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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and Structure Docket No. RM01-12-000

NOTICE OF OPTIONS PAPER

(April 10, 2002)

Take notice that the Commission has distributed an options paper for resolving rate and transition issues for standardized transmission service and wholesale electric market design. The purpose of this paper is to stimulate public discussion that can guide the development of a proposed rulemaking on these issues. Parties filing comments are requested to make recommendations on the options that should be included in the proposed rulemaking as well as to address the pros and cons of the various options contained in the paper.

The options paper is being placed in the record of this rulemaking docket. It will also be available on the Commission's website at http://www.ferc.gov/Electric/RTO/mrkt-strct-comments/discussion_paper.htm.

Comments on this paper should be filed with the Commission by May 1, 2002. Comments may be filed in paper format or electronically. For paper filings, the original and 14 copies of the comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington D.C. 20426. For electronic filings via the Internet, see 18 CFR 385.2001(a)(1)(iii) (2001) and the instructions on the Commission's web site under the "e-Filing" link. All comments will be placed in the Commission’s public files and will be available for inspection in the Commission’s Public Reference Room at 888 First Street, N.E., Washington D.C. 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's Homepage using the RIMS link. User assistance for RIMS is available at 202-208-2222, or by e-mail to rimsmaster@ferc.gov.

Magalie R. Salas
Secretary

Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design

The Working Paper on Standardized Transmission Service and Wholesale Electric Market Design issued March 15, 2002, identifies several issues that require further discussion. These issues involve embedded cost recovery under the proposed Network Access Service and transition issues involved moving to one tariff for all service. Specifically, the issues are: 1) the manner in which embedded costs of the transmission system will be recovered; 2) the manner in which Transmission Rights will be allocated among customers; and 3) the transition of customers under existing contracts (real or implicit) to the new service. The Working Paper also identifies the issue of long-term generation adequacy as an area where further discussion is needed. This paper identifies options the Commission has for resolving these issues. Parties are requested to provide comments on the advantages and disadvantages of these options. Parties may also propose other options they believe the Commission should consider in resolving these issues. These comments will be used in developing proposals to be included in the Notice of Proposed Rulemaking (NOPR) to be issued this summer.

Current Services and Recovery of Transmission Revenue Requirements

Under the pro forma tariff, there are two types of services that are used to transmit wholesale power – Network Integration Transmission Service and Point-to-Point service. In addition, Point-to Point Service is available on a firm or a non-firm basis. Network Integration Transmission Service (Network Service) is designed for load serving entities and can only be used to serve network load. If the customer wants to serve non-network load, it must do so under a separate Point-to-Point contract. There are no restrictions on the type of entity that can buy Point-to-Point service. Transmission providers (i.e., traditional public utilities) are not required to take service under the pro forma tariff if the transmission service is to be used solely to serve bundled retail load.[1]

A Network Service customer pays a monthly demand charge based on its load ratio share of the transmission provider's monthly transmission revenue requirement. The customer's load ratio share is based on the customer's hourly load coincident with the transmission provider's monthly transmission system peak. The Point-to-Point firm

[1]However, the transmission provider, on behalf of its bundled retail customers, is required to designate resources and load in the same manner as a customer under Network Service.

customer pays a monthly demand charge for each unit of capacity that it has reserved. Non-firm Point-to-Point customers pay a charge for the capacity reserved for the service.

The two ISO's that currently use Locational Marginal Pricing (LMP), PJM Interconnection, L.L.C. (PJM) and New York Independent System Operator (NYISO), use the same three basic services, but with changes to reflect the different pricing system under LMP. PJM sells firm Point-to-Point transmission service.[2] The customer pays a demand charge for the reserved capacity and will also be charged for the cost of congestion between the requested source and sink if the customer does not have Financial Transmission Rights for the source and sink. PJM also sells non-firm Point-to-Point transmission service. In PJM, non-firm Point-to-Point service can flow if the customer pays the cost of congestion. If the customer is unwilling to pay the cost of congestion, the non-firm service will be interrupted when congestion occurs. The non-firm customer is charged the higher of the demand charge for the reserved capacity or the congestion charge. The revenues received from non-firm service each month are credited to the customers purchasing firm Point-to-Point or Network Service in proportion to the charges they pay. PJM sells Network Service which is consistent with the service contained in the pro forma tariff. However, rather than calculating the customer's load ratio share based on the transmission system's monthly peak load (as in the pro forma tariff) the load ratio share is calculated based on the transmission system's annual peak load.[3]

