

Federal Energy Regulatory Commission

Working Paper on Standardized Transmission Service and Wholesale Electric Market Design

To enhance competition in wholesale electric markets and broaden the benefits and cost savings to all wholesale and retail customers, the Commission intends to reform public utilities' open access tariffs to reflect a standardized wholesale market design. The goals of this initiative are to: provide more choices and improved services to all wholesale market participants; reduce delivered wholesale electricity prices through lower transactions costs and wider trade opportunities; improve reliability through better grid operations and expedited infrastructure improvements; and to increase certainty about market rules and cost recovery for greater investor confidence to facilitate much-needed investments in this crucial economic sector. A key challenge will be to balance the need for standardization for a seamless transmission grid with streamlined operations and costs with the need to permit regional differences and market innovation.

The Commission is conducting this effort through Docket No. RM01-12-000 and plans to issue a notice of proposed rulemaking, containing a reformed open access transmission tariff, this summer. The reformed tariff will be filed by regional transmission organizations (RTOs) and other public utilities that own, operate or control interstate transmission facilities.

The Commission's Order Nos. 888 and 889 established non-discriminatory open access transmission services and stranded cost recovery rules for the transition to competitive markets. These rules established a sound foundation for competitive bulk power markets in the United States, but did not address every issue now before us. There is wide consensus today about the need to update the pro forma tariff and the basic elements of wholesale electric market design. On some issues, there is clear consensus about what needs to be done; on others, further policy decisions are needed to move forward. The Commission intends this paper to offer that policy guidance and allow the parties to move forward in a focused process that builds upon Order Nos. 888 and 889, and the institutional innovations of RTOs identified in Order No. 2000, to complete the establishment of robust, seamless competitive wholesale electric markets.

Based on dialogue with a wide array of stakeholders and state commissioners over the past few months, this paper lays out principles and policy decisions on the standard market design to guide the Commission in developing a revised transmission tariff. Most of these reflect consensus voiced by the parties in written comments and in the conferences and workshops held by the Commission with the industry between October 2001 and February 2002. These policy calls are subject to further dialogue with and comment from participants. The Commission will issue a notice of proposed rulemaking this summer and all affected parties will be able to further comment on the notice of proposed rulemaking. The Commission will consider all comments in determining the final rule.

Attached hereto is an Appendix that responds to a number of questions on market design from the Electronic Scheduling Collaborative.

A. The Need for a Single Transmission Tariff

Order Nos. 888 and 889 established the foundation needed to develop competitive bulk power markets. However, it has become clear that the Order No. 888 open access transmission tariff (OATT) contains provisions that, in practice and in conjunction with market design rules that currently exist in the electric utility industry, allow energy suppliers that also provide transmission service to favor their own generation and disadvantage other energy suppliers. For example, a vertically integrated utility determines available transmission capability and the facilities necessary to interconnect a new generator. In both cases, the transmission provider has the incentive to favor its own generation. This creates barriers for other energy providers, raises costs from inefficiency for all grid operations, and often results in higher delivered energy prices to end-use customers. The lack of regional coordination of the grid (for instance, the calculation of Available Transmission Capacity and Total Transmission Capacity on a company basis) contributes to inefficient operations by causing unnecessary transmission congestion and transaction curtailments. In addition, market design issues not addressed by the current tariff impede a seamless national transmission grid and the development of broad, fully competitive electricity markets.

At present there is no single set of rules governing transmission of electric energy. The electrons moving across the grid do not distinguish between bundled retail and other services, and behave according to the laws of physics rather than the laws of a particular jurisdiction. With more non-integrated electricity suppliers and a deeper reliance on wholesale electric markets, there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers. To protect all customers and assure the benefits of competition for all, consistent transmission rules must be applied.

The existing tariff reveals different flaws in different regions of the country. In areas where most energy transactions occur through bilateral contracts without centralized spot markets for energy and ancillary services, more and more transactions are being curtailed under transmission loading relief (TLR) mechanisms that rely on non-price allocation methods. In these cases, congested transmission capacity is not being consistently allocated to the market participants who value transmission the most.

Market design flaws are visible in every regional electric market today under the existing tariff. These flaws are allowing operational problems such as the “socialization” or “uplift” of congestion management prices across all customers in a region, which obscures the potential for price signals to indicate where new generation, demand response or transmission is needed. In other regions, high fees are being collected for the value of generation capacity that do not clearly incent the construction of new capacity. A third type of flaw has been the sequential clearing of energy and ancillary service

markets, which fails to deliver efficient prices for the service delivered. No region has been exempt from market design flaws of one type or another.

Even where market designs appear to be very similar in contiguous regions, "seams" problems have persisted. A seams problem occurs when differences in business practices, market design, reliability rules, or software platforms between regions impedes trade between the regions. When these seams problems prevent the economic exchange of energy, they increase transactions costs.

Even within a region, a poorly designed or inefficiently managed transmission system can result in significant increased costs to customers. It is useful to review the approximate costs of electric generation and transmission to see the impact that transmission can have on energy costs. Consider these approximate costs as viewed by retail customers (excluding distribution and load-serving entities'

(LSEs) operating costs, which represent about 15% or less of the average retail bill) for two regional markets, for the year 2000:¹

	PJM		NY	
	\$ Millions	% of Total Cost	\$ Millions	% of Total Cost
Energy Costs	\$9,822	92.2%	\$7,599	88.6%
Congestion Costs	\$134	1.2%	\$1,209	14.1%
Line Losses	\$491	4.5%	\$380	4.5%
Transmission Revenue Requirement	\$832	7.8%	\$979	11.4%
Total Cost	\$10,654	100%	\$8,578	100%
Peak Load (MW)	49,417		30,200	

These markets are used because we have information readily available for them. These figures illustrate several important points. First, within the delivered retail bill, the cost of transmission alone is small compared to the cost of generation, but these costs are still large in absolute terms. Second, two elements which are substantially affected by the design and operation of the transmission system have a significant effect on energy costs, *i.e.*, the cost of transmission congestion (which is actually the opportunity cost of having too little transmission) and the cost of line losses (the additional generation that must be produced to make up for energy lost in the delivery of electrons through the grid, averaging about 5% of total electricity produced). Third, the costs hint at the substitutability between generation and transmission – specifically, as the grid becomes constrained, energy costs rise markedly due to the redispach of more expensive plants to work around the transmission constraints. This can be seen in the higher congestion costs in New York caused by the unavailability of the Indian Point nuclear plant in

