, FERC has said that an RTO:

> . . . must ensure the development and operation of market mechanisms to manage transmission congestion. The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage system.[30]

The author is unsure that there is a single perfect solution to that perceived problem, short of a mechanism that transforms the natural monopoly of transmission into a service amenable to authentic competition. However, I believe that there must be a solution that is simpler, more logical, and less costly to consumers than Professor Hogan's LMP model. In my view, any acceptable solution must satisfy the following criteria:

- Congestion costs must be lim-

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not attempt to distinguish the relative merits of the two concepts. For purposes of discussion, the terms can be used interchangeably without detracting from the argument.

10. In its *Profile on Electricity Issues*, March 1997, Electricity Consumers Resource Council (ELCON) issued a position paper that specifically states that an RTO should not make the market, guarantee market outcomes, or operate a spot market or a power exchange.

11. In this case, there would need to be a separate market where generators would bid the prices at which they would be willing to be constrained on or constrained off.

12. It should be noted that this same siting difficulty is often associated with new generation facilities. Thus, the same value-of-service pricing example described here is applicable to generation prices for facilities located in load pockets.

13. See William Hogan, *Contract Networks for Electric Power Transmission*, J. REG. ECON., Sept. 1992.

14. Some readers may opine that the marginal cost at Node 2 is only $25 per MWh because that is the clearing price for D, the last generator dispatched. However, by changing the load at Node 2 to just slightly over 200 MW, or restricting the transfer capacity to slightly under 50 MW, we actually would need to dispatch Generator C. While the math would be somewhat more messy, the import of this example would be unchanged.

15. I assume here that the consumers in question do not possess TCCs to hedge the congestion charges or that the cost of those hedges offset the benefits.

16. The author acknowledges that in some circles the term competitive pool is an oxymoron.

17. It should be noted that in practice higher-variable-cost generation bids would likely include some reasonable profit margin and/or contribution to fixed costs in their bid, unless those generators have also made capacity sales.

18. Analysis has shown that in many instances we can expect generators to bid prices that are higher than their variable costs (including some reasonable profit margin). See, for example, ALEKSANDR RUDKEVICH, MAX DUCKWORTH, AND RICHARD ROSEN, *Modeling Electricity Prices in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco*. ENERGY J. Vol. 19, No. 3, 1998. Readers may wish to ponder how generators may alter their bids to best take advantage of this situation. For example, in the congestion case we are considering, generator D may wish to bid consid-

erably more than $50 per MWh since it will be the "swing" generator at Node 1 with only slightly more load. In that case, our little example may understate the consumer loss and the monopolist gain.

19. Since in this example we are focusing only on incremental or decremental profit, we can legitimately ignore fixed costs for purposes of our analysis and define profit as price less variable cost.

20. In this example we assume full subscription to the available TCCs of 50 MW.

21. Even if Generator C's variable cost and bid were $26 MWh instead of $50 MWh, Node 2 Consumers would pay $200 extra, or four times the actual redispatch cost of $50.

22. While it is true that holders of a TCC will know how much the price will cost in advance, at the end of this article the author will show that TCCs are not a panacea for the serious problems of LMP.

23. James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, PRINCIPLES OF PUBLIC UTILITY RATES (Public Utilities Reports, 2nd ed., 1988).

24. Steven Stoft, *Congestion Pricing with Fewer Prices than Zones*, ELEC. J., May 1998.

25. The interested reader should be able to convince himself that the generation at Node 1 is (D + 3L)/2 and at Node 2 it is (D − 3L)/2 where D is the Demand and Node 3 and L is the thermal limit between Node 1 and Node 2. Note that the two TCCs are simultaneously feasible since the net TCC flow between Node 1 and Node 2 would be 100 MW. Also, note many other possible combinations of TCCs that would lead to full subscription. In all cases full subscription of TCCs would result in a net TCC flow of 100 MW from Node 1 to Node 2 and net congestion rents of $3,000.

26. The result is that nonfirm users of the transmission system have to pay congestion charges to have their power moved when congestion occurs since they do not have FTRs. Firm users only pay congestion charges if they deviate from their firm transmission rights. FTRs are awarded such that if there is no nonfirm use and firm users stick to using their FTR rights, redispatch will very rarely, if ever, be required.

27. New York market orientation course given by New York ISO.

28. Docket No. ER98-3594-000, at 8. While California did not technically accept LMP, the author believes this observation is relevant to the LMP issue.

29. *Id.*, at 20.

30. Docket No. RM-99-2-000. Regional Transmission Organizations. Notice of Proposed Rulemaking Part 35.34 (j) (2), May 13, 1999.

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