NYISO also offers Point-to-Point (firm and non-firm) and Network Service. However, in NYISO non-firm service is interrupted when congestion occurs. If a customer is willing to pay congestion costs to ensure the service will flow, the customer buys firm service. The system will be redispatched to support the firm transactions, both Point-to-Point and Network. A transmission service charge is charged all wholesale customers (Network, firm and non-firm Point-Point) to recover the embedded cost of transmission owners. The transmission service charge applies to deliveries to load within

[2]Point-to-Point customers are subject to the energy imbalance charges under Schedule 4 of the OATT. Imbalances for network customers are resolved through the real-time market.

[3]The transmission owner calculates an annual revenue requirement and an annual charge for Network Service per megawatt per year. This is then converted to a daily charge by dividing the annual charge by 365. This daily charge is then multiplied by the daily load of the Network customer coincident with the annual peak for the zone. This number is then multiplied by the number of days in the calendar month to obtain the monthly demand charge that is paid by the Network customer.

NYISO as well as wheel throughs and exports.[4] The transmission service charge is paid for each MWh scheduled during the month.

Both PJM and NYISO use a license plate rate design. With a "license plate rate" the rate paid for transmission services varies depending on where power is delivered within the RTO.[5] The license plate rate recovers the embedded costs of the transmission owner of the facilities where power is delivered.[6] PJM and NYISO have different rate designs for exports and wheel throughs. PJM uses a weighted average of the charges of all transmission providers for these types of transactions. NYISO uses the transmission charge of the owner of the intertie which serves as the point of delivery to the adjacent control area.

Changes Proposed in the Services

The Working Paper proposes to blend these three types of service into a new Network Access Service that could be purchased by load serving entities as well as non-load serving entities. The service could be used to move power between two points, a source and a sink. A Network Access customer would have access to all sources and sinks on the system. Under the Network Access Service there would be two types of transmission related rights. The first is the Access Right, i.e., the right to move power between any two points on the system. The second is the Transmission Right, i.e., the right to a predetermined price for service between two specific points on the system (the customer does not have to pay congestion charges for service between those two points). Either the Access Right or the Transmission Right could be used as the basis for recovery of the embedded costs of the transmission system.

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[4]A wheel through is a transaction that originates in one control area, is transmitted through a second control area (in this case NYISO), and then delivered to a third control area. An export is the transmission of power from one control area (in this case NYISO) to another.

[5]The alternative to a license plate rate is a postage stamp rate. Under this methodology, the revenue requirements of all the transmission owners in the RTO would be aggregated and used to design a single rate for service within the RTO.

[6]The revenue requirements of each transmission owner are kept separate. A rate is calculated that recovers the revenue requirement of each transmission owner from deliveries made on the transmission owner's facilities.

The Working Paper also proposes to use LMP to manage congestion on the system. Under an LMP system, the distinction between firm and non-firm service is less important than under the current pro forma tariff. Except in very rare cases, a non-firm service can be scheduled on any day if the customer is willing to pay the cost of congestion.[7] The price for transmission service for curtailable transactions may be high at times because of the cost of congestion. The customer may respond to those price signals by reducing its purchases of transmission service.

An access charge would be used to recover the embedded costs of the system.[8] The same methodologies used by either PJM or NYISO to recover the embedded costs of the transmission systems could be used. However, Network Access Service would differ from the existing pro forma services in that both current Point-to-Point and Network customers would receive the same service. This may necessitate a change in the methodology for recovery of embedded costs.

Additionally, under the current rate designs, a user that transmits power from one system to another pays two transmission charges to recover the embedded costs of the system from which power was exported as well as the embedded costs of the system where power is delivered to load. In designing the rates for Network Access Service, the rates could be designed to continue the payment of multiple transmission charges or they could be designed so that only one transmission charge is paid.