¹ Energy Costs for each independent system operator (ISO) are derived from Form 1 data for each of the utilities in the ISO. It is calculated as the sum of Total Power Production Costs (Form 1, page 321, line 80) of each of the utilities in the ISO. Congestion costs are from the websites of each ISO. Line losses are assumed to be 5% of Energy Costs (4.5% of Total Cost). The transmission revenue requirement for each ISO is the sum of the annual transmission revenue requirements of each utility in Attachment H to the OATT of each ISO. Total Cost is the sum of Energy Costs and the Transmission Revenue Requirement. Peak load for PJM Interconnection, L.L.C. (PJM) is from "PJM Interconnection State of the Market Report 2000." Peak load for New York Independent System Operator (NYISO) is from "Power Alert: New York's Energy's Crossroads" (March 2001).

the summer of 2000. Additions to the grid may slightly increase the transmission revenue requirement but yield large reductions in total energy cost per kWh from lower congestion costs and greater access to cheaper bulk power sources.

The table above shows the relative costs of energy and transmission within two areas that have markets designed similarly to the standard market design proposed here. In other areas, where transmission constraints are not managed with similar mechanisms, the impact of congestion on energy costs is likely far greater. Adoption of a standard market design in those areas would improve price signals and encourage more efficient expansion of the transmission grid with corresponding reductions in energy costs. Even if the energy costs reductions are small in percentage terms, there could still be large savings in absolute terms.

In Order No. 2000, the Commission recognized the need to make further changes to its regulations to address these inefficiencies and discrimination problems. However, Order No. 2000 primarily dealt with the structure and independence of the new RTOs. It did not directly address the market rules that were needed to achieve the objective of competitive electric wholesale markets.

We must act now to remedy any undue discrimination and unjust and unreasonable pricing caused by the problems highlighted above and to achieve the reliability and cost-saving benefits of competition. We must restructure electric transmission service to provide comparability for all sellers of electricity, use transmission assets more efficiently, and reduce inefficiencies by standardizing market rules. This should be done by creating a new, flexible transmission service to be offered by all transmission providers to all customers, with a new standard market design for wholesale electric markets.

To assure fairness and transparency for all participants, an entity independent of the market participants must administer the imbalance energy markets that are to be part of the standard market design proposed here. As described below, the Commission is proposing to use Locational Marginal Pricing (LMP) as the system for congestion management. Under LMP, the imbalance and transmission markets must operate together. Thus, it is more efficient to have one entity perform the two functions identified by NERC in its new Functional Model as the Balancing Authority and the Transmission Service Provider. In this document, we use the term "transmission provider" for the independent entity that would perform functions including accepting and processing requests for transmission service, administering the OASIS, scheduling transactions, and administering the imbalance markets. Thus, an RTO or independent system operator (ISO) would meet the definition of transmission provider. However, vertically-integrated public utilities who are not part of an RTO or ISO would have to contract with an independent entity to serve as the "transmission provider" to perform these functions. The question of whether an independent transmission company, *i.e.*, one that has no affiliation with a generator or power marketer, qualifies as a transmission provider requires further consideration.

B. General Principles for Standard Market Design

The lessons learned in existing markets lead us to establish a set of principles to guide the development of standard market design:

1. The objective of standard market design for wholesale electric markets is to establish a common market framework that promotes economic efficiency and lowers delivered energy costs, maintains power system reliability, mitigates significant market power and increases the choices offered to wholesale market participants. All customers should benefit from an efficient competitive wholesale energy market, whether or not they are in states that have elected to adopt retail access.
2. Standardization of market design and business practices reduces transaction costs and reduces "seams issues" that restrict trading. In developing and implementing standard market design, the maximum benefit will be gained by standardizing as much as practicable. Deviations or changes from the standards must be consistent with or superior to standard market design. Such changes must also be compatible with neighboring systems to prevent seams issues.
3. Market rules and market operation must be fair, well defined and understandable to all market participants.
4. Imbalance markets and transmission systems must be operated by entities that are independent of the market participants they serve.
5. Energy and transmission markets must accommodate and expand customer choices. Buyers and sellers should have options which include self-supply, long-term and short-term energy and transmission acquisitions, financial hedging opportunities, and supply or demand options.
6. Market rules must be technology- and fuel-neutral. They must not unduly bias the choice between demand or supply sources nor provide competitive advantages or disadvantages to large or small demand or supply sources. Demand resources and intermittent supply resources should be able to participate fully in energy, ancillary services and capacity markets.
7. Standard market design should create price signals that reflect the time and locational value of electricity. The price signal – here, created by LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times. But while price signals should support efficient decisions about consumption and new investment, they are not full substitutes for a transmission planning and expansion process that identifies and causes the construction of needed transmission and generation facilities or demand response.
8. Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for

choice by wholesale and end-use customers.

9. Transmission owners will continue to have the opportunity to recover the embedded and new costs of their transmission systems. Consistent with current policy, merchant transmission capacity would be built without regulatory assurance of cost recovery.
10. Customers under existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design. However, transmission capacity not currently used and paid for by these customers must be made available to others.
11. Standard market design must not be static. It must not inhibit adaptation of the market design to regional requirements nor hinder innovation.

C. The New Transmission Service

Transmission providers should be required to offer a nondiscriminatory, standard transmission service, "Network Access Service," for all customers, including vertically integrated utilities. Network Access Service would combine features of both of the existing open access transmission services, the flexibility and universal access of network integration transmission service and the reassignment rights of point-to-point service. This allows all customers to have a system of tradable transmission property rights that will expand their transmission options and enable and enhance competition in wholesale electric markets. All transmission services should be performed under a single set of market rules.

To complement Network Access Service and implement the standard market design, transmission providers should manage congestion using LMP. To handle imbalances and the procurement of ancillary services, the transmission provider would operate markets for energy, regulation and operating reserves in conjunction with the markets for transmission services. These markets would be bid-based markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. For both the day-ahead and real-time time frames, the transmission provider would assure that purchases and sales of energy, regulation and operating reserves through the centralized energy, regulation and operating reserves markets, or through self-supply or bilateral contract, are coordinated with transmission services on the grid. The transmission provider would establish schedules for transmission service, and sales and purchases of energy, regulation and operating reserves, to ensure the most efficient use of the transmission grid.