There are three main issues in designing the access charge: 1) who pays the access charge for deliveries within the transmission provider's system?; 2) should the access charge apply to exports and wheel throughs?; and 3) is the charge billed based on peak load or actual usage? The answers to these questions will affect the allocation of costs among the various users of the transmission provider's system. Each of these issues is a separate question and the preference for a particular option on one question should not determine the preference on another option. Finally, the rate treatment for exports and wheel throughs should be consistent among transmission providers to avoid the creation

[7]Under an LMP system, whether a customer has a transmission right or not has a far greater impact on what the customer ultimately pays than whether the service is characterized as firm or non-firm. A customer with a transmission right has price certainty, while a customer without a transmission right must pay the cost of congestion. It is possible that in times of peak demand (especially if there is a bid cap in effect), that the operator may not be able to redispatch the system to serve all non-firm requests.

[8]The options in this section assume that either a license plate or postage stamp rate design could be used for the access charge.

of artificial incentives or disincentives for trade across regions. However, allowing regional variations on the other two cost allocation issues may not have the same potential for affecting regional trade. Where there is an RTO in place, the Commission could permit flexibility on the cost allocation decisions for that region.

Who pays the access charge for deliveries within the transmission provider's system??

Option 1: Access charge applies to anyone that schedules deliveries within the transmission provider's system, whether it be an import, service between a receipt and delivery node in the system, or purchases of power by load from the energy markets. The general principle is that anyone that schedules these transactions is receiving transmission service (the Access Right) under Network Access Service. Since there is only one service, all users of the service should be subject to the access charge. Under this approach there could be multiple access charges paid if there are intermediate transactions to get power to load, e.g., a marketer aggregating generation at a trading hub and a load serving entity buying power from the marketer at the trading hub.

Option 2: *Access charge is paid only by customers that take power off the grid.* The general principle is that load pays the access charge - only the customer taking ultimate delivery of the power would pay an access charge.[9] Generators or marketers delivering power to or between hubs would not pay the access charge. However, they would pay any applicable congestion charges and losses.[10]

Option 3: Payment of *access charges and the receipt of Transmission Rights or the auction revenues from those rights would be linked together.* Payment of the access charge to recover embedded costs could be tied to whether the customer has protection against congestion charges or not. The access charge could be paid only by customers that can be offered Transmission Rights or an allocation of revenues from the

[9]Load would pay the access charge for power taken off the grid. Load may also have to pay congestion costs depending on the specific sources and sinks that are used. If a load serving entity has Transmission Rights for a specific source and sink combination and uses that specific source and sink combination, the load serving entity would not have to pay congestion costs. However, if the load serving entity were to use another source and sink combination, the load serving entity would pay congestion costs. The load serving entity would pay for losses in either case.

[10]The holder of the Transmission Right for the source and sink used in the transaction would receive the congestion charges for the transaction. Thus, it would help offset the embedded cost charges paid by the holder of the Transmission Right.

sale of Transmission Rights. Customers that do not receive these protections against congestion costs would only pay congestion charges and losses for transmission service. If the new customer wanted Transmission Rights it could either acquire them through an auction or pay for the construction of new facilities in which case the customer would receive the Transmission Rights for the added capacity. Thus, under this option some customers would pay the access charge and some would not.

Should the access charge apply to exports and wheel throughs?

Option 1: The access charge would apply to these transactions. These transactions use the facilities within the transmission provider's system and thus should pay for the use of these facilities. If the access charge is paid, it will be recovered in the delivered price of power to the load that ultimately uses the power. It is appropriate that these ultimate customers should contribute to the recovery of the embedded costs of the transmission systems that were used to transmit the power. This option continues the current pricing policy for exports and wheel throughs.

Option 2: The access charge would not apply to these transactions. A transaction originating in one transmission provider's system and terminating at a load in another transmission provider's system would only pay one access charge, the access charge for the transmission system where power is ultimately delivered to load. However, the transaction would still be responsible for applicable congestion charges and losses in the originating and any intermediate transmission systems. This option encourages broader areas of competition by eliminating multiple access charges (pancaking of rates).

Option 3: The access charge would not apply to individual transactions. But, there would be an annual revenue adjustment. As in option 2, a transaction originating in one transmission system and terminating at a load in another transmission system would only pay one access charge, the access charge for the transmission system where power is ultimately delivered to load. However, the aggregate transactions for the year would be taken into account in setting the revenue requirements to be recovered through the access charges for each transmission system. For example, if RTO A were a net exporter through the year to neighboring RTO B, a pro rata share of RTO A's revenue requirement would be allocated for recovery through the access charge of RTO B. Thus, the load in RTO B would contribute to the recovery of the embedded costs of RTO A.

Option 4: *A lower access charge would apply to exports and wheel throughs than for deliveries within the transmission provider's system.* This option is a compromise between Option 1 and Option 2 – all customers would pay something for the use of the grid, but the reduction (but not elimination) of multiple access charges for service across neighboring systems would encourage a broader area of competition.

Is the access charge billed based on peak load or total usage?

The Attachment to this paper provides an illustrative example of how different rate designs can significantly affect the cost impact on customers depending on their usage patterns throughout the year. Rate designs that allocate cost responsibility based on peak usage favor high load factor customers whose use of the system at peak periods is close to their use of the system at off-peak periods. Rate designs that allocate costs on the basis of monthly peak usage will allocate proportionately more costs to customers that use the system more extensively during off-peak periods. Rate designs that allocate cost responsibility based on annual usage, favor low load factor customers whose use of the system at peak periods is much higher than their annual use of the system.

Option 1: Use monthly peak load for billing the access charge. This continues the methodology that is contained in the current pro forma tariff. Embedded costs represent sunk costs that are unaffected by any usage or investment decision that customers make now or in the future. Therefore, the mechanism to recover these costs should be designed to have as little effect as possible on current decision making, i.e., day-to-day usage of the system. Continuation of the current methodology in the pro forma tariff is consistent with this rationale. Use of a monthly allocation factor recognizes that different customers will have different load patterns throughout the year. For example, some customers may use the transmission system more during off-peak periods. A monthly allocation factor will capture these differences in usage throughout the year.

Option 2: Use annual peak load for billing the access charge. The same basic rationale as in Option 1 for using a demand charge based on peak usage would also apply to this option. Using annual peak load as the allocation factor encourages customers to increase their load factor by reducing their use of the system at peak periods. High load factor customers (customers whose load at peak periods is similar to their load at off-peak periods) will pay less under this option than under Option 1. Conversely, low load factor customers (customers whose load at peak periods is much higher than their load at off-peak periods) will pay more under this option than under Option 1. Seasonal customers who do not take service on the system peak may pay nothing for transmission service under this option.

Option 3: Bill the access charge for each MWh used. This methodology would bill the costs to customers based on total use of the system and thus may be viewed as an equitable way to allocate the costs among the customers. However, because the access charge would be billed based on actual usage, it could affect decisions on the day-to-day usage of the transmission system. This rate design methodology produces the lowest cost responsibility for low load factor customers who make much greater use of the system during peak periods than at other times.

Transition of Customers under Existing Wholesale Contracts and Bundled Retail Customers Load to Transmission Service under the Revised Pro Forma Tariff

Some transmission problems currently exist because customers under existing wholesale contracts and customers taking bundled retail service have different terms and conditions of service than those customers taking pursuant to an open access transmission tariff. For example, differences in scheduling terms and conditions has resulted in transmission capability not being fully utilized because of more favorable scheduling terms for customers under existing wholesale contracts. With respect to customers taking bundled retail service, transmission providers have tended to favor those customers by preferentially reserving ATC for their future use and reserving transmission capacity for reliability purposes (capacity benefit margin) without directly assigning the costs to the customers benefitting by the reservation. This is a particular problem because customers taking bundled retail service comprise a majority of total load.

A further problem also arises if these non-pro forma tariff customers are not required to abide by the same terms and conditions of service. Because they generally comprise a large proportion of the total load, it would be extremely difficult to implement a congestion management system, such as LMP, for a transmission provider without placing this load under the tariff.

When standard market design is implemented, there will need to be a transition process in place so that most if not all of the transmission provider's customers will be taking service under the new standard market design tariff. Standard market design will apply both to service within an RTO as well as service on systems that are not part of an RTO. A transition process will be needed in both cases. However, where there will be an RTO in place when standard market design is implemented, the Commission could permit some regional flexibility in designing a transition process.

Option 1: All service occurs under an open access transmission tariff at the time standard market design is implemented. If this approach is taken, other transition steps would need to be taken to ensure that existing customers continue to receive the approximate level and quality of service that they previously received. One way to do this would be to give existing customers the ability to convert to Transmission Rights based on their historical use of the system.

Under this approach all transmission customers would be treated the same way under the same terms and conditions of service. This will make the implementation of standard market design, including congestion management, easier.