Network Access Service

Network Access Service would give the customer the right to transmit power between two points, a source and a sink. A source is defined here as the location where a transaction originates, and a sink is defined as the location where a transaction terminates. Sources and sinks would be defined to include both individual nodes as well as aggregated points such as trading hubs. Thus, a Network

Access Service customer could use this service to move power from a generator (source) to a load (sink), from a generator (source) to a trading hub (sink), from one trading hub to another, or from a trading hub (source) to a load (sink). A Network Access Service customer would have access to all sources and sinks on the system. An access charge would be used to recover the embedded costs of the transmission system. The manner in which embedded costs will be recovered requires further discussion to be resolved.

Some transactions cannot occur without causing congestion on the transmission system. Network Access Service gives customers two options for how to handle the costs of this congestion, either: (1) a predetermined price, using "transmission rights," or (2) the applicable congestion charge in which the customer bears the full cost of congestion management. The issue of how to allocate transmission rights is difficult and contentious. However, our intent is to preserve the existing rights of current users of the system.

Transmission rights for transmission price certainty

A customer can achieve price certainty for Network Access Service by acquiring transmission rights. A transmission right allows the customer to schedule power from specific source(s) and sink(s) without having to pay congestion for service between those points. Anyone can hold a transmission right. A key implementation issue will be the initial assignment of transmission rights. One option is to directly allocate the transmission rights to customers that pay the embedded costs of the system. Any transmission rights not claimed by these customers would be auctioned. Another option would be to conduct an auction to apportion the transmission rights, with the proceeds from the auction allocated to those customers that pay the embedded costs of the system.

However transmission rights are initially issued, transmission rights holders can sell them into a secondary market so that others can buy transmission price certainty. If a transmission rights holder chooses not to schedule transmission service at a particular time, the transmission capacity will be made available to the market and the transmission rights holder will receive the associated congestion revenue.

The transmission provider must offer to sell transmission rights for all of the capacity on the grid, but it cannot sell more rights than the capacity can accommodate. After the initial allocation of transmission rights, there may need to be a regular reallocation of the transmission rights or the auction revenues to reflect changes in load responsibilities due to retail unbundling or other factors. Over the long term, if a customer (or merchant transmission company) pays to construct new transmission facilities that add transfer capability, the entity that pays for the construction, whether a customer or transmission owner, should receive the transmission rights associated with the new transfer capability (unless they receive credits against the Network Access Service access charge). This issue needs further consideration.

Transmission without price certainty

The alternative to predetermined transmission prices under transmission rights is for the Network Access Service customer to schedule service by agreeing to pay for any congestion costs of a particular transaction. Congestion costs occur when the capacity of the grid is limited and it is not possible to transfer more energy across the grid from the customer's intended source to sink without compromising grid reliability. In this situation, the transmission provider will redispatch a more expensive generator on the other side of the constraint to deliver to the intended sink. The incremental cost of this "out-of-merit" redispatch is charged to customers who have not secured transmission rights. Customers who hold transmission rights would not be charged the redispatch costs.

Day-ahead scheduling

Every day, the transmission operator would develop a schedule for use of the transmission system for each hour of the next day. The schedule would accommodate the requests of customers with transmission rights and those without, as well as transmission needed for delivery of purchases and sales made through the centralized energy spot market (described further below). Customers with transmission rights who want transmission service between their designated source and sink points would schedule their desired service between those specific points, and would be charged for losses but not congestion. Customers without transmission rights (including the transmission provider on behalf of customers purchasing or selling through the centralized energy spot market) would also schedule transmission service, by agreeing to pay the costs of losses and congestion between the desired source and sink points. Transmission rights are either source-and-sink-specific or flowgate-specific (discussed below). If a customer with transmission rights for a specific source-sink pair (from A to B) wants transmission service between a different set of source and sink points (from C to B), the customer would need to pay the cost of congestion and losses for transmission service between those new points (C to B).

Through the scheduling process, customers will be able to react to price signals by indicating how prices affect their demand for transmission service. In requesting transmission service, customers without transmission rights could either: (1) submit a bid stating the maximum congestion charge they are willing to pay for transmission service, or (2) indicate that they desire transmission service regardless of the price. Customers with transmission rights could voluntarily submit bids indicating the price above which they are willing to reduce their purchases of transmission service in exchange for receiving congestion revenues. For example, a customer with transmission rights from A to B may prefer receiving the congestion revenues if the congestion costs between those points is over \$150 per MWh. In that case, the customer would voluntarily reduce its demand (for example, through a demand-side response program) for transmission service between those points.

If there is sufficient transmission capacity to accommodate all requested transmission service, then all requests would be scheduled, and all scheduled customers would pay a charge to recover the

applicable cost of losses. However, if the amount of transmission service desired along one or more transmission paths exceeds the transmission capacity (thereby resulting in transmission congestion), then the charge for using each congested path would be raised sufficiently (based on the cost of redispatch and the price bids for transmission service) to alleviate the congestion by reducing the demand for transmission service. The added charge would be paid only by customers without transmission rights along the desired transmission path (or flowgate). As noted above, a transmission rights holder would receive congestion revenues when the path (or flowgate) is congested and the transmission rights holder elects not to schedule all or a portion of its rights.

Real-time transactions

Once all day-ahead transactions have been scheduled, any remaining transmission capacity will be made available for real-time transactions. Transactions that were not scheduled a day ahead would flow at a charge that covers the applicable cost of losses and any congestion associated with necessary redispatch. A customer with transmission rights between a specific source and sink that did not schedule transmission service between those points a day ahead could still obtain transmission service in real time. In that case the customer would pay the real-time congestion costs and losses. The customer would also receive the congestion revenues from the day-ahead market for those points.

Additional features of the standard transmission service

Transmission prices (to recover congestion and losses) developed in the transmission market must be consistent with locational energy prices developed in the energy market. A locational energy price equals the delivered cost of electricity to that point, which equals the sum of the energy price plus its congestion cost plus the value of transmission line losses from the source to the sink. The difference in energy prices between two locations should equal the transmission price that will be paid by customers without transmission rights to transmit power between these two points.