Option 2: Convert all customers taking bundled retail service upon implementation of standard market design and provide strong incentives for customers under existing contracts to convert. Under this option, the Commission would require all customers taking bundled retail service to take transmission service under the revised tariff. However, rather than require customers under existing wholesale contracts to take service under the revised tariff, the Commission would encourage those customers to convert to service under the revised tariff. For example, customers that convert to the new Network Access Service would receive the additional flexibility available under this new service. The Commission could also provide customers that chose to convert to the new Network Access Service with conversion rights to the allocation of Transmission Rights.[11] The Commission could impose restrictions on changes to current contracts to ensure that customers can only get the additional flexibility by converting to Network Access Service.

This option avoids the problem of having to deal with contract abrogation. It also would allow the Order No. 888 approach to these customers to further play out. Under that approach, if a customer modified, changed or revised an existing contract, it was obligated to then take service under an open access transmission tariff.

As provided in Option 1, if this approach is taken with respect to customers taking bundled retail service, transition steps should be taken to ensure that these customers receive approximately the same level and quality of service that they previously received.

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[11]This option is similar to how the Commission implemented restructuring in Order No. 636. Bundled sales contracts were automatically converted to firm open access transportation service. Customers with non-open access firm transportation contracts could either convert to open access service or not. However, if a customer chose not to convert its contract it paid a rate that was often higher than the rate an open access customer would pay for service and the non-open access customer did not have the additional flexibility of open access transportation service, e.g., the ability to temporarily change receipt and delivery point rights through the scheduling process and the ability to resell unneeded capacity in a secondary market.

Option 3: Allow regional variations. Under this option, the Commission could permit the issue of how to convert customers under existing wholesale contracts and taking bundled retail service to be decided on a regional basis if there will be an RTO in place when standard market design is implemented. This option would not be available on transmission systems that would not be in an RTO. The Commission could allow each RTO to make a proposal for converting these customers to service under the revised tariff. If this approach is taken, the NOPR would only give general guidelines on what would or would not be acceptable. The specific mechanisms would be developed by each RTO. Of course, the Commission would need to analyze the proposals to ensure that the regional variations do not create seams problems or interfere with the implementation of standard market design.

Allocation of Transmission Rights

There are several different transition issues that arise when moving to an LMP system. Under an LMP system of congestion management, Transmission Rights that provide protection against the cost of congestion are potentially very valuable. The initial allocation of these rights among customers is mainly a question of equity and not efficiency. As long as these Transmission Rights are defined so that they are tradable property rights, an efficient market solution should result. However, the method that is used to make the initial allocation can convey benefits on particular customers or classes of customers.

Should historical customers get the initial Transmission Rights ?

Option 1: Convert existing customers' usage to the initial Transmission Rights. In the Working Paper issued on March 15, 2002, one of the general principles states that customers with existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design. If a transmission system has constraint points, as most if not all do, then to satisfy this general principle existing customers, many of which are load serving entities, should receive a conversion right for the initial Transmission Rights. On a constrained system, more participants will want Transmission Rights than can be issued. Participants that do not currently have contract rights will want to acquire Transmission Rights for the constrained points. If the use of the system by existing customers is not recognized in the transition mechanism, either through an allocation of Transmission Rights or an allocation of the auction revenues for these rights, there may be significant cost shifts because of congestion costs. The objective of this option is to preserve the service quality for the load served by the existing customer. To recognize retail choice and to not discourage the entry of new suppliers, if load moves from one load serving entity to another, the Transmission Rights would move with the load. This way the new supplier would have access to Transmission Rights to serve the load.

Option 2: Give all customers that pay access charges the same rights to Transmission Rights. Under Network Access Service the number of customers could increase significantly. If all of the Transmission Rights are assigned to the existing customers, there would be none left to assign to any new customers. Earlier in this paper, the options for assessing the access charge were discussed. A decision on the billing of the access charge could affect the approach that is taken on the initial allocation of Transmission Rights. The Commission could either allocate the Transmission Rights or the auction revenues for the Transmission Rights to all customers that pay the access charge. Procedures would also be needed for reallocating the Transmission Right or auction revenues as new customers are added. Such an approach would benefit new entrants because it would make it easier for them to acquire Transmission Rights. However, it would likely significantly increase the costs of transmission service (including congestion costs) to end-use customers.