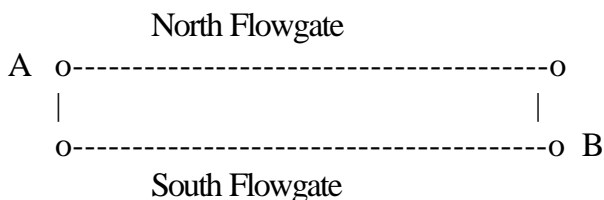
Transmission rights can be defined in two ways: (1) source-to-sink rights, and (2) flow-based, or flowgate, rights. Both source-to-sink and flowgate rights are direction-specific (*i.e.*, a right in one direction is different from a right in the opposite direction). A source-to-sink right is specified by a source (which can be a generator node, an aggregation of generator nodes, an interface, or a trading hub) and a sink (which can be a delivery node, an aggregation of delivery nodes, an interface, or a trading hub), and the total MW that are to be injected and withdrawn from the system at a point in time. It entitles the holder to schedule transmission of the specified MW of energy in the day-ahead market from the source to the sink without paying congestion charges. To the extent that the holder does not schedule its full MW entitlement, the holder is entitled to collect the congestion revenues from the source to the sink for the unscheduled capacity.

A flowgate right is specified by the total MW capacity over a particular transmission facility (or group of facilities, *e.g.*, an interface) rather than just the source and sink points. It entitles the holder to

receive the congestion revenue associated with the specified MW flow over the identified transmission facility in the specified direction.²

Transmission rights can be specified as obligations or options. An obligation requires the customer either to (a) physically transmit energy from its source to its sink points, or (b) receive the congestion revenues (either positive or negative) between the points. An option gives the customer the entitlement to transmit energy or collect the congestion revenues, but the customer has no obligation to do either.³ Currently, the transmission rights offered in ISOs that use LMP are obligations, although there is customer interest for transmission rights that are options. Existing firm point-to-point transmission contracts are similar to transmission rights that are options. At the start of Network Access Service, the transmission provider must offer source-to-sink obligations. Upon the request of market participants, the transmission provider must also offer source-to-sink options and flowgate rights as soon as it is technically feasible.

²Consider, for example, a very simplified transmission network that connects two points, A and B, with two different but interconnected transmission lines, a northern line and a southern line, as shown below:



Each transmission line would be a separate transmission facility or flowgate, and separate flowgate rights could be issued for each line. The holder of a flowgate right on the northern line from west to east would be entitled to the congestion revenues associated with that line in the west-to-east direction. However, holding a flowgate right on the northern line would not entitle the holder to congestion revenues associated with the southern line. Hence, if transmission service results in energy flows over several flowgates, the buyer must obtain sufficient rights on each flowgate to obtain a complete congestion hedge. By contrast, the holder of a source-to-sink right from west-to-east (*i.e.*, from A to B) would be entitled to congestion revenues in the west-to-east direction regardless of whether the northern or the southern lines were congested and thus would have a complete hedge for this transaction.

³The difference between obligations and options becomes important when congestion occurs in the opposite direction from the right, that is, when there is congestion from the sink to the source points. In this case, congestion revenues in the direction of the right are negative. "Collecting" negative revenues means the holder pays congestion revenues to the transmission provider. If the rights holder does not physically transmit from its source to its sink when congestion is negative, an obligation holder must pay congestion revenues, but an option holder would not be required to pay.

D. Energy Market Design

One of the problems under the current OATT is the treatment of imbalances. The current rules give a competitive advantage to control area operators because they allow the operator to net out its imbalances over a large load and operate a number of power plants, while charging other sellers and buyers penalties for imbalances. The remedy for these problems is a balancing market with imbalances charged the real-time price for any excess or deficiency of energy.

Unlike gas pipeline systems, electric systems must balance supply and demand in real time. In electric networks, this balance is generally achieved by adjusting generator settings (energy production) rather than controls on the electric transmission network itself (as is done for the gas transmission system). Additionally, electric systems are affected by the operation of other electric systems in the interconnection (i.e., loop flow and parallel flows as externalities affecting all transactions on the grid), while gas pipelines rely on controls on the gas transmission network to balance supply and demand and do not face significant interaction and interdependency effects.

These differences in the operations of the systems argue for different systems for handling imbalances. On a gas system with storage, a small daily imbalance may have little or no operational effect and not threaten service to other customers. But on an electric transmission system, a similar imbalance could threaten service reliability unless the imbalance can be cured in real time. Consequently, while there is no need for centralized regional coordination on a gas system, such a need exists for an electric system, and that coordination is best effected using a real-time market for energy. Such a real-time market will improve system efficiency and lower costs relative to the requirements of Order Nos. 888 and 889.

While a day-ahead market is not strictly necessary for resolving imbalances, experience has shown that the combination of a day-ahead market and real-time market enhances system reliability and efficiency compared to operating only a real-time market. The day-ahead market lets the system operator ensure that sufficient generating units and transmission elements are committed to serve the next day's load. The day-ahead market also provides the opportunity for a generator's bids to better reflect the operational constraints and costs of generating units through multi-part bidding. Additionally, the day-ahead market provides better scheduling opportunities for the demand side to participate in the market. Markets that have operated with both a real-time and day-ahead market are more efficient than those with only a real-time market.

Day-Ahead Energy Market

The transmission provider must operate a day-ahead market in order to develop a joint day-ahead schedule for transmission service, energy, and ancillary services. The day-ahead schedule will be developed so as to maximize the combined economic value of transmission service, energy, and ancillary services, based on the bids submitted.

The energy market component of the day-ahead market performs two functions – through bids evaluated at auction, the market selects those units to be run in the next day and sets the energy prices to be paid in each hour for that energy. Those unit commitments are coordinated with the transmission scheduling operation to assure that energy can be delivered from the generation point to the delivery point, in a secure and reliable fashion.

General Features

1. The transmission provider must run a voluntary, bid-based, security constrained day-ahead market. "Voluntary" means that market participants do not have to buy or sell in the day-ahead market, as explained further below. "Bid-based" means that participants in the energy market may provide prices over the range of quantities that they offer into the market or seek to buy from the market. "Security constrained" means that the market administrator, through the energy auction process, accounts for all transmission system constraints, such as contingency limits, needed for reliable system operations.
2. The day-ahead market should be transparent (*i.e.*, the rules of operation should be clear and understandable, and the software implementing the rules should produce predictable results) so that market participants can offer informed bids and trust market operations.
3. Since the day-ahead market is voluntary for market participants, market participants should be able to schedule bilateral transactions and/or self supply rather than bid into the day-ahead market. Long-term contracts and other means of avoiding price volatility and ensuring generation capacity adequacy should be fully accommodated.
4. Bidding parameters must allow customers the opportunity to reflect the value they place on purchasing in the energy market and allow suppliers the opportunity to reflect the costs and operational constraints of production in the energy market.
5. Demand can best respond by participating in the day-ahead market. Demand response options should be available so that end users can respond to price signals and reduce loads as they feel the price exceeds their individual willingness to pay for delivered electricity.

Scheduling and Bidding Rules

6. The demand side must be able to participate in the energy market. The demand side can participate as buyers or sellers (e.g., offering to sell operating reserves). As a buyer, an entity must be able to submit bids that indicate it is willing to vary the quantities it purchases based on the prices that it may be charged.
7. Sellers (including demand side) must have the option of submitting multi-part bids, e.g., submitting separate but related bids for start-up costs, no load costs and energy. Multi-part bidding allows generators to provide more detailed cost information that can improve the ability of the grid operator to dispatch generators with the lower total cost. Buyers must also be able to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy in the day-ahead market.
8. Individual market participants must not be required to submit balanced schedules (where demand and supply are equal), although they may submit balanced schedules if they choose to. The transmission provider will match separate unbalanced supply and demand bids to ensure that aggregate generation and load are matched and the aggregate schedule is balanced. However, as discussed in principle 11 in the Real-Time Energy Markets section below, special rules may be necessary to address deviations in real time from day-ahead schedules that threaten transmission reliability.
9. Bids need not be tied to a physical resource. However, for reliability purposes, bids must indicate whether or not they are tied to a physical resource.
10. Limits may be necessary on bidding flexibility to mitigate market power. For example, suppliers may be required to submit a start-up bid which would remain in place for a period of several months (rather than re-bid every day). As more demand response becomes available in a regional market, limits on supplier bidding flexibility can be relaxed.
11. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.
12. Intermittent resources should be able to participate in the day-ahead market on the same basis as other resources.

Price Determination and Settlement

13. Nodal pricing must be used for both buyers and sellers in the day-ahead market. Nodal pricing establishes separate prices at each node (in contrast to zonal pricing, which establishes the same price at all nodes within a zone regardless of congestion). Energy prices incorporate the total value of generation, transmission congestion, and losses at each node on the system.
14. An auction must be run to establish a single market-clearing price at each node. These prices at a minimum are hourly prices. (Smaller time intervals are acceptable.) Buyers and sellers transact at the clearing price. However, if a seller's total bid costs (including startup, no-load costs, minimum run time, and other physical characteristics as well as energy running costs) over the entire day are not fully covered by its revenues from selling at the hourly clearing prices, it will receive an uplift payment for the net revenue shortfall for the day. Hourly energy prices are based only on energy bids; start-up cost bids are not used in calculating hourly energy prices. Thus, a generator may have legitimate start-up costs that are not fully covered by selling at the hourly energy price over the day; paying uplift may be necessary to ensure that generators selected in the auction will receive revenues that fully cover their bid-costs.⁴
15. The results of the day-ahead market must be financially binding on buyers and sellers. In other words, sellers must be paid the day-ahead price for energy scheduled to be sold in the day-ahead market, and buyers must pay the day-ahead price for energy scheduled to be bought in the day-ahead market. In addition, to the extent sellers and buyers fail to produce or take energy according to their respective schedules, such imbalances must be settled at the real-time energy price. Thus, a seller must pay the real-time price for any scheduled energy that it promises but fails to produce in real time. Similarly, a buyer must be paid the real-time price for any scheduled energy that it promises but fails to take in real time.

⁴For example, suppose that the transmission provider needs to supply an additional 100 MW load in each of 20 hours over the next day. Two generators, A and B, are available. Generator A has energy costs of \$30/MWh, but must incur \$10,000 in start-up costs before beginning production. Generator B has energy costs of \$40/MWh, and has no start-up costs. Generator A's total cost of meeting the load would be \$70,000 (i.e., total energy costs of \$60,000 [$\$30/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$] PLUS start-up costs of \$10,000). Generator B's total cost would be \$80,000, comprised exclusively of energy costs (i.e., $\$40/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$). Generator A should be chosen because its total costs (\$70,000) would be less than Generator B's total costs (\$80,000). Suppose that the hourly clearing price in each hour is \$32/MWh. By selling 100 MWh in each of 20 hours, Generator A would receive total revenues of \$64,000 (i.e., $\$32/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$), which is \$6,000 less than its total bid-in costs of \$70,000. Generator A would thus need to receive a \$6,000 uplift payment in addition to its energy revenues. Paying \$6,000 in uplift is still cheaper for customers than the alternative of dispatching Generator B.

16. Upon request of the market participants, the transmission provider should establish trading hub(s), i.e., a hub price that is the weighted average of prices at selected nodes on the system.
17. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Real-Time Energy Markets

General Features

1. The transmission provider must run a bid-based, security constrained real-time market. These characteristics are explained above.
2. The real-time market should be transparent so that market participants can offer informed bids and trust market operations.
3. Market participants must be able to revise their schedules for bilateral transactions, including long-term contracts, and self-supply after the close of the day-ahead market. However, all imbalances will be settled through the real-time market, i.e., to the extent a buyer or seller is short, it must purchase power at the applicable real-time price for the shortfall; to the extent the buyer or seller is long, it will be paid the applicable real-time price for the excess amount.

Scheduling and Bidding Rules

4. Bids to sell in the real-time market must be one-part energy bids, i.e., bids for energy only. (Separate bids should not be submitted for start-up and no load costs since the energy suppliers should already be on-line and ready to respond to dispatch instructions. Real-time market bids may, however, include information regarding minimum run times).
5. The demand side must be able to participate in the real-time market.
6. Limits may be necessary on bidding flexibility to address market power issues.
7. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.

8. Intermittent resources should be able to participate in the real-time market on the same basis as other resources.

Price Determination and Settlement

9. Nodal pricing must be used for both buyers and sellers in the real-time market. Locational energy prices should reflect transmission congestion and losses.
10. Real-time prices will be established for each node through market clearing price auctions. These prices are generally for five-minute periods within the hour. Buyers and sellers transact at the clearing price.
11. All deviations and imbalances from the day-ahead market will be settled through the real-time market at the real-time price. In addition, real-time imbalances (*i.e.*, individual market participants' uninstructed deviations in real time from their day-ahead schedules or dispatch instructions) that threaten transmission system reliability may require special rules, including penalties.
12. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Regulation and Operating Reserves to Meet Reliability Requirements

Transmission providers must ensure that ancillary services, including regulation and operating reserves, are provided. Regulation provides moment-by-moment balancing of generation and load on the system. Operating reserves ensure reliable service by covering contingencies such as the failure of a supply source or a transmission line. Order No. 888 envisioned that these would be provided as a tariff service subject to a cost-based rate. With the establishment of markets to provide balancing services, a more market-oriented approach is needed for regulation and operating reserves. (Other ancillary services, such as reactive power, would continue to be procured much as they are today.) The same generators that could be supplying regulation or operating reserves also could be supplying energy for balancing services. Procuring regulation and operating reserves compatibly with the procurement of energy for balancing services will lead to a more efficient and rational price structure for both. As noted below, the technical requirements of regulation service are different from those of operating reserves, so it is likely that some differences in their respective market rules will be appropriate.