<u>If existing customers are given the initial conversion rights, how should Transmission Rights be allocated?</u>

Option 1: Assign rights based on existing contract rights and historical usage. The Commission could assign the Transmission Rights based on existing sources and sinks in Point-to-Point contracts and the designated resources for Network Integration Service and bundled retail load. In essence, those customers that currently are using those points for firm service would get the right to continue to use those points without paying for congestion. In some cases, the requests for existing customers for Transmission Rights between specific points may exceed the Transmission Rights that can reliably be granted. In that case, actual usage of those points in a recent historical period could be used to allocate the rights among existing customers. Usage of the system particularly by network customers changes over time. For example, peak load may increase more rapidly in one service territory than another. Or, the load of the traditional utility may decrease because of state retail choice programs. Consequently, the allocation of Transmission Rights may need to be regularly adjusted to ensure that there continues to be an equitable allocation of Transmission Rights.

This approach comes closest to replicating the rights customers currently have under existing contracts or for bundled retail load. However, under this methodology it may be difficult for new entrants to acquire Transmission Rights.

Option 2: Auction Transmission Rights and assign the auction revenues based on existing contract rights (real and implicit). Under this approach all Transmission Rights would be auctioned. This way the entity that values these rights the most would obtain them. New entrants and existing customers could obtain Transmission Rights through the auction. The revenues from the auction would be allocated to existing contracts, primarily load. This would serve to reduce the total transmission costs including congestion costs paid by these customers. Under an auction methodology load could ensure that it gets the Transmission Rights by bidding high in the auction.[12]

Theoretically, Options 1 and 2 should produce the same end result if there is a secondary market for trading Transmission Rights. However, some existing customers have expressed doubts that it would. They are not certain that the auction revenues would cover the congestion costs they may face. Additionally, there has been a more active secondary market for Transmission Rights where there is an auction for Transmission Rights (NYISO) rather than an allocation of Transmission Rights (PJM).

The auction methodology may be preferred by load in states that have had significant divestiture of generation. In those states, this methodology may give load a better ability to hedge congestion costs when buying from a variety of suppliers. This type of methodology is used in NYISO and is proposed for use in ISO-NE, both areas where there has been substantial divestiture of generation.

Option 3: Partial allocation and auction. As a transition mechanism, the Commission could permit a combination of the two methodologies. For example, 75% of the rights could be allocated and 25% could be auctioned with the revenues allocated to existing customers. Over time, an increasing amount of the Transmission Rights could be auctioned. This method provides some opportunity for new entrants to acquire Transmission Rights through the auction. It also gives existing customers allocated Transmission Rights for most of their load to provide a transition to a more competitive wholesale market.

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[12] If auction revenues are allocated so that the historical user of a transmission path receives the auction revenues associated with rights on that path, that user would always be financially capable of outbidding others in the auction. Whatever price the user pays in the auction for the rights would be fully offset by its allocation of auction revenues. However, depending on the timing of the auction payments and the crediting of the auction revenues back to the customer, there may be some cash flow issues.

Option 4: Allow regional variation. Where an RTO will be in place when standard market design is implemented, the Commission could permit existing customers on each RTO to choose the methodology that will be used for the initial allocation of Transmission Rights. This option would not be available on transmission systems that are not part of an RTO. As long as the Transmission Rights are tradable property rights with the same characteristics, using different allocation methodologies for the initial allocation will not create seams problems. Because states have adopted different polices on generation divestiture and retail choice, different allocation methodologies may better suit the needs of the customers. For example, if there has been little divestiture of generation on a system, an allocation of Transmission Rights may permit customers to more closely replicate the service they currently receive. On the other hand, if most of the generation on a system has been divested, an allocation of auction revenues may give customers more flexibility in buying from multiple sellers. The Commission could find that either method is acceptable and let the existing customers choose which method better addresses their needs.

Long-Term Generation Adequacy

The Working Paper identified the issue of ensuring adequate generation resources as a contentious issue that needs further discussion. At the conferences held in January and February, there was wide support for some type of program either administered at a state, regional, or federal level. However, there were significant disagreements over what the mechanisms should be to ensure long-term generation adequacy as well as who should administer the program.