General Features

1. The LSE has the responsibility to procure regulation and operating reserves or pay for the regulation and operating reserves procured by the transmission provider on its behalf.

2. Suppliers of regulation and operating reserves must meet specific operational requirements to provide these services. For example, generators offering regulation typically must have equipment providing automatic generation control capability. Suppliers of these services also typically must meet response time requirements; regulation needs to fully respond to a dispatch instruction within 5 minutes, while various categories of operating reserves must respond within 10 minutes or longer. Demand must have the opportunity to supply operating reserves if it meets the necessary operational requirements (which should be designed to enable demand response participation).
3. The transmission provider must have a bid-based day-ahead and real-time market so it can procure regulation and operating reserves on behalf of LSEs. If there are a limited number of sellers for certain operating reserves, then market power mitigation measures may need to be included in the market design.
4. Reliability authorities may establish locational requirements for operating reserves. To the extent they choose to do so, this may require the reservation of transmission capacity. The cost of the "transmission reserves" must be included in the total cost of procuring the operating reserves for the LSE involved.

Scheduling and Bidding Rules

5. LSEs that have a regulation and operating reserve obligation may fulfill this obligation through self-supply, bilateral transactions, or by paying the market-clearing price in the auction run by the transmission provider. LSEs may meet their obligation through combinations of these transactions as long as the full obligation is met.
6. The transmission provider must procure regulation and operating reserves through a bid-based auction for all those who do not self-supply. The financial responsibility for regulation and operating reserves procured through the auction will be borne by those LSEs that did not self-supply.
7. Demand-side supply of operating reserves must have non-discriminatory bidding opportunities in the market.
8. Regulation and operating reserve markets must allow sellers to submit availability bids in addition to energy bids. The availability bid allows the bidder to specify the minimum payment that it requires to be available to provide regulation and operating reserves.

Price Determination and Settlement

9. The day-ahead regulation and operating reserve markets must clear simultaneously with the day-ahead markets for energy and transmission service in bidding and scheduling. The market-clearing prices must be based on winning bids that jointly optimize energy, regulation, operating reserves, and transmission service.
10. Market rules should be structured so that the price of energy is never less than the price of operating reserves and the price of higher-quality operating reserves is never less than the price of lower-quality operating reserves. For instance, the market-clearing price of spinning reserves must never be lower than the price of non-spinning reserves. The price of non-spinning reserves with a shorter availability (e.g., ten minutes) must never be lower than the price of non-spinning reserves with a longer availability (e.g., thirty or sixty minutes).
11. All market-clearing prices must recognize the substitution possibilities among operating reserves and conduct a least-cost procurement of the products. Higher-quality operating reserves bid at lower cost must displace lower-quality operating reserves at higher cost.

E. Other Changes to Improve the Efficiency of the Markets under Standard Market Design

The changes discussed above will require extensive revisions to the current pro forma tariff. The OATT also establishes other rules on the provision of transmission service. Some of these rules also need to be updated to achieve the objective of a competitive wholesale electric market. There are inefficiencies in the application of some of these rules on a company-by-company basis rather than on a regional basis. In others, the OATT does not allocate the costs of reserved capacity to only those customers that have reserved the capacity. The remedy is to update the OATT to correct these problems.

1. Capacity Benefit Margin (CBM), which is a set-aside of transmission capacity by the transmission provider to ensure access to external resources in case of a contingency, ties up valuable interface capacity without a specific reservation and payment by the customers who benefit from the service. Therefore, capacity currently set aside for CBM should not automatically receive a transmission rights allocation, but should be posted on the OASIS and specifically reserved and paid for by the entity requiring the service, whether it be for additional reliability or access to other resources.
2. Calculations of transmission capability and the performance of facilities studies for transmission expansions should be performed by an independent entity. This reduces the ability of an entity to use its transmission system to favor its own generation.

3. The new tariff should recognize the regional nature of today's energy markets. As such, transmission capabilities must be calculated not for one utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems. All transmission providers that are not part of a Commission-approved RTO must contract with an independent entity to perform transmission capability calculations on a regional basis. Likewise, a common OASIS should be required for the region.
4. Proactive long-term planning and expansion must be done regionally. The RTO, must offer a mechanism for participants to bring long-term planning and expansion needs and proposed solutions to the RTO. The RTO would choose an ultimate solution, whether transmission, generation or demand side, after vetting proposals through an open stakeholder process. The recommended solution(s) must then be put out under request(s) for proposals for construction and/or implementation. If a transmission provider is not part of an RTO, it must participate in regional long-term planning and expansion.
5. To minimize the implementation costs of standard market design, the software should be modular to allow multiple vendors to provide the components of the overall software platform. Standardized data formats and data transfer protocols may also be appropriate to minimize implementation costs.

F. Market Power Monitoring and Mitigation

Market rules, such as poor auction designs, can create or enhance market power by artificially limiting entry, preventing demand response, or providing artificial incentives to withhold. Many of the problems with generation markets identified by market monitors in the first few years of regional market operations have been caused by design flaws. The standard market design will include preventive mitigation measures in the form of bidding rules. The best way to avoid market power stemming from poorly designed markets is to establish efficient designs. Market rules should mitigate market power in the least intrusive manner.

Structural solutions to mitigate market power are generally more effective than behavioral mitigation. RTOs and independent transmission operators are structural mitigation for vertical market power because they remove the control of transmission access from transmission companies that also compete in generation markets. With respect to generation market power, market forces such as supply and demand responses are the most potent and lasting means of mitigating market power, so solutions that increase the potential number of suppliers or increase price-responsive demand must be promoted. If market power is not mitigated through structural solutions, market rules need to be designed to mitigate market power. For example, locational market power in generation load pockets with only one or a small number of generating units will require behavioral mitigation. These load pockets should be identified and the behavioral mitigation measures should be in place before implementation of standard market design.

Market monitoring should focus on two general areas. First, it should identify any problems in the design of the market that lead to inefficient outcomes and should propose prospective market rule changes. Market monitoring should serve as an early warning system for events that are not yet severe, so corrective action can be taken before exercises of market power become significant and sustained. Second, market monitoring should focus on the behavior of the market participants. Market power can be exercised by withholding capacity or output from the market (physical withholding) or raising the price or offer (economic withholding). Therefore, monitoring for withholding will be an important focus of market monitoring activities. Market monitoring units (MMU) within each region will be the first line of defense, but ultimately the Commission has the responsibility for monitoring wholesale energy markets and the authority to take corrective actions when needed. For transmission providers that are not part of an RTO, further thought is required to address market monitoring.

Set out below are some general principles to guide the development of market power mitigation rules and a market monitoring plan, as well as some specific measures that should be included in the standard market design. These are based on the Commission's experience with market power mitigation methods in recent years and are intended to reflect the best observed practices that are compatible with the elements of standard market design.

Principles

1. Market rules should be designed to improve the competitive structure of the markets and to build into the design of the markets customer protections against market power.
2. Market rules should minimize market power by facilitating new entry and increase demand response to improve the competitive structure of the market.
3. The regional transmission planning process should identify opportunities for increasing competition, particularly the elimination of local market power when possible, and should be aggressive about facilitating new demand response, transmission or generation construction as needed.
4. Where behavioral rules are needed to mitigate market power, the mitigation rules should be clear, and not subject to discretionary actions. Effective ex ante mitigation is preferable to retroactive price changes.
5. Market rules should not require offers to sell below marginal opportunity costs of a unit, including the verifiable geographic opportunity cost of selling to other regions and the temporal opportunity cost of selling energy-limited resources in other time periods.

6. Market monitoring should focus on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity) and assessing the efficiency of the market.

Mitigation Measures

7. A bid cap, as a proxy for demand bidding, must be in effect until sufficient demand response develops in the relevant wholesale power market. Mitigation rules that limit bidding flexibility will also be needed. As a region develops substantial price-responsive demand, mitigation rules can be reduced correspondingly.
8. The transmission provider may identify generating units that must run for reliability. Because these units have locational market power, the bids submitted by these units should be subject to mitigation. Similarly, market power in load pockets must be mitigated with on-going behavioral mitigation, such as call options or bid caps, unless structural solutions are possible.
9. Limitations on the flexibility to change bids, e.g., for start-up and no load costs, may be needed. For example, it may be appropriate to limit how often market participants are permitted to change their start-up and/or no load bids.
10. The transmission provider must be able to coordinate maintenance and outage schedules for generation and transmission facilities in order to assist in reliability planning and to monitor withholding. Information on maintenance and outage schedules should be made available to the market on a timely basis.

Monitoring

11. Each RTO should have an MMU that is independent of the RTO management. The MMU should be funded by the RTO, but it should report directly to the Commission and to the independent governing board of the RTO.
12. The Commission will exercise oversight of MMU activities and the impact of RTO operations on the efficiency and effectiveness of the market.
13. An MMU will monitor all markets (including the impact of generation, transmission, and load) in its region, principally for economic and physical withholding.
14. The MMUs will conduct periodic reviews and analyses of the general performance of the markets, and the impact of the market rules, on the efficiency and effectiveness of the markets in the RTO's region and will propose rule changes, when appropriate, to the Commission.

15. The MMUs should work with each other, the states and the Commission to develop market performance measures that are common to all regions.

G. Long-Term Generation Adequacy

Most of the above discussion deals with maintaining reliable day-to-day operations of the system in a market-oriented way. On a long-term basis, for the system to be reliable and the markets to function efficiently, there must be adequate generation resources and transmission resources. To do that, there may be a need to include specific measures to ensure that LSEs maintain a reasonable supply reserve margin. The issue of how to do this is a contentious one that needs further discussion among industry participants. However, there are certain basic principles that should be used in standard market design.

1. Standard market design may include measures to ensure adequate long-term generation supplies. Any such measures should be forward-looking and flexible enough to accommodate changing load obligations.
2. Preferably, state and regional reliability authorities will coordinate with one another to set a regional, long-term reserve margin to be maintained by LSEs subject to their jurisdiction.
3. When load must be curtailed due to insufficient generation, the transmission provider should avoid curtailing LSEs that have procured sufficient generation, if operationally possible.

H. State Participation in RTO Operations

State commissions have an important role in the process of creating an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for FERC and state commissions to discuss issues related to RTO development. However, there currently is no formal process for state commissioners to engage in a similar dialogue with the independent entity that would operate the electric grid under standard market design. The standard market design rule will establish a formal role for state regulators to participate on an ongoing basis in the decision making process of these organizations.

Each RTO or other independent entity that operates the grid should have an advisory committee whose members include state representatives reflecting the breadth of retail customers' interests. The specifics of how this advisory committee would be formed and operate could vary regionally and by RTO.

The standard market design rule will require the establishment of an MMU within the RTO. The MMU will provide reports to the independent governing board of the RTO and the Commission on

the efficiency of the markets and the need for rule changes. The MMU should also provide these reports directly to the advisory committee.

Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe the advisory committee can bring a valuable regional perspective to these issues and should play a role in deciding these issues in partnership with the Commission. Once the advisory committees are established, we will work with them to establish protocols for deciding these regional rate issues.

I. System Security

The Standard Market Design and RTO conferences to date have focused on various aspects of market design. System security is critical to the reliable operation of the interstate transmission grid. In this respect, the current OATT defines "good utility practice" as:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. . . .

Similar concerns about reliability led us to require that an RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. In a region lacking a Commission-approved RTO, individual transmission operators must perform the same function. The current OATT will be revised to state more explicitly the obligation of transmission providers to comply with all appropriate standards for ensuring system security and reliability.