There are several different approaches that could be used to design the forward-looking supply obligation. Standard market design would apply to transmission systems that are part of an RTO as well as to transmission systems that have not joined an RTO. Parties are requested to comment on whether the same approaches should be used in both instances or whether different approaches should be used.

Option 1: Rely on energy prices and information on projected supply/demand situation. This option would make load serving entities responsible for acquiring sufficient supplies to meet their needs. This option assumes that energy prices will reflect the supply/demand situation in the region and send the appropriate price signals to investors.

Since energy markets are regional in nature, an individual load serving entity may not have sufficient information to assess the regional supply/demand situation. Therefore, the transmission provider would conduct and publish studies projecting the short and long-term supply/demand situation for the region as a whole. These studies would also identify the supply/demand situation for the load pockets within its area. These studies should provide the market with information that can be used to project whether energy prices in the area are likely to rise or remain stable. It also would provide information on where new generation and/or demand response programs are needed in the near future.

This information should provide load serving entities with the information they need to make rationale choices to minimize their total supply costs. Load serving entities would determine the mix of supply sources, long-term and spot purchases, that best meet their needs.[13] If the studies indicate that there will be a large surplus of power in the region for the next several years, the load serving entity may decide that it will rely more heavily on short-term contracts. On the other hand, if the studies show that supply conditions may be tightening in the near future, the load serving entity may decide to hedge its future energy costs through long-term contracts or other financial measures. The transmission provider should also develop load shedding procedures that ensure, to the extent operationally feasible, that in times of shortage, load shedding would be targeted to the load serving entities that did not have adequate supplies.

Option 2: Require a regional supply obligation. Each region would have a single region wide supply obligation for all load serving entities in the region, comparable to the traditional utility-specific reserve margin.[14] The obligation would be imposed on all load serving entities within the region, e.g., a traditional utility or an energy marketer serving retail loads. The level of the supply obligation would be set within each region with the active involvement of the state commissions in the region.

The transmission provider would determine if each load serving entity in the region has enough supply to satisfy its share of the regional supply requirement. The supply obligation could be satisfied by generation owned or under contract, firm contracts for energy that are backed by specific generation units or a portfolio of designated generation units, and demand side resources that can be verifiably curtailed.[15]

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[13]State commissions would retain the ability to review the decisions of load serving entities subject to their jurisdiction or to impose requirements on the purchasing decisions of these load serving entities.

[14]In the case of an RTO, the region would be the territory covered by the RTO.

[15]The firm contract could be either a forward contract for the purchase of energy or an option to purchase energy as long as the firm contract is backed by specified

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The firm contract would be for a forward looking period selected based on the time needed to construct new generation, e.g., one to five years. The load serving entity would also need to demonstrate that these generating units and demand side resources are physically feasible, i.e., the units are capable of generating the power planned or reducing the demand planned, and transmission is available from the generating unit or demand resource to the individual load serving entity.[16]

There are two different types of enforcement mechanisms that could be used. First, if the load serving entity did not meet the regional supply requirement, it could be required to file a curtailment plan with the transmission provider. This way there would be an up front understanding that a load serving entity that fails to satisfy the regional supply obligation would be among the first curtailed in a shortage and the method of curtailment is understood by all from the outset. Alternatively, a load serving entity could be required to satisfy the regional supply obligation as a condition of receiving an allocation of Transmission Rights or an allocation of the auction revenues from the sale of those rights.

Option 3: Require a regional capacity obligation. Under this option there would be an obligation for load serving entities to obtain capacity resources for both energy and reserves similar to the capacity obligations that are currently in effect in the three Northeastern ISOs. As with the prior option, each region would set a region wide capacity obligation with the active participation of state commissions. The transmission provider would also determine the capacity obligation for each load serving entity. As in Option 1, the capacity obligation could only be satisfied by the load serving entity demonstrating that it owned or had contracts with generators or marketers for specific generating units and demand response sources.

The major differences between this option and Option 2 are in the timing of the supply obligation and the enforcement mechanisms. Under this option there would be an ongoing capacity obligation. To satisfy the capacity obligation the load serving entity would need show that it had met the capacity obligation for the month or season before the beginning of that month or season. Under Option 2 the supply obligation would be for a longer period (e.g., one to five years) and the load serving entity would have to demonstrate that it satisfied this obligation at least several months in advance.

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[15](...continued)
generating units.