Infrastructure security of grid equipment and operations and control hardware and software is essential to ensure day-to-day grid reliability and operational security. The Commission will expect all transmission providers, market participants, and generators interconnected to the grid to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

J. Transitional Considerations

We recognize that implementation of a new transmission tariff and standard market design on a nationwide basis may take some time. Standard market design requires many institutional changes and

software development. Therefore, the rule will require a phased compliance for standard market design changes in order to implement certain changes as soon as possible. The first phase will focus on a few major points that can be implemented within the existing Order No. 888 open access tariffs fairly quickly. Later phases will involve a full tariff redesign to incorporate all of the elements of standard market design. The first phase will include:

1. Physical trading hubs: Flexibility in choosing resources based on hourly marginal costs is an inherent advantage of network service over point-to-point service, particularly with respect to a merchant generator located in a different control area than the load while competing with the host traditional public utility. Transmission providers that do not offer centralized markets should file a proposal to offer physical trading hubs. Suppliers must be permitted to schedule to physical hubs within the transmission provider's system so that load can choose from a variety of resources, and supply can reach a variety of loads. The transmission charge should be commensurate with the cost of providing the service.
2. Clarifications and updates to the tariff: In the six years since the issuance of Order No. 888, the Commission has clarified numerous provisions in the pro forma tariff. These clarifications should be consistently applied to all existing transmission tariffs. Examples of these are “right of first refusal” time frames and the ability to redirect a long-term reservation. For redirects, competing generators or marketers would be confident that they could attain additional flexibility if the Commission were to revise the pro forma tariff to allow partial term redirects of a long-term point-to-point reservation (i.e., permit a long-term firm point-to-point transmission customer to request alternate firm points for a portion of the contract term and return to the original points later in the term).
3. First Phase tariff compliance time frame: Transmission providers must revise their existing transmission tariffs to include physical trading hubs and clarifications to the Order No. 888 pro forma tariff within 60 days of the date the Final Rule becomes effective.

K. Issues that Need Further Discussion

This paper identifies the general vision for a standard market design for wholesale electric markets and a new transmission tariff. It does not attempt to answer all the questions that will need to be answered to implement the standard market design and write a new transmission tariff. Based on the guidance contained in this document, Commission staff will be developing tariff language for further discussion by stakeholders.

There are many issues involved in the transition to the new services, including: (1) transition of customers under existing contracts to the new Network Access Service; (2) allocation of transmission rights; and (3) development of a schedule for phased compliance and implementation of standard market design. Many of these may need to be decided on a regional basis.

As noted in the discussion of the role of state commissions, there are many rate issues associated with these new services. There needs to be further work on transmission pricing issues, such as who pays for embedded transmission costs, whether postage stamp or license plate rates should be used for existing facilities, and cost allocation for new transmission facilities. All of these issues will require further discussion, with the goal of resolving them as soon as possible.

Finally, this paper envisions that RTOs will have significant responsibilities under standard market design. Consistent with the Commission's November 2001 order, the Commission will use a two track approach to resolve RTO issues. Issues of scope and governance will be handled in individual RTO cases, not in the Standard Market Design rulemaking.

APPENDIX

Electronic Scheduling Collaborative Issues

On October 5, 2001, the Electronic Scheduling Collaborative filed a Status Report on OASIS Phase II Business Practices. The report provided an update on the ESC's efforts to standardize a set of Business Practices for implementation of OASIS Phase II and Electronic Scheduling. As part of that report the Electronic Scheduling Collaborative identified certain issues as candidates for standardization or rulemakings and presented some key policy questions that needed to be answered. As part of the description of standard market design elements in this paper, we have provided preliminary answers to the questions on market design. The questions from the Electronic Scheduling Collaborative and the answers that are contained in this paper are summarized below.

1. Congestion Management -- When Operational Security Violations occur, how is the system to be stabilized in a fair and equitable manner that is nonetheless efficient? Will LMP based systems be standard, or will there be others that must be accommodated?

Answer: The transmission provider would use market mechanisms whenever possible to deal with potential Operational Security Violations. Thus, locational marginal pricing will be used as the standard method of congestion management. The transmission provider would also develop a security constrained, day-ahead unit commitment and a security constrained real-time dispatch that account for all transmission constraints, such as contingency limits, needed for reliable system operations. Only if these market mechanisms do not stabilize the system will non-market mechanisms be used.

2. Transmission Service -- Are transmission services required to schedule ("covered" schedules only) or are they risk management tools protecting from congestion charges (both "covered" and "uncovered" schedules are allowed)?

Answer: Anyone wanting to transmit power between two points will need to obtain transmission service. However, Network Access Service could be obtained either well in advance of real time or through the day-ahead or real-time markets. If a customer wants to achieve price certainty (protection from the cost of congestion), it would need to separately procure transmission rights.

3. Loop Flows -- Are contract-path based or flow-based transmission services appropriate? If contract-path based, how are parallel path issues to be addressed?

Answer: The Network Access Service would be a flow-based transmission service within the RTO. A flow-based system better recognizes the regional nature of the transmission grid.

4. Grandfathered Transmission Service -- Should contracts existing prior to RTO development be transferred, or is there an equitable way to retire those contracts? Are there other solutions?

Answer: This is a transition issue that needs further discussion and may require different regional approaches. Customers under existing contracts should continue to receive the same level and quality of service under standard market design. However, transmission capacity not used by these customers must be made available to others in the day-ahead and real-time markets.

5. Energy Imbalance Markets -- How are imbalance markets to function? Will they serve as real-time energy markets (support unbalanced schedules), be limited to supplying needs of imbalance service (require balanced schedules) or will they be required at all?

Answer: The day-ahead and real-time markets will support unbalanced schedules.

6. Ancillary Services -- Will ancillary services be developed in standard ways? Will entities be required to actually schedule ancillary services (required to schedule), or will they be treated primarily as financial instruments (protecting against real-time Provider of Last Resort (POLR) charges)?

Answer: Ancillary services will be developed in standard ways. Customers will be required to procure operating reserves and schedule ancillary services through self-supply, bilateral transactions, or by paying the market-clearing price in the operating reserves auction(s) run by the transmission provider.

7. Losses -- Can we utilize the imbalance markets to support losses? Can we create specific loss standards that facilitate the scheduling process, or must we support methods that are currently in tariffs, but technically unwieldy?

Answer: The imbalance markets can be used to support losses. New loss standards will be developed and included in the new pro forma tariff.

8. Non-Jurisdictional Entities (NJE) -- How are NJEs to be integrated into the new world? Should systems be designed with the assumption that non-jurisdictional entities will be part of an RTO? Or should they be designed to treat each NJE as a separate entity?

Answer: This question is not specifically addressed as part of standard market design. However, the Commission's policy is that RTOs should be structured to permit non-jurisdictional entities to voluntarily join RTOs. Issues related to the participation of non-jurisdictional entities in RTOs will be addressed in the individual RTO proceedings.