[16]The region could also impose locational requirements on the generating units that a load serving entity could use to satisfy its supply obligation.

The enforcement mechanism under this option is that a load serving entity would be subject to an administrative penalty based on the capital cost of a new generating unit for the amounts it was deficient. The transmission provider would also administer markets for load serving entities that are short to acquire capacity credits from generators that have excess capacity to sell. The administrative penalty would serve as a *de facto* upper limit on the price of capacity credits sold in these markets.

Option 4: Impose a supply obligation on load serving entities only if projected reserves fall below a trigger level. Under this option on an annual basis each region would make a region wide projection of future demand for energy with an appropriate reserve margin e.g., 15%-18% and future supplies available. State commissions would play an active role in this process. If this region wide projection shows that the region will have adequate supplies for future needs, e.g., projected needs one to three years in advance, then there would be no supply obligation on load serving entities. If this region wide projection shows that there are not adequate supplies for the future, then each load serving entity would have a supply obligation. When the region was short the supply obligation could be similar to the supply obligations described in Options 2 and 3. The same conditions on generating units or demand side resources that could be used to satisfy the supply obligation could also apply. Conceptually, either an administrative enforcement mechanism like those described in Option 2 or a penalty and capacity market enforcement mechanism like that described in Option 3 could be used. However, if the supply obligation would only be triggered in certain years, an administrative enforcement mechanism would likely be the more cost effective option.

Option 5: Capacity obligations for operating reserves only – forward reserves contracts. Under this option the transmission provider would acquire an option on generation that could be used to provide reserve capacity at some time in the future or would assign to load serving entities the requirement to procure such reserve capacity.[17] The transmission provider or the load serving entity would buy a call option on energy to be produced in the future. Sellers would offer various options available at different strike prices. Accepted sellers would be required to submit bids on a daily basis to supply

[17]The transmission provider would acquire an option on generation only to satisfy the anticipated future need for operating reserve capacity for the region. It would not acquire an option for the future energy needs of the region. Load serving entities would be responsible for procuring their own energy needs. However, there would be no forward-looking capacity or supply obligation imposed on load serving entities for these energy supplies. Thus, the capacity obligation under this option is much lower than under Option 3.

energy at the designated strike prices. The buyer could select from these various options to specify the strike prices at which energy would be sold if called upon. Alternatively, the option could be structured so that if exercised, the energy could be sold at the market clearing price. If the RTO transmission provider would procure the options for reserve capacity for the region as a whole, individual load serving entities would receive a bill for their share of the cost of reserve capacity. Consequently, there would be no need for an enforcement mechanism such as a deficiency charge, since load serving entities would not be required to procure their own options on future reserve capacity. However, by procuring generation capacity, the transmission provider would be taking a position in the market. Alternatively, if load serving entities are assigned the requirement to procure the options, transmission providers would not take a position in the market. However, if load serving entities are assigned the requirement, a mechanism would be required to enforce the requirement.

Attachment

Simplified Example:
Sample Customers and Rate Designs for the Access Charge

Customers:

(1) Load serving entity serving high load factor industrials (e.g. a manufacturer running around the clock): 100 MW per hour all hours

(2) Load serving entity serving seasonal users (e.g. a ski resort): 0-100 MW per hour, seasonal use

(3) Load serving entity serving residential customers (lighting, air conditioning): 50-300 MW per hour, varies by season

Customer Usage at System Peak Hour, by month (MW)

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
(1)	100	100	100	100	100	100	100	100	100	100	100	100
(2)	100	100	100	100	100	50	0	0	0	0	0	50
(3)	50	50	50	50	50	50	100	100	150	300	150	100
Totals	250	250	250	250	250	200	200	200	250	400	250	250

Effects on Load Ratio Share of the Three Rate Options

	12-month Avg Peak			Annual Peak		Usage Method**	
	Total Peaks	Avg.	LRS*	Peak (Aug)	LRS	Total Usage	LRS
(1)	1200	100	40%	100	25%	1200	57%
(2)	600	50	20%	0	-0-	300	14%
(3)	1200	100	40%	300	75%	600	29%
Totals	3000	250		400		2100	

* Load Ratio Share

** Assumes that the monthly usage rate is ½ of peak hour usage. For simplicity and since the object is to determine the load ratio share, the calculations above do not take the steps of multiplying out the hourly usage rate times the number of hours in the month.